California Independent
System Operator Corporation

# Attachment C

# California ISO

# Revised MRTU Grid Management Charge Rate Proposal

## Project Lead: Ben Arikawa

## December 3, 2007

Prepared by: Ben Arikawa
Version: 2.1

# Table of Contents

## 1.0 Executive Summary

This paper summarizes the current status of the Grid Management Charge (GMC) rate structure under the Market Redesign and Technology Update project (MRTU). In September 2006, the California ISO initiated the stakeholder process to review changes in the GMC rate structure necessary due to MRTU. The California ISO sought comments and proposals for the GMC rate structure under MRTU[1]. The California ISO developed a straw proposal to encourage discussion and lay out a potential path forward. In that straw proposal, the California ISO proposed to simplify the rate structure by eliminating certain elements of the existing rate structure[2], to reflect the new market design by incorporating bill determinants for the new market services, to make certain other changes including changing the fixed rate for an existing service (Settlements, Metering and Client Relations) and potentially adding a charge related to Congestion Revenue Rights. The proposal also anticipated completion of the stakeholder process in early December for filing with the Federal Energy Regulatory Commission (FERC or Commission) in January 2007.

Based on comments received from stakeholders throughout the past year, the California ISO has revised the approach and the schedule. In the revised approach, the California ISO sought agreement on an outline of the elements of the GMC rate structure to be submitted to the MRTU Settlements and Market Clearing ("SaMC") team by the end of November 2006. The SaMC team required in the near term sufficient information about the likely rate structure to develop configuration guides and develop the software for testing and deployment prior to MRTU startup. This approach did not require agreement on the cost allocation and, ultimately, the final rate structure that would be filed at the Commission. However, as many components of the rate structure are unchanged from the pre-MRTU design, this focused stakeholder discussion on the elements of the rate structure that are likely to change. Because there was some agreement on the elements of the rate structure prior to the end of 2006, this approach also provided the information necessary to begin configuration and coding of the GMC in SaMC several months earlier than contemplated under the initial straw proposal, while also allowing additional time for consideration of the cost allocation and rate impacts.

In the stakeholder process held in the fall of 2006, there was consensus among stakeholders that a new cost of service study, detailing the relationship of CAISO costs to the GMC service categories, was necessary as four years had past since the last study was performed. In the spring of 2007, the stakeholder process began anew. The California ISO completed and released the updated cost of service study. Beginning in June 2007, the California ISO provided bill impact analysis using this cost of service study and subsequent revisions. Based on consideration of stakeholder comments, the California ISO has revised its earlier proposal and updated the cost of service study consistent with those revisions. Updated cost allocations, hypothetical rates and bill impact analysis were released in late October 2007. The revised proposal includes an updated cost of service for a Market Usage – Forward Energy and a Transmission Ownership Right Usage charges. Discussions on the revised proposal and open issues continue into November with the objective of a December 2007 filing with the FERC.

---

[1] Documents related to the stakeholder process are located on the CAISO website at: http://www.caiso.com/1872/18728fb96b370.html.

[2] Elements are defined components of the rate structure, which are, ultimately, the charge type/code configurations, and the bill determinants of those components.

## 2.0 Purpose and Scope

The primary objective is to complete discussion on the rate structure changes necessary and the final design prior to a December 2007 filing. The California ISO must complete the discussion by late November, so that the MRTU GMC rate structure can be filed at the FERC.

Discussion of the elements of the rate structure is not in the scope of this process. The configuration of SaMC was set in order to allow sufficient time prior to MRTU market simulations scheduled for this spring. Modifications to account for bill impacts can take place through adjustments to the cost allocation.

## 3.0 Grid Management Charge Background

The California ISO recovers its administrative, debt service and capital expenditures through the GMC. The California ISO charges the GMC to its customers based on their use of California ISO services. These services, the allocation of California ISO costs to these services and the rates charged are defined in the California ISO Tariff, which was updated as a result of settlement discussions held in 2004 (ER04-115-000). The GMC Settlement was originally scheduled to terminate on December 31, 2006. In 2006, the California ISO and many GMC parties agreed to an extension of the Settlement rate design until December 31, 2007. The FERC approved this agreement (ER06-1281-000) on September 6, 2006. In the fall of 2007, the California ISO and many GMC parties agreed to another extension of the Settlement rate design until MRTU startup or December 31, 2008. That proceeding has been designated as ER08-135-000.

