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July 5, 2011

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation,
Docket No. ER11- ___
Revised Grid Management Charge Proposal

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO") hereby submits for filing proposed amendments to its tariff to implement a revised grid management charge ("GMC").[1]

With these tariff amendments, the ISO proposes to simplify its GMC rate design and more closely to align the cost allocation categories with the ISO's nodal market, which became operational in 2009. Based on the results of a cost-of-service study and a review of the rate designs used by other ISOs and RTOs with nodal markets, the ISO proposes to substantially revise the GMC rate design while preserving the use of a formula rate with a revenue requirement cap. The ISO proposes to reduce the number of formula-rate charges from seven to three: market services, system operations and congestion revenue rights ("CRR") services. The proposed GMC rate structure also includes four administrative fees, a fixed charge for transmission ownership rights ("TORs"), and a narrowly targeted and time-limited exemption from the system operations charge for certain power supply contracts.

The ISO proposes an effective date of January 1, 2012 for the revisions and urges the Commission to rule on its tariff proposals by September 30, 2011, so that there will be sufficient time to timely implement and test the system changes with market participants in advance of the January 1, 2012 implementation date.

[1] This filing is submitted pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d and 18 C.F.R. § 35.15.

For these reasons, the ISO is making this filing well in advance of the proposed effective date and respectfully requests that the Commission waive the requirement of 18 C.F.R. § 35.3 that a rate schedule be filed not more than 120 days from the effective date.

I. Executive Summary

A. The 2012 GMC Stakeholder Process

The ISO initiated the 2012 GMC stakeholder process in April 2010. At that time, the ISO described the proposed cost-of-service study, announced that it would consider completely redesigning the GMC rate structure based on the cost-of-service study, and solicited stakeholder input. On October 8, 2010, ISO posted a discussion paper containing the results of the cost-of-service study and proposed new cost categories that would form the basis of charges. After considering stakeholder comments, the ISO developed the billing determinants that would be used with each cost category to calculate annual GMC charges, as well as determining that certain fixed transactional and administrative fees should also be included in the new rate design. The ISO posted a straw proposal on November 11, 2010, and provided bill impact information to scheduling coordinators, based on historical information and using the proposed new GMC rate structure.

The ISO's bill impact analysis revealed that certain supply resources would be disproportionately impacted by the new rate structure, and that some of these resources were prohibited by the terms of their power purchase agreements from passing GMC increases through to the energy buyer. Based on this information and stakeholder feedback, the ISO modified the straw proposal to provide a targeted exemption from the System Operations Charge for those power supply contracts. This limited exemption was included in the February 15, 2011 final proposal and was approved by the ISO Board of Governors in May, 2011 as part of the new GMC rate structure.

B. Cost-of-Service Study Steps and Revised Rate Design

In 2009 the ISO began implementation of a cost accounting process known as "activity-based costing". The ISO broke the costing activities into 10 core level functions (level 1 activities) that are being tracked by all employees. The ISO is in the pilot stage of implementing a further division into major processes (level 2 activities).

The ISO's activity-based costing process provided the basis for the cost-of-service study. Using the level 2 activities, the ISO mapped direct operating costs and the related indirect costs into possible GMC categories that would effectively capture the ISO's core activities and adhere to cost causation principles. The ISO determined that the level 2 activities could be appropriately categorized as related to the submission of bids or self-schedules and the awarding of schedules, the management of energy flows, and the management of CRR services. Based on this activity mapping process, the ISO developed three cost categories: (1) market services; (2) system operations; and (3) CRR services. The ISO conferred with other ISOs and RTOs across the country as part of its GMC rate design analysis, and learned that these cost categories are very similar to the structures used by other ISOs and RTOs with nodal markets to recover their administrative charges.

The ISO then allocated the costs of level 2 activities and indirect costs to these categories. Based on this analysis, the ISO allocated its revenue requirement 27% to market services, 69% to system operations, and 4% to CRR services. The ISO proposes to recover each of these categories of costs through the Market Services Charge, the System Operations Charge, and the CRR Services Charge, respectively.

The proposed billing determinants for each charge reflect each scheduling coordinator's use of the ISO's services. For market services, customers will be charged on the basis of their volume of awarded bids. For system operations, customers will be charged on the basis of their volume of metered flows. For CRR services, customers will be charged based on the total MW holdings of CRRs applicable to each hour. The billing determinants selected for each cost category are consistent with the billing determinants used by other ISOs and RTOS with nodal markets.

While the ISO's proposal to assess the system operations charge based on volume of metered flows was generally well received by stakeholders, the ISO also learned from stakeholders that this approach would cause a limited number of suppliers to experience substantial GMC increases that could not be passed on to the energy purchasers who had contracted for the resource output. In order to mitigate this impact, the ISO proposes to grandfather specific base load generation units with contracts that do not allow for recovery of additional GMC. The ISO's grandfathering proposal exempts generation units with verified long-term contracts from the System Operations Charge if the contracts meet certain criteria designed to ensure that only suppliers that would experience severe impacts through no fault of their own receive the exemption. The qualifying suppliers will be exempt from the charge until the first opportunity to renegotiate the contract or until the contract expires.

The ISO also proposes four specific transaction fees: (1) a Bid Segment Fee of \$0.005 per bid segment; (2) a CRR Transaction Fee of \$1.00 per accepted bid; (3) an Inter-Scheduling Coordinator Trade Transaction Fee of \$1.00 per trade; and (4) a Scheduling Coordinator ID Charge of \$1,000 per month with market activity. Both the Inter-Scheduling Coordinator Trade Transaction Fee and the Scheduling Coordinator ID Charge are part of the current GMC structure. These transaction and administrative fees provide an opportunity for market participants to make economic decisions about whether to incur certain expenses and are generally similar to the administrative fees assessed by other ISOs and RTOs. In addition, the ISO proposes to charge TOR holders a reduced GMC charge of $0.27 per MWh of flow based on the minimum of their supply or demand MWhs, based on an analysis of the reduced level of services that the ISO typically provides to TOR holders.

C. Revenue Requirement Cap Extension

The ISO proposes to retain a revenue requirement cap as part of the new GMC design, and has proposed the following three-year cap:

- The revenue requirement cap for 2012 will remain at $197 million;
- The revenue requirement cap for 2013 and 2014 will increase to $199 million.

Under this proposal, as long as the ISO's budgeted revenue requirement does not exceed the cap and there are no proposed changes to the GMC rate design, the ISO will not be required to make a Section 205 filing with the Commission for rates that will become effective prior to January 1, 2015. The increased cap for 2013 and 2014 is necessary because of the increased costs the ISO faces every year with merit pay increases, health insurance cost increases, and the impacts of inflation on the costs of the goods and services the ISO receives. There are no guaranteed cost reduction offsets. No stakeholder opposed this specific proposal during the stakeholder process, at the Board meeting or during the tariff development stakeholder process.

II. Background

A. GMC History

The history of the GMC is described in the testimony of Mr. Michael K. Epstein, included as Exhibit ISO-1. On October 17, 1997, the ISO filed a single bundled formula rate designed to collect the costs of operating the ISO, including the ISO's start-up and development costs and ongoing operation and maintenance costs. The ISO proposed to assess the GMC to all Scheduling Coordinators on a monthly basis.

The proceeding regarding the 1997 filing terminated in a 1998 settlement.[2] Under the settlement, the ISO agreed to conduct a stakeholder process to develop a new GMC rate design, to commence in 2001, that would unbundle the GMC into "buckets" reflecting the services provided. Following the stakeholder process, the ISO proposed in 2000 to unbundle the GMC in into three buckets: the market operations charge, the control area services charge, and the inter-zonal scheduling

[2] *Cal. Indep. Sys. Operator Corp.*, 83 FERC ¶ 61,247 (1998) (letter order approving uncontested settlement agreement dated April 7, 1998).

charge. The Commission set the proposal for hearing. In Opinion Nos. 463, 463-A, 463-B, and 463-C,[3] the Commission approved the 2001 GMC, with certain modifications. Litigation of the 2001 GMC did not terminate until 2006. During the course of the litigation, the ISO had proposed an extension of the 2001 GMC rate design, with minor revisions in the nomenclature of the buckets. Under a settlement agreement, the 2001 GMC rate design was extended through 2003, with a rate cap, subject to the outcome of the litigation.

During the litigation regarding the 2001 GMC rate design, in response to stakeholder arguments for further unbundling of the GMC, the ISO conducted another stakeholder process and, in 2003, filed a new GMC rate design, which was a formula rate with seven buckets.[4] The proceeding concluded in a settlement adopting the new design with various modifications.[5] The settlement reduced the 2004 revenue requirement and provided revenue requirement caps for 2005 and 2006, below which the ISO would not be required to seek approval of its GMC rates. From 2002 through 2009, while the ISO was working on a new market design, the ISO and its stakeholders agreed to extend the GMC rate design, the formula rate structure, and the revenue requirement cap for 2007, 2008 and into 2009 until the effective date of the new market.[6]

The Commission approved changes to the GMC needed to reflect the ISO's new market design on December 19, 2008, subject to a compliance filing in which, *inter alia,* the ISO clarified that the market usage-forward energy charge applied to both financial and physical inter-scheduling coordinator trades in the day-ahead market.[7] As part of that compliance filing, the ISO agreed to consider, with its stakeholders, modifications to the market usage-forward energy billing determinants applicable to inter-scheduling coordinator energy trades.[8] The revised GMC rates went into effect on April 1, 2009.

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[3] *Cal. Indep. Sys. Operator Corp.*, 103 FERC ¶ 61,114 (2003), *on reh'g,* 106 FERC ¶ 61,032 (2004), *following remand*, 113 FERC ¶ 61,135 (2005), *reh'g denied*, 116 FERC ¶ 61,224 (2006), *aff'd sub. nom. Western Area Power Admin. v. FERC*, 525 F.3d 40 (D.C. Cir. 2008).

[4] Specifically, the ISO proposed to unbundle the control area services charge into two sub-functions, core reliability services and energy transmission services; and to unbundle the market operations and inter-zonal scheduling charges into three service categories: forward scheduling, market usage, and congestion management. The ISO also proposed to establish a settlements, metering, and client relations charge, and further proposed that energy transmission services be divided into energy transmission services-net energy and energy transmission services-uninstructed deviations.

[5] *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,329 (2009).

[6] *See Cal. Indep. Sys. Operator Corp.*, Docket No. ER06-1281, Letter Order dated September 6, 2006; *Cal. Indep. Sys. Operator Corp.*, Docket No. ER08-135, Letter Order dated December 19, 2007, Docket No. ER09-235, Letter Order dated December 2, 2008).

[7] *See Cal. Indep. Sys. Operator Corp.*, 125 FERC ¶ 61,338 (2008).

[8] *See Cal. Indep. Sys. Operator Corp.*, Docket No. ER08-585-001, Letter Order dated March 30, 2009.

In accordance with its commitment, the ISO conducted a stakeholder process during the second and third quarters of 2009 to address the market usage-forward energy charge billing determinants. Based on stakeholder input, the ISO proposed changes to this charge as part of its request to extend the GMC through calendar year 2010. In a December 30, 2009, Order, the Commission approved the ISO's request to extend the GMC until December 31, 2010 (effective on January 1, 2010) with the exception of the proposed market usage-forward energy charge billing structure.[9] The proposed tariff modifications implementing changes to that charge were suspended until June 1, 2010, and issues related to the proposal were set for settlement discussions and a possible evidentiary hearing.[10]

Under a settlement, the revised calculation for the market-usage forward-scheduling charge was made effective from June 1, 2010 until December 31, 2011. Prior to filing rates that would go into effect on January 1, 2012, the ISO agreed to conduct a cost-of-service study that would revisit the appropriateness of the market usage-forward energy charge structure. The Commission approved the offer of settlement and stipulation by letter order dated August 4, 2010.[11] On November 2, 2010, the ISO proposed to continue the remainder of the existing GMC until December 31, 2011. The Commission approved the proposal on December 27, 2010.[12]

B. Development of the 2012 GMC

Consistent with the commitment in the 2010 settlement, the ISO undertook the new cost-of-service study and began work on revising the rate design in the summer of 2010. This process is described in the testimony of three members of the team that were part of this effort: Mr. Epstein, Ms Deborah A. Le Vine, whose testimony is included as Exhibit ISO-8, and Dr. Lorenzo Kristov, included as Exhibit ISO-9. Stakeholders had expressed concerns about the proliferation of service categories and charge codes necessitated by the current rate design, and the ISO shared those concerns. In particular, the existing rate design, with 7 service categories and 17 charge codes, did not effectively accommodate the new market structure, despite the modifications made to the GMC structure in 2009. Moreover, market enhancements had required the addition of a new service category and recovery methodology, and would likely continue to do so. Absent a fundamental GMC design change, the

[9] Cal. Indep. Sys. Operator Corp., 129 FERC ¶ 61,292 (2009).

[10] *Id.* at P 2.

[11] See *Cal. Indep. Sys. Operator Corp.,* 132 FERC ¶ 61,105 (2010). Note that the revised market usage-forward energy charge became effective, subject to refund, on June 1, 2010, in accordance with the terms of the December 30, 2009, Order. No refunds were necessary because the rate structure approved on August 4, 2010, was identical to the structure implemented on June 1, 2010.

[12] *Cal. Indep. Sys. Operator Corp.,* Docket No. ER11-2017, Letter Order dated December 27, 2010.

implementation of additional market enhancements would continue to increase the number of GMC service categories and charge codes, further contributing to the complexity of the rate structure. As a result, the ISO decided to re-evaluate the entire rate structure of the GMC.

There were other considerations that supported this decision. Changed circumstances arising since 2004 weighed in favor of a re-examination of the GMC design. Specifically, (1) the ISO had undergone a major corporate reorganization; (2) the ISO's debt structure had changed due to the ISO's construction of a new office building; (3) repayment of the bonds issued to fund the ISO's new market was imminent; (4) the new nodal market had been implemented in April 2009 and the ISO had market information not available when GMC rates had been implemented to reflect the market changes; and (4) stakeholders, who had previously participated in the 2004 GMC settlement, were now requesting greater GMC clarity, predictability and simplicity.

The testimony of Mr. Epstein describes the cost-of-service study and stakeholder process through which the ISO developed the 2012 GMC proposal, including a description of the ISO's activity-based costing and the cost impact of the proposal on the different customer groups. His testimony also discusses the derivation of the rate for transmission owner rights, as well as the ISO's inclusion of a cap on the revenue requirement, a description of the budget process and the proposed sunset date for the revenue requirement cap.

Ms. Le Vine provides testimony that explains the process by which the ISO associated the costs for specific ISO activities with the categories of services. She also describes the analysis of services provided to holders of TORs that was used in determining the GMC rate for TORs under the 2012 GMC proposal. Dr. Kristov's testimony explains the rate design and the determination of the billing determinants. Dr. Kristov also describes the ISO's proposed grandfathering of certain power supply contracts in order to mitigate disproportionate cost impacts.

1. Guiding Principles

The ISO, with input from stakeholders, established seven rate design principles to guide the development of the 2012 GMC proposal:

- Cost Causation – Costs should be properly allocated to the correct GMC buckets and charged to those who benefit from or utilize those services.

- Focus on use of ISO services, not market behavior – The new GMC design should reflect its primary purpose as a vehicle for recovering the ISO's revenue requirements based on each user's use of the ISO's services, not as a tool for shaping incentives based on market or operating behavior. Incentives such as these are appropriately addressed through the design of the market structure and market rules, not recovery of the ISO's administrative costs.

- Transparency – Costs and billing determinants should be clear, visible, and understandable to all market participants.

- Predictability – Market participants should be able to determine in advance what their GMC costs will be depending on their activity.

- Forecastability – The rates should utilize billing determinants that can be easily forecasted by both the ISO and market participants. This should result in fewer rate adjustments during the year.

- Flexibility – The new GMC structure should easily accommodate future market enhancements without excessive complexity or disrupting the overall structure.

- Simplicity – The current GMC structure should be simplified to reduce the amount of varying bill determinants and the number of charge codes.

2. Steps

The development of the new rate design comprised five tasks that were carried out by the ISO team:

- Functionalization - The process by which various activities are defined and sorted into service categories (functions and sub-functions) to reflect the different services provided by the ISO.

- Cost Allocation - The process by which the costs of providing services are allocated to the service categories (functions and sub-functions).

- Classification - The determination of billing determinants based on the customer cost causation factors.

- Rate Design - The process for deriving rates that divides the revenue requirement for each service category by the billing determinants.

- Bill Impacts/Mitigation Analysis - An evaluation of the impacts that the rate design will have on individual customer bills.

The first two activities – functionalization and cost allocation – were the purpose of the cost-of-service study.

3. Functionalization

a. Developing the Service Categories

In functionalizing ISO activities, the ISO used employee time reporting information generated by the ISO's activity-based costing model. As explained by Mr. Epstein, activity-based costing is a model that identifies activities in an organization and assigns the cost of each activity to products and services produced by the organization. Implementing this costing model required the ISO to engage in a company-wide process mapping effort that began in 2006 and developed into a hierarchy of business processes.

This analysis disaggregated the ISO operations into ten core functions (level 1 activities), and broke down each of these into major processes (level 2 activities). The ISO had begun time reporting on level 1 activities in October 2009 with pilot programs on level 2 activities. The ISO identified level 1 activities as either (1) direct operating costs, *i.e.*, those that could be directly mapped to a market, grid service or customer (six activities) or (2) indirect costs, *i.e.*, those that support the direct activity (four activities). Each level 1 activity comprised multiple level 2 activities. The level 2 activities analyzed in the cost-of-service study were the processes that had been mapped as of May, 2010.

After considering various options, as described by Mr. Epstein, the ISO determined that the activities could best be categorized according to a common and simple sequence of activities that characterized the ISO's operations: (1) customers submit bids; (2) the ISO's market systems award schedules from these bids; therefore, (3) energy flows across the grid. In addition, there were activities related to CRRs. This indicated that the ISO's activities could be classified into three distinct groups: (1) those related to the implementation and operation of the markets, including accepting and processing market participant bids, clearing the markets, and issuing market schedules; (2) those related to reliably operating the grid as energy flows; and (3) those related to CRRs. The classification of ISO activities in this manner resulted in three cost categories: Market Services, System Operations and CRR Services.

This categorization appeared to be very similar to that used in rate designs that other ISOs and RTOs with nodal markets (New York ISO, PJM, Midwest ISO and ISO New England) have implemented to recover their administrative charges.[13] These ISOs and RTOs group the vast majority of their activities (and recover the bulk of their administrative costs) in two main categories: (1) market or energy services, and (2) system operations, such as balancing authority area reliability.[14]

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[13] A summary of ISO/RTO rates and charges, as compared to the existing ISO GMC rates, is set forth in Ex. ISO-2 at pages 36-40.

[14] *See* New York ISO Open Access Transmission Tariff, Section 6 (New York ISO OATT); PJM Open Access Transmission Tariff, Schedule 9 (PJM OATT); Midwest ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff, Schedules 10, 16, & 17 (Midwest ISO Tariff); ISO New

All four of the ISOs additionally have some charge related to the administration of their congestion hedges or financial transmission rights (a charge that the current ISO GMC design currently lacks, even though the costs of administering congestion revenue rights are significant).[15] Some ISOs and RTOs also have separate transaction and administrative fees and charges as offsets to total costs,[16] and the ISO concluded that such fees and charges would appropriately be part of the GMC.

b. Mapping Level 2 Activities

Once the ISO had determined the categories of activities, the next step was to map the level 2 activities based on reasonable estimates of the percentage of time that each business unit devotes to the service categories. The integrated nature of the ISO's systems, and the lack of any metric by which to measure the division of labor for each individual activity, made it extremely difficult to identify the percentage of time devoted to each cost category with a high degree of accuracy and precision. The ISO therefore assigned a group of individuals with broad experience and a working knowledge of the division of labor to propose reasonable allocations for mapping the level 2 activities.

As explained by Ms. Le Vine, the group charged with the task of allocating level 2 activities and other costs to the three categories eventually decided to establish a limited number of "bright line" allocation percentages to use for this purpose. This was because, based on their collective experience, the group members determined that an activity would most likely be entirely devoted to one cost category; principally but not exclusively to one category; or evenly split between the categories. They also recognized that, with the exception of activities devoted exclusively to CRRs, the management of CRRs did not consume significant portions of time spent on level 2 activities. While the group could have taken the time to ascribe a specific cost allocation percentage to each level 2 activity (e.g. 75% in one category and 25% in another, rather than using 80% and

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England Transmission, Markets and Services Tariff, Section IV.A (ISO New England Tariff).

[15] PJM and Midwest ISO include FTR-related charges as a completely distinct category of expenses. PJM OATT, Schedule 9-2; Midwest ISO Tariff, Schedule 16. ISO New England includes its FTR charges as a charge under its "Energy Administration Service" (*i.e.*, market services) category of expenses. ISO New England Tariff, Section IV.A, Schedule 2. New York ISO includes its FTR-related charges in the category of expenses comprising non-physical market activity. New York ISO OATT, Section 6.1.2.4.

[16] As an example, ISO New England creates a separate administrative charge for market participants requesting a re-billing due to the untimely submission of data revisions and indicates that "Revenue from these charges will be credited to revenue requirements for the Service to which the information request is most closely related." ISO New England Tariff, Section IV .A.6.6.

20%), they concluded that additional precision would not materially affect the rates ultimately derived from these percentages.

Thus, based upon the recommendations of the group, the ISO determined that an activity would be classified as: (1) 100% in System Operations, Market Services or CRR Services, and 0% in the others; (2) 50% in Market Services and 50% in System Operations; (3) 80% in Market Services or System Operations and 20% in the other; or (4) it could be classified as 10% in CRR Services in addition to the other cost categories (for example, 45% Market Services, 45% System Operations, and 10% CRR). While developing the allocation percentages, if the group found that a certain percentage split was not sufficiently representative for certain activities, another one was developed. For example, the category of 45% Market Services, 45% System Operations and 10% CRRs was created when the 50%-50% split was not a reasonably accurate representation. Activities that could not be classified were identified as indirect costs, which were allocated to the cost categories during the final step of the revenue requirement mapping process according to the overall allocation of direct costs.[17]

The group assigned to recommend allocations applied the "bright line" cost allocation percentages to each of the 60 level 2 activities, and then to each of the 43 categories of software that support the ISO's functions.[18] Of the 60 Level 2 activities, 40, or 67%, were assigned 100% to one cost category, either Market Services, System Operations, CRR or as indirect costs; 5, or 8%, were split 80%-20%; 12, or 20%, were split 50%-50%, and 3, or 5%, were assigned 10% to CRRs and 90% to one of the other categories. Of the 43 software activities, 17, or 40%, were assigned 100% to one cost category (including the indirect cost category); 5, or 12%, were split 80%-20%; 19, or 44%, were split 50%-50%, 1, or 2%, was assigned 10% to CRRs, with the remainder split evenly; and 1, or 2%, was assigned 10% to CRRs, with the remainder split 80%-20%.[19]

The group's proposals were then discussed with the wider group working on the GMC and modified in some cases where appropriate until ultimately the wider group agreed with the determinations. When the determination of classifications, as well as the classification of activities, was presented to stakeholders in the stakeholder process, as discussed below, there were no objections.[20]

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[17] As discussed in the next section, the ISO total indirect costs of $84,544,000 (based on the 2010 revenue requirement) were allocated 27% to Market Services, 69% to System Operations and 4% to CRR Services. See Table 12, Ex. ISO-2.

[18] The subgroup prepared two tables showing the mapping percentages for each level 2 activity (Table 2) and for the software underlying debt service to the categories (Table 3), including comments detailing the rationale for each allocation. These tables are set forth in Ex. ISO-2 at pages 19 and 22.

[19] *See* Ex. ISO-8, 9.

[20] See stakeholder comments and ISO responses at Ex. ISO-11.

4. Cost Allocation

To allocate costs, the ISO applied the level 2 allocations described above to the ISO's 2010 revenue requirement to determine the costs associated with each of the three categories of activities: Market Services, System Operations, and CRR Services. The process was applied separately to operations and maintenance ("O&M") costs, to debt service and cash-funded capital expenses, and to the operating cost reserve adjustment and miscellaneous revenue. The team then aggregated the direct costs in each cost category and determined the percentage attributable to each. Those direct cost percentages were then used to allocate indirect costs and the resulting amounts were added to the totals for each cost category. Mr. Epstein describes this process and the details of the calculations in his testimony.

For O&M, Market Services represented $11.924 million, System Operations $46.373 million, CRRs $1.6 million, and indirect costs $102.798 million. These calculations appear in Table 12 of Exhibit ISO-2 at page 36 (Exhibit ISO-1, 20-21). For debt service and out-of-pocket capital items, Market Services represented $21.3 million, System Operations $46.373 million, CRRs $1.6 million, and indirect $102.798 million.[21] The ISO allocated the entire $8.1 million of miscellaneous revenue as indirect costs. The team also reviewed the components of the operating cost reserve adjustment and allocated them to the indirect category except for the change in debt service reserve. The change in debt service reserve was allocated based on the percentages applied to debt service because the debt service reserve is the reversal of the prior year's debt service and should be allocated consistently. As a result, for the operating reserve credit, $3.295 million was allocated to Market Services, $5.856 million to System Operations, $0.488 million to CRR Services, and $25.861 million to indirect costs.[22]

The total direct costs from these allocations were 27% Market Services, 69% System Operations, and 4% CRRs. After the allocation of indirect costs according to these percentages, the total revenue requirement for Market Services was $52.756 million; the total revenue requirement for System Operations was $134.883 million; and the total revenue requirement for CRRs was $7.456 million.[23]

No stakeholder objected to this cost allocation approach during the stakeholder process, at the Board meeting or during the tariff drafting stakeholder process.

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[21] *See* Ex. ISO-2 at 33 (Table 9).

[22] *See id.* at 34-35 (Table 11).

[23] *See id.* at 36 (Table 12).

C. 2012 GMC Stakeholder Process Overview

The formal stakeholder process is discussed in Mr. Epstein's testimony. It began April 21, 2010, when the ISO first discussed the process and timeline with stakeholders. On October 8, 2010, the ISO posted a discussion paper presenting methodology and initial results of the cost-of-service study and allocation of costs, which is presented as Exhibit ISO-2. The discussion paper also described the ISO proposed principles, discussed above. The ISO discussed these matters with stakeholders at a meeting on October 14 and solicited comments on the discussion paper. The comments on the discussion paper and the ISO's responses are included as Exhibit ISO-11.

After considering comments, on November 11, 2010, the ISO issued a straw proposal, attached as Exhibit ISO-3. Based on the cost categories established in the cost-of-service study, the straw proposal included three charges: Market Services, System Operations, and CRR Services. The proposal also included certain set fees. The ISO discussed the straw proposal with stakeholders during a telephone and web conference on November 18, 2010, and again solicited comments. During the conference, stakeholders requested data on bill impacts, based on the proposed GMC rate design and historical data. The stakeholder comments on the straw proposal and the ISO's responses are attached as Exhibit ISO-12.

The ISO used historical data to develop estimated bill impacts for the individual scheduling coordinators and for the major classes of customers. Under section 20 of the ISO Tariff, however, there are limits on the ISO's release of individual scheduling coordinator data. To ensure compliance with section 20, the ISO used only individual data that were six months old and did not identify, or permit identification of, the applicable scheduling coordinator. The ISO allowed scheduling coordinators to view their own bill impacts on a confidential basis. The ISO issued a market notice to this effect and released the data on December 2, 2010; that data is included as Exhibit ISO-4. The ISO conducted a stakeholder meeting to discuss this data on December 13. The stakeholder comments on the bill impacts and the ISO's responses are included as Exhibit ISO-13. The ISO also posted additional information about the proposed billing determinants addressed in the straw proposal on December 16, 2010, which appears as Exhibit ISO-5.

After considering comments on the straw proposal and on the bill impacts, the ISO posted a modified straw proposal and revised bill impact information. The modified straw proposal is Exhibit ISO-6. The ISO proposed the modification to ameliorate certain bill impacts. Specifically, the ISO proposed to phase-in the applicability of the System Operations Charge to suppliers; to exclude TORs from the Market Services Charge and to limit the exposure of TORs to the System Operations Charge, and to modify some of the fees. The ISO also proposed modification of its revenue cap proposal – from a five-year stepped cap to a three year uniform cap.

The ISO held another stakeholder telephone and web conference to discuss the modification of the GMC proposal on January 20, 2011. Stakeholder comments and the ISO's responses are included as Exhibit ISO-14. On February 8, 2011, the ISO again conducted a stakeholder telephone and web conference, this time to discuss further modification of the straw proposal; instead of phasing in the applicability of the System Operations Charge to suppliers, the ISO proposed to grandfather, *i.e.*, to exempt, suppliers that had entered long term contracts in reliance on the existing GMC provisions until the first opportunity to revise the contracts. Stakeholder comments on that proposal and the ISO's responses are included as Exhibit ISO-15. The draft final proposal, including details about the contract grandfathering proposal, was posted on February 15, 2011 and is included as Exhibit ISO-16.

The proposed GMC revisions were crafted to address concerns raised by stakeholders in the market usage-forward energy settlement, in the earlier initiatives addressing GMC components under the ISO's new market design, and in this initiative. Consequently, the proposed rate design changes are broadly supported across all categories of stakeholders.

III. Rate Design

As discussed above, the ISO developed the new rate design following the cost-of-service study and in conjunction with the stakeholder process. Mr. Kristov describes the rate design in his testimony.

Mr. Kristov's testimony explains that these billing determinants reflect each participant's use of and benefits received from the ISO's services as accurately as possible. In addition, the three categories of services and their associated billing determinants reflect the ISO's primary objective – recovering the ISO's costs based on cost-causation, *i.e.,* each market participant's use of ISO's services – rather than such concerns as the impacts that participants have on the grid and the market. In particular, they reflect the ISO's intention that the GMC not be used as a behavioral incentive or disincentive, but rather simply and objectively to allocate the ISO's costs of providing its services to those who use the services.[24]

[24] For example, although it is true that generator A might have a much greater impact on grid congestion than generator B, the costs associated with these impacts are reflected accurately (and more appropriately) in the locational marginal prices used for settlement of the energy schedules and energy flows of these two generators, and should not contaminate the design of the GMC. Similarly, other types of impacts on the ISO grid or markets are assessed through the allocation of uplift charges under the LMP market structure (which are also cost-causation based). They should not be addressed through a mechanism (the GMC) that is intended solely to enable the ISO to recover its administrative costs and reflect the causation of those administrative costs. The GMC is not -- and never was -- intended as a substitute or supplement to market pricing rules.

The ISO believes that the proposed billing determinants best achieve the objectives of the GMC rate design by reflecting each scheduling coordinator's use of the ISO's services and, consistent with the other guiding principles discussed above, are simple, transparent, predictable, and easy to forecast.

A. Market Services Charge

The proposed Market Services Charge billing determinant, set forth in proposed section 11.22.5.1, is the gross absolute value of MWh of energy cleared and MW per hour of ancillary service capacity awarded in the day-ahead and real-time markets. The metrics MW per hour for ancillary service capacity awards (and CRR awards) and MWh for energy schedules and flows are extremely simple common denominators for allocating ISO costs, and they will remain appropriate when new market enhancements and products are added. In other words, when the ISO designs and implements new features in its market structure, each market participant's total MWh of energy or MW per hour of ancillary service capacity will still provide an accurate basis for allocating the costs of market services. Other ISOs and RTOs consistently use MW per hour and MWh as their primary quantities for billing determinants because they so accurately reflect each participant's usage of services.[25]

The Market Services Charge is designed to recover costs the ISO incurs for implementing and running the markets. Because the market system processes and validates all bids and then clears supply offers against demand bids to award energy schedules and to issue dispatch instructions, supply bids and demand bids use equivalent market services and impose equivalent costs on the ISO. Moreover, a bid's use of market services is not dependent upon whether the bid is virtual demand, virtual supply, imports, exports, internal physical demand or internal physical generation. Thus, the billing determinant used in the market services category denominator does not distinguish supply bids from demand bids or virtual bids from physical bids. The charge includes the gross awarded ancillary service capacity MW and the MWh schedules and dispatch instructions of generation, imports, load, and exports in the ISO's day-ahead market, hour ahead scheduling process, and real-time market.

The ISO notes that no stakeholder objected to this cost allocation approach during the stakeholder process, at the Board meeting, or during the tariff drafting stakeholder process.

[25] A review of Section 6 of the New York ISO OATT reveals that every significant charge is based on MWh. Under the Midwest ISO Tariff, MWh are billing determinants in Schedules 10 and 16 (*i.e.*, the schedules that do not pertain to FTRs). In Schedule 9 of PJM's OATT, aside from the bid segment charges, all charges are based on MWh. Among the other four ISOs with nodal markets, ISO New England appears to have the fewest charges tied to MWh, although a significant portion of the charges still use MWh as the billing determinant.

B. System Operations Charge

The proposed billing determinant for the System Operations Charge, set forth in proposed section 11.22.2.5.2, is the gross absolute value of MWh of real-time energy flows. The fundamental mission of system operations is to operate the transmission grid reliably at all times. Because reliable grid operation involves managing the flows of energy on the grid created by both supply and demand, the system operations billing determinant is designed to capture the costs of flowing MWh in real time and is based on the settlement quality meter data that captures each participant's real-time supply and demand in each interval.[26]

An alternative approach would focus on the end-user – whose consumption constitutes demand – as the primary beneficiary of reliability, who should pay the entirety of these costs. For this reason, the ISO considered allocating the system operations costs to demand only. The ISO ultimately concluded that gross MWh of both supply and demand would be the more appropriate billing determinant for system operations because changes in grid conditions can result from changes in both supply and demand, and the ISO operators must manage both components to maintain system balance at all times.[27]

An additional basis for this design decision was the recognition that demand will play an increasingly active participatory role in the ISO markets and in real-time operations in the future, with the expansion of new technologies that shift or reduce demand such as economic demand response, storage facilities, and electric vehicles. The proposed billing determinant results in a comparable allocation of costs regardless of the technology or resource type that injects energy into or withdraws energy from the grid.

Although the System Operations Charge is applicable to the absolute value of energy flowing on the grid, both supply and demand, the ISO has proposed a limited exemption from this charge for certain baseload generation units with contracts of at least three years in length that are precluded by contractual terms from recovering GMC cost increases. A detailed discussion of this proposed "grandfathering" exemption is set forth in Section III.G below.

C. CRR Services Charge Billing Determinants

The proposed billing determinant for the CRR Services Charge, set forth in proposed section 11.22.5.3, is awarded MW per hour. The CRR metric is based

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[26] The ISO notes that imports and exports are not metered but use "deemed delivered" schedules that are proposed as the billing determinant for these flows.

[27] Assessing the System Operations Charge to generation does not dramatically change the current GMC cost allocation which charges 38% to generation. Under the ISO's proposal, the allocation to generation moves up 9.5% to 47.5%.

on awarded MWs of CRRs applicable to each market trading hour. The CRR feature of the ISO's market structure is completely separate from both the market services activities, which are related to the day-ahead and real-time markets that are run every day and every hour, and from the system operations activities, which manage energy flows 24 hours a day. The CRR feature has its own market systems and business processes whereby the ISO awards CRRs to market participants. Thus, as three other RTOs and ISOs have determined, a separate cost category for CRRs is an entirely appropriate GMC design.

The ISO notes that no stakeholder objected to the CRR Services Charge billing determinants during the stakeholder process, at the Board meeting or during the tariff drafting stakeholder process.

D. Transmission Ownership Rights Charge

The TOR Charge, set forth in proposed section 11.22.4, is $0.27/MWh, allocated to the minimum of TOR supply or TOR demand. TORs are the ownership rights to facilities within the ISO balancing authority area of entities that have not executed the transmission control agreement, such that their facilities are not a part of the ISO controlled grid. The ISO has in the past recognized that it provides only limited services to the possessors of TORs, and thus has historically not charged such entities the full GMC.

As part of the cost-of-service study, in addition to classifying activities according to cost categories, the ISO evaluated current GMC charges to determine whether a cost basis existed for continuing the charge under the revised rate design. The ISO concluded that TOR holders should continue to receive a discounted rate in the new GMC rate structure because the fundamental premise – limited use of ISO's services – has not changed. The proposed GMC does not assess any market services costs to TORs and applies a fixed charge to the minimum of a scheduling coordinator's TOR supply or TOR demand energy flows to reflect the system operations cost attributable to CRRs.

The detailed determination of the services the ISO provides to TORs and the costs thereof is described in the testimony of Mr. Epstein and Ms. Le Vine. In summary, the ISO determined that the total direct and indirect cost for activities that served TORs was $45.197 million. Because TOR MWh represent 2% of total MWh, the ISO concluded that $0.9 million in costs were attributable to TORs. The ISO evaluated different methodologies to adjust the TOR rate in order to recover this amount and determined that using the minimum of supply or demand would reduce the number of billable TOR MWh to 3.3 million MWh and that then using a rate of $0.27/MWh would collect revenue of $0.9 million.

The ISO notes that no stakeholder objected to the TOR Charge during the stakeholder process, at the Board meeting or during the tariff drafting stakeholder process.

E. Fees and Administrative Charges

The proposed GMC also includes three transaction fees and one administrative charge. As explained in greater detail below, the transaction fees – the Bid Segment Transaction Fee, the CRR Transaction Fee, and the Inter-Scheduling Coordinator Trade Transaction Fee – are designed to capture impacts on ISO systems that are not reflected in the three major cost categories and their associated billing determinants. The first two address the fact that significant volumes of bids submitted by market participants to the ISO spot markets and CRR markets do not clear those markets and therefore do not result in energy schedules or ancillary service awards, energy flows, or CRR awards. As such these submitted bids do not enter into the billing determinants for allocating the major cost categories, and the three charges therefore impose no costs on the participants that submitted them, even though they utilize the ISO market systems. The bid segment and CRR transaction fees allocate these cost impacts to the parties who submitted the bids, thereby offsetting the costs recovered through the billing determinants of the major cost categories.

In addition, submission of large quantities of small MW energy bid segments or CRR bids for exploratory or "fishing" purposes in these markets can have adverse impacts on the market systems. All ISO market systems must necessarily be designed with upper bounds on the volume of transactions they can handle, and in developing the systems the ISO establishes limits that are as high as possible within a reasonable balance between the objectives of providing ample capacity to meet market participants' business needs, acceptable system performance (e.g., time to solve and optimality of solution), and implementation cost. The impact on the ISO market systems is directly proportional to the total volume of bid segments submitted, and system performance can be severely degraded as bid segment volumes approach these limits, yet these high volumes may reflect no underlying business needs on the part of the submitters other than a desire to "fish" for, for example, low-margin arbitrage opportunities that can be profitable with high bid volumes. Moreover, a large proportion of these types of bids typically do not clear the markets and therefore would avoid any cost allocation if not for the transaction fees. The transaction fees are therefore needed to discourage submission of high bid volumes that would stress the performance capabilities of the market systems and to appropriately allocate the costs of these transactions to the bid submitters. As discussed above, the ISO observed that the rate designs used by other ISOs and RTOs include such charges as offsets to total costs in their major cost categories.

The Inter-Scheduling Coordinator Trade Fee is similar to the other fees by virtue of the fact that such trades do not result in market schedules or awards or energy flows, and yet must be processed by the ISO market and settlement systems. The inter-scheduling coordinator trade function is a service the ISO offers to market participants, which they could perform for themselves outside of the ISO market systems, but is highly desired by market participants as an ISO-provided service because these trades settle at energy prices determined in the ISO markets. Inter-scheduling coordinator trades utilize the market systems but do not contribute to the billing determinants used to recover the major cost categories and therefore would not be recoverable from the users of the service absent the proposed transaction fee.

The one administrative charge is the Scheduling Coordinator Identification Charge. This is a flat monthly charge the ISO applies to each scheduling coordinator identification for each month in which the holder had transactions with the ISO. Each scheduling coordinator that participates in the ISO markets must have at least one scheduling coordinator identification under which it transacts in the ISO markets, and many scheduling coordinators have more than one scheduling coordinator identification to reflect their business needs. The ISO incurs administrative costs to maintain each of these scheduling coordinator identifications, and these costs are not related to the magnitude of the scheduling coordinator's billing determinants for the major cost categories or its transaction volumes subject to the transaction fees. The Scheduling Coordinator Identification Charge is designed to apply to each scheduling coordinator in direct proportion to the number of active scheduling coordinator identifications that a scheduling coordinator holds and is therefore the most appropriate way to recover these administrative costs.

The ISO notes that the Inter-Scheduling Coordinator Trade Fee and the Scheduling Coordinator Identification Charge are part of the current GMC rate design.[28]

1. Bid Segment Transaction Fee

The proposed Bid Segment Transaction Fee, set forth in proposed section 11.22.5, is $.005 per bid segment and will be applied to all bid segments submitted. The rate of $.005 is a nominal charge that does not represent a significant expense to market participants under typical scheduling practices but is enough to deter the submission of excessive bid volumes.

As the total volume of bid segments submitted to the market increases, the demands on the market software can increase dramatically, resulting in longer solution times and, in the extreme, inability of the software to reach an efficient solution within the time line according to which market participants need the results. At the same time, there are documented strategies whereby a market participant may submit an extremely large quantity of small MW bid segments as a way of "phishing" for locational price sensitivities. Such strategies can have adverse impacts on the ability

[28] As described in ISO Tariff Appendix F, Schedule 1, Part A, inter-scheduling coordinator trades are assessed a per trade fee based on the annual forecasted number of non-zero MW Day-Ahead and HASP schedules with certain modifications. For 2011 that charge is $1.31. In addition, scheduling coordinators currently are charged a $1000 settlements, metering and client relations charge, per scheduling coordinator ID, for each trading month in which there is market activity.

of the software to clear the market in the required time, but have no demonstrated market efficiency benefits. The bid segment transaction fee is designed to deter strategies that involve the submission of high volumes of such "phishing" bids.

The bid segment fee and the CRR transaction fee also collect revenue from participants who submit bids that do not clear the market, but which nonetheless must be processed by the market software and thus have an impact on ISO costs and system performance. These transaction fees therefore align well with the principle of cost causation, and the revenue from these fees will offset costs that would otherwise be recovered through the market services cost category, from market participants whose bids did clear the markets and were reflected in market schedules and awards.

The Commission has previously approved a similar fee in the PJM Tariff[29] based on similar concerns.[30] The level of the Bid Segment Transaction Fee is very similar to the rate used by PJM.[31] PJM provided a similar justification when its bid segment fee was proposed, arguing that the new fee was justified based on the significant expenses it incurs from large volumes of unsuccessful bids and the related impacts those bids have on the market software. The ISO notes that no stakeholder objected to the Bid Segment Transaction Fee during the stakeholder process, at the Board meeting, or during the tariff drafting stakeholder process.

2. CRR Transaction Fee

The proposed CRR Transaction Fee, set forth in 11.22.6, is $1.00 per submitted bid, where a bid to a particular CRR market (defined by the combination of a season or a month with a time-of-use period, either on-peak or off-peak) is defined by a CRR source location, a CRR sink location, and a MW amount. Both ISO New England and PJM have a similar set of FTR charges, which combine a fee based on FTR holding with a fee based on FTR bids.[32]

The purposes of the CRR Transaction Fee are similar to those of the Bid Segment Fee. The fee will recover a portion of the CRR costs on a transactional basis. The CRR market has two methods whereby market participants can receive CRRs: (1) allocation to eligible load-serving entities; and (2) auction processes open to all

[29] *PJM Interconnection, LLC,* 107 FERC ¶ 61,007 at PP 4, 12 (2004).

[30] *PJM Interconnection, LLC*, Transmittal Letter, FERC Docket No. ER04-548-000 (Feb. 11, 2004).

[31] PJM charges a fee of $0.0577 per bid/offer segment. PJM OATT, Schedule 9-3(f).

[32] ISO New England Tariff, Section IV.A, Schedule 2 (establishing a charge of $0.60724 per FTR auction bid); PJM OATT, Schedule 9-2 (establishing a charge of $0.0018 "times the sum of (1) the number of hours in all bids to buy Financial Transmission Rights Obligations submitted by such user during such month, plus (2) five times the number of hours in all bids to buy Financial Transmission Rights Options submitted by such user during such month.").

creditworthy parties. Both methods utilize the same software systems, and therefore the ISO decided that both CRR acquisition methods should be treated the same with respect to this fee. Thus, the fee will apply to the CRR nominations in the allocation process and CRR bids in the auction for the annual and monthly CRR release processes.

Because nominations in the allocation process are single MW values with no price-quantity segments, whereas bids in the auction may have up to ten price-quantity segments, the ISO decided that the fee should apply on a comparable basis to the allocation and auction processes, and therefore decided to use bids rather than bid segments as the transaction fee basis. The revenue from this transaction fee will offset costs that would otherwise be recovered through the CRR Services Charge. The proposed bid fee will collect approximately seven percent of the total CRR cost category.

Just as in the case of the Bid Segment Fee, all submitted CRR bids or nominations impose costs on the CRR market systems, regardless of whether they clear the market or not. CRR nominations and bids that do not clear the market are still participating in the CRR allocation and auction processes, must be processed by the CRR market systems, and should therefore be responsible for a portion of the costs. In addition, like the energy markets, the CRR markets also perform best when the volumes of bids they must process are within their design limits, and their performance will be challenged if participants submit high volumes of small MW bids to fish the network for exploitable price sensitivities. Therefore it is equally important for the optimal performance of the CRR markets to make it costly for participants to employ such bidding strategies.

Certain stakeholders raised concerns about the $1.00 amount of the CRR Transaction Fee. Some parties questioned what they saw as a disparity between the $1.00 per bid CRR bid fee versus the $0.005 per bid segment market services bid fee. The reason for the different fee levels is that the market services bid fee will apply to bids submitted for every hour of every trading day, in order to buy or sell energy or capacity and obtain transmission services in the ISO spot markets. In contrast, the CRR bid fee will apply only to CRR markets, which are run only annually and monthly, (even though they will award CRRs that have settlement value in all hours of all trading days). Thus, the $1.00 CRR fee applied for each CRR allocation or auction process that the ISO conducts is much less of a burden on participants than a fee comparable to the energy bid segment fee would be if it were applied for every hour an awarded CRR bid has settlement value[33].

[33] For example, a monthly on-peak CRR would be settled for 16 hours per day, six days per week for the month. At $.005 per settlement hour this CRR bid would cost the bidder $2.08. In contrast, the $1 proposed CRR bid fee will cost the bidder only $.0025 per settlement hour. For seasonal (three-month) CRRs the comparison is even more striking. The $.005 bid fee would amount to $6.24 for the season, whereas the $1 CRR fee would be the equivalent of about $.0008 per settlement hour.

In addition, some parties contend that the level of the fee will discourage participation in the market. There is no basis for assertions that the allocation of costs to CRR management activities is excessive or that the use of the bid transaction fee will increase the total costs borne by CRR market participants. Over 80 percent of the costs attributable to CRR management reflect level 2 activities that are 100 percent devoted to CRR management.[34] Any reduction in the costs allocated to CRR management would cause other market activities to subsidize the CRR market. Moreover, by design, the proposed CRR bid fee does not increase the costs that will be borne by CRR market participants; rather it only affects the manner in which those costs are recovered from those participants. Any decrease in the fee would simply increase the per MW/hour rate for CRR awards.

The Commission has previously accepted the types of concerns expressed above as a basis for a fee based on firm transmission rights bids. Both ISO New England and PJM cited the significant expenses incurred from processing a high volume of FTR bids irrespective of whether those bids were ultimately successful as a basis for such a fee,[35] which the Commission approved.[36]

3. Inter-Scheduling Coordinator Trade Transaction Fee

The proposed Inter-Scheduling Coordinator Trade Transaction Fee, set forth in section 11.22.7, is $1.00 per party per inter-scheduling coordinator trade (i.e., $2.00 in total for each trade), which is somewhat lower than the current $1.31 charge for inter-scheduling coordinator trades. The ISO's inter-scheduling coordinator trade feature is a financial settlement service that the ISO provides to market participants. Two willing and qualified counter-parties can submit inter-scheduling coordinator trades for any market trading hour. The ISO validates the parties' submissions and, if they are valid, settles the associated financial transaction between the two parties. Inter-scheduling coordinator trades do not figure into the clearing of the market in any way and could be performed by the two parties outside of the ISO systems. Thus, the inter- scheduling coordinator trade feature is a separate, stand-alone ISO service that benefits only the users of the service and is not needed for the performance of any other ISO market functions. The revenue from this transaction fee will offset costs recovered through market services. Further, no stakeholder objected to the Inter-

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[34] *See* Ex. ISO-2, Tables 6-12.

[35] *PJM Interconnection, LLC*, Transmittal Letter, at 3-5, FERC Docket No. ER04-548-000 (Feb. 11, 2004); *ISO New England Inc*, Filing of Revised Tariff Sheets for Recovery of 2007 Administrative Costs and Request for Limited Tariff Waiver, at 31-32, FERC Docket No. ER07-116-000 (Oct. 31, 2006).

[36] *ISO New England Inc*, 117 FERC ¶ 61,310 at PP 5, 22 (2006); *PJM Interconnection, LLC,* 107 FERC ¶ 61,007 at PP 4,12 (2004).

Scheduling Coordinator Trade Transaction Fee during the stakeholder process, at the Board meeting or during the tariff drafting stakeholder process.

4. Scheduling Coordinator Identification Charge

The ISO proposes to keep the existing Scheduling Coordinator Identification Charge (formerly, the settlement, metering, and client relations fee), set forth in section 11.22.8, at the current $1,000 per month per scheduling coordinator identification, and will assess the charge to scheduling coordinator identifications only for trading months in which the scheduling coordinator has market activity. The Scheduling Coordinator Identification Charge is designed to limit the number of scheduling coordinator identifications to those needed for legitimate ongoing business purposes and to discourage parties from maintaining lapsed or unnecessary scheduling coordinator identifications. The revenue from this transaction fee will offset costs recovered through the Market Services Charge.

5. Comparison with Current GMC

The current GMC has several administrative and transaction fees, two of which are essentially retained in the proposed new rate design. The Inter-Scheduling Coordinator Trade Fee is currently in the tariff as an inter-scheduling coordinator trade fee and the Scheduling Coordinator Identification Fee is the current settlements, metering and client relations charge.[37] For 2011, the inter-scheduling coordinator trade fee is $1.3170, which is very close to the $1.00 level being proposed for the new GMC rate design. As noted above, the $1,000 Scheduling Coordinator Identification fee is the same as in the current tariff. The Bid Segment Fee and CRR Bid Transaction Fee are new charges. The costs of other fees and charges have been eliminated and will be recovered through the larger service categories.

In addition, the ISO proposes to eliminate the current station power fee and the participating intermittent resource program process fee (although the participating intermittent resource program process fee collects administrative charges, it appears in section 11.12.3.2 of the ISO Tariff rather than in section 11.22, which identifies the GMC). These fees both recover very insignificant amounts. Station power costs will be recovered through the Market Services charge, and participating intermittent resource program process costs will be recovered through the Systems Operations Charge.

F. Grandfathering Proposal

The final step in the ISO's rate design process was to compare the bill impacts of the proposed rate structure on the various customer classes to determine whether any customer would be disproportionately affected by the new rate

[37] Current Appendix F, Schedule 1, Part A, paragraphs 6 and 8, respectively.

structure. When approving revised rates or rate structures, the Commission has often found it appropriate to include rate mitigation measures, such as phasing in, in order to avoid disproportionate impacts.[38].

As both Mr. Epstein and Dr. Kristov discuss in their testimony, the ISO performed this final step by using the proposed rate structure and historical GMC data to estimate bill impacts on participating scheduling coordinators.[39] The evaluation revealed that there was one category of customers who would be disproportionately impacted by the new design: power suppliers, who are scheduling coordinators that primarily supply energy and capacity to the ISO markets and do not have load-serving responsibilities.

Non-load serving suppliers are significantly impacted by the revised rate because the current GMC does not charge supply resources for total energy flows, but rather charges them based on behavior, particularly real-time uninstructed imbalance energy or deviations. A supply resource generator that does not significantly deviate from its forward schedule, as modified by ISO dispatch instructions, would have a minimal GMC allocation under the current rate design. In contrast, under the proposed GMC framework, because the billing determinant for the System Operations Charge will be total energy flow MWh, the generator will be charged GMC for all MWhs injected into the system (without regard to whether the flows were forward scheduled, instructed or uninstructed). The ISO also found that under the current GMC, a supplier injecting the same volume of energy into the grid that a load-serving entity withdraws from the grid pays substantially less than the load-serving entity, but under the proposed GMC both the supplier and the load-serving entity would pay the same amount.

Thus, suppliers that do not serve load would see dramatic increases in their GMC charges. In contrast, a scheduling coordinator that represents both demand and supply will not experience a similar increase in its GMC charges; although such an entity may see an increase in the charges associated with the supply resources it represents, that increase will be moderated by a decrease in the charges associated with its demand relative to the GMC charges demand pays currently. This bill impact information was shared with stakeholders and graphically depicted in the both the November 11, 2010 straw proposal and the February 15, 2011 draft final proposal.[40] As shown, without rate mitigation, the GMC charged to suppliers would increase by $3.85 million, an increase of 22% over the current GMC.

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[38] *See, e.g., Cal. Indep. Sys. Operator Corp.*, 109 FERC ¶ 61,301 at PP 64-74 (2004); *Midwest Indep. Sys. Operator*, 105 FERC ¶ 61,212 at PP 42-53 (2003).

[39] Ex. ISO-9, 26-31.

[40] See page 16 of Ex. ISO-3; page 25 and appendix to Ex. ISO-7.

Although this impact is significant, it is not problematic as a general matter because suppliers can pass the costs through to load (or marketers, who will pass it through to load). Through stakeholder interaction, however, the ISO learned that there were a few long-term energy contracts that prevented certain suppliers from passing GMC increases through to the energy purchasers. With this information, the ISO considered either grandfathering supply resources with contracts of this type, or phasing in the new GMC charge structure to supply over a period of time.

The ISO initially proposed phasing in the Systems Operations Charge to suppliers over a three year period.[41] However, further analysis showed that phasing in the System Operations Charges for all suppliers would not sufficiently mitigate the rate impacts on the suppliers most directly affected by the problematic contract provisions, and would have a significant adverse impact on the other customer classes.[42] Thus, the ISO decided to abandon the phase-in and proposed instead to grandfather a limited number of existing contracts by exempting the energy associated with those contracts from the System Operations Charge for the duration of the problematic contract provisions.[43] By limiting the total number of supply MWh excluded from the System Operations Charge grandfathering minimizes adverse cost impacts on other participants.

The grandfathering proposal exempts from the System Operations Charge only supply resources that meet certain criteria and only until the earlier of the first opportunity to renegotiate the contract or the contract expiration. To qualify for grandfathering, the contract must have been executed prior to January 1, 2012; the contract must prevent the supplier from passing the System Operations charge on to the buyer and it must be at least three years in duration.

With respect to the first criteria, the ISO proposed to stakeholders that the contract must have been executed before the supplier had notice through the ISO's 2012 GMC design initiative that it would be subject to the System Operations Charge. The 2012 GMC stakeholder process was initiated in April 2010 and stakeholders were advised that the ISO would consider a complete GMC rate structure redesign. Confirmation that suppliers could be charged GMC for absolute flows through the System Operations Charge was provided in the October, 2010 discussion paper. Billing determinants and bill impacts were discussed with stakeholders in November and early December. In addition, ISO

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[41] See January 13, 2011 modifications to GMC Straw Proposal, Ex. ISO-6.

[42] *Id.*; for example, in the first year of the proposed three year phase-in, IOUs would have had a $13.4 million increase over current GMC, as opposed to a $5.51 million increase without the phase-in as depicted on page 16 of Ex. ISO-3.

[43] The ISO also discussed with stakeholders the possibility that the contracts could be renegotiated to allow a pass-through of the increased GMC charges to the energy purchasers, but this was not a practical rate impact solution.

staff made efforts to individually contact suppliers who might be substantially impacted by the new rate design. In view of these opportunities for notice and participation in the stakeholder process, the ISO concluded that the outside date by which affected suppliers should have known that their GMC costs could be increased was January 1, 2011. Thus, to qualify for grandfathering, the contract must have been executed prior to that date.

Based on discussions with affected stakeholders, the ISO also concluded that only long-term contracts should be eligible for grandfathering. Because suppliers can more easily manage the GMC impact by quickly renegotiating the terms of a shorter agreement, rate impacts to these suppliers would not amount to the level of hardship presented by the longer term agreements. Furthermore, while some of the contracts were in excess of ten years before the first exit provision, many contracts containing provisions that prohibit the pass-through of GMC increases extended at least three years before the first exit provision. For these reasons, the ISO proposed that the contracts must have been executed prior to January 1, 2011 and must extend for at least three years after that date. Stakeholders raised no objections to these criteria.

The contract grandfathering details are described in proposed Appendix F, Schedule 1, Part E. Specifically, generation owners must provide a sworn affidavit by a company officer attesting that the contract seeking the GMC exemption meets the tariff criteria. To initiate the process, the ISO will provide a market notice and website instructions. This procedure is similar to the one implemented to grandfather certain resource adequacy contracts from the resource adequacy capacity availability standards set forth in tariff section 40.9.2.[44]

The grandfathering provision is a mitigation solution narrowly focused on the customers who will be most severely impacted by the revised design. It has minimal impact on the other customers and those impacts will gradually be reduced and finally eliminated as the contracts expire or are renegotiated.[45] The ISO notes that no stakeholder opposed the ISO's final proposal during the stakeholder process, at the Board meeting or during the tariff drafting stakeholder process.

G. Other Ratemaking Considerations

The ISO is maintaining the current fee of $0.10 per MWh on eligible intermittent resources and resources participating in the participating intermittent resources program to cover ISO costs in connection with the resource-specific forecast

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[44] *Cal. Indep. Sys. Operator Corp.*, 127 FERC ¶ 61,298 (Order Accepting In Part and Rejecting In Part Tariff Revisions Subject to Modification, June 26, 2009).

[45] The rate impacts of the grandfathering proposal are set forth at page 25 in Ex. ISO-7.

services these resources receive from the independent forecast service provider. This fee is not a grid management charge. It will be subject to review in the participating intermittent resources program stakeholder process.

In addition, the ISO tariff allows metered subsystems to elect to operate their own generating resources to follow their load in real time and thus minimize their participation in the ISO real-time market. The revised GMC exempts any metered subsystem load-following instructed imbalance energy, as set forth in a metered subsystem agreement, from the Market Services Charge because this energy quantity reflects the metered subsystem's performance of its real-time load following function, and the costs associated with this function are recovered through the System Operations charge.[46] These exemptions are discussed in the testimony of Mr. Kristov.

Stakeholders asked the ISO to consider assessing the Market Services Charge to real-time uninstructed energy deviations. The ISO decided against this approach for two reasons. First, although there is a GMC allocation to uninstructed deviations in the current rate design, that charge is actually a residue of the ISO's former zonal market structure in which, for various reasons, uninstructed real-time deviations placed a considerable operational burden on the real-time operators of the grid. With the advent of the new ISO market structure in 2009, including the improved generator operating incentives that derive from locational marginal pricing and the substantial software upgrades to support real-time operation and congestion management, there no longer is the same cost-causation basis to argue that real-time uninstructed deviations should be responsible for a greater share of ISO operating costs than other real-time flows.

Moreover, it would not be appropriate to use the GMC as a way to try to discourage real-time uninstructed deviations, as that would be counter to the guiding principles discussed above. In particular, such an objective would violate the principle that the GMC should focus on recovering the costs associated with providing ISO services and should not address market participant behavior. Incentives for market participants to behave in ways that best support the efficiency of the ISO markets and the operational needs of the grid are best addressed through the market design itself, *i.e.*, through exposure to real-time prices, eligibility for bid cost recovery, and responsibility for the different categories of market uplift charges (Ex. ISO-9, 25-26).

[46] The ISO notes that the exemption for metered subsystems load-following instructed imbalance energy has been moved from tariff Section 11.22.3 and is described as an exemption from the Market Services Charge calculation in Appendix F, Part 1, Section A because it is part of the calculation of the Market Services Charge, and not a separate charge.

IV. Rates and Cost Basis

A. Revenue Requirement and Rate Estimates

The proposed GMC, like the current GMC, is primarily a formula rate to recover the revenue requirement. The ISO's revenue requirement used in the rate will continue to be determined by the annual budget process and will be trued up to actual costs on a quarterly basis. The costs to be recovered are set forth according to the Commission's Uniform System of Accounts in Appendix F, Schedule 1, Part C of the ISO Tariff.[47]

As described in Mr. Epstein's testimony, the ISO develops the budget through a stakeholder process that provides for significant stakeholder input. This process was established through the settlement that followed the ISO's 2003 GMC filing.

Under the budget process, the 2012 budget, which will form the basis for the 2012 GMC charges, is not yet available. The budget for 2011 was $189.8 million, which was a $5.2 million decrease from 2010. A complete copy of the 2011 budget report is included as Exhibit ISO-17.

Under the revised tariff provisions, the ISO allocates the revenue requirement 27% Market Services, 69% System Operations, and 4% CRRs. For the 2011 budget, the total revenue requirement for Market Services would have been $52.756 million; the total revenue requirement for System Operations would have been $134.883 million; and the total revenue requirement for CRRs would have been $7.456 million.

This allocation is based on the cost-of-service study as described above and in the testimony of Mr. Epstein. As described, the ISO allocated costs based on level 2 activities, which were assigned to cost categories 100%, 80%-20%, 50%-50%, or 45%-45%-10%. While the choice of these bright lines, e.g., 80%-20%, as opposed to 75%-25% or 70%-30%, was not based on any particular empirical study, the ISO concluded, based on the experience and expertise of the team assigned to perform the allocations, that this split was an accurate representation of an activity that was principally, but not exclusively, devoted to one cost category. The ISO submits that using a set number of representative percentages to allocate direct operating, debt service and out of pocket capital costs to the cost categories is within the "zone of reasonableness" under the

[47] Included in this filing are non-substantive clarifications to two cost categories that are part of the GMC formula and the elimination of the Section 11.17 requirement that operating and capital reserves be deposited to a separate account. Specifically, the ISO has renamed the "CAISO Operating and Capital Reserves Cost" category to the "CAISO Operating Cost Reserve" which more accurately reflects that there is an operating reserve credit for amounts over 15% of the reserve requirement that will be paid to stakeholders each year. The ISO also proposes a new cost category- "CAISO Cash-Funded Capital and Project Costs" that separates cash (not bond) funded capital and non-capital projects from the operations and maintenance account, thus reflecting the higher level of management and stakeholder scrutiny that these projects receive.

circumstances and was not opposed by any stakeholders during the stakeholder process, at the Board meeting or during the tariff drafting process.

The ISO does not at this time have forecasted volume information to use in calculating the rates. The available historical date is for the period June 1, 2009, to May 31, 2010. The ISO is able to use that data, with the 2010 revenue requirement equalized to actual GMC collections , to provide estimated rates of $0.0914/MWh (energy) or MW (award) for the Market Services Charge; $0.2700/MWh for the System Operations Charge; and $0.0113/MWh for the CRR Services Charge.

B. Revenue Requirement Cap

The proposed GMC includes a revenue requirement cap of $197 million for 2012 and $199 million for 2013 and 2014. Rather than implement the cap by requiring an annual filing, with an exemption if the ISO's revenue requirement is below the cap, the proposed cap is simply a limit on the revenue requirement.[48] Thus, the GMC rate design and the 2012-2014 revenue requirement caps will remain effective unless the ISO seeks a revision under section 205 of the FPA or the Commission revises them under section 206 of the FPA, on its own initiative or in response to a complaint. Section 11.22.2.5 does, however, require the ISO to make a filing establishing a new revenue cap for 2015 and subsequent years.

It is important to note that the Commission has not made a revenue requirement cap a prerequisite to the use of a formula rate. Because a formula rate reflects actual costs, it is necessarily just and reasonable unless a utility attempts to include imprudent or impermissible costs in the calculation of the rates, and section 206 provides a remedy against attempts to pass through imprudent or impermissible costs. The Commission has approved formula rates to recover management costs for both the New York ISO and the Midwest ISO without incorporating a revenue requirement cap.

The ISO recognizes that a revenue cap may be a valuable tool to discipline a utility's development of its budget. Because of stakeholder concerns about the growth of the ISO's budget, the ISO accepted a revenue requirement cap as part of the settlement of the 2003 GMC filing.

The ISO's record since the settlement of the 2003 filing has demonstrated significant budget discipline. Nonetheless, because of stakeholder concerns, the ISO does not propose eliminating a revenue cap, but rather proposes to retain the current cap for one year and to provide a one-time increase of $2 million for the following two years. The ISO submits that the proposal level of the cap is well within the bounds of a just and reasonable rate. As Mr. Epstein notes in his testimony, if one assumes a volume growth of 1% and an operations and maintenance cost increase of 1.6%, and out-of-pocket capital of $19.5 million,

[48] See proposed Section 11.22.2.5,

the ISO's revenue requirement will be $193 million in 2012, $194 million in 2013, and $196 million in 2015.[49] If operations and maintenance costs instead increase by a still modest 3.1%, the revenue requirement for those years would be $193 million, $195 million, and $197 million, respectively.[50] The proposed caps thus only exceed the projected revenue requirement by between 1% and 2%. This is minimal headroom that allows to ISO to accommodate unforeseen contingencies without an additional filing.

The ISO's revenue requirement projections through 2015 are based on a bundled GMC rate of less than $0.80 and include very conservative assumptions about operations and maintenance cost increases, which include merit pay increases, increases in health insurance costs, inflation in the costs of goods and services and other operating expenses that will not be offset by cost reductions. As explained above, even with these assumptions, the ISO forecasts that its revenue requirement will be below the $197 million revenue requirement cap in 2011 and below the $199 million revenue requirement cap in 2013 and 2014.

The ISO's revenue requirement is the result of an extremely robust and transparent budget setting process in which stakeholders are openly and actively engaged. The robustness of that process can be seen by reviewing the documentation at the budget and GMC initiative pages on the ISO's website.[51] The ISO nonetheless proposes a revenue requirement cap in order to provide assurance that the ISO will continue to exercise budget discipline. The proposed cap provides a minimal degree of leeway so that the ISO can raise its revenue requirement to meet changing economic circumstances without making a 205 filing for rates in effect prior to January 1, 2015. No party opposed the ISO's final revenue cap proposal in the stakeholder process, at the Board meeting, or in the tariff development stakeholder process. Indeed, numerous stakeholders strongly supported the proposal.

C. Request for Waiver of Cost-of-service Data Requirements

Because the proposed GMC is a formula rate, the ISO requests a waiver of section 35.13 of the Commission regulations, including waivers of the requirements to submit full Period I and Period II data and workpapers and cost-of-service statements in sections 35.13(c)(6), 35.13(d)(1), (2), and (5), and 35.13(h). These waivers are justified because the GMC is based on a revenue requirement vetted through the budget process with stakeholders and trued up to actual costs. In addition, the accompanying testimony explains in detail the

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[49] Service charges for the debt incurred to implement the ISO's 2009 market design changes will be retired by 2014 and the ISO will finance long-term capital and non-capital projects through out-of pocket capital in lieu of long-term bonds.

[50] These assumptions are well within the range of current forecasts. *See, e.g., http://myweb.rollins.edu/wseyfried/forecast.htm.*

[51] Budget website *http://www.caiso.com/docs/2002/08/02/2002080216283419989.html.*

changes in the terms of the formula rate and provides extensive costs data regarding the 2010 revenue requirement, the allocation of that revenue requirement to rates, and the rates that would have resulted (summarized above). The Commission has previously granted waivers of the requirements to provide such data in a number of cases involving transmission formula rates.[52]

D. Bill Impacts Analysis

The new GMC rate design will have the biggest impact on holders of CRRs. Their share of the overall GMC would be $4.43 million, up from $0.33 million. The share paid by investor-owned utilities will increase from $121.55 million to $128.39 million and that paid by suppliers would increase from $17.20 million to $19.44 million (assuming that the eligible contracts are exempted from the System Operations Charge, as discussed above). The share paid by municipal utilities will decrease to $17.59 million from $19.93 million and that paid by importers and marketers will decrease from $30.98 million to $20.93 million. Other market participants, a catch-all category, would pay $4.33 million, versus $5.11 million under the current rate design.[53] The ISO believes that these results more closely align the GMC rate with cost causation and that this outcome is just, reasonable and in line with the guiding principles developed at the outset of the rate design initiative.

V. Tariff Revisions

The proposed amendment makes the following tariff revisions, as set forth in the attached blacklines:

Section 11.17 is eliminated because the ISO does not maintain an operating and capital reserve account. The calculation of the operating reserve credit is described in Appendix F, Schedule 1, Part c (4).

Section 11.22.2 is revised to more accurately reflect the purpose of the GMC and to update the categories of costs recovered through the GMC.

Section 11.22.2.5 is revised to improve consistency with the formula rate nature of the GMC and to identify the three service charges that comprise the new GMC. The revisions also establish the revenue requirement cap of $197 million for Fiscal Year 2012 and $199 million for Fiscal Years 2013 and 2014, and the requirement that the ISO make a filing to establish a revenue cap for future years.

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[52] *See., e.g., . PPL Elec. Utils. Corp.,* 125 FERC ¶ 61,121, at P 40-41 (2008); *Pub. Serv. Elec. & Gas Co.,* 124 FERC ¶ 61,303, at P 23 (2008); *Oklahoma Gas & Elec. Co.,* 122 FERC ¶ 61,071 (2008); *Commonwealth Edison Co.,* 119 FERC ¶ 61,238, at P 94 (2007).

[53] See page 25 of Ex. ISO-7.

Section 11.22.2.5.1 is revised to set forth the new Market Services Charge.

Section 11.22.2.5.2 is revised to set forth the new System Operations Charge.

Section 11.22.2.5.3 is revised to set forth the new CRR Services Charge.

Sections 11.22.2.5.4 through 11.22.2.5.9 are deleted.

Section 11.22.2.6 is revised to establish the allocation of the ISO revenue requirement to the service categories: 27% to Market Services; 69% to System Operations; and 4% to CRR Services. The section is also revised to be consistent with the filing requirements set forth in section 11.22.2.5.

Section 11.22.3 is deleted.

