Report to the Federal Energy Regulatory Commission: Studies Conducted Pursuant to the October 30, 1997 Order

Executive Summary

In its October 30, 1997 Order authorizing limited operation of the California ISO and the California PX, Pacific Gas and Electric. Co., et al., 81 FERC ¶ 61,122, the Federal Energy Regulatory Commission (FERC) addressed many issues and directed the ISO to perform the following three studies:

1) A study that evaluates the effectiveness of the current criteria for considering whether to create or modify Congestion Management Zones;

2) A study that evaluates the effect of the current ISO methodology for calculating and assigning scaled marginal losses to individual SCs versus a methodology that assigns to each SC the full marginal losses associated with its actual scheduled transactions; and

3) A study that evaluates the one-part vs. two-part Ancillary Services bid evaluation methodologies.

For each of the three ordered studies, this document outlines the concerns of FERC, as stated in the October 30, 1997 Order, provides pertinent background information, describes the technical approaches that were used in the studies, presents the results of analyses and simulations that were conducted, and provides conclusions drawn from these studies.

Below are the executive summaries of these three studies.

Study of Congestion Zone Criteria

The currently adopted criteria for converting a transmission path within an existing Zone to an active Inter-Zonal Interface are as follows:

a) Intra-Zonal Congestion Management costs over a 12-month period should amount to at least 5% of the product of the interface rating and the corresponding weighted access fee. This is commonly referred to as "the 5% criterion." The product of the interface rating and the corresponding weighted average access fee is a measure of the transmission revenue for the interface. The interface rating is the WSCC non-simultaneous total power transfer capability for the interface. The weighted access fee is the weighted average of the Participating Transmission Owner (PTO) access fees where the weights are the respective ownership percentages on the interface.

b) In order for a new Zone to be an Active Zone, there should be workable competition on both sides of the interface. This criterion is necessary to ensure that Adjustment Bids submitted on either side of the interface can be used effectively to manage congestion on the relevant Inter-Zonal Interface.

The transmission interfaces for transmission into the San Francisco and Humboldt areas, although meeting the first criterion, do not currently satisfy the second criterion. Consequently, these Inter-Zonal Interfaces are currently declared inactive, and the corresponding congestion Zones of San Francisco (SF) and Humboldt (HUMB) are also inactive. The ISO does not perform Inter-Zonal Congestion Management on inactive interfaces.

In its October 30, 1997 Order, FERC directed the ISO to undertake a study for:

- The evaluation of the effectiveness of the 5% criterion;
- The calculation of congestion costs associated with currently inactive Inter-Zonal Interfaces; and
- The evaluation of the effectiveness of adopted mechanisms for mitigating market power in the currently inactive congestion Zones.

The study of the 5% criterion requires the use of historical Intra-zonal Congestion Management costs. During 1998 and 1999, Intra-zonal Congestion was mitigated solely in the Real-time market and not in the Day-ahead and Hour-ahead forward markets due to software staging. Except for the Path 26 interface in the SP15 Zone, most of the Intra-zonal Congestion during this period was managed by using Reliability Must Run (RMR) units. While, this report provides data on historical RMR costs, it is important to point out that not all RMR costs can be attributable to Intra-zonal Congestion. RMR units are utilized in Real-time operation of the ISO Controlled Grid to maintain reliability, and to resolve Intra-zonal and Inter-zonal Congestion between Active and Inactive Zones and within the Active and Inactive Zones. To quantify the impact of MW and costs related to RMR units on Inter-Zonal and Intra-Zonal Congestion Management, these MW and costs should be split into various categories. The ISO does not have sufficient data for 1998 to perform such a break-up of RMR costs but believes that this can be done for 1999. In this report, the ISO proposes the general methodology for the break-up of the RMR costs based on available dispatch instruction and commits to prepare a subsequent report based on this analysis. The ISO requests guidance from FERC on the proposed methodology and the data to be studied in the subsequent report.

In studying the effectiveness of the 5% criterion, it is helpful to remember that the ISO's design contemplates that Congestion Zones are areas within which congestion (Intra-Zonal) is relatively infrequent and the congestion costs are relatively low. Conversely, Inter-Zonal Interfaces consist of transmission facilities over which the congestion costs are expected to be relatively high. The 5% criterion represents the level at which congestion costs are sufficiently great to warrant conversion of an Intra-Zonal path to an Inter-Zonal Interface.

In order to assess the 5% criterion, the ISO compared the congestion charges for a transmission path that was elevated to an Inter-Zonal Interface with congestion charges for the other Inter-Zonal Interfaces. In making this comparison, the ISO used a ratio of the congestion charges to the maximum transmission revenues for the Inter-Zonal Interfaces.

Specifically, the ISO took the following steps. First, the ISO summed the Inter-Zonal congestion revenues collected in the first 12 months of operations. Second, he ISO developed an estimate of the transmission revenues for the Inter-Zonal interfaces where there was congestion. Third, the ISO divided the Inter-Zonal congestion revenues by the transmission revenues associated with the Inter-Zonal interfaces to arrive at a congestion percentage. Since Inter-Zonal congestion by definition is significant, the congestion percentage is an appropriate reference point to use to evaluate the use of the 5% criterion. The ISO then compared this congestion percentage with the congestion percentage for a transmission path that was elevated to an Inter-Zonal Interface using the 5% criterion.

In its study of the effectiveness of the 5% criterion, the ISO has determined that the congestion percentage from the existing congested interfaces was 14.61% for the first 12 months of operations, and 28% for the nine month period from January 1, 1999 through September 30, 1999. It is expected that the ratio will increase beyond the 28% level in the future due to more utilization of the transmission system and load increases. A case study of Path 26 (which is to be converted to an active Inter-Zonal Interface in accordance with a recent action by the ISO Governing Board) indicates that the estimated congestion percentage for Path 26 is approximately 30%. This percentage is above the congestion percentage for the existing Inter-Zonal Interfaces and suggests that use of the 5% criterion leads to results that are consistent with the congestion experienced on the existing Inter-Zonal Interfaces. Based on these results, the ISO believes use of the currently effective 5% threshold is not unreasonable. In addition, the ISO believes annual evaluation of the criterion for creating and modifying Zones is justified since congestion costs and transmission utilization are likely to vary. Moreover, frequent monitoring of the accumulation of congestion costs will be useful in identifying potential improvements in the ISO's management of congestion, including the creation of new zones, if justified, as early as possible.

Transmission Loss Study

The current methodology for transmission loss allocation is based on *scaled Marginal Loss Rates*. The ISO calculates losses at each supplier node using the Marginal Loss Rate (MLR) method. This method measures losses by injecting one megawatt at that node. The one-megawatt injection is allocated pro rata to all loads in the system, while taking into account incremental transmission losses. The MLR may be negative at a node, indicating that power injection at that node reduces transmission losses. The application of the MLR to the metered energy supply would result in transmission loss responsibilities that would add up to a value higher than the actual loss in the system.

This is because transmission losses increase non-linearly with increase in demand. The ISO currently scales down the MLRs across the entire ISO to avoid over-collection for transmission losses. Only suppliers, i.e., generators and imports, are allocated transmission loss responsibilities.

In its October 30, 1997 Order, FERC directed the ISO to undertake a study including:

- a comparison of the effects of the currently used transmission loss allocation with a methodology based on *full* (unscaled) Marginal Loss Rates that take into account the actual scheduled transactions of each Scheduling Coordinator (SC), rather than using a pro rata allocation to all load (i.e. distributed system load slack); and

- a comparison of transmission loss responsibilities and their monetary values at applicable energy prices for various conditions under the two methods.

The ISO has conducted the transmission loss study as directed in the October 30, 1997 Order and has determined that the application of full Marginal Loss Rates would be inappropriate for the structure of the California energy market. In California, transmission loss responsibility has been excluded from Congestion Management. Therefore, congestion prices reflect only the cost of network constraints and not the cost of transmission losses. The latter is an externality that is left as a responsibility to suppliers, which could either self-provide that obligation, or purchase it from others or from the real-time imbalance energy market. Using full MLRs would result in an over-collection of transmission losses, which would have the adverse effects of artificially thinning the Ancillary Services capacity markets (due to increased generation allocation to losses resulting in less capacity available for A/S) and depressing the ex post price due to overgeneration.

The conclusion of the study is that the ISO's current transmission loss allocation methodology, using nodal Generation Meter Multipliers (GMMs) based on scaled MLRs, is appropriate for the California energy market since it maintains the relative significance of the economic signals (the scaling factor is the same for all MLRs) without the undesirable effects associated with over-collection for transmission losses. A refinement on this methodology is possible, for more equitable allocation of transmission losses, as FERC suggested, taking into account the location of the particular scheduled transactions of each SC in calculating MLRs. To quantify the impact of the proposed refinement, the ISO modified the current methodology of allocating losses in its simulation studies, by computing SC-specific GMMs based on individual SC schedules. For a representative set of hours, no major changes in transmission loss responsibility were observed for most SCs. However, we observed that, for a few SCs, there was a shift in transmission loss responsibility.

The objective of equitable allocation of transmission losses must be balanced with potential impacts on market efficiency. The ISO believes that system-wide GMMs, as currently computed, allocate transmission losses equitably and provide efficient locational signals for generation siting and should therefore be preserved. The results of the ISO's study provide no justification for changing the current ISO methodology.

Single Versus Two-Part Ancillary Service Bid Evaluation

The ISO currently selects units to provide Ancillary Service capacity using a *single-part bid* evaluation approach, which awards capacity directly based on capacity bid prices. Under the *two-part* bid evaluation approach proposed as part of the ISO's initial tariff filing, A/S capacity bids were to be evaluated based on the Total Bid price, i.e., the sum of two components: the capacity bid price, plus an energy price component, derived by multiplying each unit's energy bid price by a factor representing the estimated percentage of A/S capacity that would be dispatched to provide real time energy. Under this approach, it was proposed that each bidder selected to provide A/S capacity be paid a capacity payment equal to the highest Total Bid accepted by the ISO *minus* the energy component used in evaluating each unit's Total Bid. The proposed two-part bid approach also called for units providing A/S capacity to be paid their energy bid price (rather than the real time imbalance price) when dispatched by the ISO to provide real time imbalance energy.

The ISO's current single-part bid evaluation approach was adopted in the ISO's August 1997 tariff filing based on an analysis showing that this approach would result in lower overall costs than the two-part approach.[1] In its October 30, 1997 Order, FERC approved the use of the single-part approach, but requested a study "that explores the issue of bid evaluation further," after allowing "the ISO and market participants to gain experience and data under the proposed method." This report provides a comparison of these two bid evaluation approaches. Key findings of this report are summarized below:

- Recent market performance supports the conclusion that the single-part approach is more efficient and results in lower overall costs due to the significant supply of supplemental energy in the real time energy market during most hours. Since suppliers of A/S capacity must compete against this supply of supplemental energy in the real time market, units selected to provide A/S capacity have an incentive to submit competitive energy bids under the single-part approach. Since the ISO began operations, supplemental energy bids have accounted for over 70% of the energy dispatched for real time incremental energy, reflecting the fact that, for most hours, there is a deep and liquid market for real time energy.

- While the single-part bid approach provides incentives for bidders to bid close to their actual incremental costs, the two-part bid approach would create incentives for suppliers to modify their bidding behavior to be less reflective of actual costs. Under the two-part approach, units with a high probability of being dispatched

[1] A recent paper on this analysis, "Incentive-Compatible Evaluation and Settlement Rules: Multi-Dimensional Auctions for Procurement of Ancillary Services in Power Markets," by Hung-po Chao and Robert Wilson (February 16, 1999), was presented at the *Electricity Industry Restructuring Fourth Annual Conference*, March 5, 1999, University of California Energy Institute, Berkeley, CA. This paper is included as an appendix to this report.

would have an incentive to increase their energy bid prices, since they would be paid their bid price rather than the market clearing price for imbalance energy. At the same time, units with a low probability of being dispatched could increase their capacity payment under the two-part bid approach by decreasing their energy bid price. Thus, compared to the single-part approach, the two-part approach would result in less efficient dispatch and higher overall A/S capacity and energy payments.

- The specific algorithm considered for the two-part bid evaluation approach is not guaranteed to minimize total capacity and energy costs. This is because this algorithm would weight each unit's energy bid by the same factor, although units are actually dispatched in merit order based on their energy bid price.

Finally, the report identifies a variety of factors and outstanding issues that would make the two-part approach highly problematic to implement. Based on the analysis and findings presented in this report, the ISO concludes that its current single-part bid evaluation is both more efficient and less complex than the two-part bid approach.

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1. Introduction

In its October 30, 1997 Order,[2] FERC directed the ISO to perform studies on the following issues:

1) **The ISO's existing criterion for determining whether to create or modify Zones (October 30, 1997 Order at 61,484**);

2) **The ISO's existing transmission loss calculation and allocation methodology (October 30, 1997 Order at 61,522**); and

3) **The ISO's approach for Ancillary Services bid evaluations (October 30, 1997 Order at 61,494).**

The studies performed pursuant to the October 30, 1997 Order are addressed below in that order. The report on each study is in the following format:

- The directive provided in the FERC Order;
- An overview of the context in which FERC has ordered the study, i.e., the problems and concerns that FERC may have on the underlying issue;
- A description of the technical or theoretical approach used in the study;
- A listing of results compiled from simulations or historical data, and comparison of various scenarios; and
- Conclusions drawn from the simulation results and theoretical analyses.

[2] Order Conditionally Authorizing Limited Operation of an Independent System Operator and Power Exchange, Conditionally Authorizing Transfer of Control Facilities on an Interim Basis to an Independent System Operator, Granting Reconsideration, Addressing Rehearing, Establishing Procedures and Providing Guidance. Pacific Gas and Electric Co., et al., 81 FERC ¶ 61,122 (1997) (hereafter the "October 30, 1997 Order").

2. Study of Congestion Zone Criteria

2.1. FERC Order

In the October 30, 1997 Order, the Commission directed the ISO "to conduct a study that evaluates the effectiveness of the 5 percent criterion for considering whether to create or modify Zones" (October 30, 1997 Order at 61,484).

FERC stated that the study should include the following information:

1. The total number of MWs and the associated redispatch costs of Intra-Zonal Congestion within each Active and Inactive Zone, for each hour in the Day-Ahead and Hour-Ahead Schedules, starting from the date the ISO commences operations;

2. The total number of MWs and the associated redispatch costs of Inter-Zonal Congestion between each Inactive and adjacent Zone, for each hour in the Day-Ahead and Hour-Ahead Schedules, starting from the date the ISO commences operation; and

3. The effects of activating the Inactive Zones on Usage Charges and the MWs and redispatch costs calculated in (1) and (2) above.

In addition, since an Inactive Zone is defined as not having "workable competition" on at least one side of the Inter-Zonal interface, the Commission indicated that the study should also include:

4. The effectiveness of all proposed mechanisms for mitigating market power within an Inactive Zone, including call contracts, divestiture, and transmission rights, and whether these mechanisms cause there to be workable competition in the Inactive Zone.

2.2. Overview

In the process of scheduling power over transmission facilities for the Scheduling Coordinators (SCs), the ISO may encounter transmission constraint violations (*transmission congestion*). In such instances the ISO must somehow adjust the schedules so that the relevant constraints are no longer violated. The California ISO uses a zonal approach methodology for managing congestion. This methodology is based on separating congestion into *Inter-Zonal* congestion and *Intra-Zonal* congestion.

2.2.1. Inter-Zonal Congestion Management

Inter-Zonal Congestion Management is performed over Inter-zonal interfaces between congestion Zones that are defined by the ISO. Over these interfaces transmission congestion is expected to be relatively frequent and costly with widespread effects. The

Inter-Zonal methodology currently utilized by California ISO in the foreword market (Day/Hour-ahead) allocates the transmission capacity to those bidders that value it the most, based on a uniform-price auction where the transmission bids are imputed from voluntarily submitted resource Adjustment Bids. When the submitted Adjustment Bids are exhausted prior to fully mitigating Inter-Zonal congestion, transmission capacity is subsequently allocated pro rata. This scheme opts for allocating congested transmission capacity efficiently and pricing it at marginal cost. Because the congestion on Inter-Zonal Interfaces is expected to be frequent and costly, the net revenue from the users of the congested transmission is expected to be relatively high. The congestion revenue is credited to the Participating Transmission Owners (PTOs), offsetting their Transmission Revenue Requirements by factoring the congestion revenue into the following year's transmission access fees.

An optimal power flow algorithm is used to determine Usage Charges ($/MWh), which represent the marginal costs for power transfer from one congestion Zone to another. When transmission capacity is allocated pro rata because of insufficient Adjustment Bids, the Usage Charges are set administratively to prices that are no lower than the last rejected imputed transmission bid. All SCs pay the same Usage Charge for power transfers between a pair of given Zones in the same direction, irrespective of the particular location of their resources within the sending or receiving Zone. Congestion Management adjustments to the submitted balanced schedules are calculated so that each SC portfolio is kept in balance. Additionally, a DC power flow model is used where transmission losses, voltage, and reactive power constraints are ignored. Intra-zonal constraints (network constraints within congestion Zones) are also ignored. The objective of disregarding these constraints is to calculate marginal costs for transmission that capture only the cost due to Inter-Zonal constraints. These marginal costs provide economic signals for the efficient use and future expansion of Inter-Zonal transmission. Transmission losses are an externality that was decoupled from transmission pricing. As described further below, transmission losses are accounted for by the use of Generator Meter Multipliers (GMMs) that internalize losses in *effective* power supply that is used for schedule balancing. In that respect, GMMs provide to suppliers economic signals for transmission losses, which are separate from the economic signals for transmission.

For Inter-Zonal Congestion Management in real time, due to the nature of real time operations, the California ISO does not utilize the same methodology described above. The California ISO utilizes Adjustment Bids and energy obtained under RMR contracts to resolve congestion across active and inactive Inter-Zonal Interfaces in real time.

2.2.2. Intra-Zonal Congestion Management

Intra-Zonal Congestion Management, currently applied only in real-time, is performed over congested transmission paths that are wholly contained within congestion Zones (hereafter, such paths are referred to as "Intra-Zonal interfaces) Over these interfaces, transmission congestion is expected to be relatively infrequent or of low cost and to have local effects only. Intra-Zonal Congestion Management is primarily focused on resolving steady state problems such as overload on the transmission system or low voltage at key substations. The Intra-Zonal methodology does not explicitly allocate the transmission capacity to particular SCs who place a high value on it. Adjustment Bids and Imbalance Energy bids are used as economic indicators to increment or decrement SC resources to eliminate Intra-Zonal constraint violations. When Intra-Zonal Congestion Management is based on competitive bids, resources that are incremented are paid as bid for their additional energy supply, whereas resources that are decremented are charged as bid for their additional energy consumption. The net cost of these adjustments is allocated to *all* SCs pro-rata on metered demand within each Zone via the Grid Operations Charge (GOC). Consequently, the economic signals are weak and equal to all users of the transmission grid in the Zone, irrespective of whether they are responsible for Intra-Zonal congestion or not.

For Intra-Zonal congestion where there are either insufficient Adjustment Bids available or the available resources are limited presenting a market power concern, the ISO dispatches Reliability Must Run (RMR) units or exercises its authority to dispatch resources to manage Intra-Zonal Congestion.[3] With the creation of an active Inter-Zonal Interface on Path 26, none of the areas in which Intra-Zonal Congestion has been experienced have sufficient resources to permit the competitive resolution of the congestion.

2.2.3. Formation of Congestion Zones

There are currently four effective congestion Zones defined in California, with a new one coming into effect in February 2000. The original four Zones were formed by studying historical cost data for re-dispatching generation to alleviate constraints on transmission interfaces within the ISO control area and applying the following criterion to form an Inter-Zonal Interface (and thus a Zone):

> If over the course of a 12 month period the annual re-dispatch cost to alleviate congestion on an interface is 5% or more of the product of the rated capacity of the interface and the weighted average of the access charges levied by the PTOs, a new Zone may be formed by making the interface an Inter-Zonal Interface.

By applying the 5% criterion the original four Zones were formed. However, the cost of re-dispatch used in the analysis was based on utility generation fuel costs, rather than Adjustment Bids under the new competitive environment. Figure 2-1 illustrates the congestion Zones in California and the inter-ties of the ISO Controlled Grid with other control areas. For Congestion Management purposes, since the interties have limited transmission capacity, they are also considered Inter-Zonal Interfaces, and the corresponding Scheduling Points outside the ISO Controlled Grid are treated as single-node congestion Zones where the zonal price may be different than the zonal price within the ISO Controlled Grid due to congestion on the corresponding intertie.

[3] This authority, and the ISO's proposal to add an additional cost-based payment option for resources so dispatched, are addressed in Amendment No. 23 to the ISO Tariff, filed with the Commission on November 10, 1999.

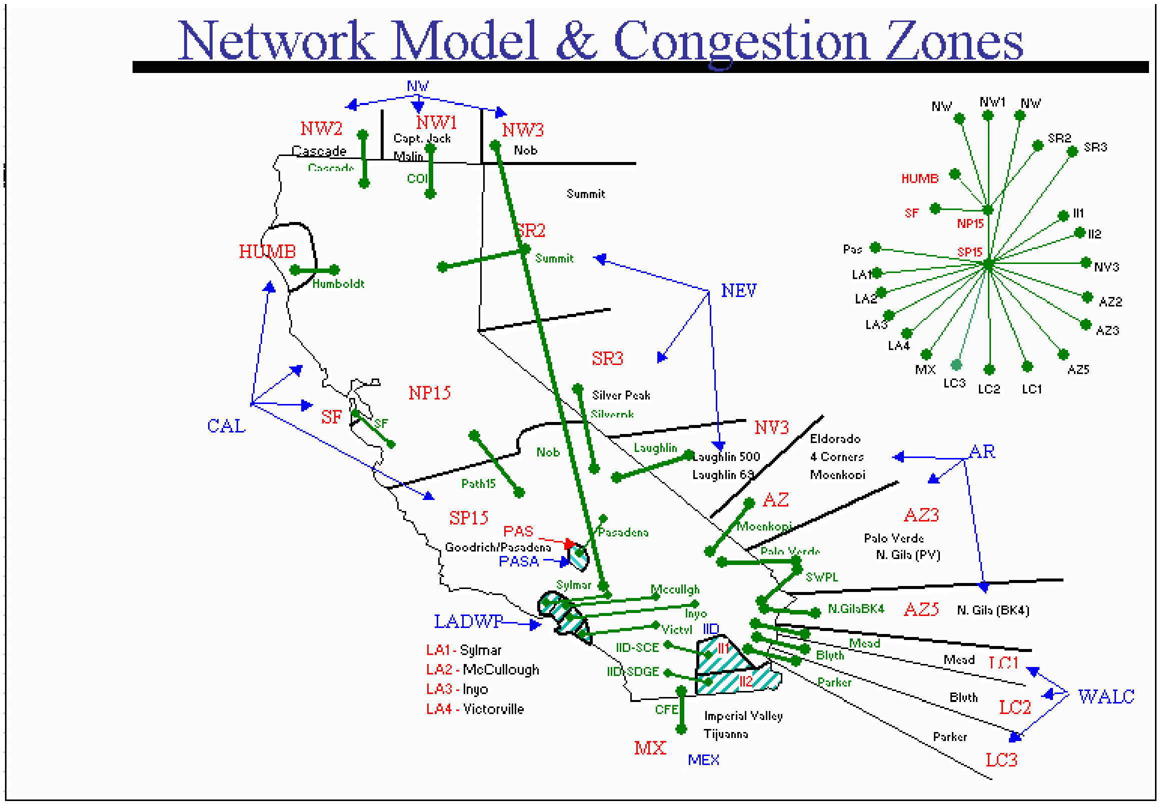


Figure 2-1. *Network model and congestion Zones*[4]

2.2.4. Active and Inactive Zones

Besides the 5% criterion that was used to form congestion Zones, another criterion was further used to determine if a Zone would be *Active* or *Inactive*. If workable competition is present on both sides of the Inter-Zonal Interface the Zone is active, otherwise inactive. Both the San Francisco (SF) and Humboldt (HUMB) Zones were declared inactive due to lack of workable competition.[5]

The ISO mitigates congestion on inactive Inter-zonal interfaces by dispatching RMR units within the Inactive Zones. RMR units within these Inactive Zones are typically dispatched to provide incremental energy after final Day Ahead schedules are submitted in order to ensure that sufficient generation within these Inactive Zones is on-line to ensure local reliability. The decremental costs of the units that are being decremented to accommodate the RMR resources are accounted for in the imbalance energy market. This

4 Pasadena has recently joined the ISO and the corresponding Scheduling Point no longer exists. Additionally, a new Scheduling Point (NV4) has been recently added for the interconnection of the new Merchant generating plant at El Dorado, near the border of Nevada and Arizona.

5 Within the San Francisco Zone, approximately 48% of available generation is owned by a single new generation owner (NGO), with the remaining 52% of capacity owned by Pacific Gas & Electric (PG&E). Within the Humbolt Zone, all capacity is owned by PG&E. This concentration of ownership, combined with transmission constraints on imports from the adjacent Zone (NP15), create a lack of workable competition within these Zones.

approach is similar to performing Intra-Zonal Congestion Management on the inactive Inter-Zonal Interfaces, with two key differences.

First, the decision to dispatch RMR units is based primarily on the need to ensure local system reliability in the event of potential operating contingencies, rather than the need to mitigate Intra-zonal congestion that may exist each hour. RMR dispatches are also used to mitigate Intra-zonal congestion over Inactive Inter-zonal interfaces.

Second, RMR costs are not charged to the consumers in the Zone through the GOC, but are instead charged to the corresponding PTO. Therefore, these congestion costs are reflected in the PTO access fee paid by all users of the PTO transmission grid.

2.3. Questions and Concerns raised by FERC

In the October 30, 1997 Order, FERC does not question the effectiveness of the Inter-Zonal Congestion Management methodology since that methodology provides clear and strong economic signals for the efficient use of congested transmission. Under that methodology, transmission capacity is awarded to those users that value it the most and only those users are charged with a uniform marginal cost price for their use.

However, the FERC order did raise questions on the efficiency of applying the Intra-Zonal Congestion Management methodology. This methodology may cause cost shifting in that the net costs incurred by the ISO to manage Intra-Zonal Congestion are spread over to all SCs in the Zone regardless of whether they contribute to Intra-Zonal congestion. FERC, however, recognizes the usefulness of separating congestion into Inter-Zonal and Intra-Zonal. For example, in the October 30, 1997 Order, FERC explicitly mentions the administrative conveniences of fewer Zones, as a counter to the inefficiencies of managing congestion within a Zone (October 30, 1997 Order at 61,484). Another advantage of the zonal approach is that the zonal price is less volatile than the underlying nodal prices within a Zone,[6] providing for a more useful and practical economic signal for the marketplace. Nevertheless, as FERC stated, there is a trade-off between the administrative conveniences of fewer Zones and the inefficiencies introduced by the cost shifting in Intra-Zonal Congestion Management.

Therefore, FERC recognizes the importance of the criteria used in the formation of the Zones, and thus the separation of congestion costs into Inter-Zonal and Intra-Zonal components. These criteria determine the level of trade-off between simplicity of implementation and market efficiency. In the October 30, 1997 Order, FERC approved the 5% criterion as set out in the ISO Tariff, but requested the ISO to evaluate its effectiveness and examine possibilities for refinement. The outcome of this effectiveness study provides insights into new criteria that may be used in the future since as stated in the ISO Tariff (7.2.7.2.5) "the ISO may change the criteria for establishing or modifying zone boundaries subject to regulatory approval by FERC." FERC has also expressed concerns on the declaration and treatment of Inactive Zones, based again on the fact that the RMR dispatch costs are spread to all PTO customers causing cost shifting that may

[6] The zonal price is calculated as a weighted average of all nodal prices in the Zone.

reduce market efficiency. Consequently, FERC has requested the ISO to evaluate the effectiveness of all market power mitigation mechanisms inside Inactive Zones.

2.4. Response in Compliance with the FERC Order

The following sub-sections address the four specific FERC requests about information and analyses. The effectiveness analysis of the 5% criterion is included in the next section.

2.4.1 Volume and Costs of Redispatch for Intra-Zonal Congestion Management in Active and Inactive Zones in the Day-Ahead and Hour-Ahead Markets

The ISO does not currently perform Intra-Zonal Congestion Management in the forward markets because the required software is not yet available. This functionality has been staged since the commencement of ISO operations. The ISO currently resolves Intra-Zonal congestion only in real time. Therefore, there are no associated volumes and redispatch costs for Intra-Zonal Congestion Management in the Day-Ahead and Hour-Ahead Markets.

As noted above, the ISO currently dispatches any additional generation needed from RMR units to meet local reliability criteria after final Day Ahead schedules are submitted to the ISO. Although these dispatches are based on broader local reliability criteria, RMR dispatches have the effect of mitigating congestion that may otherwise exist in Inactive Zones (SF and HUMB).

Generally, RMR Day-ahead notices are associated with reliability and Real-time RMR dispatch is attributed to solving both Intra and Inter-Zonal Congestion. Because the dispatch of RMR generation serves multiple purposes related to reliability and in order to quantify the impact of Intra and Inter-Zonal Congestion in Real-time, it is appropriate to separate the RMR MW volumes and costs into different categories.

Specifically, the RMR costs can be broken down into two major categories:

1) *RMR costs related to reliability criteria*

This set of RMR costs is based on various reliability criteria that include contingency criteria (N-1, N-2, G-1, G-2), voltage, angle separation, and stability criteria.

2) *RMR costs related to real time operation to maintain steady state*

This set of costs includes costs related to RMR dispatch for reasons other then the reliability criteria outlined above. There are three major factors that contribute to these costs:

1) Ancillary Services

2) Intra Zonal Congestion Management in real time

3) Inter Zonal Congestion Management in real time

Of the above three categories of costs, the first (i.e., Ancillary Services), was limited to the first few months of ISO operation in 1998 and was not a significant factor in 1999.

For 1998, the ISO does not have sufficient data to disaggreagte RMR costs as outlined above. However, for 1999 the ISO believes it is feasible to develop a more refined estimate of the portion of the RMR costs that can be attributable to Real-time operation (i.e. Ancillary Services, Intra-zonal Congestion Management and Inter zonal Congestion Management in real time). The ISO proposes a follow-up study to report the results of this analysis if the Commission believes such an approach would provide useful information.

2.4.2. Volume and Costs of Redispatch for Inter-Zonal Congestion Management between Active and Inactive Zones in the Day-Ahead and Hour-Ahead Markets

Constraints on inactive Inter-Zonal Interfaces are not enforced in Day-Ahead or Hour-Ahead Inter-Zonal Congestion Management. Therefore, Inter-Zonal Congestion Management does not apply to inactive Inter-Zonal Interfaces. This is because, by definition, there is no workable competition within the Inactive Zones. The absence of workable competition within the Inactive Zones gives market power to the few owners of generating units within these Zones that could theoretically drive the corresponding zonal price arbitrarily high should there be Congestion Management on the inactive interface. Congestion on the inactive Inter-Zonal Interfaces is effectively eliminated by dispatching RMR units within the Inactive Zones.

