



CALIFORNIA ISO

California Independent
System Operator

California ISO

Rate Structure Proposal For the 2004 GMC Rate Structure Project DRAFT

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1.0 Introduction

This document and its appendices detail the California Independent System Operator's alternative rate structure proposal as part of the 2004 GMC Rate Structure Project to redesign the structure of its Grid Management Charge (GMC) in accordance with the Initial Decision in ER 01-313-000, *et. al.* and the Settlement Agreement in ER 02-250-000, *et. al.*. They also serve to describe and record the efforts of the California Independent System Operator (California ISO) in developing the proposal.

In developing this proposal, the California ISO and participants reviewed the rate structures of other North American Independent System Operators, FERC ratemaking standards and traditional and marginal cost ratemaking methodologies. In addition, the California ISO worked with participants to review the California ISO's current GMC structure and cost accounting methods and to develop a comprehensive listing of California ISO activities. The California ISO and participants also worked together to develop a list of potential billing determinants for use by any party in developing their own proposal.

The California ISO adopted, where possible, reasonable and appropriate concepts put forth in other parties' rate proposals. The California ISO also took note of the imperatives of the Initial Decision to unbundle California ISO rates, consider demand charges, and to look at alternative methods of cost assignment of certain cost centers.

The California ISO also kept in mind the following criteria from the 2004 GMC Rate Structure Project Charter:

- Develop a rate structure that meets the FERC "just and reasonable" standard, and appropriately allocates ISO costs among the ISO's users;
- Develop a rate structure based on the principle of cost causation, which charges customers for the cost of services that they use/cause;
- Design a rate structure that is easy to administer (including reasonably cost effective, and benefits of change should outweigh the costs) and understandable;
- Develop a rate structure that does not result in unmanageable adverse operational impacts;
- Develop a rate structure that is arrived at through an open and balanced stakeholder process;
- Recover approved ISO costs in a stable, low risk manner without excess volatility;
- Have the new rate structure filed with FERC by November 1, 2003, so that it can be effective January 1, 2004; and,
- Meet the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.¹

¹ 2004 GMC Rate Structure Project, a Stakeholder Process, (project charter) page 2.

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2. Summary of Proposal

Table 1 Summary of the California ISO Rate Proposal Functionalization and Billing Determinants						
Function	Grid Reliability Services		Market Services			Settlements, Metering and Client Relations
Sub-Function	Core Reliability Services	Energy and Transmission Services	Forward Scheduling	Congestion Management	Market Usage and Services	
Billing Determinant	Non-coincident peak demand (MW)	(1) ISO Controlled Grid Load plus exports and (2) absolute value of net uninstructed deviations by settlement interval MWh	Final HA schedules submitted, no charge for changes to DA schedules	Net Scheduled Interzonal flows MWh	Purchases and sales of Ancillary Services, instructed energy and absolute value of net uninstructed deviations by settlement interval MWh	(1) Fixed monthly charge per customer (2) Remaining costs to be recovered by association with other billing determinants

The table above summarizes the functionalization aspect of the California ISO rate proposal. The Grid Management Charge would consist of three functions. Two of the functions would be sub-functionalized. These functions, with their associated sub-functions are:

1. Grid Reliability Services
 - a. Core Reliability Services
 - b. Energy and Transmission Services
2. Market Services
 - a. Forward Scheduling
 - b. Congestion Management
 - c. Market Usage and Services
3. Settlements, Metering and Client Relations

These are described more fully below.

2.1 Grid Reliability Services

The California ISO provides for the safe, reliable operation and maintenance of the Control Area, provides for transmission expansion planning coordinates with neighboring Control Areas, manages transmission flows and complies with regional and national reliability standards.

The following is a partial listing of activities in Grid Reliability Services (a more complete list is in Appendix A):

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- Monitoring of system conditions and dispatching to maintain reliability
- Coordination, communication, and integration with neighboring Control Areas
- Intertie scheduling
- Compliance with reliability standards
- Transmission and generation outage coordination
- Management, monitoring and approval of new generator interconnections
- Evaluation of transmission expansion
- Performance of operational studies, system security analyses and system planning studies to ensure overall reliability

Portions or all of the following systems can be attributed to Grid Reliability Services:

- Energy Management System (EMS)
- Bill's Interchange Transaction Management System (BITS)
- Out-of-Sequence and Out-of-Market Settlements Information System (OSMOSIS)
- Global Reliability Resource Management Application (GRMMA)
- Automated Dispatch System (ADS)
- Scheduling Logging for the ISO of California (SLIC)
- Generator Communication Project (GCP)
- Electronic Tagging (ETAG)

The Grid Reliability Services function consists of two sub-functions, Core Reliability Services and Energy and Transmission Services.