Section 11.22.4 is revised to set forth the Transmission Ownership Rights Charge.

Section 11.22.5 is revised to set forth the Bid Segment Fee.

Section 11.22.6 is revised to set forth the CRR Transaction Fee.

Section 11.22.7 is revised to set forth the Inter-Scheduling Coordinator Trade Transaction Fee.

Section 11.22.8 is revised to set forth the Schedule Coordinator ID Charge (formerly the Settlements, Metering, and Client Relations Fee).

Appendix A is revised to add the following definitions reflecting the new GMC rate design categories and charges, and also to add two GMC cost formula categories:

Bid Segment Fee
CAISO Cash-Funded Capital and Project Costs
CAISO Operating Cost Reserve
CRR Services Charge
CRR Transaction Fee
Inter-SC Transaction Fee
Market Services Charge
Scheduling Coordinator ID Charge
System Operations Charge
TOR Charge

Appendix A is revised to eliminate the following definitions that are no longer applicable under the proposed new rate design and to eliminate unnecessary descriptions of the ISO operating reserves requirements:

CAISO Operating and Capital Reserves Account
CAISO Operating and Capital Reserves Costs
Core Reliability Services- Demand Charge
Core Reliability Services- Energy Export Charge
Core Reliability Services/Energy Transmission Services- TOR
Energy Transmission Services-Net Energy Charge
Energy Transmission Services- Uninstructed Deviations Charge
Forward Scheduling Charge
Market Usage Charge
Settlements, Metering and Client Relations Charge
Virtual Award Charge

Appendix F, Schedule 1, Part A is revised to set forth the calculation of the Market Services Charge, System Operations Charge, and CRR Services Charge.

Appendix F, Schedule 1, Part B is revised to provide for accounting of amounts received from fees in quarterly rate adjustments. In addition, the percentage change in revenues from each category that would trigger a quarterly adjustment has been changed from five percent to two percent to adjust for the level of revenues assigned to each category. This revision sets the upper dollar level at which an adjustment will be triggered at approximately the same level as under the current GMC structure.

Appendix F, Schedule 1, Part C is revised to update the cost categories recovered through the GMC, including the identification of those costs according to the Commission's Uniform System of Accounts.

Appendix F, Schedule 1, Part D is revised to reflect the fact that the budget is reviewed by the entire ISO Governing Board, rather than a committee, to delete unused optional proceedings, and for consistency with the revenue cap requirements of section 11.22.2.5.

Former Appendix F, Schedule 1, Part E is deleted for consistency with the allocation provisions of section 11.22.2.5 and a new Part E is added to provide for the grandfathering of long term power supply contracts, as discussed above.

Appendix F, Schedule 4 is revised to eliminate the Participating Intermittent Resources Process Fee.

Appendix F, Schedule 5, regarding Station Power Charges, is deleted.

VI. Effective Date and Request for Waiver and Surcharge Authority

The ISO requests that the Commission make the tariff revision contained in the instant filing effective January 1, 2012 and requests waiver of the requirements of section 205 of the Federal Power Act and of 18 C.F.R. § 35.3 as necessary for this purpose. However, although the ISO does not intend to implement the new rate design until January 1, 2012, the ISO seeks approval of its proposed tariff amendments by no later than September 30, 2011. This approval date will provide the ISO with sufficient time to develop new charge codes and make the required settlement system changes, as well as providing an opportunity to test these system changes with stakeholders. It is for this reason that the ISO has submitted its new GMC proposal well ahead of the proposed effective date and stakeholders have supported this filing schedule.

The ISO recognizes that, if the Commission sets this filing for hearing, the GMC will be collected subject to refund, based on the outcome of further Commission proceedings. In the event that the instant filing is set for hearing, the ISO requests that the Commission grant the ISO conditional surcharge authority to be exercised if the Commission determines that a different cost allocation should be applied retroactively, with the effect of lowering aggregate GMC charges to some customers and raising them to others. Because the ISO is a not-for-profit entity, with no invested equity, it must have the ability to surcharge the latter customers to enable it to pay refunds to the former. The only other alternative where retroactive refunds are authorized is to borrow the amounts necessary to pay refunds, with the costs to be borne by future customers. That alternative, however, is problematic in part because of the ISO's limited access to capital markets. A better solution is to authorize surcharges.

VII. Communications

Communications regarding this filing should be addressed to the following individuals, whose names should be put on the official service list established by the Commission with respect to this submittal:

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* Individuals designated for service pursuant to Rule 203(b)(3),

18 C.F.R. § 385.203(b)(3).

VIII. Request for Waivers

The ISO has set forth above specific requests for waivers of the notice requirements of section 205 of the Federal Power Act and of 18 C.F.R. § 35.3, and of the cost-of-service data requirements of 18 C.F.R. § 35.13. In addition, the ISO respectfully requests waiver of any other Commission regulations as may be necessary in order for these tariff revisions to become effective as necessary.

IX. Service

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO Website.

X. Attachments

The following attachments, in addition to this transmittal letter, support the instant filing:

Attachment A	Revised Tariff sheets that incorporate the proposed change described above
Attachment B	The proposed change to the Tariff shown in black-line format
Exhibit ISO-1	Testimony of Michael K. Epstein
Exhibit ISO-2	2012 GMC Cost of Service Study Discussion Paper with Exhibits, October 8, 2010
Exhibit.ISO-3	2012 GMC Straw Proposal, November 11, 2010
Exhibit ISO-4	2012 GMC Customer Bill Comparison Analysis, December 2, 2010
Exhibit. ISO-5	Appendix to 2012 GMC Straw Proposal Billing Determinant Definitions, December 16, 2010

Exhibit ISO-6	2012 GMC Proposed Modifications to November 11, 2010 Straw Proposal, January 13, 2011
Exhibit ISO-7	2012 GMC Draft Final Proposal, February 15, 2011
Exhibit ISO-8	Testimony of Deborah A. Le Vine
Exhibit ISO-9	Testimony of Dr. Lorenzo Kristov
Exhibit ISO-10	Stakeholder Comments and ISO Response on 2012 GMC Rate Design Discussed April 21, 2010
Exhibit ISO-11	Stakeholder Comments and ISO Response on GMC 2012 Cost of Service Study Discussion Paper October 8, 2010
Exhibit ISO-12	Stakeholder Comments and ISO Response on GMC 2012 Straw Proposal Issued November 11, 2010
Exhibit ISO-13	Stakeholder Comments and ISO Response on GMC 2012 Bill Comparison Stakeholder Meeting December 13, 2010
Exhibit ISO-14	Stakeholder Comments and ISO Response on GMC 2012 Bill Comparison stakeholder call January 13, 2011
Exhibit ISO-15	Stakeholder Comments and ISO Response on February 8, 2011 call on GMC Grandfathering
Exhibit ISO-16	Stakeholder Comments and ISO Response on February 22, 2011 call on the GMC Draft Final Proposal
Exhibit ISO-17	2011 Budget and Grid Management Charge Rates

IX. Conclusion

For the foregoing reasons, the Commission should accept the proposed tariff changes contained in the instant filing to become effective on January 1,

2011. Please contact the undersigned if you have any questions regarding this matter.

/s/ Michael E. Ward
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Attachment A – Clean Tariff Sheets

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

* * *

11.17 [NOT USED]

* * *

11.22.2 Costs Recovered Through The Grid Management Charge

The Grid Management Charge shall recover the following costs incurred by the CAISO, as described in more detail in Appendix F, Schedule 1:

(1) CAISO Operating Costs;

(2) CAISO Other Costs and Revenues;

(3) CAISO Financing Costs; and

(4) CAISO Operating Cost Reserve adjustment; and

(5) CAISO Cash-Funded Capital and Project Costs

* * *

11.22.2.5 Allocation of the GMC Among Scheduling Coordinators

The costs recovered through the Grid Management Charge shall be allocated to the service charges that comprise the Grid Management Charge. The costs recovered through the Grid Management Charge shall not exceed $197 million for 2012 and $199 million for 2013 and 2014 unless the ISO submits a tariff amendment increasing such amounts pursuant to Section 205 of the FPA and FERC accepts such amendment. For subsequent years, the ISO must submit a tariff amendment establishing a maximum revenue requirement, which shall be subject to FERC approval. The service charges, as described in more detail in Appendix F, Schedule 1, Part A, are as follows:

(a) Market Services Charge;

(b) System Operations Charge; and

(c) CRR Services Charge.

The charges shall be levied separately monthly in arrears on all Scheduling Coordinators based on the billing determinants specified below for each charge in accordance with formulae set out in Appendix F, Schedule 1, Part A

11.22.2.5.1 Market Services Charge

Subject to Section 11.22.4, the Market Services Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A.

11.22.2.5.2 System Operations Charge

Subject to the exemption for certain long term contracts set forth in Appendix F, Schedule 1, Part E, the System Operations Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A.

11.22.2.5.3 CRR Services Charge

The CRR Services Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A.

11.22.2.6 Calculation and Adjustment of the Grid Management Charge

The charges set forth in Section 11.22.2.5 that comprise the Grid Management Charge shall be calculated through the formula set forth in Appendix F, Schedule 1, Part A. The formula set forth in Appendix F, Schedule 1, Part C sums the CAISO Operating Costs (less any available expense recoveries), CAISO Other Costs and Revenues, CAISO Financing Costs, and CAISO Operating Cost Reserve adjustment and CAISO Cash-Funded Capital and Project Costs associated with each of the CAISO service charges to obtain a total revenue requirement. This revenue requirement is allocated to each service as follows: twenty seven (27) percent to Market Services; sixty nine (69) percent to System Operations; and four (4) percent to CRR Services. The revenue requirement for each service then shall be divided by the forecast annual or periodic billing determinant volume to obtain a rate for each service, which will be payable by Scheduling Coordinators as set forth in Section 11.22.2.5. The rates so established will be adjusted annually, through the operation of the formula set forth in Appendix F, Schedule 1, Part A. The CAISO shall post on the CAISO Website each year, before the adjusted rates go into effect, as described in Appendix F, Schedule 1, Part D, data showing the rates adjusted to reflect any change in the annual revenue requirement, variance between forecast and actual costs for the previous year or period, or any surplus revenues from the previous year or period (as defined in Section 11.17), or the inability to recover from a Scheduling Coordinator its share of the Grid Management Charge, or any under-achievement of a forecast of the billing determinant volumes used to establish the rates. Appendix F, Schedule 1, Part B sets forth the conditions under which a quarterly adjustment to the Grid Management Charge will be made.

11.22.2.6.1 Credits and Debits of the Grid Management Charge

In addition to the adjustments permitted under Section 11.29.7.3.3, the CAISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any overpayment or underpayment of the Grid Management Charge that the CAISO determines occurred due to error, omission, or miscalculation by the CAISO or the Scheduling Coordinator.

11.22.3 [NOT USED]

11.22.4 TOR Charges

The ISO will exempt TORs from the Market Services Charge and the System Operations Charge that are calculated through the formula set forth in Appendix F, Schedule 1, Part A. The TOR Charge will be $0.27/MWh, assessed on the minimum of a Scheduling Coordinator's TOR supply or TOR demand per Settlement Interval.

11.22.5 Bid Segment Fee

Each Scheduling Coordinator submitting a Bid will be subject to a Bid Segment Fee of $0.005 per segment of the Bid. The ISO will credit amounts recovered through the Bid Segment Fee against the revenue requirement for Market Services Charge as described in Appendix F, Schedule 1, Part A.

11.22.6 CRR Transaction Fee

Each Scheduling Coordinator submitting a CRR Allocation nomination or CRR Auction bid will be subject to a CRR Transaction Fee of $1.00 per submitted nomination or bid. The ISO will credit amounts recovered through the CRR Transaction Fee against the revenue requirement for CRR Services Charge as described in Appendix F, Schedule 1, Part A.

11.22.7 Inter-Scheduling Coordinator Trade Transaction Fee

Each Scheduling Coordinator submitting an Inter-Scheduling Coordinator Trade will be subject to an Inter-Scheduling Coordinator Trade Transaction Fee of $1.00 per party per Inter-Scheduling Coordinator Trade. The ISO will credit amounts recovered through the Inter-Scheduling

Coordinator Trade Transaction Fee against the revenue requirement for Market Services Charge as described in Appendix F, Schedule 1, Part A.

11.22.8 Scheduling Coordinator ID Charge

The Scheduling Coordinator ID Charge for each Scheduling Coordinator is $1,000.00 per month, per Scheduling Coordinator ID Code for any Trading Month in which the Scheduling Coordinator has market activity. The ISO will credit amounts recovered through the Scheduling Coordinator ID Charges against the revenue requirement for Market Services Charges as described in Appendix F, Schedule 1, Part_A.

* * *

Appendix A

Master Definition Supplement

* * *

- Bid Segment Fee

The GMC fee described at Section 11.22.5.

* * *

- CAISO Cash-Funded Capital and Project Costs

Costs for projects or studies undertaken during the year or over several years, determination of requirements for capital, projects or assets with a useful life of more than one (1) year and project office labor devoted to capital that are funded from the GMC instead of being financed.

*** * ***

- CAISO Operating Cost Reserve

The CAISO Operating Cost Reserve requirement is fifteen (15) percent of annual CAISO Operating Costs, unless otherwise specified by (1) the rate covenants of the official statements for each CAISO bond offering, (2) the CAISO Governing Board or (3) the FERC. The CAISO Operating Cost Reserve consists of the projected CAISO Operating Cost Reserve balance for December 31 of the prior year less the reserve requirement, as calculated according to the formula set forth in Appendix F, Schedule 1, Part C. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period.

* * *

- CRR Services Charge

The GMC component described in Section 11.22.2.5.3.

* * *

- CRR Transaction Fee

The GMC fee described in Section 11.22.6.

* * *

- Inter-SC Trade Transaction Fee

The GMC fee described in Section 11.22.7.

* * *

- Market Services Charge

The GMC component described in Section 11.22.2.5.1.

* * *

- Scheduling Coordinator ID Charge

The GMC charge described in Section 11.22.8.

* * *

- System Operations Charge

The GMC component described in Section 11.22.2.5.2.

* * *

- TOR Charge

The GMC component for TOR holders described in Section 11.22.4.

* * *

Appendix F Rate Schedules

Schedule 1
Grid Management Charge

<u>Part A – Monthly Calculation of Grid Management Charge (GMC)</u>

The GMC consists of the following separate service charges: (1) the Market Services Charge; (2) the System Operations Charge; and (3) the CRR Services Charge. The GMC revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the service charges specified in Part A of this Schedule 1 as follows: twenty seven (27) percent to Market Services; sixty nine (69) percent to System Operations; and four (4) percent to CRR Services.

1. The rate for the Market Services Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by the forecast annual gross absolute value of MW per hour of Ancillary Services capacity awarded in the Day-Ahead and Real-Time Markets, MWh of Energy cleared in the Day-Ahead market, Virtual Demand Award, Virtual Supply Award, and Instructed Imbalance Energy, less the forecast annual gross absolute value of such Energy as may be excluded for a load following MSS pursuant to an MSS agreement, Standard Ramping Energy, Regulation Energy, Ramping Energy Deviation, Residual Imbalance Energy, Exceptional Dispatch Energy and Operational Adjustments for the Day-Ahead and Real-Time.

2. The rate for the System Operations Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by forecast

annual gross absolute value of MWh of real-time energy flows on the ISO Controlled Grid, net of amounts excluded pursuant to Part E of this Schedule.

3. The rate for the CRR Services Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by the forecast annual sum of awarded MW of CRRs per hour.

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve (12) months, in the manner set forth in Part D of this Schedule.

Part B – Quarterly Adjustment, If Required

Each component rate of the GMC will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as posted on the CAISO Website, as applicable, if the estimated revenue collections for that component, after accounting for revenue collected from the Bid Segment Transaction Fee, the CRR Transaction Fee, the Inter-Scheduling Coordinator Trade Transaction Fee, and the Scheduling Coordinator ID Charge, on an annual basis, change by more than two (2) percent or $1 million, whichever is greater, during the year. Such adjustment may be implemented not more than once per calendar quarter, and will be effective the first day of the next calendar month.

The rates will be adjusted according to the formulae listed in Appendix F, Schedule 1, Part A with the billing determinant(s) readjusted on a going-forward basis to reflect the change of more than two (2) percent or $1 million, whichever is greater, from the estimated revenue collections provided in the annual informational filing.

Part C – Costs Recovered through the GMC

As provided in Section 11.22.2 of the CAISO Tariff, the GMC includes the following costs, as projected in the CAISO's budget for the year to which the GMC applies:

- CAISO Operating Costs;
- CAISO Other Costs and Revenues, including penalties, interest earnings and other revenues;
- CAISO Financing Costs, including debt service on CAISO Start Up and Development Costs and subsequent capital expenditures;
- CAISO Operating Cost Reserve; and
- CAISO Cash Funded Capital and Project Costs

Such costs, for the CAISO as a whole, are allocated to the service charges that comprise the GMC: (1) Market Services, (2) System Operations, and (3) CRR Services, according to the factors listed in Part A of this Schedule 1, and

adjusted annually for:

- any surplus revenues from the previous year as deposited in the CAISO Operating Reserve Account, or deficiency of revenues, as recorded in a memorandum account;

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

- a change in the volume estimate used to calculate the individual GMC components, if, on an annual basis, the change is five (5) percent or $1 million, whichever is greater, from the estimated revenue collections provided in the annual informational filing.

-

The GMC revenue requirement formula is as follows:

GMC revenue requirement =

CAISO Operating Costs + CAISO Financing Costs + CAISO Other Costs and Revenues + CAISO Operating Reserve Credit + CAISO Cash Funded Capital and Project Costs,

[The "USoA" reference below is the FERC Uniform System of Accounts, and is intended to include subsequent re-numbering or re-designation of the same accounts or subaccounts.]

Where,

(1) CAISO Operating Costs include:

(a) Transmission expenses (USoA 560-574);

(b) Regional market expenses (USoA 575.1-575.8);

(c) Maintenance accounts (USoA 576-576.5)

(d) Customer accounting expenses (USoA 901-905);

(e) Customer service and informational expenses (USoA 906-910);

(f) Sales expenses (USoA 911-917);

(g) Administrative & general expenses (USoA 920-935);

(h) Taxes other than income taxes that relate to CAISO operating income (USoA 408.1); and

(i) Miscellaneous, non-operating expenses, penalties and other deductions (USoA 426 subaccounts).

(2) CAISO Financing Costs include:

(a) For any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any CAISO notes. This amount includes the current year accrued principal and interest payments due in the first one hundred twenty (120) days of the following year except for the collection of the remaining payments of the 2008 bonds which shall be divided evenly between 2012 and 2013.

(b) The debt service coverage requirement, which is a percentage of the senior lien debt service, i.e., all debt service that has a first lien on CAISO net operating revenues. The coverage requirement is twenty-five (25) percent, unless otherwise specified by the rate covenants of the official statements for each CAISO bond offering.

(3) CAISO Other Costs and Revenues include:

(a) Interest earnings (USoA 419) on funds not restricted by bond or note proceeds specifically designated for capital projects or capitalized interest. Unrealized gains or losses shall be excluded and realized gains and losses shall be included. If it has been determined that a permanent impairment in an investment has occurred, it shall be included.

(b) Miscellaneous revenues (USoA 421 and 456 subaccounts), including but not limited to Scheduling Coordinator application and training fees, and fines assessed and collected by the CAISO.

(c) Other interest expenses (USoA 431) not provided for elsewhere.

(4) CAISO Operating Cost Reserve adjustment is the sum of

(a) The excess or shortfall in collections of the prior year's rates compared to the budgeted amounts;

(b) The excess or shortfall in actual CAISO Operating Costs, CAISO Other Costs and Revenues and CAISO Financing Costs for the prior year compared to the budgeted amounts;

(c) The estimate of current year collections and costs compared to budgeted amounts for the current year; and

(d) The change in CAISO Operating Cost Reserve consistent with the level of the CAISO Operating Cost Reserve requirement.

(5) CAISO Cash-Funded Capital and Project Costs include funding from current year revenues for approved capital and projects.

A separate revenue requirement shall be established for each component of the GMC by developing the revenue requirement for the CAISO as a whole and then assigning such costs to the service categories using the allocation factors provided in Appendix F, Schedule 1, Part E.

<u>Part D – Information Requirements</u>

Budget Schedule

The CAISO will convene, prior to the commencement of the annual budget process, an initial meeting with stakeholders to: (a) receive ideas to control CAISO costs; (b) receive ideas for projects to be considered in the capital budget development process; and, (c) receive suggestions for reordering CAISO priorities in the coming year.
Within two (2) weeks of the initial meeting, the ideas presented by the stakeholders shall be communicated in writing to the CAISO's officers, directors and managers as part of the budget development process, and a copy of this communication shall be made available to stakeholders.

Subsequent to the initial submission of the draft budget to the CAISO Governing Board, the CAISO will provide stakeholders with the following information: (a) proposed capital budget with indicative projects for the next subsequent calendar year, a budget-to-actual review for capital expenditures for the previous calendar year, and a budget-to-actual review of current year capital costs; and, (b) expenditures and activities in detail for the next subsequent calendar year (in the form of a draft of the budget book for the CAISO Governing Board), budget-to-actual review of expenditures and activities for the previous calendar year, and a budget-to-actual review of expenditures for the current year. Certain of this detailed information which is deemed commercially sensitive will only be made available to parties that pay the CAISO's GMC (or regulators) who execute a confidentiality agreement.

The CAISO shall provide such materials on a timely basis to provide stakeholders at least one full Board meeting cycle to review and prepare comments on the draft annual budget to the CAISO Governing Board.

At least one month prior to the CAISO Governing Board meeting scheduled to consider approval of the proposed budget, the CAISO will hold a meeting open to all stakeholders to discuss the details of the CAISO's budget and revenue requirement for the forthcoming year.

Prior to a final recommendation by the CAISO Governing Board on the CAISO's draft annual budget, the CAISO shall respond in writing to all written comments on the draft annual budget submitted by stakeholders and/or the CAISO shall issue a revised draft budget indicating in detail the manner in which the stakeholders' comments have been taken into consideration.

The CAISO will provide no fewer than forty-five (45) days for stakeholder review of its annual budget between initial budget posting and final approval of the budget by the CAISO Governing Board.

Budget Posting

After the approval of the annual budget by the CAISO Governing Board, the CAISO will post on the CAISO Website the CAISO operating and capital budget to be effective during the subsequent fiscal year, and the billing determinant volumes used to develop the rate for each component of the GMC, together with workpapers showing the calculation of such rates.

Periodic Financial Reports

The CAISO will create periodic financial reports consisting of an income statement, balance sheet, statement of operating reserves, and such other reports as are required by the CAISO Governing Board. The periodic financial reports will be posted on the CAISO Website not less than quarterly.

Part E –System Operations Charge Exemption for Certain Long-Term Power Supply Contracts

(1) The real time MWh Energy flows from Generating Units with certain existing power supply contracts will be exempt from the System Operations Charge until the first opportunity to renegotiate the contract or the contract expires. To be eligible for this exemption, the generating unit and the power supply contract must meet the following criteria:

- (a) The generator owner must be the Scheduling Coordinator for the generating unit;
- (b) The power supply contract may not be with another Scheduling Coordinator that has the same parent company as the generator owner;
- (c) The power supply contract may not be with the same Scheduling Coordinator ID Code as the Generating Unit;
- (d) The power supply contract precludes the supplier from recovering additional GMC costs incurred as a result of the GMC rate design that became effective on January 1, 2012:
- (e) The power supply contract must have been executed prior to January 1, 2011;
- (f) The duration of the power supply contract must be such that it is three (3) years or more until the termination of the contract or the first opportunity to renegotiate the terms and conditions of the contract.

(2) To establish eligibility for exemption from the System Operation charge, the generator owner must submit the following information in accordance with the procedures set forth on the ISO website:

- (a) Power supply contract timeline, including the execution date and either termination date or the earliest date upon which the contract may be renegotiated;
- (b) Resource ID;
- (c) SCID; and,
- (d) Effected MW.

(3) An officer of the generation owner company must provide a signed affidavit attesting to the information that demonstrates the power supply contract eligibility for the exemption.

Part F –[Not Used]

* * *

Schedule 4

Eligible Intermittent Resources Forecast Fee

A charge up to $.10 per MWh shall be assessed on the metered Energy from Eligible Intermittent Resources as a Forecast Fee, provided that Eligible Intermittent Resources smaller than 10 MW that are not Participating Intermittent Resources and that sold power pursuant to a power purchase agreement entered into pursuant to PURPA prior to entering into a PGA or QF PGA shall be exempt from the Forecast Fee.

The rate of the Forecast Fee shall be determined so as to recover the projected annual costs related to developing Energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, that are incurred by the CAISO as a direct result of participation by Eligible Intermittent Resources in CAISO Markets, divided by the projected annual Energy production by all Eligible Intermittent Resources.

The initial Forecast Fee, and all subsequent changes as may be necessary from time to time to recover costs incurred by the CAISO for the forecasting conducted on the behalf of Eligible Intermittent Resources pursuant to the foregoing rate formula, shall be set forth in a Business Practice Manual.

Participating Intermittent Resources Export Fee

A Participating Intermittent Resources Export Fee shall be assessed to Exporting Participating Intermittent Resources each calendar month. The Participating Intermittent Resources Export Fee shall be calculated as the product of (1) the sum of all Settlement costs avoided by Participating Intermittent Resources for the preceding calendar month, or portion thereof, consisting of Charge Codes 6486 [Real Time Excess Cost For Instructed] and 1487 [Energy Exchange Program Neutrality], but excluding charges for Uninstructed Energy associated with Charge Code 6475, (2) by the ratio of the total MW/h generated by an Exporting Participating Intermittent Resource during the calendar month, or portion thereof (based on metered output), by the total MW/h generated by all Participating Intermittent Resources during the calendar month, or portion thereof (based on metered output), and (3) by the percentage of the Exporting Participating Intermittent Resource's capacity deemed exporting under Section 5.3 of the EIRP or PIR Export Percentage.

Participating Intermittent Resources Export Fee per Participating Intermittent Resource =

Program Costs x (MW/h individual Participating Intermittent Resource/MW/h all Participating Intermittent Resources) x PIR Export Percentage

Schedule 5

[NOT USED]

* * *

Attachment B - Blacklines

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

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11.17 [NOT USED]~~CAISO Operating And Capital Reserves Account~~

~~Revenues collected to fund the CAISO financial operating reserves shall be deposited in the CAISO Operating and Capital Reserves Account until such account reaches a level specified by the CAISO Governing Board. The CAISO Operating and Capital Reserves Account shall be calculated separately for each GMC service category. The allocation factors, reassignments and reallocations specified in Appendix F, Schedule 1, Parts E and F, will be accounted for in the development of the CAISO Operating and Capital Reserves Account for each component. If the CAISO Operating and Capital Reserves Account as calculated for such service category is fully funded, surplus funds will be considered an offset to the CAISO's revenue requirement of the next fiscal year.~~

* * *

11.22.2 Costs ~~Included In The~~ Recovered Through The Grid Management Charge

The Grid Management Charge shall ~~include~~ recover the following costs incurred by the CAISO, as described in more detail in Appendix F, Schedule 1:

(1) CAISO Operating Costs;

(2) CAISO Other Costs and Revenues;

(3) CAISO Financing Costs; and

(4) CAISO Operating Cost Reserve adjustment; and

(5) CAISO Cash-Funded Capital and ~~Reserves~~ Project Costs

* * *

11.22.2.5 Allocation of the GMC Among Scheduling Coordinators

The costs recovered through the Grid Management Charge shall be allocated to the service charges that comprise the Grid Management Charge. The costs recovered through the Grid Management Charge shall not exceed $197 million for 2012 and $199 million for 2013 and 2014 unless the ISO submits a tariff amendment increasing such amounts pursuant to Section 205 of the FPA and FERC accepts such amendment. For subsequent years, the ISO must submit a tariff amendment establishing a maximum revenue requirement, which shall be subject to FERC approval. ~~If the CAISO's revenue requirement for any service charge changes from the most recent FERC-approved revenue requirement for that service charge, the costs recovered through that service charge shall be delineated in a filing to be made at FERC as set forth in Section 11.22.2.6.~~ The service charges, as described in more detail in Appendix F, Schedule 1, Part~~s~~ A ~~and F~~, are as follows:

(a) ~~Core Reliability Services – Demand Charge~~ Market Services Charge;

(b) ~~Core Reliability Services – Energy Exports Charge~~System Operations Charge; and

(c) ~~Energy Transmission Services – Net Energy Charge~~CRR Services Charge.~~;~~

~~(d) Energy Transmission Services – Uninstructed Deviations Charge;~~

~~(e) Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge;~~

~~(f) Forward Scheduling Charge;~~

~~(g) Market Usage Charge;~~

~~(h) Settlements, Metering, and Client Relations Charge; and~~

~~(i) Virtual Award Charge.~~

The charges shall be levied separately monthly in arrears on all Scheduling Coordinators based on the billing determinants specified below for each charge in accordance with formulae set out in Appendix F, Schedule 1, Part A. ~~, subject to the requirements set out in Appendix F, Schedule 1, Part F.~~

11.22.2.5.1 Market Services Charge ~~Core Reliability Services – Demand Charge~~

Subject to Section 11.22.4, ~~T~~the ~~Core Reliability Services – Demand Charge~~ Market Services Charge for ~~a~~ each Scheduling Coordinator~~'s~~ ~~Load that is not associated with Energy Exports~~ is calculated according to the formula in Appendix F, Schedule 1, Part A.~~, subject to the requirements set out in Appendix F, Schedule 1, Part F.~~

11.22.2.5.2 System Operations Charge ~~Core Reliability Services – Energy Exports Charge~~

Subject to the exemption for certain long term contracts set forth in Appendix F, Schedule 1, Part E, the ~~Core Reliability Services – Energy Exports Charge~~ System Operations Charge ~~for the load associated~~ for ~~with~~ each~~a~~ Scheduling Coordinator~~'s Energy Exports~~ is calculated according to the formula in Appendix F, Schedule 1, Part A.~~, subject to the requirements set out in Appendix F, Schedule 1, Part F.~~

11.22.2.5.3 CRR Services Charge ~~Energy Transmission Services – Net Energy Charge~~

The CRR Services Charge ~~Energy Transmission Services – Net Energy Charge~~ for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A.~~, subject to the requirements set out in Appendix F, Schedule 1, Part F.~~

~~**11.22.2.5.4 Energy Transmission Services – Uninstructed Deviations Charge**~~

~~The Energy Transmission Services – Uninstructed Deviations Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's net Uninstructed Imbalance Energy by Settlement Interval, according to the formula in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Part F.~~

~~**11.22.2.5.5 Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge**~~

~~The Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Part F.~~

~~**11.22.2.5.6 Forward Scheduling Charge**~~

~~The Forward Scheduling Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Part F.~~

~~**11.22.2.5.7 Market Usage Charge**~~

~~The Market Usage Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Part F. For a Scheduling Coordinator for a Load following MSS, Instructed Imbalance Energy~~

~~associated with Load following instructions will not be assessed the Market Usage Charge for Instructed Imbalance Energy and will be netted with Uninstructed Imbalance Energy for determining the Market Usage Charge for net Uninstructed Imbalance Energy.~~

~~11.22.2.5.8 Settlements, Metering, and Client Relations Charge~~

~~The Settlements, Metering, and Client Relations Charge for each Scheduling Coordinator is fixed at $1000.00 per month, per Scheduling Coordinator ID Code with a non-zero invoice value where the non-zero value reflects market activity in the current Trading Month, as indicated in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Part F. Excess GMC costs related to the provision of these services that are not recovered through this charge are allocated to the other GMC service categories as specified in Appendix F, Schedule 1, Part E.~~

~~11.22.2.5.9 Virtual Award Charge~~

~~The Virtual Award Charge for each Scheduling Coordinator will be calculated according to the formula in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Parts A, C and E.~~

11.22.2.6 Calculation and Adjustment of the Grid Management Charge

The charges set forth in Section 11.22.2.5 that comprise the Grid Management Charge shall be calculated through the formula set forth in Appendix F, Schedule 1, Part A. The formula set forth in Appendix F, Schedule 1, Part C sums the CAISO Operating Costs (less any available expense recoveries), CAISO Other Costs and Revenues, CAISO Financing Costs, and CAISO Operating Cost Reserve adjustment and CAISO Cash-Funded Capital and Project ~~Reserves~~ Costs associated with each of the CAISO service charges to obtain a total revenue requirement. This revenue requirement is allocated to each service as follows: twenty seven (27) percent to Market Services; sixty nine (69) percent to System Operations; and four (4) percent to CRR Services. ~~among the charges of the GMC through the application of the factors specified in Appendix F, Schedule 1, Part E.~~

The revenue requirement for each service then shall be divided by the forecast annual or periodic billing determinant volume to obtain a rate for each service, which will be payable by Scheduling

Coordinators as set forth in Section 11.22.2.5. The rates so established will be adjusted annually, through the operation of the formula set forth in Appendix F, Schedule 1, Part A. The CAISO shall post on the CAISO Website each year, before the adjusted rates go into effect, as described in Appendix F, Schedule 1, Part D, data showing the rates adjusted to reflect any change in the annual revenue requirement, variance between forecast and actual costs for the previous year or period, or any surplus revenues from the previous year or period (as defined in Section 11.17), or the inability to recover from a Scheduling Coordinator its share of the Grid Management Charge, or any under-achievement of a forecast of the billing determinant volumes used to establish the rates. ~~The circumstances under which the CAISO is permitted to put the adjusted rates into effect without submitting a filing to the FERC are described in Appendix F, Schedule 1, Part D.~~ Appendix F, Schedule 1, Part B sets forth the conditions under which a quarterly adjustment to the Grid Management Charge will be made.

11.22.2.6.1 Credits and Debits of the Grid Management Charge

In addition to the adjustments permitted under Section 11.29.7.3.3, the CAISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any overpayment or underpayment of the Grid Management Charge that the CAISO determines occurred due to error, omission, or miscalculation by the CAISO or the Scheduling Coordinator.

11.22.3 [NOT USED]~~MSS GMC Charges~~

~~If the CAISO is charging Grid Management Charges for Uninstructed Imbalance Energy, and the Scheduling Coordinator for a Load-following MSS has Uninstructed Imbalance Energy associated with the MSS's resources, then the CAISO will net the Generation and imports into the MSS to match the Demand and exports out of the MSS, and will not assess the Grid Management Charge associated with Uninstructed Imbalance Energy for such portion of Energy that is used to match MSS Demand and net exports.~~

~~**11.22.3.1** If Generation, above the amount to cover Demand and exports, was sold into the CAISO's Real-Time Market, then the Scheduling Coordinator for the MSS will be charged the Grid Management Charge associated with Uninstructed Imbalance Energy for this quantity.~~

~~**11.22.3.2** If insufficient Generation and imports was available to cover Demand and exports, and the Scheduling Coordinator for the MSS purchased Uninstructed Imbalance Energy from the CAISO Markets, then such Scheduling Coordinator will be charged the Grid Management Charge associated with Uninstructed Imbalance Energy for this quantity.~~

~~**11.22.3.3** Grid Management Charges associated with Uninstructed Imbalance Energy (the Energy Transmission Services – Uninstructed Deviations and Market Usage Charges) will be treated on a net basis by Settlement interval. The Core Reliability Services – Demand Charge, Core Reliability Services – Energy Exports Charge, and Energy Transmission Services – Net Energy Charge will be charged based on Metered Balancing Authority Area Load, including exports out of the MSS. Ancillary Service Bids accepted by the CAISO and Instructed Imbalance Energy will be assessed the applicable Market Usage Charges.~~

~~**11.22.4 Virtual Bid Submission Charge**~~

~~Each Scheduling Coordinator submitting a Virtual Bid will be subject to a Virtual Bid Submission Charge of $0.005 for each Virtual Bid segment that is passed to the IFM.~~

11.22.4 TOR Charges

The ISO will exempt TORs from the Market Services Charge and the System Operations Charge that are calculated through the formula set forth in Appendix F, Schedule 1, Part A. The TOR

Charge will be $0.27/MWh, assessed on the minimum of a Scheduling Coordinator's TOR supply or TOR demand per Settlement Interval.

11.22.5 Bid Segment Fee

Each Scheduling Coordinator submitting a Bid will be subject to a Bid Segment Fee of $0.005 per segment of the Bid. The ISO will credit amounts recovered through the Bid Segment Fee against the revenue requirement for Market Services Charge as described in Appendix F, Schedule 1, Part A.

11.22.6 CRR Transaction Fee

Each Scheduling Coordinator submitting a CRR Allocation nomination or CRR Auction bid will be subject to a CRR Transaction Fee of $1.00 per submitted nomination or bid. The ISO will credit amounts recovered through the CRR Transaction Fee against the revenue requirement for CRR Services Charge as described in Appendix F, Schedule 1, Part A.

11.22.7 Inter-Scheduling Coordinator Trade Transaction Fee

Each Scheduling Coordinator submitting an Inter-Scheduling Coordinator Trade will be subject to an Inter-Scheduling Coordinator Trade Transaction Fee of $1.00 per party per Inter-Scheduling Coordinator Trade. The ISO will credit amounts recovered through the Inter-Scheduling Coordinator Trade Transaction Fee against the revenue requirement for Market Services Charge as described in Appendix F, Schedule 1, Part A.

11.22.8 Scheduling Coordinator ID Charge

The Scheduling Coordinator ID Charge for each Scheduling Coordinator is $1,000.00 per month, per Scheduling Coordinator ID Code for any Trading Month in which the Scheduling Coordinator has market activity. The ISO will credit amounts recovered through the Scheduling Coordinator ID Charges against the revenue requirement for Market Services Charges as described in Appendix F, Schedule 1, Part A.

* * *

Appendix A

Master Definition Supplement

* * *

- Bid Segment Fee

The GMC fee described at Section 11.22.5.

* * *

- CAISO Cash-Funded Capital and Project Costs

Costs for projects or studies undertaken during the year or over several years, determination of requirements for capital, projects or assets with a useful life of more than one (1) year and project office labor devoted to capital that are funded from the GMC instead of being financed.

*** * ***

~~**- CAISO Operating And Capital Reserves Account**~~

~~The account in the name of the CAISO with the CAISO Bank to which revenues collected to fund the CAISO financial operating reserves are transferred, in accordance with Section 11.17. Such financial operating reserves shall be utilized to minimize the impact of any variance between forecast and actual costs throughout the year.~~

~~**- CAISO Operating And Capital Reserves Costs**~~

~~The CAISO's annual budgeted cost of cash funded capital and project expenditures and the amount (positive or negative) sufficient to maintain the CAISO Operating and Capital Reserves Account at the level specified by (1) the rate covenants of the official statements for each CAISO bond offering, (2) the CAISO Governing Board, or (3) the FERC.~~

* * *

- CAISO Operating Cost Reserve

The CAISO Operating Cost Reserve requirement is fifteen (15) percent of annual CAISO Operating Costs, unless otherwise specified by (1) the rate covenants of the official statements for each CAISO bond offering, (2) the CAISO Governing Board or (3) the FERC. The CAISO Operating Cost Reserve consists of the projected CAISO Operating Cost Reserve balance for December 31 of the prior year less the reserve requirement, as calculated according to the formula set forth in Appendix F, Schedule 1, Part C. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period.

* * *

~~**- Core Reliability Services – Demand Charge**~~

~~The component of the Grid Management Charge that provides for the recovery of the CAISO's costs of providing a basic, non-scalable level of reliable operation for the CAISO Balancing Authority Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services – Demand Charge is set forth in Appendix F, Schedule 1, Part A.~~

~~**- Core Reliability Services – Energy Export Charge**~~

~~The component of the Grid Management Charge that provides for the recovery of the CAISO's costs of providing a basic, non-scalable level of reliable operation for the CAISO Balancing Authority Area and meeting regional and national reliability requirements. The formula for determining the Core Reliability Services – Energy Exports Charge is set forth in Appendix F, Schedule 1, Part A.~~

~~**- Core Reliability Services/Energy Transmission Services – TOR**~~

~~The component of the Grid Management Charge that provides for the recovery of the CAISO's costs of providing reliability services to Transmission Ownership Rights within the CAISO Balancing Authority Area. The formula for determining the Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge is set forth in Appendix F, Schedule 1, Part A.~~

* * *

- CRR Services Charge

The GMC component described in Section 11.22.2.5.3.

* * *

- CRR Transaction Fee

The GMC fee described in Section 11.22.6.

* * *

~~**- Energy Transmission Services – Net Energy Charge**~~

~~The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services – Uninstructed Deviations Charge, for the recovery of the CAISO's costs of providing reliability on a scalable basis, i.e., a function of the intensity of the use of the transmission system within the Balancing Authority Area and the occurrence of system outages and disruptions. The formula for determining the Energy Transmission Services – Net Energy Charge is set forth in Appendix F, Schedule 1, Part A.~~

~~**- Energy Transmission Services– Uninstructed Deviations Charge**~~

~~The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services – Net Energy Charge, for the recovery of the CAISO's costs of providing reliability on a scalable basis, in particular for the costs associated with balancing transmission flows that result from Uninstructed Imbalance Energy. The formula for determining the Energy Transmission Services – Uninstructed Deviations Charge is set forth in Appendix F, Schedule 1, Part A.~~

* * *

~~**- Forward Scheduling Charge**~~

~~The component of the Grid Management Charge that provides for the recovery of the CAISO's costs, including, but not limited to, the costs of providing the ability to Scheduling Coordinators to submit a Bid for Energy and Ancillary Services and the cost of processing accepted Ancillary Services Bids. The formula for determining the Forward Scheduling Charge is set forth in Appendix F, Schedule 1, Part A.~~

* * *

- Inter-SC Trade Transaction Fee

The GMC fee described in Section 11.22.7.

* * *

- Market Services Charge

The GMC component described in Section 11.22.2.5.1.

* * *

~~**- Market Usage Charge**~~

~~The component of the Grid Management Charge that provides for the recovery of the CAISO's costs, including, but not limited to, the costs for processing Day-Ahead, Hour-Ahead Scheduling Process and Real-Time Bids, maintaining the Open Access Same-Time Information System, monitoring market performance, ensuring generator compliance with market rules as defined in the CAISO Tariff and the Business Practice Manuals, and determining LMPs. The formula for determining the Market Usage Charge is set forth in Appendix F, Schedule 1, Part A.~~

* * *

- Scheduling Coordinator ID Charge

The GMC charge described in Section 11.22.8.

* * *

~~**- Settlements, Metering, And Client Relations Charge**~~

~~The component of the Grid Management Charge that provides for the recovery of the CAISO's costs, including, but not limited to, the costs of maintaining customer account data, providing account information to customers, responding to customer inquiries, calculating market charges, resolving customer disputes, and the costs associated with the CAISO's Settlement, billing, and metering activities. Because this is a fixed charge per Scheduling Coordinator ID Code, costs associated with activities listed above also are allocated to other charges under the Grid Management Charge according to formula set forth in Appendix F, Schedule 1, Part A.~~

* * *

- System Operations Charge

The GMC component described in Section 11.22.2.5.2.

* * *

- TOR Charge

The GMC component for TOR holders described in Section 11.22.4.

* * *

~~**- Virtual Award Charge**~~

~~The component of the Grid Management Charge that provides for the recovery of the CAISO's costs related to Virtual Awards. The methodology for determining the Virtual Award Charge is set forth in Appendix F, Schedule 1, Part A.~~

* * *

Appendix F Rate Schedules

Schedule 1
Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)

The G~~rid~~ M~~anagement~~ C~~harge~~ consists of the following separate service charges: (1) the Market Services Charge; (2) the System Operations Charge; and (3) the CRR Services Charge. The GMC revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the service charges specified in Part A of this Schedule 1 as follows: twenty seven (27) percent to Market Services; sixty nine (69) percent to System Operations; and four (4) percent to CRR Services. ~~(1) the Core Reliability Services – Demand Charge, (2) the Core Reliability Services – Energy Exports Charge; (3) Energy Transmission Services – Net Energy Charge, (4) the Energy Transmission Services – Uninstructed Deviations Charge, (5) the Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge, (6) the Forward Scheduling Charge, (7) the Market Usage Charge, (8) the Settlements, Metering, and Client Relations Charge, and (9) the Virtual Award Change.~~

1. The rate for the Market Services Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by the forecast annual gross absolute value of MW per hour of Ancillary Services capacity awarded in the Day-Ahead and Real-Time Markets, MWh of Energy cleared in the Day-Ahead market, Virtual Demand Award, Virtual Supply Award, and Instructed Imbalance Energy, less the forecast annual gross absolute value of such Energy as may be excluded for a load following MSS pursuant to an MSS agreement, Standard Ramping Energy, Regulation Energy, Ramping Energy Deviation, Residual Imbalance Energy, Exceptional Dispatch Energy and Operational Adjustments for the Day-Ahead and Real-Time. ~~The rate in \$/MW for the Core Reliability Services – Demand Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any, as may be modified in accordance with Part F of this Schedule 1), reduced by thirty-four percent (34%) of the sum of all Scheduling Coordinators' metered non-coincident peak Demands occurring during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, including Sundays and holidays; provided that if a Scheduling Coordinator's metered non-coincident peak Demand hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, the rate shall be~~

~~sixty-six percent (66%) of the standard Core Reliability Services – Demand Charge rate.~~

2. The rate for the System Operations Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by forecast annual gross absolute value of MWh of real-time energy flows on the ISO Controlled Grid, net of amounts excluded pursuant to Part E of this Schedule.~~The rate in $/MWh for the Core Reliability Services – Energy Exports Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered volume of Energy Exports in MWh, excluding each Scheduling Coordinator's Energy Exports associated with Transmission Ownership Rights.~~

3. The rate for the CRR Services Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by the forecast annual sum of awarded MW of CRRs per hour.~~The rate in $/MWh for the Energy Transmission Services – Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Balancing Authority Area Load, excluding each Scheduling Coordinator's Metered Balancing Authority Area Load associated with Transmission Ownership Rights.~~

~~4. The rate in $/MWh for the Energy Transmission Services – Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecasted net Uninstructed Imbalance Energy (netted within a Settlement Interval summed over the calendar month) in MWh; provided that the rate for each Scheduling Coordinator's Participating Intermittent Resources will be assessed against the Uninstructed Imbalance Energy of such Participating Intermittent Resources netted over the Trading Month.~~

~~5. The rate in $/MWh for the Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Balancing Authority Area Load associated with Transmission Ownership Rights.~~

~~6. The rate in $ per Schedule or $ per Inter-SC Trade for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted number of non-zero MW Day-Ahead and HASP Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service and Residual Unit Commitment Bids and all Inter-SC Trades, including Inter-SC Trades of IFM Load Uplift Obligations. This charge will be assessed separately with respect to Schedules and Inter-SC Trades.~~

~~7. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total purchases and sales (including out-of-market transactions) of Ancillary Services, Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with Uninstructed Imbalance Energy for Participating Intermittent Resources netted over the Trading Month and all other Uninstructed Imbalance Energy being netted within a Settlement Interval) in~~

~~MWh. A Market Usage Charge rate will be calculated separately for two sets of CAISO Markets: (i) the Ancillary Services and RTM rate will be based on MWh of purchases and sales of Ancillary Services in the DAM, the HASP, and the RTM, MWh of Instructed Imbalance Energy, and MWh of Uninstructed Imbalance Energy netted over the Settlement Interval; and (ii) the rate for the Day-Ahead Market for Energy will be based on MWh of Day-Ahead Schedules. The rate for the Day-Ahead Market for Energy will be based on the sum, for all Scheduling Coordinators and all Settlement Periods, of the greater of the amount of MWh associated with each Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.~~

~~8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $1000.00 per month, per Scheduling Coordinator ID Code (SCID) with a non-zero invoice value where the non-zero value reflects market activity in the current Trading Month.~~

~~9. The rate in $/MWh for the Virtual Award Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total virtual supply and virtual demand cleared in the IFM. This service category will be allocated nine (9) percent of the Forward Scheduling Charge and Market Usage – Forward Energy service categories based upon the total annual forecasted cleared supply and demand. All amounts collected from the assessment of the Virtual Bid Submission Charge in a given year will be used to offset the amount of the Virtual Award Charge for the next year.~~

~~For a Scheduling Coordinator for a Load following MSS, the GMC service charges set forth in above shall be applied as set forth in Section 11.22.3 of the CAISO Tariff.~~

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve (12) months, in the manner set forth in Part D of this Schedule.

Part B – Quarterly Adjustment, If Required

Each component rate of the G~~rid~~ M~~anagement~~ C~~harge~~ will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as ~~stated in the CAISO's filing or~~ posted~~ing~~ on the CAISO Website, as applicable, if the estimated revenue collections for that component, after accounting for revenue collected from the Bid Segment Transaction Fee, the CRR Transaction Fee, the Inter-Scheduling Coordinator Trade Transaction Fee, and the Scheduling Coordinator ID Charge, on an annual basis, change by more than two~~five~~ (2) percent ~~(5%)~~ or $1 million, whichever is greater, during the year. Such adjustment may be implemented not more than once per calendar quarter, and will be effective the first day of the next calendar month.

The rates will be adjusted according to the formulae listed in Appendix F, Schedule 1, Part A with the billing determinant(s) readjusted on a going-forward basis to reflect the change of more than two~~five~~ (2) percent ~~(5%)~~ or $1 million, whichever is greater, from the estimated revenue collections provided in the annual informational filing.

Part C – Costs Recovered through the GMC

As provided in Section 11.22.2 of the CAISO Tariff, the G~~rid~~ M~~anagement~~ C~~harge~~ includes the following costs, as projected in the CAISO's budget for the year to which the G~~rid~~ M~~anagement~~ C~~harge~~ applies:

- CAISO Operating Costs;

- CAISO Other Costs and Revenues, including penalties, interest earnings and other revenues;
- CAISO Financing Costs, including debt service on CAISO Start Up and Development Costs and subsequent capital expenditures;~~ and~~
- CAISO Operating Cost ~~and Capital~~ Reserve~~s Costs~~; and
- CAISO Cash Funded Capital and Project Costs~~Out of Pocket Project and Capital Costs.~~

Such costs, for the CAISO as a whole, are allocated to the service charges that comprise the G~~rid~~ M~~anagement~~ C~~harge~~: (1) Market Services~~Core Reliability Services - Demand Charge~~, (2) System Operations~~Core Reliability Services – Energy Exports Charge~~, and (3) CRR Services~~Energy Transmission Services – Net Energy Charge, (4) Energy Transmission Services – Uninstructed Deviations Charge, (5) Core Reliability Services/ Energy Transmission Services – Transmission Ownership Rights Charge, (6) Forward Scheduling Charge, (7) Market Usage Charge, (8) Settlements, Metering, and Client Relations Charge, and (9) Virtual Award Charge~~, according to the factors listed in Part ~~E~~A of this Schedule 1, and

adjusted annually for:

- any surplus revenues from the previous year as deposited in the CAISO Operating ~~and Capital~~ Reserve Account~~s~~, or deficiency of revenues, as recorded in a memorandum account;

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

- a change in the volume estimate used to calculate the individual G~~rid~~ M~~anagement~~ C~~harge~~ components, if, on an annual basis, the change is five (5) percent ~~(5%)~~ or $1 million, whichever is greater, from the estimated revenue collections provided in the annual informational filing.
-

The G~~rid~~ M~~anagement~~ C~~harge~~ revenue requirement formula is as follows:

G~~rid~~ M~~anagement~~ C~~harge~~ revenue requirement =

CAISO Operating Costs + CAISO Financing Costs + CAISO Other Costs and Revenues + CAISO Operating ~~and Capital~~ Reserve~~s~~ Credit + CAISO Cash Funded Capital and Project Costs,

[The "USoA" reference below is the FERC Uniform System of Accounts, and is intended to include subsequent re-numbering or re-designation of the same accounts or subaccounts.]

Where,

(1) CAISO Operating Costs include:

(a) Transmission expenses (USoA 560-574);

(b) Regional market expenses (USoA 575.1-575.8~~ subaccounts~~);

(c) Maintenance accounts (USoA 576-576.5)

(~~c~~d) Customer accounting expenses (USoA 901-905);

(~~d~~e) Customer service and informational expenses (USoA 906-910);

(~~e~~f) Sales expenses (USoA 911-917);

(~~f~~g) Administrative & general expenses (USoA 920-935);

(~~g~~h) Taxes other than income taxes that relate to CAISO operating income (USoA 408.1); and

(~~h~~i) Miscellaneous, non-operating expenses, penalties and other deductions (USoA 426 subaccounts).

(2) CAISO Financing Costs include:

(a) For any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any CAISO notes. This amount includes the current year accrued principal and interest payments due in the first one hundred twenty (120) days of the following year except for the collection of the remaining payments of the 2008 bonds which shall be divided evenly between 2012 and 2013.

(b) The debt service coverage requirement, which is a percentage of the senior lien debt service, i.e., all debt service that has a first lien on CAISO net operating revenues. The coverage requirement is twenty-five (25) percent~~ (25%)~~, unless otherwise specified by the rate covenants of the official statements for each CAISO bond offering.

(3) CAISO Other Costs and Revenues include:

(a) Interest earnings (USoA 419) on funds not restricted ~~CAISO Operating and Capital Reserves Account balances, excluding interest on~~ by bond or note proceeds specifically designated for capital projects or capitalized interest. Unrealized gains or losses shall be excluded and realized gains and losses shall be included. If it has been determined that a permanent impairment in an investment has occurred, it shall be included.

(b) Miscellaneous revenues (USoA 421 and 456 subaccounts), including but not limited to Scheduling Coordinator application and training fees, and fines assessed and collected by the CAISO.

(c) Other interest expenses (USoA 431) not provided for elsewhere.

(4) CAISO Operating Cost ~~and Capital~~ Reserve~~s~~ ~~Costs~~adjustment is the sum of ~~include:~~

~~(a) The projected CAISO Operating and Capital Reserves Account balance for December 31 of the prior year less the reserve requirement. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. The reserve requirement is fifteen percent (15%) of annual CAISO Operating Costs, unless otherwise specified by (1) the rate covenants of the official statements for each CAISO bond offering, (2) the CAISO Governing Board or (3) the FERC.~~

(a) The excess or shortfall in collections of the prior year's rates compared to the budgeted amounts;

(b) The excess or shortfall in actual CAISO Operating Costs, CAISO Other Costs and Revenues and CAISO Financing Costs for the prior year compared to the budgeted amounts;

(c) The estimate of current year collections and costs compared to budgeted amounts for the current year; and

(d) The change in CAISO Operating Cost Reserve consistent with the level of the CAISO Operating Cost Reserve requirement.

(5) CAISO Cash-Funded Capital and Project Costs include

~~(b)~~ f~~F~~unding from current year revenues for approved capital and projects ~~initiated in the fiscal year~~.

A separate revenue requirement shall be established for each component of the G~~rid~~ M~~anagement~~ ~~Charge~~ by developing the revenue requirement for the CAISO as a whole and then assigning such costs to the service categories using the allocation factors provided in Appendix F, Schedule 1, Part E.

Part D – Information Requirements

Budget Schedule

The CAISO will convene, prior to the commencement of the annual budget process, an initial meeting with stakeholders to: (a) receive ideas to control CAISO costs; (b) receive ideas for projects to be considered in the capital budget development process; and, (c) receive suggestions for reordering CAISO priorities in the coming year.
Within two (2) weeks of the initial meeting, the ideas presented by the stakeholders shall be communicated in writing to the CAISO's officers, directors and managers as part of the budget development process, and a copy of this communication shall be made available to stakeholders.

Subsequent to the initial submission of the draft budget to the ~~finance committee of the~~ CAISO Governing Board, the CAISO will provide stakeholders with the following information: (a) proposed capital budget with indicative projects for the next subsequent calendar year, a budget-to-actual review for capital expenditures for the previous calendar year, and a budget-to-actual review of current year capital costs; and, (b) expenditures and activities in detail for the next subsequent calendar year (in the form of a draft of the budget book for the CAISO Governing Board), budget-to-actual review of expenditures and activities for the previous calendar year, and a budget-to-actual review of expenditures for the current year. Certain of this detailed information which is deemed commercially sensitive will only be made available to parties that pay the CAISO's GMC (or regulators) who execute a confidentiality agreement.

The CAISO shall provide such materials on a timely basis to provide stakeholders at least one full ~~committee~~ Board meeting cycle to review and prepare comments on the draft annual budget to the ~~finance committee of the~~ CAISO Governing Board.

At least one month prior to the CAISO Governing Board meeting scheduled to consider approval of the proposed budget, the CAISO will hold a meeting open to all stakeholders to discuss the details of the CAISO's budget and revenue requirement for the forthcoming year. ~~To the extent that such a meeting will deal with complex matters of budgetary and policy import, the CAISO will endeavor to host a workshop on the CAISO's budget preparation process in advance of the meeting to better prepare stakeholders.~~

Prior to a final recommendation by the ~~finance committee of the~~ CAISO Governing Board on the CAISO's draft annual budget, the CAISO shall respond in writing to all written comments on the draft annual budget submitted by stakeholders and/or the CAISO shall issue a revised draft budget indicating in detail the manner in which the stakeholders' comments have been taken into consideration.

The CAISO will provide no fewer than forty-five (45) days for stakeholder review of its annual budget between initial budget posting and final approval of the budget by the CAISO Governing Board.

Budget Posting

After the approval of the annual budget by the CAISO Governing Board, the CAISO will post on the CAISO Website the CAISO operating and capital budget to be effective during the subsequent fiscal year, and the billing determinant volumes used to develop the rate for each component of the G~~rid~~ M~~anagement~~ C~~harge~~, together with workpapers showing the calculation of such rates.

~~Annual Filing~~

~~If the Grid Management Charge revenue requirement for any Budget Year does not exceed $197 million, the CAISO shall not be required to make a Section 205 filing to adjust the GMC charges calculated in accordance with this Schedule 1 to collect such revenue requirement. In order for the CAISO to adjust the GMC charges to collect a Grid Management Charge revenue requirement for a Budget Year that exceeds $197 million, the CAISO must submit an application to the FERC under FPA Section 205. In any event, the CAISO shall submit a filing under FPA Section 205 for approval of the Grid Management Charge to be effective no later than January 1, 2012. In such filing, the CAISO may revise the Grid Management Charge rates set forth in this Schedule 1, but shall not be required to do so.~~

Periodic Financial Reports

The CAISO will create periodic financial reports consisting of an income statement, balance sheet, statement of operating reserves, and such other reports as are required by the CAISO Governing Board. The periodic financial reports will be posted on the CAISO Website not less than quarterly.

Part E –~~Cost Allocation~~System Operations Charge Exemption for Certain Long-Term Power Supply Contracts

(1) The real time MWh Energy flows from Generating Units with certain existing power supply contracts will be exempt from the System Operations Charge until the first opportunity to renegotiate the contract or the contract expires. To be eligible for this exemption, the generating unit and the power supply contract must meet the following criteria:

(a) The generator owner must be the Scheduling Coordinator for the generating unit;
(b) The power supply contract may not be with another Scheduling Coordinator that has the same parent company as the generator owner;
(c) The power supply contract may not be with the same Scheduling Coordinator ID Code as the Generating Unit;
(d) The power supply contract precludes the supplier from recovering additional GMC costs incurred as a result of the GMC rate design that became effective on January 1, 2012:
(e) The power supply contract must have been executed prior to January 1, 2011;
(f) The duration of the power supply contract must be such that it is three (3) years or more until the termination of the contract or the first opportunity to renegotiate the terms and conditions of the contract.

(2) To establish eligibility for exemption from the System Operation charge, the generator owner must submit the following information in accordance with the procedures set forth on the ISO website:

(a) Power supply contract timeline, including the execution date and either termination date or the earliest date upon which the contract may be renegotiated;

(b) Resource ID;
(c) SCID; and,
(d) Effected MW.

(3) An officer of the generation owner company must provide a signed affidavit attesting to the information that demonstrates the power supply contract eligibility for the exemption.