2.4.3. Volume and Costs of Redispatch for Intra-Zonal and Inter-Zonal Congestion Management and Usage Charges in Absence of Inactive Zones in the Day-Ahead and Hour-Ahead Markets

As explained in the previous section, the existence of market power within Inactive Zones prevents effective Inter-Zonal Congestion Management through competitive mechanisms on the inactive Inter-Zonal Interfaces between the Inactive Zones and the adjoining Active Zones. Consequently, no Usage Charges are calculated for the inactive interfaces.

The current treatment of Inactive Zones is an appropriate measure since the economic signal associated with managing congestion over an inactive interface (the above market costs of RMR dispatch) is directed to the PTOs, which are deemed responsible for the weaknesses of the transmission network, rather than to the demand within the Inactive Zones. Such demand is mostly inelastic and not responsible for the congestion.

2.4.4. Effectiveness of Market Power Mitigation Mechanisms inside Inactive Zones

Although generation divestiture had a significant overall impact in mitigating market power in California, as shown by the charts in Figure 2-2, it could not possibly mitigate market power within Inactive Zones. Within these Zones, because of the existence of very few generating units, divestiture is not sufficient to mitigate market power. The new generator owners of divested plants would simply inherit the locational market power associated with these plants from the prior utility owners.

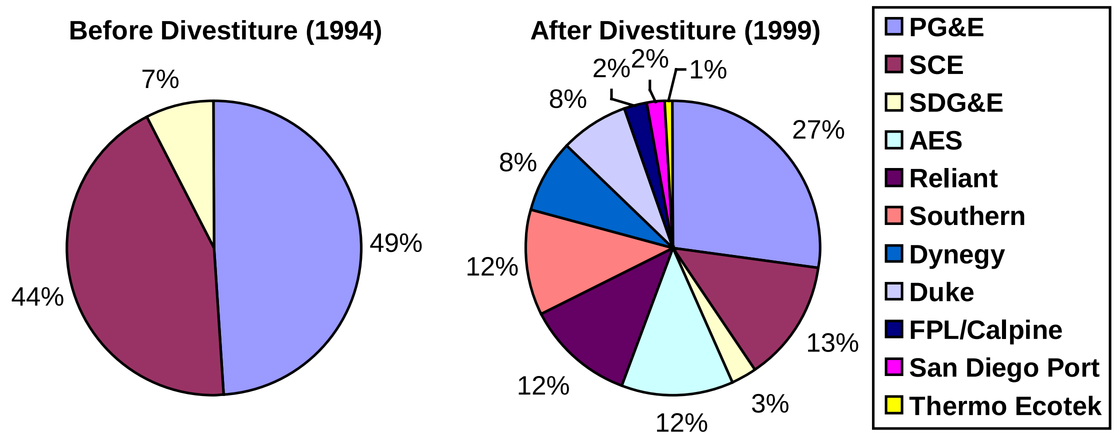


Figure 2-2. *Effects of Utility generation divestiture*

Signing RMR contracts and dispatching RMR units to relieve congestion for which there is no competitive market solution has been an effective mitigation of market power. Furthermore, the use of RMR dispatch provides an effective economic signal to the PTOs since they are responsible for the conditions that mandate the use of RMR contracts and the above market costs of RMR unit operation. It is this economic signal that has recently provided the right incentives to one PTO, Southern California Edison to upgrade its transmission network and reduce the number of RMR units in its service territory.

2.5. 5% Criterion Effectiveness Evaluation

In this section we will conduct an analysis to determine the effectiveness of the 5% criterion for creating or eliminating Zones and examine possibilities for refinement.

2.5.1. Description of the 5% Criterion

Under the ISO Tariff,

> **7.2.7.2.1** If over a 12-month period, the ISO finds that within a Zone the cost to alleviate the Congestion on a path is equivalent to at least 5 percent of the product of the rated capacity of the path and the weighted average Access Charge of the Participating TOs the ISO may announce its intention to create a new Zone. In making this calculation, the ISO will only consider periods of normal operations. A new Zone will become effective 90 days after the ISO Governing Board has determined that a new Zone is necessary.

The 5% criterion is a threshold for the accumulated Intra-Zonal Congestion Management costs on an Intra-Zonal interface over a period of 12 months. When these costs exceed the threshold, a new congestion Zone may be created.

2.5.2. Analysis of the 5% Criterion

The threshold is set to a specified percentage of the product of the Intra-Zonal interface rating and the weighted average[7] of the relevant PTO access fees. This product can be seen as the maximum transmission revenue from the specific Intra-Zonal interface, which would be collected if that interface were fully used throughout the year. Although, the Operating Transfer Capability (OTC) is usually less than the rating of a transmission interface, the rating is used in the criterion because the OTC may vary considerably throughout the year. Therefore, the percentage criterion is the relative portion of the maximum transmission revenue collected from an interface that is considered significant to sacrifice simplicity in favor of market efficiency by promoting the interface to an Inter-Zonal Interface with the creation of a new Zone. In this analysis we will evaluate whether 5% is an appropriate level of significance.

Table 2-2 lists the Transmission Revenue Requirement (TRR) of the three PTOs for effective days in 1998 and 1999. The last column is a weighted average that represents the TRR for the first year of operations for the ISO, from April 1998 through March 1999.

Table 2-2. *PTO Transmission Revenue Requirement*

PTO	Effective Day			1st year
	4/1/1998	10/30/1998	1/1/1999	
PG&E	$ 285,616,000	$ 315,811,000	$ 315,811,000	$ 298,273,082
SCE	$ 211,054,000	$ 211,054,000	$ 208,188,401	$ 210,347,414
SDG&E	$ 103,621,000	$ 103,621,000	$ 97,892,043	$ 102,208,380
Total	$ 600,291,000	$ 630,486,000	$ 621,891,444	**$ 610,828,877**

Table 2-3 lists the congestion revenues that were collected by the ISO on all Inter-Zonal Interfaces in the first year of operations and were paid to the PTOs. Table 2-3 contains only congestion revenues collected from Day-Ahead Inter-Zonal Congestion Management. Congestion revenues from the Hour-Ahead market were negative in the first 12 months of operations due to an anomaly referred to as the “TO debit.” The TO debit scenario was typically triggered after a reduction in the Available Transmission Capacity (ATC) of an Inter-Zonal Interface, e.g., due to a contingency, after the closure of the Day-Ahead market and prior to the Hour-Ahead market. In this case, PTOs were forced to buy back in the Hour-Ahead market unavailable transmission capacity that was previously sold in the Day-Ahead market. The transmission price was typically much higher in the Hour-Ahead market, and often hit the upper limit of the administratively set Default Usage Charge (DUC) of $250/MWh because of the thinness of that market. This

[7] The weights that are used in the weighted average are the percentages of ownership of each PTO on the Intra-Zonal interface.

resulted in tremendous financial loss for the PTOs. This anomaly was corrected in March 1999 by requiring the PTOs to buy the derated capacity at the Day-Ahead price. Table 2-3 does not include the PTO losses due to this anomaly because they would otherwise skew the analysis.

Table 2-4 lists the congestion revenues for the first 12 months of operations by Inter-Zonal Interface. Table 2-4 also lists the rated capacity of each interface.

To derive a benchmark for the 5% criterion, we have calculated a *normalized yearly access fee* (*NYAF*), by dividing the total TRR by the peak demand (44,927 MW) in the first 12 months of operations, as follows:

$$NYAF = \frac{\$610{,}828{,}877}{44{,}927\ \mathrm{MW}} = \$13{,}596/\mathrm{MW}$$

Then, we have calculated a *normalized transmission revenue* (*NTR*) from the Inter-Zonal Interfaces where there was congestion in the first 12 months of operations, as follows:

$$NTR = NYAF \times 19{,}018\ \mathrm{MW} = \$258{,}569{,}314$$

Table 2-3. *Congestion revenue by month*

Month	Congestion Revenues
April-98	$ 63,956
May-98	$ 1,533,109
June-98	$ 970,925
July-98	$ 5,441,323
August-98	$ 2,100,037
September-98	$ 2,455,948
October-98	$ 5,504,187
November-98	$ 4,496,471
December-98	$ 3,744,686
January-99	$ 3,858,392
February-99	$ 1,840,466
March-99	$ 5,771,924
Total	**$ 37,781,424**

Table 2-4. *Congestion revenue by interface*

Interface	From Zone	To Zone	Capacity [MW]	Congestion Revenue
COI	NW1	NP15	4,800	$ 10,832,478
ELDORADO	AZ2	SP15	1,557	$ 4,697,504
MEAD	LC1	SP15	1,460	$ 623,076
NOB	NW3	SP15	3,100	$ 4,338,598
PALOVRDE	AZ3	SP15	2,823	$ 5,186,983
PATH15	SP15	NP15	3,900	$ 11,878,656
SILVERPK	SR3	SP15	18	$ 22,953
SUMMIT	SR2	NP15	160	$ 11,899
SYLMAR-AC	LA1	SP15	1,200	$ 189,277
		Total	**19,018**	**$ 37,781,424**

A *normalized congestion cost ratio* (*NCCR*) can be derived by dividing the total congestion revenues collected in the first 12 months of operations by *the NTR factor*, as follows:

$$NCCR = \frac{\$37,781,424}{\$258,569,314} = 14.61\%$$

This percentage is the normalized congestion cost ratio of existing congestion and can be used as a reference point to evaluate the currently adopted threshold for the ratio of congestion costs over transmission revenue on a given interface. However, the congestion cost used in the 5% criterion is the Intra-Zonal congestion cost, not the Inter-Zonal congestion cost. Therefore, we need to further evaluate how the congestion costs relate under the two different scenarios: a) the Intra-Zonal scenario where the relevant interface is Intra-Zonal and congestion is mitigated using the Intra-Zonal Congestion Management protocols; and b) the Inter-Zonal scenario where the relevant interface becomes Inter-

Zonal and congestion is mitigated using the Inter-Zonal Congestion Management protocols.

2.5.3. Financial Impact of New Congestion Zones

When a transmission path previously designated as a Intra-Zonal interface is converted to an Inter-Zonal Interface, the original Zone that contained the interface is divided into two new Zones, separated by the new Inter-Zonal Interface. This is illustrated in Figure 2-3 where the activation of a new active Inter-Zonal Interface between nodes A and B divides the original Zone Z into two new Zones: Z_1 and Z_2.

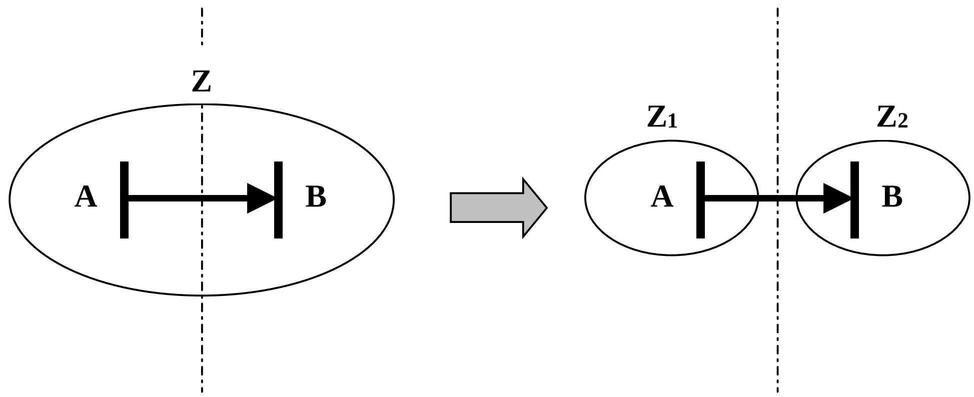


Figure 2-3. *Effects of Zone division*

The financial implications of this change on the marketplace depend on the structure of the SC balanced schedules and the division of supply and demand resources within the new Zones. The effects also depend on the direction of congestion. To simplify the analysis, we have assumed that the direction of congestion in the example network of Figure 3 is from node A to node B. Then, the financial impact of the Zone division can be evaluated by comparing the costs to Market Participants (MPs) under the two scenarios: 1) Intra-Zonal congestion, and 2) Inter-Zonal congestion.

Scenario 1
Intra-Zonal Congestion

a) SCs are not charged explicitly for using the Intra-Zonal interface. It does not matter whether a SC is using the interface and in what direction.

b) Congestion costs are calculated as bid and charged to all SCs pro rata on the demand (load and exports) in the Zone.

Scenario 2
Inter-Zonal Congestion

a) SCs are charged explicitly for using the Inter-Zonal Interface in the direction of congestion, and paid explicitly for using the Inter-Zonal Interface in the opposite direction.

b) Congestion costs are calculated at marginal cost and charged or paid to all SCs using the interface depending on the direction.

c) PTOs do not receive congestion revenues and there is no impact on next year's access fees.

c) PTOs do receive congestion revenues that are reflected on next year's access fees.

d) Supply resources are paid the same Market Clearing Price (MCP) irrespective of their particular location in Zone Z.

d) Supply resources are paid different MCPs depending on whether they are located in Zone Z_1 or Z_2. Supply is paid usually less in Zone Z_1 and more in Z_2, compared to Scenario 1.

e) Demand resources pay the same MCP irrespective of their particular location in Zone Z.

e) Demand resources pay different MCPs depending on whether they are located in Zone Z_1 or Z_2. Demand pays usually less in Zone Z_1 and more in Z_2, compared to Scenario 1.

Assume the following notation for the generation, demand, and MCP, for a SC under Scenarios 1 and 2, where Intra-Zonal adjustments are not included since they are settled as bid:

	Scenario 1		**Scenario 2**	
	Zone Z_1	**Zone Z_2**	**Zone Z_1**	**Zone Z_2**
Generation	G_1	G_2	G_1'	G_2'
Demand	D_1	D_2	D_1'	D_2'
MCP	P	P	P_1	P_2

In order to simplify this example, we also assume that there are no imports or exports outside of Zone Z, and no inter-SC trades in the portfolio. Then because of the requirement of balanced schedules:

$$G_1 + G_2 = D_1 + D_2 = G_1' + G_2' = D_1' + D_2' \qquad (2\text{-}1)$$

Ignoring congestion on other interfaces, the cost of congestion on the interface from node A to node B is the allocated GOC under Scenario 1 and the MCP differential under Scenario 2, where

$$P_1 \leq P \leq P_2. \qquad (2\text{-}2)$$

The cost of Zone division (switching from Scenario 1 to Scenario 2) on the demand is given by

$$C_D = P_1 \times D_1' + P_2 \times D_2' - P \times (D_1 + D_2) - GOC. \qquad (2\text{-}3)$$

The cost of Zone division on the supply is given by

$$C_G = P \times (G_1 + G_2) - P_1 \times G_1' - P_2 \times G_2'. \qquad (2\text{-}4)$$

These quantities can be negative, in which case the Zone division is beneficial, depending on how demand and supply divide across the interface. The overall cost on the SC portfolio is given by

$$C = C_D + C_G = P_1 \times (D_1' - G_1') + P_2 \times (D_2' - G_2') - GOC, \tag{2-5}$$

which could be further simplified using (2-1) as follows:

$$C = (P_2 - P_1) \times (D_2' - G_2') - GOC \tag{2-6}$$

The MCP differential in (2-6) is the Usage Charge, which is the same for all SCs. The amount by which the demand exceeds supply in (2-6) is equal to the scheduled flow on the interface, i.e., the SC's use of the transmission capacity. The net use from all SCs is equal to the OTC of the interface. Therefore, although the impact of Zone division varies from SC to SC and from supply to demand, the overall effect on the marketplace can be studied by comparing the GOC under the Intra-Zonal scenario with the congestion revenue under the Inter-Zonal scenario, and how they accumulate over time. However, this comparison does not capture the benefit to SCs that do not use the interface. This benefit is two-fold: a) eliminating GOC charges; and b) paying a lower access fee due to congestion revenues collected from other SCs that use the interface.

This analysis above assumes that the bidding behavior of MPs will not change between scenarios, i.e., SCs will submit the same Adjustment Bids under either scenario. This assumption should be reasonable for a highly competitive market since, in such an environment, the dominant bidding strategy is cost-reflective bidding. In our case, this assumption can be challenged since at least Intra-Zonal Congestion Management is prone to market power problems due to its locational nature.

2.5.4. Path 26 Case Study

We will use Path 26 as a study case. Path 26 is a recognized WSCC transmission path, and part of the ISO Controlled Grid, which consists of three parallel 500 Kv transmission lines between PG&E’s Midway and SCE’s Vincent Substations. Both ends of Path 26 are located within the SP15 Congestion Zone (south of Path 15). Therefore, Path 26 is currently an SP15 Intra-Zonal interface.

In the first 12 months of the ISO’s operation, Path 26 has been congested in the north to south direction during many hours. In these hours, the ISO has managed congestion in real time by increasing the output of resources south of Path 26 and decreasing the output of resources north of Path 26. Incremental and decremental adjustments were paid and charged as bid, respectively, according to the Intra-Zonal Congestion Management protocol. The congestion costs (net of payments minus charges) that the ISO has incurred in the first 12 months of operations are listed in Table 2-5. These costs were recovered from the demand through the GOC.

Table 2-5. *Path 26 Intra-Zonal congestion costs*

Month	Congestion Hours	Congestion Cost
April-98	0	$ -
May-98	45	$ 56,781
June-98	136	$ 1,692,991
July-98	103	$ 1,433,252
August-98	59	$ 742,033
September-98	0	$ -
October-98	2	$ 4,745
November-98	0	$ -
December-98	6	$ 173,031
January-99	5	$ 4,875
February-99	6	$ 82,181
March-99	36	$ 530,102
Total	**398**	**$ 4,719,991**

The maximum transmission revenue on Path 26 is calculated in Table 2-6.

Table 2-6. *Path 26 maximum transmission revenue*

PTO	Access Charge	Ownerchip	Rated Capacity	Yearly Cost
PG&E	$3.53/MWh	16.67%	500 MW	$ 15,461,400
SCE	$2.69/MWh	83.33%	2500 MW	$ 58,911,000
SDG&E	$6.82/MWh	0.00%	0 MW	$ -
Total		100.00%	3000 MW	**$ 74,372,400**

For Path 26, the 5% criterion has been met since the ratio of $4,719,991 over $74,372,400 equals 6.35%. Furthermore, the second criterion that requires workable competition on both sides of a new Inter-Zonal Interface in order for a new Zone to be an Active Zone also holds for Path 26. Consequently, in August 1999, the ISO Governing Board directed the ISO to create a new congestion Zone between Path 15 and Path 26 by converting Path 26 to an Inter-Zonal Interface so that congestion on Path 26 becomes Inter-Zonal congestion and priced at marginal cost according to the ISO Tariff. The new Zone is referred to as “ZP26” and will become effective at the same time with the Firm Transmission Rights (FTRs), for trade day 2/1/2000.[8]

Figure 2-4 illustrates the demand Zones in the ISO controlled grid, and Table 2-7 shows how these demand Zones map to the existing and new congestion Zones. Zone ZP26 will encompass only the PGE4 demand Zone, which is currently part of the SP15 congestion Zone.

[8] The Commission recently issued an order on Amendment No. 22 to the ISO Tariff which approved Tariff changes related to the creation of this new Zone. California Independent System Operator Corp., 89 FERC ¶ 61,229 (November 24, 1999).

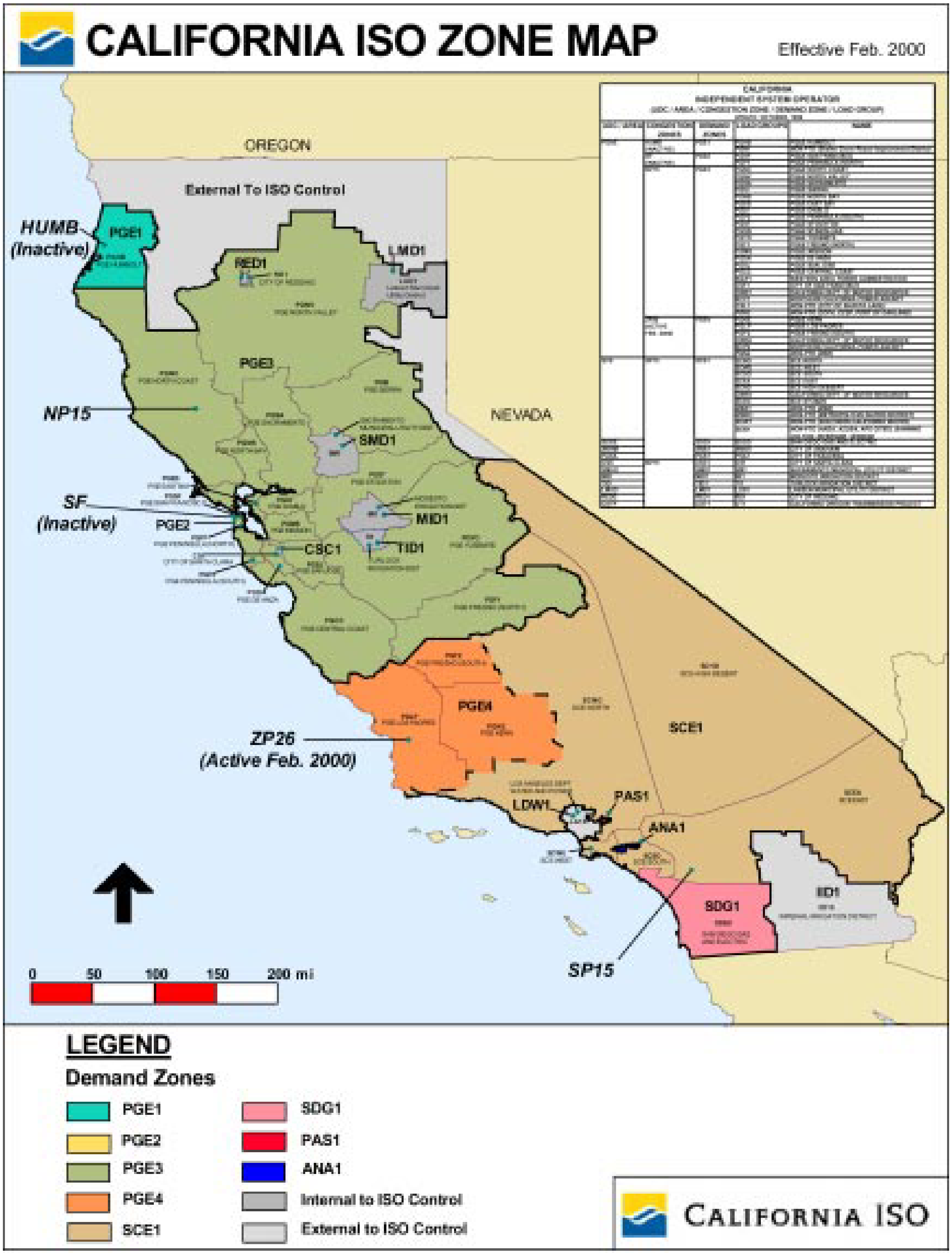


Figure 2-4. *ISO Zones*

Table 2-7. *Demand Zone mapping to Congestion Zones*

Demand Zones	Congestion Zones	
	Current	**After 2/1/2000**
PGE1	HUMB	HUMB
PGE2	NP15	NP15
PGE3	SF	SF
PGE4	SP15	ZP26
SCE1	SP15	SP15
SDG1	SP15	SP15

The objective of the case study is to compare the actual congestion costs that were incurred by performing Intra-Zonal Congestion Management on Path 26 in real time with the congestion costs that would have been incurred should Path 26 were an Inter-Zonal Interface in the first 12 months of operations. To calculate the latter, Inter-Zonal Congestion Management simulations were performed using the historically submitted schedules and bids, but on a modified network model where Path 26 is an Inter-Zonal Interface and ZP26 is defined as a separate congestion Zone. The simulations were performed only for the Day-Ahead market, since the volume and activity in the Hour-Ahead market were very small in the first 12 months of operations. Furthermore, the simulations were limited to the hours where Path 26 was congested according to the submitted schedules and the estimated OTC of the path. The estimated OTC of the path was calculated based on the ATC of Path 26 and certain assumptions about the transmission capacity usage and reservation on behalf of Existing Transmission Contract (ETC) rightsholders.

Congestion on Path 26 was present only in the southbound direction. The ATC on Path 26 is 2600 MW in that direction, which is considerably lower than its WSCC rating of 3000 MW. Path 26 was congested during 367 hours in the Day-Ahead market Inter-Zonal Congestion Management simulation. Although this number is close to the total number of hours where Path 26 was congested in real time, 398, as shown in Table 2-8, there is no good correlation between the individual hours. This is due to the fact that, at times, a lower ATC on Path 15 was used by the ISO to reduce real time Intra-Zonal congestion on Path 26.

Table 2-9 lists the total congestion revenues collected over all congested Inter-zonal interfaces in the Day-Ahead market for the study set of the 367 hours from

a) Historical results of Inter-Zonal Congestion Management where Path 26 congestion was ignored, and

b) Simulation results of Inter-Zonal Congestion Management where Path 26 congestion was eliminated.

It is important to compare the overall effects in the network rather than the costs on Path 26 only, since mitigation of Path 26 congestion may affect the marginal costs on other congested Inter-Zonal Interfaces, most notably, Path 15.

Table 2-8. *Congestion revenues by month*

Month	Congestion Hours	Congestion Revenues		
		Historical Results	Simulation Results	Path 26 Effect
April-98				$ -
May-98				$ -
June-98				$ -
July-98				$ -
August-98	137	$ 138,021	$ 12,890,897	$ 12,752,876
September-98	129	$ 123,632	$ 9,203,160	$ 9,079,528
October-98	2	$ 9,280	$ 101,754	$ 92,473
November-98	11		$ 337,147	$ 337,147
December-98	47	$ 161,885	$ 1,489,952	$ 1,328,067
January-99	24	$ 54,050	$ 526,363	$ 472,313
February-99	1	$ 488	$ 2,273	$ 1,784
March-99	16	$ 369,220	$ 775,033	$ 405,813
Total	367	$ 856,577	$ 25,326,578	**$ 24,470,001**

The congestion revenue differences (the 5th column in Table 2-8) between the simulation and the historical results can be attributed to the conversion of Path 26 from an Intra-Zonal interface to an Inter-Zonal Interface. The cumulative 12-month effect on the individual Inter-Zonal Interfaces is shown in Table 2-9. These data could provide useful information about how Path 26 may affect the values of FTRs on the other Inter-Zonal Interfaces. However, it is important to keep in mind that historical bids are used in the simulation. The Path 26 effect, will not be so pronounced if we take into account the likelihood that bidders will modify their bidding behavior to self-manage congestion.

Table 2-9. *Congestion revenues by Inter-Zonal Interface*

Inter-Zonal Interface	From Zone	To Zone	Congestion Revenues		
			Historical Results	Simulation Results	Path 26 Effect
COI	NW1	NP15	$ 336,537	$ 121,808	$ (214,730)
ELDORADO	AZ2	SP15	$ 151,825	$ 262,888	$ 111,063
MCCULLGH	LA2	SP15		$ 33	$ 33
MEAD	LC1	SP15		$ 1,830,816	$ 1,830,816
NOB	NW3	SP15	$ 48,037	$ 277,167	$ 229,130
PALOVRDE	AZ3	SP15	$ 50,321	$ 122,218	$ 71,897
PATH15	SP15/CP15	NP15	$ 256,528	$ 382	$ (256,146)
PATH26	CP15	SP15		$ 22,709,738	$ 22,709,738
SUMMIT	SR2	NP15		$ 8	$ 8
SYLMAR-AC	LA1	SP15	$ 13,329	$ 1,521	$ (11,808)
		Total	$ 856,577	$ 25,326,578	**$ 24,470,001**

The Inter-Zonal congestion costs for Path 26 alone, $22.7M, are several times more than the Intra-Zonal congestion costs that were actually incurred on Path 26. As mentioned earlier, this should be viewed as the upper bound of possible values. Dividing the $22.7 million by the Path 26 maximum transmission revenue of $74,372,400 results in a congestion percentage of approximately 30%, which is above the congestion percentage of 14.61% for the existing Inter-Zonal Interfaces. This suggests that use of the 5% criterion leads to results that are consistent with the congestion experienced on the existing Inter-Zonal Interfaces.

The chart in Figure 2-5 illustrates the effect of Path 26 congestion at the SC level. The Path 26 costs dwarf all other costs. However, the chart shows that these Inter-Zonal Congestion Management costs would not be at all distributed evenly among SCs. Only a few SCs would be charged for the great majority of these costs, whereas only a few others would realize a benefit. These are the SCs that make use of the path in the direction of congestion and in the counterflow direction, respectively. Nevertheless, in the Intra-Zonal scenario, all SCs are charged the costs of Congestion Management pro rata on their demand. Under the Inter-Zonal scenario, there are more significant Congestion Management costs, and these costs are allocated to individual SCs based on their use of the congested Inter-Zonal Interface. Figure 2-5 provides an indication of the increased efficiencies in using congested transmission capacity that occur with Inter-Zonal Congestion Management. These efficiencies will begin when Path 26 becomes an Inter-Zonal Interface, effective on February 1, 2000.

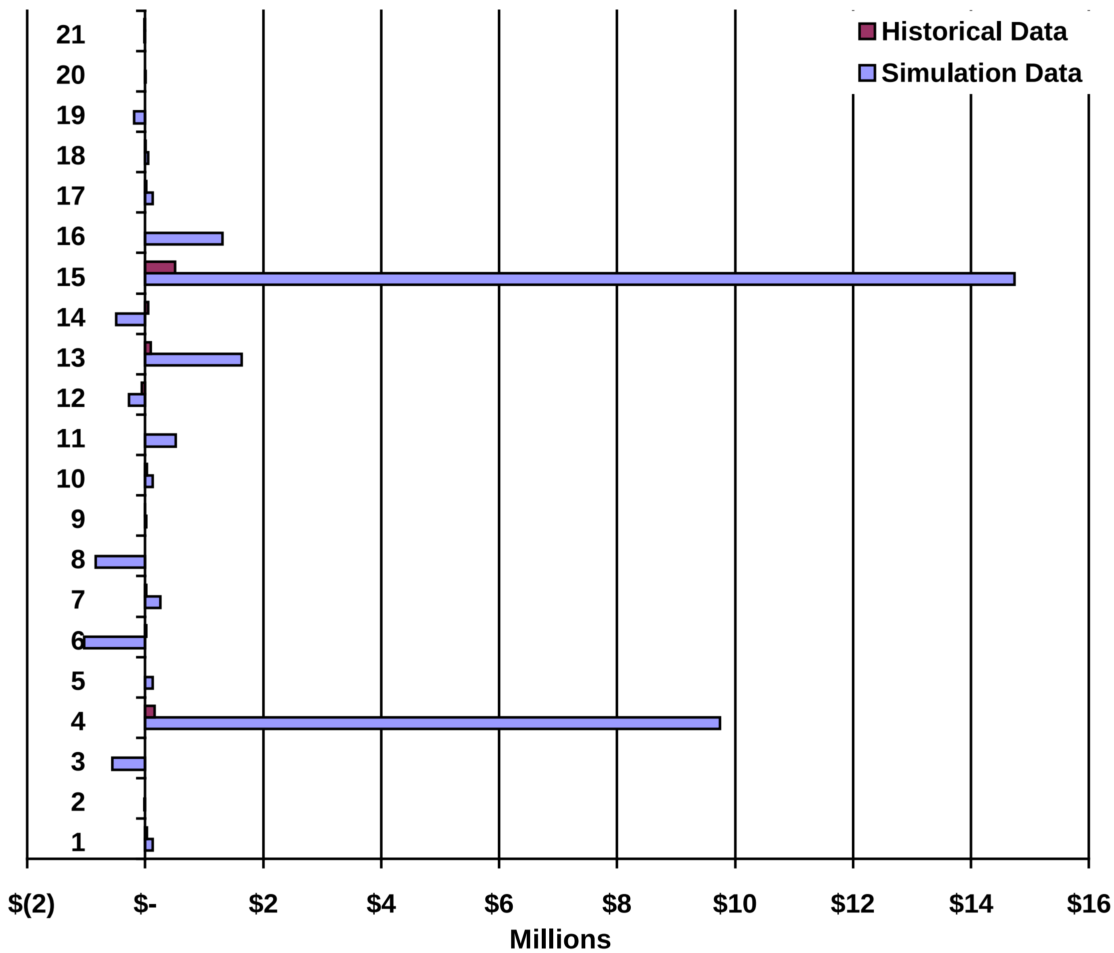


Figure 2-5. *Congestion charges by SC*

The graph in Figure 2-6 shows how Path 26 congestion costs were accumulated in the first 12 months of operations under both Intra-Zonal and Inter-Zonal scenarios and how they compared to the 5% criterion. Note that the results of the Path 26 congestion simulation can be considered as the upper bound of the congestion costs under the Inter-Zonal scenario since MPs would be able to self-manage congestion and alter their bidding behavior to reduce their exposure to congestion costs. Nevertheless, continuous monitoring of either cost would have suggested the creation of the new Zone in as early as August 1998.