The GMC rate structure that is effective as of January 1, 2007 is shown in Table 1. There are 14 charge types corresponding to the 8 charges as described in the Tariff[3].

[3] The current GMC configuration guides are located on the California ISO website at: http://www.caiso.com/docs/2005/10/07/2005100710100423746.html. Please refer to these guides for an accurate description of the current GMC.

**Table 1**
**California ISO Grid Management Charge Structure**
**Effective January 1, 2007**
**Function, Rate, Bill Determinant and Charge Code**

| Function | Rate Name | Bill Determinant | Charge Code |
|---|---|---|---|
| Core Reliability Services | CRS-Demand (peak) | Monthly NCP HE07 – HE 22 | 4501 |
| | CRS-Demand (off-peak) | Monthly NCP all other hours | 4502 |
| | CRS-Energy Export | MWhs of exports | 4503 |
| CRS/ETS | CRS/ETS-NE – Mohave Energy Export | MWhs of Mohave exports to Nevada Power and SRP | 4504 |
| Energy Transmission Services | ETS-Net Energy | MWhs of Metered Load | 4505 |
| | ETS-Uninstructed Deviations | MWhs of net uninstructed deviations | 4506 |
| Forward Scheduling | FS | Count of hourly schedules | 4511 |
| | FS-Inter SC trades | Count of hourly trades | 4512 |
| | FS-PGAB Inter-SC trades | Count of hourly trades for PGAB | 4513 |
| Congestion Management | CONG | MWh of net Hour Ahead Final Interzonal flows | 4522 |
| Market Usage | Purchases and sales of Ancillary Services (Day Ahead and Hour Ahead) | MWhs | 4534 |
| | Instructed Energy (Real Time) | MWhs | 4535 |
| | Net Uninstructed Deviations (Real Time) | MWhs | 4536 |
| Settlements, Metering, and Client Relations | SMCR | Monthly customer charge | 4575 |

## 4.0 ISO Functions and Rate Categories Under MRTU

This section discusses ISO functions and the rate categories that have been configured in SaMC[4]. Bill determinants for these rate categories and components are discussed in the Section 5 of this document.

## 4.1 Grid Reliability Services

The California ISO provides for the safe, reliable operation and maintenance of the Control Area, provides for transmission and generation 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:

- 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)
- Advanced Network Applications (NA) such as the State Estimator
- Automated Dispatch System (ADS)
- Scheduling Logging for the ISO of California (SLIC)
- Control Area Scheduler (CAS)
- California ISO Outage Modeling Tool (COMT)
- Automated Load Forecasting (ALFS)

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

[4] A Congestion Revenue Rights (CRR) charge was considered in the initial phase of the stakeholder process. However, historical data to perform bill impact analysis is not available. Also, integration of CRR bill determinants with SaMC could not be completed in time for MRTU startup.

### 4.1.1 Core Reliability Services (CRS)

CRS is part of the Grid Reliability Services function. Under CRS, the California ISO provides for reliable operation of a Control Area surrounded by other control areas and achieving minimal disruptions to system operation. The ISO provides a stable grid and meets regional and national regulatory requirements, such as NERC and WECC reliability criteria and some FERC requirements (e.g., 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. 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.

There are three rate components under Core Reliability Services[5]. These are:

- Core Reliability Services Demand (Peak)
- Core Reliability Services Demand (off-Peak)
- Core Reliability Services – Energy Export

### 4.1.2 Energy Transmission Services (ETS)

This service represents the scalable portion of Grid Reliability Services, and 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). The previously proposed Energy Transmission Services – Injections charge was removed after consideration of bill impacts.