~~1. The Grid Management Charge revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the service charges specified in Part A of this Schedule 1 as follows, subject to Section 2 of this Part E and to Part F of this Schedule 1. Expenses projected to be recorded in each cost center shall be allocated among the charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1. In the event the CAISO budgets for projected expenditures for cost centers are not specified in Table 1 to Schedule 1, such expenditures shall be allocated based on the allocation factors for the respective CAISO division hosting that newly-created cost center. Such divisional allocation factors are specified in Table 1 to this Schedule 1.~~

~~Debt service expenditures for the CAISO's existing bond offerings shall be allocated among the charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1. Capital expenditures shall be allocated among the charges in accordance with the allocation factors listed in Table 2 to this Schedule 1, subject to Section 2 of this Part E and to Part F of this Schedule 1, for the system for which the capital expenditure is projected to be made.~~

~~Any costs allocated by the factors listed in Table 1 and Table 2 to the Settlements, Metering, and Client Relations Charge category that would remain un-recovered after the assessment of the charge for that service specified in Section 8 of Part A of this Schedule 1 on forecasted billing determinant volumes shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.~~

~~The cost allocation factors in Tables 1, 2, and 3 to this Schedule 1 include the following association of factors to the components of the Grid Management Charge, subject to Part F of this Schedule 1:~~

~~CRS: This factor is the allocation of costs to the Core Reliability Services – Demand Charge and Core Reliability Services - Energy Exports Charge.~~

~~ETS: This factor is the allocation of costs to the Energy Transmission Services – Net Energy Charge and Energy Transmission Services – Uninstructed Deviations Charge, subject to Section 2 of this Part E.~~

~~CRS/ETS TOR: This factor is the allocation of costs to Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge for the assessment of the Core Reliability Services – Demand Charge, Core Reliability Services – Energy Exports Charge, and the Energy Transmission Services – Net Energy Charge to Metered Balancing Authority Area Load served over Transmission Ownership Rights.~~

~~FS: This factor is the allocation of costs to the Forward Scheduling Charge.~~

~~MU: This factor is the allocation of costs to the Market Usage Charge, except for the application of the Market Usage Charge to purchases or sales of Energy in the Day-Ahead Market.~~

~~MU-FE: This factor is the allocation of costs to the Market Usage Charge as applied to Day-Ahead Schedules. For each Scheduling Coordinator, the charge for the Day-Ahead Market for Energy will be based on the sum, for all Settlement Periods, of the greater of the amount of MWh associated with the Scheduling Coordinator's Day-Ahead Schedule of Supply or the amount associated with its Day-Ahead Schedule of Demand for each Settlement Period.~~

~~SMCR: This factor is the allocation of costs to the Settlements, Metering, and Client Relations Charge.~~

~~The allocation of costs to cost allocation factors FS and MU-FE includes the allocation of costs to the Virtual Award Charge.~~

~~2. The allocation of costs in accordance with Section 1 and Tables 1 and 2 of this Part E shall be adjusted as follows:~~

~~Costs allocated to the Energy Transmission Services (ETS) category in the following tables are further apportioned to the Energy Transmission Services – Net Energy Charge and Energy Transmission Services – Uninstructed Deviations Charge subcategories in eighty percent (80%) and twenty percent (20%) ratios, respectively.~~

~~Table 1~~

~~O&M, Debt Service, and Other Expense Recoveries Cost Allocation Factors~~

~~CC#~~	~~Cost Center Name~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~2111~~	~~CEO-General~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2121~~	~~Market Monitoring~~	~~22.40%~~	~~0.00%~~	~~0.00%~~	~~6.20%~~	~~46.69%~~	~~17.11%~~	~~7.60%~~	~~100.00%~~
~~2122~~	~~Market Surveillance Committee (Non-labor costs only)~~	~~25.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~75.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2211~~	~~Planning and Infrastructure Development~~	~~53.25%~~	~~46.75%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2221~~	~~Regional Transmission-North~~	~~57.67%~~	~~42.33%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2231~~	~~Regional Transmission-South~~	~~54.60%~~	~~45.40%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2241~~	~~Grid Assets~~	~~68.34%~~	~~31.66%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2242~~	~~Generator Interconnections~~	~~100.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2251~~	~~Network Applications~~	~~0.00%~~	~~100.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2311~~	~~CFO General~~	~~37.33%~~	~~14.40%~~	~~0.42%~~	~~3.96%~~	~~10.70%~~	~~5.12%~~	~~28.05%~~	~~100.00%~~
~~2321~~	~~Accounting~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~

~~CC#~~	~~Cost Center Name~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~2331~~	~~Financial Planning and Treasury~~	~~31.41%~~	~~12.20%~~	~~0.36%~~	~~3.46%~~	~~10.76%~~	~~2.86%~~	~~38.95%~~	~~100.00%~~
~~2341~~	~~Human Resources~~	~~40.85%~~	~~16.67%~~	~~0.47%~~	~~3.01%~~	~~10.06%~~	~~6.00%~~	~~22.94%~~	~~100.00%~~
~~2351~~	~~Facilities~~	~~40.85%~~	~~16.67%~~	~~0.47%~~	~~3.01%~~	~~10.06%~~	~~6.00%~~	~~22.94%~~	~~100.00%~~
~~2361~~	~~Procurement and Vendor Management~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2371~~	~~Enterprise Risk Management~~	~~34.73%~~	~~11.83%~~	~~0.38%~~	~~5.53%~~	~~9.35%~~	~~6.78%~~	~~31.40%~~	~~100.00%~~
~~2372~~	~~Internal Audit~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2373~~	~~Information Security~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~2374~~	~~Physical Security~~	~~40.85%~~	~~16.67%~~	~~0.47%~~	~~3.01%~~	~~10.06%~~	~~6.00%~~	~~22.94%~~	~~100.00%~~
~~CC#~~	~~Cost Center Name~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~2411~~	~~Information Technology-General~~	~~35.13%~~	~~8.03%~~	~~0.35%~~	~~8.08%~~	~~11.07%~~	~~4.65%~~	~~32.69%~~	~~100.00%~~
~~2412~~	~~Asset Management (Non-Labor costs only)~~	~~32.40%~~	~~9.79%~~	~~0.33%~~	~~7.51%~~	~~12.78%~~	~~5.37%~~	~~31.83%~~	~~100.00%~~
~~2421~~	~~IT Projects~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~2431~~	~~IT Project Management~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~2441~~	~~Software Quality Assurance~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~2451~~	~~IT Support &~~	~~37.26%~~	~~10.02%~~	~~0.39%~~	~~9.71%~~	~~12.49%~~	~~2.34%~~	~~27.78%~~	~~100.00%~~

~~CC#~~	~~Cost Center Name~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
	~~Operations~~								
~~2452~~	~~System & Database Administration~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~2453~~	~~Data Center & Operations~~	~~40.24%~~	~~18.35%~~	~~0.49%~~	~~2.44%~~	~~14.15%~~	~~1.64%~~	~~22.70%~~	~~100.00%~~
~~2454~~	~~Architecture & Systems Engineering~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~2462~~	~~EMS Information Technology~~	~~94.09%~~	~~2.45%~~	~~0.80%~~	~~0.00%~~	~~1.33%~~	~~0.00%~~	~~1.33%~~	~~100.00%~~
~~2463~~	~~Operations Information Technology~~	~~31.43%~~	~~9.40%~~	~~0.33%~~	~~13.67%~~	~~26.52%~~	~~0.00%~~	~~18.65%~~	~~100.00%~~
~~2464~~	~~Corporate Systems~~	~~32.52%~~	~~10.30%~~	~~0.32%~~	~~1.22%~~	~~10.23%~~	~~1.92%~~	~~43.49%~~	~~100.00%~~

~~CC#~~	~~Cost Center Name~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~2511~~	~~Operations-General~~	~~46.52%~~	~~16.54%~~	~~0.75%~~	~~1.33%~~	~~15.19%~~	~~2.09%~~	~~17.58%~~	~~100.00%~~
~~2521~~	~~Grid Operations~~	~~68.53%~~	~~24.09%~~	~~1.42%~~	~~0.00%~~	~~5.96%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2522~~	~~Real-Time Operations~~	~~60.99%~~	~~29.70%~~	~~1.20%~~	~~0.00%~~	~~8.11%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2523~~	~~Scheduling~~	~~65.75%~~	~~32.87%~~	~~1.38%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2524~~	~~Outage Management~~	~~94.00%~~	~~0.37%~~	~~4.17%~~	~~0.00%~~	~~1.47%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2531~~	~~Alhambra Grid Operations~~	~~100.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2541~~	~~Market Services~~	~~5.38%~~	~~0.00%~~	~~0.00%~~	~~5.02%~~	~~44.24%~~	~~7.90%~~	~~37.46%~~	~~100.00%~~
~~2542~~	~~Market Operations~~	~~5.14%~~	~~0.00%~~	~~0.00%~~	~~13.08%~~	~~56.08%~~	~~20.56%~~	~~5.14%~~	~~100.00%~~
~~2543~~	~~Billing and Settlements~~	~~12.56%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~87.44%~~	~~100.00%~~
~~2544~~	~~Settlement Projects~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~2545~~	~~Market Information~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2551~~	~~Operations Support~~	~~38.68%~~	~~19.64%~~	~~0.00%~~	~~0.00%~~	~~1.76%~~	~~0.00%~~	~~39.92%~~	~~100.00%~~
~~2552~~	~~Operations Data and Compliance~~	~~41.75%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~58.25%~~	~~100.00%~~
~~2553~~	~~Operations Procedures and Training~~	~~63.23%~~	~~36.77%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2554~~	~~Model & Contract Implementation~~	~~35.54%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~8.77%~~	~~0.00%~~	~~55.69%~~	~~100.00%~~

~~2555~~	~~Information Engineering & Analysis~~	~~8.80%~~	~~46.39%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~44.82%~~	~~100.00%~~
~~2561~~	~~Reliability Coordination~~	~~100.00 %~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~

~~CC#~~	~~Cost Center Name~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~2611~~	~~General Counsel-General~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2621~~	~~Asst General Counsel-Corporate~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2631~~	~~Asst General Counsel-Regulatory~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2641~~	~~Asst General Counsel Tariff & Compliance~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2651~~	~~Asst Corporate Secretary~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2711~~	~~Market Development-Program Mgmt-General~~	~~18.92%~~	~~21.45%~~	~~0.04%~~	~~8.86%~~	~~42.78%~~	~~0.43%~~	~~7.51%~~	~~100.00%~~
~~2721~~	~~Market and Product Development~~	~~7.43%~~	~~14.86%~~	~~0.00%~~	~~7.43%~~	~~62.86%~~	~~0.00%~~	~~7.43%~~	~~100.00%~~
~~2722~~	~~Tariff and Regulatory/ Policy Development~~	~~0.00%~~	~~9.34%~~	~~0.00%~~	~~18.69%~~	~~71.97%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~2723~~	~~Infrastructure Policy & Contracts~~	~~45.42%~~	~~44.49%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~10.09%~~	~~100.00%~~
~~2731~~	~~Program Office~~	~~38.89%~~	~~15.11%~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2741~~	~~MRTU Program~~	~~10.30%~~	~~4.25%~~	~~0.12%~~	~~19.93%~~	~~10.75%~~	~~16.19%~~	~~38.46%~~	~~100.00%~~

~~CC#~~	~~Cost Center Name~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~2811~~	~~External Affairs-General~~	~~12.89%~~	~~5.00%~~	~~0.15%~~	~~1.42%~~	~~4.41%~~	~~1.17%~~	~~74.96%~~	~~100.00%~~
~~2821~~	~~Communications & Public Relations~~	~~38.89%~~	~~15.11 %~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2822~~	~~Information Products & Services~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~2831~~	~~State/Federal Affairs~~	~~38.89%~~	~~15.11 %~~	~~0.44%~~	~~4.29%~~	~~13.32%~~	~~3.54%~~	~~24.42%~~	~~100.00%~~
~~2841~~	~~Customer Services and Industry Affairs~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~

~~Financing and Capital Project Budgets~~								
	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~1998/2000 Bond Financed Capital~~	~~29.96%~~	~~8.36%~~	~~0.31%~~	~~11.78 %~~	~~16.47%~~	~~1.07%~~	~~32.05%~~	~~100.00%~~
~~2004 Bond Financed Capital~~	~~16.20%~~	~~5.07%~~	~~0.17%~~	~~17.67 %~~	~~10.90%~~	~~14.09%~~	~~35.90%~~	~~100.00%~~
~~2007 Bond Financed Capital~~	~~13.44%~~	~~5.08%~~	~~0.15%~~	~~19.05 %~~	~~10.48%~~	~~15.71%~~	~~36.09%~~	~~100.00%~~

~~Other Revenues and Expense Credits~~								
~~SC Application and Training Fees~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00 %~~	~~0.00%~~	~~0.00%~~	~~100.00 %~~	~~100.00%~~
~~WECC Reimbursement/NERC Reimbursement~~	~~100.00 %~~	~~0.00%~~	~~0.00%~~	~~0.00 %~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~COI Path Operator Fee~~	~~71.81%~~	~~28.19%~~	~~0.00%~~	~~0.00 %~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Large Generator Interconnection Project~~	~~100.00 %~~	~~0.00%~~	~~0.00%~~	~~0.00 %~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Interest Earnings~~	~~34.78%~~	~~12.18%~~	~~0.38%~~	~~7.33 %~~	~~12.98 %~~	~~5.30%~~	~~27.06%~~	~~100.00%~~

~~Table 2~~

~~Capital Cost Allocation Factors~~

~~System~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~ACC Upgrades (Communication between ISO & IOUs)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Ancillary Services~~	~~14.88%~~	~~0.00%~~	~~0.12%~~	~~40.00%~~	~~45.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~

~~System~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~Management (ASM) Component of SA~~								
~~Application Development Tools~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~Automated Dispatch System (ADS)~~	~~49.59%~~	~~0.00%~~	~~0.41%~~	~~25.00%~~	~~20.00%~~	~~0.00%~~	~~5.00%~~	~~100.00%~~
~~Automated Load Forecast System (ALFS)~~	~~69.42%~~	~~0.00%~~	~~0.58%~~	~~10.00%~~	~~20.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Automatic Mitigation Procedure (AMP)~~	~~0.00%~~	~~84.30%~~	~~0.70%~~	~~0.00%~~	~~15.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Backup systems (Legato/Quantum)~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~Balance of Business Systems (BBS)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Balancing Energy Ex Post Price (BEEP) Component of SA~~	~~49.59%~~	~~2.83%~~	~~0.43%~~	~~20.00%~~	~~27.14%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Bill's Interchange Schedule (BITS)~~	~~84.30%~~	~~0.00%~~	~~0.70%~~	~~0.00%~~	~~15.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~CAISO Outage Modeling Tool (COMT)~~	~~64.47%~~	~~1.42%~~	~~0.55%~~	~~15.00%~~	~~18.57%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~CaseWise (process modeling tool)~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~CHASE~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Client Relations Tools~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~

~~System~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~Common Information Model (CIM)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Compliance~~	~~41.75%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~58.25%~~	~~100.00%~~
~~Congestion Management (CONG) Component of SA~~	~~0.00%~~	~~28.34%~~	~~0.23%~~	~~0.00%~~	~~71.43%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~

~~System~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~Congestion Reform-DSOW~~	~~0.00%~~	~~63.76%~~	~~0.53%~~	~~0.00%~~	~~35.71%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Congestion Revenue Rights (CRR)~~	~~0.00%~~	~~22.67%~~	~~0.19%~~	~~0.00%~~	~~77.14%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~DataWarehouse~~	~~31.59%~~	~~2.86%~~	~~0.00%~~	~~3.07%~~	~~18.90%~~	~~6.93%~~	~~36.65%~~	~~100.00%~~
~~Dept. of Market Analysis Tools (SAS/MARS)~~	~~22.40%~~	~~0.00%~~	~~0.00%~~	~~6.20%~~	~~46.69%~~	~~17.11%~~	~~7.60%~~	~~100.00%~~
~~Dispute Tracking System (Remedy)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Documentum~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Electronic Tagging (Etag)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Energy Management System (EMS)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Engineering Analysis Tools~~	~~59.51%~~	~~39.67%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Evaluation of Market Separation~~	~~0.00%~~	~~14.17%~~	~~0.12%~~	~~0.00%~~	~~85.71%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Existing Transmission Contracts Calculator (ETCC)~~	~~24.79%~~	~~4.25%~~	~~0.24%~~	~~20.00%~~	~~30.71%~~	~~0.00%~~	~~20.00%~~	~~100.00%~~
~~FERC Study Software~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Firm Transmission Right (FTR) and Secondary~~	~~0.00%~~	~~17.00%~~	~~0.14%~~	~~15.00%~~	~~57.86%~~	~~0.00%~~	~~10.00%~~	~~100.00%~~

~~Registration System (SRS)~~								
~~Global Resource Reliability Management Application (GRRMA)~~	~~74.38%~~	~~14.88%~~	~~0.74%~~	~~0.00%~~	~~10.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Grid Operations Training Simulator (GOTS)~~	~~62.48%~~	~~36.70%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Hour-Ahead Data AnalysisTool, Day-Ahead Data AnalysisTool,~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Human Resources~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~

~~System~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~IBM Contract (also known as Outsourced Contracts)~~	~~34.79%~~	~~13.90%~~	~~0.40%~~	~~4.29%~~	~~11.66%~~	~~4.26%~~	~~30.69%~~	~~100.00%~~
~~Integrated Forward Market (IFM)~~	~~9.92%~~	~~0.00%~~	~~0.08%~~	~~35.00%~~	~~0.00%~~	~~55.00%~~	~~0.00%~~	~~100.00%~~
~~Internal Development~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~Interzonal Congestion Management reform - Real Time~~	~~0.00%~~	~~63.76%~~	~~0.53%~~	~~0.00%~~	~~35.71%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Land and Building Costs~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Local Area Network (LAN)~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Locational Marginal Pricing (LMPM)~~	~~9.92%~~	~~0.00%~~	~~0.08%~~	~~35.00%~~	~~55.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Market Quality System (MQS)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Masterfile~~	~~19.84%~~	~~0.00%~~	~~0.16%~~	~~20.00%~~	~~55.00%~~	~~0.00%~~	~~5.00%~~	~~100.00%~~
~~Meter Data Acquisition System (MDAS)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Miscellaneous (2004 related capital)~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~Monitoring (Tivoli)~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~MRTU Capital~~	~~12.68%~~	~~4.68%~~	~~0.14%~~	~~19.01%~~	~~10.75%~~	~~15.41%~~	~~37.33%~~	~~100.00%~~
~~Network Applications~~	~~0.00%~~	~~99.18%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~New Resource Interconnection (NRI)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~New System Equipment (replacement of owned equipment)~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~NT/web servers~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~NT-servers~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~

~~System~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~Office Automation - desktop/laptop (OA)~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Office equipment (scanner, printer, copier, fax, Communication Equip.)~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Open Access Same-Time Information System (OASIS)~~	~~9.92%~~	~~2.83%~~	~~0.11%~~	~~25.00%~~	~~42.14%~~	~~0.00%~~	~~20.00%~~	~~100.00%~~
~~Operational Meter Analysis and Reporting (OMAR)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Oracle Corporate Financials~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Oracle Enterprise Manager (OEM)~~	~~6.46%~~	~~0.68%~~	~~0.06%~~	~~43.90%~~	~~26.52%~~	~~0.00%~~	~~22.38%~~	~~100.00%~~
~~Oracle Licenses~~	~~6.46%~~	~~0.68%~~	~~0.06%~~	~~43.90%~~	~~26.52%~~	~~0.00%~~	~~22.38%~~	~~100.00%~~
~~Oracle Market Financials BBS~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Out of Sequence Market Operation Settlements Information System (OOS)~~	~~4.96%~~	~~4.96%~~	~~0.08%~~	~~0.00%~~	~~90.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Outage Scheduler (OS)~~	~~49.59%~~	~~5.67%~~	~~0.46%~~	~~10.00%~~	~~34.29%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Participating Intermittent Resource Project (PIRP)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~64.75%~~	~~35.25%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Physical Facilities Software Application/Furniture/Leasehold Improvements~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Portal~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Post Transaction Repository (PTR)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Process Information System (PI)~~	~~79.34%~~	~~0.00%~~	~~0.66%~~	~~0.00%~~	~~10.00%~~	~~0.00%~~	~~10.00%~~	~~100.00%~~
~~Rational Buyer~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Real Time Energy Dispatch System (REDS)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~

~~Real Time Nodal Market~~	~~34.71%~~	~~0.00%~~	~~0.29%~~	~~10.00%~~	~~55.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Reliability Management System (RMS)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~

~~System~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~Remedy (related to Transmission Registry, New Resource Interconnection and Resource Registry)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Remote Intelligent Gateway (RIG) & Data Processing Gateway (DPG)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Resource Adequacy~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Resource Register (RR)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~RMR Application Validation Engine (RAVE)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Scheduling & Logging for ISO California (SLIC)~~	~~64.47%~~	~~1.42%~~	~~0.55%~~	~~15.00%~~	~~18.57%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Scheduling & Tagging Next Generation (STiNG)~~	~~84.30%~~	~~0.00%~~	~~0.70%~~	~~0.00%~~	~~15.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Scheduling Architecture (SA)~~	~~15.51%~~	~~12.00%~~	~~0.23%~~	~~19.99%~~	~~52.27%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Scheduling Infrastructure (SI)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~64.75%~~	~~35.25%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Scheduling Infrastructure Business Rules (SIBR)~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~64.75%~~	~~35.25%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Security Constrained Economic Dispatch (SCED)~~	~~0.00%~~	~~39.67%~~	~~0.33%~~	~~0.00%~~	~~60.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Security- External/Physical~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Security-ISS (CUDA)~~	~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~Settlements and Market Clearing~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~	~~100.00%~~
~~Sign Board (Symon Board maint.)~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Startup Costs through 3/31/98, Working Capital-3 months~~	~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Storage (EMC symmetrix)~~	~~24.87%~~	~~6.18%~~	~~0.21%~~	~~13.62%~~	~~17.62%~~	~~4.11%~~	~~33.40%~~	~~100.00%~~

~~System Equipment Buyouts (lease buyouts)~~	~~44.00%~~	~~1.00%~~	~~0.00%~~	~~7.00%~~	~~11.00%~~	~~0.00%~~	~~37.00%~~	~~100.00%~~
~~Tactical Emergency Management System (TEMS)~~	~~99.18%~~	~~0.00%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~

	~~System~~	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~Telephone/PBX~~		~~40.34%~~	~~19.26%~~	~~0.49%~~	~~1.52%~~	~~14.24%~~	~~1.70%~~	~~22.45%~~	~~100.00%~~
~~Training Systems~~		~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~Transmission Constrained Unit Commitment (TCUC) Must Offer Obligation~~		~~0.00%~~	~~99.18%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Transmission Map Plotting & Display~~		~~49.59%~~	~~49.59%~~	~~0.82%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~0.00%~~	~~100.00%~~
~~Treasury Workstation/Investment Program~~		~~40.21%~~	~~19.26%~~	~~0.49%~~	~~1.81%~~	~~15.60%~~	~~2.00%~~	~~20.62%~~	~~100.00%~~
~~Trustee Costs, Interest-Capitalized, User Groups~~		~~17.40%~~	~~2.96%~~	~~0.17%~~	~~17.81%~~	~~19.94%~~	~~0.03%~~	~~41.69%~~	~~100.00%~~
~~Utilities - System i.e. Print drivers~~		~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~Vitria (Middleware)~~		~~23.53%~~	~~3.01%~~	~~0.22%~~	~~9.91%~~	~~6.42%~~	~~9.47%~~	~~47.44%~~	~~100.00%~~
~~Wide Area Network (WAN)~~		~~38.26%~~	~~0.93%~~	~~0.32%~~	~~19.89%~~	~~12.46%~~	~~0.63%~~	~~27.51%~~	~~100.00%~~

~~Table 3~~

~~Reallocation Factors for Projected Unrecovered Portion of Settlements, Metering, and Client Relations Revenue Requirement~~

	~~CRS~~	~~ETS~~	~~CRS/ETS TOR~~	~~FS~~	~~MU~~	~~MU-FE~~	~~SMCR~~	~~Total~~
~~Functional Association of Settlements, Metering, and Client Relations~~	~~0.00%~~	~~65.68%~~	~~0.25%~~	~~0.70%~~	~~23.73%~~	~~9.64%~~	~~0.00~~	~~100.00~~

Part F –[Not Used]

* * *

Schedule 4
Eligible Intermittent Resources Forecast Fee

A charge up to $.10 per MWh shall be assessed on the metered Energy from Eligible Intermittent Resources as a Forecast Fee, provided that Eligible Intermittent Resources smaller than 10 MW that are not Participating Intermittent Resources and that sold power pursuant to a power purchase agreement entered into pursuant to PURPA prior to entering into a PGA or QF PGA shall be exempt from the Forecast Fee.

The rate of the Forecast Fee shall be determined so as to recover the projected annual costs related to developing Energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, that are incurred by the CAISO as a direct result of participation by Eligible Intermittent Resources in CAISO Markets, divided by the projected annual Energy production by all Eligible Intermittent Resources.

The initial Forecast Fee, and all subsequent changes as may be necessary from time to time to recover costs incurred by the CAISO for the forecasting conducted on the behalf of Eligible Intermittent Resources pursuant to the foregoing rate formula, shall be set forth in a Business Practice Manual.

~~Participating Intermittent Resources Process Fee~~

~~A process fee charge shall be assessed, for each calendar quarter, to each Exporting Participating Intermittent Resource that exported Energy in the quarter. On an annualized basis, the aggregate quarterly charges shall total to $10,000. The charge is not volumetric, and shall be calculated as follows:~~

~~($10,000/4)/N = $quarterly charge~~
~~N = number of Participating Intermittent Resources exporting Energy in the quarter~~

Participating Intermittent Resources Export Fee

A Participating Intermittent Resources Export Fee shall be assessed to Exporting Participating Intermittent Resources each calendar month. The Participating Intermittent Resources Export Fee shall be calculated as the product of (1) the sum of all Settlement costs avoided by Participating Intermittent Resources for the preceding calendar month, or portion thereof, consisting of Charge Codes 6486 [Real Time Excess Cost For Instructed] and 1487 [Energy Exchange Program Neutrality], but excluding charges for Uninstructed Energy associated with Charge Code 6475, (2) by the ratio of the total MW/h generated by an Exporting Participating Intermittent Resource during the calendar month, or portion thereof (based on metered output), by the total MW/h generated by all Participating Intermittent Resources during the calendar month, or portion thereof (based on metered output), and (3) by the percentage of the Exporting Participating Intermittent Resource's capacity deemed exporting under Section 5.3 of the EIRP or PIR Export Percentage.

Participating Intermittent Resources Export Fee per Participating Intermittent Resource =

Program Costs x (MW/h individual Participating Intermittent Resource/MW/h all Participating Intermittent Resources) x PIR Export Percentage

Schedule 5

[NOT USED]

~~STATION POWER CHARGES~~

~~The CAISO shall assess a charge of $500 to the Scheduling Coordinator representing the owner of one or more Generating Units that submits an application to establish a Station Power Portfolio or to change the configuration of Station Power meters or the generating facilities included in a Station Power Portfolio. If the generating facilities in a single Station Power Portfolio are scheduled by more than one Scheduling Coordinator, then the Scheduling Coordinator representing the most installed capacity shall be assessed the application charge.~~

~~A charge of $200 will be assessed to the Scheduling Coordinator of Generating Units that have Station Power meters each time the CAISO is required to shift Meter Data to a unique Load identifier pursuant to the Station Power Protocol. For example, if a Scheduling Coordinator has two Station Power meters, and both Remote Self Supply and Third Party Supply is attributed to each Station Power meter in a single Netting Period, then the CAISO must shift Meter Data to a total of four unique Load identifiers and the charge would be $800 in that month (2 meters x 2 Load IDs x $200).~~

~~All revenue collected by the CAISO pursuant to this Schedule 5 shall be considered "Other Revenues" and applied as a credit to the Grid Management Charge revenue requirement in accordance with Schedule 1 of Appendix F.~~

* * *

Exhibit No. ISO-1 – Testimony of Michael K. Epstein

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)))	ER11-____-000

DIRECT TESTIMONY OF
MICHAEL K. EPSTEIN
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Michael K. Epstein. I am employed as Director of Financial Planning for the California Independent System Operator Corporation (the "ISO"). My business address is 250 Outcropping Way, Folsom, CA 95630.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES?

A. I am responsible for the ISO's budget preparation and management; long term planning; accounting for the FERC refund case; market cash settlements; and audit coordination for all the ISO's settlement and operations activities. As part of my duties at the ISO, I oversee the development of the ISO's grid management charge, or "GMC." The GMC is the mechanism by which the ISO collects its administrative costs from participants in the markets conducted by the ISO and from others that benefit from the ISO's services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received both an MBA and a BA with a major in accounting from the University of Southern California in Los Angeles, California. Previously to my current position, I was the Controller of the ISO from 1997-2009. From 1994-1997, I was Vice President (Finance) of Siskon Gold Corporation, a publicly-traded mining company located in Grass Valley, California. From 1989-1994, I was Controller of the Grupe Company, a privately held diversified real estate company located in Stockton, California. From 1985-1989, I was Controller of Brush Creek Mining and Development Company located in Auburn, California. Prior to that, I was a

Certified Public Accountant in the practice of public accounting with both local and international accounting firms.

Q. HAVE YOU PROVIDED EXPERT TESTIMONY PREVIOUSLY?

A. Yes. I previously presented testimony in support of the ISO's GMC filing for 2001 in Docket No. ER01-313-000. I have also presented testimony as an expert witness in several real estate valuation cases, in insurance claim matters, and in a tax and securities investigation.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain the development of the ISO's 2012 GMC proposal. Specifically, I will discuss the background of the GMC, the cost-of-service study and stakeholder process through which the ISO developed the 2012 GMC proposal, including the ISO's use of Activity Based Costing, or "ABC," and the cost impact of the proposal on the different customer groups. I will also discuss the derivation of the rate for Transmission Owner Rights. Finally, I will explain the ISO's inclusion of a cap on the revenue requirement and a sunset date.

Ms. Deborah A. Le Vine is providing testimony that explains the process by which the GMC team associated the costs for specific ISO activities with the categories of services. She will also describe the analysis of services provided to the Transmission Ownership Rights holders that was used in determining the rate for Transmission Ownership Rights under the 2012 GMC proposal. Dr. Lorenzo Kristov's testimony will explain the rate design and the determination of the billing determinants. Dr. Kristov will also explain the ISO's proposed grandfathering of certain power purchase agreements in order to mitigate extreme cost impacts.

Q. AS YOU TESTIFY, WILL YOU BE USING ANY SPECIALIZED TERMS?

A. Yes. Unless otherwise indicated, capitalized terms have the meanings set forth in the Master Definitions, Appendix A of the ISO Tariff.

I. <u>HISTORY OF THE GRID MANAGEMENT CHARGE</u>

Q. HAS THE GMC ALWAYS EMPLOYED THE SAME RATE DESIGN?

A. No. There have been three iterations of the GMC rate design: the original GMC rate design, in effect 1998 through 2000; the 2001 GMC rate design, in effect with minor modifications through 2003; and the 2004 rate design, which is in effect with certain modifications at the current time.

Q. PLEASE DESCRIBE THE ORIGINAL GMC FILING.

A. The ISO filed its original GMC on October 17, 1997. The original GMC was a single bundled formula rate designed to collect the costs of operating the ISO, including the ISO's start-up and development costs as well as ongoing operation and maintenance costs. The GMC was designed to be a monthly charge assessed to all Scheduling Coordinators.

Q. HOW DID THE GMC CHANGE IN 2001?

A. The filing of the original GMC led to negotiations and a settlement in 1998. The settlement called for a stakeholder process designed to unbundle the GMC into "buckets" reflecting the services provided. As a result of the stakeholder process, the ISO proposed in a filing in 2000 to unbundle the GMC into three buckets: the Market Operations Charge, the Control Area Services Charge, and the Inter-Zonal Scheduling Charge. The 2001 GMC rate design was the subject of prolonged litigation. While litigation was underway, the ISO proposed an extension of the 2001 GMC rate design, with minor revisions in the nomenclature of the buckets. Pursuant to a settlement, the 2001 GMC rates design was extended through 2003, with a rate cap, subject to the outcome of the litigation. In Opinion Nos. 463, 463-A, 463-B, and 463-C, the Commission approved the 2001 GMC, with certain modifications.

Q. HOW WAS THE GMC REVISED IN 2004?

A. During the stakeholder process and litigation regarding the 2001 GMC rate design, certain parties argued for further unbundling of the GMC in order to more closely track the services that the ISO provides. Following another stakeholder process, and while litigation continued regarding the 2001 GMC, the ISO filed in 2003 a new GMC rate design, which was a formula rate with seven buckets. Specifically, the ISO proposed to unbundle the Control Area Services charge into two sub-functions, Core Reliability Services and Energy Transmission Services; and to unbundle the Market Operations and Inter-Zonal Scheduling Charges into three service categories; Forward Scheduling, Market Usage, and Congestion Management. The ISO also proposed to establish a Settlements, Metering, and Client Relations Charge, and further proposed that Energy Transmission Services be divided into Energy Transmission Services-Net Energy and Energy

Transmission Services-Uninstructed Deviations. The proceeding concluded in a settlement adopting the new design with various modifications. The settlement reduced the 2004 revenue requirement and provided revenue requirement caps for 2005 and 2006 below which the ISO would not be required to seek approval of its GMC rates.

Q. HOW WAS THE REVENUE REQUIREMENT FOR THE FORMULA RATE TO BE DETERMINED FOR 2005 AND 2006?

A. The revenue requirement was to be based on the ISO budget, as determined through the ISO's annual budget process. The rate was to be trued up to actual costs on a quarterly basis.

Q. YOU STATED THAT THIS RATE DESIGN IS CURRENTLY IN EFFECT. HOW DID THAT OCCUR?

A. From 2002 through 2009, the ISO was working on a new market design. Because of delays in implementation of the new market design, the ISO and its stakeholders agreed to extend the GMC rate design, the formula rate structure, and revenue requirement cap for 2007, 2008 and into 2009 until the effective date of the new market.

Q. WHAT WERE THE MODIFICATIONS OF THE 2004 RATE DESIGN THAT YOU MENTIONED?

A. Concurrently with extending the GMC on these three occasions, the ISO worked with its stakeholders to develop rate design modifications that would be necessary to reflect service category changes brought about by the new market structure. The ISO proposed to retain the basic rate structure and make only those changes to the design needed to implement the new market. The modification consisted of (1) the elimination of the Congestion Management Charge; (2) modifications to the Core Reliability Services and Energy Transmission Services Charges to reflect flows on Transmission Ownership Rights; 3) changes in the billing determinants for Forward Scheduling and Market Usage Charges; and 4) an increase in the Settlements, Metering, and Client Relations Charge from $500 to $1,000. The Commission approved the proposal in 2008 and it went into effect on April 1, 2009.

Q WERE THERE ANY OTHER MODIFICATIONS?

A. Yes. Following the implementation of the new GMC, the ISO conducted a stakeholder process to address stakeholder concerns about the application of the Market Usage-Forward Energy Charge to inter-scheduling coordinator energy trades in the day-ahead market. This process culminated with the filing of a proposal to modify the billing determinants for the Market Usage-Forward Energy Charge and to extend the rest of the GMC until December 31, 2010. The Commission approved the extension of the GMC but suspended the Market Energy-Forward Usage Charge revision and set the matter for hearing and settlement procedures. Pursuant to a settlement, the revisions to the Market Usage-Forward Energy Charge went into effect on June 1, 2010. The settlement also extended the GMC rate design until December 31, 2011. In addition, as part of the settlement, the ISO agreed to conduct a new cost-of-service study for the 2012 GMC.

Q. WHAT IS A COST-OF-SERVICE STUDY?

A. A cost-of-service study determines how the activities of each cost center or business unit should be distributed to cost categories. The results are used to assign costs to customers in a manner that reflects cost-causation.

Q. HOW DID THE ISO COMPLY WITH ITS COMMITMENT TO CONDUCT A NEW COST-OF-SERVICE STUDY FOR THE 2012 GMC?

A. The ISO determined that sufficient staff resources were available to conduct the 2012 GMC cost of service internally, but that it would require a robust internal process, employing subject matter expertise across many ISO business units, including system operations, markets and policy development, settlements, finance and others. The ISO accordingly assembled a team of internal experts to work on the project -- the “GMC team”. I served as the GMC team lead. The ISO conducted the cost-of-service study as part of the development of the proposed revised GMC design that is the subject of this proceeding. In contrast to the cost-of-service study conducted in 2007, by which we intended to update cost allocations and billing determinants without requiring substantial changes to the GMC rate design, the ISO started the cost-of-service study for the 2012 GMC at ground level and re-evaluated all aspects of the GMC structure.

II. ISO REVENUE REQUIREMENT

Q. YOU STATED THAT THE REVENUE REQUIREMENT FOR THE FORMULA RATE IS DETERMINED THROUGH THE ISO'S BUDGET PROCESS. PLEASE DESCRIBE THAT PROCESS.

A. The budget process is set forth in Appendix F, Schedule 1, Part D of the ISO Tariff. It begins with an initial meeting with stakeholders, generally in June of each calendar year, at which the ISO receives ideas to control ISO costs; ideas for projects to be considered in the capital budget development process; and, suggestions for reordering ISO priorities in the coming year. Within the following two weeks, those ideas are submitted to the ISO's officers, directors and managers as part of the budget development process.

The ISO then prepares and submits a draft budget to the ISO Governing Board on an informational basis, after which it provides stakeholders with (a) the proposed capital budget with indicative projects for the subsequent calendar year, a budget-to-actual review for capital expenditures for the previous calendar year, and a budget-to-actual review of current year capital costs; and, (b) expenditures and activities in detail for the subsequent calendar year (in the form of a draft of the budget book for the ISO Governing Board), budget-to-actual review of expenditures and activities for the previous calendar year, and a budget-to-actual review of expenditures for the current year. This presentation generally occurs at the September or early October Board meeting each calendar year.

With this schedule, stakeholders then have substantially more time than the tariff-required forty-five (45) days for review between initial budget posting and final approval of the budget by the ISO Governing Board in December. At least one month prior to the ISO Governing Board meeting on the proposed budget, generally in November, the ISO holds a stakeholder meeting or conference call to discuss the details of the ISO's budget and revenue requirement. If necessary, the ISO will host a workshop on the ISO's budget preparation process in advance of the meeting.

As described in the tariff, the ISO responds in writing to all written comments on the draft annual budget submitted by stakeholders or issues a revised draft budget indicating in detail the manner in which the stakeholders' comments have been taken into consideration.

Q. WHAT WAS THE 2011 BUDGET?

A. The 2011 budget provided for a revenue requirement of $189.8 million, which was a $5.2 million decrease from 2010. A complete copy of the 2011 budget report is included as Exhibit No. ISO-17.

Q. WHAT IS THE STATUS OF THE 2012 BUDGET?

A. The kick-off meeting for the 2012 budget was held on June 16, 2011.

II. GMC DESIGN REVISION

Q. WHY DID THE ISO DECIDE TO REVISE THE DESIGN OF THE GMC?

A. The ISO introduced a new market design with new rules on April 1, 2009. Although the ISO revised the GMC to reflect the new market design, the structure of the new market is significantly different from the prior structure and the current GMC design does not accommodate the new market structure well. The ISO currently has 7 GMC service categories, which contain 17 charge codes and do not align well with market activities. Moreover, market enhancements frequently require the addition of a new service category and recovery methodology. The ISO concluded that absent a fundamental GMC design change, the implementation of additional market enhancements will increase the number of GMC service categories and charge codes, further contributing to the complexity of the rate structure.

Q. COULD YOU PROVIDE SOME EXAMPLES OF ISSUES THAT HAVE ARISEN WITH THE CURRENT GMC DESIGN?

A. Among other issues, because the current GMC structure could not accommodate the recovery of the costs of implementing convergence bidding in a manner related to cost-causation, the ISO had to create a new service category containing two new charge codes. Fairly allocating the Market Usage-Forward Energy charge presented similar challenges; virtually all parties agreed that the settlement related to the Market Usage-Forward Energy charge, while just and reasonable, was not ideal and needed to be revisited. Although the new market already has uplift costs to deter deviations, the current GMC design additionally charges scheduling coordinators for imbalances, which are very difficult to forecast. Finally, the Settlements, Metering, and Client Relations Charge, as structured, only collects a small fraction of the indirect costs associated with these functional areas; the remaining costs are allocated to the other service categories.

Q. ARE THERE OTHER REASONS THAT CONTRIBUTED TO THE DECISION TO REVISE THE GMC DESIGN?

A. Yes. Other circumstances had changed significantly from those that existed at the time of the 2004 GMC settlement and those changed circumstances weighed in favor of a re-examination of the GMC design. Specifically, (1) the ISO had undergone a major corporate reorganization; (2) the ISO's debt structure had changed due to the ISO's construction of a new office building; (3) repayment of the bonds issued to fund the ISO's new market was imminent; and (4) stakeholders, who had previously participated in the 2004 GMC settlement, were now requesting greater GMC clarity, predictability and simplicity.

Q. DOES THE ISO PROPOSE TO CHANGE THE UNDERLYING FUNDAMENTAL DESIGN OF THE GMC?

A. No. The current GMC is a formula rate, whereby the ISO's revenue requirement is allocated based on a matrix of percentages allocating the activities of all the ISO cost centers to a set of GMC components, and then ultimately to GMC charge codes. These GMC charge codes are then recovered from the users of ISO services in accordance with objective billing determinants, which are calculated for each user in each billing period and reflect each user's activities and use of ISO services. The ISO's revenue requirement is determined by the annual budget developed with stakeholder input according to a process set forth in the tariff and approved by the ISO Board. The tariff contains a revenue requirement "cap" under which the ISO may continue to recover the GMC without seeking FERC approval for changes to particular charges due to the formula rate implementation. The ISO believes that these aspects of the GMC design work well, and stakeholders have not expressed an interest in changing these aspects.

Q. ON WHAT PRINCIPLES DID THE GMC TEAM RELY IN DEVELOPING THE 2012 GMC?

A. In consultation with stakeholders, the team relied upon seven rate design principles in developing the 2012 GMC proposal:

- Cost Causation – Costs will be properly allocated to the correct GMC buckets and charged to those who benefit from or utilize those services.
- Focus on use of ISO services, not market behavior – The new GMC design should reflect its primary purpose as a vehicle for recovering the ISO's revenue requirements based on each user's use of the ISO's services, not as a tool for shaping incentives based on market or operating behavior. Incentives such as these are appropriately addressed through the design of the market structure and market rules.
- Transparency – Costs and billing determinants will be clear, visible, and understandable to all market participants.
- Predictability – Market participants will be able to determine in advance what their GMC costs will be depending on their activity.

- Forecastability – The rates should utilize billing determinants that can be easily forecasted by both the ISO and market participants. This should result in fewer rate adjustments during the year.
- Flexibility – The new GMC structure should easily accommodate future market enhancements without excessive complexity or disrupting the overall structure.
- Simplicity – Simplify the current GMC structure to reduce the amount of varying bill determinants and the number of charge codes.

Q. PLEASE DESCRIBE THE PROCESS FOR DEVELOPING THE 2012 GMC.

A. There were five activities that we performed, in consultation with stakeholders, in developing the 2012 GMC:

- Functionalization - The process by which various activities are defined and sorted into service categories (functions and sub-functions) to reflect the different services provided by the ISO.
- Cost Allocation - The process by which the costs of providing services are allocated to the service categories (functions and sub-functions).
- Classification - The determination of billing determinants based on the customer cost causation factors.
- Rate Design - The process for deriving rates that divides the revenue requirement for each service category by the billing determinants.
- Bill Impacts Analysis - An evaluation of the impacts that the rate design will have on individual customer bills.

The first two of these activities are achieved through the cost-of-service study. As I previously stated, I will be describing those two activities and the bill impact analysis. Ms. Le Vine will discuss the development of the allocation matrix used in cost allocation, and Dr. Kristov will discuss classification and rate design.

III. STAKEHOLDER PROCESS

Q. PLEASE DESCRIBE STAKEHOLDER INVOLVEMENT IN THE DEVELOPMENT OF THE 2012 GMC PROPOSAL.

A. As I have noted, stakeholder interest in greater clarity, predictability and simplicity was one of the factors that prompted the ISO's decision to revise the GMC design for 2012. The formal stakeholder process began April 21, 2010, when the ISO first discussed the process and timeline with stakeholders. On October 8, 2010, the ISO posted a discussion paper presenting methodology and initial results of the cost of service study and allocation of costs, which is presented as Exhibit No. ISO-2. The discussion paper also described the ISO proposed principles, discussed above. The ISO discussed these matters with stakeholders at a meeting on October 14 and solicited comments on the discussion paper. The comments on the discussion paper and the ISO's responses are included as Exhibit No. ISO-11.

Q. WHAT WERE THE NEXT STEPS?

A. After considering comments, on November 11, 2010, the ISO issued a straw proposal, which appears here as Exhibit No. ISO-3. The straw proposal included three charges: Market Services, System Operations, and Congestion Revenue

Rights, or "CRR," Services. The proposal also included certain set fees. The ISO discussed the straw proposal with stakeholders during a telephone and web conference on November 18 and again solicited comments. During the conference, stakeholders requested data on bill impacts, based on the proposed GMC rate design and historical data. The stakeholder comments on the straw proposal and the ISO's responses are included as Exhibit No. ISO-12.

Q. HOW DID THE ISO RESPOND TO THE REQUEST FOR BILL IMPACT DATA?

A. The GMC team used historical data to develop estimated bill impacts for the individual scheduling coordinators and for the major classes of customers. Under section 20 of the ISO Tariff, however, there are limits on the ISO's release of individual scheduling coordinator data. To ensure compliance with section 20, the ISO used only individual data that were six months old and did not identify, or permit identification of, the applicable scheduling coordinator. The ISO allowed scheduling coordinators to view their own bill impacts on a confidential basis. The ISO issued a market notice to this effect and released the data on December 2, 2010, which is included as Exhibit No. ISO-4. The ISO conducted a stakeholder meeting to discuss the data on December 13. The stakeholder comments on the bill impacts and the ISO's responses are included as Exhibit No. ISO-13. The ISO also posted additional information about the proposed billing determinants addressed in the straw proposal on December 16, 2010, which appears as Exhibit No. ISO-5.

Q. HOW DID THE ISO PROCEED AFTER THE DECEMBER 13 MEETING?

A. After considering comments on the straw proposal and on the bill impacts, the ISO posted a modified straw proposal and revised bill impact information. The modified straw proposal is Exhibit No. ISO-6. The ISO proposed the modification to ameliorate certain bill impacts. Specifically, the ISO proposed to phase in the applicability of the System Operations Charge to suppliers; to exclude Transmission Ownership Rights from the Market Services Charge and to limit the exposure of Transmission Ownership Rights to the System Operations charge, and to modify some of the fees. The ISO also proposed modification of its revenue cap proposal – from a five-year stepped cap to a three year uniform cap. The ISO held another stakeholder telephone and web conference to discuss the modification of the GMC proposal on January 20, 2011. Stakeholder comments and the ISO's responses are included as Exhibit No. ISO-14. On February 8, 2011, the ISO again conducted a stakeholder telephone and web conference, this time to discuss further modification of the straw proposal; instead of phasing in the applicability of the Systems Operation Charge to suppliers, the ISO proposed to grandfather, *i.e.*, to exempt, suppliers that had entered long term contracts in reliance on the existing GMC provisions until the first opportunity to revise the contracts. Stakeholder comments on that proposal and the ISO's responses are included as Exhibit No. ISO-15.

Q. HOW DID THE ISO PROCEED FROM THIS POINT?

A. After considering the comments on the most recent proposal, the ISO posted a draft final proposal on February 15, 2011, presented as Exhibit No. ISO-7, and hosted a stakeholder telephone and web conference regarding the proposal on February 22, 2011. Stakeholder comments on that proposal and the ISO's responses are included as Exhibit No. ISO-16. Following consideration of these comment, the ISO management finalized the 2012 GMC proposal for presentation to the ISO Board of Governors.

IV. COST-OF-SERVICE STUDY: FUNCTIONALIZATION

Q. YOU STATED EARLIER THAT THE ISO USED ACTIVITY-BASED COSTING, OR "ABC," IN THE COST-OF-SERVICE STUDY. WHAT IS ACTIVITY-BASED COSTING?

A. ABC is a costing model that identifies activities in an organization and assigns the cost of each activity to products and services produced by the organization according to the actual consumption by each. While the ISO did not begin using ABC until 2008, the identification of the information needed to make the costing model successful began in 2006 with a company-wide process mapping effort, which developed into a hierarchy of business processes. The ISO's ABC analysis disaggregated the ISO operations into ten core functions (level 1 activities). Each of the core activities were broken down into major processes (level 2 activities). Unlike earlier descriptions of ISO activities for developing cost categories, the ABC activities are linked to specific processes and are measurable. Time reporting on level 1 activities commenced October 2009 with pilot programs on level 2 activities. The ISO intends to move to full level 2 time-reporting by the end of 2011.

Q. WHAT ACTIVITIES WERE IDENTIFIED FOR THE COST-OF-SERVICE STUDY?

A. The level 1 activities can be categorized into two types: (1) direct operating costs, *i.e.*, those that can be directly mapped to a market, grid service or customer and (2) indirect costs, *i.e.*, those that support the direct activity. Of ten level 1 activities, the GMC team categorized six as direct operating costs and four as indirect or support costs. They are described in Table 1 of Exhibit No. ISO-2. Each of the level 1 activities comprised multiple level 2 activities. The level 2 activities analyzed in the cost-of-service study were the processes that had been mapped as of May, 2010. A complete list of level 2 activities is included as Exhibit 1 to the October 8, 2010 Discussion Paper (Exhibit No. ISO-2).

Q. HOW DID THE ISO USE THE ABC ANALYSIS IN DEVELOPING THE 2012 GMC?

A. The ISO considered a number of options for aggregating activities. The first option was to map activities to the existing GMC service categories. However, the existing structure was too complex to achieve the goals of greater transparency, predictability and simplicity. Level 2 activities would need to be further broken down in order to make mapping possible. For example the ISO does not have any activity related specifically to deviations, although there is a GMC charge related to deviations.

We then examined a second option: to map activities to customer categories. The ISO prepared a list of 31 customer categories, including utility distribution companies, merchant generation, proxy demand response, self-scheduled exports, and many more. When we mapped these categories to the level 2 activities, it soon became apparent that in a majority of cases the level 2 activity applied to all categories. This observation prompted a third option, identifying common activities across all customers.

Q. WHAT COMMON ACTIVITIES DID THE ISO IDENTIFY?

A. An examination of the ISO's map of customer activity for the new nodal market systems revealed a common sequence of activities. Energy flowed on the ISO grid based on (1) bids that customers submitted and (2) schedules that the ISO's market systems subsequently awarded. In addition, there were activities related to Congestion Revenue Rights, or "CRRs." Based on this sequence, the ISO established three categories of activities: Market Services, System Operations, and CRR Services. This structure, incidentally, is very similar to what other ISOs and RTOs with nodal markets have implemented to recover their administrative charges.

Q. WHAT WAS THE NEXT STEP IN FUNCTIONALIZATION?

A. The next, and final, step in functionalization was to produce an allocation matrix that mapped the level 2 activities to the three cost categories. The ISO mapped direct costs as (1) all in one category or not in the category (100% or 0%), (2) split between two categories (50% / 50%), or (3) partially in one category or another (80% or 20%), or in the case of CRRs, a small portion of the activity (10%). The ISO mapped support costs as "indirect," for later allocation to the cost categories. The ISO also applied the mapping to the software underlying the debt service portion of the revenue requirement. Ms. Le Vine will testify regarding this mapping process. The allocation matrix is included as Tables 2 and 3 in Exhibit No. ISO-2.

V. COST-OF-SERVICE STUDY - COST ALLOCATION.

Q. PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

A. As I noted earlier, cost allocation is the process by which the costs of providing services are allocated to the service categories (functions and sub-functions). In this case, we applied the level 2 allocation matrix to the ISO's 2010 revenue requirement to determine the costs associated with each of the three categories of activities: Market Services, System Operations, and CRR Services. We applied this process separately to operations and maintenance, or "O&M" costs, to debt service and out of pocket capital expenses, and to the operating reserve credit and miscellaneous revenue. We then aggregated the direct costs in each cost category and determined the percentage attributable to each. We used those direct cost percentages to allocate indirect costs and added the results to the totals for each cost category.

Q. HOW DID THE ISO MAP THE O&M COSTS?

A. We first reviewed the 2010 O&M budget to segregate non-ABC costs, that is, those costs that could not be associated with level 2 activities, such as facilities costs. The next step was to associate activity-related costs with specific level 2 activities. Because each of the ISO's 80 cost centers had been coding their time to level 1 activities during 2010, the ISO was able to identify each cost center that had recorded time to direct level 1 activities. We recorded all of the activity costs for cost centers with no direct activities as indirect (support) costs. We sent a questionnaire to the managers of each such cost center that had direct costs asking them to identify the percentage of time devoted to each of the level 2 activities and met with each of them to review their responses for reasonableness. We then applied the reported percentages to the cost center's 2010 budget to determine that cost center's costs associated with each level 2 activity. By aggregating the costs reported by the cost centers for each level 2 activity, we were able to calculate an ISO-wide cost for that activity.

We next used the level two allocation matrix to allocate the costs of the level 2 activity to the Market Services, System Operations, CRR Services, or Indirect (support) cost categories. Finally, by aggregating the amounts allocated to each cost category, the ISO determined the total O&M to be included in each of those categories.

We then turned to the non-ABC costs. With one exception, we allocated those costs to the indirect (support) category. We allocated professional fees for the audit of controls around the settlement of the market (the SAS 70 audit) 45% to Market Services, 45% to Systems Operations, and 10% to CRRs. These were the same percentages used for the allocation of the level 2 activities for market settlements.

Finally, we summed the O&M cost for each category. Market Services represented $11.924 million, System Operations $46.373 million, CRRs $1.6 million, and Indirect $102.798 million. These calculations appear in Table 12 of Exhibit No. ISO-2.

Q. HOW DID THE ISO ALLOCATE DEBT SERVICE AND OUT-OF-POCKET EXPENSES TO COST CATEGORIES?

A. As I mentioned above, we had prepared a cost allocation matrix for each of the debt service and out-of-pocket capital items in the budget. We applied that matrix to the budgeted amounts and summed the results for each cost category. Market Services represented $21.3 million or 27%, System Operations $46.373 million or 48%, CRRs $1.6 million or 4%, and Indirect $102.798 million or 21%. These calculations appear in Table 9 of Exhibit No. ISO-2.

Q. HOW DID THE ISO ALLOCATE MISCELLANEOUS REVENUE AND OPERATING RESERVE CREDIT TO COSTS CATEGORIES?

A. We review the components of miscellaneous revenue and determined that the entire $8.1 million should be classified as indirect. We also reviewed the components of the operating reserve credit. With one exception, we allocated them to the indirect category. We allocated the change in debt service reserve based on the percentages we had calculated for debt service. As a result, we allocated the operating reserve credit $3.295 million to Market Services, $5.856 million to System Operations, $0.488 million to CRRs and $25.861 million to indirect costs. This information is in Table 11 of Exhibit No. ISO-2.

Q. WHAT WAS THE TOTAL ALLOCATION TO COST CATEGORIES?

A. The percentages of direct costs were 27% Market Services, 69% System Operations, and 4% CRRs. After we allocated a total of $84.544 million of indirect costs according to these percentages, the total revenue requirement for Market Services was $52.756 million; the total revenue requirement for System Operations was $134.883 million; and the total revenue requirement for CRRs was $7.456 million. The breakdown of these amounts appears in Table 12 of Exhibit No. ISO-2.

Q. HAVE YOU CALCULATED ESTIMATED RATES BASED ON THESE DATA?

A. Yes. During the development of the GMC, we used volume data from June 1, 2009, to May 31, 2010, and equalized the 2010 revenue requirement to the actuals expenditures for that period. With that data, the rate for Market Services would have been $0.0914/MWh (energy) or MW (award); the System Operations rate would have been $0.2700/MWh; and the CRR Services rate would have been $0.0113/MWh.

VI. TRANSMISSION OWNERSHIP RIGHTS

Q. YOU MENTIONED SPECIAL RATE TREATMENT FOR TRANSMISSION OWNERSHIP RIGHTS. PLEASE EXPLAIN THAT.

A. Transmission Ownership Rights refers to the ownership rights to facilities within the ISO Balancing Area of entities that have not executed the Transmission Control Agreement, such that their facilities are not a part of the ISO Controlled Grid. The ISO has in the past recognized that it provides only limited services to the possessors of Transmission Ownership Rights, and thus has historically not charged such entities the full GMC.

Q. HOW DID THE ISO DETERMINE THE RATE FOR TRANSMISSION OWNERSHIP RIGHTS?

A. As Ms. Le Vine discusses in her testimony, as part of the cost-of-service study, the ISO determined that the only services provided to Transmission Ownership Rights are a limited number of ABC level 2 activities. These activities are all related to System Operations because there is no Transmission Ownership Rights participation in the Market Services category. The ISO calculated the direct costs of those activities and the percentage of System Operations direct costs that those activities represent. The ISO then allocated indirect costs to those activities based on the percentage of direct costs. The total direct and indirect costs for activities that served Transmission Ownership Rights was $45.197 million. Next, the ISO determined the ratio of Transmission Ownership Rights MWh to total MWh, which was 2%. Applying the 2% to the total direct and indirect costs, the ISO determined that $0.9 million in costs were attributable to Transmission Ownership Rights. The ISO evaluated different methodologies to adjust the Transmission Ownership Rights rate in order to recover this amount. We determined that using the minimum of supply or demand would reduce the number of billable Transmission Ownership Rights MWh to 3.3 million MWh and that then using a rate of $0.27/MWh would collect revenue of $0.9 million.

VII. BILL IMPACT ANALYSIS

Q. YOU STATED THAT BILL IMPACT ANALYSIS WAS THE LAST PHASE OF DEVELOPING A REVISED GMC RATE DESIGN. WHAT BILL IMPACT ANALYSIS DID THE ISO PERFORM?

A. As I discussed in connection with the stakeholder process, the ISO performed a bill impact analysis on its initial straw proposal, both for individual scheduling coordinators and on an aggregate basis by customer type, which led to proposed modifications, for which the ISO also performed bill impact analyses. Subsequently, the ISO abandoned one of the proposed modifications – phasing in of System Operations charges to suppliers – in favor of grandfathering of certain suppliers, which is included in the final proposal and discussed in Dr. Kristov's testimony.

Q. WHAT IS THE AGGREGATED BILL IMPACT OF THE FINAL PROPOSAL?

A. The 2012 GMC rate design would have the biggest impact on holders of CRRs. Their share of the overall GMC would be $4.43 million, up from $0.33 million. The share paid by Investor-Owned Utilities would increase from $121.55 million to $128.39 million and that paid by suppliers would increase from $17.20 million to $19.44 million. The share paid by municipal utilities would decrease to $17.59 million from $19.93 million and that paid by importers and marketers would decrease from $30.98 million to $20.93 million. Other market participants, a catch-all category, would pay $4.33 million, versus $5.11 million under the current rate design. The ISO believes these results are the result of more closely aligning the GMC rate with cost causation.

IX. REVENUE CAP AND SUNSET

Q. WHY DID THE ISO INCLUDE A RATE CAP AND SUNSET DATE?

A. Because the GMC is a formula rate, the ISO does not believe that a revenue requirement cap or sunset date is a necessary element of the rate. Nonetheless, as part of the settlement of the 2004 GMC, the ISO agreed to a revenue requirement cap. Under that settlement, the parties agreed that, until 2007, the ISO could avoid a filing under section 205 if the revenue requirement did not exceed $195 million in 2004 and 2005 and $197 million in 2006. As I discussed above, this aspect of the agreement was extended on an annual basis and is in place today. Because the rate cap remains important to a number of stakeholders, the ISO decided to include a rate cap in its current proposal.

It is, of course, difficult to forecast the ISO's revenue requirements more than three years out and to persuade stakeholders to accept such forecasts. Rather than attempt to specify future revenue requirements, the ISO decided to limit the current GMC to three years, after which the ISO can revisit the revenue requirement and rate structure if it desires. The ISO recognizes that a sunset date is not necessary to achieve this end and that stakeholders that believe that the formula is no longer reasonable can always file a complaint. Nonetheless, the ISO believes that a sunset date provides greater comfort to those stakeholders that have concerns about potential ISO spending.

Q. WHAT REVENUE CAP DOES THE ISO PROPOSE?

A. The ISO is proposing to maintain the current revenue cap of $197 million for 2012. For 2013 and 2014, the ISO is proposing a cap of $199 million.

Q WHAT IS THE BASIS FOR THIS PROPOSED CAP?

A. The cap was determined through the stakeholder process. There was general support and no opposition to the proposal. The ISO's revenue requirement was approximately $190 million for 2010. Future revenue requirements will be affected by load growth and inflation. If one assumes a volume growth of 1% and an operations and maintenance cost increase of 1.6%, the out-of-pocket capital of $19.5 million, the ISO's revenue requirement will be $193 million in 2012, $194 million in 2013, and $196 million in 2015. If operations and maintenance costs instead increase by a still modest 3.1%, the revenue requirement for those years would be $193 million, $195 million, and $197 million, respectively. A revenue cap, to serve its purpose, should be sufficiently above those amounts to allow for contingencies, but not by so much to encourage profligate spending. The caps exceed the projected revenue requirement by between 1% and 2%, which the ISO believes is consistent with these purposes.

Q. THANK YOU, MR. EPSTEIN. I HAVE NOTHING FURTHER.

DECLARATION OF WITNESS

I, Michael E. Epstein, declare under penalty of perjury that the statements contained in the Direct Testimony of Michael K. Epstein on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 5th day of July, 2011.

/s/ Michael K. Epstein
Michael K. Epstein

Exhibit No. ISO-2 –

2012 GMC Cost of Service Study Discussion Paper with Exhibits, October 8, 2010

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California ISO

California ISO

2012 GMC Cost of Service Study
Discussion Paper with Exhibits

October 8, 2010

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Introduction

The California Independent System Operator Corporation (the ISO) proposes to substantially revise the design of its grid management charge (GMC) beginning on January 1, 2012. The GMC is the vehicle through which the ISO recovers all of its annual administrative, operating and capital costs from the entities that utilize the ISO's services. The redesign of the GMC involves two main design activities, which will be the subjects of this initiative. The first design activity is to assign all of the ISO's annual costs to major cost categories or GMC buckets that reflect distinct aspects of the ISO's services or core functions. Fundamental to this first design activity is the ISO's completion of a cost of service study to determine how the activities of each ISO cost center or business unit should be distributed to cost categories. The ISO's efforts to date on this first design activity, including the methodology and results of the cost of service study, comprise the primary subject of this initial discussion paper and will be the main focus of the upcoming October 14, 2010 stakeholder meeting.

The second design activity is to specify how to allocate the dollar amounts in each of the cost categories to users of the ISO's services in an objective and transparent manner; i.e., to specify what are generally referred to as the billing determinants by which each user will be allocated an appropriate share of the costs. This second design activity will be the subject of a subsequent discussion paper and stakeholder meeting, although the present paper initiates the discussion and requests stakeholder input on this topic.

At the conclusion of this initiative in 2011, ISO management will present the proposed GMC redesign to its Board of Governors for approval and then file the appropriate tariff changes at the Federal Energy Regulatory Commission (FERC) on a schedule, which is discussed later in this paper, which will allow the new GMC to take effect on January 1, 2012.

The decision to redesign the GMC is based on five primary drivers: 1) corporate reorganization; 2) changes in debt structure due to the ISO's construction of a new office building; 3) imminent repayment of the bonds issued to fund the ISO's comprehensive market design that began operation on April 1, 2009; 4) implementation of the new market rules and procedures under the new market structure that began in 2009; and 5) requests by stakeholders for greater GMC clarity, predictability and simplicity.

The GMC, as the vehicle through which the ISO recovers its costs, is a formula rate whereby the ISO's revenue requirement is allocated based on a matrix of percentages reflecting the activities of all the ISO cost centers to a set of GMC components, and then ultimately to GMC charge codes. These GMC charge codes are then recovered from the users of ISO services in accordance with objective billing determinants, which are calculated for each such user in each billing period and reflect each user's activities and use of ISO services.

The ISO's revenue requirement is reflected in the annual budget developed with stakeholder input according to a process set forth in the tariff and approved by the ISO Board. The tariff contains a revenue requirement "cap" under which the ISO may continue to recover the GMC without seeking FERC approval for changes to particular charges due to the formula rate implementation. As noted above, the changes being considered in the present initiative will require ISO Board approval and FERC approval of tariff changes.

The current GMC formula rate structure and revenue requirement cap, containing seven GMC components (buckets) and fifteen separate charge codes, is based largely on a settlement agreement with stakeholders approved by the FERC on September 22, 2005 for the period January 1, 2004 through December 31, 2006. Except for certain modifications needed to reflect the new market design and other market enhancements, the ISO and its stakeholders have agreed to successive extensions of the GMC until a cost of service study could be undertaken. Under the current cost of service study, the ISO proposes to substantially revise the GMC rate design based on seven guiding principles while preserving the fundamental design strategy of using a formula rate structure and a revenue requirement cap mechanism. This discussion paper describes the ISO's approach to the cost of service study, the results of the study and the ISO's rationale for proposing to change the GMC structure and cost allocations.

Guiding Principles for Redesign

The ISO proposes to use the following guiding principles in developing the framework for a new GMC structure. The ISO requests stakeholder comments on these principles and any suggestions they may have for other principles to consider.

1) **Cost Causation** – Costs will be properly allocated to the correct GMC buckets and charged to those who benefit from or utilize those services.
2) **Focus on use of ISO services, not market behavior** – The new GMC design should reflect its primary purpose as a vehicle for recovering the ISO's revenue requirements based on each user's use of the ISO's services, not as a tool for shaping incentives based on market or operating behavior. Incentives such as these are appropriately addressed through the design of the market structure and market rules.
3) **Transparency** – Costs and billing determinants will be clear, visible, and understandable to all market participants.
4) **Predictability** – Market participants will be able to determine in advance what their GMC costs will be depending on their activity.
5) **Forecastability** – The rates should utilize billing determinants that can be easily forecasted by both the ISO and market participants. This should result in fewer rate adjustments during the year.
6) **Flexibility** – The new GMC structure should easily accommodate future market enhancements without excessive complexity or disrupting the overall structure.
7) **Simplicity** – Simplify the current GMC structure to reduce the amount of varying bill determinants and the number of charge codes.

GMC Background

2001-2003 Rate Structure

The ISO originally proposed the first charge to recover its cost of operations in a filing made on October 17, 1997 in Docket No. ER 98-211-000. The original GMC was a bundled formula rate. Following a settlement with stakeholders that extended the bundled rate through 2000 and gave rise to a stakeholder process to unbundle the GMC, the ISO proposed an unbundled GMC on November 1, 2000 that had three service charges: 1) the Control Area Services Charge; 2) Congestion Management (the Inter-Zonal Scheduling Charge); and 3) Ancillary Services (AS) and Real-time Energy Operations (the Market Operations Charge). Each charge was recovered through a volumetric (MWh) rate designed to recover the costs through related customer usage.

The 2001 GMC was the subject of much litigation, and was not finally resolved until refunds were completed in March 2010. Although the three service charges were approved in an initial FERC decision issued on May 10, 2002, the ISO was directed to consider further unbundling and to re-evaluate the GMC rate design with its stakeholders. Pursuant to a negotiated settlement submitted in October 2002, in which the rate design was altered slightly, the ISO was allowed to avoid a new Section 205 rate filing if its rates for 2003 were kept under certain set ceilings for the three service categories. The 2002 GMC settlement also set forth certain procedures and milestones that were to be followed during the rate design evaluation process.

2004 Rate Structure Redesign

The 2002 GMC settlement gave rise to what became known as the 2004 rate structure project that involved a comprehensive stakeholder process and a re-examination of all parts of the rate design. During this process, the ISO and its consultants reviewed all aspects of ISO operations, conducted a cost of service analysis, and considered proposals and suggestions from other parties. Although the ISO started with the three GMC service categories approved in the 2001 GMC decision, the analysis included a re-assessment of ISO activities as assigned to the service categories (functions), a review of the billing determinants used to classify customer usage patterns, and revisions to the ISO's cost allocation matrix.

The 2004 GMC proposal was submitted on October 31, 2003 in ER 04-115-000 and introduced the GMC rate components that generally remain in place today. Specifically, the ISO proposed to unbundle the Control Area Services charge into two sub-functions; Core Reliability Services (CRS) and Energy Transmission Services (ETS), and to unbundle the Market Operations / Inter-Zonal Scheduling Charges into three service categories; Forward Scheduling, Market Usage, and Congestion Management. The ISO also proposed to establish the Settlements, Metering, and Client Relations (SMCR) Charge, and further proposed that ETS be divided into ETS-Net Energy and ETS-Uninstructed Deviations. The GMC would continue to be a formula rate, using specific factors to allocate the ISO's expenses and capital spending to the service categories.

FERC accepted and suspended the revised GMC proposal and directed the parties to reach a settlement or the matter would be set for hearing. The ISO and its stakeholders were able to reach a partial settlement offer that was submitted to FERC in July 2004 and approved on September 22, 2005. The settlement introduced certain modifications to the ISO's proposed rate design, including capping the percentage of costs allocated to the CRS and Forward Scheduling Charges, dividing the CRS charge billing determinants into demand and energy (the latter for loads associated with Energy Exports), and reducing the applicability of Forward Scheduling Charges to Inter-SC Trades (ISTs). In addition, there were several GMC rate changes that were specific to individual market participants.

The settlement offer also outlined the current budget development process, reduced the 2004 revenue requirement, and provided revenue requirement caps for 2005 and 2006 below which the ISO would not be required to seek approval of its GMC rates. If the ISO's revenue requirement exceeded the caps during those years, the ISO would be required to seek approval of an adjustment to the charges to achieve the revenue requirement but not to modify the rate design. The parties agreed that no changes to the GMC rate design would be sought for rates in effect prior to January 1, 2007 except to the extent necessary to implement a nodal system of congestion management employing locational marginal pricing (the ISO's new market design).

GMC Changes Reflecting the New Market Implementation

Due to delays in implementation of the new market, the ISO and its stakeholders agreed to extend the GMC rate design, the formula rate structure, and revenue requirement cap for 2007, 2008 and into 2009 until the effective date of the new market. Concurrently with extending the GMC on these three occasions, the ISO worked with its stakeholders to develop the rate design modifications that would be necessary to reflect service category changes brought about by the new market structure. The ISO proposed to retain the basic rate structure and make only those changes to the design needed to implement the new market, as well as updating the cost allocation matrix to reflect organizational changes and a cost allocation study conducted during 2007. Despite the need to make these modifications, the formula rate structure design and revenue requirement cap were retained in the proposed new grid management charge.

The ISO's proposed changes to the GMC rate design were submitted to FERC in February 2008 and consisted of: 1) the elimination of the Congestion Management Charge; 2) modifications to the CRS and ETS Charges to reflect flows on Transmission Ownership Rights (TORs); 3) changes in the billing determinants for Forward Scheduling and Market Usage Charges (including the introduction of the Market Usage-Forward Energy Charge (MUFE)); and 4) an increase in the SMCR Charge from $500 to $1,000. The proposal was approved by FERC on December 18, 2008 and went into effect on April 1, 2009.

Modifications to the MUFE Charge

Following the implementation of the new GMC, the ISO held a stakeholder process beginning in mid-2009 to address stakeholder concerns about the application of the MUFE charge to the inter-scheduling coordinator energy trades (ISTs) in the day-ahead market. This process culminated with a proposal to modify the billing determinants for the MUFE charge to: 1) eliminate ISTs from the MUFE charge code calculation; 2) eliminate "netting" forward energy from the calculation; and 3) implement a “greater of” mitigation solution in the MUFE calculation. The ISO proposed that the “greater of” mitigation solution would remain in place on an interim basis until the ISO conducts a new cost of service study and considers, with its stakeholders, necessary changes to the GMC rate design that would be implemented in 2012.

The MUFE charge proposal, along with a proposal to extend the rest of the GMC until December 31, 2010, was approved by the Board at the October 2009 meeting and filed with FERC on October 30, 2009. On December 30, 2009, FERC approved the extension of the GMC but suspended the effective date of the MUFE charge proposal (subject to refund) until June 1, 2010 and scheduled a settlement conference.

Subsequent to the settlement conference, the ISO and participating parties came to an agreement that MUFE charge modifications, as proposed by the ISO, could be placed into effect on June 1, 2010 and remain in effect on an interim basis through December 31, 2011. The parties filed a settlement offer with FERC on March 23, 2010 that was approved on August 4, 2010. The MUFE charge proposal became effective on June 1, 2010.

Proposed Charge for Convergence Bidding

On June 25, 2010, the ISO submitted tariff changes to implement convergence bidding, including two new GMC categories applicable to convergence bidding participants. Specifically, the ISO proposed to implement a “virtual award“ charge that will be assessed on dollars of cleared gross megawatt hours and a “virtual bid submission” transaction charge assessed on all bid segments that pass the ISO’s bid validation rules and are passed on to the integrated forward market software. The ISO has requested that all of the convergence bidding tariff changes, including the new convergence bidding GMC categories, become effective on February 1, 2011.

Extending the Current GMC

As discussed above, all of the GMC categories, except for the MUFE charge and the convergence bidding charge, will expire as of December 31, 2010. Accordingly, the ISO Board has approved a management proposal to maintain the revenue requirement cap at $197 million (which includes ISO costs related to convergence bidding) and to extend the current GMC formula rate through calendar year 2011 until January 1, 2012. This proposal will be submitted to FERC no later than November 1, 2010.

Commitment to Conduct a Cost of Service Study

The GMC rate design modifications proposed to implement the new market were, of necessity, developed without the actual market data reflecting customer usage and activities in the new market. Similarly, the 2007 cost study and modifications to the ISO cost allocation matrix were based on historic organizational changes and other cost changes that were anticipated once the new market became operational. For these reasons, among others that will be discussed in this paper, the ISO committed to its stakeholders that a complete cost of service study would be conducted once enough market information was available for evaluation. The ISO anticipated that this study could be completed in time to develop and propose GMC rate design changes that would become effective on January 1, 2012. According to this time schedule and commitment to its stakeholders, the ISO has completed the first step of its 2012 GMC cost of service study.

Cost of Service Studies and Ratemaking Principles

As discussed above, the ISO committed to perform a cost of service study as part of the March 2010 offer of settlement addressing the MUFE billing determinant issues. This study will provide the information needed to address possible GMC rate design changes to be implemented in 2012. The purpose of this paper is to describe the methodology used by the ISO to conduct the cost of service study, and to present initial preliminary results. In contrast to the cost of service study conducted in 2007 that was intended to update cost allocations and billing determinants without requiring substantial changes to the GMC rate design, for the 2012 GMC Project the ISO proposes to start at ground level and re-evaluate all aspects of the GMC structure.[1] Thus, before turning to the ISO's preliminary findings and proposals, a brief overview of cost of service study and rate design principles would be helpful to ensure that all stakeholders have the same expectations.

A traditional utility cost of service analysis is designed to determine the services provided by the utility (the ISO), to determine the costs incurred in providing these services, and to develop rates and charges to bill the customers using such services. The steps included in conducting a cost of service study are:

1) Functionalization -	The process by which various activities are defined and sorted into service categories (functions and sub-functions) to reflect the different services provided by the ISO.
2) Cost Allocation -	The process by which the costs of providing services are allocated to the service categories (functions and sub-functions).
3) Classification -	The determination of billing determinants based on the customer cost causation factors.
4) Rate Design -	The process for deriving rates that divides the revenue requirement for each service category by the billing determinants.
5) Bill Impacts Analysis -	An evaluation of the impacts that the rate design will have on individual customer bills.

The ISO has completed the functionalization and cost allocation steps in accordance with these fundamental ratemaking principles and the overall rate design objectives outlined in this paper. The cost allocation step has been greatly simplified and expedited by the ISO's Activity Based Costing (ABC) methodology; whereas the 2004 and 2007 cost allocation approach was to interview the managers, directors and Vice Presidents of the existing cost center to elicit the information needed to allocate their budgeted costs to the existing (or proposed) GMC buckets.

The ISO seeks stakeholder input on these results as well as proposals for the next step - identifying the appropriate billing determinants for the proposed service categories. With this

[1] This does not include the revenue requirement cap and current budget development process which the ISO proposes to retain in its tariff and will be addressed with stakeholders at later points in the 2012 GMC cost of service study process.

information, the ISO will develop rates and address bill impacts with stakeholders, according to the schedule set forth in the final section below.

Issue Overview

The 2012 GMC cost of service study will need to address several factors. These include lessons learned from the launch of the new market, reviewing our current rate structure, utilizing activity based costing, and benchmarking against other ISO's.

The New Market

The new market was launched on April 1, 2009 and is significantly different than the previous market construct. The major changes included an integrated forward market, nodal pricing, as well as future enhancements including convergence bidding. The structure of the new market has significant differences from the prior structure and the ISO believes there is an opportunity to use the cost of service study to more closely align the functionality of the new market with cost causation. Additionally, the ISO desires a system where future enhancements integrate into the rate structure without the need to create new GMC service categories and/ or charge codes.

GMC Service Categories

The ISO currently has 7 GMC service categories which contain 17 charge codes (when convergence bidding goes live which is anticipated to be February 1, 2011). ISO management has observed that every market enhancement seems to require the addition of a new service category and recovery methodology. Management has concluded that absent a fundamental design change, the implementation of additional market enhancements will increase the number of GMC service categories and charge codes, further contributing to the complexity of the rate structure.

Recent Issues with GMC Structure

1) Implementation of Convergence Bidding – The addition of convergence bidding to the new market design could not be accommodated under the current GMC structure. A new service category containing two new charge codes had to be created.

2) MUFE – The original structure of MUFE included IST's and netted supply and demand. This was the subject of a stakeholder process which the majority of the group agreed that netting was not appropriate and that ISTs should not be included. The revised structure used the greater of supply or demand and did not include ISTs. The ISO agreed to revisit the structure of this charge code in the cost of service study.

3) Significant changes in rates – A steady decline in the number of export MWh's continues to drive the export GMC rate higher, therefore having the unintended consequence of further reducing export volumes.

4) Current design attempts to manage behavior – The current GMC design charges scheduling coordinators for imbalances. These quantities are very difficult to forecast and are unnecessary as the new market already has uplift costs to deter deviations.

5) CRR recovery – Currently there is no cost recovery mechanism for direct costs associated with managing CRRs.

6) SMCR under recovery – The SMCR rate only collects a small fraction of the indirect costs associated with these functional areas. The remaining costs are allocated to the other service categories in recognition of the fact that increasing the rate to collect all of the costs would create a significant barrier to entry to the ISO markets. The SMCR rate needs to be aligned with its intended purpose, the effort required to manage the number of SCIDs that must be supported by ISO systems , not to recover a minimal percentage of allocated indirect costs.

Activity Based Costing

Over the past 2 years, the ISO has undergone an effort to implement ABC. This effort was staged into two parts. The first was to use ABC level 1 activities consisting of ten processes which align to corporate goals. This was then expanded to include 122 level 2 activities which align to the level 1 activities. The ISO believes that the use of ABC in the cost of service study will produce superior cost causation alignment than with the existing structure.

Best Practices

The ISO conducted conference calls with other ISO's/ RTO's to gain a better understanding of how there administrative charges are structured, budgeted, and collected. This information is summarized in the section below and illuminates the fact that the ISO's current GMC structure is much more complex than other grid operators.

Activity Based Costing Overview

ABC is a costing model that identifies activities in an organization and assigns the cost of each activity to all products and services according to the actual consumption by each. While the ISO did not begin using ABC until 2008, the underlying information needed to make the costing model successful began in 2006 with a company-wide process mapping effort which developed into a hierarchy of business processes.

In 2007 an effort to map the new market processes inspired reshaping the business process framework into five core areas:

- Initiative Lifecycle
- Infrastructure Development & Maintenance
- Bid-to-Bill
- External Relations & Interface
- Employee Services & Support

In 2008, the ISO's decision to implement ABC aligned well with the need to comply with increasingly complex tariff requirements. Research on ABC implementations revealed that many companies struggle to implement and support their ABC systems. Quite often companies start off by defining thousands of activities for time tracking, resulting in confusion for employees and a burdensome system to maintain. Of the multiple options considered, it was determined that the initial rollout should follow a simple approach with one primary objective; to track time spent working on projects versus processes. The data management collected in the fourth quarter of 2009 would provide the basis for estimating resource availability for strategic initiatives in 2010. Research into governance, risk, and compliance initiatives revealed that companies contending with complex or rigid regulatory requirements, e.g. pharmaceutical, aviation, transportation, food safety and sanitation and electric utilities, often employ process-centric approaches to translate complex, abstract and legal requirements into implementable procedures.