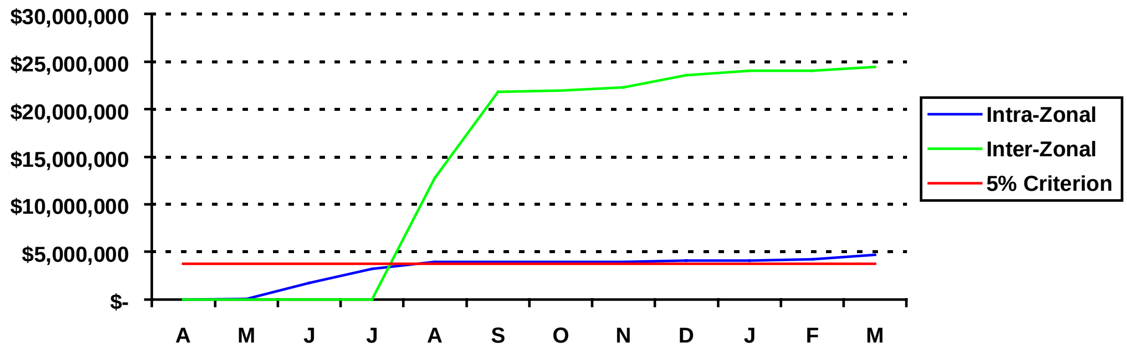


Figure 2-6. *Path 26 congestion cost accumulation*

2.6. Conclusions on the Zone Criteria

The basis for the analysis of the Zone creation criteria in this study is the comparison of congestion costs to transmission revenue, for a candidate Intra-Zonal interface. This ratio is compared to the ratio of total congestion revenue versus normalized transmission revenue from all existing congested Inter-Zonal Interfaces. The latter ratio or congestion percentage is used as a reference point to assess the results of using the 5% criterion. Therefore, if the congestion percentage for a transmission path that has been elevated to an Inter-Zonal Interface is equal to or above the reference point congestion percentage of 14.61% for the existing Inter-Zonal Interfaces, the congestion on the estimated congestion on new Inter-Zonal Interface is consistent with the congestion for the other, existing Inter-Zonal Interfaces. Consequently, this is an indication that use of the 5% criterion is reasonable and that the interface should be treated as an active Inter-Zonal Interface, if it also meets the second criterion of having workable competition on both sides of the interface.

The ratio of total congestion revenue to normalized transmission revenue requirement is 14.6% for the first 12 months of operations. Moreover, congestion costs have increased significantly after the first 12 months, raising that percentage to 28% for the nine month period from January 1, 1999 through September 30, 1999. It is expected that, in the future, this percentage will continue to increase due to increased utilization of the transmission system and an increase of the demand. The ISO is currently using a 5% threshold that is reviewed annually. In this study, we have used Path 26 as a case study to evaluate the application of the 5% criterion. The results from simulations of Path 26 congestion mitigation with Path 26 being an Inter-Zonal Interface show that the congestion costs under the Inter-Zonal scenario are several times greater than the congestion costs under the Intra-Zonal scenario. However, these Inter-Zonal costs should be viewed only as an upper bound for the congestion costs that would have incurred since MPs are expected to react to the economic signals by altering their bidding behavior and schedules. Nevertheless, continuous monitoring of congestion costs under either scenario against a 5% threshold would have indicated that Path 26 should have become an Inter-Zonal Interface after August 1998. The ISO Governing Board did direct that Path 26 be made an Inter-Zonal Interface at the first opportunity after the first year of operations.

This change will be effective at the same time that Firm Transmission Rights (FTRs) become effective, on February 1, 2000, since any change in the zonal configuration of the network will have an impact on the value of FTRs that are auctioned yearly. Therefore, in the case of Path 26, the 5% criterion was effective. However, the threshold should be evaluated every year as the congestion costs vary. This is particularly important for next year when Path 26 will probably contribute significant amounts of congestion revenue. A more frequent monitoring of congestion cost accumulation will also provide more insight in the determination of appropriate criteria for Zone creation. New Zones would still not be created more frequently than once a year, because of the yearly term of FTRs, but the decisions, and necessary network and system changes for new Zones can be made in advance.

3. Transmission Loss Allocation Comparison Study

3.1. FERC Order

In its October 30, 1997 Order, FERC directed the ISO to undertake a study which evaluates the effect of the current ISO method for calculating and assigning scaled marginal losses to individual SCs versus a method that assigns to each SC the full marginal losses associated with its actual scheduled transactions. FERC stated that the report should include "a comparison of loss assignments (and their monetary value at applicable energy prices) under the two methods for a variety of transactions that reflect differences in distance and direction between the generator and load, as well as differences in line loading." (October 30, 1997 Order at 61,522).

3.2. The FERC's Evaluation Requirements

In FERC's request for an evaluation of the transmission loss allocation, it identifies three basic requirements for an allocation methodology, whose results will be compared to the current methodology:

1. The allocation should use full marginal losses, in other words, the loss should still be allocated to resources within each SC's schedule based on marginal loss rate methodology;

2. The allocation to each resource within that SC's schedule should be based solely on the scheduled transaction with the SC's schedule; and

3. The evaluation for comparing the two methodologies should be made under a variety of transactions that reflect differences in distance and direction between the generator and load, as well as differences in line loading.

3.3. Overview of the Current Transmission Loss Allocation

In the process of transmitting bulk electrical energy over the ISO Controlled Grid, transmission losses will occur due to resistance in the high voltage power lines, corona losses, resistance in transformer windings and hysteresis and eddy-current losses in transformer cores.

It was decided upon through the stakeholder process, before the start of operation of the ISO, that the responsibility for providing for the transmission losses would go to the individual generators/imports. In other words, when an SC submits a balanced schedule the generator/import will need to generate more or less than the load schedule depending on its loss responsibility. The loss allocated to each SC is then the sum of all losses allocated to each generator/import in that SC's schedule.

The ISO allocates losses to each generator/import based on the respective Hour-Ahead GMM and the generator metered value (the imports are not metered and their value is taken to be the Hour-Ahead schedule). The corresponding GMM is applied to the full value of the generator's/import's metered value, and the result provides the *effective* generation/import, i.e., the amount delivered to the load. The ISO's methodology of deriving the GMMs is described in the next section.

3.3.1. Current Transmission Loss Allocation Derivation

3.3.1.1. Sensitivity Analysis

The GMM for each generator/import is derived from marginal loss rate (*MLR*) analysis. The *MLR* is a sensitivity factor that estimates the change in transmission losses ($\Delta Loss$) to a change in a specific generator/import (ΔP) under the conditions of a change of load in the system ($\Delta Load$), where all other generators/imports are not allowed to change their operating point. The change in generation/import is equal to the change in losses plus the change in the load, i.e., $\Delta P = \Delta Loss + \Delta Load$. Mathematically, the *MLR* is in the form of a partial derivative,

$$\Delta Loss = \frac{\partial Loss}{\partial P} \cdot \Delta P = MLR \cdot \Delta P \, .$$

The marginal loss rate analysis is based on a linearized power flow formulation that incorporates a distributed load slack formulation (see the Appendix for a full description of this analysis). This linearized power flow formulation is based on the Hour-Ahead data and thus derives Hour-Ahead based *MLR*s. In this formulation, the change in load ($\Delta Load$) is accommodated by having *all* loads change in the system at a rate based pro-rata on their initial values. This concept of incrementing all loads pro-rata is referred to as incrementing the *system load-center*.

3.3.1.2. Incremental Analysis – a More Intuitive Analysis

Although the *MLR*s are calculated using true sensitivity analysis, the derivation can also be looked at in terms of incremental analysis as explained below.

Change the system load-center by incrementing *all* the loads in the system, pro-rata based on their initial values, by a very small amount, e.g., a total system load change of 1 MW ($\Delta Load = 1$). Solve the power flow formulation while only letting one generator/import move (ΔP) to balance the system, i.e., this one generator/import would be the slack generator. Recalculate the total system loss and find the difference between the new and old values ($\Delta Loss$). Or equivalently, the change in loss can also be calculated as, $\Delta Loss = \Delta P - \Delta Load$. The marginal loss rate would then approximately be:

$$MLR = \frac{\Delta Loss}{\Delta P} = \frac{\Delta P - \Delta Load}{\Delta P} = 1 - \frac{\Delta Load}{\Delta P} \, .$$

With all loads changed slightly and only one generator/import change, there will, in general, be a resultant change in the electrical current flowing down each branch that transfers the power from this generator/import to all the loads. For each branch, this *change in electrical current flow* will either be positive, zero or negative. If it is positive (negative), a positive (negative) change in the branch loss will result. If it is zero, no loss difference will result. The change in the loss on each branch can be summed, providing a net change in loss value ($\Delta Loss$). This net value may be positive, zero or negative. If negative, this means that the marginal loss rate is negative, and this generator/import actually reduces losses.

3.3.1.3. Scaled Marginal Loss Rates

After the *MLR* data are calculated for all generators/imports, the next step under the ISO's methodology is to determine the total system losses. This value is calculated based on the data from the power flow solution. The *MLR* data are then scaled by α (= total system losses)/(sum of losses as determined by the product of the un-scaled *MLR* and generator/import metered output) to determine the scaled marginal loss rates (*SMLR*). The *SLMR*, when multiplied by the respective generation/import metered output, will provide the losses allocated to that generator/import, and when these losses are summed over all generators/imports, the total will equal the system losses.

3.3.1.4. Generator Meter Multiplier Calculation

The GMM for the generator/import is equal to $1 - (\alpha \cdot MLR)$ or $1 - SMLR$. As noted above, the full-metered output of the generator/import is applied to the GMM. This is equivalent to $P \cdot \text{GMM} = P\,(1 - SMLR) = P - P \cdot SMLR$, where P is the metered value of the generator/import. The term $P \cdot SMLR$ is equal to the transmission losses allocated to that generator/import.

3.3.2. Full vs. Scaled Marginal Loss Rates

What is important about the *MLR*s, is not necessarily the magnitude of the estimation of losses that they produce, but rather the relative value in magnitude (and sign) from one generator/import to another. For example, consider two generators, with MLR_1 = 2%, P_1 = 10, MLR_2 = 3%, and P_2 = 20. The respective loss allocation would be 0.2 and 0.6. If the *MLR*s were scaled by ½, the resultant loss allocations would be 0.1 and 0.3. The key is that P_2 is allocated 3.0 times as much loss responsibility as compared to P_1 in *both* the full and scaled cases, thus preserving any economic signals that these *MLRs* provide.

Because the *MLR*s are linear sensitivity factors, they should be applied with incremental values as noted in the previous section. However, in this methodology, it is assumed that the *MLRs* vary linearly with different system load levels. In other words, the *MLR* for a generator/import stays basically at the value when calculated at different system load level conditions. Under these circumstances, the application of the full-metered value (as opposed to an incremental value) to the *MLR* would approximate the full loss allocation. But, since the *MLR* is a sensitivity factor, it still provides only an estimate and not the exact loss allocation. Since the total system loss is known, these *MLRs* can be scaled so that the summation over each allocation to a generator/import will equal the total system losses without changing the relative loss allocation.

If the *MLRs* were not scaled, the resultant loss allocation to each generator/import would generally be larger in magnitude. If each generator/import would schedule its output to account for this inflated loss allocation, problems such as over-generation, artificial thinning of the Ancillary Services market and artificial depression of the ex-post prices would result. If the full *MLR*s were used and the resultant allocations summed, a typical value of two times the system loss may occur. In fact, in the case study case described below, the value was 1.8 times the actual system loss.

3.4. Schedule Based Transmission Loss Allocation Methodology

A methodology for transmission loss allocation, called the *schedule based transmission loss allocation* (SBTLA), has been developed for the purposes of the loss allocation evaluation. The SBTLA is a modified version of the current algorithm used by the ISO for loss allocation. The SBTLA satisfies the requirements set forth by FERC as described below.

The SBTLA satisfies the Commission's first requirement to the extent that the methodology is based on marginal loss rate analysis; however, scaled marginal loss rates are used instead of full marginal loss rates. The reason for this approach is that the scaled marginal loss rates still preserve the same economic signals of the full marginal loss rates without the undesirable consequences of the full marginal loss rates as noted above.

The SBTLA also satisfies the Commission's second requirement. In the SBTLA, the branches utilized by a SC's generators/imports to serve only the loads/exports in that SC's schedule are identified, and allocation factors based on the extend of branch utilization are determined to allocate branch losses to the SC. A marginal loss rate analysis is then performed to allocate the SC's losses to individual generators/imports with the SC's schedule. This marginal loss rate analysis utilizes a SC-specific load-center instead of a system load-center. In the SC-specific load-center, only those loads/exports in the SC's schedule are taken into consideration in the analysis.

An evaluation of the SBTLA as compared to the current method has been made under the conditions requested by FERC.

The SBTLA methodology consists of two integrated parts. An overview of the two parts and then a more detailed pseudo algorithm, which included detail on how the SBTLA methodology satisfies FERC's requirements, are provided in the next two sections.

3.4.1. Overview of the Schedule Based Transmission Loss Allocation Methodology

The SBTLA methodology consists of two integrated parts Note that this methodology will be applied to hourly scheduled energy data.

1. The first part of this methodology involves calculating the actual system loss allocation for each generator/import (and thus each SC). This part satisfies FERC's second requirement and consists of five sub-parts:

    a. Determine the actual loss on each transmission branch;

    b. By utilizing a DC power flow (DCPF) model (see the Appendix for a description of the DC power flow model) and applying scaled load/export at the respective locations as specified in the SC's schedule, allocation factors, based on the active power flow on the branch, are calculated. These allocation factors are then used to allocate the transmission branch losses to each generator/import.

       This is the crucial step in this process. Only the specific locations of the load/export in the SC's schedule are taken into consideration as well as those branches (where the losses actually occur) that are utilized to transfer the power to serve those loads. In comparison, in the system load-center method, the SC's load (regardless of the actual location as specified in the schedule) is spread proportionately to all load locations throughout the entire system.

       The DCPF formulation is the same formulation used in the ISO's Congestion Management methodology;

    c. Allocate the individual transmission branch losses to individual generators/imports by using the allocation factors;

    d. Calculate the total loss allocated to each generator/import by summing up the allocated loss for each transmission branch; and finally

    e. Calculate the loss allocated to each SC by summing up the losses allocated to each generator/import within that SC's schedule.

2. The second part consists of utilizing marginal loss analysis (a methodology similar to that in the current loss allocation method). This part satisfies FERC's first requirement to the extent of using marginal loss rate analysis and satisfies the second requirement by utilizing a SC-specific load-center. The second part of this methodology consists of two sub-parts:

    a. *MLR*s are calculated for each generator/import in the SC's schedule, except in the SBTLA methodology an SC-specific load-center, based on the loads in the SC's schedule is used instead of the system load-center; and

    b. These *MLR*s are scaled based on the loss allocated to that SC as calculated in Part 1e. Based on these *MLR*s, each generator/import can be assigned a GMM.

The pseudo algorithms for these two integrated parts are given in the next section.

3.4.2. Detailed Pseudo Algorithm of the Schedule Based Transmission Loss Allocation Methodology

This section provides the detailed pseudo algorithm of the SBTLA methodology and highlights several key points.

3.4.2.1. Data Setup:

The data that are used in the evaluation of the current methodology to the SBTLA are the final forward market schedule, i.e., hour-head schedules. When a SC submits an energy schedule to the ISO it may be comprised of:

1) Individual generator/import schedules;

2) Load/export schedules (the load schedules can be either at the demand Zone, load group, or load point level); and

3) Inter-SC trades, where one SC is selling energy to another SC, with a congestion Zone specified as the delivery point of the energy. For a SC, the inter-SC trades may result in:

    a) A net export of energy out of its schedule, i.e., in effect the SC is providing energy to other SCs. This implies that the SC has a larger generation/import schedule as compared to its load schedule;

    b) A net import of energy into its schedule, i.e., in effect the SC is receiving energy from other SCs. This implies that the SC has a larger load/export schedule as compared to its generation/import schedule ; and

    c) A net import (net export) of zero, i.e., in effect the SC is proving energy to other SCs at the same amount it is receiving energy from other SCs. This implies that the SC has a balanced schedule in terms of load/export and generation/import schedule to begin with.

Taking into consideration the inter-SC trades, it is a requirement that an SC's schedule is balanced: total generation/import minus net export of generation due to inter-SC trades plus net import of energy due to inter-SC trades must equal total load/export.

There are two additional requirements placed on a SC's schedule by the SBTLA methodology:

1) *Load schedules at load points*: as noted above, SCs can submit load schedules at the demand Zone, load group or load point level. The SBTLA requires that schedules, if submitted at the demand Zone or load group level, are broken down to the load point level. This breakdown is performed using a set of normalized load distribution factors for each load point that correspond to the demand Zones

and load groups. These load distribution factors are based on the loads modeled in seasonal power flow cases. This pre-processing of the load schedules must be performed so that the load can be applied directly to individual nodes (which are the load points) within the power flow model. This pre-processing is performed in the current transmission loss allocation methodology. The SC does need not submit load schedules at the load point level, however, the data must be pre-processed before being input to the algorithm.

2) *Inter-SC trades*: the SBTLA methodology requires that each SC schedule be balanced in terms of physical generation/import and load/export. As noted above, if a SC is a net importer of energy via inter-SC trades, then its load/export schedule is larger than its generation/import (it must receive extra energy from a trading SC to balance its schedule and thus is a net buyer of generation). In this situation, the net amount of load/export in its schedule will be shifted to those SCs that are supplying it with energy. Due to the pre-processing of all load schedules to the load point level, the load will not be shifted from the physical load point – the load will stay in its place. Rather the role of load scheduler will transfer from the net buyer to those who are supplying the energy. The details of how this inter-SC load transfer takes place are described in the Appendix.

Since it is the generator's/import's responsibility to account for the losses, the idea of transferring the load that the generator/import is really serving via the inter-SC trade, into the serving SC's schedule is consistent with the process described above.

3.4.2.2. Part 1 of the Pseudo Algorithm:

The five sub-parts of part 1 of the SBTLA methodology are as follows:.

1. Determine the actual loss on each transmission branch.

   All SC generation/import and load/export schedules are applied to the full AC power flow model,[9] and a power flow solution is calculated. The power flow formulation used in this solution is a distributed generation slack, where all generators (with non zero schedules) are participating based pro-rata on their maximum generation values. This formulation is used in the ISO's current methodology.

   Losses on each branch are calculated via I^2r, where I is the magnitude of the current and r is the transmission branch or transformer resistance (both transformers and transmission branches are referred to generally as branches). Let BL_b be the branch loss for branch b.

2. Calculate branch loss allocation factors corresponding to each branch in the system for each generator/import over all SC schedules.

[9] The reactive load is set at each node by using predefined power factors for each load node.

Consider SC *i*.

Let R_j be the Hour-Ahead effective energy value (excluding any estimated loss obligation) for the j^{th} generator/import in SC *I*'s schedule.

At this point, all load schedules have been processed so all load is at the load point level. Let L_k be the Hour-Ahead energy value of the k^{th} load point/export in SC *I*'s schedule.

Note that both the generator/import and load point/export are each located at a specific node in the power system model (the load point is a node).

Note that, due to the balanced schedule constraint,

$$\sum_{\text{over } j} R_j = \sum_{\text{over } k} L_k .$$

Apply each generator/import and an equal amount of load/export, one at a time, to the DCPF model and determine branch loss allocation factors. The load values at each load point/export are scaled based on the ratio of R_j to $\sum_{\text{over } j} R_j$. Let

$$ratio = \frac{R_j}{\sum_{\text{over } j} R_j} .$$

Scale the value at each load point/export,

$$L'_k = ratio \cdot L_k .$$

Setup the net injection vector, $\boldsymbol{P}_{netinj}$, as defined in the Appendix. This consists of applying R_j to its respective node and applying the *negative*[10] of each L'_k on its respective node. The DCPF matrix equation is then solved for the angle vector.

Based in the node angles, calculate the active power flows across each branch. The branch loss allocation factor for each branch is taken to be the active power flow. Let this factor be denoted as,

$$BLAF_{I,j,b.}$$

Where *b* denotes the branch. A factor is determined for all branches in the system.

This process is repeated for all generators/imports in SC *I*'s schedule.

[10] The reference direction for power is into the network, thus the load value is made negative.

Go to the next SC and again repeat the process through all generators/imports in the SC's schedule.

If there are R_n number of total generators/imports being scheduled and B_n number of branches there will be $R_n \times B_n$ number of *BLAF* factors.

Discussion:

- The assumption is made that each generator/import in a SC's schedule serves a proportionate amount of load/export throughout that SC's load/export schedule.

- Since the DCPF is a linear formulation, the superposition property holds for the active power flow (which are the branch loss allocation factors) across each branch. In other words, if two generators/imports were applied to the system (as described above) separately, the two corresponding branch flows on any branch would equal the branch flow (on the same branch) if both generators/imports were applied together (along with both corresponding sets of scaled load points/exports).

- With all generators/imports applied to the DCPF formulation, the corresponding active power flow on any branch should approximately equal the active power flow across that same branch as determined by the full AC power flow model. In a full AC power system model with high power factor loads, i.e., relatively small reactive loads, and near nominal voltages (as is the case with the ISO system), the active power flow across a branch is approximately equal to the magnitude of the current flowing through the branch (in per-unit terms). Combining these two approximations, the active power flow across a branch in the DCPF model should be approximately equal to the magnitude of the current in the full AC model.

  Thus, by applying each generator/import to the DPCF model one at a time with an equal amount of load/export proportionately allocated at the locations specified in the SC's schedule, an approximation can be made of that generator's/import's contribution to the total current magnitude through each branch. This is due to the superposition property and the fact the DCPF active power flow approximates the current magnitude.

  This concept takes into consideration the location of the generators/imports with respect to the loads/exports that are part of the SC's schedule. If generation/import are close to load/export then the electrical current contribution on those branches electrically close to the generation/import and load/export will be relatively larger than those branches that are remote to the generation/import and load/export. And in turn, the generator/import should be allocated a higher proportion of the losses on those branches as compared to the allocation for the remote branches.

  The loss on a branch is actually proportional to the magnitude of the branch current squared (branch loss = I^2r). With the above stated approximations, the losses on the branch should be approximately proportionate to the square of the DCPF derived active power flow across the branch.

However, in this methodology, the square of the active power flow is not used, but rather the value of active power flow itself is used. The reason for this is that, although there can be only one SC that schedules energy for a generator, there can be many SCs scheduling energy at an intertie, and any SC can specify a value for an import energy schedule more than once with its schedule. If the square term was used, an SC could, for example, submit many small schedules for an import, which could result in small (less than 1.0) active power flows. If the active power flow was less than 1.0, the square of the active power flow would be even smaller, resulting in less allocation for this SC. The loss allocation to this SC for that import could then be much smaller than if the SC had just listed the import once in its schedule at the aggregate value. This kind of gaming can be avoided with a linear branch loss allocation.

3. Allocate the transmission branch loss to each generator/import by using the allocation factors. This allocation method is referred to as the *NetFlow* allocation.

Now that the branch loss allocation factors are calculated for each generator/import, the actual branch loss must be allocated to each generator/import based on these factors.

Consider branch b with branch loss, $BranchLoss_b$, and the set of branch loss allocation factors $BLAF_{I,j,b}$:

Note that, since the superposition property holds in this methodology, the corresponding flow on branch b with all generators/imports applied (call this active power flow the *NetFlow*) is equal to the summation of the active power flows as determined by applying one generator/import at a time.

Let the summation of all branch loss allocation factors (i.e., the active power flows) that flow in the same direction as the *NetFlow* be denoted as *WithFlow* and the summation of those that flow in the opposite direction be the *AgainstFlow.*

Determine the loss per net active power flow as,

$$LossPerNetFlow = \frac{BranchLoss_b}{NetFlow} .$$

The generators/imports with flows in *WithFlow* are allocated in aggregate (or debited) the branch loss as,

$$DebitedLoss = WithFlow \times LossPerNetFlow.$$

Since we cannot allocate more or less than the actual branch loss, the generators/imports with flows in *AgainstFlow* are credited in aggregate with the amount equal to,

$$CreditedLoss = DebitedLoss - BranchLoss_{b.}$$

Now all generators/imports with flows in *WithFlow* are allocated the *DebitedLoss* pro-rata on the their branch loss allocation factors (which are their active power flows on the branch). Similarly, all generators/import with flows in the *AgainstFlow* are credited the *CreditedLoss* pro-rata on the their branch loss allocation factors.

In the event that the absolute value of *NetFlow* is below a certain relatively small threshold, such as 1×10^{-7}, but there are non-zero branch loss allocation factors, the branch loss is allocated pro-rata on the absolute value of the allocation factors.

Discussion:

In the standard case, where |*NetFlow*| is larger than the given threshold the *WithFlow,* generator/imports will be allocated as a whole an amount equal to or greater than the value of the actual branch loss. Likewise, the *AgainstFlow* generator/imports will be allocated as a whole an amount equal to or less than zero. The reason for this is that the generators/imports in the *AgainstFlow* are actually reducing the current flow on the branch and thus the losses by scheduling energy in the counter (against) direction. Thus, these generators/imports will receive a credit. Without these schedules, the current flow on the branch would be larger, and a larger loss would result. This is why the *WithFlow* is debited potentially with a larger amount of losses.

4. Calculate the total loss allocated to each generator/import per SC by summing up the allocated loss for each transmission branch; and

   In this step, the loss allocated (debited or credited) to each generator/import is added to the running total for each generator/import as the process in step 3 is continued through all the branches.

5. Calculate the loss allocated to each SC by summing up the losses allocated to each generator/import within that SC's schedule.

   In this step, the loss allocated (debited or credited) to each generator/import is similarly added to the running total for each SC for which that generator/import belongs as the process in step 3 is continued through all the branches. Let this loss for SC *I* be denoted as, $SCLoss_i$.

Discussion:

There are other allocation methods that could be implemented, such as the use of absolute values of the branch loss allocation factors. In this case, there would be no credit given to anyone generator/import and the allocation would be based just on the amount of use of the branch.

The *NetFlow* allocation concept is consistent with marginal loss analysis (FERC's first requirement). It is possible for marginal loss rates to be negative, indicating that a small positive increase in generation/import will create a slightly lower total system loss. The generators/imports in the *AgainstFlow* have this same impact. Thus, the *NetFlow* method is compatible in determining loss allocations to the SCs which in turn will be allocated back to the generators/imports within that SC's schedule based on SC-specific marginal loss rate analysis.

Example:

> For this example, let there be 3 SCs, each with 2 generator/imports. The loss allocation (debited/credited) to each generator/import will be shown for a branch with losses of 10 (the actual unit of measure is not important in this example). The following table shows the example branch loss allocation factors for each generator/import for the branch.

Table 3-1 *Example branch loss allocation factor data*

SC Name	SC Gen/Import	BLAF	Loss Allocation
SC1	Gen11	10	2.222
SC1	Gen12	– 2	– 0.444
SC2	Gen21	20	4.444
SC2	Gen22	20	4.444
SC3	Gen31	– 2	– 0.444
SC3	Gen32	– 1	– 0.222

The *NetFlow* = 10 –2 + 20 + 20 –2 –1 = 45.

The *WithFlow* = 10 + 20 + 20 = 50.

The *AgainstFlow* = – 2 – 2 –1.

The *LossPerNetFlow* is 10/45.

The loss allocated (debited) to the *WithFlow* is 50 × 10/45 = 100/9 = 11.11.

The loss credited to the *AgainstFlow* is 11.11 – 10 = 1.11.

The debited loss is allocated to each of the generators/imports with flow in the same direction as the *NetFlow*. These are SC1/Gen11, SC2/Gen21, and SC2/Gen22. The loss allocations to these 3 generators are:

SC1/Gen11: 10/50 × 11.11 = 2.222.

SC2/Gen21: 20/50 × 11.11 = 4.444.

SC2/Gen22 20/50 × 11.11 = 4.444.

Similarly, the credits to the other 3 generators with flow in the same direction as the *AgainstFlow* are:

SC1/Gen12: 2/5 × 1.11 = 0.444.

SC3/Gen31: 2/5 × 1.11 = 0.444.

SC3/Gen32 1/5 × 1.11 = 0.222.

Note that the sum of the loss allocations is equal to 10, the branch loss.

3.4.2.3. Part 2 of the Pseudo Algorithm:

The second part of the SBTLA consists of utilizing an SC-specific marginal loss rate analysis. The two sub-parts are as follows:.

Consider SC *i*.

1. The *MLR*s are calculated for each generator/import in the SC's schedule, except that in the SBTLA methodology a SC-specific load-center, based on the loads in the SC's schedule, is used instead of the system load-center (which is used in the present methodology). The methodology for calculating the *MLR* is given below (refer to the Appendix, for a more full description of this methodology).

Calculate the load/export distribution factors for each load/export in SC *I*'s schedule.

As noted above, L_k is a load point/export in SC *I*'s schedule. Let the k^{th} load point/export correspond to the m^{th} node in the power system model. Let NL_m be the hour energy value corresponding to L_k at node *m*.