There are two rate components under Energy Transmission Services[6]. These are:

- Energy Transmission Services – Net Energy
- Energy Transmission Services – Uninstructed Deviations

### 4.1.3 Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights

This service for Transmission Ownership Rights is a combination of Core Reliability Services and Energy Transmission Services. This service includes both the nonscalable and scalable portions of Grid Reliability Services related to monitoring and supporting flows on TORs.

TORs are associated with use of an entity's own non-ISO Grid transmission, defined as transmission facilities within the CAISO Control Area which are either wholly or partly owned by an entity that is not a Participating

[5] CRS-Energy Export (Mohave) will be eliminated under MRTU. Southern California Edison notified the California ISO that they will not seek a continuation of the discounted Mohave Energy Export rate under MRTU. For this reason, the CRS/ETS-NE Mohave Energy Export rate is no longer needed.
[6] ETS-NE (Mohave) will be eliminated under MRTU. See fnt. 5.

Transmission Owner (PTO). Scheduled flows on TORs are typically wheel throughs, balanced import-export combinations on non-ISO Grid facilities within the Balancing Area, that do not require the same level of Grid Reliability Services as flows on PTO transmission, due to the fact that they are not typically subject to redispatch and typically are balanced schedules with minimal to no deviations from forward schedule.

A separate service category for TORs is justified in that the level of their use of Grid Reliability Services is lower than that for flows on PTO transmission. Among the services that the California ISO would not provide on a routine basis are transmission planning, Operations Engineering, Operations Support, determination of resource adequacy, dispatch of energy associated with Ancillary Services and load and resource balancing. For this reason, Balancing Authority services provided to users of TORs constitute a sub-set of Grid Reliability Services.

Scheduled flows on TORs typically do use Outage Management and Scheduling (intertie scheduling and checkout) among the Grid Reliability Services. The California ISO is also prepared to support for TOR flows on an emergency basis. Other Grid Reliability Services, such EMS system monitoring, AGC Services and voltage support, also apply, but to a lesser extent.

However, should actual flows on TORs deviate from forward scheduled flows, e.g., for transmission losses or in the event path derates that only affect one side of a wheel through or wheel out, TORs may utilize the additional Real Time services and therefore will be subject to the ETS – Uninstructed Deviations charge, which recovers the Grid Operations cost of managing deviations[7].

The single rate component under CRS/ETS TOR is:

- Core Reliability Services / Energy Transmission Services – TOR

## 4.2 Market Services

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 energy, Residual Unit Commitment (RUC), and Ancillary Services bids
- Publish market information
- Operate Hour Ahead Scheduling Process and Real-Time market

[7] To the extent that TORs submit schedules and use the Market to buy or sell Energy or Ancillary Services, the California ISO provides Market Services as it does for other market participants. There is no basis for distinguishing between the Market Services provided to TORs and other market participants.

- Determine Locational Marginal Prices
- Administer Congestion Revenue Rights allocation and secondary registration
- Monitor market performance

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

- Scheduling Infrastructure Business Rules (SIBR)
- Open Access Same-Time Information System (OASIS)
- Automated Dispatch System (ADS)
- Integrated Forward Market (IFM), including RUC
- Congestion Revenue Rights (CRR)
- Hour Ahead Scheduling Process (HASP)/Real Time Market (RTM)

The Market Services function consists of two sub-functions: (1) Forward Scheduling and (2) Market Usage.

### 4.2.1 Forward Scheduling (FS)

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

Forward Scheduling consists of three rate components:

- Forward Scheduling (non-inter-SC trade schedules)
- Forward Scheduling – Inter-SC trade schedules
- Forward Scheduling – PGAB Inter-SC trade schedules

PG&E and its ETC customers requested that the ISO retain the Forward Scheduling – PGAB Inter-SC trade schedules pending the result of ongoing discussions.

### 4.2.2 Market Usage (MU)

In this function, the California ISO processes bids for Day Ahead, Hour Ahead Scheduling Process and Real Time Energy and Ancillary Services, maintains and controls the Open Access Same-Time Information System (OASIS), monitors market performance, ensures generator compliance with market protocols, and determines market prices. The Market Usage rate recovers the costs of services provided to customers for the Real Time and Day Ahead Energy markets.