2.1.1 Core Reliability Services

The California ISO provides a basic level of reliable operation of a Control Area surrounded by other control areas and achieving minimal disruptions to system operation. In this sub-function, the California ISO provides a stable grid and meets regional and national regulatory requirements (such as NERC and WECC reliability criteria) and some FERC requirements (such as a basic level of transmission planning). All necessary activities attributable to Control Area operation including the capability of handling a system that is as geographically dispersed as the present system, but without features that are scalable (i.e., that vary according to use or size of flow) are contained in this function. However, only a basic level of activity is contained in this service. The level of activity does not represent fully functioning operations for a robust Control Area in which there are outages and growth as new generation and transmission projects are developed.

These services must be constantly available in order for the Control Area to operate reliably and must reflect the fact that the Control Area is interconnected with and interacting with other Control Areas and in compliance with all regulatory mandates placed on it.

Included in the costs of these services are the costs of systems applications necessary to operate the Control Area.

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The charge to recover the costs of this service would be assessed on the metered non-coincident peak (NCP) demand of Scheduling Coordinators (SCs) on a monthly basis. The ISO is no longer proposing to calculate a separate adder for behind the meter Standby Load and behind the meter load of other entities. At this time, the ISO is waiting for the final Commission decision in the QF PGA, ER98-997-000 to determine how SCs may comply with the metering requirements of the ISO Tariff.²

2.1.2 Energy and Transmission Services

The California ISO provides for the safe, reliable operation of the Control Area assuming everyday (normal and extraordinary) operational requirements in which outages and disruptions (such as weather-related incidents) occur. This is the scalable portion of Grid Reliability Services that is necessary to respond to the everyday occurrence of system activity.

The level of activity is a function of the intensity of use of the transmission system within the Control Area and the occurrence of system outages and disruptions (e.g., weather-related incidents). This includes the services for simultaneously managing energy imbalances and transmission flows beyond those in a steady state Control Area.

For example, grid planning requires more resources in a control area that has growing load and significant need for new transmission and generation facilities. The use of the grid will be more intense if load-serving entities generate only part of their own power and buy part, bringing it to load centers through the grid within the Control Area. A higher level of uninstructed deviations will increase the workload of the California ISO, since actions must be taken to offset these deviations to ensure system-wide balance in real time.

Included in the costs of Energy and Transmission Services are the scalable portion of systems applications and the hardware necessary to operate the Control Area.

In this sub-function, the level of activity within the Control Area drives costs. Thus, they will vary with the volume of flows and the level of net uninstructed deviations within a settlement period. Two volumetric billing determinants will be used: monthly ISO Controlled Grid Load³ plus exports (MWh) and the absolute value of net uninstructed deviations by settlement interval (in MWh).

2.2 Market Services

² The ISO Tariff requires SCs to schedule and meter gross demand and generation. However, the ISO waived this requirement for Qualifying Facilities pending a final FERC decision in ER98-997-000. An Initial Decision has been issued, but the Commission has not yet voted to affirm that decision.

³ The ISO Controlled Grid includes the system of transmission lines and associated facilities of the Participating Transmission Owners that have been placed under the ISO's Operational Control.

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Under Market Services, the California ISO provides access to its scheduling infrastructure, manages congestion to facilitate transmission flows, operates and maintains California ISO markets for participants, and monitors market performance.

Contained in this function are activities related to the maintenance, monitoring, operation and performance of the forward and Real-Time markets. These activities span many of the activities within the ISO's current Congestion Management and Ancillary Services/Real-Time Energy Operations services.