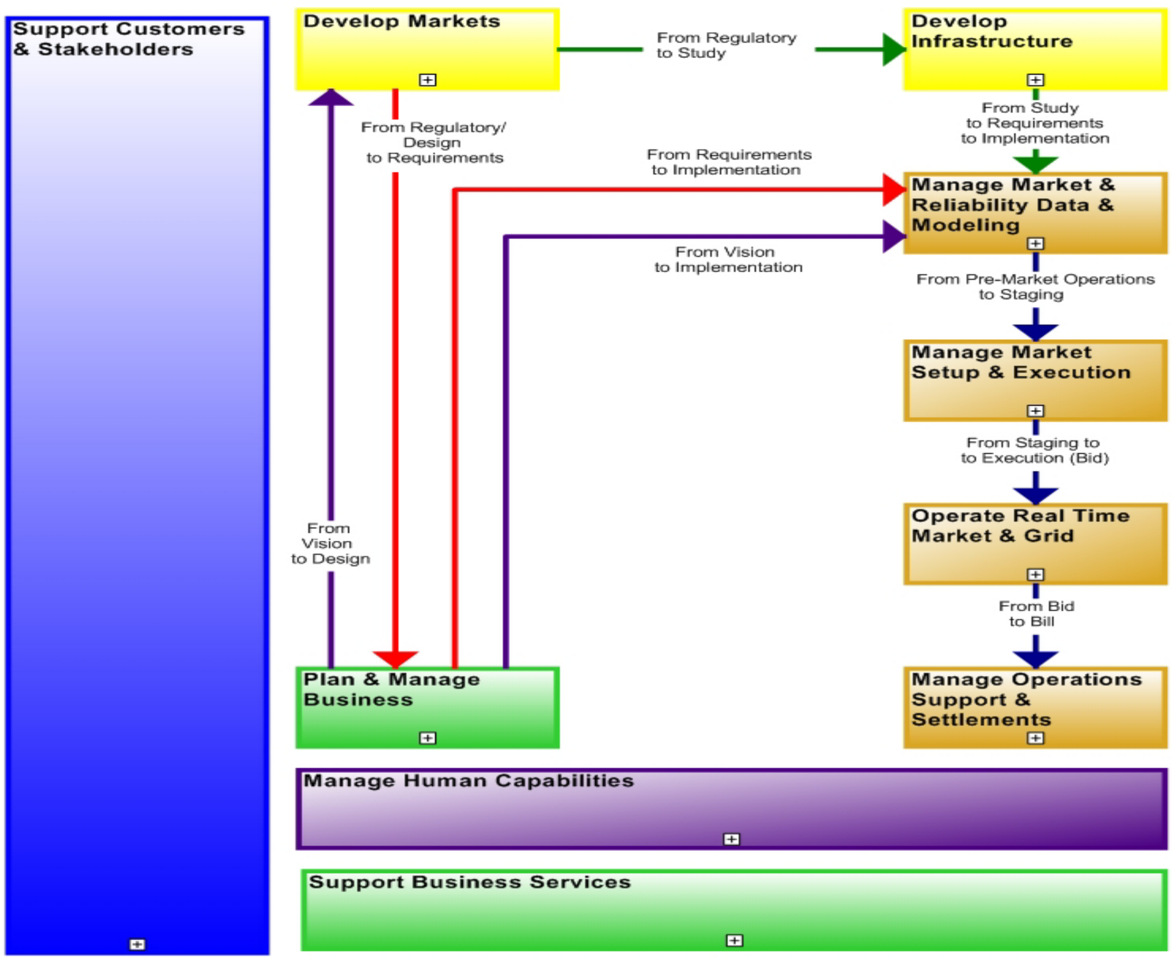
Of the multiple options considered, it was determined that the most sensible approach would include formalizing the ISO's business process framework. Best practices frequently show process frameworks visually organized into multiple levels which promote common understanding of processes for audiences at different levels. For example:

Process Level	Perspective	Description
1 - Strategic	Executive	High level business activities, objectives, goals and metrics
2 – Tactical	Process owner/ business unit	Core process activities and tactical performance metrics
3 – Operational	Desk/ role based	Task oriented, procedural activities

As divisions, departments and business units define metrics and goals, they focus on measures and controls that are defined vertically by their chain-of-command. As a result, business requirements are not integrated in a way that allows information technology (IT) to be optimized across process boundaries in a cost effective manner, leading to acquisition and support of disparate technologies and platforms. Ultimately, hierarchical structures often discourage collaboration, hinder agility, and have high systems maintenance costs.

Best practices also showed that when end-to-end process groupings are formed, they often reflect how the organization conducts its business. This perspective aligned well with both the ABC and compliance objectives. It was determined that all core business functions would be represented as individual processes that could be identified within a level 1 end-to-end process grouping (no outliers).

Further research into process classification frameworks led to the American Product Quality Center (APQC) best practice framework definition for the electric utility industry and helped shape the ten high level activities/ processes that the ISO is currently using.



The ISO process framework serves as a common business architecture blueprint that is reusable across multiple initiatives like ABC, enterprise risk management, compliance and controls, strategic planning, and performance management. Additionally, supporting process areas can align their services with the ISO's core business activities (e.g. IT support processes can align systems monitoring activities across process areas without being hindered by organizational boundaries).

For ABC purposes the consistent process framework primarily enables:

- Gathering and providing data for resource allocation decision making by demonstrating how resources are allocated to the ISO's end-to-end business processes
- Tracking actual time spent on processes and projects that allows managers the ability to compare results to what was expected/planned
- Data compilation for stimulating continuous business process improvement efforts related to efficiency and best use of resources
- The alignment of strategies with executable processes which ensures that metrics support corporate objectives and goals

Due to the complexities of running the day-to-day business, costing by business process is better suited to management for decision making than traditional cost accounting. Traditional cost/ financial accounting is constrained by external reporting needs and generally accepted accounting principles (GAAP) rules. While these constraints provide value for financial statements and reporting purposes, they limit management's ability to use the information for internal decision making, whereas the purpose of costing by business process is to provide useful information for operating the business and identifying opportunities for improvement.

Application of ABC to GMC Structure

The ABC analysis has disaggregated the CAISO into ten core processes (level 1 activities). Each of the core activities were broken down into major processes (level 2 activities) which were mapped to the level 1 activities. A significant initiative is underway to complete the definition of the level 2 processes by the end of 2010. Time reporting on level 1 activities commenced October 2009 and pilot programs have started on level 2 activities with the goal of full level 2 reporting on January 1, 2011. This process is continually being reviewed and developed, and changes in definitions and levels will occur as the ISO continues to improve the documentation and definitions. The level 2 processes discussed in this study are the processes mapped and defined as of May 2010. The level 1 activities can be categorized into two types: (1) direct operating costs – those that can be directly mapped to a market, grid service or customer and (2) indirect costs – those that support the direct activity.

Table 1- Level 1 ABC Activities

Level 1 ABC Activity	Direct or support cost	Number of Level 2 ABC activities
Develop Infrastructure	Direct operating cost	8
Develop Markets	Direct operating cost	8
Manage Market & Reliability Data & Modeling	Direct operating cost	16
Manage Market Setup & Execution	Direct operating cost	6
Manage Real Time Market & Grid	Direct operating cost	8
Manage Operations Support & Settlements	Direct operating cost	14
Support Customers & Stakeholders	Support or indirect cost	5
Plan & Manage Business	Support or indirect costs	12
Support Business Services	Support or indirect costs	30
Manage Human Capabilities	Support or indirect costs	15

This ABC functionality is superior to the earlier descriptions of ISO activities for developing cost categories. These activities are defined, linked to specific processes, and measurable. A complete list of level 2 activities is attached as **Exhibit 1.**

Several options to aggregate activities were considered. The first option was to map activities to the existing GMC service categories. However, as discussed above, the existing structure was considered too complex given a goal of more transparency, predictability and simplicity. Level 2 activities would need to be further broken down or mapping was not possible. For example the ISO does not have any activity related specifically to deviations.

Thus, the ISO considered the second option, which was to map activities to customer categories. A list of 31 customer categories was prepared. The categories included utility distribution companies, merchant generation, proxy demand response, self-scheduled exports, and many more. These categories were then mapped to the level 2 activities. As seen in **Exhibit 2**, it soon became apparent that in a majority of cases the level 2 activity applied to all categories.

This raised the question that if customer activity was the common theme then what were the common activities across all customers? An examination of the ISO's new nodal market systems process map of customer activity revealed the following:

Customers submit bids	>>	Market systems award schedules	>>	Energy flows

In addition, there are processes related to Congestion Revenue Rights (CRRs).

Based on this process map, the following three cost categories were developed:

1. Market Services
2. System Operations
3. CRR Services

This structure is very similar to what other ISO/ RTOs with nodal markets have implemented to recover their administrative charges.

Using these three categories, the level 2 activities were mapped as either: 1) all in one category or not in the category (100% or 0%), 2) a split between two categories (50% / 50%), or 3) partially in one category or another (80% or 20%), or in the case of CRRs, a small portion of the activity (10%). This mapping was also applied to the software underlying the debt service portion of the revenue requirement. Indirect costs are allocated proportional to direct costs. **See Exhibit 3.**

Table 2 - Mapping Level 2 Activities to Categories

Mapping of ABC level 2 Direct Operating Activities to cost categories					
ABC Level 2 Activities	Market services	System Operations	CRRs	Indirect	Comments
	% of cost to allocate to category				

Mapping of ABC level 2 Direct Operating Activities to cost categories					
ABC Level 2 Activities	**Market services**	**System Operations**	**CRRs**	**Indirect**	**Comments**
	% of cost to allocate to category				
Definitions used in allocation	100%				the costs are entirely to support the market results & function resulting in a fi9nancially binding schedule or AS award
		100%			the costs are entirely to support system operations
			100%		the costs are entirely to support the CRR process
				100%	not distinguishable attribute to any specific category
	50%	50%			the costs support equally both market and system operations
	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
	80%	20%			the costs are predominantly market related but have some operational relationship
	20%	80%			the costs are predominantly operational flow based but have some market relationship
Develop Infrastructure (DI) (80001)					
Develop & monitor regulatory contract procedures		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage LGIP cluster studies		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage long-term transmission planning		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage new transmission resources & grid changes		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage SGIP studies		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage short-term transmission planning		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage transmission maintenance standards		100%			managing the building of the grid thus the costs are entirely to support system operations
NERC / WECC loads & resources data requests		100%			managing the building of the grid thus the costs are entirely to support system operations
Regulatory contract negotiations		100%			managing the building of the grid thus the costs are entirely to support system operations
Develop Markets (DM) (80002)					
BPM change management process				100%	not distinguishable attribute to any specific category
Develop State / Federal regulatory policy				100%	not distinguishable attribute to any specific category
Manage regulatory filings				100%	not distinguishable attribute to any specific category
Manage tariff amendments				100%	not distinguishable attribute to any specific category
Market design & regulatory policy	100%				the costs are entirely to support the market results & function
Manage market analysis & development	100%				the costs are entirely to support the market results & function
Perform market analysis	100%				the costs are entirely to support the market results & function
Manage Market & Reliability Data & Modeling (MMR) (80004)					
ISO meter certification		100%			measuring flows on the grid thus the costs are entirely to support system operations
Facilitate SC certification				100%	not distinguishable attribute to any specific category
High level manage FNM maintenance	50%	50%			the costs support equally both market and system operations
Manage & facilitate procedure maintenance	20%	80%			significantly more operational procedures, thus the costs are predominantly operational flow based but have some market relationship
Manage CRRs			100%		the costs are entirely to support the CRR process
Manage credit & collateral	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage network applications		100%			involves EMS thus the costs are entirely to support system operations

Mapping of ABC level 2 Direct Operating Activities to cost categories					
ABC Level 2 Activities	**Market services**	**System Operations**	**CRRs**	**Indirect**	**Comments**
	% of cost to allocate to category				
Manage operations engineering studies		100%			studying flows on the grid thus the costs are entirely to support system operations
Execute & track operations training	20%	80%			significantly more operational procedures, thus the costs are predominantly operational flow based but have some market relationship
Plan & develop operations training	20%	80%			significantly more operational procedures, thus the costs are predominantly operational flow based but have some market relationship
Manage reliability requirements		100%			relates to actual system operations thus the costs are entirely to support system operations
Master file updates	50%	50%			resource attributes that support both thus the costs support equally both market and system operations
EMAA telemetry (RIGs)		100%			relates to actual system operations thus the costs are entirely to support system operations
Provide stakeholder training				100%	not distinguishable attribute to any specific category
Station power application procedure	80%	20%			based on procedures for station power
Market services implementation	50%	50%			resource attributes that support both thus the costs support equally both market and system operations
Manage Market Setup & Execution (MMS) (80005)					
Manage D+2 analysis	50%	50%			the costs support equally both market and system operations
Manage DA market	50%	50%			while managing market it results in system starting point for operational flows thus the costs support equally both market and system operations
Manage DA & RT runs & price validations	50%	50%			the costs support equally both market and system operations
Manage generation outages		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage interchange scheduling		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage transmission outages		100%			relates to actual system operations thus the costs are entirely to support system operations
Operate Real Time Market & Grid (OMG) (80006)					
Manage critical facility systems				100%	not distinguishable attribute to any specific category
Manage emergency operations		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage operations engineering support	20%	80%			based on support of day-ahead and real time thus the costs are predominantly operational flow based but have some market relationship
Manage RT market - after close of market	50%	50%			the costs support equally both market and system operations
Manage RT market - prior to close of market bidding	50%	50%			the costs support equally both market and system operations
Manage RT operations - generation dispatch		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage RT operations - transmission dispatch		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage RT interchange scheduling		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage Operations Support & Settlements (MOS) (80007)					
Manage rules of conduct				100%	not distinguishable attribute to any specific category
Manage regulation no pay & deviation penalty calculations		100%			measuring actual performance thus the costs are entirely to support system operations
Manage dispute analysis & resolution				100%	not distinguishable attribute to any specific category
Manage energy measurement acquisition & analysis		100%			measuring actual performance thus the costs are entirely to support system operations
Manage market billing &	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs

Mapping of ABC level 2 Direct Operating Activities to cost categories					
ABC Level 2 Activities	Market services	System Operations	CRRs	Indirect	Comments
	% of cost to allocate to category				
settlements					
Manage market clearing	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage market performance	50%	50%			the costs support equally both market and system operations
Manage price validation & corrections	50%	50%			related to proper outage allocation thus the costs support equally both market and system operations
Manage the market quality system (MQS)	50%	50%			portion of MQS relates to operational flows thus the costs support equally both market and system operations
Manage data requests				100%	not distinguishable attribute to any specific category
WREGIS application process		100%			measuring actual performance thus the costs are entirely to support system operations
ISO meter engineering		100%			measuring actual performance thus the costs are entirely to support system operations
ISO RIG engineering		100%			measuring actual performance thus the costs are entirely to support system operations
Market issues steering committee	50%	50%			portion related to operational practices & procedures thus the costs support equally both market and system operations

Table 3 – Mapping Software Underlying Debt Service to Categories

Allocation of Debt Service and Out of Pocket Capital to GMC cost categories					
System	Market services	System operations	CRRs	Indirect	Comments
	% of cost to allocate to category				
Definitions used in allocation	100%				the costs are entirely to support the market results & function resulting in a fi9nancially binding schedule or AS award
		100%			the costs are entirely to support system operations
			100%		the costs are entirely to support the CRR process
				100%	not distinguishable attribute to any specific category
	50%	50%			the costs support equally both market and system operations
	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
	80%	20%			the costs are predominantly market related but have some operational relationship
	20%	80%			the costs are predominantly operational flow based but have some market relationship
Operations Related Software					
Automated Dispatch System (ADS)		100%			RT instructions from market to system operations thus the costs are entirely to support system operations
Automated Load Forecast System (ALFS)	50%	50%			market & operations both need forecasts thus the costs support equally both market and system operations
Automatic Mitigation Procedure (AMP)		100%			the costs are entirely to support system operations
Congestion Revenue Rights (CRR)			100%		the costs are entirely to support the CRR process
Credit Liabilities	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Data Warehouse	20%	80%			5 min intervals in RT only hourly intervals in market thus the costs are predominantly operational flow based but have some market relationship
Energy Management System (EMS)		100%			the costs are entirely to support system operations
Existing Transmission Contracts Calculator (ETCC)	50%	50%			needed for market & system operations thus the costs support equally both market and system operations

Allocation of Debt Service and Out of Pocket Capital to GMC cost categories					
System	**Market services**	**System operations**	**CRRs**	**Indirect**	**Comments**
	% of cost to allocate to category				
Full Network Model / State estimator	50%	50%			needed for market & system operations thus the costs support equally both market and system operations
Grid operations Training Simulator (GOTS)	20%	80%			staff training where substantially more procedures in operations versus market thus the costs are predominantly operational flow based but have some market relationship
Integrated Forward Market (IFM)	50%	50%			results support both financially binding schedules and system operations thus the costs support equally both market and system operations
Market Quality System (MQS)	50%	50%			aligns with direct operating process thus the costs support equally both market and system operations
Master file	50%	50%			aligns with direct operating process thus the costs support equally both market and system operations
Meter Data Acquisition System (MDAS)		100%			data feed reflecting settling actual flow of systems operations performance thus the costs are entirely to support system operations
Multistage Generation (MSG)	50%	50%			the costs support equally both market and system operations
Network Applications	50%	50%			the costs support equally both market and system operations
New Resource Interconnection (RIMs)	20%	80%			based on staff training for market services & system operations thus the costs are predominantly operational flow based but have some market relationship
Open Access Same Time Information System (OASIS)	50%	50%			the costs support equally both market and system operations
Operational Meter Analysis & Reporting (OMAR)		100%			same as MDAS thus the costs are entirely to support system operations
Proxy Demand response (PDR)	50%	50%			the costs support equally both market and system operations
Participating Intermittent Resource Project (PIRP)	20%	80%			based on staff training for market services & system operations thus the costs are predominantly operational flow based but have some market relationship
Portal	50%	50%			the costs support equally both market and system operations
CAISO Market Results interface (CMRI)	50%	50%			the costs support equally both market and system operations
Process Information System (PI)		100%			the costs are entirely to support system operations
Real Time markets (RTMA)	20%	80%			support & provide actual dispatches to balance system thus the costs are predominantly operational flow based but have some market relationship
Hour Ahead Market (HASP)	50%	50%			includes market power mitigation thus the costs support equally both market and system operations
Resource Adequacy	50%	50%			the costs support equally both market and system operations
Operations Related Software (continued)					
RMR application Validation Engine (RAVE)	50%	50%			the costs support equally both market and system operations
Scheduling & Logging for ISO CA (SLIC)	50%	50%			the costs support equally both market and system operations
Control Area Scheduler (CAS)	50%	50%			the costs support equally both market and system operations
Scheduling Infrastructure Business Rules (SIBR)	50%	50%			this contains interface to operations thus the costs support equally both market and system operations
Settlements & Market Clearing (SaMC)	15%	75%	10%		based on DA & RT charge codes which settle 12 intervals operations hour for operations versus hourly for market thus after a minimum allocation to CRRs the costs are predominantly operational flow based but have some market relationship
General Software					
Client relations & engineering analysis tools				100%	not distinguishable attribute to any specific category

Allocation of Debt Service and Out of Pocket Capital to GMC cost categories					
System	**Market services**	**System operations**	**CRRs**	**Indirect**	**Comments**
	% of cost to allocate to category				
DMM & compliance Tools (SAS MARS)	50%	50%			the costs support equally both market and system operations
Local Area Network (LAN), WAN & monitoring (Tivoli)				100%	not distinguishable attribute to any specific category
Office automation desktop laptop (OA)				100%	not distinguishable attribute to any specific category
Oracle Corporate Financials				100%	not distinguishable attribute to any specific category
Security External Physical & ISS (CUDA)				100%	not distinguishable attribute to any specific category
Storage (EMC symmetrix)				100%	not distinguishable attribute to any specific category
Fixed Assets					
Land & feasibility studies				100%	not distinguishable attribute to any specific category
NT servers & WEB servers				100%	not distinguishable attribute to any specific category
New system equipment				100%	not distinguishable attribute to any specific category
Office equipment, physical facilities software, furniture & leasehold improvements				100%	not distinguishable attribute to any specific category

After this mapping is completed it can be applied to the ISOs revenue requirement to derive the related cost of service.

Costing the 2010 Revenue Requirement

The allocation matrix of level 2 activities and software was applied to the ISO's 2010 revenue requirement to determine the costs associated with the three categories:

1. Market services
2. System operations and
3. CRR services

Using the 2010 revenue requirement has several advantages. It is recent; 2009 and 2010 are very similar, and it can be used to compare with existing GMC, which is available for the same period. The 2010 revenue requirement is made up of the following categories:

Table 4 - Mapping of 2010 Revenue Requirement Categories

Revenue Requirement	2010 Budget ($ in thousands)

O&M	$ 162,695
Debt Service and out of pocket capital	76,000
Other income	(8,100)
Operating reserve	(35,500)
Total Revenue Requirement	**$ 195,095**

Completing the analysis required the following steps:

1. Mapping the O&M costs into three components: level 2 activities, support costs, and non-ABC support costs
   a. Allocating cost centers to level 1 ABC activities
   b. Applying cost category percentages to level 1 support costs
   c. Obtaining time estimates for level 2 activities for those level 1 activities that are direct operating costs
   d. Allocating costs to level 2 activities
   e. Applying cost category percentages
2. Breaking out non-ABC support costs and applying cost category percentages to these costs
3. Mapping debt service and out of pocket capital expenses to cost categories and applying cost category percentages to these costs
4. Mapping revenue credit and miscellaneous revenue to cost categories and applying cost category percentages to these costs
5. Aggregating costs and allocate indirect costs to cost categories based on percentage of direct costs

Step 1: Allocation of Operating and Maintenance (O&M) Costs

There are two types of O&M costs; those that are activity related such as costs attributed to personnel, and non-ABC costs - such as facilities costs. The O&M budget was broken down into those two categories.

For activity related O&M costs, the recent ABC structure was utilized to allocate costs between the cost categories. The ISO's activities have been broken out into ten level 1 ABC activities. These Level 1 activities have been further broken out into Level 2 activities. The Level 1 activities were determined to be either direct or support activities. For those Level 1 activities that were attributed to direct costs, the associated level 2 activities were mapped to one of the three cost categories as described in the previous section. Support activities were allocated to indirect costs category.

The O&M budget is comprised of approximately 80 cost centers. ISO staff has been coding their time to ABC level 1 activities during 2010 and in some instances to level 2 activities. A questionnaire was prepared for those cost centers that showed time in one of the Level 1 activities that could be directly allocated.

The cost center managers reviewed the questionnaire and allocated their time to Level 2 activities. These percentages were applied to the 2010 O&M budget which resulted in the costs of each cost center being allocated into the appropriate level 2 activities. The costs of all cost centers were aggregated for each level 2 activity.

The percentages of the Level 2 activity by cost category for market services, system operations, CRR services and indirect were applied to the costs. Non-ABC costs were analyzed separately to determine the appropriate category. The breakdown and allocation of cost center costs to direct or support activities and non-ABC costs is shown in **Exhibit 4.**

Table 5 – Cost Allocation to Direct and Support Activity and Non-ABC Costs

Activity and Non-ABC Costs

Mapping costs to direct and support activities & Other costs	2010 Budget ($ in thousands)		
Organization Name	**Total**	**Activities**	**Other**
Chief Executive Officer	$ 6,514	$ 6,514	$ -
VP of Human Resources	6,104	6,104	-
VP of Market & Infrastructure Development	14,093	14,093	-
VP of Technology, Corporate Services & CFO	65,412	36,592	28,820

VP of Operations	48,994	48,994	-
VP, General Counsel & Corporate Secretary	12,671	8,471	4,200
VP of Policy & Client Services	8,907	8,907	-
Total	**$ 162,695**	**$ 129,675**	**$ 33,020**

Allocating Direct Operating Activities

Mapping costs to direct and support activities & Other costs	Percentage of time related to direct operating activities					
	Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)
Organization Name	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**
Chief Executive Officer	2%	2%	0%	0%	0%	0%
VP of Human Resources	0%	0%	0%	0%	0%	0%
VP of Market & Infrastructure Development	64%	36%	0%	0%	0%	0%
VP of Technology, Corporate Services & CFO	0%	0%	3%	0%	0%	1%
VP of Operations	2%	3%	21%	18%	38%	16%
VP, General Counsel & Corporate Secretary	1%	7%	0%	0%	0%	0%
VP of Policy & Client Services	1%	0%	0%	0%	0%	0%
Total	**8%**	**6%**	**9%**	**7%**	**14%**	**6%**

Mapping costs to direct and support activities & Other costs	Allocation of direct operating costs ($ in thousands)						
	Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Direct operating activities
Organization Name	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**Total**
Chief Executive Officer	$ 159	$ 159	$ -	$ -	$ -	$ -	$ 318
VP of Human Resources	-	-	-	-	-	-	-
VP of Market & Infrastructure Development	8,959	5,036	49	-	49	-	14,093
VP of Technology, Corporate Services & CFO	124	-	947	-	-	234	1,305
VP of Operations	1,050	1,507	10,431	8,762	18,642	7,943	48,335
VP, General Counsel & Corporate Secretary	88	561	-	-	-	-	649
VP of Policy & Client Services	125	-	-	-	-	-	125
Total	**$ 10,505**	**$ 7,263**	**$ 11,427**	**$ 8,762**	**$ 18,691**	**$ 8,177**	**$ 64,825**

Allocating Support Activities

Mapping support activities	Percentage of time to support activities			
	Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)
Organization Name	**80010**	**80003**	**80008**	**80009**
Chief Executive Officer	0%	0%	55%	40%
VP of Human Resources	0%	100%	0%	0%
VP of Market & Infrastructure Development	0%	0%	0%	0%
VP of Technology, Corporate Services & CFO	0%	0%	20%	76%
VP of Operations	0%	0%	0%	1%
VP, General Counsel & Corporate Secretary	0%	0%	12%	80%
VP of Policy & Client Services	88%	0%	11%	0%
Total	**6%**	**5%**	**10%**	**29%**

Mapping support activities	Allocation of support costs $ in thousands				
	Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support activities
Organization Name	**80010**	**80003**	**80008**	**80009**	**Total**
Chief Executive Officer	$ -	$ -	$ 3,565	$ 2,631	$ 6,196
VP of Human Resources	-	6,104	-	-	6,104
VP of Market & Infrastructure Development	-	-	-	-	-
VP of Technology, Corporate Services & CFO	131	77	7,405	27,674	35,287
VP of Operations	40	-	-	619	659
VP, General Counsel & Corporate Secretary	-	-	1,018	6,804	7,822
VP of Policy & Client Services	7,813	-	969	-	8,782
Total	**$ 7,984**	**$ 6,181**	**$ 12,957**	**$ 37,728**	**$ 64,850**

ABC Direct Operating Activities

For direct operating activities the costs were aggregated at the level 2 basis and allocated to the cost category identified earlier.

Table 6 - Mapping ABC Direct Operating Activities to Cost Categories

ABC Direct Operating Activities									
ABC Level 2 Activities	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Develop Infrastructure (DI) (80001)									
Various level 2 activities		100%			$10,324	$ -	$ 10,324	$ -	$ -
Develop Markets (DM) (80002)									
BPM change management process				100%	790	-	-	-	790
Develop State / Federal regulatory policy				100%	1,121	-	-	-	1,121
Manage regulatory filings				100%	806	-	-	-	806
Manage tariff amendments				100%	661	-	-	-	661
Market design & regulatory policy	100%				2,563	2,563	-	-	-
Manage market analysis & development	100%				1,307	1,307	-	-	-
Perform market analysis	100%				173	173	-	-	-
Total					**7,421**	**4,043**	**-**	**-**	**3,378**
Manage Market & Reliability Data & Modeling (MMR) (80004)									
ISO meter certification		100%			240	-	240	-	-
Facilitate SC certification				100%	-	-	-	-	-
High level manage FNM maintenance	50%	50%			1,131	565	566	-	-
Manage & facilitate procedure maintenance	20%	80%			591	118	473	-	-
Manage CRRs			100%		1,299	-		1,299	-
Manage credit & collateral	45%	45%	10%		645	290	290	65	-
Manage network applications		100%			1,249	-	1,249	-	-
Manage operations engineering studies		100%			1,047	-	1,047	-	-
Execute & track operations training	20%	80%			915	183	732	-	-
Plan & develop operations training	20%	80%			1,523	305	1,218	-	-
Manage reliability requirements		100%			786	-	786	-	-
Master file updates	50%	50%			306	153	153	-	-
EMAA telemetry		100%			190	-	190	-	-
Provide stakeholder training				100%	231	-	-	-	231
Station power implementation	80%	20%			316	253	63	-	-
Market services implementation	50%	50%			1,118	559	559	-	-
Total					**11,587**	**2,426**	**7,566**	**1,364**	**231**

ABC Direct Operating Activities									
ABC Level 2 Activities	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Manage Market Setup & Execution (MMS) (80005)									
Manage D+2 analysis	50%	50%			714	357	357	-	-
Manage DA market	50%	50%			994	497	497	-	-
Manage DA & RT runs & price validations	50%	50%			3,093	1,546	1,547	-	-
Manage generation outages		100%			1,028	-	1,028	-	-
Manage interchange scheduling		100%			1,051	-	1,051	-	-
Manage transmission outages		100%			1,727	-	1,727	-	-
Total					**8,607**	**2,400**	**6,207**	**-**	**-**
Operate Real Time Market & Grid (OMG) (80006)									
Manage critical facility systems				100%	555	-	-	-	555
Manage emergency operations		100%			327	-	327	-	-
Manage operations engineering support	20%	80%			808	162	646	-	-
Manage RT market - after close of market	50%	50%			253	126	127	-	-
Manage RT market - prior to close of market bidding	50%	50%			252	126	126	-	-
Manage RT operations - generation dispatch		100%			6,005	-	6,005	-	-
Manage RT operations - transmission dispatch		100%			5,264	-	5,264	-	-
Manage RT interchange scheduling		100%			5,247	-	5,247	-	-
Total					**18,711**	**414**	**17,742**	**-**	**555**
Manage Operations Support & Settlements (MOS) (80007)									
Manage rules of conduct				100%	109	-	-	-	109
Manage regulation no pay & deviation penalty calculations		100%			438	-	438	-	-
Manage dispute analysis & resolution				100%	1,364	-	-	-	1,364
Manage energy measurement acquisition & analysis		100%			794	-	794	-	-
Manage market billing & settlements	45%	45%	10%		1,028	462	463	103	-
Manage market clearing	45%	45%	10%		325	146	146	33	-
Manage market performance	50%	50%			834	417	417	-	-
Manage price validation & corrections	50%	50%			1,079	539	540	-	-
Manage the market quality system (MQS)	50%	50%			906	453	453	-	-
Manage data requests				100%	291	-	-	-	291

ABC Direct Operating Activities									
ABC Level 2 Activities	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
WREGIS application process		100%			41	-	41	-	-
ISO meter engineering		100%			206	-	206	-	-
ISO RIG engineering		100%			412	-	412	-	-
Market issues steering committee	50%	50%			348	174	174	-	-
Total					**8,175**	**2,191**	**4,084**	**136**	**1,764**
Total					**$ 64,825**	**$ 11,474**	**$ 45,923**	**$1,500**	**$ 5,928**
Direct O&M %					**100%**	**19%**	**78%**	**3%**	

ABC Support Activities

For non direct activities the costs were aggregated at the level 1 basis and allocated to the indirect cost category

Table 7 - Mapping ABC Support Activities to Cost Categories

Allocation of ABC Support Activities									
ABC Level 1 Activities	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Support Customers & Stakeholders (SCS) (80010)				100%	$ 7,984	$ -	$ -	$ -	$ 7,984
Manage Human Capabilities (MHC) (80003)				100%	6,181	-	-		6,181
Plan & Manage Business (PMB) (80008)				100%	12,957	-	-		12,957
Support Business Services (SBS) (80009)				100%	37,728	-	-	-	37,728
Total					**$64,850**	**$ -**	**$ -**	**$ -**	**$64,850**

<u>Step 2: Breaking Out Non-ABC Support Costs</u>

The significant non specific department costs were removed from the ABC analysis and reviewed separately. Except for the SAS 70 audit and operations review the costs were allocated to the indirect cost category. These budgeted audit costs were allocated using the same percentages as the level 2 manage market billings and settlements.

Table 8 - Mapping Non-ABC Costs to Cost Categories

Allocation of Non-ABC support costs									
Non-ABC support costs	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Corporate Services									
occupancy				100%	$ 6,759	$ -	$ -	$ -	$ 6,759
hardware and software maintenance				100%	10,900	-	-	-	10,900
communications (AT&T)				100%	6,050	-	-		6,050
insurance				100%	2,205	-	-		2,205
software & equipment leases				100%	1,906	-	-		1,906
professional fees - SAS 70 audit	45%	45%	10%		1,000	450	450	100	-
Subtotal					28,820	450	450	100	27,820
General Counsel									
professional fees - legal				100%	4,200				4,200
Subtotal					4,200	-	-		4,200
Total					**$ 33,020**	**$ 450**	**$ 450**	**$ 100**	**$ 32,020**

Step 3 - Allocating Debt Service and Out-of-Pocket Capital to Cost Categories

Debt service is the aggregation of principle, interest, and a debt service reserve on the 2008 bonds of $61 million and 2009 out of pocket capital of $15 million. The debt service is the capital spent on projects over the last four years because the 2008 bonds rolled up the 2004, 2006, and 2007 bonds. The assets funded were broken down into operations related software, general software, and fixed assets. Based on the percentage allocation discussed in the previous section, the cost allocation of costs is as follows:

Table 9 - Mapping Debt Service and Out-of-Pocket Capital to Cost Categories

Debt Service and Out of Pocket Capital									
System	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Operations Related Software									
Automated Dispatch System		100%			$ 74	$ -	$ 74	$ -	$ -
Automated Load Forecast System	50%	50%			1,446	723	723	-	-
Automatic Mitigation Procedure		100%			308	-	308	-	-
CAISO Market Results interface	50%	50%			1,016	508	508	-	-
Congestion Revenue Rights			100%		2,114	-	-	2,114	-
Control Area Scheduler	50%	50%			116	58	58	-	-
Credit Liabilities	45%	45%	10%		70	32	32	6	-
Data Warehouse	20%	80%			1,500	300	1,200	-	-
Energy Management System		100%			3,279	-	3,279	-	-
Existing Transmission Contracts Calculator	50%	50%			13	6	7	-	-
Full Network Model / State estimator	50%	50%			451	225	226	-	-
Grid operations Training Simulator	20%	80%			262	52	210	-	-
Hour Ahead Market HASP	50%	50%			3,173	1,586	1,587	-	-
Integrated Forward Market IFM	50%	50%			15,432	7,716	7,716	-	-
Market Quality System	50%	50%			2,506	1,253	1,253	-	-
Master file	50%	50%			1,012	506	506	-	-
Meter Data Acquisition System		100%			38	-	38	-	-
Multistage Generation MSG	50%	50%			214	107	107	-	-
Network Applications	50%	50%			1,668	834	834	-	-
New Resource Interconnection	20%	80%			542	108	434	-	-
Open Access Same Time Information System OASIS	50%	50%			163	81	82	-	-
Operational Meter Analysis & Reporting OMAR		100%			239	-	239	-	-
Participating Intermittent Resource Project PIRP	20%	80%			3,511	702	2,809	-	-
Portal	50%	50%			2,520	1,260	1,260	-	-
Process Information System		100%			338	-	338	-	-
Proxy Demand response	50%	50%			212	106	106	-	-
Real Time markets RTMA	20%	80%			3,173	635	2,538	-	-
Resource Adequacy	50%	50%			107	53	54	-	-
RMR application Validation Engine	50%	50%			12	6	6	-	-
Scheduling & Logging for ISO	50%	50%			729	364	365	-	-
Scheduling Infrastructure Business Rules SIBR	50%	50%			4,453	2,226	2,227	-	-
Settlements & Market Clearing	15%	75%	10%		8,422	1,263	6,317	842	-

Debt Service and Out of Pocket Capital									
System	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Total Operations related software	35%	60%	5%	0%	59,113	20,710	35,441	2,962	-
General Software									
Client relations & engineering analysis tools				100%	761	-	-	-	761
DMM & compliance Tools	50%	50%			1,180	590	590	-	-
Local Area Network, WAN & monitoring (Tivoli)				100%	1,598	-	-	-	1,598
Office automation desktop laptop				100%	209	-	-	-	209
Oracle Corporate Financials				100%	1,713	-	-	-	1,713
Security External Physical & ISS				100%	406	-	-	-	406
Storage (EMC symmetrix)				100%	4,297	-	-	-	4,297
Total general related software	6%	6%	0%	88%	10,164	590	590	-	8,984
Fixed Assets									
Land & feasibility studies				100%	700	-	-	-	700
NT servers & WEB servers				100%	573	-	-	-	573
New system equipment				100%	4,411	-	-	-	4,411
Office equipment, physical facilities software, furniture & leasehold improvements				100%	1,039	-	-	-	1,039
Total fixed assets	**0%**	**0%**	**0%**	**100%**	**6,723**	**-**	**-**	**-**	**6,723**
Total debt service	**27%**	**48%**	**4%**	**21%**	**76,000**	**21,300**	**36,031**	**2,962**	**15,707**
Direct software %	**35%**	**60%**	**5%**		**$60,293**	**$21,300**	**$36,031**	**$2,962**	**$ -**

Step 4 – Allocating Miscellaneous Revenue and Operating Reserve

Miscellaneous Revenue

The components of other revenue were reviewed and all revenues were included in the indirect cost category.

Table 10 - Mapping Miscellaneous Revenue to Cost Categories

Allocation of Miscellaneous Revenue									
Type	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
SC application fee				100%	$ 50	$ -	$ -	$ -	$ 50

Allocation of Miscellaneous Revenue									
Type	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
MSS penalties				100%	100	-	-	-	100
Wind forecasting fee				100%	250	-	-	-	250
Station power				100%	50	-	-	-	50
SC training fees				100%	50	-	-	-	50
LGIP study fees				100%	1,800	-	-	-	1,800
Interest				100%	3,800	-	-	-	3,800
COI path operator fees				100%	2,000	-	-	-	2,000
Total					**$ 8,100**	**$ -**	**$ -**	**$ -**	**$ 8,100**

Operating Reserve Credit

The components of the Operating reserve credit were reviewed. The change in the debt service was allocated based on the percentages derived from the debt service and out of pocket capital allocation. All other costs were allocated to indirect costs.

Table 11 – Mapping Reserve Credit to Cost Categories

Allocation of Operating reserve credit									
Type	Market Services	System Operations	CRRs	Indirect	2010 Budget	Market Services	System Operations	CRRs	Indirect
	% of costs allocated to activity				Cost of category $ in thousands				
Increase (decrease) in 15% reserve for O&M				100%	$ (900)	$ -	$ -	$ -	$ (900)
25% debt service reserve	27%	48%	4%	21%	12,200	3,295	5,856	488	2,561
Collection of additional months GMC				100%	15,400	-	-	-	15,400
Reduction of interest on Generator fines				100%	8,800	-	-	-	8,800
Total					**$ 35,500**	**$ 3,295**	**$ 5,856**	**$ 488**	**$ 25,861**

Step 5 - Aggregating Revenue Requirement into Cost Categories

The individual revenue requirements were aggregated and indirect costs allocated based on the total of direct costs.

Table 12 – Mapping Revenue Requirement to Cost Categories

ABC Direct Operating Activities					
Revenue Requirement ($ in thousands)	**2010 Budget**	**Market Services**	**System Operations**	**CRRs**	**Indirect**
Direct O&M $	$ 64,825	$ 11,474	$ 45,923	$ 1,500	$ 5,928
Support O&M $	64,850	-	-	-	64,850
Non-ABC support O&M $	33,020	450	450	100	32,020
Total O&M	**162,695**	**11,924**	**46,373**	**1,600**	**102,798**
O&M Direct %		**20%**	**77%**	**3%**	
Debt Service	76,000	21,300	36,031	2,962	15,707
Debt service Direct %		35%	60%	5%	
Other income	(8,100)	-	-	-	(8,100)
Operating reserve	(35,500)	(3,295)	(5,856)	(488)	(25,861)
Total before allocation of indirect	**195,095**	**29,929**	**76,548**	**4,074**	**84,544**
Direct Costs %		27%	69%	4%	
Allocate indirect	-	22,827	58,335	3,382	(84,544)
Total Revenue Requirement $	**$ 195,095**	**$ 52,756**	**$ 134,883**	**$ 7,456**	
Total Revenue Requirement %	**100%**	**27%**	**69%**	**4%**	

Mapping the revenue requirement to cost categories is shown in **Exhibit 5.** This completes the first part of the cost of service study. The cost categories have been identified and the revenue requirement for 2010 allocated into those cost categories. The next step will be to determine how those costs will be recovered from ISO customers. These issues will be discussed at the next stakeholder meeting.

Comparison of ISOs and RTOs

Set forth below is a summary comparison of ISO/RTOs throughout the country. There are two groups; those that do not have a nodal market, and those that have a nodal market similar to the nodal market implemented by the ISO in 2009.

ISO/RTOs without a Nodal Market

Southwest Power Pool (SPP)

- Tariff administration service: 100% of Revenue Requirement charged to capacity or load (MWh of capacity reserved or load)

SPP Rates
$0.195 per MWh of load and capacity

ERCOT

- Administrative fee: 100% of Revenue Requirement charged to withdrawals (MWh of exports and load)
- Also has charges for:
  - Nodal implementation surcharge (MWh of gen)
  - Application fees
  - Wide area network installation and monthly fee
  - Mismatched schedule fee

ERCOT Rates
$0.4171 – withdrawals
$0.375 – nodal implementation surcharge

<u>ISO/RTOs with a Nodal Market</u>

New York ISO

- Injections: 20% of Revenue Requirement charged to injections (MWh of imports, internal gen, and wheels)
- Withdrawals: 80% of Revenue Requirement charged to withdrawals (MWh of exports, internal load, and wheels)
- Transmission Congestion Contracts
- Also have charges for:
  - Virtual bids at $.065 per MWh of
  - Station power and reliability payments use actual costs
- Indirect costs allocated by percentage of direct costs

NYISO Rates
$0.1784 – injections
$0.7136 – withdrawals
$0.02 – transmission contracts
$0.065 – virtual bids
$0.7136 – actual costs

PJM

- Control area administrative service: 60% of Revenue Requirement charged to withdrawals (MWh of load)
- Market support service: 32% of Revenue Requirement charged to injections and withdrawals (MWh of load and gen) and a per bid segment charge
- FTR service: 5% of Revenue Requirement charged to FTR's (MWh of FTR's)
- Also have charges for:
  - Regulation & frequency response administration: 1% of Revenue Requirement charged to regulation and frequency (MWh of hourly regulation
  - Capacity resource & obligation management: 2% of Revenue Requirement charged to capacity (MWh of unforced capacity obligation charged to LSE's)
  - Actual costs for cost of second control center
- Indirect costs allocated by percentage of direct costs

PJM Rates
$0.1809 – withdrawals
$0.0016 – hours of FTR bid
$0.0024 – MWh of FTR
$0.0525 – per bid segment
$0.0338 – MWh of injections and withdrawals
$0.2026 – MWh of hourly regulation
$0.0803 – MWh of unforced capacity obligation

Midwest ISO (MISO)

- Energy & operating reserve market support administration service cost recovery adder: 50% of Revenue Requirement charged to injections, withdrawals and virtual (MWh of gen, load, and virtual)
- ISO cost recovery adder: 45% of Revenue Requirement charged to load (50% to MWh of load, 50% based on peak capacity for month)
- FTR administration service cost recovery adder: 5% of Revenue Requirement charged to FTR's (MW of FTR capacity)
- Indirect costs allocated by percentage of direct costs

MISO Rates
$0.0585 – MWh of load
$0.0465 – Peak capacity for month
$0.0145 – MWh of FTR capacity
$0.0816 – MWh of injections and withdrawals

ISO New England (ISO-NE)

- Energy administration service: 40% of Revenue Requirement charged to load, gen, and FTR's (15% based on energy, incremental and decremental changes, and FTR bids, 85% based on monthly load and gen obligation)
- Reliability administration service: 35% of Revenue Requirement charged to withdrawals (MWh of peak load and exports)
- Scheduling service: 25% of Revenue Requirement charged to load (MWh and reserved capacity of the highest hourly amount during the month)
- Indirect costs allocated by percentage of direct costs

ISO-NE Rates
$0.19 – MWh of load
$0.065 – energy, inc, dec, and FTR bids
$0.1813-$0.1483 – monthly load and gen obligation
$0.242 – non-coincident peak load
$0.37 – MWh of exports

Comparison - California ISO
Core reliability service: 23.1% of Revenue Requirement charged to load and exports (18% based on peak load MWh in month, 0.5% to off peak load MWh in month, 4.5% to exports MWh)

- Energy transmission services:
    - 36% of Revenue Requirement charged to load (MWh of load)

- 6% of Revenue Requirement charged to Uninstructed Imbalance Energy (MWh of UIE)

- Core reliability service / energy transmission services: 0.5% of Revenue Requirement charged to Transmission Ownership Rights (MWh of load for TOR's)
- Forward scheduling: 7% of Revenue Requirement charged to schedules (# of schedules submitted)
- Markey usage17.5% of Revenue Requirement charged to market usage (MWh of AS, IE, or UIE)
- Market usage forward energy: 8.1% of Revenue Requirement charged to forward energy (max MWh of supply or demand in forward market)
- Convergence bidding: 9% of forward scheduling and market usage forward energy charged to convergence bidding ($.005 per bid segment and MWh of convergence bidding)
- Energy transmission service / market usage: 0.5% of Revenue Requirement charged to PIRP deviations (MWh of UIE for PIRP resources)
- Also have charges for:
  - $1000 per scheduling coordinator per month charge
  - Data requests
  - Station power
  - PIRP forecasting fee
  - Customized training
  - Operating fee on a specific transmission line
- Indirect costs allocated by various methods to service categories

California ISO Rates

$94.70– MWh of peak load in month
$62.51 – MWh of off peak load in month
$1.83 – MWh of exports
$0.35 – MWh of load and exports
$1.98 – MWh of uninstructed imbalance energy
$0.23 – MWh of TOR load
$2.53 – per schedule
$0.23 – market usage per MWh of AS, IE, or UIE
$0.06 – max of supply of demand in forward market
$0.005 – per bid segment of convergence bidding
$0.0629 – MWh of convergence bidding
$1.3889 – MWh of PIRP UIE in month
$1000 – per SCID fee

As shown above, the ISO has the most complex structure with the most charges of any ISO/RTOs with a nodal market. The other ISO/RTOs organize their rate structures around a few large groupings such as:

- Market or energy services and injections – all ISO/RTOs
- System operations - Control area or reliability service, cost adder or withdrawals - all ISO/RTOs

- FTRs or transmission congestion – PJM, MISO & NYISO
- Scheduling - ISO-NE
- Other
  - Virtual bids – NYISO
  - Regulation & capacity – PJM

These cost categories are similar to those proposed by the ISO:

- Market services,
- System operations and
- Congestion (CRR) services.

Scheduling in the ISO market is a function where bids are submitted to the integrated forward market. The software processes the bids and awards resulting in schedules. Virtual bidding in the ISO market will be an added functionality. These three categories are also the three categories that arose from the ABC analysis discussed earlier.

Evaluation of Potential Billing Determinants

The next step in completing the GMC redesign is to establish the billing determinants for the three cost categories: Market Services, System Operations and CRR Services. This step is only introduced here and will be scheduled for in-depth discussion later in this initiative. In developing the billing determinants, the ISO seeks to incorporate the guiding principles discussed at the beginning of this paper. There are two elements of a billing determinant: (1) the metric, such as MWh, and (2) the establishment of the denominator, i.e., the specification of the transactions to be included. An ISO straw proposal for billing determinants and the billing impacts will be reviewed with stakeholders in November 2010.

Based upon benchmarking of the billing determinants used by the other ISOs and RTOs, there are potential approaches to developing billing determinants.

- Allocation to Demand: Establishing a metric and calculating the denominator by summing the energy withdrawals by load and exports.
- Allocation to Supply and Demand: Establishing a metric and calculating the denominator by summing the injections by generation and imports and the withdrawals by load and exports.
- Transaction Fees to Offset Total Cost: Transaction fees, such as bid segment fees, are set at an appropriate level to allow a market participant to make an economic decision whether to incur the added expense. The transaction fee creates a marginal cost that serves two purposes: (1) limits excessive usage by market participants, and (2) recovers costs of transactions that participate but do not result in a successful outcome (e.g., energy bids that do not clear the market). The costs recovered by transaction fees are used to offset the revenue requirement of the associated cost category. For example, a bid segment fee would offset the revenue requirement of the Market Services Cost Category.
- Administrative Fees: Administrative fees are used to establish an appropriate cost to allow a market participant to make an economic decision whether to incur the added expense. For example, a SCID monthly fee can be used to manage the number of active/inactive SCIDs maintained in the system. The costs recovered in this manner are typically used to offset the revenue requirements of the other cost categories.

The ISO seeks input from stakeholders on potential billing determinant design in written comments to this paper.

Next Steps

The stakeholder process for the 2012 GMC Cost of Service Study will continue with the following timeline:

- October 14, 2010 – in person meeting at ISO
- October 21, 2010 – comments due on discussion paper
- November 11, 2010 – Publish Straw Proposal
- November 18, 2010 – in person meeting at ISO
- November 29, 2010 – Comments due on Straw Proposal
- December 13, 2010 – in person meeting at ISO
- January 21, 2011 – in person meeting at ISO (new headquarters building)

Template for comments

Please use the template below to submit comments to the CAISO. Comments are due by close of business Thursday, October 21, 2010 to gmc@caiso.com.

Stakeholder Comments Template
Subject: 2012 GMC Cost of Service Study Discussion Paper

Submitted by (Name and phone number)	Company or Entity	Date Submitted

ISO seeks written stakeholder comments on its 2012 GMC Cost of Service Study Discussion Paper located at: http://www.caiso.com/281a/281ac7f165ad0.html

Stakeholders should use this Template to submit written comments and or suggestions. Written comments should be submitted no later than Close of Business on Thursday, October 21, 2010 to: gmc@caiso.com. Comments will be posted on the ISO website.

The subject areas upon which ISO seeks stakeholder input are:

1. Please comment on the design principles listed in the discussion paper, and suggest any others you believe should be considered.

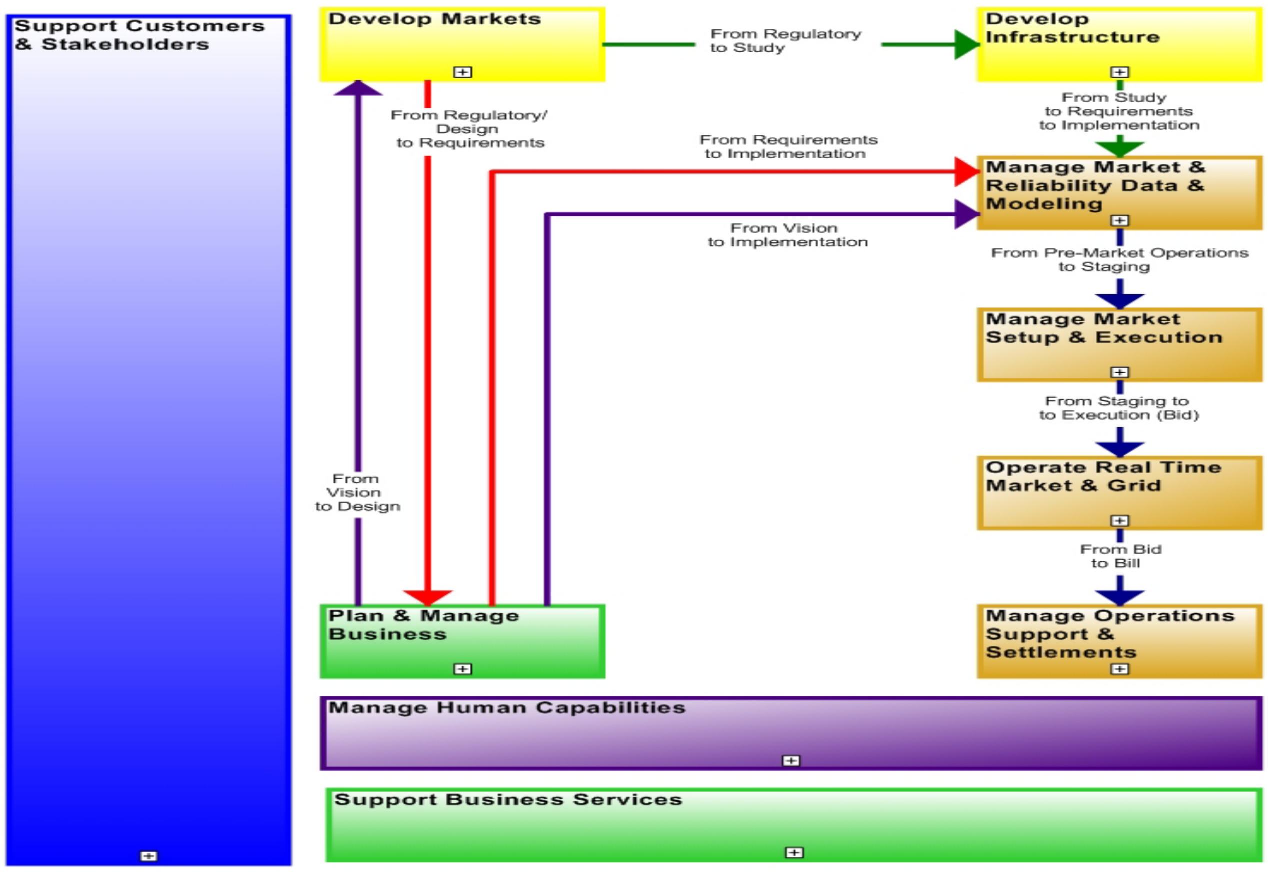
2. Please comment on the use of ABC and the allocations into the 3 proposed GMC service categories.

3. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered.

Exhibit 1 - Business Process Overview and level 2 activities

CAISO Business Process Framework Overview v2.3 (5/21/10)

- Illustrates high-level information streams between each of the Level I processes
- Shows how core processes in three supporting groups apply to all of the processes at the ISO
- Groups the Level II processes into logical groupings at executive ownership levels



Last Updated: 10/06/09

Process Name	Key Activities
Develop Infrastructure (DI) (80001)	Transmission Planning, Grid Assets Reviews and Interconnections
Develop Markets (DM) (80002)	Regulatory, Market, Policy and Product Design
Manage Human Capabilities (MHC) (80003)	Employee Lifecycle, Training, Organizational Development
Manage Market & Reliability Data & Modeling (MMR) (80004)	Resource Data Setup and Changes, Training, Base Model Setup, Congestion Revenue Rights
Manage Market Setup & Execution (MMS) (80005)	Outages, Day Ahead Market, Interchange Scheduling
Operate Real Time Market & Grid (OMG) (80006)	Hour Ahead, Real Time, Generation and Transmission Dispatch
Manage Operations Support & Settlements (MOS) (80007)	Operations Data Analysis, Billing & Settlements, Disputes
Plan & Manage Business (PMB) (80008)	Strategic Planning, Governance, Budgeting, Project Management
Support Business Services (SBS) (80009)	General, IT, Financial, Legal & Compliance Support Services
Support Customers & Stakeholders (SCS) (80010)	Client, Account and Stakeholder Processes, Government Affairs and Communications

Develop Infrastructure (DI) (80001)

- Enables the ISO to take a proactive approach to transmission planning by facilitating the building of needed projects
- Provides an important platform for success in addressing future challenges, though an enhanced planning process
- Satisfies compliance requirements, meets other regulatory and policy goals, and participates in joint regional planning groups

Processes	Process Descriptions
Develop & Monitor Regulatory Contract Procedures	Infrastructure Policy & Contracts is responsible for managing all regulatory contracting mechanisms for the CAISO. Contracts staff works with internal and external personnel to secure the necessary approvals, prepare the requested agreement, initiate and track the agreement execution process, notify internal staff as necessary for implementation, and maintains all official files.
Manage LGIP Cluster Studies	Depicts the ISO Grid Assets oversight and implementation of the Federal Energy Regulatory Commission (FERC) approved Large Generation Interconnection Procedures (LGIP) and any required coordination with affected adjacent systems.
Manage Long Term Transmission Planning	Depicts the process to develop the CAISO Transmission Plan, support CPUC Resource Adequacy (RA), support the Day Ahead and Real Time market simulations, develop Generator Interconnection Study obligations, assess long-term CRRs, perform annual congestion studies, conduct Deliverability and Locational Capacity Studies, develop Generation and transmission reliability assessments, and represent the ISO in technical groups and committees
Manage New Transmission Resources & Grid Changes	Depicts the activities required to communicate the scope of new transmission and grid resource projects to ISO's business units, produce status reports and reminders of tasks, gather and document project information, maintain the accuracy and integrity of the network model, operator displays, and the transmission registry, document the operating procedure changes for Grid Ops, maintain a documentation library of information, and reduce the financial risk of introducing new projects by ensuring the accuracy and integrity of the network model.
Manage SGIP Studies	Depicts the ISO Grid Assets oversight and implementation of the Federal Energy Regulatory Commission (FERC) approved Small Generation Interconnection Procedures (SGIP) and any required coordination with affected adjacent systems.
Manage Short Term Transmission Planning	Depicts the coordinated effort between Regional Transmission Engineering and Operations Engineering to identify and analyze operational issues and short-term planning issues. Operational issues (0-1 year) will require OEs to develop a solution, and short-term issues (1-3 years) will require Planners to develop a solution. Both operational and short-term issues will then be written into a short-term plan, which is then incorporated into the long-term transmission plan.
Manage Transmission Maintenance Standards	Depicts the ISO Grid Assets oversight and review activities as coordinated with the participating transmission owners to manage the ISO Transmission Maintenance Standards (Transmission Control Agreement Appendix C), mandated by Public Utilities Code 348 and adopted by the ISO.
NERC/ WECC Loads & Resources Data Requests	Depicts the process for developing templates and documentation, requesting demand response & energy efficiency data from LSEs, and compiling the actual, DR, EE, and forecasts using the WECC template.
Regulatory contract negotiations	This process is responsible for the negotiation, drafting, and administration of the CAISO pro-forma and special agreements with market participants and operators of other control areas. These contract negotiations accommodate the other party's request to the extent the negotiations/provisions of the contract are within the framework of the CAISO's Tariff, policies and procedures, and acceptable to FERC and other market participants.

Develop Markets (DM) (80002)

- Designs and implements value-added enhancements to the wholesale market design
- Improves the ISO's abilities to review and analyze the efficiency and quality of market results
- Creates a framework that will accommodate demand response participation in the ISO market

Processes	Process Descriptions
BPM Change Management Process	Depicts the required activities for managing modifications and additions to Business Practice Manuals (BPMs). BPMs were created to guide ISO operations post MRTU launch and document the consistent and transparent manner in which the ISO will adhere to Tariff provisions. Revision requests for the BPMs may be submitted by stakeholders or an internal ISO department.
Develop State/ Federal Regulatory Policy	This process is responsible for the development of corporate and regulatory policies related to the physical infrastructure of the electric power system. Staff engages with stakeholders and Federal or State regulatory agencies to produce new regulatory policy, necessary CAISO tariff provisions, and implementation of required business processes.
Manage Regulatory Filings	The Draft and Review Filing sub process collects all relevant information needed from the project team to prepare an initial draft which is then reviewed by the project team and legal for quality and accuracy, completion of the evidence, strength of the case as well as whether the order sought enables the business process.
Manage Tariff Amendments	Draft tariff language is published for review and comment prior to filing with FERC in a tariff amendment filing. Market participants have a minimum of one week to review and comment. Stakeholder meeting (usually conference call) is held to discuss written comments and to respond to questions raised on the call. If time permits, revised tariff language may be published prior to FERC filing.
Market Design & Regulatory Policy	This process includes the design and specification of efficient and effective wholesale electricity spot markets including the identification and development of new products and services as well as the development of solutions to existing market performance issues. This process also covers the formulation of market policies and designs which encourage infrastructure investment.
Manage Market Analysis & Development	Depicts the process of identifying and classifying market issues, and developing and prototyping potential solutions. Identifies market design, market tuning, modeling constraints or variances, and determines whether the ISO can solve the issues, or whether a vendor should provide the solution.
Perform Market Analysis	This process is concerned with the identification and analysis of a market design issue, as it progresses throughout the organization potentially leading up to a Conceptual Design specification and FERC tariff filing.

Manage Human Capabilities (MHC) (80003)

- Comprises the objective of institutional sustainability (people, technology)
- Develops a talent pool to leverage expert technical knowledge and leadership skills
- Creates a work environment that supports and nurtures the ISO's goals

Processes	Process Descriptions
Benefit Design	Depicts the activities surrounding the development and review of programs including health & welfare benefits, employee benefits, retirement, leave of absence, and workers compensation.
Benefits Management (Under Development)	Depicts the activities surrounding the maintenance of employee benefits, which could include but are not limited to open enrollment, status changes, and life-event changes (marriage, birth of a child, etc).
Compensation Design	Depicts the activities surrounding the development and review of programs including compensation, executive compensation, job descriptions, and annual merit/equity and incentive programs.
Employee Relations	This process details ensuring the workplace environment to allow for maximum productivity and satisfaction. This is achieved by: Addressing employee and/manager concerns, coaching for employees/managers, conducting investigations and providing recommendations on remediations, ensuring ISO is compliant with employment-related laws, marketing the ISO internally/externally as a best place to work.
Human Resources Compliance (Under Development)	Depicts the activities surrounding the maintenance of HR's compliance program which ensures that HR's processes satisfy Department of Labor, Corporate Policy and other requirements
Human Resources Infrastructure Design	This hierarchy represents the functional decomposition of manage HR policies & systems sub-function which is part of managing human resources function. The key processes are: Manage leave of absence and workers compensation, Manage payroll, Manage executive compensation, Manage Systems, and Manage Policies
Human Resources Strategy	Human Resources delivers competitive Human Resources programs and policies to ensure the organization's ability to promote quality treatment of employees and management practices that enable the CAISO to attract, retain, develop, and engage a dedicated and inspired world-class team.
Manage Bi-Weekly Payroll	Depicts the key activities from the time a timecard is submitted through ESS until a paycheck is issued to an employee.
Manage Employee Health & Safety Compliance	Depicts the core functions and activities of the Safety Department as required by Federal, State and Local law as it pertains to employee health and safety. Reinforces and builds the safety culture within the ISO
Manage Immigration Processes	Permanent Resident: Represents the conversion process for existing employees to become permanent residents Existing Employees: Process applies to existing employees who have non-immigrant visas and require H1B or CPT/OPT extensions and conversions New Candidates: Manage Immigration Process for New Candidates that have been identified through the HR- Recruiting process and have existing H1B or TN or CPT or OPT visas or are relocating from a foreign country and need a new visa
Manage Personnel Screening	Depicts the process for screening employee and contractor resources prior to badge issuance as well as initiation of the 7-year background check process and background checks due to self-reports. Also includes activities required to perform personnel risk assessments and drug screenings.
Manage Recruitment	This process details the processes related to the sourcing, screening and hiring of employees at the ISO. Executes the strategy identified by division executives related to workforce planning and supports ancillary processes including managing relocation and immigration.
Organizational Development & Training	This processes depicts the required activities for fulfilling the corporate-wide Training and Development (T&D) requirements. The process involves the following: Consult with manager to identify T&D opportunity or Problem, perform environmental scans and initial analysis, design and develop T&D intervention, deploy T&D intervention, and track, evaluate and make necessary adjustments to (T&D) intervention
Resource Access & Asset Control (Under Development)	Onboarding: Depicts the process for on-boarding employee and contractor resources based on inputs from the Recruitment and Procurement and Vendor Management process. Includes key activities which ensure that each resource has appropriate building and systems access and assets- as required for their particular role. Status Changes: Depicts the process for managing employee and contractor resource status changes. Should includes key activities such as promotions, department changes, management changes, conversions, etc in order to ensure that each resource has appropriate building and systems access and assets- as required for their particular role. Terminations: Depicts the process for terminating employee and contractor resources and disabling their access to buildings and systems as well as the collection of assets.
Talent Management (Under Development)	Depicts the activities surrounding the maintenance of employee internal resumes/ competencies. May also include planning processes for competencies/ skills building and career path development.

Manage Market & Reliability Data & Modeling (MMR) (80004)

- Checks and rechecks network modeling policies and protocols to reduce non-market energy dispatches
- Assures that models reflect all grid constraints and produce timely and accurate prices results
- Improves the visibility and transparency of the ISO's business while keeping monitoring and reporting duties secure

Processes	Process Descriptions
ISO Meter Certification	Depicts the process of certifying new metered entities to provide meter data in the ISO's markets.
Facilitate SC Certification	This Process defines the Scheduling Coordinator (SC) certification process and identifies all the requirements which are needed to complete SC certification. Customer Services oversees the SC certification process and ensures that all requirements are fulfilled prior to letting the SC submit schedules in the CAISO market.
High-Level Manage FNM Maintenance	Depicts the required activities to maintain and update the Full Network Model (FNM) -- the computer-based model that provides technical specifics of the ISO control area transmission network. The FNM includes a combination of physical network data and commercial data needed to support the reliability goals of the ISO and ensure that network constraints are enforced and feasible operational schedules identified.
Manage & Facilitate Procedure Maintenance	Depicts the required activities for managing the development, review, and modification of ISO Operating Procedures. Operating Procedures were created to guide ISO grid operations and document the consistent and transparent manner in which the ISO will adhere to Tariff provisions. Revision requests for the Operating Procedures may be submitted by stakeholders or an internal ISO department.
Manage Congestion Revenue Rights (CRR)	Depicts the required activities for the allocation and auction of Congestion Revenue Rights (CRRs) to market participants as well as the trading of these rights in the secondary market. The allocation and auction processes occur both annually (prior to the start of a new calendar year) and monthly (prior to the start of a new month).
Manage Credit & Collateral	Manage Credit: Depicts the required activities to ensure that Market Participants comply with CAISO credit policy by ensuring that a Market Participant's Aggregate Credit Limit ("ACL"; i.e., unsecured credit plus posted financial security) exceeds their Estimated Aggregate Liability ("EAL"). Manage Collateral: The process of setting a Market Participant's ACL by determining any unsecured credit that the Market Participant may be eligible for as well as receiving and posting other forms of financial security from the Market Participant.
Manage Network Applications	The Network Applications department is responsible for the development and implementation of the Network Model and the Network Applications - a critical tool both for reliably operating the grid and for supporting production. This includes testing, validation, maintenance, user training and deployment of the model/ tool.
Manage Operations Engineering Studies	Depicts the study and training activities performed by Operations Engineers outside of Real Time support. These activities include ongoing and annual procedure studies, planning support for the Short Term Transmission plan, procedure training for operators, and WECC seasonal studies which are performed 3x per year.
Execute & Track Operations Training	Depicts the process for conducting required training throughout the year, including planned and ad hoc training. Also includes activities related to reporting training completion to regulatory agencies.
Plan & Develop Operations Training	Depicts the required activities for managing the design, development, and delivery of operations (Grid and Market) related training courses, simulator scenarios and training programs to real-time personnel, Operators-in-training (OITs), other ISO departments, and external entities in form of Grid Ops Training, Summer Workshops, and on-the-job training (OJT).
Manage Reliability Requirements	Depicts the required activities to support the Resource Adequacy program adopted by the California Public Utilities Commission (CPUC) and other local regulatory agencies in compliance with California mandates. The RA program ensures that sufficient resources are available to meet the expected peak demand and provides for reliable power delivery throughout the ISO Control Area.
Master File Updates	Depicts the required activities to maintain and update the Master File - a database that stores all of the operational data regarding generators, loads and other system resources that participant in the ISO markets. Requests for Master File additions and updates are received directly from market participants and also from various internal areas such as customer service, market operations and settlements. The process for clarifying, implementing and confirming requests requires at least 5 business days and may take up to 11 depending on the complexity of the request.
EMAA Telemetry	Depicts the process for configuring and testing telemetry for new or existing generators including PDR. The process describes how RIG engineers review documentation to develop point lists, finalize data point lists with generators, and submit the point lists to EMS for QAS testing. RIG engineers then verify the QAS output, perform point-to-point testing and work with MCI to setup A/S testing.
Provide Stakeholder Training	This process describes detailed steps for providing training to stakeholders.
Station Power Implementation	Station Power is the Energy used to operate auxiliary equipment and other Load that is directly related to the production of Energy by a Generating Unit (ex. Heating and lighting for offices located at the plant). FERC has established a policy that allows a single entity that owns one or more Generating Units to self-supply Station Power over a monthly netting period using Energy generated on-site or remotely. Through the ISO Station Power Service program, Generators can convert their Station Power from retail service to wholesale service.

Manage Market & Reliability Data & Modeling (MMR) (80004) (Continued)	
Processes	**Process Descriptions**
Market Services Implementation	Depicts the coordination activities required to prepare new resources to participate and provide services in the ISO markets and grid. This can also include managing changes to information regarding a resource's participation and services provided in the ISO markets and grid. A resource's eligibility to participate and/or provide market and grid services is defined by the ISO Tariff and associated regulatory agreements. The resources can include, but are not limited to, generation and load resources as well as portions of the scheduling coordinator, CRR, transmission rights allocation (TRTC) and Transmission Control Agreement (TCA) processes as needed for market participation. It does not include managing the interconnection of transmission resources. Although this process triggers and coordinates changes across multiple other ISO interconnection and implementation process areas (e.g. Resource Data Maintenance, Reliability Requirements, Metering and Telemetry, Regulatory Contracts, Full Network Model, Operations Procedure Maintenance, etc) the primary objective of the process is to align the implementation timelines and activities between a participating resource and the ISO in order to achieve the planned Commercial Operation Date (COD).