A load distribution factor is calculated for each node *j* that corresponds to a load point/export in SC *I*'s schedule. This corresponds to SC *I*'s specific load-center,

$$\beta_m = \frac{NL_m}{\sum_{\text{over } m} NL_m}.$$

The load distribution factors are then inserted into the active power flow Jacobian matrix as shown (refer to the Appendix for the notation used in this matrix). Even though the matrix below shows a load distribution factor for each node, all distribution factors are zero, except for those calculated by the above equation.

$$\begin{bmatrix} \frac{\partial P_{mismatch,1}}{\partial \theta_1} & \cdots & \frac{\partial P_{mismatch,1}}{\partial \theta_{N-1}} & -\beta_1 \\ \vdots & \ddots & \vdots & \vdots \\ \frac{\partial P_{mismatch,N}}{\partial \theta_1} & \cdots & \frac{\partial P_{mismatch,N}}{\partial \theta_{N-1}} & -\beta_N \end{bmatrix}.$$

As noted above, R_j is a generator/import in SC *I*'s schedule. Let the j^{th} generator/import correspond to the n^{th} node in the power system model. Now for j^{th} generator/import in the system, a –1 is inserted into the corresponding n^{th} position in the right-side vector (as shown below) and the following linear is solved for the term $\dfrac{\partial \Psi}{\partial P_{gen,n}}$. In this notation $P_{gen,n}$ is generation/import at the n^{th} node.

$$\begin{bmatrix} \dfrac{\partial \theta_1}{\partial P_{gen,n}} \\ \vdots \\ \dfrac{\partial \theta_{N-1}}{\partial P_{gen,n}} \\ \underbrace{\dfrac{\partial \Psi}{\partial P_{gen,n}}}_{\text{the value we want}} \end{bmatrix} = \begin{bmatrix} \dfrac{\partial P_{mismatch,1}}{\partial \theta_1} & \cdots & \dfrac{\partial P_{mismatch,1}}{\partial \theta_{N-1}} & -\beta_1 \\ \vdots & \ddots & \vdots & \vdots \\ \dfrac{\partial P_{mismatch,N}}{\partial \theta_1} & \cdots & \dfrac{\partial P_{mismatch,N}}{\partial \theta_{N-1}} & -\beta_N \end{bmatrix}^{-1} \begin{bmatrix} 0 \\ \vdots \\ \underbrace{-1}_{\text{let this be the } n^{th} \text{ position}} \\ 0 \end{bmatrix}.$$

From this term, the *MLR* for the generator/import, R_j can be found by,

$$MLR_j = \frac{\partial L_{system}}{\partial P_{gen,n}} = 1 - \frac{\partial \Psi}{\partial P_{gen,n}}.$$

This process is repeated for all generators/imports in SC *I*'s schedule.

2. The *MLR*s for each generator/import in SC *I*'s schedule are scaled based on the loss allocated to that SC as calculated in *NetFlow* method. Based on these scaled *MLR*s, each generator/import can be assigned a GMM, i.e., a SC-specific GMM.

Calculate the scaling factor that will be used to scale the *MLR*s,

$$\alpha = \frac{SCLoss_i}{\sum_{\text{over } j} R_j \cdot MLR_j}.$$

Scale each *MLR* to derive a scaled marginal loss rate (*SMLR*),

$$SMLR_j = \alpha \times MLR_{j.}$$

A GMM is then calculated for each generator/import,

$$GMM_j = 1 - SMLR_{j.}$$

Note that this second part of the SBTLA methodology meets FERC's first requirement for use of marginal loss analysis, albeit, scaled marginal analysis. This part also satisfies requirement 2. An SC-specific load-center, which takes into account only those load/exports in the SC's schedule, is used. By looking at this in terms of the incremental analysis as provided in Section 3.3.1.2.

3.4.3. Loads Allocations of the System Load-center vs. SC-specific Load-center

In the SBTLA methodology, the SC's load schedule (with location) is taken into account in both the *NetFlow* method (which determines the loss allocation to SCs) and in the SC-specific load-center based marginal analysis (which uses the loss allocations from *NetFlow*). The present methodology for allocating system losses uses a system load-center. Both methods have been presented and the following example may help to distinguish and highlight the differences between the two methodologies.

Consider another example with three SCs, where each only schedules one generator. The following figure is a one-line diagram of a power system with six nodes (N1, …, N6), three load points (L1, L2 and L3), three generators (G1, G2 and G3) and six branches (B1, …, B6). The table below provides the generation and load schedules (at load points) for each SC (the unit of measure are not important in this example).

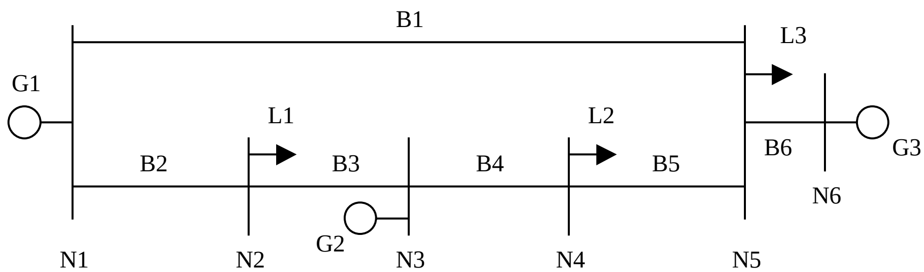


Figure 3-1 *Example one line diagram*

The system load-center concept can be looked at as an SC-specific load-center with SC loads redistributed to all load points so that the total SC load stays the same and the total load on each load point also stays the same.

Recall that, in the system load center (refer to Section 3.3.1.2 for the incremental analysis of this method), the load change is accommodated by changing all the loads at each load point pro-rata based on their initial values. This change in load is actually performed through load distribution factors (LDFs). These are the percent of total load on a load point divided by the total system load. The LDFs are shown in the table. In terms of the incremental analysis, if the system load is incremented by 1 unit, the individual load points (L1, L2 and L3) would be incremented by 0.375, 0.125 and .500 units, respectively.

If the total load for each SC were distributed to each load point using these LDFs, the total SC load would stay the same, and the total load on each load point would also stay the same. Therefore, this redistribution of load can be thought of more as a redistribution of the *responsibility* of scheduling a portion of the load, rather than an actual shift of load. And since the total load on each load points has not changed the flows on each branch will remain the same as before the distribution.

For example, SC1 has a total load of 5 units, and the LDF for L1 is 0.375 units; the new load responsibility on L1 (it was 5 units) for SC1 would now be 1.875 = 5.0 × 0.375

units. Also, for example, SC3 has no load scheduled on load point L2, but now it is responsible for 2.500 units. The new load schedules are shown in the bottom half of the table.

Now, for example, when system load-center marginal loss rate analysis (think of the more intuitive incremental analysis) is applied to Generator 1, the actual increment in the load can be seen as an increment in SC1's load. Thus, the similarity to the SC-specific load-center is exposed.

This example demonstrates how the actual locational responsibilities of the loads are lost in the present (system load center) methodology, whereas in the SBTLA they are preserved. And in turn, the resulting marginal loss rates will be different.

Table 3-2 Changes in Locational Responsibilities for load scheduling

SC/Gen	Gen	L1	L2	L3	Total Load Per SC
SC1/G1	5	5	0	0	5.0
SC2/G2	15	10	5	0	15.0
SC3/G3	20	0	0	20	20.0
Total Node Load		15	5	20	40.0
% Load to Total Load (LDFs)		0.375	0.125	0.500	
Redistributed SC Load		System Load-Center Loads			
SC1/G1	5	1.875	0.625	2.500	5.0
SC2/G2	15	5.625	1.875	7.500	15.0
SC3/G3	20	7.500	2.500	10.000	20.0
Total Node Load		15	5	20	40.0

3.5. Evaluation of the Schedule Based Transmission Loss Allocation Methodology to the Current Methodology

The results of the evaluation of the SBTLA methodology as compared to the current methodology are given in this section. The evaluation is performed on an SC level basis by comparing loss values and monetary values allocated to a SC under the SBTLA method as compared to those allocated to the same SC under the current method. The ISO allocates the losses based on meter data, however, for this evaluation, it is assumed that all generators/imports follow their Hour-Ahead schedule and, as such, Hour-Ahead generator/import schedules are used in place of metered values.

Note that, in the results presentation, true SC names are masked and the index used in this presentation is **not** the same as that used in the study of the Congestion Zone criteria.

3.5.1. Data Used in the Evaluation

The third requirement of FERC for this study is to evaluate the SBTLA method vs. the current method under a variety of transactions that reflect differences in distance and direction between the generator and load, as well as differences in line loading. This requirement is satisfied by using 72 hours of actual Hour-Ahead scheduling data with the following attributes:

1. The 72 hours span over 1 year, starting from 4/22/1998 to 3/21/1999; and

2. The 72 hours all come from 24 distinct days with 3 hours in each day. There are approximately 2 days in each month over the date range, with one day being a weekday and the other a weekend. The 3 hours in the day consists of a *peak* hour from 4 to 5 PM, a *partial peak* period from 10 to 11 PM and an *off peak* period from 4 to 5 AM.

The exact hours of study are given in the Appendix, along with the uninstructed zonal ex-post prices, the total system loss, the aggregate Hour-Ahead load schedule and the percent of losses to load.

3.5.2. SC Loss Allocation Comparison

Three sets of SC loss allocation comparisons are presented:

1. A comparison of the average percentage of allocated losses to scheduled load/export per SC per peak, partial peak and off peak periods; plus a comparison of the average percentages over all the hours in the study set.

2. A comparison of the loss allocations for the largest Hour-Ahead scheduled aggregate load over the period 3/31/1998 to 3/31/1999.

   This aggregate Hour-Ahead schedule is 46,050 MWh and occurred on 8/4/1998, 4 to 5 PM. Since this is a single hour, the proximity of the generators/imports to the loads/exports will be investigated and a correlation to the allocations will be made.

3. A comparison of the weighted average price ($/MWh) for losses per SC under the two methods .

3.5.2.1. A Comparison of the Average Percentage of Loss Allocation to Load per SC by Peak, Partial Peak and Off Peak Period Hours

This section provides bar graphs showing the average percentage of loss allocation to scheduled load/export per SC, by peak, partial peak and off-peak periods and over all hours in the study set. Note that the percentage of total system losses to total scheduled load/export for each hour of the study set is provided in the Appendix.

As noted, there are 24 peak, partial peak and off peak hours in the study set. For each SC, the percentage of loss allocation to scheduled load/export (for that SC in that hour) is calculated for each of the 24 hours (if the SC has scheduled load for that hour) in a period (peak, partial or off peak). These percentages are then summed and divided by the number of hours the SC scheduled load/export in that period to give the average loss allocation to scheduled load/export. A similar procedure is followed for the percentages over all hours.

These percentages provide a good measure of the loss allocation to an SC and is thus used in the comparison of the current method to the SBTLA method.

A detailed analysis of these average percentages of loss allocation to load/export is not given, since these results are based on averaging over the whole study set. Rather, these results are provided to show the similarities and differences in the allocations per SC over the study set.

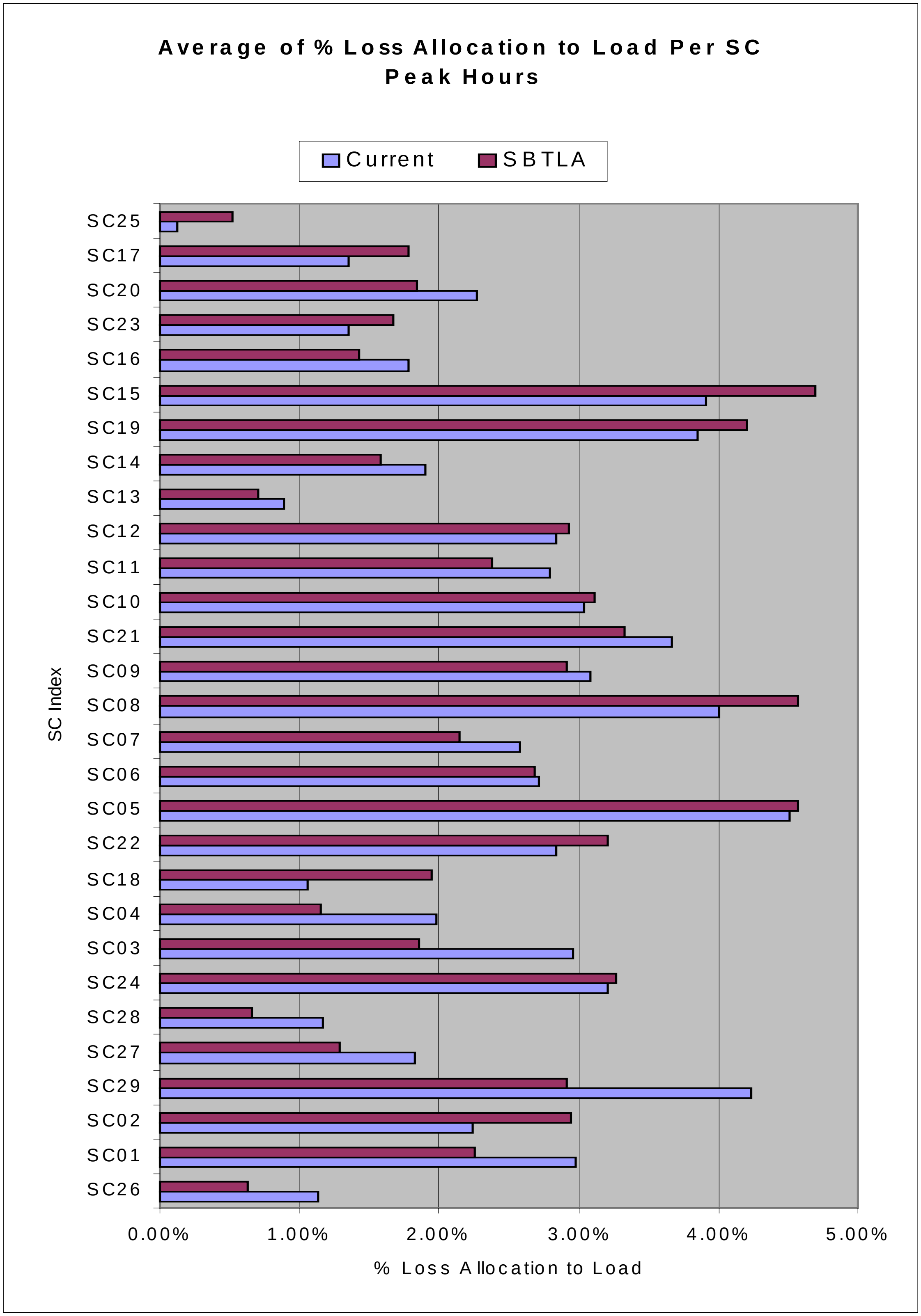


Figure 3-2 *Average % of loss allocation to load, peak hours*

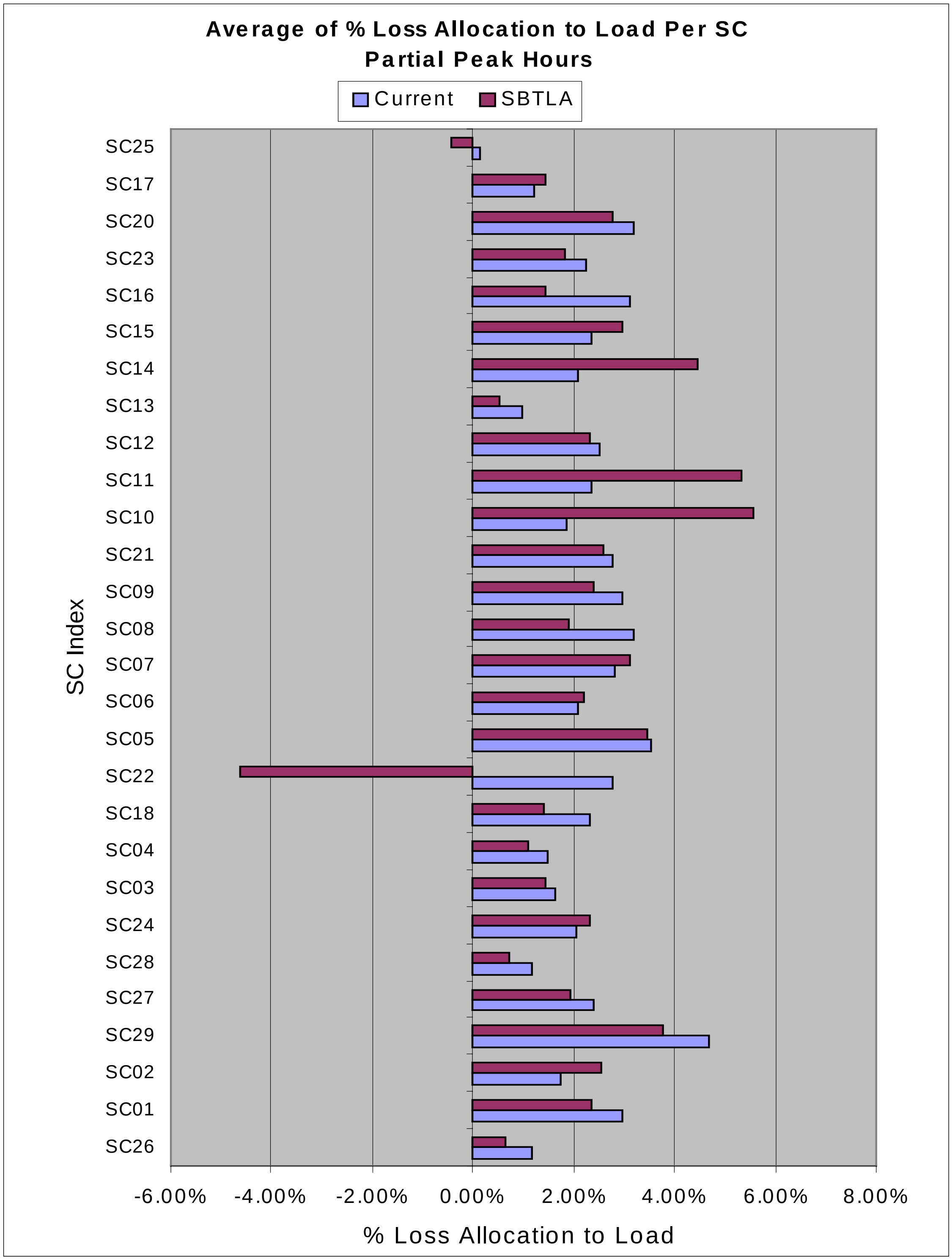


Figure 3-3 *Average % of loss allocation to load, partial peak hours*

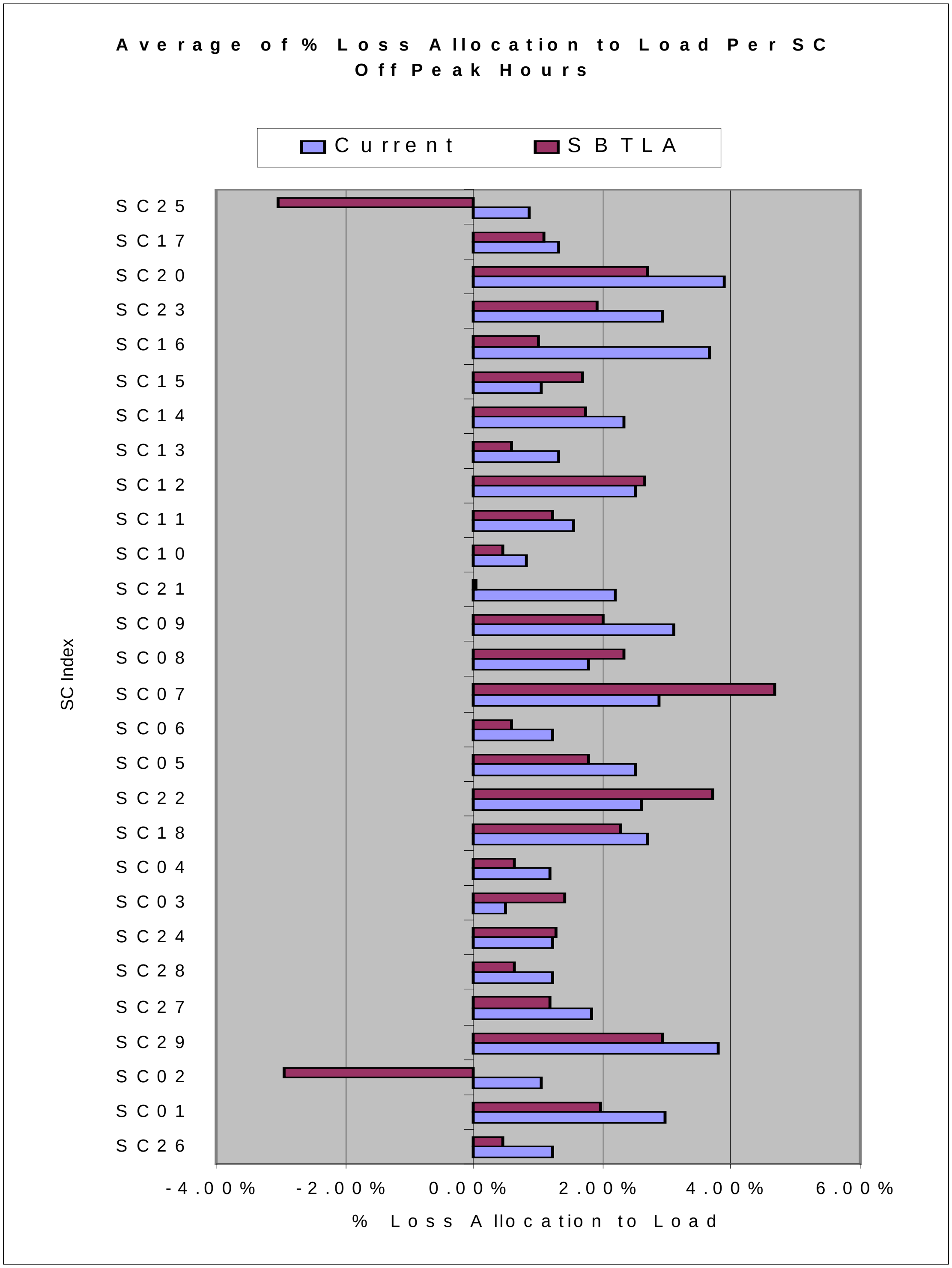


Figure 3-4 *Average % of loss allocation to load, off peak hours*

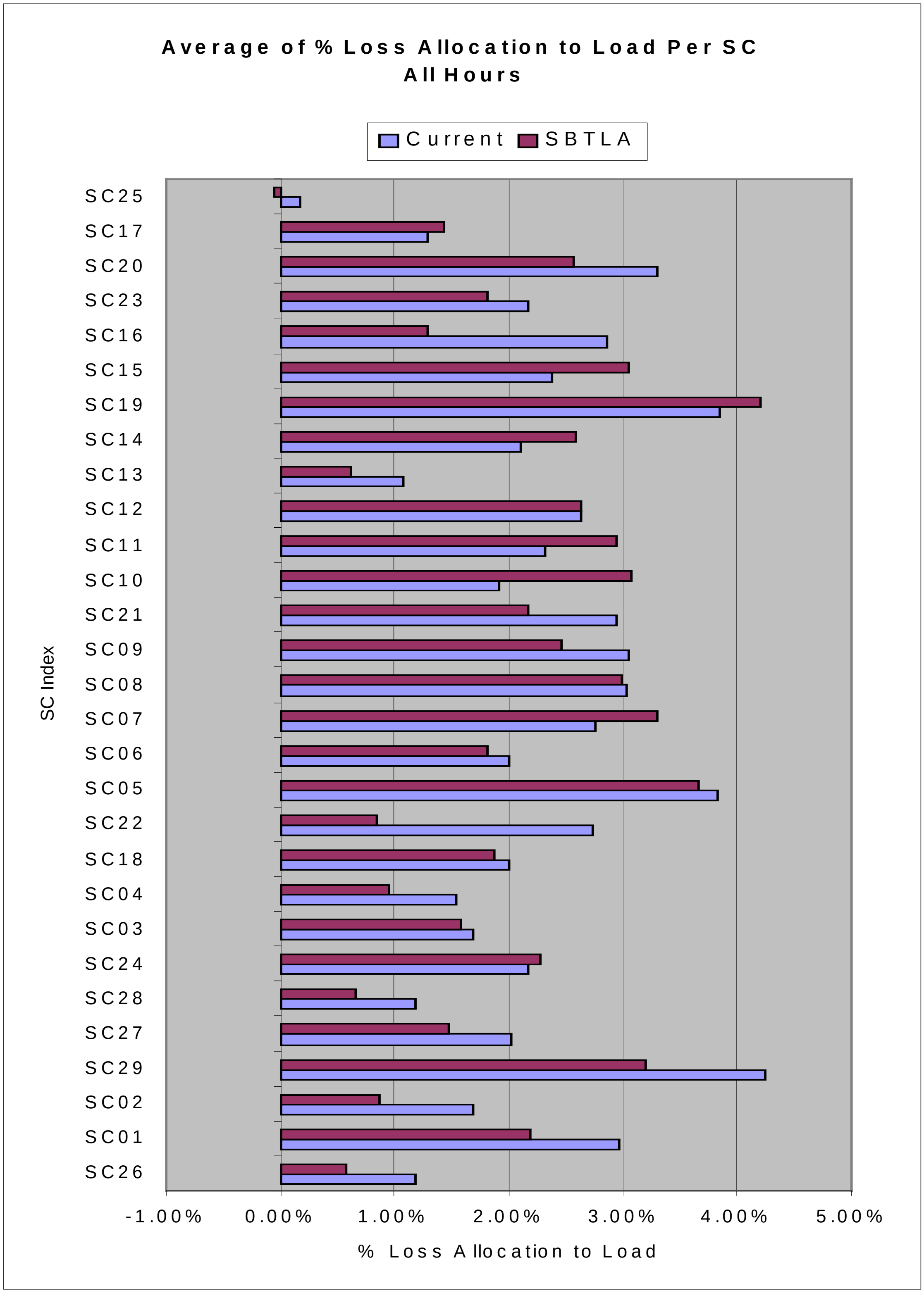


Figure 3-5 *Average % of loss allocation to load, all hours*

These results show:

1. For the majority of the SCs, over the 3 periods (peak, partial and off) and over all the hours, the average percentage of allocated loss to load/export under the two allocation methodologies are comparable. The results are even more comparable in the peak period. The reason for this is that the load is larger and generally more distributed in the peak period than in the other two. And as an SC's demand schedule more resembles the load distribution, as defined by the system load-center, the results should become more comparable.

2. For a few SCs, there is a distinct difference in the allocations, e.g., SC02 and SC25 in the off peak period and SC22 in the partial peak period.

3.5.2.2. A Comparison of the Loss Allocations for 8/4/1998, 4 to 5 PM Hour-Ahead Schedule

The following two bar charts show the loss allocations per SC for 8/4/1998, 4 to 5 PM, which was the date/hour in the first year of the ISO's operation that had the largest Hour-Ahead aggregate schedule. Note that there are different MWh scales for these two charts.

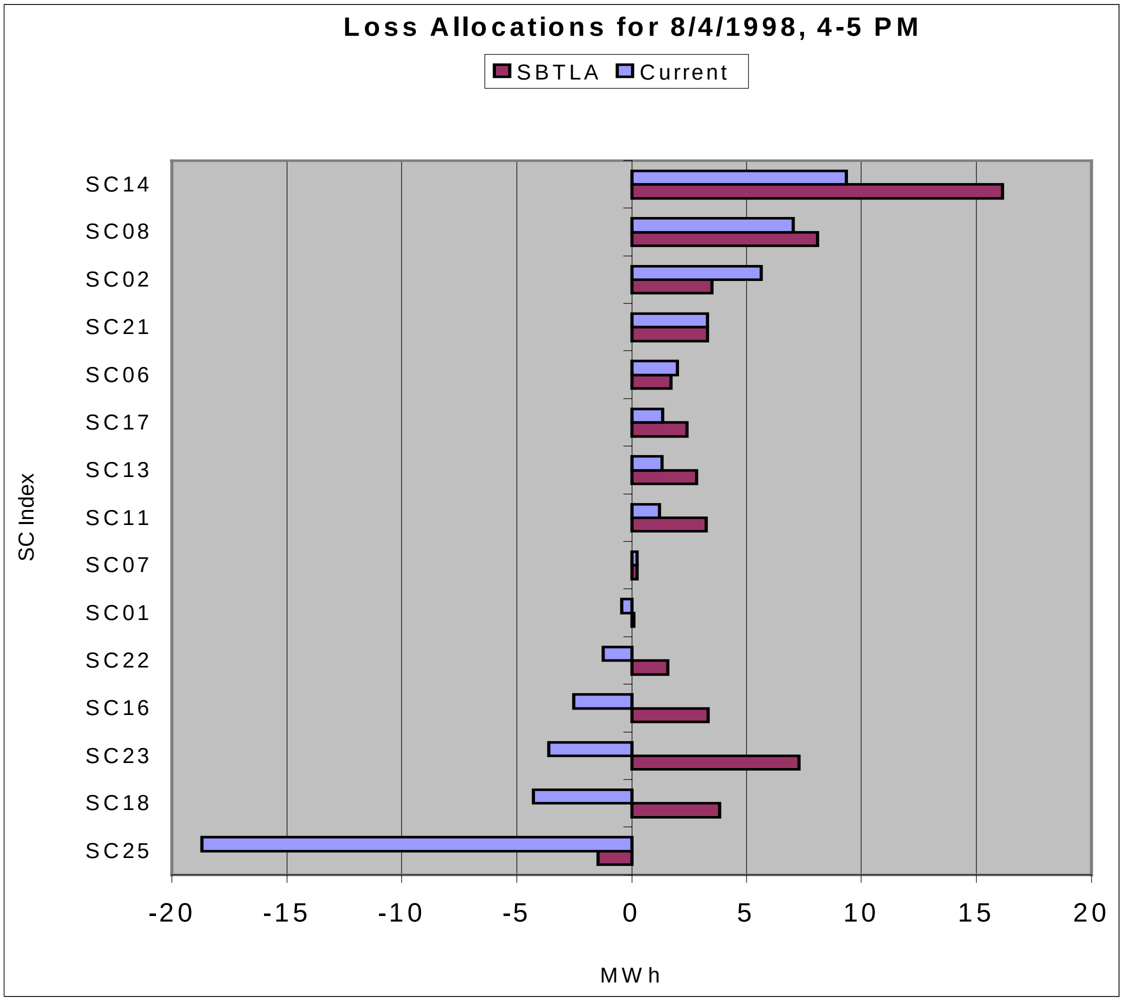


Figure 3-6 *Loss allocation comparison for August, 4, 1998, 4 –5 PM*

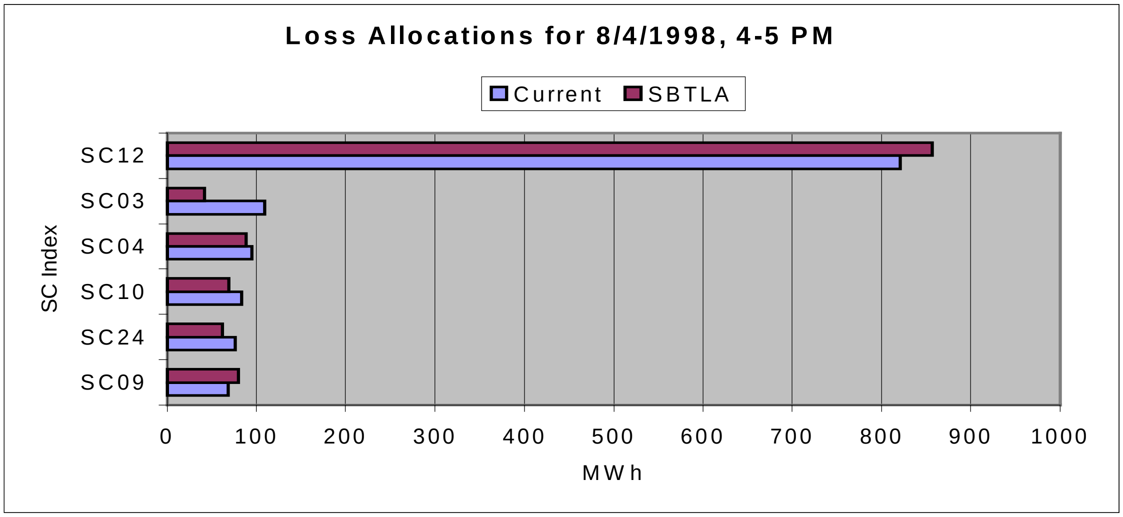


Figure 3-7 *Loss allocation comparison for August, 4, 1998, 4 –5 PM*

Discussion:

The majority of the SCs have comparable allocations under the SBTLA method as compared to the current ISO method. But, also there are a few SCs with some distinct differences.