There are four rate components under Market Usage. These are:

- Market Usage – Purchases and Sales of Ancillary Services
- Market Usage – Instructed Energy (Real Time)
- Market Usage – Net Uninstructed Deviations

- Market Usage – Forward Energy

## 4.3 Settlements, Metering and Client Relations (SMCR)

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, Market Clearing and Metering activities as well as Client Relations and External Affairs. Certain settlement activities may be assigned to other functions. For example, RMR settlement activity is assigned to CRS because its activities are related to the maintenance and provision of RMR services to the Control Area.

The following is a partial listing of activities in Settlements, Metering and Client Relations:

- Determine charges associated with transmission services, forward market schedules, HASP, Real-Time market, 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:

- Settlements and Market Clearing (SaMC)
- Meter Data Acquisition System (MDAS)
- Market Quality System (MQS)
- Client Relations Tools

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. There are major fixed costs associated with this function. Thus, the mitigation of the bill impacts of assigning these costs on a per customer basis has been essential and appropriate.

# 5.0 Bill Determinants

Because much of the rate structure will not be changing, many of the bill determinants will not change. However, as there will be additional services provided by California ISO, principally market operations, bill determinants will need to be updated.

## 5.1 Grid Reliability Services

### 5.1.1 Core Reliability Services

The bill determinants for the rate components of Core Reliability Services are load and export based. The CRS-Demand charge will continue to be recovered through an assessment on non-coincident peak demand by time period. The CRS-Energy Export charge will continue to be assessed on export volumes, exclusive of flows on TORs.

There are three rate components/bill determinants under CRS. These are:

- CC 4501 Core Reliability Services Demand (Peak)
  - Non-coincident peak load (not including exports) in MW-months between HE 07 and HE 22
- CC 4502 Core Reliability Services Demand (Off-Peak)
  - Non-coincident off-peak load (not including exports) in MW-months all hours not between HE 07 and HE 22
- CT 4503 Core Reliability Services – Energy Export
  - Exports from the Balancing Authority in MWhs
  - Does not include exports associated with TORs

### 5.1.2 Energy Transmission Services

Metered Control Area Load (load and exports) is the bill determinant for Energy Transmission Services- Net Energy, with an exemption for flows on TORs. Net Uninstructed Imbalance Energy[8] netted over the Settlement Interval is the bill determinant for ETS-UE, with an exception for deviations related to generators in the Participating Intermittent Resource Program (PIRP). Uninstructed Imbalance Energy-related charges associated with PIRP resources are netted over the month, will be assessed through a different charge code.

- CC 4505 Energy Transmission Services – Net Energy (Load and exports)
  - An exception for flows on Transmission Ownership Rights
- CC 4506 Energy Transmission Services – Uninstructed Deviations
  - Uninstructed Imbalance Energy by SC ID netted within the Settlement interval and across the SC's portfolio
  - An exception for Uninstructed Imbalance Energy associated with PIRP
- CC 4546 (portion attributable to ETS-UE) Energy Transmission Services/Market Usage –PIRP Deviations
  - Uninstructed Imbalance Energy netted over the trade month

### 5.1.3 Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights

Metered Control Area Load on TORs is the bill determinant for CRS/ETS – TOR. Flows on TORs are exports, typically wheel throughs.

- CC 450X CRS/ETS – TOR
  - Metered Control Area Load associated with TORs

[8] Uninstructed Imbalance Energy is defined as the sum of deviations from instructions (UIE1) and deviations from schedule (UIE2). Previously, deviations for GMC purposes only counted deviations from schedule.