Manage Market Setup & Execution (MMS) (80005)

- Manages transmission and generation outages to ensure continuous flow of power to all customers
- Includes dutiful execution of the Day Ahead Market and Interchange Scheduling
- Ensures all local capacity requirements are met and the power is delivered in the least cost possible by avoiding congested areas

Processes	Process Descriptions
Manage D+2 Analysis	Depicts the analysis activities which occur after the Day Ahead Market (D+1) has been run. Currently the D+2 run is run "today" for 2 days out and utilizes the appropriate outages and load forecasts for that D+2 date, but utilizes the D+1 Master File and Bid data. The D+2 run includes MPM-RRD, IFM and RUC- results are reported but not published externally. The Day Ahead operators run the D+2 processes and are supported by Market Operations and Engineering to analyze the pricing, binding constraints and other outputs. The objective for the analysis is to discover any issues or inconsistencies in the outputs which can be resolved before reaching the D+1 run.
Manage Day Ahead Market	Depicts the required activities to run the Day Ahead Market from the time that bids can be submitted (T-7) through to when the results have published and are passed through to the Real Time Market.
Manage Day Ahead & Real Time Runs & Price Validations	Depicts the activities related to the validation and correction of market solution results from both the Day-Ahead and Real-Time Markets including market conditions and prices (Locational Marginal Prices or LMPs). The goal of this process is to minimize the occurrence and length of situations where invalid or problematic market solutions affect the dispatch of energy which thereby reduces the number of associated price corrections. Process outcomes and corrections are published on the ISO website in a weekly Market Validation Report.
Manage Generation Outages	Depicts the required activities to coordinate and manage planned and forced generation outages to best ensure system reliability while successfully meeting demand and managing system congestion.
Manage Interchange Scheduling	The Manage Interchange Scheduling process involves validating and approving requests for interchange schedules (RFIs), implementing approved schedules in Real Time and resolving Net Scheduled Interchange (NSI) and Net Actual Interchange (NAI) discrepancies both prior to schedule implementation in EMS as well as After the Fact (ATF). The Prescheduling process ensures that the inter-tie schedules submitted prior to the operating day have valid e-Tags, have Day Ahead Market awards, conform to all market and contractual obligations and are checked out with Adjacent Balancing Authorities
Manage Transmission Outages	Depicts the required activities to coordinate and manage planned and forced transmission outages to best ensure system reliability while successfully meeting demand and managing system congestion.

Operate Real Time Market & Grid (OMG) (80006)

- Manages Real Time Scheduling to ensure that load is balanced to generation and that dispatch instructions are generated
- Operates the Day Ahead and Real Time energy markets
- Performs Generation and Transmission Dispatch

Processes	Process Descriptions
Manage Critical Facility Systems	Depicts the process of monitoring, detecting, and assessing the severity of events that adversely affect critical systems. Also includes the notification of other ISO parties, procuring vendors as needed, and managing the event resolution activities to completion.
Manage Emergency Operations	This process includes stages of emergency situations ranging from reserve shortages, to load shedding, to brown/black restoration, etc. As well as system restoration steps. * Trigger: Grid event, Reserve Deficiency, Generation / Transmission forced outage, External Control Area Emergency, Fires - Environmental Hazards * Performance measures: Emergency response and resolution * Frequency: As needed * Turnaround time / due time: ASAP
Manage Operations Engineering Support	Depicts the activities surrounding engineering support of real time operations, which could include analysis as well as tool and procedure updates.
Manage Real Time Market- After Close of Market (RTPD)	Depicts the required activities to run the Real-Time Market following its close and the receipt of all real-time bids. System Operations performs the following: (1) Run the Real-Time Market Power Mitigation (MPM) and Reliability Requirements Determination (RRD) processes (2) Manage the Hour-Ahead Scheduling Process (HASP) and (3) Run unit commitment processes - Short-Term Unit Commitment (STUC) runs hourly looking 5 hours ahead, Real-Time Unit Commitment (RTUC) runs every 15 minutes, and Real-Time Economic Dispatch (RTED) runs every five minutes for imbalance energy needs. The time horizon represented by the full process is Trade Hour minus 45 minutes to Trade Hour plus 60 minutes.
Manage Real Time Market- Prior to Close of Market Bidding	Depicts the required activities to prepare for running the Real-Time Market. System Operations performs the following: (1) Reviews and adjusts Day-Ahead schedules as needed (2) Manages the real-time bidding process and (3) Prepares for the Real-Time Market hourly intervals process. Time horizon represented by the full process is Trade Hour minus 30 minutes Trade Hour plus 240 minutes.
Manage Real Time Operations- Generation Dispatch (Working Copy)	Depicts the required activities for executing the 5 minute dispatches as well for monitoring and mitigating ACE, AGC, reserves, contingencies, exceptional dispatch, etc
Manage Real Time Operations- Transmission Dispatch (Working Copy)	Depicts the required activities for managing, monitoring and mitigating flows throughout the ISO's grid from the transmission dispatch perspective.
Manage RT Interchange Scheduling	The Real Time/ Intra Hour Change process ensures that Real Time updates and adjustments to inter-tie schedules include validation of e-Tags, confirmation of CISO market awards, conform to all market and contractual obligations and are checked out with Adjacent Balancing Authorities (ABAs) and WECC Interchange (WIT) in accordance with NERC policies.

Manage Operations Support & Settlements (MOS) (80007)

- Improves market efficiency by finding the most cost effective way of doing business
- Lowers the financial risk of participating in the wholesale market that in turn lowers the cost of doing business with the ISO
- Translates lower costs into less overhead for ISO customers who can pass the savings to ratepayers

Processes	Process Descriptions
Manage Rules of Conduct	Depicts the process to identify and review potential violations of the Rules of Conduct in CAISO Tariff, levy sanctions where violations are confirmed, allocate those funds as appropriate, and refer specific matters to DMM for further research and possible referral to FERC.
Manage Regulation No Pay & Deviation Penalty Calculations	Depicts the process to manage regulation no pay and deviation penalty calculations for settlement statements.
Manage Dispute Analysis & Resolution	Depicts the required activities to coordinate a timely, efficient and accurate dispute resolution process.
Manage Energy Measurement Acquisition & Analysis	Depicts the required activities to collect, analyze and validate meter data submitted by scheduling coordinators, ISO-metered entities, metered subsystems and the Interties. Data must be confirmed as Settlement Quality Meter Data (SQMD) before being passed on to the Settlements team for use in the market clearing process.
Manage Market Billing & Settlements	The process of Market Billing and Settlements depicts the required activities of collecting market data, processing pass through bill (PTB) data, calculating charges, and publishing Initial and Recalculation (Recalc) statement & invoices to market participants.
Manage Market Clearing	Depicts the process of reconciling Market and RMR invoices and receiving funds from market participants. Once funds are received, the ISO moves funds to investment and corporate accounts as necessary, and sends wire transfers to Market Participants to clear the market.
Manage Market Performance	Depicts the required activities to monitor and report on the daily, routine performance of the ISO markets to identify operations trends and anomalies and monitor ongoing issues. Market performance is summarized within daily internal reports and monthly reports to the Board of Governors and FERC.
Manage Price Validation & Corrections	Depicts the process of receiving price issues from the Day Ahead or Real Time markets, researching the issues, and providing corrected pricing data.
Manage the Market Quality System (MQS)	Depicts the activities related to the completion of post-process corrections on data from the Day-Ahead and Real-Time Markets. This process reduces the need for manual validation, verification and correction of transactional data that could affect market settlements, thereby reducing invoice errors and disputes. The Market Quality System (MQS) calculates expected energy costs, dispatch operating point, trading hubs, settlement allocations and start up/minimum load costs and publishes them on the OASIS website.
Manage Data Requests	Depicts the required activities to coordinate a timely, efficient and accurate response to data requests from internal and external parties.
WREGIS Application Process	Depicts the process for parties to apply to receive WREGIS QRE services from the CAISO. WREGIS is a western interconnect-wide renewable energy registry and tracking system established to promote verified tracking of renewable energy production and procurement and facilitate the growth of renewable energy. Qualified Reporting Entities (QREs) report generation output data into the WREGIS tracking system on behalf of renewable generators.
ISO Meter Engineering (Under Development)	Depicts the process of working on service calls received by certified meter inspectors, CAISOME meter owners, utilities, municipalities, and all other meter and polling inquiries.
ISO RIG Engineering (Under Development)	Depicts the processes require to provide support services to existing RIG installations to provide reliable generation data to real time operations.
Market Issues Steering Committee	The CAISO Market Issue Management policy provides the framework by which a cross function team of Operations, Information Technology and Market and Infrastructure Development can successfully manage issues associated with market functionality, processes or policy.

Plan & Manage Business (PMB) (80008)

- Aligns the strategic planning process more closely with budget planning
- Defines, creates and nurtures a culture of cost-consciousness as well as enhancing services while not adding costs
- Allows stakeholders to participate in ISO governance where costs and reliability issues are balanced

Processes	Process Descriptions
Compliance Committee (Under Development)	Will depicts the Compliance Committee activities which could include decisions as well as inputs to the Corporate Governance processes (ELT, Board of Governors, etc).
Develop & Implement Process, Risk, Strategy & Business Continuity Programs (Under Development)	Will depict Organizational Effectiveness activities as related to planning, organizing, monitoring and maintaining enterprise Process, Risk, Strategy and Business Continuity programs and projects
Enterprise Corporate Governance (Under Development)	Board Process: Depicts the activities involved in the planning of regularly scheduled Board meetings, including agenda topic development, memo and presentation drafting, executive review of materials, delivery of materials to the Board, presentation dry run, and post-meeting activities. Board Selection Process: Depicts the process surrounding the selection of a new member or the reappointment of an existing member, to the ISO Board prior to the expiration of any Board member's term. CMC Project Approval: Depicts the process of formal review and approval for initial and continued funding for projects and assets
Project Demand Management	Depicts Program Office driven activities from portfolio and release planning through to software development and funding activities.
Financial Planning	Financial Planning, Budgeting & Rates: Presents the milestones needed to complete the Operating & Maintenance and Capital Projects. This would ensure development of a comprehensive, well thought-out budget to meet CAISO needs. Manage Financial Planning: Depicts the process for long-term financial planning beyond the yearly budget. Considers the long-term rate structure for the ISO, looks at out years to develop the 10-year budget forecast, and includes the process of issuing bonds.
Identify, Assess, Mitigate, and Monitor Enterprise Risk	This process depicts activities engaged in across business functions to identify risks and opportunities in the ISO's internal and external environments that would impact its business objectives, evaluate them to determine residual risk exposure, and develop and monitor enterprise risk mitigation strategies to address them. It leverages information across all business functions, and is a key input into the strategic planning process.
IT Application & Technology Portfolio Management	This process Identifies new or potential upgrade target technologies for implementation into the ISO's computing infrastructure (includes data architecture).
IT Resource Planning (Under Development)	Depicts the process of resource planning of human resources among various projects or operational activities, maximizing the utilization of available personnel resources to achieve business goals.
Manage & Monitor Enterprise Performance (Under Development)	Will depict a process that covers the collecting, analysis and reporting of enterprise performance metrics, including those that measure the ISO's execution against corporate goals and initiatives as well as others that measure the overall health of the organization.
Policy Review Committee	This process ensures consistency of ISO policy positions and coordination of approaches across ISO activities in order to enhance organizational effectiveness. To accomplish this, the process performs timely triage when new issues are identified, and provides guidance as needed to in-progress policy and implementation activities.
Project Demand Management	Depicts Program Office driven activities from portfolio and release planning through to software development and funding activities.
Strategic Planning	The process by which the ISO gathers internal and external inputs, evaluates them against the existing five-year strategy, updates strategic objectives and corporate initiatives, defines annual corporate goals, and aligns internal business strategies and resources to successfully implement the corporate initiatives and achieve strategic objectives. Also included in this process is the manner by which the ISO monitors and reports on corporate performance, as well as maintaining the corporate dashboard.

Support Business Services (SBS) (80009)

- Comprises the objective of institutional sustainability (people, technology) along with the Manage Human Capabilities process
- Supports well-defined, measured & controlled processes, disciplined business decision making, quality assurance & efficient implementations
- Expands the ISO's enterprise risk management initiative, and supports the development of defined and measurable controls

Processes	Process Descriptions
Compliance Evidence Review & Audit (New & Updates)	Depicts the process where the Compliance Team reviews new or revised standards from NERC and WECC, reviews findings or recommendations from Internal Audit, reviews updates from business units, and examines compliance events or opportunities to improve the quality of compliance evidence.
Compliance Violations (NERC and WECC)	Depicts the actions needed for reporting, investigating, and mitigating compliance incidents
Compliance With New & Revised Standards	Depicts the actions needed for managing changes to standards and the development of new standards
Corporate Compliance Risks Follow Through Accountability and Tracking	Depicts the activities after information about a corporate policy risk or non-compliance incident is communicated, through evaluation and analysis processes, until appropriate actions have been determined. Possible outcomes may include but are not limited to- decision that the incident is not a violation, that a violation occurred and remedial and/or disciplinary actions are required.
Identify Tariff Violations & Ineffective Market Rules	This process performs the following: 1) Identify and review potential violations of Rule of Conduct in CAISO Tariff or ineffective market rules 2) Refer potential violations of Rules of Conduct to FERC 3) Recommend potential rule changes to CAISO
Invest Corporate Funds	This process involves the short-term and intermediate term (up to 5 years) investing of ISO funds sourced from GMC collections. Investing is done within the parameters of the Board approved investment policy.
IT Application & System Maintenance (Working Copy)	All application support and maintenance which is not directly related to a project, Incident Management or Problem Management.
IT Asset Management (Working Copy)	Business practices that join financial, contractual and inventory functions to support life cycle management and strategic decision making for the IT environment. Assets include all elements of software and hardware that are found in the business environment.
IT Availability Management (Working Copy)	Ensures the level of service availability delivered in all services is matched to or exceeds the current and future agreed needs of the business.
IT Capacity Management (Working Copy)	Ensures the cost-justifiable IT capacity in all areas of IT always exists and is matched to the current and future needs of the business in a timely manner. Also reports the current state and future forecast of IT Capacity.
IT Configuration, Change & Release Management- High Level Process Flow	Depicts the process to ensure that standardized methods and procedures are used for efficient and prompt handling of all changes to a controlled IT infrastructure, in order to minimize the number and impact of any related incidents upon implementation of changes.
IT Environment Management (Working Copy)	Provides the framework to manage IT system environment usage for projects, enhancements, maintenance and training.
IT Event Management (Working Copy)	Depicts the process to create new monitoring to detect and analyze events.
IT Incident Management (Working Copy)	Depicts the process to ensure restoration to a normal service operation as quickly as possible while minimizing the impact on business operations, thus ensuring that the best possible levels of service quality and availability are maintained
IT Information Security Management (Working Copy)	Ensure validation of critical cyber assets, quarterly. Align IT and business security to ensure information security is managed effectively in all services and service management activities
IT Problem Management	Depicts the process to resolve the root cause of IT problems. These may involve system tuning, changing operating system or device parameters, or even refactoring the application software to resolve poor performance due to poor design or bad coding practices.
IT Service Desk (Working Copy)	The objectives of the Service Desk are: 1) Providing a single (informed) point of contact for customers and 2) Facilitating the restoration of normal operational service with minimal business impact on the customer within agreed SLA levels and business priorities.
IT Service Level Management (Working Copy)	Ensures an agreed to level of IT service is provided for all current IT services and the future services are delivered to agreed achievable targets. This includes the development and maintenance of SLA's and OLA's with the business and within IT.
IT Service Validation & Testing (QA) (Not Project Related) (Under Development)	For an enhancement: 1. Request for a software modification comes in from the Business Unit or possibly a MP. For a defect fix/CMR: 1. Issue is identified by QA, Business SME or MP, a defect is written against the software.
Maintain Work Environment	Depicts the process to provide and manage a highly reliable building infrastructure that supports a safe, efficient and comfortable work environment and contributes to enterprise-wide teamwork and collaboration.
Manage Corporate Incident Response	Depicts how the ISO will implement the Incident Command System (ICS) to manage an incident that affects business across the organization. Once implemented, the Incident Management Team uses this process to stabilize, mitigate, and terminate an incident.
Manage Dispute Resolution & Litigation	This process deals with Managing Litigation after it is received by the Legal Department at the ISO.
Manage Enterprise Independent Assessments	Manage Annual Operational Assessment: Depicts the process of selecting topics, performing dry-runs and actual audits, and reporting the results for the Operational Assessment. Corporate Internal Financial Controls: Details the periodic review of Internal controls on the processes that directly impact the presentation and review of the financial statements of the company.
Manage Financial Reporting	Depicts the monthly, quarterly, and annual sub-processes needed to complete the financial reporting cycle.
Manage Internal Audit	Depicts the approval and performance activities required for the scheduling, planning, conducting, documenting, and follow-up for deficiencies identified during internal audits.

Support Business Services (SBS) (80009) (continued)

Processes	Process Descriptions
Manage Monthly Financial Cycle	Collections: Details the Corporate Accounts Receivables activities which include invoicing, processing payments and bank deposits. Accounts Payable (Invoices): Validates invoice/PO, approval of payments, disbursements to vendors. Accounts Payable (Expense Reports): Validates Expense Reports, approval of payments, disbursements employees. Financial Cycle: Details the collection, analysis and reporting of monthly financial data in an organized and timely manner for management and business units.
Manage Procurement	This process starts with identification of Business requirements or changes to an approved project and details various activities from project package preparation & approval, commercial contract finalization, vendor selection to delivery of goods/services to business units as a part of corporate procurement activity.
Monitor Market	This process flow describes the market monitoring procedures followed for reviewing market behavior and market results.
Physical Security Access Control	Depicts the process of identifying visitors to ISO facilities and determining their access requirements for badge issuance. Includes the monitoring of active badges and ensuring that badges have been deactivated for visitors and contractors who no longer require access.
Provide Legal Advice & Counsel (Under Development)	Depicts the process of providing legal advice and counsel to other business units in the ISO.

Support Customers & Stakeholders (SCS) (80010)

- Provides the highest quality of service to its customers, market participants and stakeholders
- Includes timely resolution of customer issues, corporate-wide customer relationship management and streamlined access to market information
- Provides a market design to accommodate renewables and demand response, while keeping costs reasonable and maintaining grid reliability

Processes	Process Descriptions
Communications & Public Relations	The Communications and Public Relations Department presents a single, consistent and timely ISO voice and provides a broad range of clear, correct, and useful information to employees, stakeholders, media and the public-at-large. Corporate communication materials are developed and distributed by the department. These include brochures, information kits, annual reports, articles, news releases, market notices and broadcast productions. The team manages three websites: Internet, Market Participant Portal and Intranet sites. The department also develops new products and services, conducting stakeholder focus groups to identify and meet the business needs of market participants. Media relations provided by the department extends to newspaper, radio and TV as well as trade media and international news outlets. CommPR spokespersons provide 24/7 support to media and promote electricity conservation during peak periods of stress on the grid. The department trains in emergency preparedness and performs crisis communication management. All corporate events are coordinated by the department and the team also facilitates tours and speaking engagements.
Government Affairs Process	Depicts the activities required to perform the following: 1) Respond to inquiries from government and regulatory entities 2) Develop strategy jointly with ISO divisions 3) Maintain relationships with government and regulatory entities 4) Address concerns 5) Communicate the ISO's position to government and regulatory entities 6) Communicate government and regulatory entity positions internally at the ISO 7) Monitor the governmental environment 8) Develop work plans to implement ISO initiatives and strategies
Manage Stakeholder Process	Administer the stakeholder process in compliance with a set of quality control guidelines for the consistent management of meetings, documents, stakeholder comments and general process structure. Working with other depts, CSIA staff plans each engagement, from conception through the final Board meeting. A master engagement plan is created to guide the stakeholder process for each major initiative. A team is formed between CSIA and the functional organization leading the stakeholder process. Customer engagements, whether they be meetings, papers or conference calls, are planned and executed by these teams. A feedback loop at the end of each meeting helps to validate success, and sets the stage for ongoing improvements.
Resolve Client Issues	This process aims to improve Customer Service and ensure that CAISO's Scheduling Coordinators' (SC's) issues and inquiries get resolved in a timely manner. 1. Each SCs is assigned a Client Representative (CR). SC either calls Client Representative to raise inquiry or issue or directly logs the query in TRAIN through external web interface. 2. CAISO uses TRAIN to route the inquiry along the company. 3. Customer Services will either resolve the inquiry internally or will route it to a business unit using ownership matrix. 4. Assigned Business Unit plans and provides resolution back to Customer Services 5. Customer Services communicated the resolution to SC and closes the ticket in TRAIN Issues that fall outside the bid to bill processes, example CAISO policy issues, are handled by Accounts Managers (AM).
Strategic Client Account Management	ISO Account Managers develop high-level relationships with clients, with the goal of supporting quality dialogue between the ISO and key customers. Tasks include: fast response to customer inquiries on major projects and policy matters, working in in concert with customer staff to arrange senior level meetings and their agendas, coordinating the interaction with senior stakeholders and their ISO management peers, overseeing the response by the ISO to stakeholder questions, contributing to individual client interactions within the stakeholder process, and reporting to management on key customer issues, particularly on policy matters that will be addressed by the Board.

Exhibit 2 - Level 2 Activities by customer classes

ABC Level 1 Activities		Develop Infrastructure (80001)									
ABC Level 2 Activities		Develop & monitor regulatory contract procedures	Manage LGIP cluster studies	Manage long term trans-mission planning	Manage new trans-mission resources & grid changes	Manage SGIP studies	Manage short term trans-mission planning	Manage trans-mission inter-connect-ions	Manage trans-mission maint-enance standards	NERC / WECC loads & resources data requests	Regulatory contract negotiat-ions
Customer Categories											
CRR		No	Y	Y	Y	Y	Y	No	No	No	Y
PTO		Y	Y	Y	Y	Y	Y	Y	Y	No	Y
MSS	LOAD FOLLOWING	Y	Y	Y	Y	Y	Y	No	No	Y	Y
MSS	NET vs GROSS	Y	Y	Y	Y	Y	Y	No	No	Y	Y
IL	UDC	No	Y	Y	Y	Y	Y	No	No	Y	Y
IL	ESP	No	Y	Y	Y	Y	Y	No	No	Y	Y
IL	PARTICIPATING LOAD	No	Y	Y	Y	Y	Y	No	No	Y	Y
IL	PUMP LOAD	No	Y	Y	Y	Y	Y	No	No	Y	Y
IG	RENEWABLES	Y	Y	Y	Y	Y	Y	Y	No	Y	Y
IG	subject to RA	Y	Y	Y	Y	Y	Y	Y	No	Y	Y
IG	QF	Y	Y	Y	Y	Y	Y	Y	No	Y	Y
IG	MERCHANT (BID vs SELF-SCHED)	Y	Y	Y	Y	Y	Y	Y	No	Y	Y
IG	PDR	Y	Y	Y	Y	Y	Y	Y	No	Y	Y
IG	RMR										
IG	PUMP GEN	Y	Y	Y	Y	Y	Y	Y	No	Y	Y
IMPORT	SELF SCHED	No	Y	Y	Y	Y	Y	Y	No	No	No
IMPORT	BID	No	Y	Y	Y	Y	Y	Y	No	No	No
IMPORT	WHEELS	No	Y	Y	Y	Y	Y	Y	No	No	No
IMPORT	PSEUDO'S	Y	Y	Y	Y	Y	Y	Y	No	No	Y
IMPORT	subject to RA										
IMPORT	DYNAMICS	Y	Y	Y	Y	Y	Y	Y	No	No	Y
EXPORT	SELF SCHED	No	Y	Y	Y	Y	Y	Y	No	No	No
EXPORT	BID	No	Y	Y	Y	Y	Y	Y	No	No	No
EXPORT	WHEELS	No	Y	Y	Y	Y	Y	Y	No	No	No
EXPORT	PSEUDO'S	Y	Y	Y	Y	Y	Y	Y	No	No	Y
EXPORT	DYNAMICS	Y	Y	Y	Y	Y	Y	Y	No	No	Y
FINANCIAL	CONVERGENCE BIDDING	No	No	No	No	No	No	No	No	No	No
FINANCIAL	ISC TRADE	No	No	No	No	No	No	No	No	No	No
ETC		No	Y	Y	No	Y	Y	No	Y	No	No
TOR	EXISTING	No	Y	Y	No	Y	Y	No	Y	No	No
TOR	NEW	Y	Y	Y	Y	Y	Y	No	Y	No	Y

Exhibit 2 - Level 2 Activities by customer classes

ABC Level 1 Activities		Develop Markets (80002)						
ABC Level 2 Activities		BPM change manage-ment process	Develop State / Federal regulatory policy	Manage regulatory filings	Manage tariff amend-ments	Market design & regulatory policy	Manage market analysis & develop-ment	Perform market analysis
Customer Categories								
CRR		Y	Y	Y	Y	Y	Y	Y
PTO		Y	Y	Y	Y	No	No	No
MSS	LOAD FOLLOWING	Y	Y	Y	Y	Y	Y	Y
MSS	NET vs GROSS	Y	Y	Y	Y	Y	Y	Y
IL	UDC	Y	Y	Y	Y	Y	Y	Y
IL	ESP	Y	Y	Y	Y	Y	Y	Y
IL	PARTICIPATING LOAD	Y	Y	Y	Y	Y	Y	Y
IL	PUMP LOAD	Y	Y	Y	Y	Y	Y	Y
IG	RENEWABLES	Y	Y	Y	Y	Y	Y	Y
IG	subject to RA	Y	Y	Y	Y	Y	Y	Y
IG	QF	Y	Y	Y	Y	Y	Y	Y
IG	MERCHANT (BID vs SELF-SCHED)	Y	Y	Y	Y	Y	Y	Y
IG	PDR	Y	Y	Y	Y	Y	Y	Y
IG	RMR							
IG	PUMP GEN	Y	Y	Y	Y	Y	Y	Y
IMPORT	SELF SCHED	Y	Y	Y	Y	Y	Y	Y
IMPORT	BID	Y	Y	Y	Y	Y	Y	Y
IMPORT	WHEELS	Y	Y	Y	Y	Y	Y	Y
IMPORT	PSEUDO'S	Y	Y	Y	Y	Y	Y	Y
IMPORT	subject to RA							
IMPORT	DYNAMICS	Y	Y	Y	Y	Y	Y	Y
EXPORT	SELF SCHED	Y	Y	Y	Y	Y	Y	Y
EXPORT	BID	Y	Y	Y	Y	Y	Y	Y
EXPORT	WHEELS	Y	Y	Y	Y	Y	Y	Y
EXPORT	PSEUDO'S	Y	Y	Y	Y	Y	Y	Y
EXPORT	DYNAMICS	Y	Y	Y	Y	Y	Y	Y
FINANCIAL	CONVERGENCE BIDDING	Y	Y	Y	Y	Y	Y	Y
FINANCIAL	ISC TRADE	Y	Y	Y	Y	No	No	No
ETC		Y	Y	Y	Y	Y	No	No
TOR	EXISTING	Y	Y	Y	Y	Y	No	No
TOR	NEW	Y	Y	Y	Y	Y	No	No

Exhibit 2 - Level 2 Activities by customer classes

ABC Level 1 Activities		Manage Market & Reliability Data & Modeling (MMR) (80004)															
ABC Level 2 Activities		ISO meter certifi-cation	Facilitate SC certifi-cation	High level manage FNM mainten-ance	Manage & facilitate procedure mainten-ance	Manage CRRs	Manage credit & collateral	Manage network appli-cations	Manage operat-ions engineer-ing studies	Execute & track operat-ions training	Plan & develop Manage operat-ions training	Manage reliability require- ments	Master file updates	EMAA telem-etry	Provide stake-holder training	Station power inple-mentation	Market services imple-mentation
Customer Categories																	
CRR		No	No	Y	No	Y	Y	Y	No	No	No	No	Y	No	Y	Y	No
PTO		No	No	Y	Y	No	Y	Y	Y	Y	Y	No	Y	No	No	Y	Y
MSS	LOAD FOLLOWING	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	No
MSS	NET vs GROSS	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	No
IL	UDC	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	No
IL	ESP	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	No
IL	PARTICIPATING LOAD	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	No
IL	PUMP LOAD	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	No
IG	RENEWABLES	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	No	Y	Y	Y	Y	No
IG	subject to RA	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	No
IG	QF	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	No	Y	Y	Y	Y	No
IG	MERCHANT (BID vs SELF-SCHED)	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	No	Y	Y	Y	Y	No
IG	PDR	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	No	Y	Y	Y	Y	No
IG	RMR																Y
IG	PUMP GEN	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	No	Y	Y	Y	Y	No
IMPORT	SELF SCHED	No	Y	Y	No	No	Y	Y	Y	Y	Y	No	Y	No	Y	Y	No
IMPORT	BID	No	Y	Y	No	No	Y	Y	Y	Y	Y	No	Y	No	Y	Y	No
IMPORT	WHEELS	No	Y	Y	No	No	Y	Y	Y	Y	Y	No	Y	No	Y	Y	No
IMPORT	PSEUDO'S	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	No	Y	Y	Y	Y	No
IMPORT	subject to RA																
IMPORT	DYNAMICS	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	No	Y	Y	Y	Y	No
EXPORT	SELF SCHED	No	Y	Y	No	No	Y	Y	No	No	No	No	Y	No	Y	Y	No
EXPORT	BID	No	Y	Y	No	No	Y	Y	No	No	No	No	Y	No	Y	Y	No
EXPORT	WHEELS	No	Y	Y	No	No	Y	Y	No	No	No	No	Y	No	Y	Y	No
EXPORT	PSEUDO'S	Y	Y	Y	Y	No	Y	Y	No	No	No	No	Y	Y	Y	Y	No
EXPORT	DYNAMICS	Y	Y	Y	Y	No	Y	Y	No	No	No	No	Y	Y	Y	Y	No
FINANCIAL	CONVERGENCE BIDDING	No	Y	Y	No	No	Y	Y	No	No	No	No	Y	No	Y	Y	No
FINANCIAL	ISC TRADE	No	Y	No	No	No	Y	No	No	No	No	No	Y	No	Y	Y	No
ETC		No	No	Y	Y	No	No	Y	Y	Y	Y	No	Y	No	No	Y	No
TOR	EXISTING	No	No	Y	Y	No	No	Y	Y	Y	Y	No	Y	No	No	Y	No
TOR	NEW	No	No	Y	Y	No	No	Y	Y	Y	Y	No	Y	No	No	Y	No

Exhibit 2 - Level 2 Activities by customer classes

ABC Level 1 Activities		Manage Market Setup & Execution (MMS)						Operate Real Time Market & Grid (OMG) (80006)							
ABC Level 2 Activities		Manage D+2 analysis	Manage DA market	Manage DA & RT runs & price valida- tion	Manage generation outages	Manage inter- change scheduling	Manage trans- mission outages	Manage critical facility systems	Manage emergency opera- tions	Manage opera- tions engin- eering support	Manage RT market - after close of market	Manage RT market - prior to close of market bidding	Manage RT opera- tions - genera- tion dispatch	Manage RT opera- tions - trans- mission dispatch	Manage RT inter- change scheduling
Customer Categories															
CRR		No	No	No	No	No	No	Y	No	No	No	No	No	No	No
PTO		No	No	No	No	No	Y	Y	Y	Y	No	No	No	Y	No
MSS	LOAD FOLLOWING	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
MSS	NET vs GROSS	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IL	UDC	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IL	ESP	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IL	PARTICIPATING LOAD	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IL	PUMP LOAD	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	RENEWABLES	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	subject to RA	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	QF	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	MERCHANT (BID vs SELF-SCHED)	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	PDR	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	RMR														
IG	PUMP GEN	Y	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y
IMPORT	SELF SCHED	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IMPORT	BID	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IMPORT	WHEELS	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IMPORT	PSEUDO'S	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IMPORT	subject to RA														
IMPORT	DYNAMICS	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EXPORT	SELF SCHED	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EXPORT	BID	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EXPORT	WHEELS	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EXPORT	PSEUDO'S	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EXPORT	DYNAMICS	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
FINANCIAL	CONVERGENCE BIDDING	Y	Y	Y	No	No	No	Y	No	No	No	No	No	No	No
FINANCIAL	ISC TRADE	No	No	No	No	No	No	Y	No	No	No	No	No	No	No
ETC		No	No	No	No	No	Y	Y	Y	Y	No	No	No	Y	No
TOR	EXISTING	No	No	No	No	No	Y	Y	Y	Y	No	No	No	Y	No
TOR	NEW	No	No	No	No	No	Y	Y	Y	Y	No	No	No	Y	No

Exhibit 2 - Level 2 Activities by customer classes

ABC Level 1 Activities		Manage Operations Support & Settlements (MOS) (80007)													
ABC Level 2 Activities		Manage rules of conduct	Manage regula-tion no pay & deviation penalty calcula-tions	Manage dispute analysis & resolution	Manage energy measure-ment acquisition & analysis	Manage market billing & settlements	Manage market clearing	Manage market perfor-mance	Manage price valida-tion & correct-ions	Manage the market quality sustem (MQS)	Manage data requests	WREGIS applica-tion process	ISO meter engin-eering	ISO RIG engin-eering	Market issues steering committee
Customer Categories															
CRR		No	No	Y	No	Y	Y	Y	Y	No	Y	Y	No	No	Y
PTO		No	No	No	No	Y	Y	No	No	No	Y	Y	No	No	Y
MSS	LOAD FOLLOWING	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
MSS	NET vs GROSS	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IL	UDC	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IL	ESP	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IL	PARTICIPATING LOAD	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IL	PUMP LOAD	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	RENEWABLES	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	subject to RA	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	QF	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	MERCHANT (BID vs SELF-SCHED)	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	PDR	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IG	RMR														
IG	PUMP GEN	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IMPORT	SELF SCHED	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	No	No	No
IMPORT	BID	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	No	No	No
IMPORT	WHEELS	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	No	No	No
IMPORT	PSEUDO'S	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
IMPORT	subject to RA														
IMPORT	DYNAMICS	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EXPORT	SELF SCHED	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	No	No	No
EXPORT	BID	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	No	No	No
EXPORT	WHEELS	Y	Y	Y	No	Y	Y	Y	Y	Y	Y	Y	No	No	No
EXPORT	PSEUDO'S	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EXPORT	DYNAMICS	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
FINANCIAL	CONVERGENCE BIDDING	No	No	Y	No	Y	Y	Y	Y	No	Y	Y	No	No	No
FINANCIAL	ISC TRADE	No	No	No	No	Y	Y	No	Y	No	Y	Y	No	No	No
ETC		No	No	No	No	Y	Y	No	No	No	Y	Y	No	No	No
TOR	EXISTING	No	No	No	No	Y	Y	No	No	No	Y	Y	No	No	No
TOR	NEW	No	No	No	No	Y	Y	No	No	No	Y	Y	No	No	Y

Exhibit 2 - Level 2 Activities by customer classes

ABC Level 1 Activities	
ABC Level 2 Activities	
Customer Categories	
CRR	
PTO	
MSS	LOAD FOLLOWING
MSS	NET vs GROSS
IL	UDC
IL	ESP
IL	PARTICIPATING LOAD
IL	PUMP LOAD
IG	RENEWABLES
IG	subject to RA
IG	QF
IG	MERCHANT (BID vs SELF-SCHED)
IG	PDR
IG	RMR
IG	PUMP GEN
IMPORT	SELF SCHED
IMPORT	BID
IMPORT	WHEELS
IMPORT	PSEUDO'S
IMPORT	subject to RA
IMPORT	DYNAMICS
EXPORT	SELF SCHED
EXPORT	BID
EXPORT	WHEELS
EXPORT	PSEUDO'S
EXPORT	DYNAMICS
FINANCIAL	CONVERGENCE BIDDING
FINANCIAL	ISC TRADE
ETC	
TOR	EXISTING
TOR	NEW

Abbreviations

BA	Balancing authority (CAISO control area)
CRR	Congestion revenue right
DA	Day ahead
ESP	Energy service provider (Direct access)
ETC	Existing transmission contract (phasing out)
FNM	Full network model
IG	Internal generation (generation in the BA)
IL	Internal load (load in the BA)
IST	Inter Scheduling Coordinator trades
MSS	Metered sub-system
PDR	Proxy demand response
PTO	Participating transmission owner
QF	Qualifying facility
RA	Resource adequacy
RT	Real time
SC	Scheduling coordinator
TOR	transmission ownership rights
UDC	Utility distribution company

Mapping of ABC level 2 Direct Operating Activities to cost categories					
ABC Level 2 Activities	Market services	System Operations	CRRs	Indirect	Comments
	% of cost to allocate to category				
Definitions used in allocation	100%				the costs are entirely to support the market results & function resulting in a fi9nancially binding schedule or AS award
		100%			the costs are entirely to support system operations
			100%		the costs are entirely to support the CRR process
				100%	not distinguishable attribute to any specific category
	50%	50%			the costs support equally both market and system operations
	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
	80%	20%			the costs are predominantly market related but have some operational relationship
	20%	80%			the costs are predominantly operational flow based but have some market relationship
Develop Infrastructure (DI) (80001)					
Develop & monitor regulatory contract procedures		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage LGIP cluster studies		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage long-term transmission planning		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage new transmission resources & grid changes		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage SGIP studies		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage short-term transmission planning		100%			managing the building of the grid thus the costs are entirely to support system operations
Manage transmission maintenance standards		100%			managing the building of the grid thus the costs are entirely to support system operations
NERC / WECC loads & resources data requests		100%			managing the building of the grid thus the costs are entirely to support system operations
Regulatory contract negotiations		100%			managing the building of the grid thus the costs are entirely to support system operations
Develop Markets (DM) (80002)					
BPM change management process				100%	not distinguishable attribute to any specific category
Develop State / Federal regulatory policy				100%	not distinguishable attribute to any specific category
Manage regulatory filings				100%	not distinguishable attribute to any specific category
Manage tariff amendments				100%	not distinguishable attribute to any specific category
Market design & regulatory policy	100%				the costs are entirely to support the market results & function
Manage market analysis & development	100%				the costs are entirely to support the market results & function
Perform market analysis	100%				the costs are entirely to support the market results & function
Manage Market & Reliability Data & Modeling (MMR) (80004)					
ISO meter certification		100%			measuring flows on the grid thus the costs are entirely to support system operations
Facilitate SC certification				100%	not distinguishable attribute to any specific category
High level manage FNM maintenance	50%	50%			the costs support equally both market and system operations
Manage & facilitate procedure maintenance	20%	80%			significantly more operational procedures, thus the costs are predominantly operational flow based but have some market relationship
Manage CRRs			100%		the costs are entirely to support the CRR process
Manage credit & collateral	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage network applications		100%			involves EMS thus the costs are entirely to support system operations
Manage operations engineering studies		100%			studying flows on the grid thus the costs are entirely to support system operations
Execute & track operations training	20%	80%			significantly more operational procedures, thus the costs are predominantly operational flow based but have some market relationship
Plan & develop operations training	20%	80%			significantly more operational procedures, thus the costs are predominantly operational flow based but have some market relationship
Manage reliability requirements		100%			relates to actual system operations thus the costs are entirely to support system operations
Master file updates	50%	50%			resource attributes that support both thus the costs support equally both market and system operations
EMAA telemetry (RIGs)		100%			relates to actual system operations thus the costs are entirely to support system operations
Provide stakeholder training				100%	not distinguishable attribute to any specific category
Station power application procedure	80%	20%			based on procedures for station power
Market services implementation	50%	50%			resource attributes that support both thus the costs support equally both market and system operations

Mapping of ABC level 2 Direct Operating Activities to cost categories					
ABC Level 2 Activities	Market services	System Operations	CRRs	Indirect	Comments
	% of cost to allocate to category				
Definitions used in allocation	100%				the costs are entirely to support the market results & function resulting in a fi9nancially binding schedule or AS award
		100%			the costs are entirely to support system operations
			100%		the costs are entirely to support the CRR process
				100%	not distinguishable attribute to any specific category
	50%	50%			the costs support equally both market and system operations
	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
	80%	20%			the costs are predominantly market related but have some operational relationship
	20%	80%			the costs are predominantly operational flow based but have some market relationship
Manage Market Setup & Execution (MMS) (80005)					
Manage D+2 analysis	50%	50%			the costs support equally both market and system operations
Manage DA market	50%	50%			while managing market it results in system starting point for operational flows thus the costs support equally both market and system operations
Manage DA & RT runs & price validations	50%	50%			the costs support equally both market and system operations
Manage generation outages		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage interchange scheduling		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage transmission outages		100%			relates to actual system operations thus the costs are entirely to support system operations
Operate Real Time Market & Grid (OMG) (80006)					
Manage critical facility systems				100%	not distinguishable attribute to any specific category
Manage emergency operations		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage operations engineering support	20%	80%			based on support of day-ahead and real time thus the costs are predominantly operational flow based but have some market relationship
Manage RT market - after close of market	50%	50%			the costs support equally both market and system operations
Manage RT market - prior to close of market bidding	50%	50%			the costs support equally both market and system operations
Manage RT operations - generation dispatch		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage RT operations - transmission dispatch		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage RT interchange scheduling		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage Operations Support & Settlements (MOS) (80007)					
Manage rules of conduct				100%	not distinguishable attribute to any specific category
Manage regulation no pay & deviation penalty calculations		100%			measuring actual performance thus the costs are entirely to support system operations
Manage dispute analysis & resolution				100%	not distinguishable attribute to any specific category
Manage energy measurement acquisition & analysis		100%			measuring actual performance thus the costs are entirely to support system operations
Manage market billing & settlements	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage market clearing	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage market performance	50%	50%			the costs support equally both market and system operations
Manage price validation & corrections	50%	50%			related to proper outage allocation thus the costs support equally both market and system operations
Manage the market quality system (MQS)	50%	50%			portion of MQS relates to operational flows thus the costs support equally both market and system operations
Manage data requests				100%	not distinguishable attribute to any specific category
WREGIS application process		100%			measuring actual performance thus the costs are entirely to support system operations
ISO meter engineering		100%			measuring actual performance thus the costs are entirely to support system operations
ISO RIG engineering		100%			measuring actual performance thus the costs are entirely to support system operations
Market issues steering committee	50%	50%			portion related to operational practices & procedures thus the costs support equally both market and system operations

Exhibit 3

Allocation of Debt Service and Out of Pocket Capital to GMC cost categories					
System	**Market services**	**System operations**	**CRRs**	**Indirect**	**Comments**
	% of cost to allocate to category				
Definitions used in allocation	100%				the costs are entirely to support the market results & function resulting in a fi9nancially binding schedule or AS award
		100%			the costs are entirely to support system operations
			100%		the costs are entirely to support the CRR process
				100%	not distinguishable attribute to any specific category
	50%	50%			the costs support equally both market and system operations
	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
	80%	20%			the costs are predominantly market related but have some operational relationship
	20%	80%			the costs are predominantly operational flow based but have some market relationship
Operations Related Software					
Automated Dispatch System (ADS)		100%			RT instructions from market to system operations thus the costs are entirely to support system operations
Automated Load Forecast System (ALFS)	50%	50%			market & operations both need forecasts thus the costs support equally both market and system operations
Automatic Mitigation Procedure (AMP)		100%			the costs are entirely to support system operations
Congestion Revenue Rights (CRR)			100%		the costs are entirely to support the CRR process
Credit Liabilities	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Data Warehouse	20%	80%			5 min intervals in RT only hourly intervals in market thus the costs are predominantly operational flow based but have some market relationship
Energy Management System (EMS)		100%			the costs are entirely to support system operations
Existing Transmission Contracts Calculator (ETCC)	50%	50%			needed for market & system operations thus the costs support equally both market and system operations
Full Network Model / State estimator	50%	50%			needed for market & system operations thus the costs support equally both market and system operations
Grid operations Training Simulator (GOTS)	20%	80%			staff training where substantially more procedures in operations versus market thus the costs are predominantly operational flow based but have some market relationship
Integrated Forward Market (IFM)	50%	50%			results support both financially binding schedules and system operations thus the costs support equally both market and system operations
Market Quality System (MQS)	50%	50%			aligns with direct operating process thus the costs support equally both market and system operations
Master file	50%	50%			aligns with direct operating process thus the costs support equally both market and system operations
Meter Data Acquisition System (MDAS)		100%			data feed reflecting settling actual flow of systems operations performance thus the costs are entirely to support system operations
Multistage Generation (MSG)	50%	50%			the costs support equally both market and system operations
Network Applications	50%	50%			the costs support equally both market and system operations
New Resource Interconnection (RIMs)	20%	80%			based on staff training for market services & system operations thus the costs are predominantly operational flow based but have some market relationship
Open Access Same Time Information System (OASIS)	50%	50%			the costs support equally both market and system operations
Operational Meter Analysis & Reporting (OMAR)		100%			same as MDAS thus the costs are entirely to support system operations
Proxy Demand response (PDR)	50%	50%			the costs support equally both market and system operations
Participating Intermittent Resource Project (PIRP)	20%	80%			based on staff training for market services & system operations thus the costs are predominantly operational flow based but have some market relationship
Portal	50%	50%			the costs support equally both market and system operations
CAISO Market Results interface (CMRI)	50%	50%			the costs support equally both market and system operations
Process Information System (PI)		100%			the costs are entirely to support system operations
Real Time markets (RTMA)	20%	80%			support & provide actual dispatches to balance system thus the costs are predominantly operational flow based but have some market relationship
Hour Ahead Market (HASP)	50%	50%			includes market power mitigation thus the costs support equally both market and system operations
Resource Adequacy	50%	50%			the costs support equally both market and system operations

Allocation of Debt Service and Out of Pocket Capital to GMC cost categories					
System	**Market services**	**System operations**	**CRRs**	**Indirect**	**Comments**
	% of cost to allocate to category				
Definitions used in allocation	100%				the costs are entirely to support the market results & function resulting in a fi9nancially binding schedule or AS award
		100%			the costs are entirely to support system operations
			100%		the costs are entirely to support the CRR process
				100%	not distinguishable attribute to any specific category
	50%	50%			the costs support equally both market and system operations
	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
	80%	20%			the costs are predominantly market related but have some operational relationship
	20%	80%			the costs are predominantly operational flow based but have some market relationship
Operations Related Software (continued)					
RMR application Validation Engine (RAVE)	50%	50%			the costs support equally both market and system operations
Scheduling & Logging for ISO CA (SLIC)	50%	50%			the costs support equally both market and system operations
Control Area Scheduler (CAS)	50%	50%			the costs support equally both market and system operations
Scheduling Infrastructure Business Rules (SIBR)	50%	50%			this contains interface to operations thus the costs support equally both market and system operations
Settlements & Market Clearing (SaMC)	15%	75%	10%		based on DA & RT charge codes which settle 12 intervals operations hour for operations versus hourly for market thus after a minimum allocation to CRRs the costs are predominantly operational flow based but have some market relationship
General Software					
Client relations & engineering analysis tools				100%	not distinguishable attribute to any specific category
DMM & compliance Tools (SAS MARS)	50%	50%			the costs support equally both market and system operations
Local Area Network (LAN), WAN & monitoring (Tivoli)				100%	not distinguishable attribute to any specific category
Office automation desktop laptop (OA)				100%	not distinguishable attribute to any specific category
Oracle Corporate Financials				100%	not distinguishable attribute to any specific category
Security External Physical & ISS (CUDA)				100%	not distinguishable attribute to any specific category
Storage (EMC symmetrix)				100%	not distinguishable attribute to any specific category
Fixed Assets					
Land & feasibility studies				100%	not distinguishable attribute to any specific category
NT servers & WEB servers				100%	not distinguishable attribute to any specific category
New system equipment				100%	not distinguishable attribute to any specific category
Office equipment, physical facilities software, furniture & leasehold improvements				100%	not distinguishable attribute to any specific category

Mapping costs to direct and support activities & Other costs	2010 Budget $ in thousands			Percentage of time to direct operating activities						Allocation of direct operating costs $ in thousands						
				Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Direct operating activities
Organization Name	**Total**	**Activities**	**Other**	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**Total**
Chief Executive Officer	6,514	6,514	-	2%	2%	0%	0%	0%	0%	159	159	-	-	-	-	318
VP of Human Resources	6,104	6,104	-	0%	0%	0%	0%	0%	0%	-	-	-	-	-	-	-
VP of Market & Infrastructure Development	14,093	14,093	-	64%	36%	0%	0%	0%	0%	8,959	5,036	49	-	49	-	14,093
VP of Technology, Corporate Services & CFO	65,412	36,592	28,820	0%	0%	3%	0%	0%	1%	124	-	947	-	-	234	1,305
VP of Operations	48,994	48,994	-	2%	3%	21%	18%	38%	16%	1,050	1,507	10,431	8,762	18,642	7,943	48,335
VP, General Counsel & Corporate Secretary	12,671	8,471	4,200	1%	7%	0%	0%	0%	0%	88	561	-	-	-	-	649
VP of Policy & Client Services	8,907	8,907	-	1%	0%	0%	0%	0%	0%	125	-	-	-	-	-	125
Total	**162,695**	**129,675**	**33,020**	**8%**	**6%**	**9%**	**7%**	**14%**	**6%**	**10,505**	**7,263**	**11,427**	**8,762**	**18,691**	**8,177**	**64,825**

Mapping costs to direct and support activities & Other costs	2010 Budget $ in thousands			Percentage of time to support activities				Allocation of support costs $ in thousands				
				Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support activities
Organization Name	**Total**	**Activities**	**Other**	**80010**	**80003**	**80008**	**80009**	**80010**	**80003**	**80008**	**80009**	**Total**
Chief Executive Officer	6,514	6,514	-	0%	0%	55%	40%	-	-	3,565	2,631	6,196
VP of Human Resources	6,104	6,104	-	0%	100%	0%	0%	-	6,104	-	-	6,104
VP of Market & Infrastructure Development	14,093	14,093	-	0%	0%	0%	0%	-	-	-	-	-
VP of Technology, Corporate Services & CFO	65,412	36,592	28,820	0%	0%	20%	76%	131	77	7,405	27,674	35,287
VP of Operations	48,994	48,994	-	0%	0%	0%	1%	40	-	-	619	659
VP, General Counsel & Corporate Secretary	12,671	8,471	4,200	0%	0%	12%	80%	-	-	1,018	6,804	7,822
VP of Policy & Client Services	8,907	8,907	-	88%	0%	11%	0%	7,813	-	969	-	8,782
Total	**162,695**	**129,675**	**33,020**	**6%**	**5%**	**10%**	**29%**	**7,984**	**6,181**	**12,957**	**37,728**	**64,850**

Cost Center	Mapping costs to direct and support activities & Other costs	2010 Budget $ in thousands			Percentage of time to direct operating activities						Allocation of direct operating costs $ in thousands						
					Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Direct operating activities
	Organization Name	**Total**	**Activities**	**Other**	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**Total**
2100	**Chief Executive Officer**																
2111	CEO - General	2,373	2,373	-							-	-	-	-	-	-	-
2131	Organizational Effectiveness	1,216	1,216	-							-	-	-	-	-	-	-
2120	***Market Monitoring***																
2121	Market Monitoring - General	634	634	-							-	-	-	-	-	-	-
2123	Monitoring & Reporting	1,059	1,059	-							-	-	-	-	-	-	-
2124	Analysis & Mitigation	914	914	-							-	-	-	-	-	-	-
2122	Market Surveillance Committee	318	318	-	50%	50%					159	159	-	-	-	-	318
	Total	**6,514**	**6,514**	**-**							**159**	**159**	**-**	**-**	**-**	**-**	**318**
2340	**VP of Human Resources**																
2341	Human Resources - General	3,930	3,930	-							-	-	-	-	-	-	-
2342	Learning & Organizational Development	430	430	-							-	-	-	-	-	-	-
2343	Compensation and Benefits	888	888	-							-	-	-	-	-	-	-
2344	HR Operations	856	856	-							-	-	-	-	-	-	-
	Total	**6,104**	**6,104**	**-**							-	-	-	-	-	-	**-**
2200	**VP of Market & Infrastructure Development**																
2211	Market & Infrastructure Development - General	1,063	1,063	-	83%	17%					882	181	-	-	-	-	1,063
2221	Regional Transmission - North	2,438	2,438	-	92%	6%	1%		1%		2,244	146	24	-	24	-	2,438
2231	Regional Transmission - South	2,500	2,500	-	92%	6%	1%		1%		2,300	150	25	-	25	-	2,500
2241	Grid Assets	2,222	2,222	-	100%						2,222	-	-	-	-	-	2,222
2720	***Market & Infrastructure Policy***																
2721	Market & Infrastructure Policy - General	1,354	1,354	-	33%	67%					447	907	-	-	-	-	1,354
2722	Market Design & Regulatory Policy	914	914	-		100%					-	914	-	-	-	-	914
2723	Infrastructure Policy & Contracts	1,290	1,290	-	67%	33%					864	426	-	-	-	-	1,290
2760	***Market Analysis & Development***																
2761	Market Analysis & Development - General	709	709	-		100%					-	709	-	-	-	-	709
2762	Market Analysis	932	932	-		100%					-	932	-	-	-	-	932
2751	Western Regional Initiatives	671	671	-		100%					-	671	-	-	-	-	671
	Total	**14,093**	**14,093**	**-**							**8,959**	**5,036**	**49**	**-**	**49**	**-**	**14,093**

Cost Center	Mapping costs to direct and support activities & Other costs	2010 Budget $ in thousands			Percentage of time to direct operating activities						Allocation of direct operating costs $ in thousands						
					Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Direct operating activities
	Organization Name	**Total**	**Activities**	**Other**	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**Total**
2400	**VP of Technology, Corporate Services & CFO**																
2411	Corporate Services - General	1,291	1,291	-							-	-	-	-	-	-	-
2311	Treasurer	2,937	732	2,205			72%				-	-	527	-	-	-	527
2321	Accounting	1,373	1,373	-	9%					4%	124	-	-	-	-	55	179
2331	Financial Planning	1,887	887	1,000						11%	-	-	-	-	-	98	98
2351	Facilities	7,793	1,184	6,609							-	-	-	-	-	-	-
2361	Procurement & Vendor Management	1,211	1,211	-							-	-	-	-	-	-	-
2374	Physical Security	1,920	1,920	-							-	-	-	-	-	-	-
2481	Power System Technology, Architecture & Development	321	321	-							-	-	-	-	-	-	-
2482	Advanced Power Network Technology	971	971	-							-	-	-	-	-	-	-
2483	Smart Grid Technologies and Strategy	-	-	-							-	-	-	-	-	-	-
2440	***Business Solutions & Quality***																
2463	Business Solutions & Quality - General	1,314	1,314	-							-	-	-	-	-	-	-
2441	Software Quality	2,469	2,469	-							-	-	-	-	-	-	-
2460	***Operations Information Technology***																
2461	IT Strategy & Support - General	1,281	1,281	-							-	-	-	-	-	-	-
2454	Architecture & Systems Engineering (inactive)	1,675	1,675	-							-	-	-	-	-	-	-
2456	System Administration	2,357	2,357	-							-	-	-	-	-	-	-
2462	EMS Information Technology	2,473	2,473	-			17%			1%	-	-	420	-	-	25	445
2464	Corporate Systems	2,950	2,950	-							-	-	-	-	-	-	-
2465	Critical Systems	1,866	1,866	-						3%	-	-	-	-	-	56	56
2450	***IT Support & Operations***																
2451	IT Support & Operations - General	6,366	416	5,950							-	-	-	-	-	-	-
2412	Asset management (HW & SW expense only)	13,607	801	12,806							-	-	-	-	-	-	-
2452	System & Database Administration	1,807	1,807	-							-	-	-	-	-	-	-
2453	Data Center & Operations (includes Info Security)	2,638	2,388	250							-	-	-	-	-	-	-
2455	Support Services	2,156	2,156	-							-	-	-	-	-	-	-
2730	***Program Office***																
2731	Program Office - General	2,104	2,104	-							-	-	-	-	-	-	-
2741	Program Life Cycle & Process	645	645	-							-	-	-	-	-	-	-
	Total	**65,412**	**36,592**	**28,820**							**124**	**-**	**947**	**-**	**-**	**234**	**1,305**

Cost Center	Mapping costs to direct and support activities & Other costs	2010 Budget $ in thousands			Percentage of time to direct operating activities						Allocation of direct operating costs $ in thousands						
					Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Direct operating activities
	Organization Name	**Total**	**Activities**	**Other**	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**Total**
2500	**VP of Operations**																
2511	Operations - General	1,182	1,182	-	29%	22%			49%		343	260	-	-	579	-	1,182
2520	***System Operations***																
2521	System Operations - General	1,891	1,891	-				55%	45%		-	-	-	1,040	851	-	1,891
2522	Real-Time Operations	15,759	15,759	-					100%		-	-	-	-	15,759	-	15,759
2523	Scheduling	1,949	1,949	-				54%	22%	24%	-	-	-	1,052	429	468	1,949
2524	Outage Management	2,152	2,152	-			2%	98%			-	-	43	2,109	-	-	2,152
2542	Market Operations	4,366	4,366	-		4%	8%	85%		3%	-	175	349	3,711	-	131	4,366
2530	***Reliability & Market Modeling***																
2531	Reliability & Market Modeling - General	3,034	3,034	-			47%	28%	25%		-	-	1,425	850	759	-	3,034
2251	Network Applications	982	982	-			100%				-	-	982	-	-	-	982
2554	Model & Contract Implementation	1,688	1,688	-	1%		99%				17	-	1,671	-	-	-	1,688
2540	***Market Services***																
2541	Market Services - General	672	672	-			25%			75%	-	-	168	-	-	504	672
2543	Billing & Settlements	3,411	3,411	-		15%	40%			45%	-	512	1,364	-	-	1,535	3,411
2545	Market Information	1,999	1,999	-		8%	48%			44%	-	160	960	-	-	879	1,999
2552	Energy Measurement, Acquisition & Analysis	2,055	2,055	-		13%	32%			55%	-	267	658	-	-	1,130	2,055
2555	Market Services Analysis & Resolution	3,363	3,363	-			2%			98%	-	-	67	-	-	3,296	3,363
2550	**Operations Process, Quality & Compliance**																
2551	Operations Process, Quality & Compliance - General	318	318	-			53%				-	-	169	-	-	-	169
2553	Operations Procedures & Training	2,118	2,118	-			100%				-	-	2,118	-	-	-	2,118
2581	Operations Compliance	212	212	-							-	-	-	-	-	-	-
2556	Operations Process & Performance	516	516	-			50%				-	-	258	-	-	-	258
2571	Grid System Architecture & Renewable Integration	1,327	1,327	-	52%	10%	15%		20%		690	133	199	-	265	-	1,287
	Total	**48,994**	**48,994**	**-**							**1,050**	**1,507**	**10,431**	**8,762**	**18,642**	**7,943**	**48,335**
2600	**VP, General Counsel & Corporate Secretary**																
2611	General Counsel - General	5,825	1,625	4,200							-	-	-	-	-	-	-
2620	***Assistant General Counsel***																
2621	Assistant General Counsel - Corporate	1,098	1,098	-							-	-	-	-	-	-	-
2631	Assistant General Counsel - Regulatory	1,460	1,460	-	6%	34%					88	496	-	-	-	-	584
2641	Assistant General Counsel - Tariff & Compliance	1,167	1,167	-							-	-	-	-	-	-	-
2681	Assistant General Counsel - Litigation & Compliance	-	-	-							-	-	-	-	-	-	-
2661	Paralegal & Office Administration	653	653	-		10%					-	65	-	-	-	-	65
2651	Assistant Corporate Secretary	731	731	-							-	-	-	-	-	-	-
2671	Mandatory Standards Compliance	1,127	1,127	-							-	-	-	-	-	-	-
2372	Internal Audit	610	610	-							-	-	-	-	-	-	-
	Total	**12,671**	**8,471**	**4,200**							**88**	**561**	**-**	**-**	**-**	**-**	**649**
2800	**VP of Policy & Client Services**																
2811	Policy & Client Services - General	969	969	-							-	-	-	-	-	-	-
2840	***Customer Services & Industry Affairs***																
2841	Customer Services & Industry Affairs - General	1,279	1,279	-							-	-	-	-	-	-	-
2842	Customer Service	1,931	1,931	-							-	-	-	-	-	-	-
2843	Stakeholders & Industry Affairs	1,044	1,044	-	12%						125	-	-	-	-	-	125
2830	***Regulatory Affairs***																
2831	State Affairs	604	604	-							-	-	-	-	-	-	-
2832	Regulatory Affairs	550	550	-							-	-	-	-	-	-	-
2833	Federal Affairs	376	376	-							-	-	-	-	-	-	-
2820	***Communications & Public Relations***																
2821	Communications & Public Relations - General	1,301	1,301	-							-	-	-	-	-	-	-
2822	Information Products & Services	853	853	-							-	-	-	-	-	-	-
	Total	**8,907**	**8,907**	**-**							**125**	**-**	**-**	**-**	**-**	**-**	**125**
	Total	**162,695**	**129,675**	**33,020**							**10,505**	**7,263**	**11,427**	**8,762**	**18,691**	**8,177**	**64,825**

Cost Center	Mapping costs to direct and support activities & Other costs	2010 Budget $ in thousands			Percentage of time to support activities				Allocation of support costs $ in thousands				
					Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support activities
	Organization Name	**Total**	**Activities**	**Other**	**80010**	**80003**	**80008**	**80009**	**80010**	**80003**	**80008**	**80009**	**Total**
2100	**Chief Executive Officer**												
2111	CEO - General	2,373	2,373	-			100%		-	-	2,373	-	2,373
2131	Organizational Effectiveness	1,216	1,216	-			98%	2%	-	-	1,192	24	1,216
2120	***Market Monitoring***												
2121	Market Monitoring - General	634	634	-				100%	-	-	-	634	634
2123	Monitoring & Reporting	1,059	1,059	-				100%	-	-	-	1,059	1,059
2124	Analysis & Mitigation	914	914	-				100%	-	-	-	914	914
2122	Market Surveillance Committee	318	318	-					-	-	-	-	-
	Total	**6,514**	**6,514**	**-**					**-**	**-**	**3,565**	**2,631**	**6,196**
2340	**VP of Human Resources**												
2341	Human Resources - General	3,930	3,930	-		100%			-	3,930	-	-	3,930
2342	Learning & Organizational Development	430	430	-		100%			-	430	-	-	430
2343	Compensation and Benefits	888	888	-		100%			-	888	-	-	888
2344	HR Operations	856	856	-		100%			-	856	-	-	856
	Total	**6,104**	**6,104**	**-**		100%			**-**	**6,104**	**-**	**-**	**6,104**
2200	**VP of Market & Infrastructure Development**												
2211	Market & Infrastructure Development - General	1,063	1,063	-					-	-	-	-	-
2221	Regional Transmission - North	2,438	2,438	-					-	-	-	-	-
2231	Regional Transmission - South	2,500	2,500	-					-	-	-	-	-
2241	Grid Assets	2,222	2,222	-					-	-	-	-	-
2720	***Market & Infrastructure Policy***												
2721	Market & Infrastructure Policy - General	1,354	1,354	-					-	-	-	-	-
2722	Market Design & Regulatory Policy	914	914	-					-	-	-	-	-
2723	Infrastructure Policy & Contracts	1,290	1,290	-					-	-	-	-	-
2760	***Market Analysis & Development***												
2761	Market Analysis & Development - General	709	709	-					-	-	-	-	-
2762	Market Analysis	932	932	-					-	-	-	-	-
2751	Western Regional Initiatives	671	671	-					-	-	-	-	-
	Total	**14,093**	**14,093**	**-**					**-**	**-**	**-**	**-**	**-**

Cost Center	Mapping costs to direct and support activities & Other costs	2010 Budget $ in thousands			Percentage of time to support activities				Allocation of support costs $ in thousands				
					Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support activities
	Organization Name	**Total**	**Activities**	**Other**	**80010**	**80003**	**80008**	**80009**	**80010**	**80003**	**80008**	**80009**	**Total**
2400	**VP of Technology, Corporate Services & CFO**												
2411	Corporate Services - General	1,291	1,291	-			50%	50%	-	-	646	645	1,291
2311	Treasurer	2,937	732	2,205			5%	23%	-	-	37	168	205
2321	Accounting	1,373	1,373	-				87%	-	-	-	1,194	1,194
2331	Financial Planning	1,887	887	1,000			69%	20%	-	-	612	177	789
2351	Facilities	7,793	1,184	6,609				100%	-	-	-	1,184	1,184
2361	Procurement & Vendor Management	1,211	1,211	-				100%	-	-	-	1,211	1,211
2374	Physical Security	1,920	1,920	-		4%		96%	-	77	-	1,843	1,920
2481	Power System Technology, Architecture & Development	321	321	-			67%	33%	-	-	215	106	321
2482	Advanced Power Network Technology	971	971	-			100%		-	-	971	-	971
2483	Smart Grid Technologies and Strategy	-	-	-			100%		-	-	-	-	-
2440	***Business Solutions & Quality***												
2463	Business Solutions & Quality - General	1,314	1,314	-			31%	69%	-	-	407	907	1,314
2441	Software Quality	2,469	2,469	-			3%	97%	-	-	74	2,395	2,469
2460	***Operations Information Technology***												
2461	IT Strategy & Support - General	1,281	1,281	-				100%	-	-	-	1,281	1,281
2454	Architecture & Systems Engineering (inactive)	1,675	1,675	-			100%		-	-	1,675	-	1,675
2456	System Administration	2,357	2,357	-				100%	-	-	-	2,357	2,357
2462	EMS Information Technology	2,473	2,473	-				82%	-	-	-	2,028	2,028
2464	Corporate Systems	2,950	2,950	-				100%	-	-	-	2,950	2,950
2465	Critical Systems	1,866	1,866	-	7%		1%	89%	131	-	19	1,660	1,810
2450	***IT Support & Operations***												
2451	IT Support & Operations - General	6,366	416	5,950				100%	-	-	-	416	416
2412	Asset management (HW & SW expense only)	13,607	801	12,806				100%	-	-	-	801	801
2452	System & Database Administration	1,807	1,807	-				100%	-	-	-	1,807	1,807
2453	Data Center & Operations (includes Info Security)	2,638	2,388	250				100%	-	-	-	2,388	2,388
2455	Support Services	2,156	2,156	-				100%	-	-	-	2,156	2,156
2730	***Program Office***												
2731	Program Office - General	2,104	2,104	-			100%		-	-	2,104	-	2,104
2741	Program Life Cycle & Process	645	645	-			100%		-	-	645	-	645
	Total	**65,412**	**36,592**	**28,820**					**131**	**77**	**7,405**	**27,674**	**35,287**

Cost Center	Mapping costs to direct and support activities & Other costs	2010 Budget $ in thousands			Percentage of time to support activities				Allocation of support costs $ in thousands				
					Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support customers & stake-holders (SCS)	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support activities
	Organization Name	Total	Activities	Other	80010	80003	80008	80009	80010	80003	80008	80009	Total
2500	**VP of Operations**												
2511	Operations - General	1,182	1,182	-					-	-	-	-	-
2520	***System Operations***												
2521	System Operations - General	1,891	1,891	-					-	-	-	-	-
2522	Real-Time Operations	15,759	15,759	-					-	-	-	-	-
2523	Scheduling	1,949	1,949	-					-	-	-	-	-
2524	Outage Management	2,152	2,152	-					-	-	-	-	-
2542	Market Operations	4,366	4,366	-					-	-	-	-	-
2530	***Reliability & Market Modeling***												
2531	Reliability & Market Modeling - General	3,034	3,034	-					-	-	-	-	-
2251	Network Applications	982	982	-					-	-	-	-	-
2554	Model & Contract Implementation	1,688	1,688	-					-	-	-	-	-
2540	***Market Services***												
2541	Market Services - General	672	672	-					-	-	-	-	-
2543	Billing & Settlements	3,411	3,411	-					-	-	-	-	-
2545	Market Information	1,999	1,999	-					-	-	-	-	-
2552	Energy Measurement, Acquisition & Analysis	2,055	2,055	-					-	-	-	-	-
2555	Market Services Analysis & Resolution	3,363	3,363	-					-	-	-	-	-
2550	**Operations Process, Quality & Compliance**												
2551	Operations Process, Quality & Compliance - General	318	318	-				47%	-	-	-	149	149
2553	Operations Procedures & Training	2,118	2,118	-					-	-	-	-	-
2581	Operations Compliance	212	212	-				100%	-	-	-	212	212
2556	Operations Process & Performance	516	516	-				50%	-	-	-	258	258
2571	Grid System Architecture & Renewable Integration	1,327	1,327	-	3%				40	-	-	-	40
	Total	**48,994**	**48,994**	**-**					**40**	**-**	**-**	**619**	**659**
2600	**VP, General Counsel & Corporate Secretary**												
2611	General Counsel - General	5,825	1,625	4,200			17%	83%	-	-	276	1,349	1,625
2620	***Assistant General Counsel***												
2621	Assistant General Counsel - Corporate	1,098	1,098	-			1%	99%	-	-	11	1,087	1,098
2631	Assistant General Counsel - Regulatory	1,460	1,460	-				60%	-	-	-	876	876
2641	Assistant General Counsel - Tariff & Compliance	1,167	1,167	-				100%	-	-	-	1,167	1,167
2681	Assistant General Counsel - Litigation & Compliance	-	-	-				100%	-	-	-	-	-
2661	Paralegal & Office Administration	653	653	-				90%	-	-	-	588	588
2651	Assistant Corporate Secretary	731	731	-			100%		-	-	731	-	731
2671	Mandatory Standards Compliance	1,127	1,127	-				100%	-	-	-	1,127	1,127
2372	Internal Audit	610	610	-				100%	-	-	-	610	610
	Total	**12,671**	**8,471**	**4,200**					**-**	**-**	**1,018**	**6,804**	**7,822**
2800	**VP of Policy & Client Services**												
2811	Policy & Client Services - General	969	969	-			100%		-	-	969	-	969
2840	***Customer Services & Industry Affairs***												
2841	Customer Services & Industry Affairs - General	1,279	1,279	-	100%				1,279	-	-	-	1,279
2842	Customer Service	1,931	1,931	-	100%				1,931	-	-	-	1,931
2843	Stakeholders & Industry Affairs	1,044	1,044	-	88%				919	-	-	-	919
2830	***Regulatory Affairs***												
2831	State Affairs	604	604	-	100%				604	-	-	-	604
2832	Regulatory Affairs	550	550	-	100%				550	-	-	-	550
2833	Federal Affairs	376	376	-	100%				376	-	-	-	376
2820	***Communications & Public Relations***												
2821	Communications & Public Relations - General	1,301	1,301	-	100%				1,301	-	-	-	1,301
2822	Information Products & Services	853	853	-	100%				853	-	-	-	853
	Total	**8,907**	**8,907**	**-**					**7,813**	**-**	**969**	**-**	**8,782**
	Total	**162,695**	**129,675**	**33,020**					**7,984**	**6,181**	**12,957**	**37,728**	**64,850**