The reason for the comparable results for the majority of the SCs is that these SC's, demand schedule resembles the system load-center. In other words, their demand is already actually spread out to the majority of the load points. Thus, the current ISO method (system load-center) has little effect on this load distribution and consequently the loss allocation.

The reason for differences in allocations for some SCs can also be explained by their load distribution (as seen in their demand schedule) as compared to the system load-center. Three SC allocations are analyzed: SC25, SC18 and SC03. These cases are analyzed due to the distinct shifts in their respective loss allocation.

SC25:

> SC25 has a loss allocation of –18 MWh under the current method and a loss allocation of only –1.5 under the SBTLA method (in both cases this SC is credited with the loss allocation).
>
> SC25 has several generators/imports most of which have negative *MLRs* (GMMs greater than 1.0) under the current method of the system load-center. Under this method, when there is an incremental shift in the load-center, only one of these generators/imports is allowed to move its operating point in order to balance out the system. In doing so there is a greater reduction in losses on various branches throughout the whole system (it is important to remember that in the system load-

center, the SC25's loads are distributed to all load points) than increases in losses on various other branches.

Under the SBTLA method, the loads/exports are placed at the load points as specified in SC25's schedule. The results of the SBTLA methodology show that two of these generators/imports still have negative loss allocation. These are situated relative to their loads that on the branches they now utilize to send power from the generator/import to the loads, net reductions in the branch losses still occur. In this situation, this SC still utilizes many of the branches they did in the system load-center method.

However, the rest of SC25's generators/imports are now all allocated positive losses. Each one of these generators/imports are situated relative to their loads such that there is now a net increase in the losses on the branches they utilize.

Overall, the reduction in the system loss is greater than the increase and loss allocated to SC25 is negative, but the magnitude is smaller as compared to the current method.

SC18:

SC18 has a loss allocation of –4 MWh under the current method and a loss allocation of + 4 MWh under the SBTLA method.

The situation is similar to that of SC25. SC18 has only a few generators/imports in its schedule and in the current method, utilizing the system load-center, most of these generators/imports have negative marginal loss rates. However, in the SBTLA method, all of SC18's generators/imports are allocated positive losses. Now when the relative location of each generator/import to its loads/exports in the schedule is taken into account, the losses on the branches that are utilized are increased.

In other words, in the current method, the generators/imports send power throughout the entire system to their loads at the system load-center, with a net result of reducing losses. There were some branches however where the losses were increased, albeit the net effect is still a reduction in losses. Now in the SBTLA where SC18's loads/exports are at the location specified in the schedule, some of these same branches are utilized to cause a net increase in branch losses.

SC03:

SC03 has a loss allocation of + 110 MWh under the current method and a loss allocation of + 40 MWh under the SBTLA method.

SC03 has a few generators, and these generators and its scheduled load are all in the congestion Zone NP15. Under the current method, this load is allocated to all load points through the entire system. However, in the SBTLA method, only those branches in NP15 are utilized in sending power to the load. Thus, there is a decrease in losses since many fewer branches are utilized in transferring the power from its generators/imports to it loads/exports.

3.5.2.3. Monetary Comparison

The following chart shows the weighted average price for losses per SC over the 72-hour study set for the current allocation method and the SBTLA method.

This weighted average price for losses per SC was calculated by first finding the total cost of losses for each SC. These costs are calculated by multiplying the loss allocated to each generator/imports by the applicable zonal uninstructed ex post price, summing over all generators/imports for the SC and then summing over all the hours. The total cost is then divided by the absolute value of the total loss allocated to the SC via the summation over all losses allocated to its generators/imports over all the hours. This ratio results in the weighted average price for losses per SC, where the weights are the hourly loss allocations.

The absolute value is taken on the total and not on each individual generator/import allocation. The absolute value of the total MWh loss allocation preserves the indication of a total cost credit or debit to the SC in the weighted average price for losses. Thus, if the weighted average price for losses is negative, this means that the SC is receiving a cost credit for losses.

Note, *that it is assumed for this comparison that the generator/import did not pick up any of its loss obligation.*

There are two $250/MWh ex post price hours in the 72-hour study set (see the Appendix for a listing). These two hours are more than 3 standard deviations from the average ex post price. Likewise, the corresponding total system losses for these two hours are also more than 3 standard deviations from the average system loss. Because these two hours are more than 3 standard deviations, they were omitted from the results, since they would tend to skew the weighted average price for losses results.

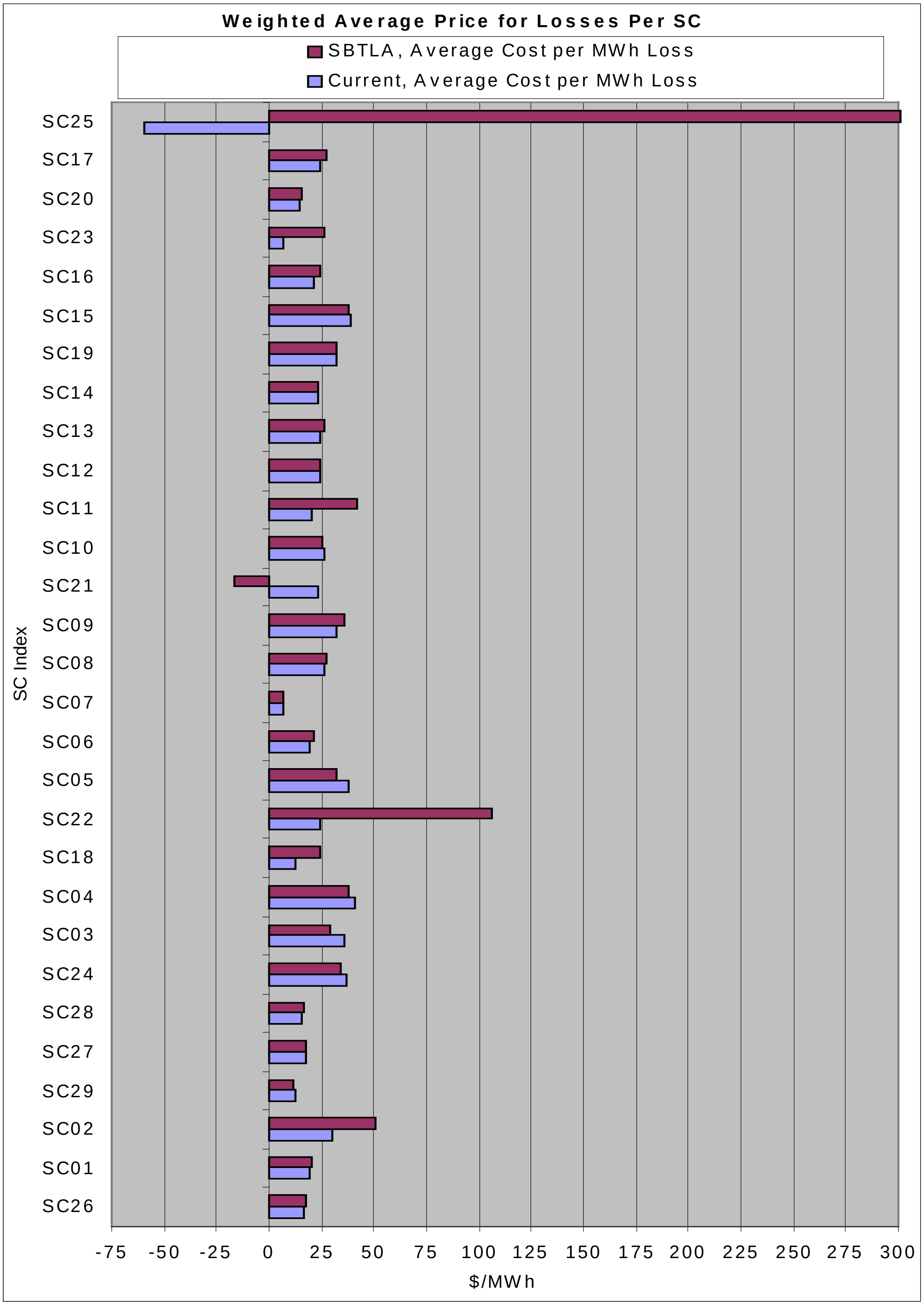


Figure 3-8 *Weighted average price for losses per SC*

These results provide the monetary comparison of the current loss allocation to the SBTLA methodology that was requested by FERC. The results show that, for the majority of the SCs, the weighted average price for losses is comparable under the current method and the STBLA method, and overall, the majority of the weighted average prices for losses per SC are comparable to the ex post prices for the study set (these prices are listed in the Appendix). Although, there are a few SCs that have distinct changes. Two of these, SC25 and SC21, will be considered in detail below.

The results may be misleading for SC25. Under the current allocation method and over the hours in the study set, SC25 is provided a loss allocation credit (e.g., see the results for 8/4/1998, 4-5 PM above) and is issued a net cost credit. Note that the total loss allocation data and total cost data for each SC over the study set are not provided in this report. Under the SBTLA method, SC25 has a combination of many generator/imports with positive loss allocation as well as negative loss allocations with the net loss allocation being a relatively small positive value (as compared to the negative allocation under the current method). It just so happens that those hours with a higher ex-post price correspond to the majority of the positive loss allocations, resulting is a net positive cost to SC25. Thus, the total cost to SC25 is high as compared to the small positive net loss it is allocated, and this effect creates the larger weighted average price for the allocated loss.

Under the current method, SC21 has a positive weighted average price for losses. Both the total cost and total loss allocations are positive. On the other hand, SC21 has a negative weighted average price for losses under the SBTLA method. The loss allocation for SC21 is, however, a net positive quantity, which is composed of both negative and positive quantities (associated with SC21's generators/imports). However, the total cost to SC21 is negative, due again to the circumstance that the negative quantities are paired up with larger ex post prices.

These results also point out the fact that the comparison of the MWh loss allocation may not be sufficient. A net positive allocation may result, whereas, there is a net credit to the SC as shown for SC21.

3.6. Conclusions

An evaluation and comparison of the current ISO method for allocating transmission losses with. The modified methodology requested by FERC has been preformed and the results are shown in this report.

As discussed, most SC's demand schedules resemble the system load-center, therefore, the ISO concludes that the current method for allocating transmission losses is for the most part fair and equitable. The simulations, which compared the current ISO method to the SBTLA method, indicate that there are some refinements in allocating losses that can be made.. However, the objective of equitable allocation of transmission losses must be balanced with potential impacts on market efficiency. The ISO believes that system-wide GMMs as currently computed provide equitable and efficient locational signals for generation siting and should be preserved.

The results of this evaluation validate the continued use of the current ISO methodology.

4. Ancillary Service Bid Evaluation Study

4.1. Section Overview

4.1.1. Single-Part and Two-Part Bid Evaluation Approaches

The ISO currently selects units to provide Ancillary Service capacity using a *single-part bid* evaluation approach, which awards capacity directly based on capacity bid prices. With this approach, all units selected to provide A/S are paid a single Market Clearing Price (MCP), established by the highest bid price of capacity selected to meet demand. When demand exists for real time incremental energy, the ISO dispatches units selected to provide A/S capacity in merit order based on energy bid prices submitted by each unit at the time of the capacity auction. All units dispatched to provide real time energy are paid the *ex post* market price for real time energy, rather than their energy bid price.

Under the two-part bid selection procedure proposed as part of the ISO's initial market design, A/S capacity bids were to be evaluated based on the sum of two components: the capacity bid price, plus an energy price component, derived by multiplying each unit's energy bid price by a factor representing the estimated probability that units providing each A/S would be called upon by the ISO to provide real time energy. Under this approach, it was proposed that each bidder selected to provide A/S capacity be paid a capacity payment equal to the highest Total Bid accepted by the ISO *minus* the energy component used in evaluating each unit's Total Bid. Finally, the two-part bid approach called for units providing A/S capacity to be paid their energy bid price (rather than the real time imbalance price) when dispatched by the ISO to provide real time imbalance energy.

4.1.2. Report Findings

4.1.2.1.Incentives for Market Efficiency

Efficient dispatch of real time energy supplies requires that energy bids closely reflect variable operating costs of each unit. However, the two-part bid approach examined in this report would create incentives for suppliers to bid less closely to their marginal operating costs in two ways:

- Generating units with a high probability of being dispatched if they bid their variable costs would have an incentive to increase their energy bid under the two-part bid approach, since they would be paid their energy bid price (rather than the real time imbalance price) for any real time energy they are called upon to provide.

- Generating units with relatively high operating costs that have a relatively low probability of being dispatched if they bid their variable costs could increase the overall capacity payment they receive under the two-part bid approach by decreasing their energy bid price. As long as such units do not decrease energy bids to a level that causes them to actually be dispatched to provide real time energy, this strategy would increase overall payments under the two-part bid system, since units' capacity payment are based on the difference between the highest Total Bid accepted and the energy component of the bid.

When suppliers' incentives to increase revenues by modifying bidding behavior in this way are taken into consideration, the analysis presented in this report shows that the two-part approach is likely to result in higher overall Ancillary Service and real time energy payments than the ISO's current single-part bid evaluation procedure. The findings of this report are consistent with comparative analysis of the bidding incentives and efficiency of these two alternative bid approaches that has been performed by leading economists involved in the design of California's energy markets, such as Professor Robert Wilson of Stanford University. A paper summarizing this analysis, which played a key role in the adoption of the single part bid approach, is included as an appendix to this report.[11]

4.1.2.2.Market Performance

This report also presents an analysis of recent market data supporting the conclusion that the single-part bid is likely to be more efficient and result in lower overall market costs than the two-part bid evaluation approach. In the market for real time energy, units supplying A/S capacity must compete against supply from Supplemental Energy bids submitted to the ISO's real time market. If the supply of supplemental energy bids is significant relative to demand, the single-part bid approach is likely to be more efficient than the two-part approach, since suppliers of A/S must compete against the supply of Supplemental Energy in the real time energy market. This report provides a variety indicators of the degree to which units providing A/S capacity must compete against Supplemental Energy bids in the real time energy market:

- Over the ISO's first 18 months of operation, Supplemental Energy bids have accounted for over 67% of energy bid and 70% energy dispatched by the ISO in the real time imbalance energy..
- An analysis of "price setters" presented in this report also shows that Supplemental Energy bids set the price for real time energy over 80% of the time.
- Less than 6% of capacity selected to provide Ancillary Services has needed to be been dispatched by the ISO to provide energy.

It is important to note that, while the supply of real time energy has been significant relative to demand during *most* hours, market power in the real time market continues to be a concern due to the thinness of supply and inelasticity of demand in the real time market during a small percentage of the total hours each year (i.e. 2-3% of hours on an

[11] See "Incentive-Compatible Evaluation and Settlement Rules: Multi-Dimensional Auctions for Procurement of Ancillary Services in Power Markets," by Hung-po Chao and Robert Wilson (February 16, 1999) , presented at the *Electricity Industry Restructuring Fourth Annual Conference*, March 5, 1999, University of California Energy Institute, Berkeley, CA, included as an appendix to this report

annual basis). During these hours, market power would exist with either the single-part or two-part bid approaches, and would create the potential for virtually unlimited prices in the real time market in the absence of any limits on real time energy bid prices. Thus, while the real time market is sufficiently competitive during most hours to ensure the efficiency of the ISO's single-part bidding system, other market power mitigation measures continue to be required to address market power concerns which exist during a relatively small percentage of hours.

4.1.2.3.Implementation Issues

In order to implement a two-part bidding approach, a variety of significant issues would need to be resolved including how the approach would be incorporated with other elements of the ISO's market design, such the Rational Buyer algorithm for Ancillary Service procurement. The two-part approach would also create additional complexity and could create unforeseen gaming opportunities for Market Participants bidding into the ISO's markets, and result in less transparent price signals in both the Ancillary Service and Real Time Energy Markets.

4.1.2.4.Study Conclusions

Based on the analysis and findings presented in this report, we conclude that the ISO's current single-part bid selection procedure is both more efficient – as well as being less complex for the ISO and Market Participants to implement – than the two-part bid approach.

4.1.2.5.Organization of Report

The reminder of this section is organized as follows.

- Section 4.2 provides background on how the two-part bid selection approach proposed in the ISO's initial tariff filing was replaced with the current single-part bid procedure prior to the opening of the ISO's markets

- Section 4.4 provides an illustrative comparison of these two bid selection approaches.

- Section 4.5 provides a more technical analysis of the impact each bid evaluation approach could be expected to have on bidding behavior and market efficiency.

- Section 4.6 presents an analysis of actual market experience under the ISO's current single-part bid procedure.

- Section 4.7 summarizes other criteria that may be taken into consideration when comparing the two bid approaches, such as the complexity of implementation and transparency of market price signals provided under each approach.

4.2. Background

4.2.1. Initial Market Design

The initial design of California's Ancillary Services markets was filed with the Commission on March 31, 1997 in a submission that included the initial ISO Tariff. Section 2.5.13 described the ISO's bid evaluation rules: "The ISO shall evaluate bids in the markets for Regulation, Spinning Reserves, Non-Spinning Reserves and Replacement Reserves to minimize the cost of procuring the required reserves." 2.5.14–2.5.17 specified that this objective would be accomplished by evaluating a combination of the capacity bid price plus an energy component, equal to the bid price for energy delivered from that capacity, multiplied by a *probability of dispatch.*[12]

This combined evaluation became known as the *two-part bid evaluation,* since the Total Bid of each unit would be composed of a capacity component plus an energy component. In the March 1997 proposal, the ISO would rank bids based on their combined Total Bid, and select the bidders with the lowest Total Bids that satisfy the demand for each auction. Under this approach, it was proposed that each selected bidder be paid the difference between the highest accepted Total Bid and the energy component in each selected Total Bid.

Under the *two-part bid evaluation* approach proposed in the ISO's initial tariff filing, units selected to provide Ancillary Services would then be paid their full energy bid price when dispatched by the ISO to provide real time imbalance energy. Units providing these ancillary Services would be dispatched by the ISO in merit order based on separate energy bid prices submitted at the time of the capacity auction.[13]

An illustrative example of the two-part bid selection procedure and how it compares to the single-part approach adopted by the ISO is provided in Section 4.6 of this report.

4.3. The August 1997 Design Revision

Following the March 1997 filing, the various participants in the development of the California market design, including stakeholders, worked towards a final implementation of that design. The implementation of the initial two-part bid evaluation scheme was revealed to be particularly troublesome, and that feature of the market design was abandoned. Several developments weighed heavily in the decision to abandon two-part bidding:

---

[12] Bids for Regulation would also include a *Regulation Adder,* that would represent the price to be paid by the ISO for *incremental* energy provided from units providing *upward Regulation*, or received by the ISO for *decremental* energy from units providing *downward Regulation*.

[13] Units bidding capacity into the auction for Spinning, Non-Spinning, and Replacement Reserves can specify energy supply curves with up to 10 increments of energy, each with a different bid price, for each different A/S market. A different energy supply curve can be specified with each of these A/S markets into which a unit is bid. When part of the capacity bid for a service is not available for that service because of selection in an earlier service in the auction sequence, the applicable energy bid price would be based on the left-most (lower priced) part of the energy bid.

- **Adverse Effects on Bidding Behavior and Market Efficiency.** Auction design specialists, along with key WEPEX members identified adverse effects of the two-part bid evaluation on the efficiency of the energy markets;[14] and

- **Implementation Problems**. Detailed implementation was troublesome, as there were no objective criteria for the weighting of the energy component in the total bid, and it was difficult to identify what portions of energy supply schedules to include in the evaluation of A/S capacity bids.

As a result, when the revised ISO Tariff was filed on August 15, 1997, the initial two-part bid evaluation scheme was replaced by a simplified sequential bid evaluation procedure. With this procedure, capacity bids for Regulation were evaluated first, and are selected based solely on the Regulation capacity bid. Capacity price bids for other Ancillary Services were evaluated in a similar sequential manner for the other Ancillary Services: Spinning Reserve, Non-Spinning Reserve, and, finally, Replacement Reserve. This valuation is known as the *single-part bid evaluation*, since units are selected to provide Ancillary Services based on capacity bid prices only.

As with the two-part bid selection procedure, the decision to dispatch all Ancillary Services except for Regulation is based on merit order using the energy bid prices submitted by each unit at the time of the capacity auction. However, under the single-part bid evaluation implemented by the ISO, units providing Ancillary Service capacity that are dispatched by the ISO to provide imbalance energy (including upward Regulation) are paid the *ex post* market price for real time energy, rather than their energy bid price.

On October 30, 1997, FERC issued an Order conditionally Authorizing Limited Operation of the California Independent System Operator and Power Exchange. The October 30, 1997 Order conditionally accepted the single-part A/S bid evaluation design, based on the ISO's explanation that the single-part bid evaluation "does encourage and promote overall cost minimization across all markets for Energy and Ancillary Services." (August 15 Filing, Appendix III, Response to Question No. #1, pp. 19–20, quoted at 81 FERC ¶ 61,122 at 61,494). However, FERC indicated that it was "not fully persuaded by the ISO/PX's assertion regarding the overall cost minimization of the new approach," and ordered a report "that explores the issue of bid evaluation further."[15] This report is submitted in compliance with that order.

4.3.1. A/S Redesign Developments

There have been a number of significant developments in California's A/S and real-time energy markets since key features of the ISO's initial market design were established in October 1997. These developments have focussed on enhancing the efficiency of the A/S

[14] In particular, these specialists included Sam Lovick and Seaborn Adamson of London Economics and Professor Robert Wilson, of Stanford University.

[15] The order also states that "report should include information for nine months of operation on the range of capacity and energy bids, and the market clearing capacity prices for Regulation, Spinning Reserve, Non-spinning Reserve and Replacement Reserves." These data are provided in an appendix to this report.

capacity markets and the real-time market. However, these developments have not focussed on issues related to the single-part bid evaluation in the A/S auctions. Some of the significant developments in the A/S markets include:

- The use of the *Regulation Energy Payment Adjustment* (REPA) to address shortages in the Regulation market. [16]

- Granting of market-based rate authority to all market participants, and elimination of REPA payments;

- Facilitation of increased imports of A/S; and

- Implementation of the 1998–99 A/S Market Redesign, which included several measures aimed at enhancing the efficiency of the A/S and real time energy markets.

The 1998–99 A/S Market Redesign represents the most significant modification to ISO procedures bid evaluation rules that must be taken into consideration when re-visiting the issue of the single-part versus two-part bid selection procedures. One of the key market redesign measures implemented by the ISO in August 1999 is the Rational Buyer procedure, which represents a direct modification to the initial bid evaluation rules adopted by the ISO. Under the Rational Buyer procedure, the ISO continues to procure A/S through a sequential auction based on capacity prices only. However, the procedure allows the ISO to minimize total A/S capacity purchase costs, while meeting its reliability-based capacity needs, by modifying the quantities of different Ancillary Services it purchases (e.g. by substituting higher quality A/S such as Spinning Reserve for lower quality services such as Non-Spinning or Replacement Reserve).

In addition, it is important to note that many of the A/S Market Redesign elements were oriented directly at improving the functionality of the ISO's real-time imbalance energy market. Specific elements of the 1998–99 A/S Market Redesign package aimed at improving the operation of the real-time market include the following:

- **Billing A/S capacity based on metered demand rather than on scheduled load.** This modification eliminated an incentive to underschedule load, which placed excessive demands on the real-time energy market and caused the ISO to make frequent out-of-market calls for energy, undermining the operation of the real-time market;

- **"No-pay" provisions for uninstructed generation out of A/S capacity.** This change increased the reliability of the real-time market, and made out-of-market energy purchases less frequent;

[16] REPA provided units supplying regulation with an additional payment (in addition to their capacity bid price) equal the greater of $20/MW or the real time imbalance price. REPA was implemented in May 1998 in response to shortages of capacity being bid into the ISO's regulation market., REPA payments were discontinued in November 1998, when it was determined that additional incentives were not necessary to ensure sufficient supplies of Regulation during most hours.

- **Effective Price settlement of deviations from real-time dispatch instructions.** This modification removed the incentives for ignoring dispatch instructions, and strengthened the link between the real-time price signals and the resolution of real-time imbalances;

- **Changed procedures for purchasing and charging Replacement Reserves.** This modification encouraged participation in the formal imbalance energy markets, relative to the informal real-time uninstructed deviations, allowing much less reliance on out-of-market energy purchases; and

- **Adoption of automated real-time dispatch.** This change enhanced the ability of the real-time market to respond timely to real-time imbalances caused by fluctuations in load and generation.

In 1997, the ISO determined that the two-part bid evaluation in the A/S auctions would interfere with the efficiency of the real-time market, and chose a market design that was consistent with that overriding objective. The market design changes implemented since the ISO commenced operation reflect the same design philosophy that were behind the August 1997 decision to move to a single-part bid-evaluation: the real-time imbalance energy market is at the heart of the ISO's market-managed pursuit of reliability, with the three Reserve Services—Spinning, Non-Spinning, and Replacement—acting to ensure adequate supplies of energy into these markets.

4.4. Illustrative Example of Single-Part and Two-Part Bid Approaches

This section provides an illustrative example of how the ISO's current one-part Ancillary Service bid evaluation procedure compares to the two-part bid evaluation procedure proposed in the ISO's initial tariff filing. The following numerical example is provided to clarify how each approach work, and to illustrate how bidding behavior would be likely to change under the two-part bid system. As shown in this example, overall costs are likely to be higher under the two-part bid procedure as a result of the incentives the two-part system would create for participants to modify their bidding behavior. A more technical mathematical analysis of the two approaches is provided in Section 4.5.

4.4.1. Illustrative Example

Figures 4-1 and 4-2 depict how a hypothetical set of Ancillary Service capacity and energy bids would be evaluated under the single-part and two-part approaches, respectively. Table 4-1 summarizes the assumptions used in this numerical example.[17]

Under the single-part bid evaluation, the five generating units bidding at the lowest capacity costs are selected to provide Ancillary Services capacity. As shown in Figure 4-1, this results in a MCP for capacity of $15. All five units selected to provide Ancillary Services (Units A, B, C, D and E) are paid this MCP for the capacity they provide. In this example, it is assumed that the real time imbalance price was $50, and that one of the five units selected to provide Ancillary Services (Unit D) was also dispatched to provide real time energy based on its energy bid price of $50/MWh.

Figure 4-2 illustrates how these same Ancillary Service capacity and energy bids would be ranked under the two-part bid evaluation. In this example, generating unit A would not be selected to provide Ancillary Service due to its relatively high energy bid price, while unit F would be selected instead. Under the two-part bid evaluation design, it was proposed that all five units selected to provide Ancillary Services be paid a capacity payment based on the difference between the maximum Total Bid accepted to met demand and the weighted energy component of the bid. When units providing Ancillary Service capacity are dispatched to provide real time energy under the two-part bid system, units are paid their energy bid price, rather than the MCP. In this example, for instance, Unit D would be paid its energy bid price ($45) rather than the overall MCP ($50) when dispatched to provide real time energy.

[17] The example assumes that the ISO requires 500 MW of an Ancillary Service (e.g. Spinning Reserve), and that 10 generating units each bid 100 MW into the market. It is also assumed that the real time energy price during this hour was $50, with one of the units selected to provide Ancillary Service being dispatched to provide 100 MWh of real time energy. It is assumed that this hour is typical of the "average operating conditions" so that the portion of energy dispatched from units providing Ancillary Services ($100 \div 500$) is equal to the weighting factor x (.20) applied to energy bid prices in the two-part bid evaluation.

Figure 4-1. Illustrative Example of Single-Part Ancillary Service Bid Ranking (Capacity Only)

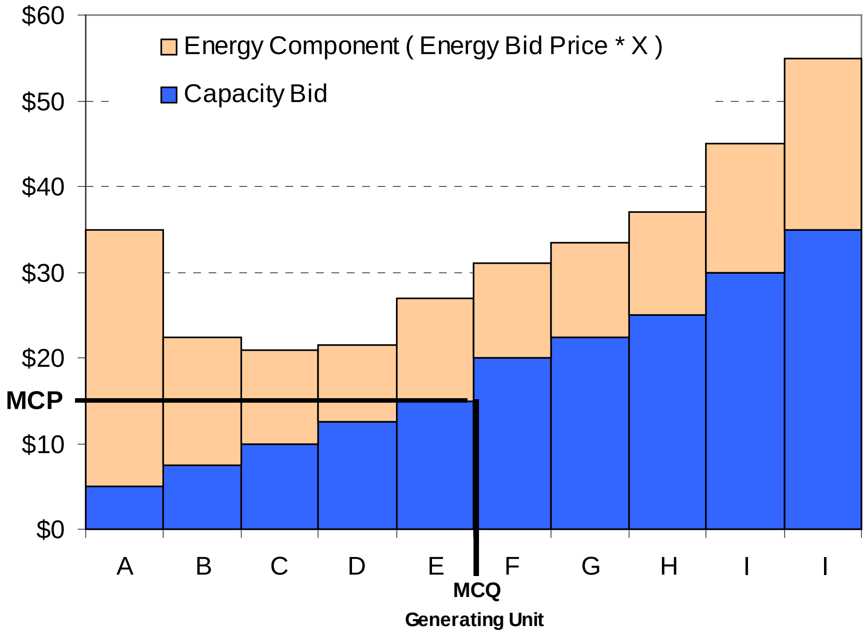


Figure 4-2. Illustrative Example of Two-Part Ancillary Service Bid Ranking With No Change in Bidding Behavior (Capacity + Weighted Energy Component)

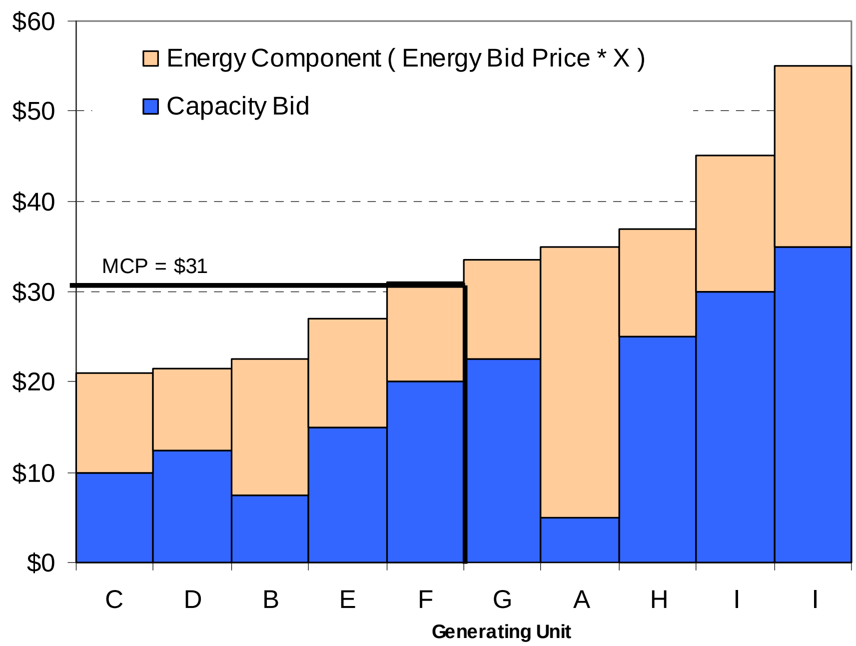


Table 4-1
Illustrative Example of Single-Part versus Two-Part Ancillary Service Bid Ranking
With No Change in Bidding Behavior

Generating Unit Bids and Market Outcomes

Generating Unit	A	B	C	D	E	F	G	H	I	J
Capacity and Energy Bids										
MW Bid	100	100	100	100	100	100	100	100	100	100
Capacity Bid	$5.00	$7.50	$10.00	$12.50	$15.00	$20.00	$22.50	$25.00	$30.00	$35.00
Energy Bid	$150	$75	$55	$45	$60	$55	$55	$60	$75	$100
Weight (X)	.20	.20	.20	.20	.20	.20	.20	.20	.20	.20
X * Energy Bid	$30.00	$15.00	$11.00	$9.00	$12.00	$11.00	$11.00	$12.00	$15.00	$20.00
Total Bid	$35.00	$22.50	$21.00	$21.50	$27.00	$31.00	$33.50	$37.00	$45.00	$55.00
Market Outcome (One-Part Bid)										
Capacity										
MW Supplied	100	100	100	100	100	0	0	0	0	0
MCP	$15.00	$15.00	$15.00	$15.00	$15.00					
Capacity Payment	$1,500	$1,500	$1,500	$1,500	$1,500					
Real Time Energy										
MWh				100						
MCP				$50						
Energy Payments				$5,000						
Market Outcome (Two-Part Bid with No Change in Bidding Behavior)										
Capacity										
MW Supplied	0	100	100	100	100	100	0	0	0	0
Capacity Price [1]		$16.00	$20.00	$22.00	$19.00	$20.00				
Capacity Payment		$1,600	$2,000	$2,200	$1,900	$2,000				
Real Time Energy										
MWh				100						
Energy Bid Price				$45						
Energy Payments				$4,500						

[1] Highest Total Bid accepted ($31) minus energy component of each unit's bid.