## 5.2 Market Services

### 5.2.1 Forward Scheduling

Schedules and Inter SC trades will remain the bill determinant for Forward Scheduling. Awarded Residual Unit Commitment will be assessed the Forward Scheduling charge, analogous to the method of assessing Forward Scheduling to awarded Ancillary Services. The following schedules will be assessed the Forward Scheduling charge:

- CC 4511 Forward Scheduling (non-inter-SC trade schedules)
  - Load
  - Export
  - Generation
  - Import
  - Awarded Ancillary Services
  - Awarded Residual Unit Commitment
- CC 4512 Forward Scheduling – Inter-SC trade schedules
  - Energy Trades
  - Trades of Ancillary Services
  - Trades of IFM uplift obligations
- CC 4513 PGAB Inter-SC Trade Schedules

### 5.2.2 Market Usage

The California ISO will continue to assess purchases and sales of Day Ahead and Hour Ahead Scheduling Process Ancillary Services, Real Time Instructed Energy[9] and net Uninstructed Imbalance Energy. Net Uninstructed Imbalance Energy on a 10-minute settlement interval basis will not include deviations from PIRP resources. Net purchases and sales through the Day Ahead Market will be assessed through the Market Usage – Forward Energy charge. Uninstructed Imbalance Energy related to PIRP resources will be netted over the month and assessed using the combined ETS/Market Usage-Uninstructed Deviations charge.

- CC 4534 Market Usage – Purchases and Sales of Ancillary Services by Resource ID
  - Day Ahead and Hour Ahead Scheduling Process
  - Real Time purchases and sales of Ancillary Services
- CC 4535 Market Usage – Instructed Energy
  - Real Time Instructed Energy purchases and sales by Resource ID and 10 minute settlement interval
  - No longer includes UIE1
- CC 4536 Market Usage – Net Uninstructed Deviations
  - Uninstructed Imbalance Energy by SC ID netted within the ten minute interval and across the SC's portfolio
  - An exception for Uninstructed Imbalance Energy related to PIRP resources

[9] Instructed Energy consists of only Instructed Energy quantities. Previously, the Instructed Energy for GMC purposes was the sum of Instructed Energy and deviations from instructions (UIE1).

- CC 4546 (portion attributable to ETS-UE) Energy Transmission Services/Market Usage – PIRP Deviations
    - Uninstructed Imbalance Energy netted over the trade month
- CC 4537 Market Usage – Forward Energy
    - Net Day Ahead Market energy purchases and sales across the SC's portfolio for the hourly Day Ahead Settlement interval

## 5.3 Energy Transmission Services/Market Usage – PIRP Deviations

Participating Intermittent Resources must submit schedules based on a California ISO hourly forecast. Since these Resources are not necessary in control of the amount of generation scheduled and weather conditions vary, the California ISO and market participants have agreed to netting of the Uninstructed Imbalance Energy of Participating Intermittent Resources over the trade month. For tracking purposes, a separate rate and bill determinant were created for these charges associated with PIRP resources.

- CC 4546 Energy Transmission Services/Market Usage – PIRP Deviations
    - Uninstructed Imbalance Energy netted over the month

## 5.4 Settlements, Metering and Client Relations (SMCR)

The bill determinant for SMCR is customer month, i.e., any trade month in which there is settlement activity. The charge is not assessed on invoices issued for prior periods, e.g., reruns of prior period charges.

- CC 4575 Settlements, Metering and Client Relations
    - Assessed if there is any settlement charge activity with a non-zero amount within the current trade month
    - Potentially to any BA ID for SCs, PTOs, and CRR holder