The following is a partial listing of activities in Market Services (a more complete list is found in Appendix A):

- Processing forward market schedules
- Adjusting forward market schedules to mitigate transmission congestion
- Maintaining market information postings
- Operating Real-Time market
- Determining market clearing prices
- Administering primary and secondary Fixed Transmission Rights markets
- Monitoring market performance

Portions or all of the following systems can be attributed to Market Services:

- Scheduling Infrastructure (SI)
- Scheduling Applications (SA)
- Open Access Same-Time Information System (OASIS)
- Automated Dispatch System (ADS)
- Balancing Energy Ex-Post Pricing (BEEP)
- Automated Load Forecasting (ALFS)
- Firm Transmission Rights (FTRs) and Secondary Registration System (SRS)
- Outage Scheduler (OS)
- Existing Transmission Contracts (ETC)
- Congestion Management (CONG)
- Day Ahead Data Analysis Tool (DADAT)
- Hour Ahead Data Analysis Tool (HADAT)

The Market Services function consists three sub-functions, (1) Forward Scheduling, (2) Congestion Management, and (3) Market Usage and Service.

2.2.1 Forward Scheduling

The California ISO provides SCs with the ability to forward schedule energy and Ancillary Services and the processing of accepted Ancillary Services bids. In this context, a schedule is represented by a scheduling template (import, export, load, generation, inter-SC trade and

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Ancillary Services, including self-provided AS) submitted to the California ISO's Scheduling Infrastructure.

The following is a partial listing of activities in Forward Scheduling:

- Processing forward energy schedules, including inter-SC trades
- Reviewing and verifying schedules

The ISO processes schedules to confirm path ratings are not exceeded, to ensure that sufficient Ancillary Services are or will be procured and that SC portfolios are balanced.

The costs incurred by the California ISO are more closely correlated with the number of schedules than energy volumes, since the basic effort encompasses processing the schedules and bids regardless of the volume within the transactions. The billing determinant will be the number of final hour-ahead schedule templates submitted, not including changes to the DA schedule (so as not to discourage load-following).

2.2.2 Congestion Management

The California ISO provides management and operation of inter-zonal congestion markets, using adjustment bids, taking Firm Transmission Rights and Existing Transmission Contracts into account, and determining the price for mitigating congestion for flows on congested paths. Congestion exists when power flowing on a transmission path exceeds the transmission path capacity. Congestion management is conducted by the California ISO during the scheduling process and results in the economic rationing of transmission service in order to prevent congestion. This currently provides for only inter-zonal congestion. Intra-zonal congestion is managed in real-time and thus incorporated in Core Reliability Services.

This service is similar to the CONG service in the current GMC rate design, but is not identical due to the other changes in this proposed rate design. When LMP is implemented, congestion management activities will be functionalized and their associated costs will be assigned to other service categories, eliminating this service category.

The costs of this service would be recovered through an assessment on net Hour-Ahead scheduled inter-zonal flows (loads).

2.2.3 Market Usage

In this sub-function of Market Services, the California ISO processes supplemental energy and Ancillary Service bids, maintains and controls the Open Access Same-Time Information System (OASIS), monitors market performance, ensures generator compliance with market protocols, and determines market clearing prices. In the future, activities associated with forward energy markets will be included here.

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The following is a partial listing of activities in Market Usage and Service (a more complete list is in Appendix A):

- Maintaining market information postings
- Operating Real-Time market
- Determining market clearing prices
- Monitoring market performance

The costs of this service would be recovered through a per MWh charge on purchases and sales of Ancillary Services, instructed energy and the absolute value of net deviations by Settlement interval by SC ID. Self-provided Ancillary Services would not be assessed this charge.

2.3 Settlements, Metering and Client Relations

Under Settlements, Metering and Client Relations, the California ISO maintains customer account data, provides account information to customers, responds to customer inquiries, calculates market charges, processes settlement statements, resolves customer disputes and provides customer training. This function includes Settlements, Billing, and Metering activities as well as Client Relations. Certain Settlements activities and some Contracts and Special Projects activities are assigned to Core Reliability Services. For example, RMR Settlements is assigned to CRS because its activities are related to the maintenance and provision of RMR services to the Control Area. Similarly, Contracts and Special Projects has a primary role in the administration of the Transmission Access Charge and the development of Metered SubSystems.