4.4.2. Illustrative Example of Change in Bidding Behavior

Table 4-2 depicts how suppliers could be expected to modify their bidding behavior under a two-part bid evaluation approach in order to increase revenues. As shown in Table 4-2:

- Units with relatively high operating costs (such as Unit B) that have a relatively low probability of being dispatched if they bid their variable costs could be expected to increase the overall capacity payment they receive by decreasing their energy bid price. As long as such units did not decrease energy bids to a level that causes them to actually be dispatched to provide real time energy, this strategy would increase overall payments under the two-part bid system, since a unit's capacity payment is based on the difference between the highest Total Bid accepted and the energy component of the bid. In this example, Unit B could decrease its energy bid from $75 to $60, and still not get dispatched to provide real time energy at the market clearing price of $50. This would increase the capacity payment received by Unit B from $1,600 to $1,900.

- Units with a high probability of being dispatched if they bid their variable costs (such as Unit D) have an incentive to increase their energy bid, since they would be paid their energy bid price (rather than the MCP) for any real time energy they are called upon to provide. In this example, Unit D could increase its energy bid from $45 to $49, and still get dispatched to provide real time energy. This would increase the amount Unit D receives for the real time energy it provides by $400 (from $4,500 to $4,900), and would decrease its capacity payment by only $80 (from $2,200 to $2,120).

4.4.3. Comparison of Results

Table 4-3 compares the total capacity and energy payments under each bid approach for the illustrative example described in the previous section. As shown in Table 4-3, a direct comparison of these two bid evaluation approaches based directly on historical Ancillary Service bid data shows that the two-part approach could decrease energy payments under this scenario, due to the fact that units supplying Ancillary Service capacity would be paid their energy bid prices, rather than the real time MCP for any imbalance energy provided. However, as shown in this example, capacity payments are likely to increase under the two-part bid approach, so that overall costs are greater than under the current single part approach. When opportunities to increase revenues by modifying bidding behavior to increase their market revenues are taken into consideration, the two-part approach may result in even higher overall costs than the ISO's current single-part bid procedure.

Table 4-2
Illustrative Example of Single-Part versus Two-Part Ancillary Service Bid Ranking
*With Changes in Bidding Behavior to Maximize Revenues**

Generating Unit	A	B	C	D	E	F	G	H	I	J
Capacity and Energy Bids										
MW Bid	100	100	100	100	100	100	100	100	100	100
Capacity Bid	$5.00	$7.50	$10.00	$12.50	$15.00	$20.00	$22.50	$25.00	$30.00	$35.00
Energy Bid	$150	$60	$55	$49	$60	$55	$55	$60	$75	$100
Weight (X)	.20	.20	.20	.20	.20	.20	.20	.20	.20	.20
X * Energy Bid	$30.00	$12.00	$11.00	$9.80	$12.00	$11.00	$11.00	$12.00	$15.00	$20.00
Total Bid	$35.00	$19.50	$21.00	$22.30	$27.00	$31.00	$33.50	$37.00	$45.00	$55.00
Market Outcome (Two-Part Bid with Change in Bids to Maximize Revenues)										
Capacity										
MW Supplied	0	100	100	100	100	100	0	0	0	0
Capacity Price [1]		$19.00	$20.00	$21.20	$19.00	$20.00				
Capacity Payment		$1,900	$2,000	$2,120	$1,900	$2,000				
Real Time Energy										
MWh				100						
Energy Bid Price				$49						
Energy Payments				$4,900						

Number in shaded boxes illustrate changes in bidding behavior that would maximize bidders revenues.

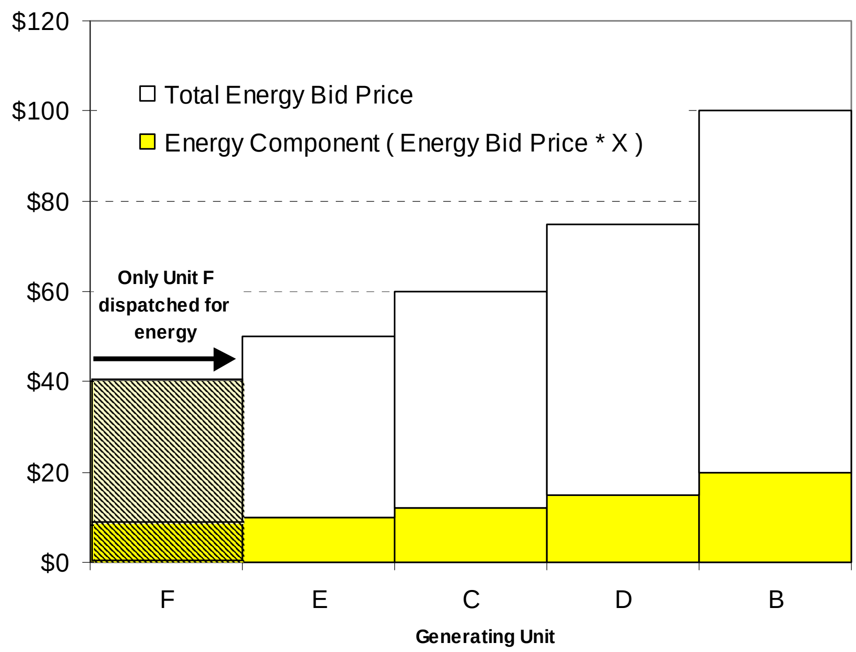
Table 4-3. Comparison of Total Payments

	Capacity	Energy	Total
Single-Part Evaluation	$7,500	$5,000	$12,500
Two-Part Evaluation			
No Change in Bids	$9,700	$4,500	$14,200
Change in Bidding Behavior	$9,920	$4,900	$14,820

Another problem with the two-part bidding system initially proposed for the ISO's ancillary Service auction is that even if bidding behavior did not change, the proposed objective function for the two-part bid evaluation algorithm would not actually minimize total capacity and energy costs. The proposed objective function for the two-part bid algorithm is to minimize the sum of capacity payments, plus a percentage of the energy bids of all the units selected to provide A/S capacity. This formulation implicitly assumes that that a constant percentage of energy bid from each unit providing A/S would be dispatched to provide real time energy. In practice, however, real time energy is dispatched by the ISO in merit order, based on bid price. This allows the ISO to select only the lowest priced portion of the real time supply curve, rather than selecting a constant portion of energy from each unit.

Figure 4-3 depicts the difference between the energy component used in the two-part bid evaluation compared to the actual amount of energy dispatched to meet real time demand, using the same numerical example presented above. In the foregoing example, the two-part bid evaluation objective function is based on the assumption that on average 20% of the energy from each unit selected to provide A/S would be dispatched. This is depicted by the lower shaded portion of each unit's energy bid price in Figure 4-3. The sum of the shaded portions of each unit's energy bid represents the total energy component being minimized by the objective function of the two-part bid evaluation. However, since units are dispatched in merit order, the ISO would actually only dispatch Unit F (representing 20% of total A/S capacity selected) to provide real time energy.

Figure 4-3. Energy Bid Price Component Used in Two-Part Bid Ranking Compared to Actual Energy Dispatched based on Merit Order of Energy Bid Prices



4.5. Comparison of Single-Part and Two-Part Bid Approaches

The single-part bid was adopted in California primarily on the grounds that, in comparison to the two-part bid evaluation initially proposed, this approach is optimal in the sense that it encourages bidders to bid most closely to their variable costs for reserve capacity and for supplying incremental energy. This section provides the theoretical rationale underlying the optimality of the single-part bid and examines the potential inefficiency of the alternative two-part bid scoring rules.

4.5.1. Bid, Cost, Price, and Profit in the Single-part Bid System

To simplify the analysis, consider the procurement of a specific A/S (e.g., the Replacement Reserve). Let us introduce the following notation. For any given generation unit, let P be its bid price for incremental energy and $G(P)$ be the probability that the real-time energy market clearing price (MCP) p is less than the bid price P, where $0 \le G(P) \le 1$ is a monotone increasing function of P. Therefore, $1-G(P)$ is the probability that the bid is selected. The lower the price of P, the larger the likelihood of MCP $\ge P$. Let also c be the marginal cost of the generation unit with the price P.

If p happens to be greater than P, then the generation unit will earn energy payment p for each MW per hour that it won. The corresponding profit is $p-c$ per MW per hour. In other words, the expected profit for the generation unit with bid price P is

$$\Pi(P,c) = [1-G(P)]*E(p-c \mid p \ge P).$$

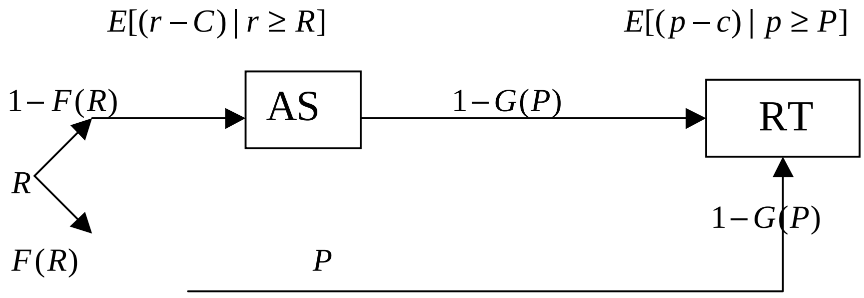
Using a similar notation, for a bid into the A/S market (with bid prices for A/S capacity and energy), the expected total profit from the A/S capacity market and the real time market is

$$(1-F(R))*E[(r-(C-\Pi(P,c))) \mid r \ge R].$$

where R is the capacity bid price, r the capacity Market Clearing Price, $1-F(R)$ the probability that the capacity clearing price (MCP) r is greater than the bid price R, with $0 \le F(R) \le 1$, and C is the “opportunity cost” . The above notation is summarized in the following table.

	Capacity	Real Time
Bid price of a given unit	R	P
MCP	r	p
Prob(MCP $\ge$ a given bid price)	$1-F(R)$	$1-G(P)$
Cost	C	c

Note that in the current California market, the ISO allows generation units, which have not participated (or have not won) in the A/S market, to bid to supply supplemental energy in the real time market. Taking this into consideration, and assuming no change in the energy bid price, the full flow of profits in ISO markets can be represented as follows:



The total expected profit is

$$
\begin{aligned}
&(1-F(R)) * E[(r-(C-\Pi(P,c))) \mid r \geq R] + F(R) * \Pi(P,c) \\
&= (1-F(R)) * E[(r-C) \mid r \geq R] + (1-G(P)) * E[(p-c) \mid p \geq P]
\end{aligned}
$$

4.5.2. Advantages of the Single-part Bid System

One important feature in the above formula is the separation of profits from the A/S capacity market and the real time market. One may notice from the derivation that such a separation cannot be achieved without the supplemental energy bids. One immediate advantage of the separation is that it reduces a potential gaming opportunity that exists when bidders design bidding strategies discussed below in conjunction with the two-part bid system. Another advantage is the simplicity for market operation to have two uncoupled settlement rules for A/S capacity and real-time energy.

4.5.3. Mathematical Optimality

Next we will use the separation property discussed above to prove the optimality of the single-part bid system adopted by California ISO. Under the single-part bid system, to maximize the profit from each of the two individual markets (A/S capacity and Real-time energy) is equivalent to maximizing the total expected profit. Because of the similarity of expected profit formulas for the two markets, we need to go through mathematical derivation once for one market. We use the imbalance energy market as an example and prove that the best bid rule for the bidder to maximize its profit in this market is to bid at "cost".

To facilitate the argument, we assume the monotone function $G(p)$ has its positive derivative $g(p)$. The market implication of this assumption is that any bid price within the range has a positive probability to set the MCP.

Under this assumption, we are now able to expand the formula for the profit in the energy market as follows:

$$(1-G(P))*E[(p-c)\mid p\geq P]=(1-G(P))*\left[\frac{\int_P^\infty pg(p)dp}{1-G(P)}-c\right]=\int_P^\infty pg(p)dp-c(1-G(P))$$

To find the bid price P that maximizes the profit, we let the derivative of the right side of the above equation with respect to P be equal to zero, i.e., $(P-c)*g(P)=0$. Therefore, the unique maximizer P for the generation unit with the cost c in supplying real time energy satisfies the equation $P=c$. Similarly, the unique maximizer R for the generation unit with cost C for reserve capacity satisfies the equation $R=C$.

4.5.4. Two-part Bid Systems

Two-part bid systems have the following two distinct aspects that differ from the single-part system discussed above. First, the energy payment when it is called is the bid price rather than the system marginal cost (SMP). Second, the probability of being called ($0\leq x\leq 1$) is taken into consideration in constructing the scoring rule and in calculating the capacity payment. The scoring rule has the form $R' = R + xP$ and the MCP is determined by R' and the market requirement. The capacity payment is MCP $-xP$, where P is the energy bid price. The SMP for the energy market is established by stacking the energy bids according to the merit order. The winners are paid as bid. These energy payments are therefore less than or equal to the SMP in the real time market.

4.5.5. Difficulty of Historical Analysis

As illustrated in the above sections, the single-part bid system encourages the bidders to bid at cost in both the capacity and the energy markets. Implementing a new bid system which might shrink their profit will definitely change their bidding behavior. Because of possible changes in bidding strategies, any attempt to use the historical data to evaluate the impact of a new set of settlement rules will be inaccurate at best, and could be very misleading at the worst.

4.5.6. Inefficient Bidding Incentives

Changes in the settlement rule can lead to significant changes in the bidders' strategies. To see this, let us use the notation $1-F(R')$, as the probability of being selected in the forward market two-part auction, and $1-G(P)$, as the probability of being called upon in real-time to generate. Let r′ be the marginal bidding score (MCP in the two-part auction), and let p be the energy SMP in the real-time market.

A full evaluation of the impact of two-part bid system on the payments from ISO is not straight forward, because the total profit from the capacity market and the energy market is not composed of two independent components any more. One can see this from the formula of the total expected profit for two-part bid system:

$$(1-F(R'))*E[(r'-C-xP)\mid r'\geq R']+(1-G(P))*(P-c).$$

In the search for the maximizers (R', P) of the total profit, we take the derivatives respect to R' and P , respectively and let the derivatives be zero. We have

$$(R'-C-xP)*f(R')=0 \text{ and } 1-G(P)-(P-c)*g(P)-x(1-F(R')=0.$$

The optimal bid score R' satisfies the equation

$$(R'-C-xP)*f(R')=0\,.$$

The result is $R'=C+xP$. For given x and P, the optimal bidding strategy for the capacity component of R' is C , which is the same as the one in the single-part bid system.

The impact of the real time payment rule on the optimal bidding strategy for the energy component cannot be evaluated strictly mathematically because of the complicity of the equation

$$1-G(P)-(P-c)*g(P)-x(1-F(R'))=0.$$

Regrouping the above equation, we have,

$$(P-c)=\frac{(1-F(R')}{g(P)}\left[\frac{1-G(P)}{1-F(R')}-x\right].$$

Note that the first term inside the brackets is the ratio of the probability of the energy bid P being selected in real-time to the probability of the two-part bid being selected in the forward market. If this ratio as perceived by the bidder exceeds the call probability x announced by the ISO, the right-hand side is positive, and thus $P>c$. In this case, the energy bid price will be higher than the marginal cost. If, however, this ratio as perceived by the bidder is less than the call probability x announced by the ISO, the right-hand side is negative, and thus $P<c$. In this case, the energy bid price will be lower than the marginal cost. This equation shows that the two-part bid system introduces greater uncertainty on the part of the bidders. This uncertainty provides perverse bidding incentives, leading to higher prices of A/S capacity plus energy.

Since all information about $F(R)$ and $G(P)$ is unknown to the bidders, another negative impact of two-part bid system is higher volatility in the market prices because bidders are forced to guess the market in search of their optimum strategy to maximum profits.

4.6. Analysis of Market Experience Under Single-Part Bid

This section presents an analysis of actual market experience under the ISO's current single-part bid procedure, and discusses how this experience may provide an additional basis for comparing the efficiency of single-part and two-part bid approaches.[18]

Dispatch of Ancillary Service Capacity to Provide Real Time Energy

The two-part bid evaluation approach proposed in the ISO's initial March 1997 tariff filing specified that Ancillary Service bids were to be evaluated based on a combination of the capacity bid price plus an energy component, equal to the bid price for energy delivered from that capacity, multiplied by a *probability of dispatch.* Thus, the difference between these two bidding approaches depends in large part on the estimated probability *of dispatch* used to weight the energy component of bids.[19] The higher the weighting factor, the greater the difference in bids that could be selected under each approach.

Table 4-4 summarizes the percentage of Ancillary Service capacity that has actually been dispatched to provide real time energy over the twelve month period from August 1998 through July 1999.[20] As shown in Table 4-4, this percentage varies significantly by Ancillary Service type and by peak versus off-peak periods. In virtually all cases, however, the percentage is very low (less than 10%), suggesting that the energy component of the two-part bid could often has little effect on the units actually selected to provide Ancillary Services.

In addition, the significant variation in the percentage of Ancillary Service capacity that has actually been dispatched to provide real time energy (from month-to-month and peak versus off-peak periods) suggests that it would be necessary, at a minimum to set different weighting factors for the different Ancillary Services, operating hours, and seasons or months of the year. At best, any such factors would still deviate significantly from the actual amount of Ancillary Services dispatched during many hours, due to significant day-to-day, hour-to-hour variation of the demand for real time energy.

[18] FERC's October 30 1997 Order specifically requires that the report further exploring the issue of bid evaluation approaches should include information for nine months of operation on the range of capacity and Energy bids, and the market clearing prices for each of the four Ancillary Services." Figure 11 and Figure 12 in this section show the range of energy bids submitted by units bidding into the Ancillary Services markets. Other data specifically requested is included in an appendix to this report.

[19] In practice, since units under both bid evaluation approaches would be dispatched to provide real time energy in merit order based on energy price bids, the *probability of dispatch* is not an exogenously determined factor that would be applicable to all units. Instead, the probability of dispatch is primarily a function of a unit's energy bid price, and the expected price of imbalance energy (which in, turn, depends on load conditions and a variety of other factors. This section ignores this additional flaw of the two-part bid approach initially proposed in order to illustrate other issues associated with setting the weighting factor that would be multiplied by each unit's energy bid under the two-part bid evaluation approach.

[20] This twelve month period is used through this section, since it represents the most recent twelve month period for which data were available for this analysis.

Table 4-6 and Figure 4-4 illustrate the tremendous range of uncertainty surrounding any *a priori* estimate of the amount of Ancillary Services that would be dispatched. Table 4-6 compares the *average* percentage of Spinning Reserve capacity dispatched to provide real time energy to the 5th, 50th and 95th percentiles of this percentage during peak hours in the month of July 1998. The asymmetrical values of the these percentiles, along with the significant difference between the mean and the 50th percentile (or median), reflect the highly skewed distribution of the percent of capacity dispatched to provide real time energy just within the peak hour of one month.

Figure 4-4, which depicts a histogram of the percentages of Spinning Reserve dispatched to provide real time energy during peak hours during July 1999, further illustrates the difficulty of setting unbiased dispatch factors for use in weighting energy bids under the two-part bid approach. As shown in Figure 4-4, the distribution of the percentage of Spinning Reserve capacity dispatched is highly skewed, with no capacity dispatched in over 70% of all peak hours in the month. In this example, the *average* percentage of capacity dispatched over the peak hours in the month (3.2%) is representative of a very small percentage of hours in the month.

Table 4-4. Percentage of Ancillary Service Capacity Dispatched to Provide Real Time Energy

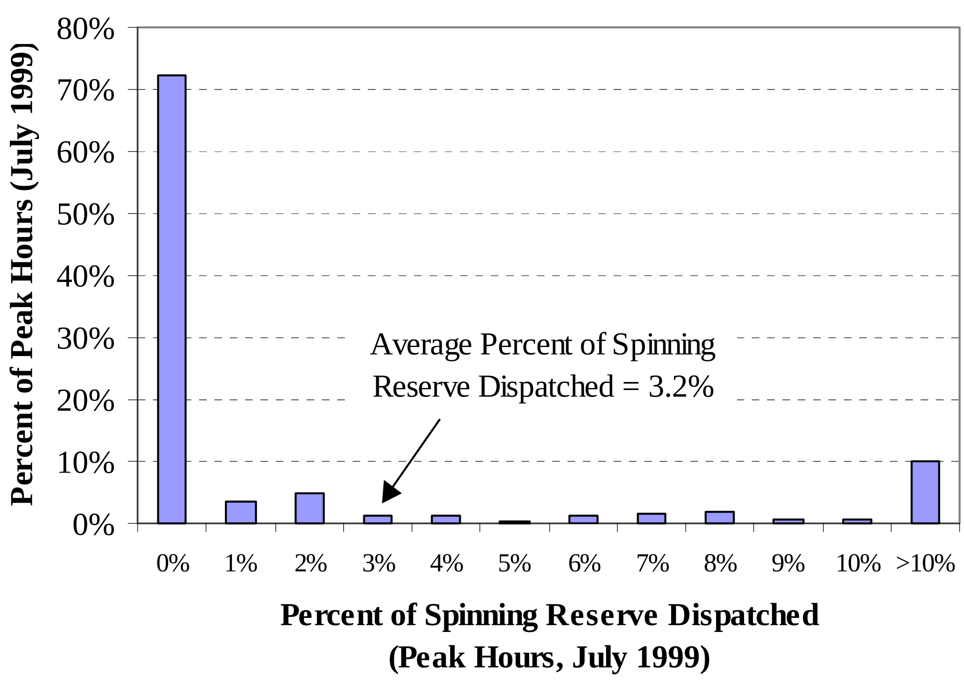
	Peak Hours (7-22)			Off-Peak (1-6, 22-24)		
Month	**Spin**	**Non-spin**	**Repl**	**Spin**	**Non-spin**	**Repl [1]**
Aug-98	13.6%	9.0%	7.5%	2.3%	1.5%	3.0%
Sep-98	5.1%	3.0%	5.8%	1.6%	2.0%	7.8%
Oct-98	16.5%	1.4%	2.6%	12.8%	1.4%	
Nov-98	7.0%	.4%	.8%	11.1%	.0%	
Dec-98	4.8%	.7%	2.0%	4.8%	.0%	
Jan-99	2.7%	.0%	.3%	2.4%	.2%	
Feb-99	5.3%	1.2%	1.8%	2.0%	.2%	
Mar-99	7.8%	.5%	3.6%	5.8%	.5%	
Apr-99	6.3%	.9%	1.4%	2.4%	1.0%	
May-99	3.1%	.8%	1.0%	1.2%	.6%	
Jun-99	2.5%	1.8%	.6%	.8%	.1%	
Jul-99	3.2%	1.3%	1.5%	2.6%	.1%	
Total	6.5%	1.8%	2.4%	4.2%	.6%	

[1] Since October 1998 the ISO has not purchased Replacement Reserve during off-peak hours.

Table 4-5. Illustrative Results of the Variation of the Percentage of Ancillary Service Capacity Dispatched to Provide Real Time Energy (Peak Hours, By Month)

		Percentiles		
Month	**Mean**	**.05**	**.50**	**.95**
Aug-98	13.6%	0%	1.9%	54%
Sep-98	5.1%	0%	0%	29%
Oct-98	16.5%	0%	13.2%	46%
Nov-98	7.0%	0%	2.7%	29%
Dec-98	4.8%	0%	.5%	21%
Jan-99	2.7%	0%	0%	18%
Feb-99	5.3%	0%	0%	29%
Mar-99	7.8%	0%	4.5%	28%
Apr-99	6.3%	0%	0%	28%
May-99	3.1%	0%	0%	16%
Jun-99	2.5%	0%	0%	13%
Jul-99	3.2%	0%	0%	19%
Total	6.5%	0%	.1%	32%

Figure 4-4. Percentage of Spinning Reserve Capacity Dispatched (Peak Hours, July 1999)



4.6.1. Supply of Supplemental Energy Bids for Real Time Energy

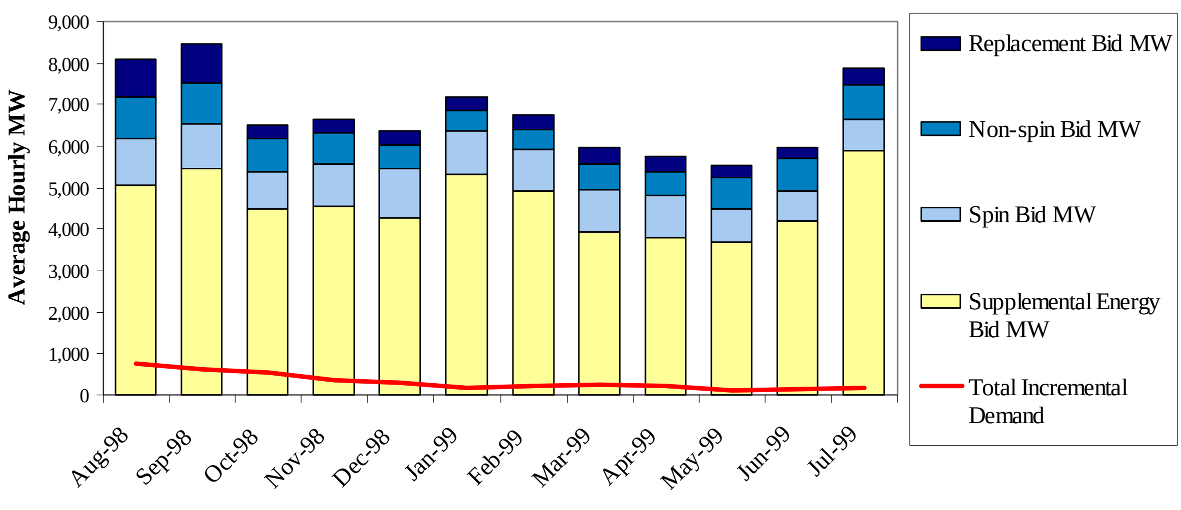
One of the key conditions under which the single-part bid evaluation approach can be shown to be more efficient and result in lower overall costs than the two-part bid approach is when suppliers of A/S capacity must compete against a significant supply of Supplemental Energy bids in the market for real time imbalance energy. As outlined in this section, experience over the ISO's first 18 months of operation indicates that, during most hours, the supply of Supplemental Energy bids has provided a significant source of potential competition for suppliers of A/S capacity in real time energy market.

4.6.1.1.Supply of Real Time Energy Bids

Figure 4-5 compares the average hourly supply of real time energy from each Ancillary Service and Supplemental Energy Bid to the amount of incremental imbalance energy dispatched by the ISO over the 12 month period from August 1998 through July 1999. As shown in Figure 4-5, overall bid sufficiency (or the amount of supply bid relative to the amount of demand for real time energy) has been extremely high during most hours. As depicted in Figure 4-6, Supplemental Energy Bids account for about 67% of total bids in the real time market.

Figure 4-7 provides a more detailed perspective of the supply of Supplemental Energy relative to demand. Figure 4-7 compares the demand for real time energy to the *unused* supply of Supplemental Energy bids (e.g. bids at a price greater than the *ex post* real time price), during peak hours when the ISO has be incrementing energy to meet real time demand.[21] As shown in Figure 4-7, the supply of unused Supplemental Energy has, on average, exceeded the total demand for real time energy by several hundred percent.

Figure 4-5. Average Hourly Real Time Energy Bids by Month



[21] In other words, this excludes those peak hours when the ISO needed to decrement (rather than increment) generation in the real time market.