| **Table 2**<br>**GMC Rate Structure Under MRTU**<br>**Function, Rate Name, Bill Determinant and Charge Code Number** | | | |
|---|---|---|---|
| **Function** | **Rate Name** | **Bill Determinant** | **Charge Code** |
| Core Reliability Services | CRS-Demand (peak) | Monthly NCP HE07 – HE 22 | 4501 |
| | CRS-Demand (off-peak) | Monthly NCP all other hours | 4502 |
| | CRS-Energy Export | MWhs of exports, excluding exports on TORs | 4503 |
| Energy Transmission Services | ETS-Net Energy | MWhs of Metered Control Area Load, excluding Load on TORs | 4505 |
| | ETS-Uninstructed Deviations | MWhs of Uninstructed Imbalance Energy netted over the Settlement Interval (except UIE associated with PIRP) | 4506 |
| CRS/ETS | TOR | Metered Control Area Load MWhs on TORs | 450x |
| Forward Scheduling | FS | Count of hourly schedules (including Awarded RUC schedules) | 4511 |
| | FS-Inter SC trades | Count of hourly trades (including trades of IFM uplift obligations) | 4512 |
| | FS-PGAB Inter-SC trades | Count of hourly trades for PGAB | 4513 |
| Market Usage | Purchases and sales of Ancillary Services | Day Ahead and Hour Ahead Scheduling Process and Real Time MWhs | 4534 |
| | Instructed Energy (Real Time) | MWhs of IE, no longer includes UIE1 | 4535 |
| | Net Uninstructed Deviations, (Real Time) | MWhs of Uninstructed Imbalance Energy netted over the Settlement Interval (except UIE associated with PIRP) | 4536 |
| | Forward Energy | MWhs of net Energy purchases or sales in Day Ahead | 4537 |
| ETS/MU | Monthly netted deviations – PIRP | MWhs of Uninstructed Imbalance Energy netted over the month for PIR | 4546 |
| Settlements, Metering, and Client Relations | SMCR | Monthly customer charge | 4575 |

## 6.0 Other Issues

## 6.1 Tariff Issues

The proposed changes in the GMC rate structure will require modification of the California ISO Tariff. In addition to the changes necessary to implement the proposed GMC rate structure, additional changes are proposed to simplify the Tariff by removing redundant and inconsistent language and, as proposed earlier this year, to modify the rate adjustment mechanism, Appendix F, Schedule 1, Part B, to avoid too frequent triggering of this mechanism.

Many of the proposed changes to the Tariff are in Section 11.22, which describes the GMC. As there is language referencing the GMC in this Section as well as Appendix F, Schedule 1, there is the potential for conflicting or inconsistent language. The California ISO proposes to eliminate much of the descriptive language in Section 11.22 by providing direct references to the language of Appendix F. There are also occurrences of Tariff references to the GMC prior to 2004. These references will be updated to reflect the current charges.

Earlier this year, the California ISO proposed to modify Appendix F, Schedule 1, Part B as one of the Tariff changes to be filed along with the MRTU GMC. The current language reads that the triggering event for a rate adjustment is: "if the estimated billing determinant volumes for that component, on an annual basis, change by 5% or more during the year." This provision was included in the Tariff to provide some assurance of revenue stability within a given year. However, with the increase in the number of GMC rates, it is possible that a rate adjustment will be triggered for revenue shortfalls that may not be significant relative to the overall revenue requirement. In order to prevent unnecessary triggering of this provision and still provide sufficient protection to revenue stability, California ISO the modification is proposed is to make the triggering event a change of greater of 5 percent in billing determinant volumes or $1 million. The $1 million will act as a floor amount and is set low enough to ensure revenue stability. The California ISO requests comments on this proposed change.

## 6.2 Implementation Issues

As noted on the October 16 conference call, some portion of the revised California ISO GMC rate proposal, if agreed to by stakeholders, may not be implemented in time for MRTU startup. In particular, as the CRS/ETS TOR rate was not identified in last year's GMC stakeholder process, it was not coded into SaMC. If the coding cannot be completed and tested prior to MRTU startup, retroactive settlements may be required.

## 7.0 Comparison with Other ISOs/RTOs

The California ISO first made a comparison of the rate structures of other ISOs/RTOs, ISO-New England (ISO-NE), New York ISO (NYISO), PJM, ERCOT, the Independent Electricity System Operator (IESO, formerly, Ontario Independent Market Operator), and the Midwest ISO (MISO) in 2003[10]. Over the past few years, their rate structures have changed somewhat. As noted four years ago, comparisons with other ISOs/RTOs are difficult because the rate structures of each organization developed differently and there is no standardized process for cost recovery. We can, however, make some high level comparisons[11].