The following is a partial listing of activities in Settlements, Metering and Client Relations (a more complete list is in Appendix A):

- Determine charges associated with transmission services, forward market schedules, Real-Time balancing market, congestion management and administrative charges
- Maintain and process Settlements data
- Perform Settlement statement re-runs
- Manage and monitor SC credit and collateral
- Collect and validate meter data
- Provide ISO Tariff guidance to Market Participants
- Facilitate resolution of Market Participant issues
- Provide training to Market Participants

Portions or all of the following systems can be attributed to Settlements, Metering and Client Relations:

- Out-of-Sequence, Out-of-Market Settlements Information System (OSMOSIS)
- Balance of Business Systems (BBS)
- Meter Data Acquisition System (MDAS)

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Settlements, Metering and Client Relations activities are essential to maintaining any connection between the SCs and the California ISO, regardless of the actual degree of service taken from the California ISO. It can be seen that there are major costs associated with this function. Thus, the mitigation of the bill impacts of assigning these costs on a per customer basis is essential and appropriate. For that reason, the California ISO proposes to recover these costs using both a small fixed monthly charge and a variable charge.

The fixed monthly charge is \$500 per SC ID. The remaining Settlements, Metering and Client Relations costs will be associated with the billing determinants of Energy and Transmission Services, Congestion Management and Market Usage. The billing determinants for these services are ISO Controlled Grid Load plus exports and net uninstructed deviations (Energy and Transmission Services), net scheduled interzonal flows (Congestion Management) and purchases and sales of Ancillary Services, instructed energy, and net uninstructed deviations (Market Usage). We made the decision not to associate costs to either Core Reliability Services or Energy and Transmission Services as these were new rates and any additional costs would increase the severity of bill impacts.

In order to associate the remaining costs with the other billing determinants, Barkovich and Yap and the ISO reviewed the occurrence of charge types in Settlement Statements over the test year period, September 2001 through August 2002. The occurrence of charge types in Settlement Statements is a measure of the activity flowing through Settlements. We associated each charge type with one of the three services above. The Settlement, Metering and Client Relations costs associated with each billing determinant were proportional to the relative number of charge types associated with each service. This association is detailed in Appendix C.

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3.0 Comparison to Other ISOs/RTOs

Comparisons with other ISOs are difficult as there is no standard for ISO rates. It is also made difficult by the application of the FERC Uniform System of Accounts that were created for application to traditional integrated electric utilities. Nonetheless, in the following we attempt to make some high level comparisons between the California ISO's proposed new rate structure and that of other ISOs/RTOs. These comparisons are shown in Appendix B, in which we compare ISO functions and the method of recovery.

3.1 Grid Reliability Services

Of the five other ISOs (ISO-NE, NYISO, PJM, ERCOT and MISO), only ISO-NE and PJM have "Reliability" functions. ISO-NE's Schedule 3, Reliability Administration, appears to be similar to the California ISO's proposed Grid Reliability Services function. ISO-NE's billing determinant is non-coincident peak demand.

PJM's reliability functions are Schedule 9-1, Control Area, Schedule 9-5, Regulation and Frequency Response, and Schedule 9-7, Capacity and Resource Obligation Management. Schedules 9-1 and 9-5 are recovered through MWh assessments. Schedule 9-1 is recovered through an assessment on point-to-point and network integration services flows in MWhs. Schedule 9-5 is recovered through an assessment on PJM regulation and scheduled regulation, including self-scheduled regulation. Schedule 9-7 is allocated to PJM East and PJM West by their relative non-coincident peaks. Within each region, the cost is recovered by an assessment on resource obligations in MW-days.

3.2 Market Services

Of the other ISOs/RTOs, only ISO-NE and PJM have separate market functions. The market functions of the ISO-NE can be found in Schedule 1-Scheduling, System Control and Dispatch and Schedule 2-Energy Administration. Schedule 1 costs are recovered through an assessment on "monthly Network load in kW plus the highest amount of reserved capacity of point-to-point transmission plus the highest amount of authorized use." Schedule 2 costs are recovered by assessments on Transaction Units (bilateral contract block hours plus generator block hours plus net deviation block hours) and on load and injections (generation). Fifteen percent of the Schedule 2 costs are recovered from Transaction Units and 85 percent from load and injections.

The market functions of PJM can be found in Schedule 9-4-Market Support, and Schedule 9-3-Fixed Transmission Rights. Market Support costs are recovered from generation and load MWhs. Fixed Transmission Rights costs are recovered through a charge on FTR MW per hour summed over hours. (Essentially, this converts the FTR MWs to MWhs over the year.)