Cost Center	Mapping costs to direct operating activities	Allocation of direct operating costs $ in thousands						
		Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Direct Activity Budget
	Organization Name	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**Total**
2100	**Chief Executive Officer**							
2120	***Market Monitoring***							
2122	Market Surveillance Committee (non labor)	-	159	159	-	-	-	318
	Total	**-**	**159**	**159**	**-**	**-**	**-**	**318**
2200	**VP of Market & Infrastructure Development**							
2211	Market & Infrastructure Development - General	882	181	-	-	-	-	1,063
2221	Regional Transmission - North	2,244	146	24	-	24	-	2,438
2231	Regional Transmission - South	2,300	150	25	-	25	-	2,500
2241	Grid Assets	2,222	-	-	-	-	-	2,222
	Market & Infrastructure Policy							
2721	Market & Infrastructure Policy - General	447	907	-	-	-	-	1,354
2722	Market Design & Regulatory Policy	-	914	-	-	-	-	914
2723	Infrastructure Policy & Contracts	864	426	-	-	-	-	1,290
	Market Analysis & Development							
2761	Market Analysis & Development - General	-	709	-	-	-	-	709
2762	Market Analysis	-	932	-	-	-	-	932
2751	Western Regional Initiatives	-	671	-	-	-	-	671
	Total	**8,959**	**5,036**	**49**	**-**	**49**	**-**	**14,093**
2400	**VP of Technology, Corporate Services & CFO**							
2311	Treasurer	-	-	527	-	-	-	527
2321	Accounting	124	-	-	-	-	55	179
2331	Financial Planning	-	-	-	-	-	98	98
2462	EMS Information Technology	-	-	420	-	-	25	445
2465	Critical Systems	-	-	-	-	-	56	56
	Total	**124**	**-**	**947**	**-**	**-**	**234**	**1,305**
2500	**VP of Operations**							
2511	Operations - General	343	260	-	-	579	-	1,182
	System Operations							
2521	System Operations - General	-	-	-	1,040	851	-	1,891
2522	Real-Time Operations	-	-	-	-	15,759	-	15,759
2523	Scheduling	-	-	-	1,052	429	468	1,949
2524	Outage Management	-	-	43	2,109	-	-	2,152
2542	Market Operations	-	175	349	3,711	-	131	4,366
	Reliability & Market Modeling							
2531	Reliability & Market Modeling - General	-	-	1,425	850	759	-	3,034
2251	Network Applications	-	-	982	-	-	-	982
2554	Model & Contract Implementation	17	-	1,671	-	-	-	1,688
	Market Services							
2541	Market Services - General	-	-	168	-	-	504	672
2543	Billing & Settlements	-	512	1,364	-	-	1,535	3,411
2545	Market Information	-	160	960	-	-	879	1,999
2552	Energy Measurement, Acquisition & Analysis	-	267	658	-	-	1,130	2,055
2555	Market Services Analysis & Resolution	-	-	67	-	-	3,296	3,363
	Operations Process, Quality & Compliance							
2551	Operations Process, Quality & Compliance - General	-	-	169	-	-	-	169
2553	Operations Procedures & Training	-	-	2,118	-	-	-	2,118
2556	Operations Process & Performance	-	-	258	-	-	-	258
2571	Grid System Architecture & Renewable Integration	690	133	199	-	265	-	1,287
	Total	**1,050**	**1,507**	**10,431**	**8,762**	**18,642**	**7,943**	**48,335**
2600	**VP, General Counsel & Corporate Secretary**							
2631	Assistant General Counsel - Regulatory	88	496	-	-	-	-	584
2661	Paralegal & Office Administration	-	65	-	-	-	-	65
	Total	**88**	**561**	**-**	**-**	**-**	**-**	**649**
2800	**VP of Policy & Client Services**							
2843	Stakeholders & Industry Affairs	125	-	-	-	-	-	125
	Total	**125**	**-**	**-**	**-**	**-**	**-**	**125**

Cost Center	Mapping costs to direct operating activities	Allocation of direct operating costs $ in thousands						
		Develop infra-structure (DI)	Develop markets (DM)	Manage market reliability & data modeling (MMR)	Manage market setup & execution (MMS)	Operate real time market & grid (OMG)	Manage operations support & settlements (MOS)	Direct Activity Budget
	Organization Name	**80001**	**80002**	**80004**	**80005**	**80006**	**80007**	**Total**
	Total	**10,346**	**7,263**	**11,586**	**8,762**	**18,691**	**8,177**	**64,825**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity									Allocation of costs to acttivity $ in thousands									
		Develop & monitor regulatory contract proce- dures	Manage LGIP cluster studies	Manage long term trans- mission planning	Manage new trans- mission resources & grid changes	Manage SGIP studies	Manage short term trans- mission planning	Manage trans- mission mainten- ance standards	NERC / WECC loads & resources data requests	Regula- tory contract negotia- tions	Develop & monitor regulatory contract proce- dures	Manage LGIP cluster studies	Manage long term trans- mission planning	Manage new trans- mission resources & grid changes	Manage SGIP studies	Manage short term trans- mission planning	Manage trans- mission mainten- ance standards	NERC / WECC loads & resources data requests	Regula- tory contract negotia- tions	Total
	Organization Name	Develop Infrastructure (DI) (80001)									Develop Infrastructure (DI) (80001)									
2100	**Chief Executive Officer**																			
2120	***Market Monitoring***																			
2122	Market Surveillance Committee (non labor)										-	-	-	-	-	-	-	-	-	-
	Total										**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2200	**VP of Market & Infrastructure Development**																			
2211	Market & Infrastructure Development - General			50%	25%		25%				-	-	440	221	-	221	-	-	-	882
2221	Regional Transmission - North	2.2%	10.9%	43.5%	10.9%	10.9%	21.7%				49	245	973	245	245	487	-	-	-	2,244
2231	Regional Transmission - South	2.2%	10.9%	43.5%	10.9%	10.9%	21.7%				51	251	997	251	251	499	-	-	-	2,300
2241	Grid Assets	5%	35%		10%	10%		20%	20%		111	779	-	222	222	-	444	444	-	2,222
	Market & Infrastructure Policy																			
2721	Market & Infrastructure Policy - General	100%									447	-	-	-	-	-	-	-	-	447
2722	Market Design & Regulatory Policy										-	-	-	-	-	-	-	-	-	-
2723	Infrastructure Policy & Contracts	21.1%	4.2%	7.0%		7.0%				60.6%	182	36	60	-	60	-	-	-	526	864
	Market Analysis & Development																			
2761	Market Analysis & Development - General										-	-	-	-	-	-	-	-	-	-
2762	Market Analysis										-	-	-	-	-	-	-	-	-	-
2751	Western Regional Initiatives		100%								-	-	-	-	-	-	-	-	-	-
	Total										**840**	**1,311**	**2,470**	**939**	**778**	**1,207**	**444**	**444**	**526**	**8,959**
2400	**VP of Technology, Corporate Services & CFO**																			
2311	Treasurer										-	-	-	-	-	-	-	-	-	-
2321	Accounting		100%								-	124	-	-	-	-	-	-	-	124
2331	Financial Planning										-	-	-	-	-	-	-	-	-	-
2462	EMS Information Technology										-	-	-	-	-	-	-	-	-	-
2465	Critical Systems										-	-	-	-	-	-	-	-	-	-
	Total										**-**	**124**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**124**
2500	**VP of Operations**																			
2511	Operations - General			50%	50%						-	-	172	171	-	-	-	-	-	343
	System Operations																			
2521	System Operations - General										-	-	-	-	-	-	-	-	-	-
2522	Real-Time Operations										-	-	-	-	-	-	-	-	-	-
2523	Scheduling										-	-	-	-	-	-	-	-	-	-
2524	Outage Management										-	-	-	-	-	-	-	-	-	-
2542	Market Operations										-	-	-	-	-	-	-	-	-	-
	Reliability & Market Modeling																			
2531	Reliability & Market Modeling - General										-	-	-	-	-	-	-	-	-	-
2251	Network Applications										-	-	-	-	-	-	-	-	-	-
2554	Model & Contract Implementation			100%							-	-	17	-	-	-	-	-	-	17
	Market Services																			
2541	Market Services - General										-	-	-	-	-	-	-	-	-	-
2543	Billing & Settlements										-	-	-	-	-	-	-	-	-	-
2545	Market Information										-	-	-	-	-	-	-	-	-	-
2552	Energy Measurement, Acquisition & Analysis										-	-	-	-	-	-	-	-	-	-
2555	Market Services Analysis & Resolution										-	-	-	-	-	-	-	-	-	-
	Operations Process, Quality & Compliance																			
2551	Operations Process, Quality & Compliance - General										-	-	-	-	-	-	-	-	-	-
2553	Operations Procedures & Training										-	-	-	-	-	-	-	-	-	-
2556	Operations Process & Performance										-	-	-	-	-	-	-	-	-	-
2571	Grid System Architecture & Renewable Integration	34.6%		32.7%	32.7%						238	-	226	226	-	-	-	-	-	690
	Total										**238**	**-**	**415**	**397**	**-**	**-**	**-**	**-**	**-**	**1,050**
2600	**VP, General Counsel & Corporate Secretary**																			
2631	Assistant General Counsel - Regulatory									100%	-	-	-	-	-	-	-	-	88	88
2661	Paralegal & Office Administration										-	-	-	-	-	-	-	-	-	-
	Total										**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**88**	**88**
2800	**VP of Policy & Client Services**																			
2843	Stakeholders & Industry Affairs		20%	20%	20%	20%	20%				-	25	25	25	25	25	-	-	-	125
	Total										**-**	**25**	**25**	**25**	**25**	**25**	**-**	**-**	**-**	**125**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity									Allocation of costs to acttivity $ in thousands									
		Develop & monitor regulatory contract proce- dures	Manage LGIP cluster studies	Manage long term trans- mission planning	Manage new trans- mission resources & grid changes	Manage SGIP studies	Manage short term trans- mission planning	Manage trans- mission mainten- ance standards	NERC / WECC loads & resources data requests	Regula- tory contract negotia- tions	Develop & monitor regulatory contract proce- dures	Manage LGIP cluster studies	Manage long term trans- mission planning	Manage new trans- mission resources & grid changes	Manage SGIP studies	Manage short term trans- mission planning	Manage trans- mission mainten- ance standards	NERC / WECC loads & resources data requests	Regula- tory contract negotia- tions	Total
	Organization Name	Develop Infrastructure (DI) (80001)									Develop Infrastructure (DI) (80001)									
	Total										**1,078**	**1,460**	**2,910**	**1,361**	**803**	**1,232**	**444**	**444**	**614**	**10,346**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity							Allocation of costs to acttivity $ in thousands							
		BPM change manage-ment process	Develop State / Federal regulatory policy	Manage regulatory filings	Manage tariff amend-ments	Market design & regulatory policy	Manage market analysis & develop-ment	Perform market analysis	BPM change manage-ment process	Develop State / Federal regulatory policy	Manage regulatory filings	Manage tariff amend-ments	Market design & regulatory policy	Manage market analysis & develop-ment	Perform market analysis	Total
	Organization Name	Develop Markets (DM) (80002)							Develop Markets (DM) (80002)							
2100	**Chief Executive Officer**															
2120	***Market Monitoring***															
2122	Market Surveillance Committee (non labor)					100%			-	-	-	-	159	-	-	159
	Total								**-**	**-**	**-**	**-**	**159**	**-**	**-**	**159**
2200	**VP of Market & Infrastructure Development**															
2211	Market & Infrastructure Development - General		25%	25%		50%			-	45	45	-	91	-	-	181
2221	Regional Transmission - North	33.3%	16.7%	16.7%	16.7%		16.7%		50	24	24	24	-	24	-	146
2231	Regional Transmission - South	33.3%	16.7%	16.7%	16.7%		16.7%		50	25	25	25	-	25	-	150
2241	Grid Assets								-	-	-	-	-	-	-	-
	Market & Infrastructure Policy															
2721	Market & Infrastructure Policy - General		16.7%	11.1%	11.1%	61.1%			-	151	101	101	554	-	-	907
2722	Market Design & Regulatory Policy	5%	5%	20%	10%	50%		10%	46	46	183	91	457	-	91	914
2723	Infrastructure Policy & Contracts		31.0%	17.2%	17.2%	34.5%			-	132	73	73	148	-	-	426
	Market Analysis & Development															
2761	Market Analysis & Development - General	5%	10%	5%	5%	10%	60%	5%	35	71	35	35	71	427	35	709
2762	Market Analysis	5%	10%	5%	5%	10%	60%	5%	47	93	47	47	93	558	47	932
2751	Western Regional Initiatives		76.9%			23.1%			-	516	-	-	155	-	-	671
	Total								**228**	**1,103**	**533**	**396**	**1,569**	**1,034**	**173**	**5,036**
2400	**VP of Technology, Corporate Services & CFO**															
2311	Treasurer								-	-	-	-	-	-	-	-
2321	Accounting								-	-	-	-	-	-	-	-
2331	Financial Planning								-	-	-	-	-	-	-	-
2462	EMS Information Technology								-	-	-	-	-	-	-	-
2465	Critical Systems								-	-	-	-	-	-	-	-
	Total								**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2500	**VP of Operations**															
2511	Operations - General					100%			-	-	-	-	260	-	-	260
	System Operations															
2521	System Operations - General	33.3%			33.4%	33.3%			-	-	-	-	-	-	-	-
2522	Real-Time Operations								-	-	-	-	-	-	-	-
2523	Scheduling								-	-	-	-	-	-	-	-
2524	Outage Management	100%							-	-	-	-	-	-	-	-
2542	Market Operations	25%				75%			44	-	-	-	131	-	-	175
	Reliability & Market Modeling															
2531	Reliability & Market Modeling - General								-	-	-	-	-	-	-	-
2251	Network Applications								-	-	-	-	-	-	-	-
2554	Model & Contract Implementation								-	-	-	-	-	-	-	-
	Market Services															
2541	Market Services - General								-	-	-	-	-	-	-	-
2543	Billing & Settlements	66.7%					33.3%		342	-	-	-	-	170	-	512
2545	Market Information	37.5%				62.5%			60	-	-	-	100	-	-	160
2552	Energy Measurement, Acquisition & Analysis	7.7%		15.3%		38.5%	38.5%		21	-	41	-	103	103	-	267
2555	Market Services Analysis & Resolution								-	-	-	-	-	-	-	-
	Operations Process, Quality & Compliance															
2551	Operations Process, Quality & Compliance - General								-	-	-	-	-	-	-	-
2553	Operations Procedures & Training								-	-	-	-	-	-	-	-
2556	Operations Process & Performance								-	-	-	-	-	-	-	-
2571	Grid System Architecture & Renewable Integration		100%						-	133	-	-	-	-	-	133
	Total								**467**	**133**	**41**	**-**	**594**	**273**	**-**	**1,507**
2600	**VP, General Counsel & Corporate Secretary**															
2631	Assistant General Counsel - Regulatory	5.9%	5.9%	35.3%	35.3%	17.6%			29	29	175	176	87	-	-	496
2661	Paralegal & Office Administration	10%		50%	40%				7	-	32	26	-	-	-	65
	Total								**36**	**29**	**207**	**202**	**87**	**-**	**-**	**561**
2800	**VP of Policy & Client Services**															
2843	Stakeholders & Industry Affairs								-	-	-	-	-	-	-	-
	Total								**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Exhibit 4

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity							Allocation of costs to acttivity $ in thousands							
		BPM change manage-ment process	Develop State / Federal regulatory policy	Manage regulatory filings	Manage tariff amend-ments	Market design & regulatory policy	Manage market analysis & develop-ment	Perform market analysis	BPM change manage-ment process	Develop State / Federal regulatory policy	Manage regulatory filings	Manage tariff amend-ments	Market design & regulatory policy	Manage market analysis & develop-ment	Perform market analysis	Total
	Organization Name	**Develop Markets (DM) (80002)**							**Develop Markets (DM) (80002)**							
	Total								**731**	**1,265**	**781**	**598**	**2,409**	**1,307**	**173**	**7,263**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity															
		ISO meter certifi-cation	Facilitate SC certifi-cations	High level manage FNM mainten-ance	Manage & facilitate procedure mainten-ance	Manage CRRs	Manage credit & collateral	Manage network appli-cations	Manage opera-tions engin-eering studies	Execute & track opera-tions training	Plan & develop opera-tions training	Manage relia-bility require-ments	Master file updates	EMAA telemetry	Provide stake-holder training	Station power applica- tion procedure	Market services imple-mentation
	Organization Name	Manage Market & Reliability Data & Modeling (MMR) (80004)															
2100	**Chief Executive Officer**																
2120	***Market Monitoring***																
2122	Market Surveillance Committee (non labor)			50%		25%						25%					
	Total																
2200	**VP of Market & Infrastructure Development**																
2211	Market & Infrastructure Development - General																
2221	Regional Transmission - North					100%											
2231	Regional Transmission - South					100%											
2241	Grid Assets																
	Market & Infrastructure Policy																
2721	Market & Infrastructure Policy - General																
2722	Market Design & Regulatory Policy																
2723	Infrastructure Policy & Contracts																
	Market Analysis & Development																
2761	Market Analysis & Development - General																
2762	Market Analysis																
2751	Western Regional Initiatives																
	Total																
2400	**VP of Technology, Corporate Services & CFO**																
2311	Treasurer					10%	90%										
2321	Accounting																
2331	Financial Planning																
2462	EMS Information Technology							100%									
2465	Critical Systems																
	Total																
2500	**VP of Operations**																
2511	Operations - General																
	System Operations																
2521	System Operations - General																
2522	Real-Time Operations																
2523	Scheduling																
2524	Outage Management			100%													
2542	Market Operations			50%										25%		25%	
	Reliability & Market Modeling																
2531	Reliability & Market Modeling - General				23.4%				66.0%		10.6%						
2251	Network Applications			25%				75%									
2554	Model & Contract Implementation			30.3%								20.2%	8.1%			1.0%	40.4%
	Market Services																
2541	Market Services - General	20%				40%											40%
2543	Billing & Settlements					12.5%	12.5%					25%	12.5%		12.5%	12.5%	12.5%
2545	Market Information					95.8%									4.2%		
2552	Energy Measurement, Acquisition & Analysis	31.3%		12.5%										15.6%	3.1%	6.3%	31.2%
2555	Market Services Analysis & Resolution											100%					
	Operations Process, Quality & Compliance																
2551	Operations Process, Quality & Compliance - General									40%	60%						
2553	Operations Procedures & Training									40%	60%						
2556	Operations Process & Performance				100%												
2571	Grid System Architecture & Renewable Integration							46.7%	53.3%								
	Total																
2600	**VP, General Counsel & Corporate Secretary**																
2631	Assistant General Counsel - Regulatory																
2661	Paralegal & Office Administration																
	Total																
2800	**VP of Policy & Client Services**																
2843	Stakeholders & Industry Affairs																
	Total																

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity															
		ISO meter certifi- cation	Facilitate SC certifi- cations	High level manage FNM mainten- ance	Manage & facilitate procedure mainten- ance	Manage CRRs	Manage credit & collateral	Manage network appli- cations	Manage opera- tions engin- eering studies	Execute & track opera- tions training	Plan & develop opera- tions training	Manage relia- bility require- ments	Master file updates	EMAA telemetry	Provide stake- holder training	Station power applica- tion procedure	Market services imple- mentation
	Organization Name	Manage Market & Reliability Data & Modeling (MMR) (80004)															
	Total																

Cost Center	Mapping costs to direct operating activities	ISO meter certification	Facilitate SC certifications	High level manage FNM maintenance	Manage & facilitate procedure maintenance	Manage CRRs	Manage credit & collateral	Manage network applications	Manage operations engineering studies	Execute & track operations training	Plan & develop operations training	Manage reliability requirements	Master file updates	EMAA telemetry	Provide stakeholder training	Station power applica- tion procedure	Market services implementation	Total
		Allocation of costs to acttivity $ in thousands																
	Organization Name	Manage Market & Reliability Data & Modeling (MMR) (80004)																
2100	**Chief Executive Officer**																	
2120	***Market Monitoring***																	
2122	Market Surveillance Committee (non labor)	-	-	79	-	40	-	-	-	-	-	40	-	-	-	-	-	159
	Total	**-**	**-**	**79**	**-**	**40**	**-**	**-**	**-**	**-**	**-**	**40**	**-**	**-**	**-**	**-**	**-**	**159**
2200	**VP of Market & Infrastructure Development**																	
2211	Market & Infrastructure Development - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2221	Regional Transmission - North	-	-	-	-	24	-	-	-	-	-	-	-	-	-	-	-	24
2231	Regional Transmission - South	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	25
2241	Grid Assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Market & Infrastructure Policy																	
2721	Market & Infrastructure Policy - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2722	Market Design & Regulatory Policy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2723	Infrastructure Policy & Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Market Analysis & Development																	
2761	Market Analysis & Development - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2762	Market Analysis	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2751	Western Regional Initiatives	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**49**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**49**
2400	**VP of Technology, Corporate Services & CFO**																	
2311	Treasurer	-	-	-	-	53	474	-	-	-	-	-	-	-	-	-	-	527
2321	Accounting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2331	Financial Planning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2462	EMS Information Technology	-	-	-	-	-	-	420	-	-	-	-	-	-	-	-	-	420
2465	Critical Systems	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**53**	**474**	**420**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**947**
2500	**VP of Operations**																	
2511	Operations - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	System Operations																	
2521	System Operations - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2522	Real-Time Operations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2523	Scheduling	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2524	Outage Management	-	-	43	-	-	-	-	-	-	-	-	-	-	-	-	-	43
2542	Market Operations	-	-	175	-	-	-	-	-	-	-	-	-	87	-	87	-	349
	Reliability & Market Modeling																	
2531	Reliability & Market Modeling - General	-	-	-	333	-	-	-	941	-	151	-	-	-	-	-	-	1,425
2251	Network Applications	-	-	246	-	-	-	736	-	-	-	-	-	-	-	-	-	982
2554	Model & Contract Implementation	-	-	506	-	-	-	-	-	-	-	338	135	-	-	17	675	1,671
	Market Services																	
2541	Market Services - General	34	-	-	-	67	-	-	-	-	-	-	-	-	-	-	67	168
2543	Billing & Settlements	-	-	-	-	171	171	-	-	-	-	338	171	-	171	171	171	1,364
2545	Market Information	-	-	-	-	920	-	-	-	-	-	-	-	-	40	-	-	960
2552	Energy Measurement, Acquisition & Analysis	207	-	82	-	-	-	-	-	-	-	-	-	103	20	41	205	658
2555	Market Services Analysis & Resolution	-	-	-	-	-	-	-	-	-	-	67	-	-	-	-	-	67
	Operations Process, Quality & Compliance																	
2551	Operations Process, Quality & Compliance - General	-	-	-	-	-	-	-	-	68	101	-	-	-	-	-	-	169
2553	Operations Procedures & Training	-	-	-	-	-	-	-	-	847	1,271	-	-	-	-	-	-	2,118
2556	Operations Process & Performance	-	-	-	258	-	-	-	-	-	-	-	-	-	-	-	-	258
2571	Grid System Architecture & Renewable Integration	-	-	-	-	-	-	93	106	-	-	-	-	-	-	-	-	199
	Total	**241**	**-**	**1,052**	**591**	**1,158**	**171**	**829**	**1,047**	**915**	**1,523**	**743**	**306**	**190**	**231**	**316**	**1,118**	**10,431**
2600	**VP, General Counsel & Corporate Secretary**																	
2631	Assistant General Counsel - Regulatory	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2661	Paralegal & Office Administration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2800	**VP of Policy & Client Services**																	
2843	Stakeholders & Industry Affairs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Cost Center	Mapping costs to direct operating activities	ISO meter certifi-cation	Facilitate SC certifi-cations	High level manage FNM mainten-ance	Manage & facilitate procedure mainten-ance	Manage CRRs	Manage credit & collateral	Manage network appli-cations	Manage opera-tions engin-eering studies	Execute & track opera-tions training	Plan & develop opera-tions training	Manage relia-bility require-ments	Master file updates	EMAA telemetry	Provide stake-holder training	Station power applica- tion procedure	Market services imple-mentation	Total
		Allocation of costs to acttivity $ in thousands																
	Organization Name	**Manage Market & Reliability Data & Modeling (MMR) (80004)**																
	Total	**241**	**-**	**1,131**	**591**	**1,300**	**645**	**1,249**	**1,047**	**915**	**1,523**	**783**	**306**	**190**	**231**	**316**	**1,118**	**11,586**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity						Allocation of costs to acttivity $ in thousands						
		Manage D+2 analysis	Manage DA market	Manage DA & RT runs & price valida-tions	Manage genera-tion outages	Manage inter-change sched-uling	Manage trans-mission outages	Manage D+2 analysis	Manage DA market	Manage DA & RT runs & price valida-tions	Manage genera-tion outages	Manage inter-change sched-uling	Manage trans-mission outages	Total
	Organization Name	Manage Market Setup & Execution (MMS) (80005)						Manage Market Setup & Execution (MMS) (80005)						
2100	**Chief Executive Officer**													
2120	***Market Monitoring***													
2122	Market Surveillance Committee (non labor)							-	-	-	-	-	-	-
	Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**
2200	**VP of Market & Infrastructure Development**													
2211	Market & Infrastructure Development - General							-	-	-	-	-	-	-
2221	Regional Transmission - North							-	-	-	-	-	-	-
2231	Regional Transmission - South							-	-	-	-	-	-	-
2241	Grid Assets							-	-	-	-	-	-	-
	Market & Infrastructure Policy													
2721	Market & Infrastructure Policy - General							-	-	-	-	-	-	-
2722	Market Design & Regulatory Policy							-	-	-	-	-	-	-
2723	Infrastructure Policy & Contracts							-	-	-	-	-	-	-
	Market Analysis & Development													
2761	Market Analysis & Development - General							-	-	-	-	-	-	-
2762	Market Analysis							-	-	-	-	-	-	-
2751	Western Regional Initiatives							-	-	-	-	-	-	-
	Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**
2400	**VP of Technology, Corporate Services & CFO**													
2311	Treasurer							-	-	-	-	-	-	-
2321	Accounting							-	-	-	-	-	-	-
2331	Financial Planning							-	-	-	-	-	-	-
2462	EMS Information Technology							-	-	-	-	-	-	-
2465	Critical Systems							-	-	-	-	-	-	-
	Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**
2500	**VP of Operations**													
2511	Operations - General							-	-	-	-	-	-	-
	System Operations													
2521	System Operations - General			100%				-	-	1,040	-	-	-	1,040
2522	Real-Time Operations							-	-	-	-	-	-	-
2523	Scheduling					100%		-	-	-	-	1,052	-	1,052
2524	Outage Management				46.4%		53.6%	-	-	-	979	-	1,130	2,109
2542	Market Operations	17.6%	23.5%	58.9%				654	872	2,185	-	-	-	3,711
	Reliability & Market Modeling													
2531	Reliability & Market Modeling - General	7.1%	14.3%		7.1%		71.5%	60	122	-	60	-	608	850
2251	Network Applications							-	-	-	-	-	-	-
2554	Model & Contract Implementation							-	-	-	-	-	-	-
	Market Services													
2541	Market Services - General							-	-	-	-	-	-	-
2543	Billing & Settlements							-	-	-	-	-	-	-
2545	Market Information							-	-	-	-	-	-	-
2552	Energy Measurement, Acquisition & Analysis							-	-	-	-	-	-	-
2555	Market Services Analysis & Resolution							-	-	-	-	-	-	-
	Operations Process, Quality & Compliance													
2551	Operations Process, Quality & Compliance - General							-	-	-	-	-	-	-
2553	Operations Procedures & Training							-	-	-	-	-	-	-
2556	Operations Process & Performance							-	-	-	-	-	-	-
2571	Grid System Architecture & Renewable Integration							-	-	-	-	-	-	-
	Total							**714**	**994**	**3,225**	**1,039**	**1,052**	**1,738**	**8,762**
2600	**VP, General Counsel & Corporate Secretary**													
2631	Assistant General Counsel - Regulatory							-	-	-	-	-	-	-
2661	Paralegal & Office Administration							-	-	-	-	-	-	-
	Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**
2800	**VP of Policy & Client Services**													
2843	Stakeholders & Industry Affairs							-	-	-	-	-	-	-
	Total							**-**	**-**	**-**	**-**	**-**	**-**	**-**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity						Allocation of costs to acttivity $ in thousands						
		Manage D+2 analysis	Manage DA market	Manage DA & RT runs & price valida-tions	Manage genera-tion outages	Manage inter-change sched-uling	Manage trans-mission outages	Manage D+2 analysis	Manage DA market	Manage DA & RT runs & price valida-tions	Manage genera-tion outages	Manage inter-change sched-uling	Manage trans-mission outages	Total
	Organization Name	Manage Market Setup & Execution (MMS) (80005)						Manage Market Setup & Execution (MMS) (80005)						
	Total							**714**	**994**	**3,225**	**1,039**	**1,052**	**1,738**	**8,762**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity								Allocation of costs to acttivity $ in thousands								
		Manage critical facility systems	Manage emergency opera- tions	Manage opera- tions engineer- ing support	Manage RT market - after close of market	Manage RT market - prior to close of market bidding	Manage RT opera- tions - genera- tion dispatch	Manage RT opera- tions - trans- mission dispatch	Manage RT inter- change scheduling	Manage critical facility systems	Manage emergency opera- tions	Manage opera- tions engineer- ing support	Manage RT market - after close of market	Manage RT market - prior to close of market bidding	Manage RT opera- tions - genera- tion dispatch	Manage RT opera- tions - trans- mission dispatch	Manage RT inter- change scheduling	Total
	Organization Name	Operate Real Time Market & Grid (OMG) (80006)								Operate Real Time Market & Grid (OMG) (80006)								
2100	**Chief Executive Officer**																	
2120	***Market Monitoring***																	
2122	Market Surveillance Committee (non labor)									-	-	-	-	-	-	-	-	-
	Total									**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2200	**VP of Market & Infrastructure Development**																	
2211	Market & Infrastructure Development - General									-	-	-	-	-	-	-	-	-
2221	Regional Transmission - North			100%						-	-	24	-	-	-	-	-	24
2231	Regional Transmission - South			100%						-	-	25	-	-	-	-	-	25
2241	Grid Assets									-	-	-	-	-	-	-	-	-
	Market & Infrastructure Policy																	
2721	Market & Infrastructure Policy - General									-	-	-	-	-	-	-	-	-
2722	Market Design & Regulatory Policy									-	-	-	-	-	-	-	-	-
2723	Infrastructure Policy & Contracts									-	-	-	-	-	-	-	-	-
	Market Analysis & Development																	
2761	Market Analysis & Development - General									-	-	-	-	-	-	-	-	-
2762	Market Analysis									-	-	-	-	-	-	-	-	-
2751	Western Regional Initiatives									-	-	-	-	-	-	-	-	-
	Total									**-**	**-**	**49**	**-**	**-**	**-**	**-**	**-**	**49**
2400	**VP of Technology, Corporate Services & CFO**																	
2311	Treasurer									-	-	-	-	-	-	-	-	-
2321	Accounting									-	-	-	-	-	-	-	-	-
2331	Financial Planning									-	-	-	-	-	-	-	-	-
2462	EMS Information Technology									-	-	-	-	-	-	-	-	-
2465	Critical Systems									-	-	-	-	-	-	-	-	-
	Total									**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2500	**VP of Operations**																	
2511	Operations - General	50%	50%							290	289	-	-	-	-	-	-	579
	System Operations																	
2521	System Operations - General		4.3%		4.4%	4.3%	87.0%			-	37	-	37	37	740	-	-	851
2522	Real-Time Operations						33.3%	33.4%	33.3%	-	-	-	-	-	5,248	5,264	5,247	15,759
2523	Scheduling				50%	50%				-	-	-	215	214	-	-	-	429
2524	Outage Management									-	-	-	-	-	-	-	-	-
2542	Market Operations									-	-	-	-	-	-	-	-	-
	Reliability & Market Modeling																	
2531	Reliability & Market Modeling - General			100%						-	-	759	-	-	-	-	-	759
2251	Network Applications									-	-	-	-	-	-	-	-	-
2554	Model & Contract Implementation									-	-	-	-	-	-	-	-	-
	Market Services																	
2541	Market Services - General									-	-	-	-	-	-	-	-	-
2543	Billing & Settlements									-	-	-	-	-	-	-	-	-
2545	Market Information									-	-	-	-	-	-	-	-	-
2552	Energy Measurement, Acquisition & Analysis									-	-	-	-	-	-	-	-	-
2555	Market Services Analysis & Resolution									-	-	-	-	-	-	-	-	-
	Operations Process, Quality & Compliance																	
2551	Operations Process, Quality & Compliance - General									-	-	-	-	-	-	-	-	-
2553	Operations Procedures & Training									-	-	-	-	-	-	-	-	-
2556	Operations Process & Performance									-	-	-	-	-	-	-	-	-
2571	Grid System Architecture & Renewable Integration	100%								265	-	-	-	-	-	-	-	265
	Total									**555**	**326**	**759**	**252**	**251**	**5,988**	**5,264**	**5,247**	**18,642**
2600	**VP, General Counsel & Corporate Secretary**																	
2631	Assistant General Counsel - Regulatory									-	-	-	-	-	-	-	-	-
2661	Paralegal & Office Administration									-	-	-	-	-	-	-	-	-
	Total									**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2800	**VP of Policy & Client Services**																	
2843	Stakeholders & Industry Affairs									-	-	-	-	-	-	-	-	-
	Total									**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity								Allocation of costs to acttivity $ in thousands								
		Manage critical facility systems	Manage emergency opera- tions	Manage opera- tions engineer- ing support	Manage RT market - after close of market	Manage RT market - prior to close of market bidding	Manage RT opera- tions - genera- tion dispatch	Manage RT opera- tions - trans- mission dispatch	Manage RT inter- change scheduling	Manage critical facility systems	Manage emergency opera- tions	Manage opera- tions engineer- ing support	Manage RT market - after close of market	Manage RT market - prior to close of market bidding	Manage RT opera- tions - genera- tion dispatch	Manage RT opera- tions - trans- mission dispatch	Manage RT inter- change scheduling	Total
	Organization Name	Operate Real Time Market & Grid (OMG) (80006)								Operate Real Time Market & Grid (OMG) (80006)								
	Total									**555**	**326**	**808**	**252**	**251**	**5,988**	**5,264**	**5,247**	**18,691**

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity													
		Manage rules of conduct	Manage regulation, no-pay & deviation penalty calcula- tions	Manage dispute analysis & resolut- ion	Manage energy measure- ment acquisi- tion & analysis	Manage market billing & settle- ments	Manage market clearing	Manage market perfor- mance	Manage price valida- tion & correct- ions	Manage the market quality sustem (MQS)	Manage data requests	WREGIS applica- tion process	ISO meter engin- eering	ISO RIG engin- eering	Market issues steering committee
	Organization Name	Manage Operations Support & Settlements (MOS) (80007)													
2100	**Chief Executive Officer**														
2120	***Market Monitoring***														
2122	Market Surveillance Committee (non labor)														
	Total														
2200	**VP of Market & Infrastructure Development**														
2211	Market & Infrastructure Development - General														
2221	Regional Transmission - North														
2231	Regional Transmission - South														
2241	Grid Assets														
	Market & Infrastructure Policy														
2721	Market & Infrastructure Policy - General														
2722	Market Design & Regulatory Policy														
2723	Infrastructure Policy & Contracts														
	Market Analysis & Development														
2761	Market Analysis & Development - General														
2762	Market Analysis														
2751	Western Regional Initiatives														
	Total														
2400	**VP of Technology, Corporate Services & CFO**														
2311	Treasurer														
2321	Accounting						100%								
2331	Financial Planning					25%	75%								
2462	EMS Information Technology				100%										
2465	Critical Systems				100%										
	Total														
2500	**VP of Operations**														
2511	Operations - General														
	System Operations														
2521	System Operations - General														
2522	Real-Time Operations														
2523	Scheduling			50%	50%										
2524	Outage Management														
2542	Market Operations														100%
	Reliability & Market Modeling														
2531	Reliability & Market Modeling - General														
2251	Network Applications														
2554	Model & Contract Implementation														
	Market Services														
2541	Market Services - General	1.3%	6.7%	13.3%	13.4%	13.3%	5.3%	6.7%	13.3%	13.3%	6.7%				6.7%
2543	Billing & Settlements		11.1%	11.1%		55.6%	11.1%				11.1%				
2545	Market Information							90.9%							9.1%
2552	Energy Measurement, Acquisition & Analysis			1.8%	36.4%	1.8%					1.8%	3.6%	18.2%	36.4%	
2555	Market Services Analysis & Resolution	3.1%	7.1%	26.5%		2.0%			30.7%	25.5%	2.0%				3.1%
	Operations Process, Quality & Compliance														
2551	Operations Process, Quality & Compliance - General														
2553	Operations Procedures & Training														
2556	Operations Process & Performance														
2571	Grid System Architecture & Renewable Integration														
	Total														
2600	**VP, General Counsel & Corporate Secretary**														
2631	Assistant General Counsel - Regulatory														
2661	Paralegal & Office Administration														
	Total														
2800	**VP of Policy & Client Services**														
2843	Stakeholders & Industry Affairs														
	Total														

Cost Center	Mapping costs to direct operating activities	% of time devoted to activity													
		Manage rules of conduct	Manage regulation, no-pay & deviation penalty calcula- tions	Manage dispute analysis & resolut- ion	Manage energy measure- ment acquisi- tion & analysis	Manage market billing & settle- ments	Manage market clearing	Manage market perfor- mance	Manage price valida- tion & correct- ions	Manage the market quality sustem (MQS)	Manage data requests	WREGIS applica- tion process	ISO meter engin- eering	ISO RIG engin- eering	Market issues steering committee
	Organization Name	Manage Operations Support & Settlements (MOS) (80007)													
	Total														

Cost Center	Mapping costs to direct operating activities	Allocation of costs to acttivity $ in thousands														
		Manage rules of conduct	Manage regulation, no-pay & deviation penalty calcula-tions	Manage dispute analysis & resolution	Manage energy measure-ment acquisi-tion & analysis	Manage market billing & settle-ments	Manage market clearing	Manage market perfor-mance	Manage price valida-tion & correct-ions	Manage the market quality sustem (MQS)	Manage data requests	WREGIS applica-tion process	ISO meter engin-eering	ISO RIG engin-eering	Market issues steering committee	Total
	Organization Name	Manage Operations Support & Settlements (MOS) (80007)														
2100	**Chief Executive Officer**															
2120	***Market Monitoring***															
2122	Market Surveillance Committee (non labor)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2200	**VP of Market & Infrastructure Development**															
2211	Market & Infrastructure Development - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2221	Regional Transmission - North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2231	Regional Transmission - South	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2241	Grid Assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Market & Infrastructure Policy															
2721	Market & Infrastructure Policy - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2722	Market Design & Regulatory Policy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2723	Infrastructure Policy & Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Market Analysis & Development															
2761	Market Analysis & Development - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2762	Market Analysis	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2751	Western Regional Initiatives	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2400	**VP of Technology, Corporate Services & CFO**															
2311	Treasurer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2321	Accounting	-	-	-	-	-	55	-	-	-	-	-	-	-	-	55
2331	Financial Planning	-	-	-	-	25	73	-	-	-	-	-	-	-	-	98
2462	EMS Information Technology	-	-	-	25	-	-	-	-	-	-	-	-	-	-	25
2465	Critical Systems	-	-	-	56	-	-	-	-	-	-	-	-	-	-	56
	Total	**-**	**-**	**-**	**81**	**25**	**128**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**234**
2500	**VP of Operations**															
2511	Operations - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	System Operations															
2521	System Operations - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2522	Real-Time Operations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2523	Scheduling	-	-	234	234	-	-	-	-	-	-	-	-	-	-	468
2524	Outage Management	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2542	Market Operations	-	-	-	-	-	-	-	-	-	-	-	-	-	131	131
	Reliability & Market Modeling															
2531	Reliability & Market Modeling - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2251	Network Applications	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2554	Model & Contract Implementation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Market Services															
2541	Market Services - General	7	34	67	68	66	27	34	67	66	34	-	-	-	34	504
2543	Billing & Settlements	-	170	170	-	855	170	-	-	-	170	-	-	-	-	1,535
2545	Market Information	-	-	-	-	-	-	799	-	-	-	-	-	-	80	879
2552	Energy Measurement, Acquisition & Analysis	-	-	20	411	20	-	-	-	-	20	41	206	412	-	1,130
2555	Market Services Analysis & Resolution	102	234	873	-	66	-	-	1,012	840	66	-	-	-	103	3,296
	Operations Process, Quality & Compliance															
2551	Operations Process, Quality & Compliance - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2553	Operations Procedures & Training	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2556	Operations Process & Performance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2571	Grid System Architecture & Renewable Integration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**109**	**438**	**1,364**	**713**	**1,007**	**197**	**833**	**1,079**	**906**	**290**	**41**	**206**	**412**	**348**	**7,943**
2600	**VP, General Counsel & Corporate Secretary**															
2631	Assistant General Counsel - Regulatory	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2661	Paralegal & Office Administration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total															
2800	**VP of Policy & Client Services**															
2843	Stakeholders & Industry Affairs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Cost Center	Mapping costs to direct operating activities	Allocation of costs to acttivity $ in thousands														
		Manage rules of conduct	Manage regulation, no-pay & deviation penalty calcula-tions	Manage dispute analysis & resolution	Manage energy measure-ment acquisi-tion & analysis	Manage market billing & settle-ments	Manage market clearing	Manage market perfor-mance	Manage price valida-tion & correct-ions	Manage the market quality sustem (MQS)	Manage data requests	WREGIS applica-tion process	ISO meter engin-eering	ISO RIG engin-eering	Market issues steering committee	Total
	Organization Name	Manage Operations Support & Settlements (MOS) (80007)														
	Total	**109**	**438**	**1,364**	**794**	**1,032**	**325**	**833**	**1,079**	**906**	**290**	**41**	**206**	**412**	**348**	**8,177**

Other costs by cost center			Detail of non-ABC costs $ in thousands						
Cost Center	Organization Name	2010 Budget $ in thousands	Occu- pancy	HW & SW maint- enance	Commun- ications	Insur- ance	Eqyip- ment & soft- ware	Profess- ional fees - legal and audit
2400	**VP of Technology, Corporate Services & CFO**							
2311	Treasurer	2,205	-	-	-	2,205	-	-
2331	Financial Planning	1,000	-	-	-	-	-	1,000
2351	Facilities	6,609	6,609	-	-	-	-	-
2450	***IT Support & Operations***							
2451	IT Support & Operations - General	5,950	-	-	5,950	-	-	-
2412	Asset management	12,806	-	10,900	-	-	1,906	-
2453	Data Center & Operations	250	150	-	100	-	-	-
	Total	**28,820**	**6,759**	**10,900**	**6,050**	**2,205**	**1,906**	**1,000**
2600	**VP, General Counsel & Corporate Secretary**							
2611	General Counsel - General	4,200	-	-	-	-	-	4,200
	Total	**4,200**	**-**	**-**	**-**	**-**	**-**	**4,200**
	Total	**33,020**	**6,759**	**10,900**	**6,050**	**2,205**	**1,906**	**5,200**

Exhibit 5

Allocation of 2010 revenue requirement to cost categories						
Revenue Requirement	**2010 Budget**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
	Cost of category - $ in thousands					
Direct O&M $	$ 64,825	$ 11,474	$ 45,923	$ 1,500	$ 5,928	6 core ABC activities
Support O&M $	64,850	-	-	-	64,850	remaining 4 ABC activities that are support
Non-ABC support O&M $	33,020	450	450	100	32,020	
Total O&M	162,695	11,924	46,373	1,600	102,798	
O&M Direct %		20%	77%	3%		
Debt Service	76,000	21,300	36,031	2,962	15,707	includes out of pocket capital as well
Debt service Direct %		35%	60%	5%		
Other income	(8,100)	-	-	-	(8,100)	
Operating reserve	(35,500)	(3,295)	(5,856)	(488)	(25,861)	
Total before allocation of indirect	195,095	29,929	76,548	4,074	84,544	
Direct Costs %		27%	69%	4%		
Allocate indirect	-	22,827	58,335	3,382	(84,544)	allocate indirect costs based on direct cost %s
Total Revenue Requirement $	**$ 195,095**	**$ 52,756**	**$ 134,883**	**$ 7,456**		
Total Revenue Requirement %	**100%**	**27%**	**69%**	**4%**		

Exhibit 5

Allocation of ABC Direct Operating Activities to cost categories										
ABC Level 2 Activities	Market services	System Operations	CRR services	Indirect	2010 Budget	Market services	System Operations	CRR services	Indirect	Comments
	Percentage allocation to cost category				Cost of category - $ in thousands					
Develop Infrastructure (DI) (80001)										
Various level 2 activities		100%			$ 10,324	$ -	$ 10,324	$ -	$ -	
Develop Markets (DM) (80002)										
BPM change management process				100%	790	-	-	-	790	
Develop State / Federal regulatory policy				100%	1,121	-	-	-	1,121	
Manage regulatory filings				100%	806	-	-	-	806	
Manage tariff amendments				100%	661	-	-	-	661	
Market design & regulatory policy	100%				2,563	2,563	-	-	-	
Manage market analysis & development	100%				1,307	1,307	-	-	-	
Perform market analysis	100%				173	173	-	-	-	
Total					7,421	4,043	-	-	3,378	
Manage Market & Reliability Data & Modeling (MMR) (80004)										
ISO meter certification		100%			240	-	240	-	-	
Facilitate SC certification				100%	-	-	-	-	-	
High level manage FNM maintenance	50%	50%			1,131	565	566	-	-	
Manage & facilitate procedure maintenance	20%	80%			591	118	473	-		
Manage CRRs			100%		1,299	-		1,299	-	
Manage credit & collateral	45%	45%	10%		645	290	290	65		
Manage network applications		100%			1,249	-	1,249	-	-	
Manage operations engineering studies		100%			1,047	-	1,047	-	-	
Execute & track operations training	20%	80%			915	183	732	-	-	
Plan & develop operations training	20%	80%			1,523	305	1,218	-	-	
Manage reliability requirements		100%			786	-	786	-	-	
Master file updates	50%	50%			306	153	153	-	-	
EMAA telemetry		100%			190	-	190	-	-	
Provide stakeholder training				100%	231	-	-	-	231	
Station power implementation	80%	20%			316	253	63	-	-	
Market services implementation	50%	50%			1,118	559	559	-	-	
Total					11,587	2,426	7,566	1,364	231	
Manage Market Setup & Execution (MMS) (80005)										
Manage D+2 analysis	50%	50%			714	357	357	-	-	
Manage DA market	50%	50%			994	497	497	-	-	
Manage DA & RT runs & price validations	50%	50%			3,093	1,546	1,547	-	-	
Manage generation outages		100%			1,028	-	1,028	-	-	
Manage interchange scheduling		100%			1,051	-	1,051	-	-	
Manage transmission outages		100%			1,727	-	1,727	-	-	
Total					8,607	2,400	6,207	-	-	

Exhibit 5

Allocation of ABC Direct Operating Activities to cost categories										
ABC Level 2 Activities	Market services	System Operations	CRR services	Indirect	2010 Budget	Market services	System Operations	CRR services	Indirect	Comments
	Percentage allocation to cost category				Cost of category - $ in thousands					
Operate Real Time Market & Grid (OMG) (80006)										
Manage critical facility systems				100%	555	-	-	-	555	
Manage emergency operations		100%			327	-	327	-	-	
Manage operations engineering support	20%	80%			808	162	646	-	-	
Manage RT market - after close of market	50%	50%			253	126	127	-	-	
Manage RT market - prior to close of market bidding	50%	50%			252	126	126	-	-	
Manage RT operations - generation dispatch		100%			6,005	-	6,005	-	-	
Manage RT operations - transmission dispatch		100%			5,264	-	5,264	-	-	
Manage RT interchange scheduling		100%			5,247	-	5,247	-	-	
Total					18,711	414	17,742	-	555	
Manage Operations Support & Settlements (MOS) (80007)										
Manage rules of conduct				100%	109	-	-	-	109	
Manage regulation no pay & deviation penalty calculations		100%			438	-	438	-	-	
Manage dispute analysis & resolution				100%	1,364	-	-	-	1,364	
Manage energy measurement acquisition & analysis		100%			794	-	794	-	-	
Manage market billing & settlements	45%	45%	10%		1,028	462	463	103	-	
Manage market clearing	45%	45%	10%		325	146	146	33	-	
Manage market performance	50%	50%			834	417	417	-	-	
Manage price validation & corrections	50%	50%			1,079	539	540	-	-	
Manage the market quality system (MQS)	50%	50%			906	453	453	-	-	
Manage data requests				100%	291	-	-	-	291	
WREGIS application process		100%			41	-	41	-	-	
ISO meter engineering		100%			206	-	206	-	-	
ISO RIG engineering		100%			412	-	412	-	-	
Market issue steering committee	50%	50%			348	174	174	-	-	
Total					8,175	2,191	4,084	136	1,764	
Total					$ 64,825	$ 11,474	$ 45,923	$ 1,500	$ 5,928	
Direct O&M %					100%	19%	78%	3%		

Exhibit 5

Allocation of ABC Support Activities to cost categories										
ABC Level 1 Activities	Market services	System Operations	CRR services	Indirect	2010 Budget	Market services	System Operations	CRR services	Indirect	Comments
	Percentage allocation to cost category				Cost of category - $ in thousands					
Manage Human Capabilities (MHC) (80003)				**100%**	$ 6,181	$ -	$ -		$ 6,181	
Plan & Manage Business (PMB) (80008)				**100%**	12,957	-	-		12,957	
Support Business Services (SBS) (80009)				**100%**	37,728	-	-	-	37,728	
Support Customers & Stakeholders (SCS) (80010)				**100%**	7,984	-	-	-	7,984	
Total Support Activities					$ 64,850	$ -	$ -	$ -	$ 64,850	

Allocation of non-ABC Support costs to cost categories										
non-ABC support costs	Market services	System Operations	CRR services	Indirect	2010 Budget	Market services	System Operations	CRR services	Indirect	Comments
	Percentage allocation to cost category				Cost of category - $ in thousands					
Corporate Services										
occupancy				**100%**	$ 6,759	$ -	$ -	$ -	$ 6,759	
hardware and software maintenance				**100%**	10,900	-	-	-	10,900	
communications (AT&T)				**100%**	6,050	-	-		6,050	
insurance				**100%**	2,205	-	-		2,205	
software & equipment leases				**100%**	1,906	-	-		1,906	
professional fees - SAS 70 audit	**45%**	**45%**	**10%**		1,000	450	450	100	-	same as level 2 settlements
Total corporate services					28,820	450	450	100	27,820	
General Counsel										
professional fees - legal				**100%**	4,200				4,200	
Total legal					4,200	-	-		4,200	
Total non-ABC support costs					$ 33,020	$ 450	$ 450	$ 100	$ 32,020	

System	Market services	System Operations	CRR services	Indirect	2010 Budget	Market services	System Operations	CRR services	Indirect	Comments
Allocation of Debt Service and Out of Pocket Capital to cost categories										
	Percentage allocation to cost category				Cost of category - $ in thousands					
Operations Related Software										
Automated Dispatch System (ADS)		100%			$ 74	$ -	$ 74	$ -	$ -	
Automated Load Forecast System (ALFS)	50%	50%			1,446	723	723	-	-	
Automatic Mitigation Procedure (AMP)		100%			308	-	308	-	-	
CAISO Market Results interface (CMRI)	50%	50%			1,016	508	508	-	-	
Congestion Revenue Rights (CRR)			100%		2,114	-	-	2,114	-	
Control Area Scheduler (CAS)	50%	50%			116	58	58	-	-	
Credit Liabilities	45%	45%	10%		70	32	32	6	-	
Data Warehouse	20%	80%			1,500	300	1,200	-	-	based on 5 min intervals in RT
Energy Management System (EMS)		100%			3,279	-	3,279	-	-	
Existing Transmission Contracts Calculator (ETCC)	50%	50%			13	6	7	-	-	
Full Network Model / State estimator	50%	50%			451	225	226	-	-	
Grid operations Training Simulator (GOTS)	20%	80%			262	52	210	-	-	
Hour Ahead Market (HASP)	50%	50%			3,173	1,586	1,587	-	-	
Integrated Forward Market (IFM) RTN	50%	50%			15,432	7,716	7,716	-	-	
Market Quality System (MQS)	50%	50%			2,506	1,253	1,253	-	-	
Master file	50%	50%			1,012	506	506	-	-	
Meter Data Acquisition System (MDAS)		100%			38	-	38	-	-	
Multistage Generation (MSG)	50%	50%			214	107	107	-	-	
Network Applications	50%	50%			1,668	834	834	-	-	
New Resource Interconnection (Rims) or (NRI)	20%	80%			542	108	434	-	-	
Open Access Same Time Information System (OASIS)	50%	50%			163	81	82	-	-	
Operational Meter Analysis & Reporting (OMAR)		100%			239	-	239	-	-	
Participating Intermittant Resource Project (PIRP)	20%	80%			3,511	702	2,809	-	-	
Proxy Demand response (PDR)	50%	50%			212	106	106	-	-	
Portal	50%	50%			2,520	1,260	1,260	-	-	
Process Information System (PI)		100%			338	-	338	-	-	
Real Time markets (RTMA)	20%	80%			3,173	635	2,538	-	-	
Resource Adequacy	50%	50%			107	53	54	-	-	
RMR application Validation Engine (RAVE)	50%	50%			12	6	6	-	-	
Scheduling & Logging for ISO CA (SLIC)	50%	50%			729	364	365	-	-	
Scheduling Infrastructure Business Rules (SIBR)	50%	50%			4,453	2,226	2,227	-	-	
Settlements & Market Clearing (SaMC)	15%	75%	10%		8,422	1,263	6,317	842	-	based on DA & RT charge codes
Total Operations related software	35%	60%	5%	0%	59,113	20,710	35,441	2,962	-	

Exhibit 5

Allocation of Debt Service and Out of Pocket Capital to cost categories										
System	Market services	System Operations	CRR services	Indirect	2010 Budget	Market services	System Operations	CRR services	Indirect	Comments
	Percentage allocation to cost category				Cost of category - $ in thousands					
General Software										
Client relations & engineering analysis tools				100%	761	-	-	-	761	
DMM & compliance Tools (SAS MARS)	50%	50%			1,180	590	590	-	-	
Local Area Network (LAN), WAN & monitoring (Tivoli)				100%	1,598	-	-	-	1,598	
Office automation desktop laptop (OA)				100%	209	-	-	-	209	
Oracle Corporate Financials				100%	1,713	-	-	-	1,713	
Security External Physical & ISS (CUDA)				100%	406	-	-	-	406	
Storage (EMC symmetrix)				100%	4,297	-	-	-	4,297	
Total general related software	6%	6%	0%	88%	10,164	590	590	-	8,984	
Fixed Assets										
Land & feasibility studies				100%	700	-	-	-	700	
NT servers & WEB servers				100%	573	-	-	-	573	
New system equipment				100%	4,411	-	-	-	4,411	
Office equipment, physical facilities software, furniture & leasehold improvements				100%	1,039	-	-	-	1,039	
Total fixed assets	0%	0%	0%	100%	6,723	-	-	-	6,723	
Total debt service	27%	48%	4%	21%	$ 76,000	$ 21,300	$ 36,031	$ 2,962	$ 15,707	
Direct software %	35%	60%	5%		$ 60,293	$ 21,300	$ 36,031	$ 2,962	$ -	

Exhibit 5

Allocation of Other revenue to cost categories										
Type	Market services	System Operations	CRR services	Indirect	2010 Budget	Market services	System Operations	CRR services	Indirect	Comments
	Percentage allocation to cost category				Cost of category - $ in thousands					
SC application fee				100%	$ 50	$ -	$ -	$ -	$ 50	
MSS penalties				100%	100	-	-	-	100	
wind forecasting fee				100%	250	-	-	-	250	
station power				100%	50	-	-	-	50	
SC trainiong fees				100%	50	-	-	-	50	
LGIP study fees				100%	1,800	-	-	-	1,800	
Interest				100%	3,800	-	-	-	3,800	
COI path operator fees				100%	2,000	-	-	-	2,000	
Total other revenue					$ 8,100	$ -	$ -	$ -	$ 8,100	

Allocation of Operating reserve credit to cost categories										
Type	Market services	System Operations	CRR services	Indirect	2010 Budget	Market services	System Operations	CRR services	Indirect	Comments
	Percentage allocation to cost category				Cost of category - $ in thousands					
Increase in 15% reserve for O&M				100%	$ (900)	$ -	$ -	$ -	$ (900)	
25% debt service reserve	27%	48%	4%	21%	12,200	3,295	5,856	488	2,561	used capital allocation
Collection of additional months GMC				100%	15,400	-	-	-	15,400	
Reduction of interest on Generator fines				100%	8,800	-	-	-	8,800	
Total operating reserve credit					$ 35,500	$ 3,295	$ 5,856	$ 488	$ 25,861	

Exhibit No. ISO-3 – 2012 GMC Straw Proposal, November 11, 2010

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California ISO

2012 Grid Management Charge Straw Proposal

November 11, 2010

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Executive Summary

This straw proposal is the next step in the process of designing the 2012 Grid Management Charge. Building upon the cost of service study functionalization and cost allocation steps reported in the October 8, 2010 Cost of Service discussion paper, this proposal reviews the guiding principles and the framework for the new GMC cost buckets. The straw proposal goes on to describe the ISO's proposal for the classification (determination of billing determinants based on customer cost causation factors) of those costs, the rate design produced by applying the billing determinants and some hypothetical, aggregated bill impacts. The October 8 discussion paper detailed the process the ISO followed to utilize its activity based costing system to allocate the costs of its activities into three main GMC cost categories or buckets (market services, system operations, and CRR services), and three transaction fees (bid segment fee, inter SC trade fee, and SCID fee). This approach offers significant improvements to the current GMC structure by increasing the amount of direct allocations of costs to buckets, reducing forecasting errors through rate simplification, reducing the number of charge codes, and simplifying the calculations of these charge codes.

This document is the next step in the process and describes the ISO's straw proposal for classifying costs to users of the ISO's services. The ISO proposes that the three GMC charge categories be allocated based on gross MWh (capacity and CRR holdings) and MWh (energy). The market service category includes awards of ancillary services, and schedules and dispatch instructions of generation, imports, load, and exports. The system operations category includes all flow quantities for generation, load, imports, and exports. The CRR category includes the total MWh quantity awarded through both the allocation process and auction.

The ISO proposes to allocate the charges as follows to each user of the ISO's services: The market services charge will be applied to the scheduling coordinator's gross absolute value of awarded MWh of energy and MW of AS in the forward and real time markets. The system operations charge will be applied to the scheduling coordinators gross absolute value of actual MWh of real time energy flows. The CRR charge will be applied to each scheduling coordinators total MW holdings of CRR that are applicable to each hour. The three administrative charges will be applied to each scheduling coordinator based on their use of the associated transactions.

The ISO will hold a conference call on November 18, 2010 to discuss this straw proposal with stakeholders.

Guiding Policy and Ratemaking Principles

The ISO is using the following guiding policy principles to conduct its cost of service study and develop the framework for a new GMC structure:

1) **Cost Causation** – Costs will be properly allocated to the correct GMC buckets and charged to those who benefit from or utilize those services.
2) **Focus on use of ISO services, not market behavior** – The new GMC design should reflect its primary purpose as a vehicle for recovering the ISO's revenue requirements based on each user's use of the ISO's services, not as a tool for shaping incentives based on market or operating behavior. Incentives such as these are appropriately addressed through the design of the market structure and market rules. In addition, SCE's comments on the October 8, 2010 discussion paper highlighted a similar theme, "there should always be a final check on GMC rates, and a continuous monitoring, to ensure that GMC rates are not unduly negatively affecting market outcomes. The ISO agrees that a properly designed GMC should seek to do no harm (negatively affecting market outcomes) avoid imposing negative incentives (address negative market behavior such as deviations), and is simply a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts.
3) **Transparency** – Costs and billing determinants will be clear, visible, and understandable to all market participants.

4) **Predictability** – Market participants will be able to determine in advance what their GMC costs will be depending on their activity.

5) **Forecastability** – The rates should utilize billing determinants that can be easily forecasted by both the ISO and market participants. This should result in fewer rate adjustments during the year.

6) **Flexibility** – The new GMC structure should easily accommodate future market enhancements without excessive complexity or disruption to the overall structure.

7) **Simplicity** – Simplify the current GMC structure to reduce the amount of varying bill determinants and the number of charge codes.

The steps included in conducting a cost of service study are:

1) Functionalization -	The process by which various activities are defined and sorted into service categories (functions and sub-functions) to reflect the different services provided by the ISO.
2) Cost Allocation -	The process by which the costs of providing services are allocated to the service categories (functions and sub-functions).
3) Classification -	The determination of billing determinants based on the customer cost causation factors.
4) Rate Design -	The process for deriving rates that divides the revenue requirement for each service category by the billing determinants.
5) Bill Impacts Analysis -	An evaluation of the impacts that the rate design will have on individual customer bills.

The ISO has completed the functionalization and cost allocation steps in accordance with these fundamental ratemaking principles and described the results (summarized in the section below) in the October 8, 2010 discussion paper. In this straw proposal the ISO: 1) proposes a classification methodology (customer billing determinants) that can be used to allocate the costs in each service category; 2) provides some rate design examples using hypothetical rates and historical data; and 3) presents aggregated bill impact information.

The 3 GMC Buckets

As described in the October 8, 2010 discussion paper, an examination of the ISO's new nodal market systems process map of customer activity revealed the following:

Customers submit bids	**>>**	**Market systems award / schedules**	**>>**	**Energy flows**

In addition, there are processes related to Congestion Revenue Rights (CRRs).

Based on this process map, the following three cost categories were developed:

1. Market Services
2. System Operations
3. CRR Services

This structure is very similar to what other ISO and RTOs with nodal markets have implemented to recover their administrative charges.

Using these three categories, the ISO's level 2 activities were mapped as either: 1) all in one category or not in the category (100% or 0%), 2) a split between two categories (50% / 50%), or 3) partially in one category or another (80% or 20%), or in the case of CRRs, a small portion of the activity (10%). This mapping was also applied to the software underlying the debt service portion of the revenue requirement. Indirect costs are allocated proportional to direct costs.

Design of an Allocation Method

A method for classifying costs in any particular cost category requires two elements. The first is a metric or unit to be used as the "denominator" in the equation that converts the total cost in each category into a per unit charge. The second is a billing determinant for calculating each party's share of the total cost in the category. The next two subsections present the ISO's straw proposals for each of these elements.

a. Selection of Metrics

The selection of the metrics to be used as denominators for each category was based on the guiding principles and a comparison of other ISOs' service charges. The ISO proposes that the market services and system operations GMC categories be based on gross MW per hour (capacity) and MWh (energy). This follows the guiding principles because it reflects each scheduling coordinator's use of the ISO's services is flexible, transparent, easy to forecast, and simple. The ISO considered other options such as per schedule charges, energy imbalances, and peak and off peak rates. However, these alternatives are very difficult to forecast for both the ISO and market participants and it is difficult to expand the metrics to include additional market enhancements.

The market services category includes the awarded ancillary services MW, and schedules and dispatch instructions of generation, imports, load, and exports (additional detail below). As discussed during the Convergence Bidding stakeholder process, the market services system impact is not dependent upon whether the bid is virtual demand or virtual supply. Market services matches offers of supply with offers of demand to award a schedule or dispatch resources. The gross MWh approach applies equal GMC costs to both parties that engaged in the trade.

The system operations category includes all flow quantities for generation, load, imports and exports (additional detail below). The fundamental purpose of system operations is to reliably balance supply and demand. Since both components (load and generation) are necessary to achieve balance, the ISO believes gross MWh is also appropriate for system operations. In addition, as new technologies that shift or reduce load such as demand response, storage, electric vehicles, increase their participation in ISO markets, load will play an important role with the integration of renewable resources. Thus load may provide similar services as generation does in maintaining grid reliability. Since both load and generation will provide similar services, we recommend that the GMC be designed in a manner that provides symmetrical marginal costs regardless of the technology used to provide the service. The marginal cost of the underlying technology should determine its competitiveness in the ISO market, not a difference attributed to GMC rate differential.

The market services and grid operations charges presented in this paper applies to Transmission Ownership Rights (TORs). The ISO acknowledges that the allocation of administrative fees to TORs is an issue for further discussion and will be addressed during the stakeholder process to finalize the GMC design.

The CRR category includes the total awarded MW per hour of CRRs. Using MW per hour for ancillary services and CRRs and MWh for energy creates simplicity in a common denominator as well as providing the flexibility to add additional MW per hour or MWh when new market enhancements and products are added. The principle of cost causation is fundamental in allocating costs to each of the administrative charges bucket. The ISO believes it is appropriate to consider the relative size of beneficiaries of a category which can be accomplished by using billing determinants that accurately reflect the volume of participation. Other ISOs also utilize MW per hour and MWh as their primary quantities for creating per unit charges and billing determinants.

b. Billing Determinants

Each of the three GMC buckets and respective billing determinants are discussed in further detail below.

1. Market Services

The market services charge code is designed to recover costs the ISO incurs for running the markets. As such, this charge code will be applied to each scheduling coordinator's gross absolute value of awarded MWh of energy and MW per hour of ancillary services in the forward and real time markets. Specifically, the charge code will apply to the following billing determinants:

Schedules and Awards (Absolute by Resource by Hour)
DA Generation Schedules (including MSS)
DA Import Schedules (including MSS)

DA Load Schedules (including MSS Gross Load)
DA Export Schedules (including MSS)
DA Ancillary Service Awards
DA Ancillary Service Self Provision
Convergence Bidding Schedules
HASP Incremental and Decremental Energy (Non Dynamic)
HASP Incremental and Decremental AncillaryService Awards
HASP Incremental and Decremental Ancillary Service Self Provision
Real Time Optimal Energy
Real-Time Minimum Load Energy
Derate Energy
Real-Time Self Schedule
MSS Load Following
Real-Time Pumping Energy
Real-Time Incremental and Decremental AncillaryService Awards
Real-Time Incremental and Decremental Ancillary Service Self Provision

2. System Operations

The system operations charge code is designed to recover costs the ISO incurs for running the grid in real time. As such, this charge code will be applied to each scheduling coordinators gross absolute value of actual real-time MWh energy flow. Specifically, the charge code will apply to the following billing determinants:

<u>Flow (Absolute by Resource by Settlement Interval)</u>
Non Dynamic System Resource Deemed Delivered Energy
Dynamic System Resource Deemed Delivered Energy
Metered Generation Quantities
Metered Default LAP Load Quantities
Metered Custom LAP Load Quantities (Including MSS Gross Load)
Metered Pumping Energy

3. CRR's

The CRR charge code is designed to recover costs the ISO incurs for running the CRR markets. As such, this charge code will be applied to each scheduling coordinator's total MW holdings of CRRs that are applicable to each hour. Specifically, this charge code will apply to the following billing determinants:

<u>CRR MWs (Absolute by Scheduling Coordinator by Financial Node)</u>
Daily Financial Node CRR Quantity

Many of the terms utilized above are defined in the appendix to the Market Operations business process manual at the following link:

https://bpm.caiso.com/bpm/bpm/version/000000000000109

c. Administrative and Transaction Fees

There are several administrative and transaction fees which will be used in the new market design. These fees will be structured in a way that allows market participants to determine if it is economic to incur the costs associated with using the service in question while taking in to consideration negative impacts to market participation if fees are too high.

1. Bid Segment Transaction Fee

The per bid segment transaction fee is designed to deter the submission of high volumes of "phishing" bids. The charge is proposed to be set at $.005 per bid segment and will be applied to all bid segments submitted. The rate of $.005 is based on a nominal charge that does not represent a significant expense to market participants under typical scheduling practices, but is enough to deter the submission of excessive bid volumes. The amount is similar to the rate used at the NYISO. The concept of a bid segment charge was raised during the Convergence Bidding stakeholder process to address concerns about bid proliferation if there was no marginal cost to place incremental bids. In addition, transaction fees collect revenue from participants who are unsuccessful in clearing the market, but who impact ISO costs. The revenue from this transaction fee will offset costs recovered through market services. Thus, if the number of unsuccessful bids increases, the market services rate for those participants who cleared the market will be reduced.

2. CRR Bid Transaction Fee

The CRR bid transaction fee is designed to recover a portion of the CRR costs on a transactional basis. The fee will apply to the CRR nominations and the CRR allocations processes. The rate of $1.00 will be used for this fee. The revenue from this transaction fee will offset costs recovered through CRR services. Thus if the number of unsuccessful bids increases, the CRR services rate for those participants who cleared the market will be reduced.

3. Inter-SC Trade Transaction Fee

The inter-SC trade transaction fee is designed to recover costs directly related to the scheduling and settling of inter-SC trades. The revenue from this transaction fee will offset costs recovered through market services. The ISO determined a rate (slightly less than the current rate) at an appropriate level so as not to deter existing activity, but also to recognize that if this was unlimited (i.e., no transaction cost) this could increase the demand and drive costs higher. A proposed fee of $1.00 per inter-SC trade (each side of trade) will apply to the following billing determinants:

INTER-SC Trade (Absolute by Trade)
DAM TO-SC Inter-SC Trade Energy (Physical and Converted)
DAM FROM-SC Inter-SC Trade Energy (Physical and Converted)
DAM TO-SC Inter-SC Trade Energy (Financial)
DAM FROM-SC Inter-SC Trade Energy (Financial)
HASP TO-SC Inter-SC Trade Energy (Physical and Converted)
HASP FROM-SC Inter-SC Trade Energy (Physical and Converted)
HASP TO-SC Inter-SC Trade Energy (Financial)
HASP FROM-SC Inter-SC Trade Energy (Financial)
Ancillary Services TO-SC Inter-SC Trade Energy
Ancillary Services FROM-SC Inter-SC Trade Energy
RUC Obligation TO-SC Inter-SC Trade Energy

The revenue from this transaction fee will offset costs recovered through market services.