## 7.1 Bundled Administrative Charges

Among the ISOs/RTOs, NYISO, ERCOT and the IESO continue to have single bundled rates to recover their operating costs. The NYISO bundled rate is assessed on load, exports, generation and imports (injections and withdrawals). The ERCOT and IESO rates are assessed on load and exports.

## 7.2 Reliability Services (Control Area Services)

Of the other ISOs/RTOs, only ISO-NE and PJM have an explicit Reliability or Control Area Services function. The ISO-NE Reliability Administration Service, Schedule 3, appears to be similar to the ISO Grid Reliability Services function (CRS and ETS). The billing determinant is non-coincident kW-months of load for market participants. Exports are assessed a volumetric charge. ISO-NE also has a Scheduling, System Control and Dispatch Service, Schedule 1, which is similar to the ISO Pre-Scheduling service for scheduling transmission service into, out of, through and within the Control Area.

PJM reliability functions can be found in their Schedules 9-1 (Control Area Administration), 9-4 (Regulation and Frequency Response Administration) and 9-5 (Capacity and Resource Obligation Management). Schedule 9-1 costs are recovered from MWhs of point to point and network integration services flows. Schedule 9-4 costs are recovered from MWhs of PJM regulation plus scheduled (including self-scheduled) regulation. Schedule 9-5 costs are recovered on a MW-day basis. PJM also has Schedule 9-6 to recover the costs of its new Advanced Second Control Center. These costs are allocated to the other PJM rate components.

## 7.3 Market Services

The ISO-NE, PJM and MISO have Market Services related functions. ISO-NE has its Energy Administration Service (Schedule 2) to recover the costs of administering the Energy Market. The rate is assessed per Energy Transaction Unit[12], increment and decrement bids submitted, increment and decrement bid accepted and on MWhs of load, exports, generation and imports.

PJM has two Market Services functions, Market Support (Schedule 9-3) and Financial Transmission Rights Administration (Schedule 9-2). Market Support costs are recovered through an assessment on injections

[10] The earlier summary can be found here: http://www.caiso.com/docs/09003a6080/24/39/09003a60802439f0.pdf.
[11] A more comprehensive description of the administrative rate structures of the other ISO/RTOs is located on the California ISO website at: http://www.caiso.com/1c86/1c86b9bb18020.pdf.
[12] An Energy Transaction Unit is an hourly contract, supply offer, demand bid, increment or decrement bid submitted to the ISO-NE. It is similar to an ISO schedule.

(generation and imports), withdrawals (load and exports), MWhs of accepted increment, decrement and congestion bids, and per Bid/Offer Segment[13]. Financial Transmission Rights Administration costs are recovered from each bid for an FTR and per FTR MWh.

In addition to its bundled ISO cost recovery charge, MISO has a two charges related to Market Services, a Financial Transmission Rights Administrative Service Cost Recovery Adder rate (Schedule 16) and an Energy Market Support Administrative Service Cost Recovery Adder (Schedule 17). The Schedule 16 rate is rate is assessed to MWhs of FTR volume. The Schedule 17 for Market Support is charged to load and exports, generation and imports, bids and offers settled in Day-Ahead market that do not result in injections or extractions.

## 7.4 Membership Fees, Customer Charges

None of the other ISOs/RTOs have an explicit Settlements, Metering and Client Relations or customer service function. Most have some form of fixed membership fee or customer charge, with the exception of the IESO, which has only a $1,000 application fee. ISO-NE, PJM and ERCOT have annual fees that vary from $500 to $5,000. NYISO has a tiered fee structure from $0 for governmental agencies to $5,000 for larger customers.

[13] A Bid/Offer Segment is an hourly supply offer, demand bid or congestion bid submitted to PJM.

## 8.0 Next Steps

In consultation with stakeholders, the California ISO plans to file the MRTU GMC no later than 60 days prior to MRTU startup, currently scheduled for trade date April 1, 2008. In order to achieve this objective, the California ISO requested stakeholder comments on the revised proposal contained in this paper and the associated cost of service and allocation methods as detailed in the concurrently posted documents. Those comments are posted on the California ISO website at: http://www.caiso.com/1c8a/1c8abe9be830.html.