3.3 Settlements, Metering and Client Relations

None of the other ISOs/RTOs have an explicit, separate Settlements, Metering and Client Relations function. All except the MISO have annual fees. These fees are described in

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Appendix B. ISO-NE, PJM and ERCOT have fixed annual fees varying from \$2,000 (ERCOT) to \$5,000 (ISO-NE and PJM). The NYISO and the Ontario IMO have tiered fees that vary by the amount of load an entity has. The NYISO has a \$5,000 fee for all other companies that do not have load.

3.4 Startup Costs

Only the NYISO has explicit recovery of start-up costs. For 2003, the monthly amount recovered is \$1,095,881. This amount is assessed equally to customers receiving transmission services under the Open Access Transmission Tariff (OATT) and to customers receiving Location Based Marginal Pricing (LBMP) market services. The current rate for those receiving service under the OATT is \$0.046223 per MWh, and the current rate for those receiving LBMP service is \$0.047346 per MWh.

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4.0 Cost Assignment Process

The process of identifying and assigning costs to functions and sub-functions was an iterative one. As the California ISO proposal developed, the California ISO's consultants, Barkovich and Yap, Inc., reviewed the current method of cost assignment using the Budget Tool and the resulting structure in the Cost Allocation Matrix (CAM). They then laid out a process in which directors and managers of directly assignable cost centers were asked to assign costs to the California ISO's proposed functions and sub-functions, ultimately to provide data for the ISO's Cost Allocation Matrix

Each set of directors and managers provided three major items. First, they provided a description of their cost center activities to each function or sub-function. Second, they assigned their personnel to the function or sub-function. Finally, they provided a justification of their personnel assignments. The results were tabulated in worksheets, which form the basis for the direct personnel assignments in the CAM.

Barkovich and Yap worked directly with most of the directors and managers, querying results, asking for clarifications, and compiling results. In most cases several meetings and conference calls were required before personnel assignments were completed.

For those cost centers that were not directly assignable, several different methods of assignment were used. The main methods were proportional to:

- Supervised cost center assignments;
- Departmental cost center assignments;
- Total directly assigned operating costs; or
- Total operating cost assignments.

The cost assignment of capital expenditures followed a method similar to that done for cost centers. Whenever possible, capital expenditures were directly assigned. This assignment was done in an iterative process by the directors and managers of the cost centers that utilized the systems. For those capital expenditures that could not be directly assigned, one of the methods in the list above was used.

The results of the cost assignments were linked to the CAM to create the revenue requirements for each function or sub-function. The resulting assignments are shown in the table below:

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Table 2 Revenue Requirements by Function	
Grid Reliability Services	
Core Reliability Services	\$ 93,544,836
Energy and Transmission Services	\$ 38,337,665
Total Grid Reliability Services	\$ 131,882,501
Market Services	
Forward Scheduling	\$ 19,039,848
Congestion Management	\$ 10,017,448
Market Usage	\$ 28,775,078
Total Market Services	\$ 57,832,374
Settlements, Metering and Client Relations	\$ 47,885,496
Total Revenue Requirement after application of reserve	\$ 237,600,371
Revenue requirements shown are based on 2003 Budget information. Cost assignments are preliminary. Further refinement may cause these assignments to change, and allocations will vary as a result of differing costs in the 2004 revenue requirement.	

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5.0 Billing Determinants For Each Service

The California ISO and participants identified a number of potential billing determinants for use by participants and the California ISO early in the Project. This was done to allow the California ISO to begin collection of data and to prevent a lack of data from impeding progress on consideration of alternative rate designs. These billing determinants are listed in:

<http://www.caiso.com/docs/09003a6080/1e/f7/09003a60801ef7fb.pdf>.

As the California ISO proposal developed and the rate functions crystallized, we analyzed the various potential billing determinants for their suitability for use. This suitability analysis looked at two factors. We preliminarily determined if the billing determinant was causally related to the function for which it was to be used. Then we considered the billing determinant's potential stability, impact on operations and market participant behavior, and its availability in the Settlements system.

Based on this assessment, the California ISO determined that looking beyond the initial list of potential billing determinants was necessary. We found that certain transaction data were suitable for use as a billing determinant. This transaction data is discussed below.