4. SCID Administrative Fee

The SCID administrative fee is designed to limit the number of SCIDs to those needed for legitimate business purposes in order to reduce the additional burden on the ISO systems and resources that an unlimited number of SCIDs could create. The ISO proposes to keep the charge at the current $1,000 per month per SCID. However, rather than applying the rate only to SCIDs with a positive or negative settlement, we propose to apply it to all active SCIDs. The revenue from this transaction fee will offset costs recovered through market services.

Examples of GMC Charges by Activity

The following are examples of the GMC charges that would be incurred for various activities, using hypothetical estimated rates based on historical data. Please note that the SCID fee of $1,000 per month would apply to all activities listed below in addition to the individual transaction charges. Also note that the market services rate does not take into account the expected volume for convergence bidding. The ISO estimates that the additional volume of convergence bids would reduce the market services rate to $.082. The GMC rates used in the calculations are based on the rates proposed in the discussion paper:

Market Services Rate: $0.09

System Operations Rate: $0.2841

CRR Services Rate: $0.0126

Bid Segment Rate: $0.005

Inter SC Trade fee: $1.00

CRR Bid Segment Transaction fee: $1.00

1. **Generation**

Scenario: A generator submits a 4-segment energy bid to the day-ahead market and is scheduled for 100 MWh. The generator then submits a 4-segment energy bid to the real-time market and is dec'd 10 MWh. Its real-time metered flow is measured at 90 MWh.

GMC charges would be:

Market Services Charge (day-ahead schedule and real-time instructions): 110 MW h * $0.09 = $9.90

System Operations Charge (real-time metered flow): 90 MWh * $0.2841 = $25.57

Bid Segment Fee: 8 * $0.005 = $.04

Total: $35.51

2. **Ancillary Services (1)**

Scenario 1: A generator submits a 2-segment AS bid and is awarded 50 MW operating reserves in the day-ahead market for hour ending 9. No contingency event occurs in hour ending 9.

GMC charges would be:

Market Services Charge (day-ahead and real-time schedules): 50 MW h * $0.09 = $4.50

Bid Segment Fee: 2 * $0.005 = $0.01

Total: $4.51

3. Ancillary Services (2)

Scenario 2: A generator submits a 2-segment AS bid and is awarded 50 MW operating reserve in the day ahead market for hour ending 9. The generator then submits a 4-segment energy bid in the real-time market and a contingency event occurs in hour ending 9 resulting in 50 MWh energy dispatch for 15 minutes.

GMC charges would be:

Market Services Charge: 50 MW h * $0.09 = $4.50

System Operations Charge: (50 MWh / 4) * $0.2841 = $3.55

Bid Segment Fee: 6 * $0.005 = $.03

Total: $8.08

4. Load

Scenario: Load self schedules 100 MWh in the day ahead market its real time meter data shows that it consumed 100 MWh in real time.

GMC charges would be:

Market Services Charge: 100 MW h * $0.09 = $9.00

System Operations Charge: 100 MWh * $0.2841 = $28.41

Bid Segment Fee: 1 * $0.005 = $0.005

Total: $37.415

5. Imports

Scenario: An importer submits a 4-segment energy bid to the day-ahead market and is scheduled for 100 MWh. The importer then submits a 2-segment energy bid to the real-time market and is inc'd 10 MWh in HASP. The 110 MWh import schedule is then deemed delivered in real-time based on the final e-tag for the transaction.

GMC charges would be:

Market Services Charge: 110 MW h * $0.09 = $9.90

System Operations Charge: 110 MWh * $0.2841 = $31.25

Bid Segment Fee: 6 * $0.005 = $0.03

Total: $41.18

6. Exports

Scenario: An exporter submits a 4-segment energy bid to the day-ahead market and is scheduled for 100 MWh. The exporter then submits a 6-segment energy bid to the real-time market and is dec'd 10 MWh in HASP. The 90 MWh export schedule is then deemed delivered in real-time based on the final e-tag for the transaction.

GMC charges would be:

Market Services Charge: 110 MW h * $0.09 = $9.90

System Operations Charge: 90 MWh * $0.2841 = $25.57

Bid Segment Fee: 10 * $0.005 = $.05

Total: $35.52

7. Convergence Bidder

Scenario: A convergence bidder submits a 10-bid segment virtual demand bid in the day-ahead market for 100 MWh.

GMC charges would be:

Market Services Charge: 100 MW h * $0.09 = $9.00

System Operations Charge: $0.00 (there is no real-time energy flow associated with virtual bids)

Bid Segment Fee: 10 * $0.005 = $.05

Total: $9.05

8. Inter-SC Trade

Scenario: Scheduling Coordinator A schedules an inter-SC trade with Scheduling Coordinator B for 100 MWh.

GMC charges would be (for both Scheduling Coordinators A and B):

Inter SC Trade Fee: 1 * $1.00 = $1.00

Total: $1.00 (each)

9. CRR's

Scenario 1: A Scheduling Coordinator bids and is awarded 100 MW CRR on peak or a LSE nominates and is allocated 100 MW CRR on peak during the October 2010 monthly process. GMC charges would be:

CRR Bid Fee = 1 * $1.00 = $1.00

CRR Charge: (100 MW * 416 hours) * $0.0126 = $524.16

Total: $525.16

Scenario 2: A Scheduling Coordinator bids and is awarded 100 MW CRR on peak or a LSE nominates and is allocated 100 MW CRR on peak through the annual process and holds the CRR for all months of the year. Note that the number of hours in a month will be dependent upon the NERC calendar. The GMC costs will be accrued monthly over the year. We utilized October 2010 as a proxy to simplify the example:

GMC charges would be:

CRR Bid Fee = 1 * $1.00 = $1.00

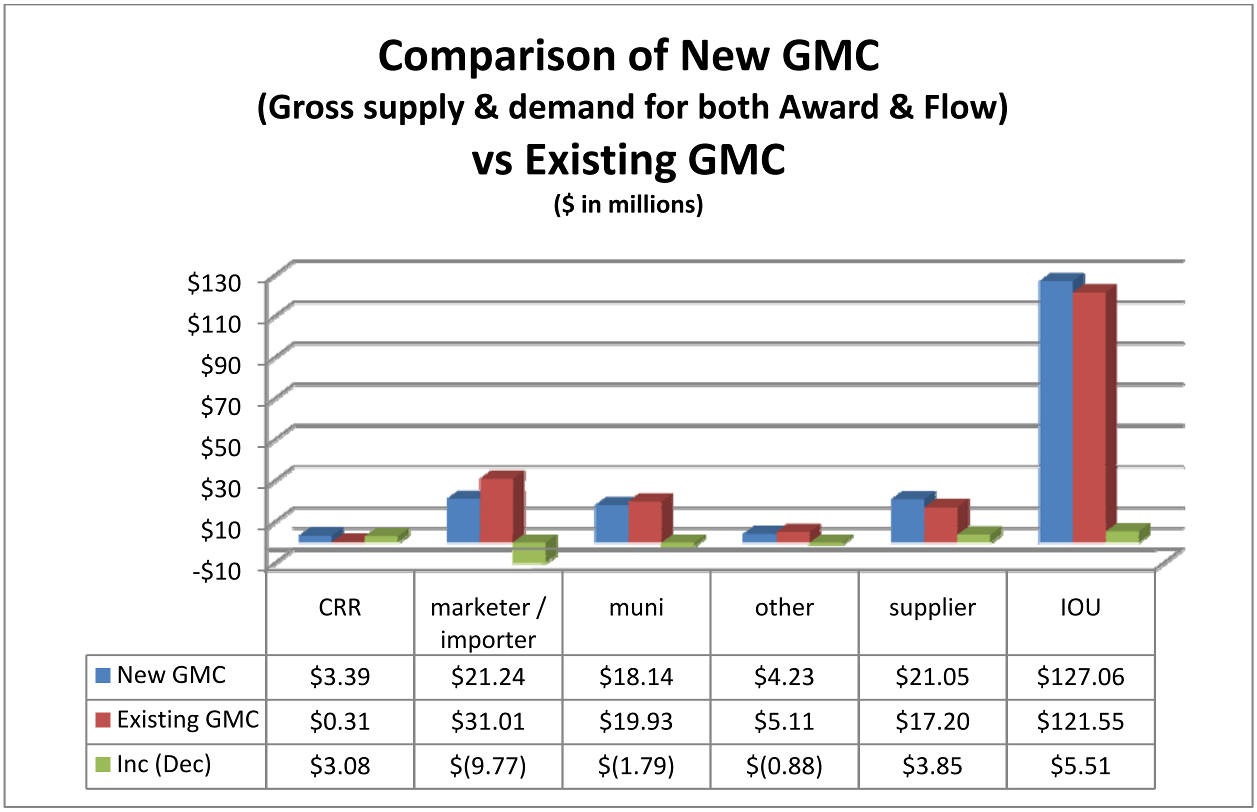
CRR Charge: (100 MW * 416 hours) * $0.0126 = $524.16 per month

Total: $6,290.92

Bill Impact Process

The ISO will provide bill impact studies by SCID of the proposed GMC rate design. To provide estimates of the impacts of the new structure, the ISO developed hypothetical billing rates using the 2010 budget amount and allocated those dollars to charge categories based on the process described in the discussion paper. The billing determinants used to calculate the rates came from market data from the period of June 1, 2009 to May 31, 2010. The ISO will apply the rates for each charge code to each SCID's volumes using the billing determinants listed above to determine the costs they would have been charged if the new GMC structure had been in place.

The ISO will communicate individual SCID information in the coming weeks. The graph below illustrates the overall impact analysis by customer type:



	CRR	marketer / importer	muni	other	supplier	IOU
New GMC	$3.39	$21.24	$18.14	$4.23	$21.05	$127.06
Existing GMC	$0.31	$31.01	$19.93	$5.11	$17.20	$121.55
Inc (Dec)	$3.08	$(9.77)	$(1.79)	$(0.88)	$3.85	$5.51

Next Steps

The stakeholder process for the 2012 GMC Cost of Service Study will continue with the following timeline:

- November 18, 2010 – conference call to discuss straw proposal
- Early December – distribute historical GMC data and what if scenario costs to individual SC's. Please provide a primary point of contact email to CAISO at gmc@caiso.com
- December 13, 2010 – in person meeting at CAISO
- January 20, 2010 *(changed from previously posted date of 1/21/11)* – in person meeting at CAISO (new headquarters building)

Exhibit No. ISO-4 – 2012 GMC Customer Bill Comparison Analysis, December 2, 2010

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California ISO

2012 Grid Management Charge
Customer Bill Comparison Analysis

December 2, 2010

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Executive Summary

The Customer Comparison Analysis is the next step in the process of designing the 2012 Grid Management Charge. Building upon on the development of billing determinants reported in the November 11, 2010 straw proposal and the cost of service study functionalization and cost allocation steps discussed in the October 8, 2010 Cost of Service discussion paper, this analysis uses the proposed new GMC design and applies it to the revenue requirements and participant activities for the period from June 2009 to May 2010 to develop estimated aggregate impacts of the new design on major customer types. The analysis follows the guiding principles and the framework for allocating ISO costs to the new GMC cost buckets, the specification of billing determinants based on customer activities (i.e., cost causation factors), the rate design produced by applying the billing determinants and some hypothetical, aggregated bill impacts. The October 8 discussion paper detailed the process the ISO followed to utilize its activity based costing system to allocate the costs of its activities into three main GMC cost categories or buckets (market services, system operations, and CRR services), and four transaction fees (bid segment fees for market bids and for CRR nominations and auction bids, inter SC trade fee, and SCID fee).

The November 11 straw proposal offers significant improvements to the current GMC structure by increasing the amount and the accuracy of direct cost allocations to buckets, reducing forecasting errors through rate simplification, reducing the number of charge codes, and simplifying the calculations of the charge codes. The ISO is proposing that the three GMC charge categories be allocated based on gross MW per hour (capacity and CRR holdings) and MWh (energy). The market services category includes awards of ancillary services, energy schedules, and dispatch instructions of generation, imports, load, and exports. The system operations category includes all flow (metered) quantities for generation, load, imports, and exports. The CRR category includes the total MW quantity of CRR holdings for each trading hour awarded through both the allocation process and auction.

In the November 11 straw proposal the ISO proposed to allocate the charges as follows to each user of the ISO's services. The market services charge will be applied to the scheduling coordinator's gross absolute value of awarded MWh of energy (cleared schedules and dispatch instructions) and MW of AS in the day-ahead and real time markets. The system operations charge will be applied to the scheduling coordinator's gross absolute value of actual MWh of real time energy flows. The CRR charge will be applied to each scheduling coordinator's total MW holdings of CRR that are applicable to each hour. The four administrative charges will be applied to each scheduling coordinator based on their use of the associated transactions.

The ISO will hold a stakeholder meeting on December 13, 2010 to discuss bill comparisons and potential impacts associated with the proposed 2012 GMC rate structure.

Guiding Policy and Ratemaking Principles

The ISO is using the following guiding principles to conduct its cost of service study and develop the framework for the new 2012 GMC structure:

1) **Cost Causation** – Costs will be properly allocated to the correct GMC buckets and charged to those who benefit from or utilize those services.
2) **Focus on use of ISO services, not market behavior** – The new GMC design should reflect its primary purpose as a vehicle for recovering the ISO's revenue requirements based on each user's use of the ISO's services, not as a tool for shaping incentives based on market or operating behavior. Incentives such as these are appropriately addressed through the design of the market structure and market rules. The ISO believes that this principle is fully consistent with SCE's comment on the October 8, 2010 discussion paper that: "there should always be a final check on GMC rates, and a continuous monitoring, to ensure that GMC rates are not unduly negatively affecting market outcomes." The ISO agrees that a properly designed GMC should seek to do no harm, i.e., should not create perverse behavioral incentives or negatively affect market outcomes. The point of this principle is simply

that the GMC design should not be used as a substitute for effective market rules to incent appropriate participant behavior and ensure efficient market outcomes, but should more narrowly provide a mechanism to recover ISO revenue requirements in a manner consistent with the other principles identified here.

3) **Transparency** – Costs and billing determinants will be clear, visible, and understandable to all market participants.

4) **Predictability** – Market participants will be able to determine in advance what their GMC costs will be depending on their activity.

5) **Forecastability** – The rates should utilize billing determinants that can be easily forecasted by both the ISO and market participants. This should result in fewer rate adjustments during the year.

6) **Flexibility** – The new GMC structure should easily accommodate future market enhancements without excessive complexity or disruption to the overall structure.

7) **Simplicity** – Simplify the current GMC structure to reduce the amount of varying bill determinants and the number of charge codes.

The steps included in conducting a cost of service study are:

1) Functionalization -	The process by which various ISO activities are defined and sorted into service categories (functions and sub-functions) to reflect the different services provided by the ISO.
2) Cost Allocation -	The process by which the costs of providing services are allocated to the service categories (functions and sub-functions).
3) Classification -	The determination of billing determinants based on the customer cost causation factors.
4) Rate Design -	The process for deriving rates that divides the revenue requirement for each service category by the total of the applicable billing determinants.
5) Bill Impacts Analysis -	An evaluation of the impacts that the rate design will have on individual customer bills.

The ISO has completed the functionalization and cost allocation steps in accordance with these fundamental ratemaking principles and described the results in the October 8, 2010 discussion paper. In the November 11, 2010 straw proposal, the ISO proposed a classification methodology (customer billing determinants) that can be used to allocate the costs in each service category. This paper presents a detailed rate design and bill comparison analysis. Additionally an appendix of billing determinants definitions was prepared and posted to the ISO's website at: http://www.caiso.com/281a/281ac7f165ad0.html

Rate Design

The October 8, 2010 discussion paper described the allocation of ISO costs to the three service categories in order to determine the revenue requirement for each category. The billing rate for each service category is then derived by dividing the revenue requirement for that service category by the total of that category's billing determinants. To develop examples and to calculate the bill comparison analysis the ISO used the 2010 GMC revenue requirement and, for the billing determinants, actual transactions data for the twelve month period from June 2009 through May 2010. The costs allocated to each of the three buckets are as follows:

2010 Revenue Requirement	Market Services	System Operations	CRR Services	Total
Percent	27%	69%	4%	100%
Amount	$52,756,000	$134,883,000	$7,456,000	$195,095,000

The actual GMC invoiced to customers for the twelve month period was $195,110,642. To ensure comparability, the additional cost of $15,642 ($195,110,642 less $195,095,000) will be added to the revenue requirement to make it equal to the actual GMC invoiced while preserving the percentage distribution shown above. The resulting cost are allocated in the following table:

GMC to recover	Market Services	System Operations	CRR Services	Total
2010 revenue requirement $	$52,756,000	$134,883,000	$7,456,000	$195,095,000
2010 revenue requirement $	27%	69%	4%	100%
Excess GMC to allocate				$15,642
Allocate excess to buckets	$4,230	$10,814	$598	$15,642
Revised GMC requirement	$52,760,230	$134,893,814	$7,456,598	$195,110,642

The next step is to calculate the fees and charges using the actual quantities of transactions for the twelve month period.

Fee or Charge	Transactions for period from Jun-09 to May-10	Rate per transaction or per month for SCID charge	Fee and charge revenue
Market bid segment fee	26,893,996	$0.005	$134,470
CRR auction bid fee	480,276	$1.00	$480,276
Inter-SC trade fee	3,854,538	$1.00	$3,854,538
SCID charge	177 scids	$1,000	$2,124,000

The fee and charge revenue is deducted from the revised GMC revenue requirement to which the billing determinants are applied to develop the net costs to be recovered through the rates for each service category.

Revised GMC requirement for Jun-09 to May-10	Market Services	System Operations	CRR Services	Total to Recover
Revised GMC requirement	$52,760,230	$134,893,814	$7,456,598	$195,110,642
Allocate fees and charges to buckets				
Market bid segment fee	($134,470)			($134,470)
CRR auction bid fee			($480,276)	($480,276)
Inter-SC trade fee	($3,854,538)			($3,854,538)
SCID charge	($2,124,000)			($2,124,000)
Costs of service to recover	$46,647,222	$134,893,814	$6,976,322	$188,517,358

The rates for each bucket are calculated by using the actual volumes for the twelve month period.

Service Category	Service category cost to recover	Transactions for period from Jun-09 to May-10	Transaction type	Service category rate
Market services	$46,647,222	519,946,950	MWs of awards	$0.089715
System operations	$134,893,814	475,167,832	MWhs of flows	$0.283887
CRR services	$6,976,322	591,726,863	MWhs of congestion	$0.011790

Combining all the charges in a single table, the final rates to be applied to the volumes of each SC are as follows:

Service Category and Fees and Charge	Service category cost or revenue	Transactions Jun-09 to May-10	Transaction type	Service category or fee rate
Market services	$46,647,222	519,946,950	MWs of awards	$0.089715
System operations	$134,893,814	475,167,832	MWhs of flows	$0.283887
CRR services	$6,976,322	591,726,863	MWhs of congestion	$0.011790
Market bid segment fee	$134,470	26,893,996	# of bid segments	$0.005
CRR auction bid fee	$480,276	480,276	# of auction bids	$1.00
Inter-SC trade fee	$3,854,538	3,854,538	# of trades	$1.00

SCID charge	$2,124,000	177 scids	Per month	$1,000
Total	$195,110,642			

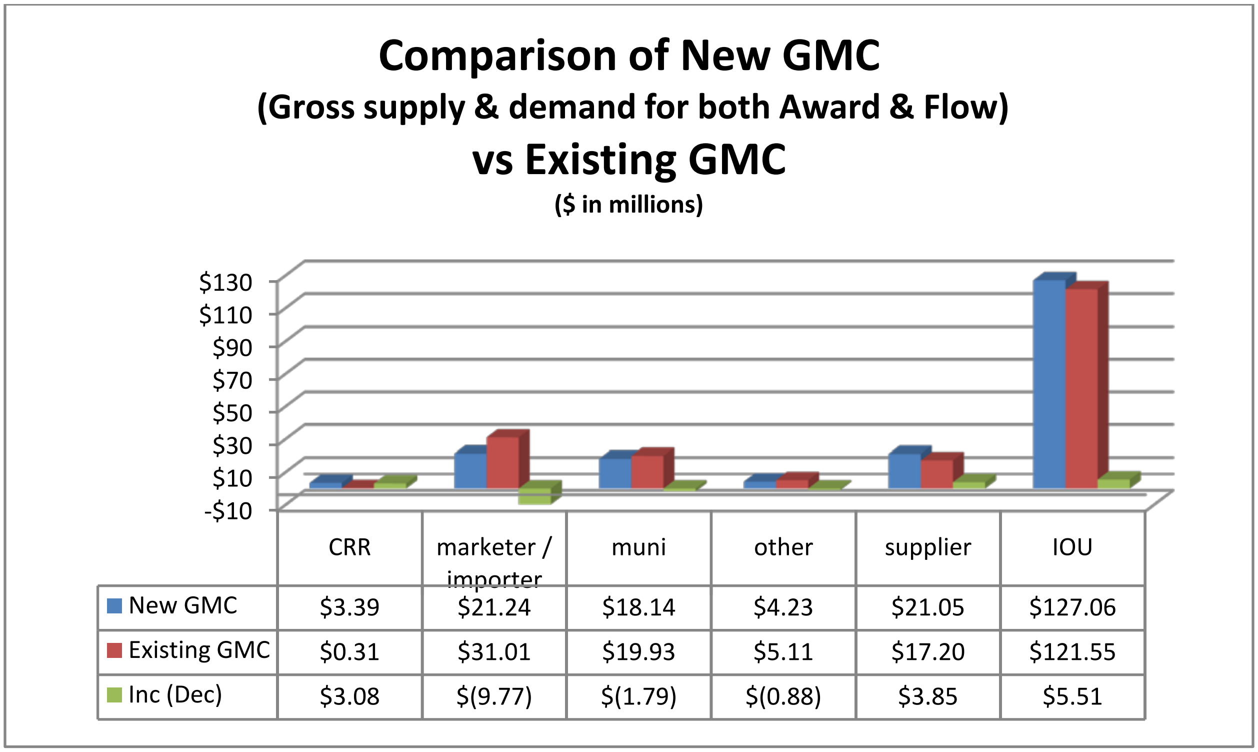
This design is also detailed in a worksheet in Exhibit 1 posted to the website at

http://www.caiso.com/281a/281ac7f165ad0.html

Please note that no differentiation has been made with respect to TORs. TOR volumes are included in the above determinants. The ISO is considering alternative treatment for TORs within the proposed GMC structure. It will be the subject of a future meeting.

Bill Impact Process

The ISO will provide a confidential bill comparison for each SCID to the appropriate ISO participant, using data for the period from June 1, 2009 to May 31, 2010 as described above and comparing the existing against the proposed GMC rate design. To provide estimates of the impacts of the new structure, the ISO developed hypothetical billing rates using the 2010 budgeted revenue requirement amount and allocated those dollars to charge categories as described above. The billing determinants used to calculate the rates came from market data from the twelve month period. The ISO applied the rates for each catagory to each SCID's volumes using the billing determinants listed above to determine the costs the SC would have been charged if the proposed GMC structure had been in place. The following graph illustrates the overall comparison analysis by customer type:



	CRR	marketer / importer	muni	other	supplier	IOU
New GMC	$3.39	$21.24	$18.14	$4.23	$21.05	$127.06
Existing GMC	$0.31	$31.01	$19.93	$5.11	$17.20	$121.55
Inc (Dec)	$3.08	$(9.77)	$(1.79)	$(0.88)	$3.85	$5.51

Notes to Graph:

- The first column contains those participants for which CRRs make up 90% or more of their GMC charge. CRR charges are applied to customers in the other columns as well but the charges do not make up as significant percentage of their GMC liability.
- Supplier refers to those customers in the balancing authority that primarily supply generation but are not included in munis or IOUs.
- Others are those customers not fitting into one of the other categories. May be load serving entities but not IOUs and munis.

Next Steps

The stakeholder process for the 2012 GMC Cost of Service Study will continue with the following timeline:

- Early December – distribute historical GMC data and what if bill comparisons to individual SC's. SC's should submit the email address for their primary contact to the ISO at gmc@caiso.com
- December 13, 2010 – in person meeting at ISO
- January 20, 2010 – in person meeting at ISO (new headquarters building)
- Additional meetings will be scheduled as needed.

Exhibit No. ISO-5 –

Appendix to 2012 GMC Straw Proposal Billing Determinant Definitions, December 16, 2010

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California ISO

Appendix to 2012 Grid Management Charge Straw Proposal Billing Determinant Definitions

December 16, 2010

Definitions of Billing Determinants

This appendix contains definitions of billing determinants used in the 2012 Grid Management Straw Proposal issued November 11, 2012.

Bill Determinant Variable Name	Bill Determinant Definition	Source Document
DA Generation Schedules (including ETC TOR)	Hourly Energy that corresponds to the flat hourly Day-Ahead Generation Schedule (DAS). It is composed of Day-Ahead Minimum Load Energy, Day-Ahead Self-Scheduled Energy, and Day-Ahead Bid Awarded Energy. It does not include the DA Energy that corresponds to the flat schedule when resource is committed in DA pumping mode. Expected energy in DA pumping mode is accounted for as DA pumping energy. Day-Ahead Scheduled Energy is settled at the IFM LMP as specified in Section 11.2.1.1. of the CAISO Tariff.	BPM for Market Operations
DA Import Schedules (including ETC TOR)	Hourly Energy that corresponds to the flat hourly Day-Ahead Import Schedule (DAS). It is composed of Day-Ahead Minimum Load Energy, Day-Ahead Self-Scheduled Energy, and Day-Ahead Bid Awarded Energy. It does not include the DA Energy that corresponds to the flat schedule when resource is committed in DA pumping mode. Expected energy in DA pumping mode is accounted for as DA pumping energy. Day-Ahead Scheduled Energy is settled at the IFM LMP as specified in Section 11.2.1.1. of the CAISO Tariff.	BPM for Market Operations
DA Export Schedules (including ETC TOR)	Hourly Energy that corresponds to the flat hourly Day-Ahead Export Schedule (DAS). It is composed of Day-Ahead Minimum Load Energy, Day-Ahead Self-Scheduled Energy, and Day-Ahead Bid Awarded Energy. It does not include the DA Energy that corresponds to the flat schedule when resource is committed in DA pumping mode. Expected energy in DA pumping mode is accounted for as DA pumping energy. Day-Ahead Scheduled Energy is settled at the IFM LMP as specified in Section 11.2.1.1. of the CAISO Tariff.	BPM for Market Operations
HASP Incremental and Decremental Energy (Non Dynamic)	IIE from Non-Dynamic System Resource, exclusive of RTPE, and RTMLE, produced or consumed due to hourly scheduling in the HASP. HASE is produced above the higher of the DAS or the Minimum Load, and below the HASP Intertie Schedule, or consumed below the DAS and above the HASP Intertie Schedule. In the latter case, HASE overlaps with DASE; HASE does not overlap with RTPE or RTMLE, but it may overlap with other IIE subtypes. HASE is indexed against the relevant Energy Bid and sliced by service type, depending on the AS capacity allocation on the Energy Bid, and by Energy Bid price. HASE slices are paid/charged the HASP Intertie LMP as reflected in Section 11.4 of the CAISO Tariff and they are included in BCR at the cost of the relevant Energy Bid prices as reflected in Section 11.8.4 of the CAISO Tariff. Any HASE slice below or above the Energy Bid has no associated Energy Bid price and it is not included in BCR. For Non-Dynamic System Resources that are designated as MSS Load Following Resources, HASE should be considered as MSS LFE in Load Following performance assessment.	BPM for Market Operations

Bill Determinant Variable Name	Bill Determinant Definition	Source Document
Real Time Optimal Energy	Any remaining IIE after accounting for all other IIE subtypes constitutes OE. OE does not overlap with SRE, RED, RIE, RTMLE, DRE, and EDE, but it may overlap with DASE, HASE, and LFE. OE is indexed against the relevant Energy Bid and sliced by service type, depending on the AS capacity allocation on the Energy Bid. OE is also divided into two parts: a) the part of OE that overlaps with MSS LFE (“Overlapping OE”), which is paid/charged the Real-Time LMP as reflected in Section 11.5.1, and it is not included in BCR since it is effectively cancelled by MSS LFE as reflected in Section 11.8.4 of the CAISO Tariff; and b) the remaining part (“Non-overlapping OE”), which is indexed against the relevant Energy Bid and sliced by Energy Bid price. The Non-overlapping OE slices are paid/charged the Real-Time LMP as reflected in Section 11.5.1 of the CAISO Tariff and they are included in BCR at the cost of the relevant Energy Bid prices as reflected in Section 11.8.4 of the CAISO Tariff. Any OE slice below or above the Energy Bid has no associated Energy Bid price and is settled as reflected in Section 11 of the CAISO Tariff and it is not included in BCR as reflected in Section 11of the CAISO Tariff.	BPM for Market Operations
Residual Imbalance Energy	Extra-marginal IIE produced or consumed at the start or end of a Trading Hour outside the hourly schedule-change band and not attributed to Exceptional Dispatch. RIE is due to a Dispatch Instruction in the previous Trading Hour or a Dispatch Instruction in the next Trading Hour. RIE may overlap only with DASE. RIE does not apply to Non-Dynamic System Resources (including Resource-Specific System Resources. RIE is settled as bid, based on the RT Energy Bid of the *reference hour*, or at the Real-Time LMP if there is no Bid as reflected in Section 11.5.1 of the CAISO Tariff, and it is not included in BCR as reflected in Section 11.8.4 of the CAISO Tariff. The *reference hour* is the previous Trading Hour, if RIE occurs at the start of a Trading Hour, or the next Trading Hour, if RIE occurs at the end of a Trading Hour.	BPM for Market Operations
Real-Time Minimum Load Energy	IIE, exclusive of SRE, RED, and RIE, produced due to the Minimum Load of a Generating Unit that is committed in the RUC or the RTM (i.e., without a Day-Ahead Schedule) or a Constrained Output Generator (COG) that is committed in the IFM with a DAS below the registered Minimum Load (because COGs are modeled as flexible in the IFM). If the resource is committed in RTM for Load Following, RTMLE is accounted as MSSLFE instead. RTMLE is IIE above the Day-Ahead Schedule (or zero if there is no DAS) and below the registered Minimum Load. RTMLE does not overlap with any other Expected Energy type. RTMLE is paid the Real-Time LMP as reflected in Section 11.5.1 of the CAISO Tariff and it is included in BCR at the relevant minimum load cost as reflected in Section 11.8.4.1.2 of the CAISO Tariff. IIE that is consumed when a resource that is scheduled in the DAM is shut down in the RTM is accounted as HASP Scheduled Energy or Optimal Energy and not as RTMLE.	BPM for Market Operations
Exceptional Dispatch Energy	Extra-marginal IIE, exclusive of SRE, RED, RIE, LFE, RTMLE, and DRE, produced or consumed due to manual (non-economic) Exceptional Dispatch Instructions that are binding in the relevant Dispatch Interval. Without MSS Load Following, EDE is produced above the *LMP index* and below the lower of the DOP or the Exceptional Dispatch instruction, or consumed below the *LMP index* and above the higher of the DOP or the Exceptional Dispatch Instruction. The LMP index is the capacity in the relevant Energy Bid that corresponds to a bid price equal to the relevant LMP. EDE does not overlap with SRE, RED, RIE, RTMLE, DRE, or Optimal Energy, but it may overlap with DASE, HASE, and LFE. Exceptional Dispatch Energy is paid/charged at a price that is specific to its type, either as-Bid or at the Real-Time LMP if there is no Bid as reflected in Section 11.5.6 of the CAISO Tariff, and it is not included in BCR as reflected in Section 11.8.4 of the CAISO Tariff.	BPM for Market Operations

Bill Determinant Variable Name	Bill Determinant Definition	Source Document
Standard Ramping Energy	IIE produced or consumed in the first two and the last two Dispatch Intervals due to hourly schedule changes. SRE is a schedule deviation along a linear symmetric 20-min ramp ("standard ramp") across hourly boundaries. SRE is always present when there is an hourly schedule change, including resource Start-Ups and Shut-Downs. SRE does not apply to Non-Dynamic System Resources (including Resource-Specific System Resources. SRE is not subject to settlement as shown in Section 11.5.1 of the CAISO Tariff.	BPM for Market Operations
Ramping Energy Deviation	IIE produced or consumed due to deviation from the standard ramp because of ramp constraints, Start-Up, or Shut-Down. RED may overlap with SRE, and both SRE and RED may overlap with DASE, but with no other IIE subtype. RED may be composed of two parts: a) the part that overlaps with SRE whenever the DOP crosses the SRE region; and b) the part that does not overlap with SRE. The latter part of RED consists only of *extra-marginal* IIE contained within the hourly schedule change band and not attributed to Exceptional Dispatch or derates. RED does not apply to Non-Dynamic System Resources (including Resource-Specific System Resources). RED is paid/charged the Real-Time LMP as reflected in Section 11.5.1 of the CAISO Tariff and it is included in BCR only for market revenue calculations as reflected in Section 11.8.1.4.5 of the CAISO Tariff.	BPM for Market Operations
Derate Energy	Extra-marginal IIE, exclusive of SRE, RED, RIE, LFE, and RTMLE, produced or consumed due to Minimum Load overrates or Maximum Capacity derates. DRE is produced above the higher of the DAS, the registered Minimum Load, or the HAS, and below the lower of the overrated Minimum Load and the DOP, or consumed below the lower of the DAS or the HAS, and above the higher of the derated Maximum Capacity or the DOP. There could be two DRE slices, one for the Minimum Load overrate, and one for the Maximum Capacity derate. DRE does not overlap with SRE, RED, RIE, RTMLE, Exceptional Dispatch Energy, or Optimal Energy, but it may overlap with DASE, HASE, and LFE. DRE is paid/charged the Real-Time LMP as reflected in Section 11.5.1 of the CAISO Tariff and it is not included in BCR as reflected in Section 11.8.4 of the CAISO Tariff.	BPM for Market Operations
Real-Time Self Schedule	The slice of Non-overlapping OE that corresponds to the Real-Time Total Self-Schedule (RTTSS). The RTTSS is the sum of all Real-Time Self-Schedules (except Pumping Self-Schedules).	BPM for Market Operations
MSS Load Following	IIE, exclusive of SRE, RED, and RIE, produced or consumed due to Load Following by an MSS. LFE is the IIE that corresponds to the algebraic Qualified Load Following Instruction (QLFI) relative to the DAS. LFE does not coexist with HASE, and it does not overlap with SRE, RED, or RIE, but it may overlap with DASE, Derate Energy, Exceptional Dispatch Energy, Real-Time Self-Scheduled Energy, and Optimal Energy. MSS LFE is paid/charged the Real-Time LMP as reflected in Section 11.5.1 of the CAISO Tariff and it is not included in BCR as reflected in Section 11.8.4 of the CAISO Tariff.	BPM for Market Operations
Real Time Pumping Energy	IIE from PSH or Pump Resources, exclusive of SRE, RED, consumed below the DAS when Dispatched in pumping mode, or produced from pumping operation due to Pumping Level reduction in real time, including pump shut-down. RTPE does not overlap with any other Expected Energy type. RTPE is charged or paid the Real-Time LMP as reflected in Section 11.5.1 of the CAISO Tariff and it is included in BCR at the relevant pumping Cost as reflected in Section 11.8.4.1.4 of the CAISO Tariff.	BPM for Market Operations
DA Ancillary Service Awards	Day Ahead Awarded Bid capacity for Business Associate B resource r for Trading Day d and Trading Hour h **(MW)**	BPM for Ancillary Services Pre-Calc
DA Ancillary Service Self Provision	Day Ahead Qualified Self-Provision capacity for Business Associate B, resource r, resource type t, Entity Component Type F', Entity_Component_Subtype S', Contract Reference Number N, Contract Type z', Intertie_Constraint_ID a' for Trading Day d and Trading Hour h **(MW)**	BPM for Ancillary Services Pre-Calc
HASP Incremental and Decremental Ancillary Service Awards	HASP Awarded Bid capacity for Business Associate B resource r for Trading Day d and Trading Hour h **(MW)**	BPM for Ancillary Services Pre-Calc

Bill Determinant Variable Name	Bill Determinant Definition	Source Document
HASP Incremental and Decremental Ancillary Service Self Provision	HASP Qualified Self-Provision capacity for Business Associate B resource r, resource type t, Entity Component Type F', Entity_Component_Subtype S', Contract Reference Number N, Contract Type z', Intertie_Constraint_ID a' for Trading Day d and Trading Hour h **(MW).** **Values are incremental with respect to IFM**	BPM for Ancillary Services Pre-Calc
Real Time Incremental and Decremental Ancillary Service Awards	Real-Time Awarded Bid capacity for Business Associate B resource r for Trading Day d and Trading Hour h and Ancillary Service interval c for the relevant Real-Time hour **(MW).** **Values are incremental with respect to IFM values.**	BPM for Ancillary Services Pre-Calc
Real Time Incremental and Decremental Ancillary Service Self Provision	Real-Time Qualified Self-Provision capacity for Business Associate B resource r , resource type t, Entity Component Type F', Entity_Component_Subtype S', Contract Reference Number N, Contract Type z', Intertie_Constraint_ID a' for Trading Day d and Trading Hour h and Ancillary Service Commitment interval c for the relevant Real-Time hour **(MW)**. **Values are incremental with respect to IFM values.**	BPM for Ancillary Services Pre-Calc
DA Load Schedules (including ETC TOR)	DA Load Schedule for Business Associate B, Resource r, Resource type t, and Trading Hour h as provided by MQS where UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M' are mapped to the Master File (Load Schedule quantity is a negative value).	BPM for RT Energy Pre-Calc
HASP Operational Adjustment	Settlement Interval Operational Adjustment from HASP Energy for Business Associate B, System Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i Resource type t, Trading Hour h, Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
Regulation Energy	Regulation energy for Business Associate B, Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
Real Time Operational Adjustments	Settlement Interval Operational Adjustment from Day Ahead or Real Time Energy for Business Associate B, System Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
Non Dynamic System Resource Deemed Deliver Energy (include ETC/TOR)	Variable Name: SettlementIntervalMeteredEnergy Settlement Interval metered energy for Business Associate B, Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
Dynamic System Resource Deemed Deliver Energy (include ETC/TOR)	Variable Name: SettlementIntervalMeteredEnergy Settlement Interval metered energy for Business Associate B, Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
Metered Generation Quantities (include ETC/TOR)	Variable Name: SettlementIntervalMeteredEnergy Settlement Interval metered energy for Business Associate B, Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
Metered Default Lap Quantities (include ETC/TOR)	Variable Name: SettlementIntervalMeteredEnergy Settlement Interval metered energy for Business Associate B, Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
Metered Custom Lap Quantities (include ETC/TOR)	Variable Name: SettlementIntervalMeteredEnergy Settlement Interval metered energy for Business Associate B, Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
Metered Pumping Energy (include ETC/TOR)	Variable Name: SettlementIntervalMeteredEnergy Settlement Interval metered energy for Business Associate B, Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc

Bill Determinant Variable Name	Bill Determinant Definition	Source Document
MSS Gross Metered Quantities (include ETC/TOR)	Variable Name: SettlementIntervalMeteredEnergy Settlement Interval metered energy for Business Associate B, Resource r, Resource Type t, UDC Index u, Entity Type T', MSS Gross/Net Energy Settlement Type I', and MSS Subgroup M', Trading Hour h and Settlement Interval i. (MWh)	BPM for RT Energy Pre-Calc
DAM TO-SC Inter-SC Trade Energy (Financial, Physical and Converted)	BA Hrly Trade Place Day Ahead To Inter-SC Trade Qty attributable to BA B during Trading Hour h at Trade Place Z and IST Type w The portion of the converted Physical Trades at Trade Place Z shall have IST Type of CPT and the portion of the valid Physical Trade at Trade Place Z shall have IST Type of PHY.	BPM for GMC - Forward Scheduling Inter-SC Trades
DAM FROM-SC Inter-SC Trade Energy (Financial, Physical and Converted)	BA Hrly Trade Place Day Ahead From Inter-Sc Trade Qty attributable to BA B during Trading Hour h at Trade Place Z and IST Type w The portion of the converted Physical Trades at Trade Place Z shall have IST Type of CPT and the portion of the valid Physical Trade at Trade Place Z shall have IST Type of PHY.	BPM for GMC - Forward Scheduling Inter-SC Trades
HASP TO-SC Inter-SC Trade Energy (Financial, Physical and Converted)	BA Hrly Trade Place HASP To Inter-SC Trade Qty attributable to Business Associate ID B, in Trading Hour h, at Trade Place Z and IST Type w The portion of the converted Physical Trades at Trade Place Z shall have IST Type of CPT and the portion of the valid Physical Trade at Trade Place Z shall have IST Type of PHY.	BPM for GMC - Forward Scheduling Inter-SC Trades
HASP FROM-SC Inter-SC Trade Energy (Financial, Physical and Converted)	BA Hrly Trade Place HASP From Inter-SC Trade Qty attributable to Business Associate ID B, in Trading Hour h, at Trade Place Z and IST Type w The portion of the converted Physical Trades at Trade Place Z shall have IST Type of CPT and the portion of the valid Physical Trade at Trade Place Z shall have IST Type of PHY.	BPM for GMC - Forward Scheduling Inter-SC Trades
Ancillary Services TO-SC Inter-SC Trade Energy	Inter-SC Trade MW Quantity bought by Business Associate B, Inter-SC Trade s, for Trading Day d and Trading Hour h (MW)	BPM for GMC - Forward Scheduling Inter-SC Trades
Ancillary Services FROM-SC Inter-SC Trade Energy	Inter-SC Trade MW Quantity sold by Business Associate B, Inter-SC Trade s, for Trading Day d and Trading Hour h. (MW)	BPM for GMC - Forward Scheduling Inter-SC Trades
RUC Obligation TO-SC Inter-SC Trade Energy	IFM Load Uplift Obligation IST (sell) of Business Associate B for Trading hour h.	BPM for GMC - Forward Scheduling Inter-SC Trades
RUC Obligation FROM-SC Inter-SC Trade Energy	IFM Load Uplift Obligation IST (bought) of Business Associate B for Trading hour h	BPM for GMC - Forward Scheduling Inter-SC Trades

Exhibit No. ISO-6 –

2012 GMC Proposed Modifications to November 11, 2010 Straw Proposal, January 13, 2011

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California ISO

2012 Grid Management Charge Proposed Modifications to November 11, 2010 Straw Proposal

January 13, 2011

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Executive Summary

The next step in the process of designing the 2012 Grid Management Charge (GMC) is to respond to stakeholder input from the ISO's November 11, 2010, straw proposal paper ("November Straw Proposal") and offer specific modifications to that proposal where appropriate. Building upon the bill comparison data discussed at the December 13, 2010 stakeholder meeting, the development of billing determinants detailed in the November Straw Proposal, and the cost of service study functionalization and cost allocation steps discussed in the October 8, 2010 Cost of Service discussion paper, the ISO now proposes certain modifications to the November Straw Proposal to meet concerns expressed by stakeholders:

- To phase in allocation of the System Operations charge to supply MW over a three-year period;
- Provide for treatment of Transmission Ownership Rights (TORs);
- Provide for application of Scheduling Coordinator Identification (SCID) fee;
- Eliminate Station Power Fees from GMC
- Exclude MSS Load Following Energy from Market Operations charge

This paper also addresses issues from the last stakeholder meeting for which the ISO is not proposing changes to the GMC design. Lastly, we will discuss the proposal for a five year revenue requirement cap.

Guiding Policy and Ratemaking Principles

The ISO used the following guiding principles to conduct its cost of service study and develop the framework for the new 2012 GMC structure:

1) **Cost Causation** – Costs will be properly allocated to the correct GMC buckets and charged to those who benefit from or utilize those services.

2) **Focus on use of ISO services, not market behavior** – The new GMC design should reflect its primary purpose as a vehicle for recovering the ISO's revenue requirement based on each user's use of the ISO's services, not as a tool for shaping incentives based on market or operating behavior. Incentives such as these are appropriately addressed through the design of the market structure and market rules. The ISO believes that this principle is fully consistent with SCE's comment on the October 8, 2010 discussion paper that: "there should always be a final check on GMC rates, and a continuous monitoring, to ensure that GMC rates are not unduly negatively affecting market outcomes." The ISO agrees that a properly designed GMC should seek to do no harm, i.e., should not create perverse behavioral incentives or negatively affect market outcomes. The point of this principle is simply that the GMC design should not be used as a substitute for effective market rules to incent appropriate participant behavior and ensure efficient market outcomes, but should more narrowly provide a mechanism to recover ISO revenue

requirements in a manner consistent with the other principles identified here.

3) **Transparency** – Costs and billing determinants will be clear, visible, and understandable to all market participants.

4) **Predictability** – Market participants will be able to determine in advance what their GMC costs will be depending on their activity.

5) **Forecastability** – The rates should utilize billing determinants that can be easily forecasted by both the ISO and market participants. This should result in fewer rate adjustments during the year.

6) **Flexibility** – The new GMC structure should easily accommodate future market enhancements without excessive complexity or disruption to the overall structure.

7) **Simplicity** – Simplify the current GMC structure to reduce the amount of varying bill determinants and the number of charge codes.

The steps included in conducting a cost of service study are:

1) Functionalization -	The process by which various ISO activities are defined and sorted into service categories (functions and sub-functions) to reflect the different services provided by the ISO.
2) Cost Allocation -	The process by which the costs of providing services are allocated to the service categories (functions and sub-functions).
3) Classification -	The determination of billing determinants based on the customer cost causation factors.
4) Rate Design -	The process for deriving rates that divides the revenue requirement for each service category by the total of the applicable billing determinants.

5) Bill Impact	Evaluating the impacts that the rate design will have on individual customer bills.

The ISO completed the functionalization and cost allocation steps in accordance with these fundamental ratemaking principles and described the results in the October 8, 2010 discussion paper. In the November Straw Proposal, the ISO proposed a classification methodology (customer billing determinants) for allocating the costs in each service category. The ISO then used historical data to develop estimated rates and bill impacts for individual SCs and for the major classes of SCs. Individual SC specific data was sent to market participants that requested this information for the December 13, 2010 stakeholder meeting. This paper presents modifications to the November Straw Proposal based on stakeholder input from the December 13, 2010 stakeholder meeting. Revised individual SC specific data integrating the proposed modifications detailed below will be made available prior to the January 20, 2011 stakeholder conference call.

Phase-in of the Systems Operations Charge to Supply

The ISO believes that the GMC proposal is equitable and adheres to the stated guiding principles, but does acknowledge that the new design results in significant bill impacts to certain customers. A primary factor behind the large impacts is that the current GMC does not charge for through-put (i.e., energy flow MWh), but does assess charges based on behavior such as uninstructed imbalance energy or deviations. In contrast, under the proposed 2012 design, the billing determinant for system operations will be total energy flow MWh, without regard to whether the flows were forward scheduled, instructed or uninstructed. Under today's GMC, a supplier that puts through the same volume as a load serving entity pays 60% less. For example, under the existing GMC, a base load generator pays $0.06 per MWh while an equivalent level of load pays $0.65 per MWh.

Stakeholders offered comments suggesting that the ISO should consider either grandfather certain generation units or phasing in the charges to supply over a period of time. The ISO reviewed these options and believes that phasing in supply to the System Operations charge over a three year period is the most appropriate mitigation plan. During year 1 (2012), 2/3 of supply MWh will be excluded from the System Operations charge. In year 2 (2013), 1/3 of supply MWh will be excluded from the System Operations charge. In year 3 (2014) and going forward (starting in 2015), no supply MWhs will be excluded from the System Operations charge. This phase- in approach will have the following aggregate impacts to the market participant classes based upon the previously distributed ISO cost data from the period of June 2009 to May 2010:

Increase over existing GMC (in millions)

Class	Year 1	Year 2	Year 3
CRR holders	$4.1	$4.1	$4.1
IOUs	$13.4	$8.6	$5.4
Marketers/importers	($12.5)	($11.2)	($10.3)
Munis	($1.5)	($2.1)	($2.5)
Others (renewables)	($1.2)	($1.0)	($0.8)

Suppliers (internal gen)	($2.2)	$1.6	$4.1

Proposed Treatment of Transmission Ownership Rights

Under the existing GMC, Transmission Ownership Rights (TORs) are granted a discounted rate due to the limited ISO services they require. The ISO believes that TORs should continue to receive a discounted rate in the new GMC structure because this fundamental premise has not changed. The ISO is proposing to continue to provide a discounted GMC rate to TORs by:

- Exempting 100% of TOR MWhs from the Market Services charge code; and
- Applying the same System Operations charge rate to TOR flow MWhs as to other SCs' energy flows, but applying that rate only to the minimum of a Scheduling Coordinator's TOR Supply MWhs or TOR Demand MWhs (see example below).

In addition, TOR energy flows will not participate in the three-year phase-in and will not be exposed to any impacts from the application of the phase-in to other non-TOR supply MWhs.

<u>Justification of a Discounted TOR rate</u>

The ISO first considered whether TORS should be assessed both the Market Services and System Operations charges from a cost of service standpoint. In the previous cost of service study, the ISO identified three areas in which ISO services were required for TORs:

1) Real-Time Operations. The ISO provides support on an emergency basis for flows on TORs, in a manner similar to standby service. A common method to allocate costs for standby service is in proportion to the demands placed on the system. In this case, the non-coincident peak demand of TORs was measured relative to total system demand. The resulting fraction was used to assign a percentage of the costs of Real-Time Operations to this service.
2) Scheduling. The ISO provides check-outs with neighboring Balancing Authorities in order to schedule flows across boundaries. For this service, the assignment method was to use the ratio of the total number of inter-tie schedules for TORs relative to the total number of ISO inter-tie schedules.
3) Outage Management. The ISO provides for the scheduling and coordination of outages across the Balancing Authority. The assignment method was the number of TOR transmission outages relative to total California ISO transmission outages.

ISO staff reviewed the above conclusions from the previous cost of service study, updated the current cost of service study, and determined that TORs utilize a portion of the following ABC level 2 activities. These activities are all related to System Operations because there is no TOR participation in the Market Services costs. The indirect dollars were then also allocated based on the direct percentage, using the process described below, to derive a total of $45.2 million in direct and indirect costs that would be allocated to TORs.

ABC Level 2 Activities	System Operations Direct Allocation (in thousands)
High level manage FNM maintenance	$ 566
Manage network applications	$ 1,249
Manage operations engineering studies	$ 1,047
Manage D+2 analysis	$ 357
Manage DA market	$ 497
Manage transmission outages	$ 1,727
Manage emergency operations	$ 327
Manage RT market - after close of market	$ 127
Manage RT operations - transmission dispatch	$ 5,264
Manage RT interchange scheduling	$ 5,247
Subtotal: TOR related direct costs	**$ 19,908**
Total Direct Costs	$ 45,923
Percentage of TORs to ABC level 2 Direct Costs	43.35%
Total Indirect Dollars	$ 58,335
Percentage of TORs indirect dollars	**$ 25,289**
Total Direct and Indirect TOR level 2 TOR costs	**$ 45,197**

Staff then allocated the ratio of TOR MWh to the total flow MWh to determine the usage percentage:

Total Flow MWh	475,167,832
TOR MWh	9,320,918
TOR as % of total flow	2.0%

The total costs related to TORs is then based on 2.0% * $45.2 million, or $0.9 million.

Collection of a Discounted TOR Rate

The cost causation detail for TORs shows that the ISO needs to collect roughly $0.9 million from TORs. The ISO evaluated different methodologies to adjust the number of TOR MWh that would be included in the System Operations charge code. The proposal to use the minimum of supply or demand is logical because it would reduce the number of billable TOR MWh to 3.3 million MWh and at the rate of $0.2867 would collect revenue of $0.9 million.

<u>Examples of the Minimum Approach for TOR Energy Flows</u>

The ISO's proposal to charge TOR flow MWh the System Operations GMC based on the minimum of TOR supply or TOR demand is illustrated in these examples:

1) SC1: TOR supply (generation or imports) = 100 MWh, TOR demand (load or exports) = 100 MWh, System Operations GMC is charged for 100 MWh.
2) SC2: TOR supply = 100 MWh, TOR demand = 60 MWh, System Operations GMC is charged for 60 MWh.
3) SC3: TOR supply = 100 MWh, TOR demand = 0, System Operations GMC is charged for 0 MWh.

In the case of SC2 and SC3 where there was more TOR supply than TOR demand, the excess supply would have been used to serve non-TOR demand and that demand would be charged the regular System Operations GMC rate.

<u>Special TOR Rate</u>

As mentioned above, the ISO is proposing that TOR energy flows be unaffected by the phase-in of supply and instead be charged GMC in 2012 and 2013 based on the year 3 approach. This will require a special TOR rate for 2012-13. The phase-in approach reduces the number of MWh for the System Operations charge code in years one and two, therefore creating a per-MWh rate that is higher than what it is in year three. If there is not a special charge code created for TORs during years one and two, then TORs (regardless of the discounted volume) will be charged the higher rate in years 1 and 2, which is too much based on the cost causation analysis shown above. The ISO therefore proposes to create a special charge code specific to TORs that would be set at the estimated year 3 System Operations rate of $0.2867. The following chart illustrates year 1-3 System Operations rates for TOR MWh and all other flow MWh:

Year 1 (2012)		Year 2 (2013)		Year 3 (2014)
System Ops Rate	TOR Rate	System Ops Rate	TOR Rate	System Ops Rate
$0.4329	$0.2867	$0.3449	$0.2867	$0.2867

In year 3 both TOR and all flow MWh will be charged the same System Operations rate.

Application of the SCID fee

ISO staff has reviewed the comments related to the SCID fee and agree with stakeholders that the monthly SCID fee should apply only to SCs that have settlements activity in a trade month, not merely for having an active SCID. The fee will remain at the current level of $1000 per month per SCID fee.

Elimination of the Station Power fee

ISO staff has reviewed the station power fee and concluded that it should not be a separate GMC charge. The amount is insignificant and the full costs are included in the System Operations charge code.

Metered Sub System Load Following Energy

The ISO has determined that it is appropriate to exclude the MSS Load Following instructed imbalance energy from the Market Services GMC charge. This energy reflects the MSS's performance of its real-time load following function, and the cost causation impacts of this function are appropriately recovered through the System Operations charge.

Other Issues

ISO staff reviewed other issues raised by stakeholders and has decided not to make changes to the proposal.

Unscheduled Energy

There was discussion to extend the Market Services charge to apply to energy delivered in real time that is not scheduled or in response to ISO dispatch instructions. ISO staff has determined that RT delivered energy does get an appropriate share of costs through the System Operations GMC charge (which includes a significant share of the cost of the ISO's settlement process) and therefore satisfies the principle of cost causation. In accordance with guiding principle 2 stated earlier in this paper, the GMC should focus on recovering the costs associated with using ISO services and should not try to address concerns about market participant behavior. In the case of unscheduled or undispatched energy flows, there are market rules that already address these uninstructed deviations such as exposure to real time prices and ineligibility for bid cost recovery. In addition, the ability to bypass the ISO market processes is limited by must offer obligations for RA resources. The ISO has therefore decided not to apply a Market Services GMC charge to these real-time deviations.

PIRP Forecast Fee

There has been discussion whether to include a separate charge for PIRP forecast fees. This question is being addressed in the ISO's Renewable Integration Market and Product Review initiative and will be resolved in that stakeholder process. If the PIRP forecast fee is retained, it would be treated for GMC purposes like the other special fees in this proposal, as an offset to the total costs to be recovered through one or more of the other buckets.

Revenue Requirement Cap Proposal

The last component of the GMC redesign for 2012 is to establish a new revenue requirement cap. The previous cap was set at $195 million in 2004 and increased to $197 million in 2006. One year extensions have been approved for each year after that. The ISO is proposing a five year revenue requirement cap in which the $197 will be the baseline cap in 2012.The cap will be then be incrementally increased by 1% per year through 2016.   The annual revenue requirement cap based on this structure over the five year period would be:

Year	Revenue Requirement Cap
2012	$197,000,000
2013	$198,970,000

2014	$200,959,700
2015	$202,969,297
2016	$204,998,990

The ISO proposes to retain the same process currently included in the tariff with respect to the revenue requirement cap so that as long as the ISO's annual budget for each year does not exceed that year's revenue requirement cap, and there are no GMC rate design or billing determinant modifications proposed for the next year, the ISO will not be required to make a section 205 with FERC seeking approval for the next year's revenue requirement.

The current budget approval stakeholder process will remain in the tariff, and that process culminates with each annual budget being presented to the ISO Board for approval at the December Board meeting and posted on the ISO website after approval. The ISO's proposed revenue requirement cap, plus annual 1% adjustments, would "sunset" on December 31, 2016 and the ISO would be required to make a 205 filing for the GMC that would become effective on January 1, 2017.

Next Steps

The stakeholder process for the 2012 GMC Cost of Service Study will continue with the following timeline:

- February 2011 – Update Board on Rate Structure
- March 2011 – Seek Board approval of Rate Structure
- May 2011 – File rate structure with FERC

Exhibit No. ISO-7 – 2012 GMC Draft Final Proposal, February 15, 2011

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California ISO

2012 Grid Management Charge
Draft Final Proposal

February 15, 2011

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Executive Summary

ISO management intends to take this draft final proposal to its Board of Governors for approval at its March 2011 meeting, and as such is the last step in the design process for the 2012 Grid Management Charge. Following discussions with stakeholders since the last posted proposal document on January 13, and further analysis by ISO staff, this draft final proposal incorporates some final modifications that are listed at the end of this section.

This paper is the culmination of the following previously published papers and data sets:

- The cost of service discussion paper published October 8, 2010
- The straw proposal published on November 11, 2010
- The comparison data published December 2, 2010
- The modifications to the straw proposal published on January 13, 2011
- The revised comparison data published on January 13, 2011
- The revised comparison data published on February 9, 2011

Building upon the cost of service study functionalization and cost allocation steps reported in the October 8, 2010 Cost of Service discussion paper, this draft final proposal reviews the guiding principles and the framework for the new GMC cost categories. The draft final proposal goes on to describe the ISO's classification (determination of billing determinants based on customer cost causation factors) of those costs, the rate design produced by applying the billing determinants and some hypothetical, aggregated bill impacts. The October 8 discussion paper detailed the process the ISO followed to utilize its activity based costing system to allocate the costs of its activities into three main GMC cost categories or buckets (Market Services, System Operations, and CRR Services), and four transaction fees (bid segment fee, inter SC trade fee, CRR bid fee, and SCID fee). This approach offers significant improvements to the current GMC structure by increasing the amount of direct allocations of costs to buckets, reducing forecasting errors through rate simplification, reducing the number of charge codes, and simplifying the calculations of these charge codes.

This document describes the ISO's draft final proposal for classifying costs to users of the ISO's services. The ISO proposes that the three GMC charge categories be allocated based on gross MWh (capacity and CRR holdings) and MWh (energy). The Market Services category includes awards of ancillary services, and schedules and dispatch instructions of generation, imports, load, and exports. The System Operations category includes all flow quantities for generation, load, imports, and exports. The CRR Services category includes the total MWh quantity awarded through both the allocation process and auction.

The ISO's draft final proposal to allocate the charges as follows to each user of the ISO's services: The Market Services charge will be applied to the scheduling coordinator's gross absolute value of awarded MWh of energy and MW of AS in the forward and real time markets. The System Operations charge will be applied to the scheduling coordinators gross absolute value of actual MWh of real time energy flows. The CRR Services charge will be applied to each scheduling coordinators total MW holdings of CRR that are applicable to each hour. The three administrative charges will be applied to each scheduling coordinator based on their use of the associated transactions.

This draft final proposal also incorporates the modifications that were published in the January 13, 2011 paper as well as others discussed on the February 8, 2011 conference call. The modifications are summarized below and will be addressed in more detail later in this draft final proposal.

- To introduce a grandfathering provision to mitigate the impact of the 2102 GMC design on certain supply contracts by excluding the energy supplied from those generating units from the System Operations charge;
- To eliminate the three-year phase-in for the application of the System Operations charge to supply energy flows;
- Provide for treatment of Transmission Ownership Rights (TORs);
- Provide for application of Scheduling Coordinator Identification (SCID) fee;
- Eliminate Station Power Fees from GMC;

- Exclude MSS Load Following Energy from Market Operations charge.

This paper also addresses issues from the December stakeholder meeting for which the ISO is not proposing changes to the GMC design proposal. Last, we will discuss the proposal for a three year revenue requirement cap.

Guiding Policy and Ratemaking Principles

The ISO is using the following guiding policy principles to conduct its cost of service study and develop the framework for a new GMC structure:

1) **Cost Causation** – Costs will be properly allocated to the correct GMC cost categories and charged to those who benefit from or utilize those services.
2) **Focus on use of ISO services, not market behavior** – The new GMC design will reflect its primary purpose as a vehicle for recovering the ISO's revenue requirements based on each participant's use of the ISO's services, not as a tool for shaping incentives based on market or operating behavior. Incentives such as these are appropriately addressed through the design of the market structure and market rules. In addition, SCE's comments on the October 8, 2010 discussion paper highlighted a similar theme, "there should always be a final check on GMC rates, and a continuous monitoring, to ensure that GMC rates are not unduly negatively affecting market outcomes." The ISO agrees that a properly designed GMC should seek to do no harm (negatively affecting market outcomes), avoid imposing negative incentives (address negative market behavior such as deviations), and should be simply a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts.
3) **Transparency** – Costs and billing determinants will be clear, visible, and understandable to all market participants.

4) **Predictability** – Market participants will be able to determine in advance what their GMC costs will be depending on their activity.

5) **Forecastability** – The rates will utilize billing determinants that can be easily forecasted by both the ISO and market participants. This should result in fewer rate adjustments during the year.

6) **Flexibility** – The new GMC structure will easily accommodate future market enhancements without excessive complexity or disruption to the overall structure.

7) **Simplicity** – The new design will simplify the current GMC structure by reducing the amount of varying bill determinants and the number of charge codes.

The steps included in conducting a cost of service study are:

1) Functionalization -	The process by which various activities are defined and sorted into service categories (functions and sub-functions) to reflect the different services provided by the ISO.
2) Cost Allocation -	The process by which the costs of providing services are allocated to the service categories (functions and sub-functions).
3) Classification -	The determination of billing determinants based on the customer cost causation factors.
4) Rate Design -	The process for deriving rates that divides the revenue requirement for each service category by the billing determinants.
5) Bill Impacts Analysis -	An evaluation of the impacts that the rate design will have on individual customer bills.

The ISO has completed the functionalization and cost allocation steps in accordance with these fundamental ratemaking principles and described the results (summarized in the section below) in the October 8, 2010 discussion paper. In this draft final proposal the ISO: 1) proposes a classification methodology (customer billing determinants) that can be used to allocate the costs in each service category; 2) provides some rate design examples using hypothetical rates and historical data; and 3) presents aggregated bill impact information.

The 3 GMC Cost Categories

As described in the October 8, 2010 discussion paper, an examination of the ISO's new nodal market systems process map of customer activity revealed the following:

Customers submit bids	**>>**	**Market systems award / schedules**	**>>**	**Energy flows**

In addition, there are processes related to Congestion Revenue Rights (CRRs).

Based on this process map, the following three cost categories were developed:

1. Market Services
2. System Operations
3. CRR Services

This structure is very similar to what other ISOs and RTOs with nodal markets have implemented to recover their administrative charges.

Using these three categories, the ISO's level 2 activities were mapped as either: 1) all in one category or not in the category (100% or 0%), 2) a split between two categories (50% / 50%), or 3) partially in one category or another (80% or 20%), or in the case of CRRs, a small portion of the activity (10%). This mapping was also applied to the software underlying the debt service portion of the revenue requirement. Indirect costs are allocated proportional to direct costs.

Grandfathering Provision

The ISO believes that the GMC draft final proposal is equitable and adheres to the stated guiding principles, but does acknowledge that the new design results in significant bill impacts to certain customers. A primary factor behind the large impacts is that the current GMC does not charge for through-put (i.e., energy flow in MWh), but does assess charges based on behavior, particularly real-time uninstructed imbalance energy or deviations. In contrast, under the proposed 2012 GMC structure the billing determinant for System Operations will be total energy flow MWh, without regard to whether the flows were forward scheduled, instructed or uninstructed. Under today's GMC, a supplier that puts through the same volume as a load serving entity consumes pays approximately 60% less. For example, under the existing GMC, a base load generator pays $0.06 per MWh while an equivalent level of load pays $0.65 per MWh.

Stakeholders offered comments suggesting that the ISO should consider either grandfathering certain generation units or phasing in the charges to supply over a period of time.

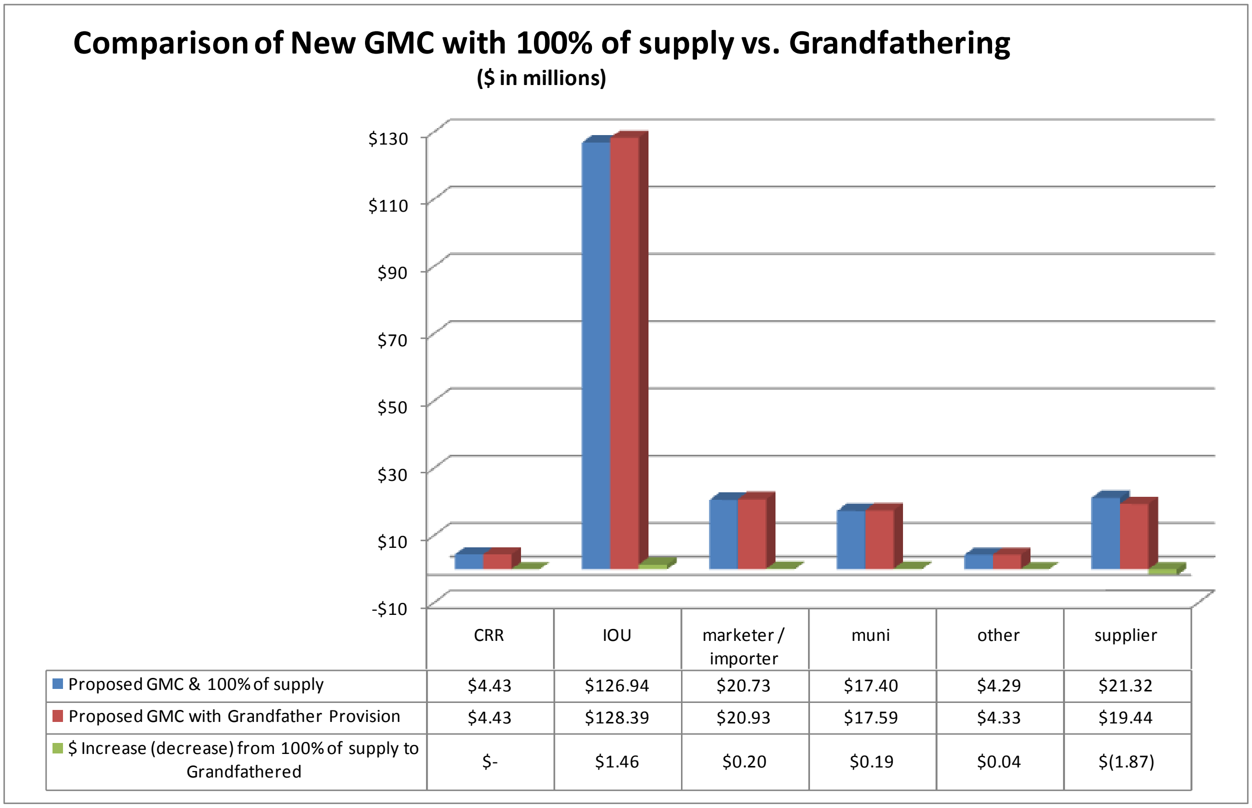
The ISO previously proposed a three-year phase-in approach, as discussed in the January 13 paper. After discussing this approach with stakeholders and performing further analysis to examine its effectiveness in addressing the identified issue, the ISO has concluded that a grandfathering approach would be the preferred option to mitigate rate impacts on a finite number of customers. To be clear, the ISO proposes to implement the grandfathering provision instead of the phase in approach – not a combination of the two. The ISO's analysis indicates that grandfathering certain baseload generator units that have contractual restrictions preventing the recovery of additional GMC charges by the supplier is a sufficient mitigation technique that specifically targets the impacted units and mitigates the GMC cost impacts for those units while causing minimal impacts on other participants, in contrast to the phase-in approach. Moreover, this method will limit the cost impact of the mitigation to other market participants by reducing the number of MWh that are excluded compared to the phase-in approach.

The proposed grandfathering provision would exempt units that meet the criteria from the System Operations charge until the first opportunity to renegotiate the contract or until the contract expires. An officer of the generation owner company will be required to provide the ISO a signed affidavit attesting to the information that demonstrates the contract's eligibility for grandfathering.

The criteria that will be used for determining units that are eligible for the grandfathering provision are:

- The contract precludes the supplier from recovering the additional GMC costs under the 2012 design from the buyer;
- The contract must have been executed prior to 1/1/2011;
- The duration of the contract must be three years or greater (until the first exit provision)
- The generation owner must be the scheduling coordinator;
- The contract may not be with another scheduling coordinator that has the same parent company as the generation owner;
- The contract may not be with the same scheduling coordinator ID as the generation unit;

The first year impacts of the grandfathering provision on the market segments are shown in the figure below. Subsequent years impacts are shown in Exhibit 1, Tab “Index”. Based on this analysis the ISO believes that the grandfathering proposal is an effective and reasonable mitigation approach which imposes minimal cost impacts on other participants. With the adoption of this grandfathering approach in the draft final proposal, the ISO is eliminating the prior phase-in proposal from the 2012 GMC design.