Figure 4-6. Percentage of Real Time Energy Bids (Aug '98-July '99)

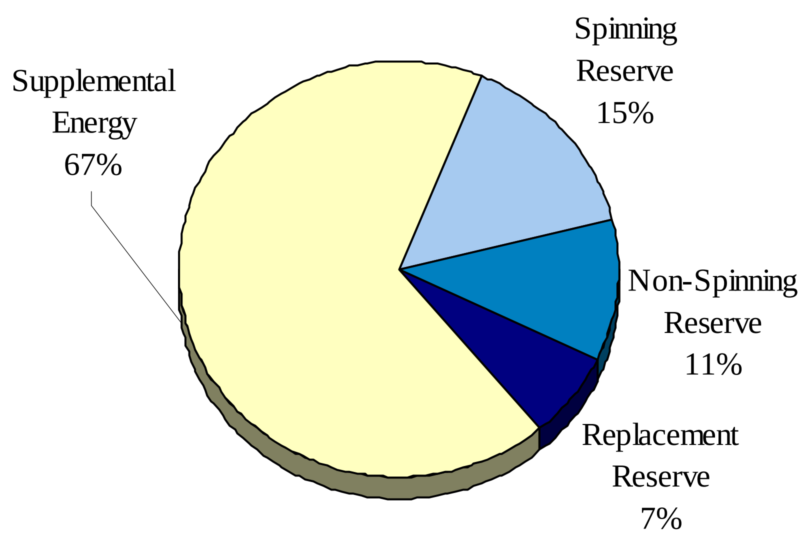
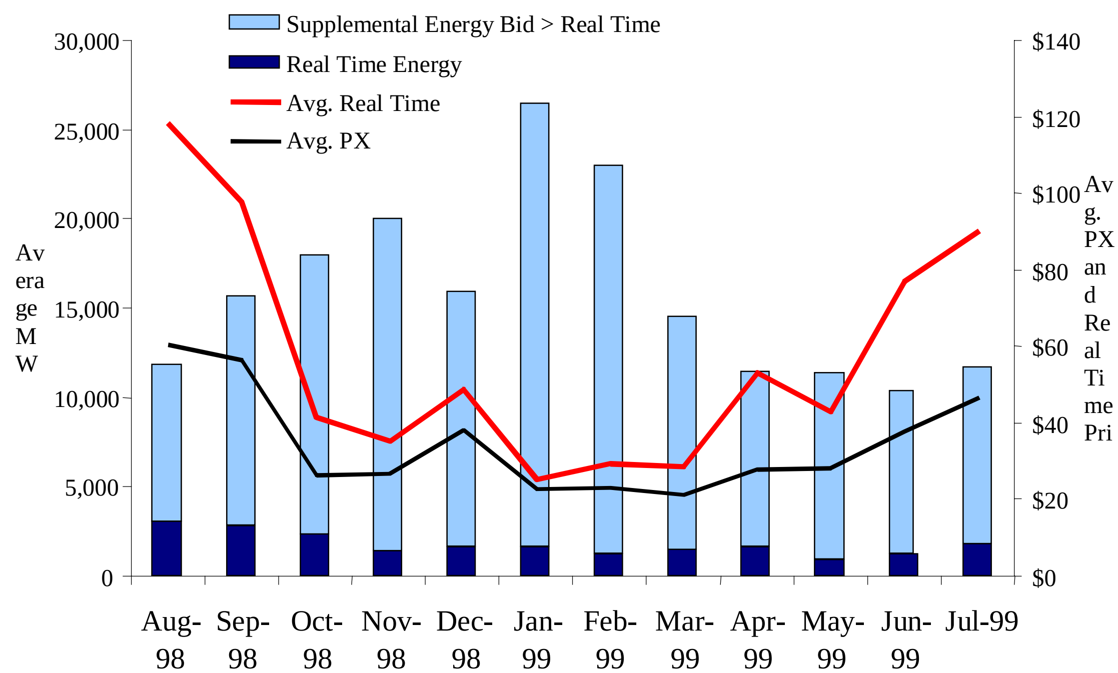


Figure 4-7. Excess Supply of Supplemental Energy Bids Peak Hours* - Aug'98-July '99



Based only on peak hours when demand for incremental energy > 0.

Figure 4-8 and Figure 4-9 provide an even more detailed look at the supply of Supplemental Energy in the real time market relative to demand during the most critical hours of the 12 month period from August 1998 through July 1999, when the supply of Supplemental Energy was lowest relative to the real time demand for energy.

Figure 4-8 plots the total demand for real time incremental energy against the supply of Supplemental Energy for each hour over this 12 month period. As shown in Figure 4-8, the supply of Supplemental Energy bids alone (excluding energy bids from A/S capacity) exceeded the total demand by a significant margin during most hours, and fell short of the demand for real time energy in a relatively small portion of hours (represented by points above the diagonal line in Figure 4-8).

Figure 4-9 shows a duration curve of the supply of Supplement Energy bids as a percentage of the total amount of incremental real time energy dispatched by the ISO each hour. As shown in Figure 9, the supply of Supplemental Energy bids relative to the demand for real time energy has been less than 100% during only about 85 hours over the 12 month period, or less than 1% of the time. The supply of Supplemental energy bids has been less than 150% of total real time energy during only about 2% of hours, and has been below 200% of real time energy demand only about 3% of the hours in this 12 month study period.

Figure 4-8. Supplemental Energy Bids versus Total Real Time Energy Dispatched-Aug'98-July '99

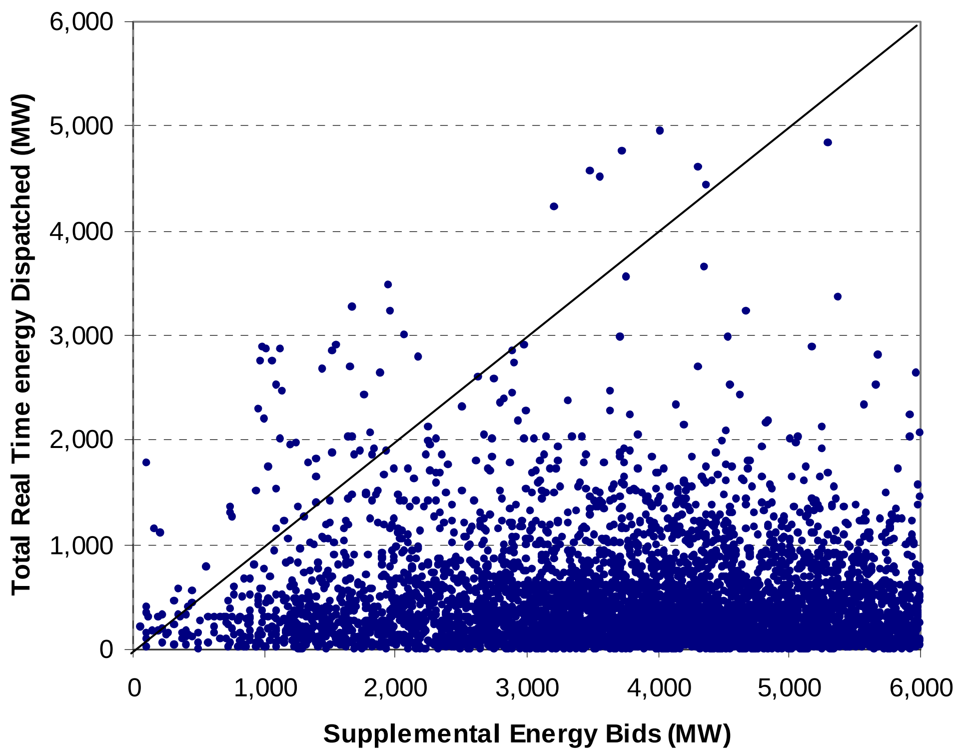
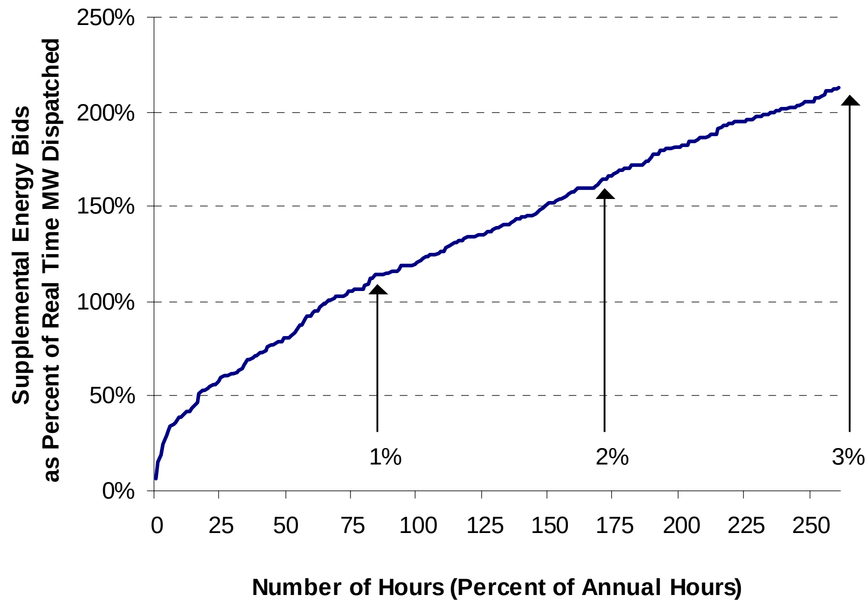


**Figure 4-9. Supplemental Energy Bids as
Percent of Total Real Time Energy Dispatched (Aug'98-July'99)**



4.5.1.2.Real Time Energy Dispatched

Figure 4-9 summarizes the percentage of real time energy dispatched by the ISO from Supplemental Energy bids and from units providing the different Ancillary Services. A comparison of Figure 4-5 and Figure 4-9 shows that Supplemental Energy bids account for 67% of supply bid into the ISO's imbalance market, but accounts for 73% of the energy actually dispatched by the ISO. The slightly higher proportion of Supplemental Energy bids dispatched reflects the fact that Supplemental Energy bids tend to be lower-priced than Ancillary Service energy bids, as depicted in Figures 4-10 and 4-11.

Figure 4-10. Percentage of Real Time Energy Dispatched (Aug '98-July '99)

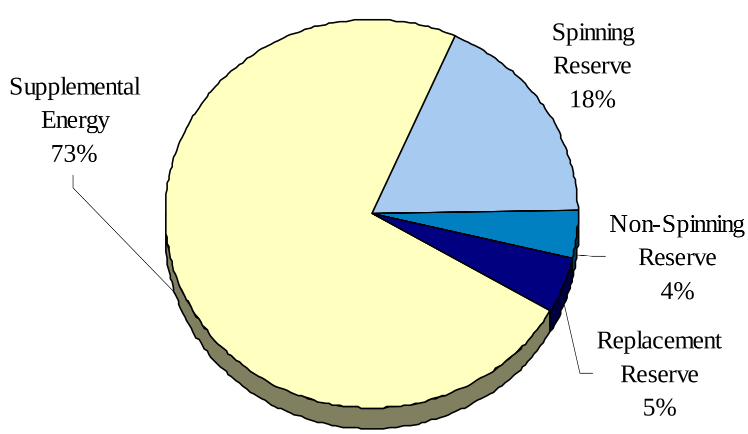


Figure 4-11. Bid Prices of Real Time Energy Supply

Supplemental Energy and Ancillary Services (Aug '98-July '99)
Average Hourly MW Bid By Each Source

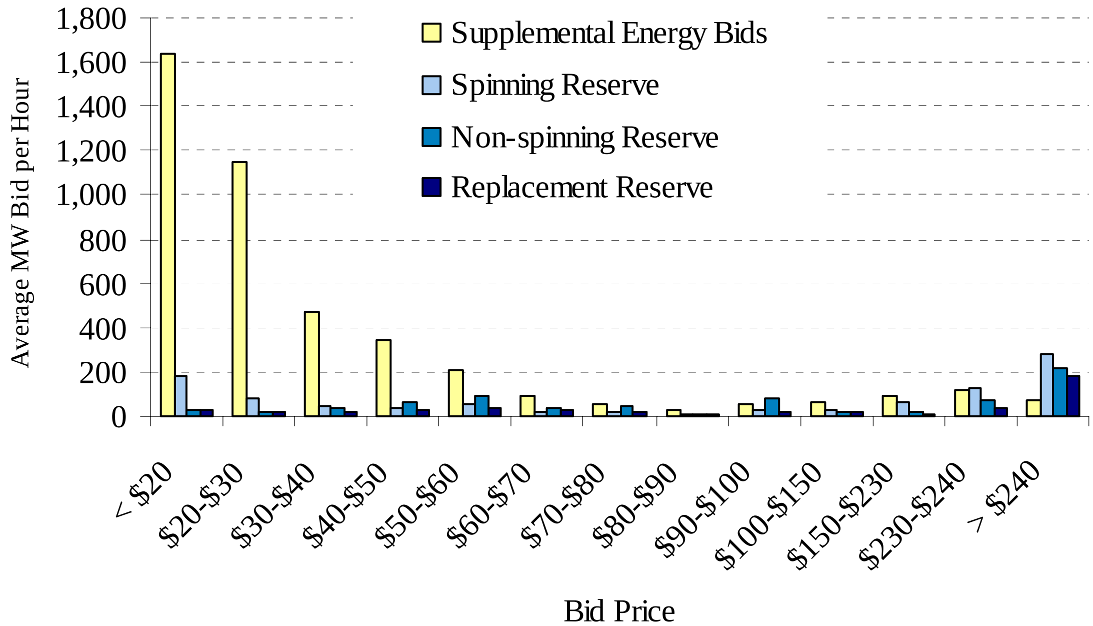
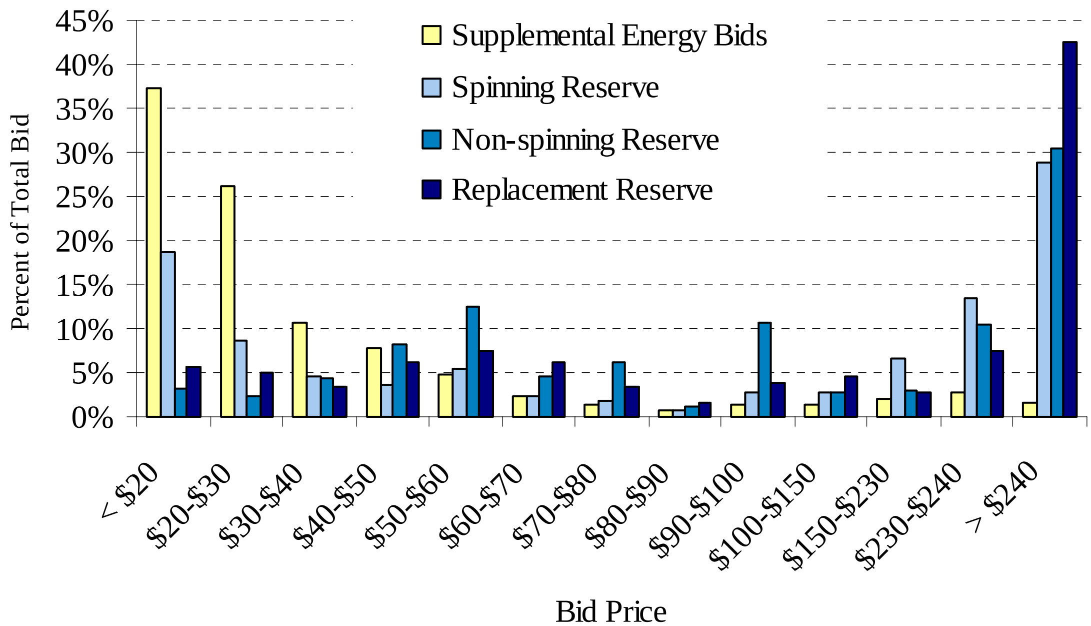


Figure 4-12. Bid Price of Real Time Energy Supply

Supplemental Energy and Ancillary Services (Aug '98-July '99)
Percentage of Total MW Bid by Each Source



4.6.1.3.Real Time Price Setters

Another indicator of the degree of competition between Supplemental Energy bids and real time energy bids from units providing Ancillary Services is the frequency that bids from these different sources actually set prices in the real time market.

The ISO's final *ex post* real time price is actually the average of six different ten-minute prices, each of which is set based on the highest price bid dispatched during that 10-minute interval. In addition, bids which are not accepted, but are just above the final market price in the real time supply curve, represent a source of competition that limits the degree to which other supply bids could be raised and still clear the market. Therefore, for this analysis, it was assumed that all real time energy bids within ± 5% of the final *ex post* price were "price setters" that could have a significant influence on final market prices.[22]

As shown in Table 4-5, the results of this analysis show that real time prices of are set primarily by Supplemental Energy bids, rather than energy bids from capacity providing Ancillary Services.

Table 4-5. Real Time Price Setters

	Peak Hours (7-22)				Off-Peak Hours (1-6,22-24)			
Month	**Suppl. Energy**	**Spin**	**Non-Spin**	**Repl.**	**Suppl. Energy**	**Spin**	**Non-Spin**	**Repl.**
Aug-98	64%	15%	10%	11%	83%	7%	4%	6%
Sep-98	73%	13%	7%	8%	82%	7%	5%	6%
Oct-98	70%	19%	5%	5%	78%	17%	5%	0%
Nov-98	81%	15%	2%	2%	86%	14%	0%	0%
Dec-98	82%	13%	1%	3%	80%	19%	1%	0%
Jan-99	87%	11%	0%	2%	86%	14%	0%	0%
Feb-99	84%	14%	1%	1%	93%	6%	1%	0%
Mar-99	79%	15%	2%	4%	80%	19%	1%	0%
Apr-99	82%	13%	2%	3%	88%	10%	1%	0%
May-99	90%	7%	2%	1%	93%	5%	3%	0%
Jun-99	91%	6%	2%	1%	95%	4%	1%	0%
Jul-99	91%	5%	2%	3%	94%	6%	0%	0%
Total	80%	13%	3%	4%	86%	11%	2%	1%

[1] Since October 1998 the ISO has not purchased Replacement Reserve during off-peak hours.

[22] Since this approach typically results in more than one bid being identified as the "price setter" each hour, results were normalized on an hourly basis to sum up to a value of one. For example, if four different bids are identified as the "price setters" in one hour, each bid was assigned a value of .25.

4.6.1.4.Continued Need for Market Power Mitigation in Real Time Energy Market

It is important to note that, while the supply of real time energy has been significant relative to demand during *most* hours, market power in the real time market continues to be a concern due to the thinness of supply and inelasticity of demand in the real time market during a small percentage of the total hours each year (i.e. 2-3% of hours on an annual basis). During these hours, market power would exist with either the single-part or two-part bid approaches, and would create the potential for virtually unlimited prices in the real time market in the absence of any limits on real time energy bid prices. Thus, while the real time market is sufficiently competitive during most hours to ensure the efficiency of the ISO's single-part bidding system, other market power mitigation measures continue to be required to address market power concerns which exist during a relatively small percentage of hours.

4.7. Other Implementation and Market Issues

In order to implement a two-part bidding approach, a variety of significant issues would need to be resolved

- The two-part bid approach would need to be incorporated with other elements of the ISO's market design, such the Rational Buyer algorithm for Ancillary Service procurement. The two-part approach would, at a minimum, require development of a more complex Rational Buyer algorithm, since not all bidders are paid the same Market Clearing Price for Ancillary Service capacity under the two-part approach.

- The two-part approach would add complexity and could create unforeseen gaming opportunities for Market Participants bidding into the ISO's markets.

- The two-part approach also results in less transparent price signals in both the Ancillary Service and Real Time Energy Markets, since not all participants are paid the same Market Clearing Price for Ancillary Service capacity or real time energy.

- Even if the bulk of real time energy was provided through Ancillary Services rather than supplemental energy, the two-part bid evaluation would, at best, be only be an approximation to the true cost minimization. The true probability that a unit selected to provide Ancillary Services will be called upon to generate in real-time depends on the units energy bid prices, as well as the overall demand for imbalance energy.

- As discussed above, selecting the factor to be used in weighting energy bids is likely to be highly problematic. Significant trade-offs would exist between the goal of setting a weighting factor that reflects the probability that units would be dispatched to provide real time energy, and the need to minimize the complexity of the two-part approach.

- Bidders could be expected to modify their bids to increase their revenues. Any real time energy savings are likely to be outweighed by increased capacity costs.

Based these factors, we conclude that the ISO's current single-part bid selection procedure is both more efficient and less complex for the ISO and Market Participants to implement than the two-part bid approach.

5. Appendix

5.1. Marginal Loss Rate Calculation

The active power flow mismatch equations in the distributed load slack power-flow formulation take the following form for node *i*:

$$P_{mismatch,i} = P_{gen,i} - P_{load,i} - \beta_i \psi - P_{network,i} (\theta, \boldsymbol{V}) = 0. \qquad (1)$$

There are *N* (this is the number of nodes in the network) number of these equations in the formulation. There is no generation slack bus because of the introduction of the distributed load slack. This load slack changes to balance the power-flow equations and is defined by the *total load slack* variable ψ as shown in equation (1). This slack power is distributed to all load nodes based on their load distribution factors, β_i. For each node, this factor is usually set (normalized) equal to the ratio of the original value of node load to the sum of the original node load values. This results in the sum of β_i to be equal to 1.

$P_{gen,i}$ and $P_{load,i}$ are the generation/import and load/export at node *i*, respectively. $P_{network,i}(\theta, \boldsymbol{V})$ is the flow of power into the network at node *i* and is dependent on node *i* and the adjacent node's voltage angles and voltage magnitudes. We assume no other power source/sink such as shunts.

The unknown variables in the above equations are:

- The node voltage angles, θ_i (we set one node angle as reference and set its value to 0);
- The node voltage magnitudes, V_i (those nodes where the voltage is not regulated); and
- The total load slack, ψ.

However, in the marginal loss rate derivation, we will assume the voltage magnitudes are constant and only use the active power equations. Thus, the unknown variables are:

- The node voltage angles, θ_i, which number N-1 (the N^{th} is set to zero and is not variable); and
- The total load slack, ψ.

Thus the total number of variables is *N* and the number of active power flow mismatch equations is *N*.

The marginal loss rate calculation for a certain generator/import is based on the change in total system losses with respect to a change in the generation/import. For a generator/import at node *i* this is written as:

$$\frac{\partial L_{system}}{\partial P_{gen,i}}.$$

In terms of our equations, the losses in the system occur in the network and are defined as:

$$L_{system} = \sum_{k=1}^{N} P_{gen,k} - \sum_{k=1}^{N} P_{load,k} - \Psi \sum_{k=1}^{N} \beta_k . \tag{2}$$

Since the sum of β_k is equal to 1, the above equation becomes:

$$L_{system} = \sum_{k=1}^{N} P_{gen,k} - \sum_{k=1}^{N} P_{load,k} - \Psi . \tag{3}$$

Taking the partial derivative with respect to $P_{gen,i}$ (see comments below on parameterization for the reason we can equate the partial derivatives) we have:

$$\frac{\partial L_{system}}{\partial P_{gen,i}} = \frac{\partial \sum_{k=1}^{N} P_{gen,k}}{\partial P_{gen,i}} - \frac{\partial \sum_{k=1}^{N} P_{load,k}}{\partial P_{gen,i}} - \frac{\partial \Psi}{\partial P_{gen,i}}, \tag{3a}$$

which equates to,

$$\frac{\partial L_{system}}{\partial P_{gen,i}} = 1 - 0 - \frac{\partial \Psi}{\partial P_{gen,i}} = 1 - \frac{\partial \Psi}{\partial P_{gen,i}}. \tag{4}$$

Thus the goal to finding the *MLR* in the distributed load slack formulation is to calculate, $\frac{\partial \Psi}{\partial P_{gen,i}}$, and this is explained below.

With a change in generation/import we can apply parameterization techniques to the power system equation set where the parameter is the generation/import. As the parameter is continuously changed a continuous set of solution variables (θ, ψ) are formed. The resulting set {θ, ψ, $P_{gen,i}$} forms a 1 dimensional manifold (path or curve) in (N-1) + 1 + 1 = N+1 space and along this curve the active power flow mismatch equations are zero. Therefore, if the values of the equations do not change along the path, the derivative along the path (defined by the parameter) is zero. Hence,

$$\frac{d\mathbf{P}_{mismatch}}{dP_{gen,i}} = \mathbf{0}.$$

The derivative can be expanded through the chain rule. By setting $\boldsymbol{y}$ = (θ, ψ) this expands to,

$$\frac{d\mathbf{P}_{mismatch}}{dP_{gen,i}} = \underbrace{\frac{\partial \mathbf{P}_{mismatch}}{\partial P_{gen,i}}}_{\text{this is a } N\times 1 \text{ vector}} + \underbrace{\frac{\partial \mathbf{P}_{mismatch}}{\partial \mathbf{y}}}_{\substack{\text{this is a } N\times N \text{ matrix} \\ \text{Jacobian}}} \underbrace{\frac{\partial \mathbf{y}}{\partial P_{gen,i}}}_{\text{this is a } N\times 1 \text{ vector}} = \mathbf{0}.$$

We see that the vector $\frac{\partial \mathbf{y}}{\partial P_{gen,i}}$ hold the values, $\frac{\partial \theta_1}{\partial P_{gen,i}},\cdots,\frac{\partial \theta_{N-1}}{\partial P_{gen,i}}$ and $\frac{\partial \Psi}{\partial P_{gen,i}}$. This last term in the vector is the term we are looking for in order to derive the marginal loss factor. Thus we need to solve for this vector. Rearranging the terms we have:

$$\frac{\partial \mathbf{y}}{\partial P_{gen,i}} = -\frac{\partial \mathbf{P}_{mismatch}}{\partial \mathbf{y}}^{-1} \frac{\partial \mathbf{P}_{mismatch}}{\partial P_{gen,i}}. \tag{5}$$

The matrix, $\frac{\partial \mathbf{P}_{mismatch}}{\partial \mathbf{y}}$, is actually the Jacobian matrix of the active power flow mismatch equations with the distributed load slack formulation. This has the form:

$$\frac{\partial \mathbf{P}_{mismatch}}{\partial \mathbf{y}} = \begin{bmatrix} \frac{\partial P_{mismatch,1}}{\partial \theta_1} & \cdots & \frac{\partial P_{mismatch,1}}{\partial \theta_{N-1}} & \frac{\partial P_{mismatch,1}}{\partial \Psi} \\ \vdots & \ddots & \vdots & \vdots \\ \frac{\partial P_{mismatch,N}}{\partial \theta_1} & \cdots & \frac{\partial P_{mismatch,N}}{\partial \theta_{N-1}} & \frac{\partial P_{mismatch,N}}{\partial \Psi} \end{bmatrix}.$$

The $\frac{\partial P_{mismatch,i}}{\partial \Psi}$ terms of the Jacobian matrix reduce to - β_i so the matrix can be written as:

$$\frac{\partial \mathbf{P}_{mismatch}}{\partial \mathbf{y}} = \begin{bmatrix} \frac{\partial P_{mismatch,1}}{\partial \theta_1} & \cdots & \frac{\partial P_{mismatch,1}}{\partial \theta_{N-1}} & -\beta_1 \\ \vdots & \ddots & \vdots & \vdots \\ \frac{\partial P_{mismatch,N}}{\partial \theta_1} & \cdots & \frac{\partial P_{mismatch,N}}{\partial \theta_{N-1}} & -\beta_N \end{bmatrix}.$$

In the other part of equation (8.5), the vector $\frac{\partial \mathbf{P}_{mismatch}}{\partial P_{gen,i}}$ is all zero except for the i^{th} entry which is 1 ($P_{gen,i}$ only shows up in the i^{th} mismatch equation).

Thus, to find $\frac{\partial \Psi}{\partial P_{gen,i}}$ we must solve matrix equation (5) which becomes (see note below):

$$
\begin{bmatrix} \dfrac{\partial \theta_1}{\partial P_{gen,i}} \\ \vdots \\ \dfrac{\partial \theta_{N-1}}{\partial P_{gen,i}} \\ \underbrace{\dfrac{\partial \Psi}{\partial P_{gen,i}}}_{\text{the value we want}} \end{bmatrix} = \begin{bmatrix} \dfrac{\partial P_{mismatch,1}}{\partial \theta_1} & \cdots & \dfrac{\partial P_{mismatch,1}}{\partial \theta_{N-1}} & -\beta_1 \\ \vdots & \ddots & \vdots & \vdots \\ \dfrac{\partial P_{mismatch,N}}{\partial \theta_1} & \cdots & \dfrac{\partial P_{mismatch,N}}{\partial \theta_{N-1}} & -\beta_N \end{bmatrix}^{-1} \begin{bmatrix} 0 \\ \vdots \\ \underbrace{-1}_{\text{let this be the } i^{th} \text{ position}} \\ 0 \end{bmatrix}. \tag{6}
$$

Note, we put a **minus** one in the i^{th} position of the $\dfrac{\partial \mathbf{P}_{mismatch}}{\partial P_{gen,i}}$ vector instead of a positive one. We do this to absorb the minus sign in front of the right hand side of the equation (5).

The marginal loss rate for the generator/import at node *i* (as stated above) is then:

$$
MLR = \frac{\partial L_{system}}{\partial P_{gen,i}} = 1 - \frac{\partial \Psi}{\partial P_{gen,i}} \tag{7}
$$

5.2. DC Power Flow Formulation

In this algorithm we utilize a DCPF (direct current power flow) formulation which assumes branch resistance is zero and that the Sine function result of the difference in the voltage angles between two nodes is approximate to the angle difference itself.

This power flow formulation simplifies to a linear system (the superposition property holds) in the form:

$\boldsymbol{P}_{netinj} = \boldsymbol{B}\ \theta.$

Where the $\boldsymbol{P}_{netinj}$ is the N-1 by 1 net injection vector (NIV) and represents the net injection, due to generation, import, load and export into the network. N being the number of nodes in the system. This vector is the input to the equation set. θ is the N-1 by 1 node voltage angle solution vector with the reference voltage angle $\theta_N = 0$. This vector is the output or result from the equation set. $\boldsymbol{B}$ is a N-1 by N-1 a matrix composed on node voltage magnitudes and branch susceptances ($B_{i,j}$ is the branch susceptance between nodes i and j), where the entries are,

$$
(i,i)\,\text{entry}: \mathbf{B}_{i,i} = \sum_{j \in CB_i} B_{i,j} V_i V_j \quad i \in \{1, 2, \cdots N-1\},
$$

$$
(i,j)\,\text{entry}: \mathbf{B}_{i,j} = -B_{i,j} V_i V_j \quad i, j \in \{1, 2, \cdots N-1\}.
$$

The set CB_i holds all nodes connected to node *i* and includes the slack (swing) node if connected to node *i*. The angle solution vector θ is calculated by:

$$\theta = \boldsymbol{B}^{-1}\,\boldsymbol{P}_{netinj.}$$

Once the angle vector is, θ, is determined, the active power from node *i* to node *j*, $P_{i,j}$ is calculated as:

$$P_{i,j} = B_{i,j} V_i V_j \left(\theta_i - \theta_j\right).$$

5.3. Inter-SC Trades

The SBTLA methodology requires that each SC schedule be balanced in terms of physical generation/import and load/export. This section describes how the inter-SC trades will be processed in order for each SC to have physically balanced schedules in terms of an algorithm.

The algorithm for this process is as follows:

1. Find the SC who is the largest net buyer of generation (i.e., this SC has more load/export than generation/import in its schedule). Call this SC, *SCbuy*, and let the amount of net buy of generation be, *NetBuyAmount*.

2. If no SC is a net buyer of generation (this implies, since the trades are also balanced that no SC is a net seller of generation) then stop. All SCs should now have a physically balanced schedule.

3. Of all the SCs who are selling generation to *SCbuy*, find the one who is selling the most to *SCbuy* and call this SC, *SCSell*. Let this amount that *SCSell* is selling to *SCbuy* be *SellAmount*.

4. Let *LoadToShift* be MIN(*NetBuyAmount*, *SellAmount*).

5. Take away the amount *LoadToShift* from the *SCbuy*'s schedule and add the amount *LoadToShift* to the *SCSell*'s schedule.

6. Go to step 1.

Note that in this process, when the load is taken away from one SC schedule and given to another SC schedule, the physical location of the load (i.e., the load point that it is on) does not change. Thus, an SC may acquire new load points in their load/export schedule.

5.4. Hours of Study and Related Data

The following table presents the dates, hours, ex post prices, total system losses, Hour-Ahead aggregate load schedule and percentage of loss to total aggregate schedule of the study set that is used in the evaluation of the present allocation and SBTLA methodologies.