5.1 Core Reliability Services

Core Reliability Services are the basic services needed to manage the Control Area reliably and safely. The billing determinant for this function should be reflective of the costs of maintaining operational control at all times of the day and seasons of the year, as well as the stress that entities place on the transmission system. The billing determinant selected is the monthly non-coincident peak (NCP) *demand* on a gross basis. An entity's NCP demand reflects the burden that the entity places on the operation of the transmission system.

Staff rejected use of an entity's coincident peak (CP) demand as the billing determinant. The coincident peak demand would not reflect the burden on system operation of entities whose peaks are not coincident with the system peak. Core Reliability Services must be provided at all times of the day, even to entities that have NCP demand occurring in the middle of the night.

5.2 Energy and Transmission Services

Contained within Energy and Transmission Services is the scalable portion of Grid Reliability Services. Scalability implies an increasing relationship with flows, outages and disturbances within the Control Area. The costs of managing the Control Area will be higher to the extent that total flows increase. They will also be higher to the extent that entities cause inadvertent flows that must be managed in real time. The billing determinants selected by the California ISO are the monthly ISO Controlled Grid Load plus exports and the absolute value of net uninstructed deviations by Settlement interval. The first billing determinant represents total flows and the second represents inadvertent flows on the transmission grid.

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The absolute value of net uninstructed deviations by Settlement interval is calculated as the absolute value of the difference between instructed energy and actual energy delivered net of changes in load. Allowing netting for changes in load permits SCs to load follow (match changes in load with changes in generation), which reduces inadvertent flows on the transmission grid.

5.3 Forward Scheduling

Forward Scheduling contains the activities associated with accepting, processing, and validating Day-Ahead and Hour-Ahead schedules. A schedule in this context is a template (import, export, load, generation, inter-SC trade, or Ancillary Service) submitted to the Scheduling Infrastructure. The costs in this sub-function relate to providing the infrastructure and to processing schedules.

All schedules are processed for each hour regardless of the time of submission. Scheduling applications run discretely for each hour and problems are resolved for each hour. The ISO re-processes each hour of a Day-Ahead schedule that rolls to the Hour-Ahead, even if it is unchanged.

The billing determinant selected by the California ISO for Forward Scheduling is the number of final Hour-Ahead schedules submitted. Only final Hour-Ahead schedules are assessed this charge. In order not to discourage SCs from modifying their Day-Ahead schedules due to better information, any changes from Day-Ahead schedules that roll over to the Hour Ahead will not be assessed an additional charge.

5.4 Congestion Management

Congestion Management contains the activities associated with mitigating scheduled transmission flows across Inter-zonal boundaries. To the extent flows increase across zonal boundaries, the California ISO incurs costs to monitor and potentially mitigate Inter-zonal congestion.

The billing determinant for Congestion Management will be assessed on net Hour-Ahead Scheduled Inter-zonal flows (load). This is the current billing determinant for the Congestion Management charge. An SC will be assessed this charge on a per MWh basis each time it schedules a flow across an Inter-zonal interface.

5.5 Market Usage

Market Usage contains the activities associated with processing Supplemental Energy and Ancillary Services, determining the Real-Time Market Clearing Price, maintaining and controlling the OASIS, monitoring market performance, and ensuring generator compliance with market protocols. In the future, activities associated with forward energy markets will be included here.

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The costs of Market Usage will be recovered from those SCs that use the Real-Time market (and the forward energy markets in the future) in a charge based on usage of these markets. The billing determinant for Market Usage will be purchases and sales of Ancillary Services, Instructed Energy and the absolute value of net portfolio deviations by Settlement interval.

This differs from the billing determinant of the current Ancillary Services/Real-Time Energy Operations Charge in that the absolute value of **net** portfolio deviations is used rather than the absolute value of **total** deviations. As was mentioned earlier, to the extent an SC accurately load follows, the California ISO need not purchase Imbalance Energy. The use of net portfolio deviations is a specific mitigation not to discourage load following.

5.6 Settlements, Metering and Client Relations

Settlements, Metering and Client Relations contains most Settlements, Billing, Metering, and Client Relations activities. Settlements, Metering and Client Relations costs are a function of the interaction of the customer and the California ISO. As many of these costs are fixed in nature, such as the requirements for settlements, billing, and processing meter data, cost recovery through a fixed charge per customer may be appropriate. There are variations in the complexity of these interactions between the California ISO and its numerous customers, which militate against recovering these costs solely through a fixed charge.

If the California ISO recovered a major portion of these costs through a single fixed charge per customer, the bill impacts would be significant. As a mitigation measure, the California ISO proposes to recover a portion of Settlements, Metering and Client Relations costs through a \$500 per month customer charge per SC ID regardless of the level of activity.

As described above, the remaining Settlements, Metering and Client Relations costs have been associated with the billing determinants of Energy and Transmission Services, Congestion Management and Market Usage. The billing determinants for these services are ISO Controlled Grid Load plus exports and net uninstructed deviations (Energy and Transmission Services), net Hour-Ahead scheduled interzonal flows (Congestion Management) and purchases and sales of Ancillary Services, instructed energy, and net uninstructed deviations (Market Usage). We made the decision not to associate costs to either Core Reliability Services or Energy and Transmission Services as these were new rates and any additional costs would increase the severity of bill impacts.

Barkovich and Yap and the ISO reviewed the occurrence of charge types in Settlement Statements over the test year period, September 2001 through August 2002. We view the occurrence of charge types in Settlement Statements as a measure of the activity flowing through Settlements. We then associated each charge type with one of the three services above. The Settlement, Metering and Client Relations costs associated with each billing determinant were proportional to the relative number of charge types associated with each service.

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Table 3 Billing Determinants by Function and Sub-Function	
Grid Reliability Services	
Core Reliability Services	534,042 MW-months (NCP demand)*
Energy and Transmission Services	
Load plus exports*	242,456,619 MWh
Absolute value of net uninstructed deviation by interval	16,403,169 MWh
Market Services	
Forward Scheduling	12,307,710 schedules
Congestion Management	87,927,387 MWh
Market Usage	45,707,872 MWh
Settlements, Metering and Client Relations	
	1,562 customer months
<p>The California ISO collected billing determinants for the twelve-month period September 2001 through August 2002. This was done to facilitate the release of masked SC-specific information to participants under the conditions of providing data at least six months old. The California ISO will review more recent historical data to determine if the collected data is representative.</p> <p>*Not yet updated to ISO Controlled Grid Load plus exports.</p>	

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6.0 Proposed Rates

Based on the process outlined in this paper, the resulting rates are shown in Table 4. We caution that these rates are indicative of the rates that would apply using budgeted costs for the year 2003. Therefore, these can be only illustrative of the actual rates for 2004.

Table 4 Indicative Rates by Function and Sub-Function		
	Service alone	Including Settlements, Metering and Client Relations adder
Grid Reliability Services		
Core Reliability Services	\$175.16 per MW- month of NCP demand	\$175.16 per MW- month of NCP demand
Energy and Transmission Services		
Load plus exports*	\$0.126 per MWh	\$0.234 per MWh
Absolute value of net uninstructed deviation by interval	\$0.467 per MWh	\$0.865 per MWh
Market Services		
Forward Scheduling	\$1.547 per schedule submitted	\$1.547 per schedule submitted
Congestion Management	\$0.114 per MWh	\$0.164 per MWh
Market Usage	\$0.630 per MWh	\$0.850 per MWh
Settlements, Metering and Client Relations	\$500 monthly per SC ID	\$500 monthly per SC ID
*Not yet updated to ISO Controlled Grid Load plus exports.		

The functionalization undertaken here reflects an effort to maximize the cost basis of the California ISO's rates. In order to implement this functionalization, it is anticipated that there will be bill impacts that require mitigation. These bill impacts will be studied in depth along with the bill impacts of other proposals. Rates will be adjusted in order to reduce the level of bill impacts to a manageable and reasonable level while preserving the cost basis of the rates to the greatest extent possible.

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7.0 Remaining Issues

As in any undertaking of this magnitude, there are a number of remaining issues that the California ISO and participants must consider. These are:

1. Discussion of commonalities among the California ISO, MID and SCE proposals and the potential for consensus.
2. Potential increased use of direct assignments of indirect expenditures
One participant has requested that the CAISO make an effort to assign more directly the costs that have been assigned indirectly in the past. For this proposal, we have directly assigned costs to the extent possible. There is still some work in this area.
3. Continued analysis of bill impacts
4. Stability of billing determinants through the first part of 2003
We will be providing more recent history on the billing determinants used in all proposals. This will be done to show if there is evidence of a trend or a change in trend since August 2002.