Table 5-1 Data used in the transmission loss allocation study

Opr Date	Opr Hour (HE)	NP15 Uninstructed Ex post Price	SP15 Uninstructed Ex post Price	Total System Losses	Hour Ahead Aggregate Load Schedule	% Loss to Hour Ahead Aggregate Load Schedule
22-Apr-98	5	18.93	18.93	450.92	19057.27	2.37
22-Apr-98	17	32.12	32.12	675.87	25475.22	2.65
22-Apr-98	23	25.69	25.69	513.84	22191.26	2.32
26-Apr-98	5	0.05	0.05	389.38	17565.94	2.22
26-Apr-98	17	22.57	22.57	532.23	21317.95	2.50
26-Apr-98	23	25.59	25.59	506.00	20337.60	2.49
20-May-98	5	1.25	1.25	460.71	18329.60	2.51
20-May-98	17	16.00	16.00	763.37	26422.04	2.89
20-May-98	23	9.18	9.18	587.59	22725.47	2.59
30-May-98	5	0.00	0.00	483.51	18533.06	2.61
30-May-98	17	6.79	6.79	747.32	23751.84	3.15
30-May-98	23	1.08	1.08	649.52	22074.71	2.94
7-Jun-98	5	0.00	0.00	461.07	18902.48	2.44
7-Jun-98	17	2.79	2.79	686.31	22704.45	3.02
7-Jun-98	23	0.21	0.21	591.28	21920.72	2.70
19-Jun-98	5	0.01	0.01	529.06	19608.89	2.70
19-Jun-98	17	24.45	24.45	1057.65	31201.62	3.39
19-Jun-98	23	0.00	0.00	758.98	25883.73	2.93
7-Jul-98	5	5.10	5.10	584.82	22092.58	2.65
7-Jul-98	17	85.00	85.00	1131.45	36689.46	3.08
7-Jul-98	23	32.57	32.57	855.34	27927.45	3.06
18-Jul-98	5	17.46	17.46	559.74	23517.78	2.38
18-Jul-98	17	39.00	39.00	1056.31	41743.29	2.53
18-Jul-98	23	30.33	19.13	706.84	30742.45	2.30
27-Jul-98	5	23.13	23.13	597.52	23497.32	2.54
27-Jul-98	17	80.86	80.86	1019.07	40399.32	2.52
27-Jul-98	23	28.90	28.90	696.53	31725.79	2.20
4-Aug-98	5	30.43	25.01	583.63	24972.39	2.34
4-Aug-98	17	250.00	250.00	1254.04	46050.48	2.72
4-Aug-98	23	51.28	51.28	768.45	34270.10	2.24
15-Aug-98	5	29.43	4.03	556.78	23520.16	2.37
15-Aug-98	17	39.49	39.49	911.24	38811.60	2.35
15-Aug-98	23	30.84	30.84	639.78	29884.29	2.14
31-Aug-98	5	34.00	34.00	508.71	24418.71	2.08
31-Aug-98	17	250.00	250.00	1239.71	44896.53	2.76
31-Aug-98	23	32.00	32.00	667.96	32818.25	2.04
1-Sep-98	5	31.00	31.00	534.06	25647.81	2.08
1-Sep-98	17	130.50	130.50	1258.22	44266.98	2.84
1-Sep-98	23	31.00	31.00	660.80	33358.16	1.98
19-Sep-98	5	29.67	29.67	564.81	21711.45	2.60
19-Sep-98	17	27.00	27.00	815.74	30786.19	2.65
19-Sep-98	23	30.33	30.33	633.22	26250.64	2.41
28-Sep-98	5	24.81	13.58	487.92	20446.22	2.39
28-Sep-98	17	26.49	26.49	814.54	30134.15	2.70
28-Sep-98	23	27.90	27.90	588.26	25436.74	2.31
13-Oct-98	5	36.80	36.80	485.58	21432.05	2.27
13-Oct-98	17	36.00	36.00	735.49	29325.84	2.51
13-Oct-98	23	45.00	45.00	505.99	25035.69	2.02
21-Nov-98	5	14.11	14.11	499.88	21340.79	2.34
21-Nov-98	17	27.29	27.29	570.41	25272.23	2.26
21-Nov-98	23	28.99	17.00	551.17	23093.64	2.39
10-Dec-98	5	20.91	6.35	472.63	22196.81	2.13
10-Dec-98	17	24.76	24.76	805.22	28985.44	2.78
10-Dec-98	23	22.00	22.00	618.80	26049.67	2.38
13-Dec-98	5	20.86	11.74	447.27	21144.17	2.12
13-Dec-98	17	22.01	22.01	638.77	25933.17	2.46
13-Dec-98	23	20.29	20.29	574.69	24291.21	2.37
6-Jan-99	5	16.76	16.76	510.13	21416.38	2.38
6-Jan-99	17	16.00	16.00	787.62	28114.73	2.80
6-Jan-99	23	21.00	21.00	658.62	24859.00	2.65
23-Jan-99	5	16.90	16.90	415.90	19668.48	2.12
23-Jan-99	17	15.85	15.85	606.06	23738.16	2.55
23-Jan-99	23	22.57	22.57	505.94	22368.14	2.26
27-Feb-99	5	9.99	9.99	521.97	21324.37	2.45
27-Feb-99	17	15.90	15.90	573.07	23116.18	2.48
27-Feb-99	23	14.01	14.01	529.90	22799.13	2.32
8-Mar-99	5	9.00	9.00	465.99	20890.31	2.23

6. Appendix: Ancillary Service Bid and Market Clearing Price Data

Summary of Ancillary Service Bid Price and Quantities

Regulation *

	Peak Hours (7-22)					Off-Peak (1-6,23-24)				
		Avg. Bid MW by Price					Avg. Bid MW by Price			
	Avg MW Demand	<$25	$25-$50	$50-$248	>$248	Avg MW Demand	<$25	$25-$50	$50-$248	>$248
April 1998	1,309	878	14	0	2	1,339	283	15	0	5
May	1,326	736	0	0	0	1,382	545	1	0	0
June	1,497	2,158	0	53	0	1,578	1,576	0	55	0
July	2,027	2,606	5	118	161	2,008	2,225	6	115	194
Aug	1,966	3,451	1	226	700	2,088	3,020	0	206	677
Sept	1,810	3,720	0	0	716	1,956	2,794	0	0	773

Upward Regulation *

	Peak Hours (7-22)					Off-Peak (1-6,23-24)				
		Avg. Bid MW by Price					Avg. Bid MW by Price			
	Avg MW Demand	<$25	$25-$50	$50-$248	>$248	Avg MW Demand	<$25	$25-$50	$50-$248	>$248
Oct 1998	832	1,743	1	24	271	1,005	2,126	2	25	414
Nov	870	1,957	117	32	118	979	2,142	89	32	121
Dec	905	1,555	808	95	153	1,015	1,871	438	241	189
Jan 1999	912	2,203	196	52	203	981	2,419	149	262	207
Feb	903	2,183	49	49	205	963	2,200	86	260	205
March	910	2,009	138	99	299	1,009	2,091	34	273	301
April	882	1,613	660	94	61	965	1,952	233	322	61
May	755	1,169	594	65	96	814	1,090	230	576	93
June	674	1,220	546	371	283	722	1,201	318	662	275
July	739	1,374	434	640	324	732	1,443	723	759	232
Aug	782	1,047	257	87	163	755	925	512	90	170

* All regulation prices include the market clearing capacity prices plus the Regulation Energy Payment Adjustment (REPA) in effect from May 21 to November 28, 1999. Under REPA, units providing regulation received the MCP for capacity plus the maximum of $20 or the *ex post* real time energy price for that hour.

Downward Regulation*

	Peak Hours (7-22)	Avg. Bid MW by Price				Off-Peak (1-6,23-24)	Avg. Bid MW by Price			
	Avg MW Demand	<$25	$25-$50	$50-$248	>$248	Avg MW Demand	<$25	$25-$50	$50-$248	>$248
Oct 1998	986	2,424	2	27	56	698	1,073	0	12	17
Nov	979	2,159	28	1	38	691	911	24	0	7
Dec	1,009	1,803	204	44	27	737	947	141	56	13
Jan 1999	1,029	1,995	98	29	6	713	1,042	84	49	2
Feb	1,020	2,072	28	11	1	701	1,194	22	36	0
March	1,028	1,693	198	4	3	735	976	84	28	0
April	963	1,651	251	16	9	683	845	88	21	0
May	811	1,345	84	26	56	524	629	81	36	56
June	563	1,350	190	225	263	314	389	103	171	244
July	550	1,624	375	304	268	326	451	146	75	229
Aug	590	1,009	118	31	156	344	279	50	2	161

Spinning Reserve

	Peak Hours (7-22)	Avg. Bid MW by Price				Off-Peak (1-6,23-24)	Avg. Bid MW by Price			
	Avg MW Demand	<$25	$25-$50	$50-$248	>$248	Avg MW Demand	<$25	$25-$50	$50-$248	>$248
April 1998	622	811	3	1	7	531	1,109	3	1	1
May	603	863	0	0	0	531	916	0	0	0
June	714	744	1	10	0	576	890	0	5	0
July	968	1,250	5	39	45	858	1,752	10	22	69
Aug	1,011	1,507	2	188	267	830	2,813	0	87	304
Sept	890	1,627	8	128	274	727	2,594	8	30	240
Oct	698	1,583	61	1	126	590	2,214	68	1	132
Nov	735	1,917	276	17	1	667	1,950	381	17	1
Dec	1,018	2,263	324	261	25	835	2,270	223	262	24
Jan 1999	917	2,803	171	192	3	791	3,067	169	130	3
Feb	918	2,847	126	111	0	739	3,132	143	77	0
March	969	2,455	131	142	1	807	2,494	149	62	0
April	948	2,109	289	77	3	776	2,271	202	67	3
May	756	1,796	309	110	75	615	1,900	155	72	72
June	727	1,668	265	383	586	556	1,832	178	211	573
July	768	1,746	457	418	516	583	2,470	255	322	584
Aug	751	1,900	419	363	621	532	2,633	260	341	687

Non-Spinning Reserve

	Peak Hours (7-22)					Off-Peak (1-6,23-24)				
		Avg. Bid MW by Price					Avg. Bid MW by Price			
	Avg MW Demand	<$25	$25-$50	$50-$248	>$248	Avg MW Demand	<$25	$25-$50	$50-$248	>$248
April 1998	626	1,748	1	0	7	547	2,207	1	0	5
May	599	1,571	0	0	0	524	1,733	0	0	0
June	690	1,622	0	1	0	537	1,951	0	0	0
July	966	1,789	5	22	59	851	2,431	10	6	65
Aug	1,029	2,080	11	294	276	846	3,478	7	154	313
Sept	909	2,403	13	179	263	747	3,881	7	34	236
Oct	725	2,754	66	33	126	609	3,843	106	1	122
Nov	671	2,464	270	107	1	609	3,233	499	17	1
Dec	566	2,427	73	290	38	472	3,088	166	222	28
Jan 1999	514	2,743	174	351	88	444	3,307	221	264	86
Feb	506	2,616	187	96	6	410	3,274	153	87	6
March	531	2,279	166	105	27	442	2,670	131	107	27
April	518	1,908	296	115	41	423	2,589	218	143	41
May	716	2,042	265	86	100	597	2,724	91	57	98
June	790	2,176	260	338	472	685	2,674	137	248	462
July	822	2,119	274	548	577	706	2,982	277	335	658
Aug	857	2,253	266	586	722	714	3,199	215	484	798

Replacement Reserve

	Peak Hours (7-22)					Off-Peak (1-6,23-24)				
		Avg. Bid MW by Price					Avg. Bid MW by Price			
	Avg MW Demand	<$25	$25-$50	$50-$248	>$248	Avg MW Demand	<$25	$25-$50	$50-$248	>$248
April 1998	985	1,928	10	2	0	729	2,603	12	2	0
May	1,000	2,065	0	0	0	1,000	2,387	0	0	0
June	1,000	2,426	4	0	0	1,000	3,843	6	0	0
July	681	1,730	14	104	531	617	3,980	17	187	1,043
Aug	968	1,937	285	537	413	964	5,548	400	380	810
Sept	850	2,815	342	477	302	700	6,388	323	138	295
Oct	500	3,187	108	19	144					
Nov	500	2,907	334	88	10					
Dec	496	2,948	123	298	64					
Jan 1999	495	3,857	248	314	97					
Feb	497	3,761	228	123	5					
March	522	2,924	290	184	20					
April	469	2,441	539	226	59					
May	346	1,742	688	105	286					
June	237	2,017	400	327	696					
July	369	2,339	525	659	856					
Aug	322	2,634	457	856	1,066					

Since October 1998, the ISO has not purchased Replacement Reserve for off-peak hours

Summary of Ancillary Service Market Clearing Prices

Regulation Capacity Prices
Day Ahead Market -NP15

	Peak Hours (7-22) ------------------------------------>						Off-Peak Hours (1-6,23-24) --------------------------->					
Month	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price
Apr 1998	11.55	6.89	33.2	7.7	9.22	9.5	11.56	7.26	33.2	7.7	9.22	9.22
May	16.73	9.61	40.05	7.7	9.22	29.5	16.83	9.62	34.35	9.22	9.22	9.22
June	41.78	59.41	282.66	20	20	34.43	82.26	101.54	277.84	20	20	244.60
July	53.23	72.13	568.82	20	24.04	78.77	51.85	97.25	546.56	20	20	25 .00
Aug	68.63	72.88	350	20	25.39	246.15	41.16	53.86	304.03	20	20	238.80
Sept	47.58	49.53	250	20	24.11	100	29.29	17.01	272.83	20	21.39	9.21
Oct	44.88	47.34	326.36	20	25.41	52.67	38.47	37.28	299.99	20	25.63	1.32
Nov	25.97	22.31	292.99	-0.5	4.78	39	27.41	5.81	47.77	10	19.25	25.97
Dec	23.21	34.37	248.5	-98.6	6	32.65	24.7	28.19	248.5	-49.94	9.1	25 .00
Jan 1999	15.58	23.41	248.5	-79.94	5.98	25.02	16.92	13.23	200	0	9	1.75
Feb	9.71	13.64	248.5	1.01	3.82	17.23	11.5	9.46	75	-99.93	7.77	1.75
March	12.72	10.25	99.99	2	4.87	28.65	17.53	16.1	237.5	-9.92	7.99	4.89
Apr	16.81	20.15	248.5	2.9	4.01	31.57	20.83	11.35	67.01	4.02	10	17.99
May	23.12	34.31	250	3	6	30.16	3.1	304.92	250	-3350.28	14.12	4.51
June	18.23	22.02	197.61	-0.1	3.81	37.98	28.22	34	225	0	6.23	12.00
July	28.08	44.86	250	0	6.75	50	24.6	26.57	250	-0.02	8.74	35.00
Aug	12.77	8.46	57	4.43	5.47	25	12.96	7.85	45	4.44	6	11.07

Day Ahead Market -SP15

	Peak Hours (7-22) ------------------------------------>						Off-Peak Hours (1-6,23-24) --------------------------->					
Month	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price
Apr 1998	11.55	6.89	33.2	7.7	9.22	9.5	11.56	7.26	33.2	7.7	9.22	33.2
May	16.73	9.61	40.05	7.7	9.22	29.5	16.83	9.62	34.35	9.22	9.22	29.22
June	42.1	60.2	282.66	20	20	34.43	82.9	102.22	277.84	20	20	264.6
July	78.95	107.25	535.14	20	20	264.6	111.62	142.98	546.56	20	20	268.78
Aug	69.63	74.68	350	20	25.87	249.99	48.39	69.46	304.03	20	20	46.21
Sept	43.43	49.2	280.04	20	20.79	67.2	26.59	17.26	272.83	20	20	33.73
Oct	41.99	47.57	326.36	20	22.32	50	28.57	35.03	269.99	20	20	32.88
Nov	24.07	22.2	292.99	-5	4.44	38	21.35	5.17	35	0	17.98	27.2
Dec	26.26	39.61	250	-98.6	6.11	36	29.44	41.07	250	-49.94	9.1	30
Jan 1999	15.56	23.41	248.5	-79.94	5.98	25.02	22.23	36.22	237.5	0	9	24.33
Feb	9.71	13.64	248.5	1.01	3.82	17.23	11.5	9.46	75	-99.93	7.77	15.81
March	12.72	10.25	99.99	2	4.87	28.65	17.53	16.1	237.5	-9.92	7.99	29.91
Apr	16.81	20.15	248.5	2.9	4.01	31.57	20.83	11.35	67.01	4.02	10	33.93
May	23.33	34.28	250	3	6	30.16	3.1	304.92	250	-3350.28	14.12	39.77
June	21.9	36.95	250	-0.1	3.81	42.09	28.22	34	225	0	6.23	43
July	28.08	44.86	250	0	6.75	50	24.6	26.57	250	-0.02	8.74	38.05
Aug	12.95	8.57	57	4.43	5.5	25	13.26	7.98	45	4.44	6	23.23

Spinning Reserve Capacity Prices
Day Ahead Market -NP15

	Peak Hours (7-22) ------------------------------------->						Off-Peak Hours (1-6,23-24) --------------------------->					
Month	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price
Apr 1998	7.90	.83	7.37	7.38	9.22	9.50	7.44	.26	7.37	7.38	7.40	9.22
May	7.51	.60	6.00	7.38	7.40	9.50	7.45	.50	6.00	7.38	7.40	9.22
June	39.73	76.07	6.90	7.38	225.00	244.60	21.80	55.17	3.97	4.47	9.22	244.60
July	17.47	41.84	6.90	7.36	9.22	25 .00	11.02	28.80	4.89	6.88	7.42	25 .00
Aug	5 .63	87.45	2.00	6.00	249.97	25 .00	5.86	15.04	1.15	1.56	7.40	238.80
Sept	28.88	68.71	1.06	4.58	75.00	25 .00	1.25	1.19	.30	.50	2.51	9.21
Oct	3.63	15.74	.43	1.05	4.16	25 .00	.53	.17	.37	.37	.78	1.32
Nov	4.45	14.02	.91	1.47	5.03	20 .01	1.05	2.55	.30	.37	1.50	25.97
Dec	15.75	4 .75	.91	3.90	29.00	25 .00	4.27	23.29	.41	.44	1.55	25 .00
Jan 1999	5.58	12.93	.00	.75	11.00	20 .00	.58	.55	.00	.01	1.52	1.75
Feb	3.82	4.48	.07	.75	7.24	6 .00	.52	.50	.00	.01	1.45	1.75
March	5.40	6.64	.75	1.50	7.36	52.35	1.24	.94	.01	.75	2.00	4.89
Apr	1 .57	15.65	.06	2.00	2 .21	20 .00	1.34	2.01	.00	.02	3.07	17.99
May	6.49	5.80	.01	1.34	15.00	38.00	1.46	1.33	.19	.37	3.48	4.51
June	6.29	14.36	.25	1.00	14.31	175.00	1.13	1.19	.20	.49	2.98	12.00
July	12.58	33.72	.00	.50	32.00	25 .00	.55	2.60	.00	.01	1.02	35.00
Aug	1 .14	24.34	.00	1.00	2 .00	249.98	.96	1.20	.00	.24	1.25	11.07
Sept	7.77	15.18	.00	.99	21.01	22 .32	2.12	5.69	.00	.00	5.30	55.00
Oct	13.66	2 .98	.01	1.25	32.55	268.08	4.60	7.97	.01	1.10	1 .00	39.04

Day Ahead Market -SP15

	Peak Hours (7-22) ------------------------------------->						Off-Peak Hours (1-6,23-24) --------------------------->					
Month	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price
Apr 1998	7.90	.83	7.37	7.38	9.22	9.50	7.44	.26	7.37	7.38	7.40	9.22
May	7.51	.60	6.00	7.38	7.40	9.50	7.45	.50	6.00	7.38	7.40	9.22
June	48.46	85.45	6.90	7.38	244.60	244.60	21.83	55.16	3.97	4.47	9.22	244.60
July	78.66	96.69	6.90	9.21	240.00	250.00	73.53	94.84	6.87	6.90	225.00	250.00
Aug	63.99	96.28	1.56	6.00	249.99	250.00	22.70	62.48	1.15	2.00	9.22	250.00
Sept	31.40	72.25	1.06	4.58	123.99	250.00	7.71	38.91	.40	.50	4.13	250.00
Oct	3.63	15.74	.43	1.05	4.16	250.00	.53	.17	.37	.37	.78	1.32
Nov	4.45	14.02	.91	1.47	5.03	200.01	1.05	2.55	.30	.37	1.50	25.97
Dec	22.75	56.99	.91	3.90	35.00	250.00	8.11	38.61	.41	.44	9.00	250.00
Jan 1999	5.62	12.94	.00	.75	11.00	200.00	1.43	12.70	.00	.00	1.52	200.00
Feb	3.82	4.48	.07	.75	7.24	60.00	.52	.50	.00	.01	1.45	1.75
March	5.40	6.64	.75	1.50	7.36	52.35	1.24	.94	.01	.75	2.00	4.89
Apr	10.57	15.65	.06	2.00	20.21	200.00	1.34	2.01	.00	.02	3.07	17.99
May	8.70	14.89	.25	1.34	17.95	99.90	1.46	1.33	.19	.37	3.48	4.51
June	10.04	32.55	.25	1.00	17.21	249.96	1.13	1.19	.20	.49	2.98	12.00
July	12.58	33.72	.00	.50	32.00	250.00	.55	2.60	.00	.01	1.02	35.00
Aug	10.12	24.72	.00	1.00	21.42	249.98	.96	1.22	.00	.24	1.25	11.07
Sept	8.30	25.98	.00	.99	10.01	188.13	.85	.81	.00	.00	2.00	4.19
Oct	11.20	13.79	.99	2.63	24.02	109.09	2.80	4.52	.99	1.12	6.97	33.00

Non-Spinning Reserve Capacity Prices
Day Ahead Market -NP15

Month	Peak Hours (7-22) Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price	Off-Peak Hours (1-6,23-24) Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price
Apr 1998	7.20	1.38	4.41	4.42	7.90	7.90	6.08	1.65	4.41	4.42	7.90	7.90
May	7.72	.97	4.42	7.88	7.90	9.50	6.45	1.72	4.42	4.42	7.90	7.90
June	3.50	2.07	.99	1.44	7.76	9.50	2.56	2.02	.99	1.15	7.14	7.88
July	24.87	82.45	1.48	3.94	7.90	500.00	6.08	2.02	1.48	3.95	7.90	7.90
Aug	41.26	85.35	1.51	3.65	250.00	250.00	2.98	1.25	.96	1.47	4.38	10.05
Sept	20.97	62.29	.50	1.36	7.85	250.00	.97	.59	.41	.45	1.90	2.94
Oct	.74	.30	.35	.38	1.17	1.99	.41	.08	.30	.34	.52	.83
Nov	1.10	1.14	.38	.66	2.00	20.00	.40	.06	.35	.38	.38	.60
Dec	4.66	28.29	.30	.50	.99	250.00	.34	.21	.19	.25	.37	2.00
Jan 1999	.76	.51	.00	.25	1.50	3.00	.26	.32	.00	.14	.25	1.99
Feb	.97	.49	.00	.49	1.79	2.30	.27	.18	.05	.05	.50	.98
March	.79	1.49	.45	.50	1.00	30.00	.46	.18	.22	.25	.65	.98
Apr	3.00	7.23	.25	.35	5.00	50.00	.32	.20	.13	.20	.50	1.29
May	4.34	4.29	.30	.67	10.00	24.00	.57	.43	.25	.33	.97	6.00
June	3.89	9.97	.10	.20	6.29	100.00	.32	.30	.10	.14	.75	2.00
July	12.11	41.68	.02	.11	17.84	250.00	.09	.12	.01	.03	.13	1.00
Aug	4.78	14.00	.01	.12	11.10	200.00	.10	.95	.01	.01	.11	15.00
Sept	5.41	16.07	.01	.01	10.50	235.79	1.21	5.73	.01	.01	2.71	55.00
Oct	7.14	26.92	.01	.01	19.33	364.85	.02	.04	.01	.01	.01	.33

Day Ahead Market -SP15

Month	Peak Hours (7-22) Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price	Off-Peak Hours (1-6,23-24) Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price
Apr 1998	7.20	1.38	4.41	4.42	7.90	7.90	6.08	1.65	4.41	4.42	7.90	7.90
May	7.72	.97	4.42	7.88	7.90	9.50	6.45	1.72	4.42	4.42	7.90	7.90
June	3.29	2.11	.99	1.39	7.76	9.50	2.56	2.02	.99	1.15	7.14	7.88
July	25.85	85.50	.79	1.37	9.22	500.00	4.12	2.90	1.18	1.22	7.90	30.00
Aug	48.70	90.27	1.51	3.57	250.00	250.00	13.83	50.97	.97	1.48	4.39	250.00
Sept	22.97	65.67	.50	1.36	7.89	250.00	.97	.59	.41	.47	1.90	2.94
Oct	.74	.30	.35	.38	1.17	1.99	.41	.08	.30	.34	.52	.83
Nov	1.10	1.14	.38	.66	2.00	20.00	.40	.06	.35	.38	.38	.60
Dec	6.91	36.69	.30	.50	.99	250.00	1.22	11.52	.19	.25	.37	175.00
Jan 1999	.75	.51	.00	.25	1.50	3.00	.20	.06	.00	.13	.25	.26
Feb	.97	.49	.00	.49	1.79	2.30	.27	.18	.05	.05	.50	.98
March	.79	1.49	.45	.50	1.00	30.00	.46	.18	.22	.25	.65	.98
Apr	3.00	7.23	.25	.35	5.00	50.00	.32	.20	.13	.20	.50	1.29
May	4.48	4.37	.30	.88	11.00	24.00	.57	.43	.25	.33	.97	6.00
June	3.91	9.96	.10	.25	6.29	100.00	.32	.30	.10	.14	.75	2.00
July	12.11	41.68	.02	.11	17.84	250.00	.09	.12	.01	.03	.13	1.00
Aug	4.77	14.20	.01	.12	11.10	200.00	.10	.97	.01	.01	.11	15.00
Sept	2.43	4.55	.01	.01	6.37	49.96	.10	.24	.01	.01	.19	1.25
Oct	5.00	9.85	.01	.01	19.33	82.92	.02	.04	.01	.01	.01	.33

Replacement Reserve Capacity Prices
Day Ahead Market -NP15

	Peak Hours (7-22) ---------->						Off-Peak Hours (1-6,23-24) ---------->					
Month	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price
Apr 1998	8.02	.58	.00	7.87	8.02	9.50	7.70	1.15	.00	7.87	7.90	9.22
May	7.93	.21	7.86	7.88	7.90	9.50	7.90	.00	7.88	7.89	7.90	7.90
June	4.23	2.02	1.21	1.47	7.49	9.22	2.89	2.12	1.40	1.43	7.49	7.90
July	27.35	89.23	.00	.00	7.90	500.00	4.47	12.31	.00	.01	7.87	189.00
Aug	50.92	92.48	.00	2.25	249.84	250.00	2.19	1.34	.75	.76	3.74	4.49
Sept	17.23	51.21	.10	.42	49.98	250.00						
Oct	.59	.70	.01	.10	1.00	10.00						
Nov	.82	1.29	.25	.31	1.20	20.00						
Dec	3.15	19.33	.30	.31	1.94	200.00						
Jan 1999	1.06	.47	.30	.50	1.90	1.99						
Feb	1.19	.44	.70	.75	1.89	1.99						
March	.91	.31	.50	.70	1.29	3.73						
Apr	2.32	4.72	.19	.40	7.00	30.00						
May	2.46	2.01	.23	.64	5.00	9.00						
June	2.04	8.34	.01	.19	2.08	75.00						
July	12.44	41.04	.01	.40	20.00	250.00						
Aug	6.50	28.86	-.01	.21	8.00	239.22						
Sept	5.40	13.47	-.01	.01	10.70	95.70						
Oct	13.44	47.87	.00	.25	20.10	534.17						

Day Ahead Market -SP15

	Peak Hours (7-22) ---------->						Off-Peak Hours (1-6,23-24) ---------->					
Month	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price	Avg Price	Std Dev	Min Price	10% Level	90% Level	Max Price
Apr 1998	8.02	.58	.00	7.87	8.02	9.50	7.70	1.15	.00	7.87	7.90	9.22
May	7.93	.21	7.86	7.88	7.90	9.50	7.90	.00	7.88	7.89	7.90	7.90
June	4.03	2.12	1.14	1.45	7.49	9.22	2.89	2.12	1.40	1.43	7.49	7.90
July	171.99	1075	.00	.00	200.00	9,999.00	2.53	19.54	.00	.00	1.48	244.60
Aug	51.58	92.89	.01	2.24	249.84	250.00	1.95	1.30	.01	.75	3.74	4.49
Sept	17.58	51.52	.10	.41	50.00	250.00						
Oct	.59	.70	.01	.10	1.00	10.00						
Nov	.82	1.29	.25	.31	1.20	20.00						
Dec	3.16	19.33	.30	.31	1.94	200.00						
Jan 1999	1.06	.47	.30	.50	1.90	1.99						
Feb	1.19	.44	.70	.75	1.89	1.99						
March	.91	.31	.50	.70	1.29	3.73						
Apr	2.32	4.72	.19	.40	7.00	30.00						
May	2.42	2.02	.23	.63	5.00	9.00						
June	1.99	8.34	.01	.19	1.00	75.00						
July	12.44	41.04	.01	.40	20.00	250.00						
Aug	6.70	29.31	-.01	.21	8.00	239.22						
Sept	3.12	9.54	-.01	.01	6.00	90.98						
Oct	6.05	17.38	.00	.10	8.98	197.89						

Summary of Real Time Energy Bid Prices

Supplemental Energy and Ancillary Service Energy Bids

Average Hourly MW by Bid Price Category

Bid Price Category	Supplemental Energy	Spinning Reserve	Non-spinning Reserve	Replacement Reserve
< $20	1,636	182	24	24
$20-$30	1,149	84	17	22
$30-$40	469	45	32	15
$40-$50	343	36	59	26
$50-$60	206	54	89	32
$60-$70	95	22	32	26
$70-$80	58	19	45	14
$80-$90	26	6	8	7
$90-$100	56	27	77	17
$100-$150	60	27	20	20
$150-$230	94	65	21	12
$230-$240	116	131	76	32
> $240	68	282	220	183
Avg. Bid MW	4,379	980	720	430

Percent of Total MW by Bid Price Category

Bid Price Category	Supplemental Energy	Spinning Reserve	Non-spinning Reserve	Replacement Reserve
< $20	37%	19%	3%	6%
$20-$30	26%	9%	2%	5%
$30-$40	11%	5%	4%	4%
$40-$50	8%	4%	8%	6%
$50-$60	5%	5%	12%	7%
$60-$70	2%	2%	4%	6%
$70-$80	1%	2%	6%	3%
$80-$90	1%	1%	1%	2%
$90-$100	1%	3%	11%	4%
$100-$150	1%	3%	3%	5%
$150-$230	2%	7%	3%	3%
$230-$240	3%	13%	11%	7%
> $240	2%	29%	31%	43%
	100%	100%	100%	100%

7. Appendix: Paper on Single-Part versus Two-Part Ancillary Service Bid Evaluation Methods