	CRR	IOU	marketer / importer	muni	other	supplier
Proposed GMC & 100% of supply	$4.43	$126.94	$20.73	$17.40	$4.29	$21.32
Proposed GMC with Grandfather Provision	$4.43	$128.39	$20.93	$17.59	$4.33	$19.44
$ Increase (decrease) from 100% of supply to Grandfathered	$-	$1.46	$0.20	$0.19	$0.04	$(1.87)

Proposed Treatment of Transmission Ownership Rights

Under the existing GMC, Transmission Ownership Rights (TORs) are granted a discounted rate due to the limited ISO services they require. The ISO believes that TORs should continue to receive a discounted rate in the new GMC structure because this fundamental premise has not changed. The ISO is proposing to continue to provide a discounted GMC rate to TORs by:

- Exempting 100% of TOR MWhs from the Market Services charge code; and
- Applying a fixed $0.27 System Operations charge rate to TOR flow MWhs, but applying that rate only to the minimum of a Scheduling Coordinator's TOR Supply MWhs or TOR Demand MWhs (see examples below).

<u>Justification of a Discounted TOR rate</u>

The ISO first considered whether TORs should be assessed both the Market Services and System Operations charges from a cost of service standpoint. In the previous cost of service study, the ISO identified three areas in which ISO services were required for TORs:

1) Real-Time Operations: The ISO provides support on an emergency basis for flows on TORs, in a manner similar to standby service. A common method to allocate costs for standby service is in proportion to the demands placed on the system. In this case, the non-coincident peak demand of TORs was measured relative to total system demand. The resulting fraction was used to assign a percentage of the costs of Real-Time Operations to this service.
2) Scheduling: The ISO provides check-outs with neighboring Balancing Authorities in order to schedule flows across boundaries. For this service, the assignment method was to use the ratio of the total number of inter-tie schedules for TORs relative to the total number of ISO inter-tie schedules.
3) Outage Management: The ISO provides for the scheduling and coordination of outages across the Balancing Authority. The assignment method was the number of TOR transmission outages relative to total California ISO transmission outages.

ISO staff reviewed the three areas noted above from the previous cost of service study, updated the current cost of service study, and determined that TORs utilize a portion of the following ABC level 2 activities. These activities are all related to System Operations because TORs do not participate in the Market Services category. The indirect dollars were then allocated based on the direct percentage, using the process described below, to derive a total of $45.2 million in direct and indirect costs that should be allocated to TORs.

ABC Level 2 Activities	System Operations Direct Allocation (in thousands)
High level manage FNM maintenance	$ 566
Manage network applications	$ 1,249
Manage operations engineering studies	$ 1,047
Manage D+2 analysis	$ 357
Manage DA market	$ 497
Manage transmission outages	$ 1,727
Manage emergency operations	$ 327
Manage RT market - after close of market	$ 127

Manage RT operations - transmission dispatch	$	5,264
Manage RT interchange scheduling	$	5,247
Subtotal: TOR related direct costs	**$**	**19,908**
Total Direct Costs	$	45,923
Percentage of TORs to ABC level 2 Direct Costs	43.35%	
Total Indirect Dollars	$	58,335
Percentage of TORs indirect dollars	**$**	**25,289**
Total Direct and Indirect TOR level 2 TOR costs	**$**	**45,197**

Staff then allocated the ratio of TOR MWh to the total flow MWh to determine the usage percentage:

Gross Flow MWh	475,167,832
Gross TOR MWh	9,320,918
TOR as % of total flow	2.0%

The total costs related to TORs is then based on 2.0% * $45.2 million, or $0.9 million.

Collection of a Discounted TOR Rate

The cost causation detail for TORs shows that the ISO needs to collect $0.9 million from TORs. The ISO evaluated different methodologies to adjust the number of TOR MWh that would be included in the System Operations charge code. The proposal to use the minimum of supply or demand is logical because it reduces the number of billable TOR quantity to 3.3 million MWh and at the System Operations rate of $0.27 would collect revenue of $0.9 million.

Examples of the Minimum Approach for TOR Energy Flows

The ISO's proposal to charge TOR flow MWh the System Operations GMC based on the minimum of TOR supply or TOR demand is illustrated in these examples:

1) SC1: TOR supply (generation or imports) = 100 MWh, TOR demand (load or exports) = 100 MWh, TOR GMC is charged for 100 MWh.
2) SC2: TOR supply = 100 MWh, TOR demand = 60 MWh, TOR GMC is charged for 60 MWh.
3) SC3: TOR supply = 100 MWh, TOR demand = 0, TOR GMC is charged for 0 MWh.

In the case of SC2 and SC3 where there was more TOR supply than TOR demand, the excess supply would have been used to serve non-TOR demand and that demand would be charged the regular System Operations GMC rate.

Design of an Allocation Method

A method for classifying costs in any particular cost category requires two elements. The first is a metric or unit to be used as the “denominator” in the equation that converts the total cost in each category into a per unit charge. The second is a billing determinant for calculating each party’s share of the total cost in the category. The next two subsections present the ISO’s final draft proposals for each of these elements.

a. Selection of Metrics

The selection of the metrics to be used as denominators for each category was based on the guiding principles and a comparison of other ISOs’ service charges. The ISO proposes that the Market Services and System Operations GMC categories be based on gross MW per hour (capacity) and MWh (energy). This follows the guiding principles because it reflects each scheduling coordinator’s use of the ISO’s services, is flexible, transparent, easy to forecast, and simple. The ISO considered other options such as per schedule charges, energy imbalances, and peak and off peak rates. However, these alternatives are very difficult to forecast for both the ISO and market participants and it is difficult to expand the metrics to include additional market enhancements.

The Market Services category includes awarded ancillary services MW, schedules and dispatch instructions of generation, imports, load, and exports (additional detail below). As discussed during the Convergence Bidding stakeholder process, the Market Services system impact is not dependent upon whether the bid is virtual demand or virtual supply. Market Services clears offers of supply with offers of demand to award a schedule or dispatch resources. The gross MWh approach applies equal GMC costs to both participants that engaged in the trade.

The System Operations category includes all flow quantities for generation, load, imports and exports (additional detail below). The fundamental purpose of System Operations is to reliably balance supply and demand. Since both components (load and generation) are necessary to achieve balance, the ISO believes gross MWh is also appropriate for System Operations. In addition, as new technologies that shift or reduce load such as demand response, storage, and electric vehicles increase their participation in ISO markets, load will play an increasingly important role with the integration of renewable resources. Thus load may provide services similar to generation in maintaining grid reliability. Since both load and generation will provide similar services, we recommend that the GMC be designed in a manner that provides symmetrical marginal costs regardless of the technology used to provide the service. The marginal cost of the underlying technology should determine its competitiveness in the ISO market, not a difference attributed to GMC rate differential.

The CRR Services category includes the total awarded MW per hour of CRRs. Using MW per hour for ancillary services and CRRs and MWh for energy achieves simplicity in a common denominator as well as providing the flexibility to add additional MW per hour or MWh when new market enhancements and products are added. The principle of cost causation is fundamental in allocating costs to each of the administrative charge categories. The ISO believes it is appropriate to consider the relative size of beneficiaries of a category which can be accomplished by using billing determinants that accurately reflect the volume of participation. Other ISOs also utilize MW per hour and MWh as their primary quantities for creating per unit charges and billing determinants.

b. Billing Determinants

Each of the three GMC buckets and respective billing determinants are discussed in further detail below.

1. Market Services

The Market Services charge code is designed to recover costs the ISO incurs for running the markets. As such, this charge code will be applied to each scheduling coordinator's gross absolute value of awarded MWh of energy and MW per hour of ancillary services in the forward and real time markets. Specifically, the charge code will apply to the following billing determinants:

Schedules and Awards (Absolute by Resource by Hour)
DA Generation Schedules (including MSS)
DA Import Schedules (including MSS)
DA Load Schedules (including MSS Gross Load)
DA Export Schedules (including MSS)
DA Ancillary Service Awards
DA Ancillary Service Self Provision
Convergence Bidding Schedules
HASP Incremental and Decremental Energy (Non Dynamic)
HASP Incremental and Decremental AncillaryService Awards
HASP Incremental and Decremental Ancillary Service Self Provision
Real Time Optimal Energy
Real-Time Minimum Load Energy
Derate Energy
Real-Time Self Schedule
Real-Time Pumping Energy
Real-Time Incremental and Decremental AncillaryService Awards
Real-Time Incremental and Decremental Ancillary Service Self Provision

2. System Operations

The System Operations charge code is designed to recover costs the ISO incurs for running the grid in real time. As such, this charge code will be applied to each scheduling coordinators gross absolute value of actual real-time MWh energy flow. Specifically, the charge code will apply to the following billing determinants:

Flow (Absolute by Resource by Settlement Interval)
Non Dynamic System Resource Deemed Delivered Energy
Dynamic System Resource Deemed Delivered Energy
Metered Generation Quantities
Metered Default LAP Load Quantities
Metered Custom LAP Load Quantities (Including MSS Gross Load)
Metered Pumping Energy

3. CRR Services

The CRR Services charge code is designed to recover costs the ISO incurs for running the CRR markets. As such, this charge code will be applied to each scheduling coordinator's total MW holdings of CRRs that are applicable to each hour. Specifically, this charge code will apply to the following billing determinants:

CRR MWs (Absolute by Scheduling Coordinator by Financial Node)
Daily Financial Node CRR Quantity

Many of the terms utilized above are defined in the appendix to the Market Operations business process manual at the following link:

https://bpm.caiso.com/bpm/bpm/version/000000000000109

c. Administrative and Transaction Fees

There are several administrative and transaction fees which will be used in the new market design. These fees will be structured in a way that allows market participants to determine if it is economic to incur the costs associated with using the service in question while taking into consideration negative impacts to market participation if fees are too high.

1. Bid Segment Transaction Fee

The per bid segment transaction fee is designed to deter the submission of high volumes of "phishing" bids. The charge is proposed to be set at $.005 per bid segment and will be applied to all bid segments submitted. The rate of $.005 is based on a nominal charge that does not represent a significant expense to market participants under typical scheduling practices, but is enough to deter the submission of excessive bid volumes. The amount is similar to the rate used at the NYISO. The concept of a bid segment charge was raised during the Convergence Bidding stakeholder process to address concerns about bid proliferation if there was no marginal cost to place incremental bids. In addition, transaction fees collect revenue from participants who are unsuccessful in clearing the market, but who use and benefit from ISO systems and processes. The revenue from this transaction fee will offset costs recovered through Market Services. Thus, if the number of unsuccessful bids increases, the Market Services rate for those participants who cleared the market will be reduced.

2. CRR Bid Transaction Fee

The CRR bid transaction fee is designed to recover a portion of the CRR costs on a transactional basis. The fee will apply to the CRR nomination and allocation processes. The rate of $1.00 will be used for this fee. The revenue from this transaction fee will offset costs recovered through CRR Services. Thus if the number of unsuccessful bids increases, the CRR services rate for those participants who cleared the market will be reduced. A number of stakeholders commented that their understanding was that IFM and convergence bids will be charged $0.005. To clarify, the price unit is $0.005 per bid segment with a limit of 10 bid segments so bids can have a maximum charge of $0.05 per bid. In contrast, the ISO's CRR GMC proposal is $1 per nomination or per bid (without consideration of the number of segments). Furthermore IFM and convergence bids are accepted for 24 hours per day for each day of the month. CRR nomination tiers and auctions are divided into two time-of-use (TOU) periods per month.

Contrasting IFM bids and CRR nominations on a comparable basis, the $1 per CRR nomination is on the same order as $0.005 per bid segment. For example, to bid 100 MW into the IFM for 744 hours in any given (31 day) month would cost a minimum of:

- IFM charge = 1 bid segment/hour x $0.005/bid segment x 744 hours = $3.72

To receive 100 MW CRR for 744 hours in any given (31 day) month would require two nominations: one for On Peak and one for Off Peak.

- Proposed CRR GMC = 2 nominations x $1/nomination = $2.00

The analysis above shows that a $1 per nomination fee for CRR is comparable to $0.005 per bid segment for IFM bids and convergence bids.

Inter-SC Trade Transaction Fee

The inter-SC trade transaction fee is designed to recover costs directly related to the scheduling and settling of inter-SC trades. The revenue from this transaction fee will offset costs recovered through Market Services. The ISO determined a rate (slightly less than the current rate), as an appropriate level so as not to deter existing activity, but also to recognize that without any transaction cost this could increase the demand for the service and drive costs higher. A fee of $1.00 per inter-SC trade (each side of trade) will apply to the following billing determinants:

<u>INTER-SC Trade (Absolute by Trade)</u>
DAM TO-SC Inter-SC Trade Energy (Physical and Converted)
DAM FROM-SC Inter-SC Trade Energy (Physical and Converted)
DAM TO-SC Inter-SC Trade Energy (Financial)
DAM FROM-SC Inter-SC Trade Energy (Financial)
HASP TO-SC Inter-SC Trade Energy (Physical and Converted)
HASP FROM-SC Inter-SC Trade Energy (Physical and Converted)
HASP TO-SC Inter-SC Trade Energy (Financial)
HASP FROM-SC Inter-SC Trade Energy (Financial)
Ancillary Services TO-SC Inter-SC Trade Energy
Ancillary Services FROM-SC Inter-SC Trade Energy
RUC Obligation TO-SC Inter-SC Trade Energy

3. SCID Administrative Fee

The SCID administrative fee is designed to limit the number of SCIDs to those needed for legitimate business purposes in order to reduce the additional burden on the ISO systems and resources that an unlimited number of SCIDs could create. The ISO proposes to keep the charge at the current $1,000 per month per SCID and only apply the charge to SCs that have settlements activity in a trade month. The revenue from this transaction fee will offset costs recovered through Market Services.

Elimination of the Station Power fee

ISO staff has reviewed the station power fee and concluded that it should not be a separate GMC charge. The amount is insignificant and the full costs are included in the System Operations charge code.

Metered Sub System Load Following Energy

The ISO has determined that it is appropriate to exclude MSS Load Following instructed imbalance energy from the Market Services GMC charge. This energy quantity reflects the MSS's performance of its real-time load following function, and the cost causation impacts of this function are appropriately recovered through the System Operations charge.

Other Issues

ISO staff reviewed other issues raised by stakeholders and has decided not to make changes to the proposal.

<u>Unscheduled Energy</u>

There was discussion to extend the Market Services charge to apply to energy delivered in real time that is not scheduled or in response to ISO dispatch instructions. ISO staff has determined that RT delivered energy does get an appropriate share of costs through the System Operations GMC charge (which includes a significant share of the cost of the ISO's settlement process) and therefore satisfies the principle of cost causation. In accordance with guiding principle 2 stated earlier in this paper, the GMC should focus on recovering the costs associated with using ISO services and should not try to address market participant behavior. In the case of unscheduled or undispatched energy flows, there are market rules that already address uninstructed deviations such as exposure to real time prices and ineligibility for bid cost recovery. In addition, the ability to avoid ISO market processes (i.e. a participant's failure to submit supply bids), is limited by must offer obligations for RA resources. The ISO has therefore decided not to apply a Market Services GMC charge to real-time deviations.

<u>PIRP Forecast Fee</u>

There has been discussion whether to include a separate charge for PIRP forecast fees. This question is being addressed in the ISO's Renewable Integration Market and Product Review initiative and will be resolved in that stakeholder process. If the PIRP forecast fee is retained, it will be treated for GMC purposes like the other special fees in this proposal, as an offset to the total costs to be recovered through one or more of the other cost categories.

Revenue Requirement Cap Proposal

The last component of the GMC redesign for 2012 is to establish a new revenue requirement cap. The previous cap was set at $195 million in 2004 and increased to $197 million in 2006. One year extensions of the revenue requirement cap and current GMC rate design have been approved for each year thereafter, including 2011. In the January 13 straw proposal modifications, the ISO proposed a revenue requirement cap that would remain in place for five years and would increase by 1% each year beginning in 2013. Stakeholders responded by raising concerns about a long term rate ceiling given the economic uncertainties facing the state, the industry, and public power agencies. In response to stakeholder concerns, the ISO proposes to shorten the length of the revenue requirement period to three years, (which extends to the end of the 2008 bonds), and at which time stakeholders will have more certainty about the future. Additionally a revenue cap escalator appears unacceptable. Thus, the ISO proposes a three year revenue requirement cap with $197 million as the baseline in 2012. The cap will be then be increased once in 2013 to $199 million and remain at that level for 2013 to 2014. The annual revenue requirement cap based on this structure over the three year period would be:

Year	Revenue Requirement Cap
2012	$197,000,000
2013	$199,000,000
2014	$199,000,000

The ISO proposes to retain the same process currently included in the tariff with respect to the revenue requirement cap so that as long as the ISO’s annual budget for each year does not exceed that year’s revenue requirement cap, and there are no GMC rate design or billing determinant modifications proposed for the next year, the ISO will not be required to make a section 205 with FERC seeking approval for the next year’s revenue requirement.

The current budget approval stakeholder process will remain in the tariff, and that process culminates with each annual budget being presented to the ISO Board for approval at the December Board meeting and posted on the ISO website after approval. The ISO's proposed revenue requirement caps, would "sunset" on December 31, 2014 and the ISO would be required to make a 205 filing for the GMC that would become effective on January 1, 2015.

Examples of GMC Charges by Activity

The following are examples of the GMC charges that would be incurred for various activities utilizing the grandfathering approach, using hypothetical estimated rates based on historical data. Please note that the SCID fee of $1,000 per month would apply to all activities listed below in addition to the individual transaction charges. Also note that the Market Services rate does not take into account the expected volume for convergence bidding. The ISO estimates that the additional volume of convergence bids would reduce the market services rate to $.082. The GMC rates used in the calculations are based on the rates provided in the grandfathering revised data set:

Market Services Rate: $0.091368

System Operations Rate: $0.29216

System Operations TOR Rate: $0.27

CRR Services Rate: $0.011318

Bid Segment Rate: $0.005

Inter SC Trade fee: $1.00

CRR Bid Segment Transaction fee: $1.00

1. **<u>Generation</u>**

Scenario: A generator submits a 4-segment energy bid in the day-ahead market and is scheduled for 100 MWh. The generator then submits a 4-segment energy bid to the real-time market and is decremented 10 MWh. Its real-time metered flow is measured at 90 MWh.

GMC charges would be:

Market Services Charge (day-ahead schedule and real-time instructions): 110 MWh * $0.091368 = $10.05

System Operations Charge (real-time metered flow): 90 MWh * $0.29216 = $26.29

Bid Segment Fee: 8 * $0.005 = $.04

Total: $36.38

2. Ancillary Services (1)

Scenario 1: A generator submits an AS bid and is awarded 50 MW operating reserves in the day-ahead market for hour ending 9. No contingency event occurs in hour ending 9.

GMC charges would be:

Market Services Charge (day-ahead and real-time schedules): 50 MW h * $0.091368 = $4.57

Bid Segment Fee: 1 * $0.005 = $0.005

Total: $4.58

3. Ancillary Services (2)

Scenario 2: A generator submits an AS bid and is awarded 50 MW operating reserve in the day ahead market for hour ending 9. The generator then submits a 4-segment energy bid in the real-time market and a contingency event occurs in hour ending 9 resulting in 50 MWh energy dispatch for 15 minutes.

GMC charges would be:

Market Services Charge: 50 MW h * $0.091368 = $4.57

System Operations Charge: (50 MWh / 4) * $0.29216 = $3.65

Bid Segment Fee: 5 * $0.005 = $.03

Total: $8.25

4. Load

Scenario: Load self schedules 100 MWh in the day ahead market and its meter data shows that it consumed 100 MWh in real time.

GMC charges would be:

Market Services Charge: 100 MWh * $0.091368 = $9.14

System Operations Charge: 100 MWh * $0.29216 = $29.22

Bid Segment Fee: 1 * $0.005 = $0.005

Total: $38.36

5. Imports

Scenario: An importer submits a 4-segment energy bid in the day-ahead market and is scheduled for 100 MWh. The importer then submits a 2-segment energy bid to the real-time market and is inc'd 10 MWh in HASP. The 110 MWh import schedule is then deemed delivered in real-time based on the final e-tag for the transaction.

GMC charges would be:

Market Services Charge: 110 MWh * $0.091368 = $10.05

System Operations Charge: 110 MWh * $0.29216 = $32.14

Bid Segment Fee: 6 * $0.005 = $0.03

Total: $42.22

6. Exports

Scenario: An exporter submits a 4-segment energy bid in the day-ahead market and is scheduled for 100 MWh. The exporter then submits a 6-segment energy bid to the real-time market and is dec'd 10 MWh in HASP. The 90 MWh export schedule is then deemed delivered in real-time based on the final e-tag for the transaction.

GMC charges would be:

Market Services Charge: 110 MWh * $0.091368 = $10.05

System Operations Charge: 90 MWh * $0.29216 = $26.29

Bid Segment Fee: 10 * $0.005 = $.05

Total: $36.39

7. Convergence Bidder

Scenario: A convergence bidder submits a 10-bid segment virtual demand bid in the day-ahead market for 100 MWh.

GMC charges would be:

Market Services Charge: 100 MWh * $0.091368 = $9.14

System Operations Charge: $0.00 (there is no real-time energy flow associated with virtual bids)

Bid Segment Fee: 10 * $0.005 = $.05

Total: $9.19

8. Inter-SC Trade

Scenario: Scheduling Coordinator A schedules an inter-SC trade with Scheduling Coordinator B for 100 MWh.

GMC charges would be (for both Scheduling Coordinators A and B):

Inter SC Trade Fee: 1 * $1.00 = $1.00

Total: $1.00 (each)

9. CRRs

Scenario 1: A Scheduling Coordinator bids and is awarded 100 MW CRR on peak or a LSE nominates and is allocated 100 MW CRR on peak during the October 2010 monthly process.

GMC charges would be:

CRR Bid or Nomination Fee = 1 * $1.00 = $1.00

CRR Charge: (100 MW * 416 hours) * $0.011318 = $470.83

Total: $471.83

Scenario 2: A Scheduling Coordinator bids and is awarded 100 MW CRR on peak or a LSE nominates and is allocated 100 MW CRR on peak through the annual process and holds the CRR for all months of the year. Note that the number of hours in a month will be dependent upon the NERC calendar. The GMC costs will be accrued monthly over the year. We utilized October 2010 as a proxy to simplify the example:

GMC charges would be:

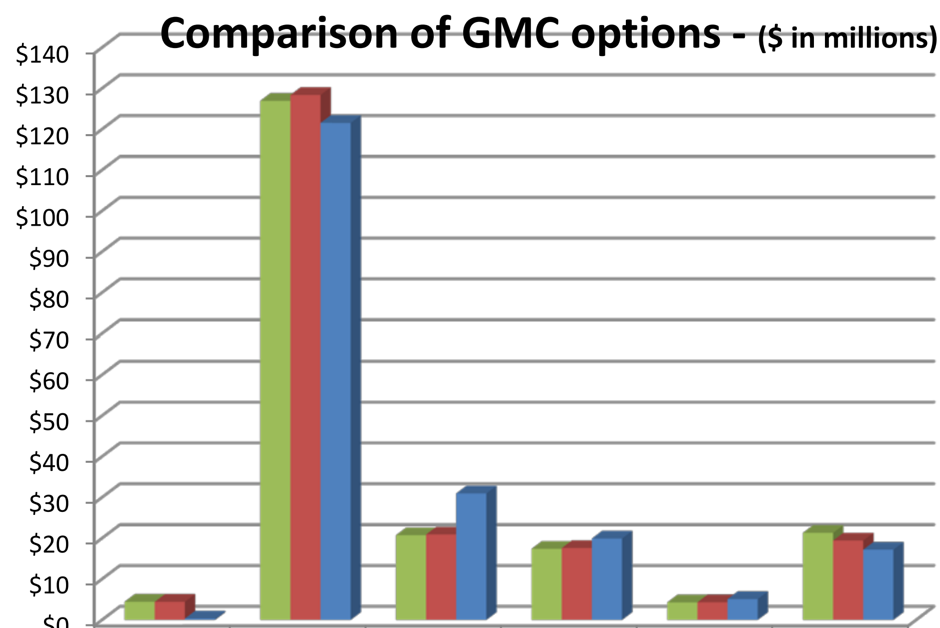
CRR Bid Fee = 1 * $1.00 = $1.00

CRR Charge: (100 MW * 416 hours) * $0.011318 = $470.83 per month

Total: $5,650.95

Bill Impacts

The ISO provided bill impact studies by SCID to market participants for the original GMC rate design as well as the draft final proposal. To provide estimates of the impacts of the new structure, the ISO developed hypothetical billing rates using the 2010 budget amount and allocated those dollars to charge categories based on the process described in the discussion paper. The billing determinants used to calculate the rates came from market data from the period of June 1, 2009 to May 31, 2010. The ISO has applied the rates for each charge code to each SCID's volumes using the billing determinants listed above to determine the costs they would have been charged if the new GMC structure had been in place. The ISO has communicated individual SCID information to those SCs who have requested the information. The graph below illustrates the overall impact analysis by customer type:



	CRR	IOU	marketer / importer	muni	other	supplier
Proposed GMC & 100% of supply	$4.43	$126.94	$20.73	$17.40	$4.29	$21.32
Proposed GMC with Grandfather Provision	$4.43	$128.39	$20.93	$17.59	$4.33	$19.44
Existing GMC	$0.33	$121.55	$30.98	$19.93	$5.11	$17.20

Next Steps

The 2012 GMC Cost of Service Study will continue with the following timeline:

- February 22, 2011 – Conference call with Stakeholders to review draft final proposal
- March 1, 2011 – Stakeholder comments on draft final proposal due
- March 30-31, 2011 – ISO will present GMC proposal to Board for approval
- April 2011- Proposed tariff language will be provided for stakeholder review
- May 2011 – Proposed tariff amendments implementing revised GMC structure filed with FERC

Proposed GMC
Grandfather 100% of specific generation in System Operations
Comparison Period Jun-09 to May-10

Options

Proposed GMC	The current proposal uses gross generation, imports, load & export MWs for both market services & system operations. It eliminates MSS load following MWh from Market Services. Modify TORs as follows: 100% of TOR volumes excluded from market services and systems operations; minimum of TOR volumes for supply or demand are charged a fixed rate of $0.27 per MWh. New CRR volumes have been pulled as there were errors in the prior bill comparison.
Proposed modifications	Exclude 100% of generation from system operations meeting the following criteria
Grandfather criteria	The contract precludes the supplier from recovering the additional GMC costs under the 2012 design from the buyer; the contract must have been executed prior to 1/1/11; the duration of the contract must be three years or greater (until the first exit provision); generator owner must be the scheduling coordinator for the unit; the contract may not be with another scheduling coordinator that has the same parent company as the generation owner; and the contract may not be with the same scheduling coordinator ID as the generation unit resides.

Billing Determinants

Awards	MWs of awarded bids used for market services
Flows	MWs of metered flow used for system operations
Excluded data	The individual data for the scids comprising the seven largest scs have been deleted. However the totals have not been changed.

Calculation of rates

Equalizes 2010 revenue requirement to actual for the June 2009 - May 2010 period.
Allocates revenue requirement to 3 cost categories
Credits Market bid fee, Inter-SC trade fee and SCID charges to the market services cost category.
Credits CRR auction bid fee to the CRR cost category.
Excludes MSS Load following from Market services
Excludes TORs from Market services and system operations
Charges minimum of supply or demand for TORs a fixed rate of $0.27 per MWh
Credits TOR revenue to the system operations cost category.
Grandfathers contracts - excludes 100% of specified generation contracts meeting defined criteria from system operations volumes
Phases in of supply refers to earlier proposal to phase into system operation 1/3 of supply in in year 1, 2/3 in year 2 and 100% in year 3
Divides the 3 cost categories by the billing determinants to derive the rates.

Rate Comparisons

	Include 100% of supply	Grandfathering of units 2012-14	2015	2016	2017	2018-21	Phase-In of Supply 1/3 in 2012	2/3 in 2013
Market bid fee	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005	$ 0.005
Inter-SC trade Fee	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
CRR auction bid fee	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
SCID monthly fee	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000
Market services rate per MWh	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914	$ 0.0914
Systems Operations rate per MWh	**$ 0.2876**	**$ 0.2922**	**$ 0.2920**	**$ 0.2913**	**$ 0.2907**	**$ 0.2901**	**$ 0.4328**	**$ 0.3455**
TOR rate per MWh	$ 0.2700	$ 0.2700	$ 0.2700	$ 0.2700	$ 0.2700	$ 0.2700	$ 0.2875	$ 0.2875
CRR services rate per MWh	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113	$ 0.0113
Excluded supply/generation - TWh	-	7.23	6.68	5.69	4.71	3.72	156.38	78.19

Index	**Index to folders**
	Grandfathering
GF rates	Rates based on proposed GMC after modification for TORs, MSS and exclude 100% of suppliers generation
GF contracts by year	Summary by year of grandfathered contracts to be excluded from system operations

Proposed GMC
Grandfather 100% of specific generation in System Operations
Comparison Period Jun-09 to May-10

	100% supply
100% supply rates	Rates based on proposed GMC after modification for TORs and phase-in of 100% supply in system operations
TORs	Shows total TORs by scid and generation, imports, load and exports. Calculates the TOR adjustment
	Existing GMC units and amounts
Actual units by CC by baid	Shows actual GMC units by SCID and charge code for the period June 2009 to May 2010
Actual dollars by CC by baid	Shows actual GMC dollar amounts by SCID and charge code for the period June 2009 to May 2010
data details	Components to GMC graphs by customer class

Listing of Billing Determinants

Market Services

Schedules and Awards (Absolute by RSRC)	**Included**
DA Generation Schedules (including ETC TOR)	YES
DA Import Schedules (including ETC TOR)	YES
DA Load Schedules (including ETC TOR)	YES
DA Export Schedules (including ETC TOR)	YES
DA Ancillary Service Awards	YES
DA Ancillary Service Self Provision	YES
Convergence Bidding Schedules	YES
MSS Gross MWh (including ETC TOR)	YES
RUC Awards	NO
WHEEL Quantities (One-Side)	YES
DA Inter-SC Trade	NO
HASP Incremental and Decremental Energy (Non Dynamic)	YES
HASP Incremental and Decremental Ancillary Service Awards	YES
HASP Incremental and Decremental Ancillary Service Self Provision	YES
HASP Inter-SC Trades	NO
HASP Incremental and Decremental Wheel (One-sided)	YES
HASP Operational Adjustment	NO
Real Time Optimal Energy	YES
Residual Imbalance Energy	NO
Real-Time Minimum Load Energy	YES
Exceptional Dispatch Energy	NO
Regulation Energy	NO
Standard Ramping Energy	NO
Ramping Energy Deviation	NO
Derate Energy	YES
Real-Time Self Schedule	YES
MSS Load Following	YES
Real Time Pumping Energy	YES
Real Time Operational Adjustments	NO
Real Time Incremental and Decremental Ancillary Service Awards	YES
Real Time Incremental and Decremental Ancillary Service Self Provision	YES

System Operations

Flow (Absolute by RSRC)	**Included**
Non Dynamic System Resource Deemed Deliver Energy (include ETC/TOR)	Yes
Dynamic System Resource Deemed Deliver Energy (include ETC/TOR)	Yes
Metered Generation Quantities (include ETC/TOR)	Yes

Proposed GMC
Grandfather 100% of specific generation in System Operations
Comparison Period Jun-09 to May-10

Metered Default Lap Quantities (include ETC/TOR)	Yes
Metered Custom Lap Quantities (include ETC/TOR)	Yes
Metered Pumping Energy (include ETC/TOR)	Yes
MSS Gross Metered Quantizes (include ETC/TOR)	Yes
Non Dynamic System Resource Wheel Deemed Deliver Energy (one sided)	Yes

Inter-SC Trades

INTER-SC Trade (Absolute by Trade)	**Included**
DAM TO-SC Inter-SC Trade Energy (Physical and Converted)	Yes
DAM FROM-SC Inter-SC Trade Energy (Physical and Converted)	Yes
DAM TO-SC Inter-SC Trade Energy (Financial)	Yes
DAM FROM-SC Inter-SC Trade Energy (Financial)	Yes
HASP TO-SC Inter-SC Trade Energy (Physical and Converted)	Yes
HASP FROM-SC Inter-SC Trade Energy (Physical and Converted)	Yes
HASP TO-SC Inter-SC Trade Energy (Financial)	Yes
HASP FROM-SC Inter-SC Trade Energy (Financial)	Yes
Ancillary Services TO-SC Inter-SC Trade Energy	Yes
Ancillary Services FROM-SC Inter-SC Trade Energy	Yes
RUC Obligation TO-SC Inter-SC Trade Energy	Yes
RUC Obligation FROM-SC Inter-SC Trade Energy	Yes

Proposed GMC modified for TORs
Grandfather 100% of specific generation contracts in System Operations
Comparison Period Jun-09 to May-10

Revised GMC Rates

Units Jun-09 to May-10	Market Service rate (Award)	Systems Operations rate (Flow)	Flow TORs	CRR (revised volumes)	CRR auction bid fee	Market bids	ISC Trades	SCIDs
Gross volumes	519,946,950	475,167,832	-	591,726,863				
TOR modification	(9,276,859)	(5,967,482)	-	-				
Transfer TORs to separate category	-	(3,353,436)	3,353,436	-				
Exclude Suppliers generation	-	(7,227,000)	-	-				
Exclude MSS load following	(128,315)	-	-	-				
Additional CRR volumes	-	-	-	24,638,375				
Net volumes	510,541,777	458,619,915	3,353,436	616,365,238				
Number of CRR auction bids					480,276			
Number of market bids						26,893,996		
Number of Inter-SC trades							3,854,538	
Number of SCIDs								177
Rate per TOR			$ 0.27					
Fee per market bid						$ 0.005		
Fee per CRR auction bid					$ 1.00			
Monthly SCID fee								$ 1,000
Annual SCID fee								$ 12,000
Fee per Inter-SC trade							$ 1.00	
Fee and charge revenue			$ 905,428		$ 480,276	$ 134,470	$ 3,854,538	$ 2,124,000

Rates for Year 1	Market Service rate (Award)	Systems Operations rate (Flow)	Flow TORs	CRR	CRR auction bid fee	Market bids	ISC Trades	SCIDs	Total
Revenue Requirement 2010	**$ 52,756,000**	**$ 134,883,000**	**$ -**	**$ 7,456,000**					**$ 195,095,000**
Actual GMC collected									195,110,642
Difference									(15,642)
% of revenue requirement	27%	69%	0%	4%	0%	0%	0%	0%	100%
Revenue Requirement	$ 52,756,000	$ 134,883,000	$ -	$ 7,456,000		$ -			$ 195,095,000
Adjust Revenue requirement to actual	$ 4,230	$ 10,814	$ -	$ 598	$ -	$ -	$ -	$ -	$ 15,642
Adjusted revenue requirement	$ 52,760,230	$ 134,893,814	$ -	$ 7,456,598	$ -	$ -	$ -	$ -	$ 195,110,642
Allocate TORs	$ -	$ (905,428)	$ 905,428	$ -	$ -	$ -	$ -	$ -	$ -
Allocate market bid fees	$ (134,470)	$ -	$ -	$ -	$ -	$ 134,470	$ -	$ -	$ -
Allocate CRR bid fees	$ -	$ -	$ -	$ (480,276)	$ 480,276	$ -	$ -	$ -	$ -
Allocate SCID fee	$ (3,854,538)	$ -	$ -	$ -	$ -	$ -	$ 3,854,538	$ -	$ -
Allocate inter-SC trade fee	$ (2,124,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,124,000	$ -
Revenue requirement for rates	**$ 46,647,222**	**$ 133,988,386**	**$ 905,428**	**$ 6,976,322**	**$ 480,276**	**$ 134,470**	**$ 3,854,538**	**$ 2,124,000**	**$ 195,110,642**
Volume Jun-09 to May-10	**510,541,777**	**458,619,915**	**3,353,436**	**616,365,238**	**480,276**	**26,893,996**	**3,854,538**	**177**	
Rates	**$ 0.091368**	**$ 0.29216**	**$ 0.27**	**$ 0.011318**	**$ 1.00**	**$ 0.005**	**$ 1.00**	**$12,000**	

Summary of Volumes for Year 1	Generation	Imports	Load	Exports	Total Volume	Separate TOR category
Market Services - Awards						
Gross volumes	201,028,000	81,946,538	227,791,195	9,181,218	519,946,950	-
Exclude TORs	(1,180,919)	(4,569,078)	(247,263)	(3,279,599)	(9,276,859)	-
Exclude MSS load following	(129,582)	731	511	25	(128,315)	
Net volumes	**199,717,499**	**77,378,191**	**227,544,442**	**5,901,645**	**510,541,777**	**-**
	-	-	-	-	-	-
System Operations - Flows						
Gross volumes	170,925,422	69,416,225	226,000,481	8,825,705	475,167,832	-
Exclude TORs	(1,180,919)	(4,591,246)	(195,318)	-	(5,967,482)	
Transfer TORs to separate category	-	-	(51,946)	(3,301,490)	(3,353,436)	3,353,436
Exclude 100% of grandfathered generation	(7,227,000)	-	-	-	(7,227,000)	-
Net volumes	**162,517,503**	**64,824,979**	**225,753,217**	**5,524,215**	**458,619,915**	**3,353,436**

Qualifying contract details by year

Qualifying contract criteria
The contract precludes the supplier from recovering the additional GMC costs under the 2012 design from the buyer
The contract must have been executed prior to 1/1/11
The duration of the contract must be three years or greater (until the first exit provision)
The generator owner must be the scheduling coordinator for the unit
The contract may not be with another scheduling coordinator that has the same parent company as the generation owner
The contract may not be with the same scheduling coordinator ID as the generation unit resides
Provision only applies to exempt System Operations charge

annual MWhs	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
7,227,000	**7,227,000**	**7,227,000**	**7,227,000**	**6,679,500**	**5,694,000**	**4,708,500**	**3,723,000**	**3,723,000**	**3,723,000**	**3,723,000**

100% supply rate

Proposed GMC modified for TORs
No grandfathering of supply - 100% included in systems operations
Comparison Period Jun-09 to May-10

Revised GMC Rates								
Units Jun-09 to May-10	**Market Service rate (Award)**	**Systems Operations rate (Flow)**	**Flow TORs**	**CRR (revised volumes)**	**CRR auction bid fee**	**Market bids**	**ISC Trades**	**SCIDs**
Gross volumes	519,946,950	475,167,832	-	591,726,863				
TOR modification	(9,276,859)	(9,320,918)	-	-				
Transfer TORs to separate category	-	(3,353,436)	3,353,436					
Additional CRR volumes	-	-	-	24,638,375				
Exclude MSS load following	(128,315)	-	-					
Net volumes	510,541,777	465,846,915	3,353,436	616,365,238				
Number of CRR auction bids					480,276			
Number of market bids						26,893,996		
Number of Inter-SC trades							3,854,538	
Number of SCIDs								177
Rate per TOR			$ 0.27					
Fee per market bid						$ 0.005		
Fee per CRR auction bid					$ 1.00			
Monthly SCID fee								$ 1,000
Annual SCID fee								$ 12,000
Fee per Inter-SC trade							$ 1.00	
Fee and charge revenue			$ 905,428		$ 480,276	$ 134,470	$ 3,854,538	$ 2,124,000

Rates	**Market Service rate (Award)**	**Systems Operations rate (Flow)**		**CRR**	**CRR auction bid fee**	**Market bids**	**ISC Trades**	**SCIDs**	**Total**
Revenue Requirement	**$ 52,756,000**	**$ 134,883,000**	**$ -**	**$ 7,456,000**					**$ 195,095,000**
Actual									195,110,642
Difference									(15,642)
% of revenue requirement	27%	69%	0%	4%	0%	0%	0%	0%	100%
Revenue Requirement	$ 52,756,000	$ 134,883,000		$ 7,456,000		$ -			$ 195,095,000
Adjust Revenue requirement to actual	$ 4,230	$ 10,814		$ 598	$ -	$ -	$ -	$ -	$ 15,642
Adjusted revenue requirement	$ 52,760,230	$ 134,893,814		$ 7,456,598	$ -	$ -	$ -	$ -	$ 195,110,642
Allocate TORs	$ -	$ (905,428)	$ 905,428						
Allocate market bid fees	$ (134,470)	$ -	$ -	$ -	$ -	$ 134,470	$ -	$ -	$ -
Allocate CRR bid fees	$ -	$ -	$ -	$ (480,276)	$ 480,276	$ -	$ -	$ -	$ -
Allocate SCID fee	$ (3,854,538)	$ -	$ -	$ -	$ -	$ -	$ 3,854,538	$ -	$ -
Allocate inter-SC trade fee	$ (2,124,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,124,000	$ -
Revenue requirement for rates	**$ 46,647,222**	**$ 133,988,386**	**$ 905,428**	**$ 6,976,322**	**$ 480,276**	**$ 134,470**	**$ 3,854,538**	**$ 2,124,000**	**$ 195,110,642**
Volume Jun-09 to May-10	**510,541,777**	**465,846,915**	**3,353,436**	**616,365,238**	**480,276**	**26,893,996**	**3,854,538**	**177**	
Rates	**$ 0.091368**	**$ 0.287623**	**$ 0.27**	**$ 0.011318**	**$ 1.00**	**$ 0.005**	**$ 1.00**	**$12,000**	

Summary of Volumes for Year 3	**Generation**	**Imports**	**Load**	**Exports**	**Total Volume**	**Separate TOR category**
Market Services - Awards						
Gross volumes	201,028,000	81,946,538	227,791,195	9,181,218	519,946,950	-
Exclude TORs	(1,180,919)	(4,569,078)	(247,263)	(3,279,599)	(9,276,859)	-
Exclude MSS load following	(129,582)	731	511	25	(128,315)	
Net volumes	**199,717,499**	**77,378,191**	**227,544,442**	**5,901,645**	**510,541,777**	**-**
	-	-	-	-	-	-
System Operations - Flows						
Gross volumes	170,925,422	69,416,225	226,000,481	8,825,705	475,167,832	-
Exclude TORs	(1,180,919)	(4,591,246)	(195,318)	-	(5,967,482)	-
Transfer TORs to separate category	-	-	(51,946)	(3,301,490)	(3,353,436)	3,353,436
Net volumes	**169,744,503**	**64,824,979**	**225,753,217**	**5,524,215**	**465,846,915**	**3,353,436**

Proposed GMC with adjustment for TORs

TOR analysis	Reported volumes				
	Generation	Imports	Load	Exports	Total
	1,180,919	4,591,246	247,263	3,301,490	9,320,918

Flows - include minimum (or exclude maximum) of supply or demand				
Generation	Imports	Load	Exports	Total
(1,180,919)	(4,591,246)	(195,318)	-	(5,967,482)

Flow Billable quantity				
Generation	Imports	Load	Exports	Total
-	-	51,946	3,301,490	3,353,436

Award - exclude all units				
Generation	Imports	Load	Exports	Total
1,180,919	4,569,078	247,263	3,279,599	9,276,859

Summary of actual GMC billing determinants Jun-09 to May-10	Monthly		Daily											Monthly	
	4501	4502	4503	4505	4506	4508	4511	4512	4513	4534	4535	4536	4537	4546	4575
	peak demand	off peak demand	exports	metered load	uninstructed imbalance energy (UIE) MWh	metered load on TORs	# of hourly schedules	# of hourly trades	PG&E trades	DA, HA & RT AS - MW	instructed energy MWh	UIE MWh	Max of supply or demand in DA	PIRP UIE MWh	monthly SCID charge
Total units	421,787	18,357	5,568,907	231,329,854	9,869,301	5,906,236	5,575,498	3,863,740	-	35,346,186	31,262,387	9,869,301	86,897,500	45,928	1,889

Summary of actual GMC $ Amounts Jun-09 to May-10	Monthly		DAILY											Monthly		Total	Station Power
	4501	4502	4503	4505	4506	4508	4511	4512	4513	4534	4535	4536	4537	4546	4575		
	peak demand	off peak demand	exports	metered load	uninstructed imbalance energy (UIE) MWh	metered load on TORs	# of hourly schedules	# of hourly trades	PG&E trades	DA, HA & RT AS - MW	instructed energy MWh	UIE MWh	Max of supply or demand in DA	PIRP UIE MWh	monthly SCID charge		
Total $ amount	30,881,248	891,603	5,665,966	70,695,820	10,907,910	816,724	8,904,327	6,012,732	-	14,179,875	14,209,685	4,205,679	25,813,211	71,864	1,854,000	195,110,642	101,600

data details

Proposed GMC Options

Comparison of $ amounts						
Customer Class	Existing GMC	Proposed GMC w/ 100% of supply	Proposed GMC w/ grandfathering	Increase (decrease) 100% supply over existing GMC	Increase (decrease) grand- fathering over existing GMC	Increase (decrease) grand- fathering over 100% supply
CRR	$ 329,611	$ 4,427,533	$ 4,428,678	$ 4,097,923	$ 4,099,067	$ 1,145
marketer / importer	$ 30,984,042	$ 20,729,511	$ 20,934,781	$ (10,254,531)	$ (10,049,261)	$ 205,270
muni	$ 19,931,172	$ 17,401,830	$ 17,585,756	$ (2,529,342)	$ (2,345,416)	$ 183,926
Other	$ 5,112,170	$ 4,291,107	$ 4,333,441	$ (821,063)	$ (778,728)	$ 42,334
supplier	$ 17,199,407	$ 21,315,501	$ 19,435,893	$ 4,116,094	$ 2,236,486	$ (1,879,608)
IOU	$ 121,554,240	$ 126,944,719	$ 128,391,924	$ 5,390,479	$ 6,837,684	$ 1,447,205
Total	**$ 195,110,642**	**$ 195,110,202**	**$ 195,110,474**	**$ (441)**	**$ (168)**	**$ 273**

Customer Class	Market Services	System Operations	CRRs	Fees & charges	Total
	Components of Charges - 100% of supply				
CRR	$ 23,242	$ 72,631	$ 3,880,718	$ 450,943	$ 4,427,533
marketer / importer	$ 5,094,895	$ 13,091,783	$ 441,302	$ 2,101,530	$ 20,729,511
muni	$ 4,136,424	$ 11,882,649	$ 224,557	$ 1,158,199	$ 17,401,830
Other	$ 883,480	$ 2,686,156	$ 67,889	$ 653,582	$ 4,291,107
supplier	$ 5,155,495	$ 14,708,166	$ 51,388	$ 1,400,452	$ 21,315,501
IOU	$ 31,353,644	$ 92,452,331	$ 2,310,168	$ 828,576	$ 126,944,719
Total	**$ 46,647,181**	**$ 134,893,715**	**$ 6,976,022**	**$ 6,593,284**	**$ 195,110,202**
	Components of Charges - grandfathering				
CRR	$ 23,242	$ 73,775	$ 3,880,718	$ 450,943	$ 4,428,678
marketer / importer	$ 5,094,895	$ 13,297,053	$ 441,302	$ 2,101,530	$ 20,934,781
muni	$ 4,136,424	$ 12,066,575	$ 224,557	$ 1,158,199	$ 17,585,756
Other	$ 883,480	$ 2,728,490	$ 67,889	$ 653,582	$ 4,333,441
supplier	$ 5,155,495	$ 12,828,558	$ 51,388	$ 1,400,452	$ 19,435,893
IOU	$ 31,353,644	$ 93,899,536	$ 2,310,168	$ 828,576	$ 128,391,924
Total	**$ 46,647,181**	**$ 134,893,987**	**$ 6,976,022**	**$ 6,593,284**	**$ 195,110,474**
	Increase (Decrease) grandfathering from 100% of supply				
CRR	$ -	$ 1,145	$ -	$ -	$ 1,145
marketer / importer	$ -	$ 205,270	$ -	$ -	$ 205,270
muni	$ -	$ 183,926	$ -	$ -	$ 183,926
Other	$ -	$ 42,334	$ -	$ -	$ 42,334
supplier	$ -	$ (1,879,608)	$ -	$ -	$ (1,879,608)
IOU	$ -	$ 1,447,205	$ -	$ -	$ 1,447,205
Total	**$ -**	**$ 273**	**$ -**	**$ -**	**$ 273**

Proposed GMC Options

Comparison of Volumes							
Customer Class	Awards	Flows 100% of supply	Flows with grand-fathering	CRRs	CRR auction bids	Market bids	ISC Trades
CRR	254,379	252,520	252,520	342,880,161	231,258	1,038	3,680
marketer / importer	55,762,359	45,283,525	45,532,413	38,991,167	70,927	7,215,076	1,358,528
muni	45,272,136	40,574,901	41,361,471	19,840,719	95,754	1,528,685	610,802
Other	9,669,470	9,339,155	9,339,155	5,998,298	20,908	432,471	318,512
supplier	56,425,611	51,136,959	43,909,959	4,540,371	15,454	10,181,255	974,092
IOU	343,157,822	319,259,854	321,577,832	204,114,522	45,975	7,535,471	588,924
Total	**510,541,777**	**465,846,915**	**461,973,350**	**616,365,238**	**480,276**	**26,893,996**	**3,854,538**

Comparison of $ rates							
Awards	Flows 100% of supply	Flows with grand-fathering	CRRs	CRR auction bids	Market bids	ISC Trades	Monthly SCID Fee
$ 0.091368	**$ 0.287623**	**$ 0.292156**	**$ 0.011318**	**$ 1.00**	**$ 0.005**	**$ 1.00**	**$ 1,000**

Exhibit No. ISO-8 – Testimony of Deborah A. Le Vine

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California Independent System
Operator Corporation
Exhibit No. ____ (ISO-8)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System	)	ER11-____-000
Operator Corporation	)	
	)	

DIRECT TESTIMONY OF
DEBORAH A. LE VINE
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Deborah A. Le Vine. I am employed as Director of System Operations for the California Independent System Operator Corporation (the "ISO"). My business address is 250 Outcropping Way, Folsom, CA 95630.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AT THE ISO?

A. As the Director of System Operations, I ensure that the day-to-day grid and market operations are maintained, thereby ensuring compliance with system reliability for the ISO balancing authority area and transmission provider as designated by the North American Electric Reliability Council (the "NERC") and the Western Electricity Coordinating Council (the "WECC"), and the market responsibilities in the ISO tariff. I also oversee and provide state mandated reporting and public notifications relative to emergency system conditions as required. In addition, I ensure that the resources of the state and external generation meet capacity obligations as outlined by the WECC and NERC Standards.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor of Science degree in Electrical Engineering from San Diego State University in San Diego, California in May 1981. In May 1987, I received a Master in Business Administration from Pepperdine University in Malibu, California. In December 2002, I completed an

Executive Program in Driving Government Performance: Leadership Strategies that Produce Results from the John F. Kennedy School of Government, Harvard University in Cambridge, Massachusetts. In August 2007, I completed an Advanced Masters Certificate program in Project Management from Villanova University in Villanova, Pennsylvania. Additionally, I am a registered Professional Electrical Engineer in the State of California.

Q. HAVE YOU PROVIDED EXPERT TESTIMONY PREVIOUSLY?

A. Yes. I have previously been a witness on behalf of the ISO in Docket Nos. ER98-997-000, et al., ("QF PGA proceeding"), regarding the application of the ISO's Participating Generator Agreement to qualifying facilities ("QFs"); Docket No. EL99-93-000, et al., regarding the Turlock Irrigation District and Modesto Irrigation District complaint; Docket No. EL00-105-007, et al., concerning the revenue requirement of the City of Vernon, CA; Docket No. ER00-2019-000, et al., involving the ISO's transmission Access Charge filing as required by California State Legislation; Docket No. ER00-2360-000, et al., regarding the PG&E Reliability Service Tariff; Docket No. ER01-313-000, et al., regarding the ISO's position with regard to certain billing determinants for the ISO's Grid Management Charge ("GMC"); and Docket No. EL03-15-000, et al., concerning the revenue requirement of the Cities of Anaheim and Riverside California. I also submitted prefiled testimony in nine other proceedings in which hearings did not take place. Additionally, I have testified in a number of proceedings before the California Public Utilities Commission, California Legislature, and in a number of arbitration disputes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain the process by which the ISO assigned specific percentages of ISO Level 2 service activities to the proposed Grid Management Charge or "GMC" categories of services, as briefly discussed in the testimony of Michael K. Epstein. I will also discuss the GMC's proposed allocation of ISO activities to Transmission Ownership Rights, or "TORs."

Q. WHAT WAS YOUR INVOLVEMENT IN THE DEVELOPMENT OF THE PROPOSED GMC RATES?

A. With 30 years in the electric utility industry including over 13 years with the ISO, I have a broad background regarding the functions of the various different business units within the ISO and participation of multiple market participants. In addition, as the Director of System Operations, I have the largest annual labor cost for a department at the ISO and I was part of the ISO internal team (the GMC team) that conducted the cost of service study and developed the proposed revisions for the GMC rate design. Although I was involved in many aspects of the work of the GMC team, I was particularly involved in the second step of the functionalization performed as part of the 2012 cost of service study described in the testimony of Mr. Epstein: the mapping of level 2 activities to the three cost categories identified in the cost of service study.

Q. AS YOU TESTIFY, WILL YOU BE USING ANY SPECIALIZED TERMS?

A. Yes. Unless otherwise indicated, capitalized terms have the meanings set forth in the Master Definitions, Appendix A of the ISO Tariff.

I. FUNCTIONALIZATION: MAPPING LEVEL 2 ACTIVITIES TO PROPOSED SERVICE CATEGORIES

Q. YOU STATED YOU WERE INVOLVED IN THE SECOND STEP OF FUNCTIONALIZATION PERFORMED IN THE COST-OF-SERVICE STUDY. PLEASE EXPLAIN.

A. As Mr. Epstein explained, the first step of functionalization was the determination of the three cost categories used in the cost-of-service study – Market Services, System Operations and Congestion Revenue Rights, or "CRRs." The next step was to allocate the Level 2 activities to the three cost categories based on reasonable estimates of the percentage of time that each business unit devotes its activities to these general categories of ISO services. The business unit activities are consistent with the general cost categories and the associated billing determinants explained by Dr. Kristov. The allocation process included an allocation of software costs underlying debt service and out of pocket capital costs to the cost categories.

Q. HOW DID THE GMC TEAM PERFORM THIS ALLOCATION?

A. A subgroup of the GMC team was in charge of proposing these allocations. We recognized that the integrated nature of the ISO's systems and the lack of any metric by which to measure the division of labor made it extremely difficult to identify the percentage of time devoted to each cost category with a high degree of accuracy and precision. We decided instead to establish a limited number of bright line classifications, based on our experience and working knowledge of how to assess the division of labor. Furthermore, we concluded that additional precision would not materially impact the rates ultimately derived from these allocations.

Q. HOW DID YOU ESTABLISH THOSE BRIGHT LINE CLASSIFICATIONS?

A. We concluded that the time spent on an activity could be entirely devoted to one cost category; principally, but not exclusively, devoted to the category, or evenly split between the cost categories. We also recognized that some activities could not be categorized. In addition, based on the subgroup's experience in managing various ISO business functions, we knew that – with the exception of activities devoted exclusively to CRR management – the management of CRRs did not consume significant portions of time spent on level 2 activities as compared to the number of level 2 activities. Keeping these factors in mind, we concluded that an activity would be classified as (1) 100% in System Operations, Market Services or CRR, and 0% in the other; (2) 50% in Market Services and 50% in System Operations; (3) 80% in Market Services or System Operations and 20% in the other; or (4) it could be classified as 10% in CRR management in addition to the other cost categories (for example, 45% Market Services, 45% System Operations, and 10% CRR). Activities that we could not classify would be identified as an indirect cost, to be allocated later according to the overall allocation of direct costs.

While the choice of 80%-20%, as opposed to 75%-25% or 70%-30% is not based on any particular empirical study, we concluded, based on our collective experience, that this split was an accurate representation of an activity that was principally, but not exclusively, devoted to one cost category. When the subgroup determined a previously created classification was not sufficiently representative, a new classification was created. For example the category of 45% Market Services, 45% System Operations and 10% CRR was created when we determined that 50% Market Services, 50% System Operations was not sufficiently representative for certain activities. We presented these classifications to the full GMC team, which agreed with them and found them appropriate. In addition, when we presented these classifications to stakeholders, there were no objections. Stakeholder comments and the ISO responses are presented in Exhibit No. ISO-11.

Q. HOW DID YOU GO ABOUT APPLYING THESE CLASSIFICATIONS TO THE LEVEL 2 ACTIVITIES?

A. Applying our collective experience with the ISO's roles and responsibilities, the subgroup went through each of the 60 Level 2 activities and made a determination regarding the classification. We prepared a chart with comments including our rationale. We then performed the same operation with each of the 43 categories of software that support the ISO's functions. The chart is presented as Table 3 in Exhibit No. ISO-2. We presented the results and the comments to the entire GMC team, who represent a cross-section of ISO responsibilities. The GMC team reviewed, discussed, modified in some cases where appropriate and ultimately agreed with the determinations. As with the determination of the classifications to be used, stakeholders, when presented with the classification of activities, raised no objections.

Q. PLEASE PROVIDE A GENERAL BREAKDOWN OF THE CLASSIFICATION OF ACTIVITIES.

A. Of the 60 Level 2 activities, 40, or 67%, were assigned 100% to one cost category, either Market Services, System Operations, CRR or as indirect costs; 5, or 8%, were split 80%-20%; 12, or 20%, were split 50%-50%, and 3, or 5%, were assigned 10% to CRRs and 90% to one of the other categories. Of the 43 software activities, 17, or 40%, were assigned 100% to one cost category (including the indirect cost category); 5, or 12%, were split 80%-20%; 19, or 44%, were split 50%-50%, 1, or 2%, was assigned 10% to CRRs, with the remainder split evenly; and 1, or 2%, was assigned 10% to CRRs, with the remainder split 80%-20%.

II. ALLOCATION OF COSTS TO TRANSMISSION OWNERSHIP RIGHTS

Q. YOU STATED YOU WERE ALSO DISCUSSING THE ALLOCATION OF GMC COSTS TO TORS. WERE THE ACTIVITIES AND RELATED COSTS ASSOCIATED WITH TRANSMISSION OWNERSHIP RIGHTS ANALYZED AS PART OF THE COST OF SERVICE STUDY?

A. Yes. As part of the cost-of-service study, in addition to classifying activities according to cost categories, the GMC team evaluated current GMC charges to determine whether a cost basis existed for continuing the charge under the revised rate design. This process included an analysis of the GMC charged to TORs. Under the current GMC, TORs are granted a discounted rate due to the limited services they require from the ISO.

Q. WHAT DID THE GMC TEAM CONCLUDE ABOUT GMC CHARGES FOR TORS?

A. The GMC team concluded that TORs should continue to receive a discounted rate in the new GMC rate structure because the fundamental premise – limited use of ISO's services – has not changed. The GMC team recommended (and the ISO Governing Board approved) exempting 100% of TOR awards from the Market Services charge; and applying a fixed charge to the minimum of a Scheduling Coordinator's TOR Supply or TOR Demand energy flows.

Q. WHAT IS THE BASIS FOR THIS RECOMMENDATION?

A. The ISO first considered whether TORS should be assessed both the Market Services and System Operations charges from a cost of service standpoint. In the previous cost of service study, which was conducted for the new market implantation in 2009, the ISO identified three areas in which ISO services were required for TORs: real-time operations, scheduling, and outage management.

Q. WHAT SERVICES DOES THE ISO PROVIDE REGARDING REAL-TIME OPERATIONS?

A. The ISO provides support on an emergency basis for flows on TORs, in a manner similar to standby service. A common method to allocate costs for standby service is in proportion to the demands placed on the system. Under the current GMC, the non-coincident peak demand of TORs is measured relative to total system demand. The resulting fraction is used to assign a percentage of the costs of Real-Time Operations to this service.

Q. WHAT SERVICES DOES THE ISO PROVIDE REGARDING SCHEDULING?

A. The ISO provides tag approval and check-outs with neighboring Balancing Authority Areas in order to schedule flows across boundaries. For this service, the ISO assigns costs using the ratio of the total number of inter-tie schedules for TORs relative to the total number of ISO inter-tie schedules.

Q. WHAT SERVICES DOES THE ISO PROVIDE REGARDING OUTAGE MANAGEMENT?

A. The ISO provides for the scheduling and coordination of outages across the Balancing Authority Area. The assignment method is the number of TOR transmission outages relative to total California ISO transmission outages.

Q. HOW DID THE ISO EVALUATE TORS IN THE CURRENT COST-OF-SERVICE STUDY?

A. The GMC team reviewed the conclusions from the previous cost of service study, updated the current cost of service study, and determined that TORs use a portion of the following ABC level 2 activities: Manage Full Network Model maintenance; Manage network applications; Manage operations engineering studies; Manage Day+2 analysis; Manage Day-Ahead market; Manage transmission outages; Manage emergency operations; Manage Real-Time market after close of market; Manage Real-Time operations- transmission dispatch; and Manage Real-Time interchange scheduling. These activities are all related to System Operations because there is no TOR participation in the Market Services. The ISO determined the percentage of the costs for these activities that were attributable to TORs and then allocated the indirect dollars based on the direct percentage to derive a total of $45.2 million in direct and indirect costs that would be allocated to TORs. Mr. Epstein explained how the GMC rate was subsequently derived.

Q. THANK YOU. I HAVE NO FURTHER QUESTIONS.

DECLARATION OF WITNESS

I, Deborah A. Le Vine, declare under penalty of perjury that the statements contained in the Direct Testimony of Deborah A. Le Vine on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 5th day of July, 2011.

/s/ Deborah A. Le Vine
Deborah A. Le Vine

Exhibit No. ISO-9 – Testimony of Dr. Lorenzo Kristov

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California Independent System
Operator Corporation
Exhibit No. ____ (ISO-9)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)))	ER11-____-000

DIRECT TESTIMONY OF
DR. LORENZO KRISTOV
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Lorenzo Kristov. My position title is Principal, Market and Infrastructure Policy for the California Independent System Operator Corporation, or "ISO". My business address is 250 Outcropping Way, Folsom, CA 95630.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AT THE ISO?

A. My primary duties are in the areas of market design and infrastructure policy. In fulfilling those duties I participate in or lead ISO staff teams and stakeholder initiatives to develop new wholesale market products or enhancements to existing ISO market products and market rules, as well as reforms to ISO policies and procedures regarding transmission planning and generator interconnection. Most recently I was a primary designer of the ISO's new market structure based on Locational Marginal Pricing or "LMP", which was implemented in 2009, and led the redesign of the ISO's transmission planning process which was approved by FERC in 2010.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. in economics from the University of California at Davis. In the course of completing the research for that degree I spent two years in Indonesia as a Fulbright scholar studying the strategies that country and the other East Asian countries were using to attract foreign direct investment in electric power. When I returned to the U.S., I went to work at the California Energy Commission on the retail side of California's electric restructuring initiative to develop the rules for retail direct access. Then in 1999 I joined the ISO as the manager of market design, with duties quite similar to what I do currently.

Q. HAVE YOU PROVIDED EXPERT TESTIMONY PREVIOUSLY?

A. Yes. I submitted prefiled expert testimony in 2006 to support the ISO's filing in Docket No. ER06-615 of its tariff for the comprehensive redesign of its wholesale markets based on LMP, as mentioned above. At that time I provided individual testimony to provide an overview of the entire redesign proposal, as well as the rationale and details of the many components of the redesign and how they work together. I also provided joint testimony with Mark Rothleder and Dr. Farrokh Rahimi on the provisions for metered subsystems under the redesign.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain how the ISO developed the billing determinants that are used in the proposed formula rates for the ISO's Grid Management Charge, or "GMC." I will also discuss the other fees and proposals that are part of the overall GMC rate structure proposal, except for the proposed rates for Transmission Ownership Rights, or "TORs," about which Ms. Le Vine and Mr. Epstein testify.

Finally, I will discuss the proposal to "grandfather" certain generators for a limited period.

Q. WHAT WAS YOUR INVOLVEMENT IN THE DEVELOPMENT OF THE PROPOSED GMC RATES?

A. Because of my expertise and principal role at the ISO in the areas of market design and infrastructure policy, Mr. Epstein asked me to participate on the GMC team to assist with the analysis of rate design, customer bill impacts, and market behavior implications. My primary participation in the development of the revised GMC rate structure centered on the last three steps of the cost of service study that Mr. Epstein discusses: classification (determination of billing determinants), rate design, and bill impacts. In addition, I assisted in the development of the three proposed cost categories, in particular in reviewing the rate structures of other ISOs and RTOs to examine how those structures classified their activities and the relevance of their structures to customer activities in the ISO's new market.

Q. AS YOU TESTIFY, WILL YOU BE USING ANY SPECIALIZED TERMS?

A. Yes. Unless otherwise indicated, capitalized terms have the meanings set forth in the Master Definitions, Appendix A of the ISO Tariff.

I. THE PROPOSED NEW RATE DESIGN: DEVELOPING THE THREE COST CATEGORIES AND TRANSACTION FEES

Q. YOU STATED THAT YOU ASSISTED IN THE REVIEW OF THE RATE STRUCTURES USED BY OTHER ISOS AND RTOS. PLEASE DESCRIBE THAT PROCESS.

A. The GMC team not only researched the tariff provisions of other ISOs and RTOs, but we also set up conference calls with each of them to discuss their rate structures. The other ISOs and RTOs throughout the country can be classified into two groups: those with a nodal market similar to the ISO (New York ISO, PJM, Midwest ISO and ISO New England), and those who do not have a nodal market (Southwest Power Pool and ERCOT). We prepared a summary of their rates and charges, as compared to the existing California ISO GMC rates, which is set forth in Ex. No. ISO-2 at pages 36-40.

Q. WHAT DID YOU LEARN FROM REVIEWING THE RATES AND CHARGES ASSESSED BY OTHER ISO/RTOS?

A. We quickly learned that the California ISO currently has the most complex rate structure of any ISO or RTO. The New York ISO has four cost categories and charges; ERCOT has two cost categories; PJM has five cost categories and two charges; Southwest Power Pool has only one charge; the Midwest ISO and ISO New England each has three categories and four charges. In contrast, the ISO has seven cost categories and seventeen charges.

We also determined that the other ISOs and RTOs with nodal markets organize their rate structures around a few large groupings of activities. The rates of all four of the ISOs and RTOs that have nodal markets group the great majority of their activities into two main categories that reflect the costs of (1) market or energy services, and (2) system operations, such as control area reliability. PJM, Midwest ISO and New York ISO also have separate charges reflecting the administration of their congestion hedges or financial transmission rights (a charge that the ISO currently lacks, even though the costs of administering our congestion revenue rights are significant).

Q. YOU MENTIONED THAT THE OTHER ISOS AND RTOS HAD CERTAIN FEES IN ADDITION TO COST CATEGORIES. DID YOU EVALUATE THOSE?

A. Yes, we observed that the rate structures used by the other ISOs and RTOs also include transaction and administrative fees as offsets to total costs. A transaction fee such as a bid segment fee is in effect a marginal cost to the market participant that requires the participant to make an economic decision whether to incur the added expense of submitting an additional transaction. The transaction fee is set at a level that is not intended to be onerous, but significant enough to serve two purposes: (1)

to discourage excessive usage of the market functionality by market participants, and (2) to recover costs of transactions that must be processed through the market systems but do not result in successful outcomes that would lead to allocation of shares of the major rate categories (e.g., energy bids that do not clear the market). The costs recovered by transaction fees are used to offset the revenue requirement of the associated major cost category. For example, a bid segment fee would offset the revenue requirement of the Market Services Cost Category.

Administrative fees are typically designed to recover the costs of specific services a market participant uses and are also set at a level that is not intended to be onerous but that will require the participant to make an economic decision whether to incur the added expense. The costs recovered from administrative fees are typically used to offset the revenue requirements of one or more of the major cost categories.

Both types of fees are thus closely aligned with the principle of cost causation because they reflect the participant's use of market functionalities or other ISO services.

Q. HOW DID THESE OBSERVATIONS MATCH UP WITH THE ISO'S EXAMINATION OF ITS OWN ACTIVITIES?

A. As Mr. Epstein explained, with the models of the other ISOs and RTOs in mind as we mapped our own customer categories to level 2 activities, we determined that the ISO's activities could be classified into three very distinct groups: (1) those related to the implementation and operation of the markets, including accepting and processing market participant bids, clearing the markets, and issuing market schedules; (2) those related to reliably operating the grid; and (3) those related to Congestion Revenue Rights, or "CRRs." The classification of ISO activities in this manner resulted in three cost categories: Market Services, System Operations and CRR Services. They reflect the same cost categories that are common to three ISOs and RTOs with nodal markets, and, in the case of the first two categories, all four. We also concluded that it would be appropriate to create certain transaction fees for the purposes mentioned above, similar to those of other ISOs and RTOs.

II. CLASSIFICATION: IDENTIFYING BILLING DETERMINANTS

Q. WHAT IS THE PURPOSE OF CLASSIFICATION?

A. Classification is the determination of billing determinants based on customer cost causation factors. The classification process provides the basis for assessing charges on certain customers or groups of customers in a manner that reflects the services or benefits they receive from the ISO's performance of its activities.

Q. WHAT IS A BILLING DETERMINANT?

A. A billing determinant is a metric for determining what share of a particular cost category will be allocated to each participant. In order to determine the rate for a particular service or category of services, you must convert the total cost of the ISO's activities in that category into a per unit charge, that is, divide the total cost of the service or category of services by the total quantity of the relevant billing determinant. There are two elements of a billing determinant. The first is the definition of the metric or unit to be used as the denominator in determining the rate. There are four basic types of metrics relevant to the services that the ISO provides: 1) maximum demand or usage, 2) volumetric, 3) per transaction, and 4) per customer. The second element is the specification of the categories of transactions to be included in calculating the denominator. This will become clearer as I get into some of the specifics below.

Once the rate is calculated from the total of the relevant costs and the total of the billing determinants for all participants, that rate is applied to an individual participant's billing determinant to determine an individual scheduling coordinator's charge. That is, the charge is the scheduling coordinators usage, as measured by its share of the total of the billing determinant, times the rate (or charge per billing determinant).

Q. WHAT BILLING DETERMINANTS DID THE GMC TEAM CONCLUDE WERE APPROPRIATE FOR THE COST CATEGORIES IN THE NEW RATE DESIGN?

A. The GMC team concluded that the metrics MW per hour (for capacity transactions and CRR holdings) and MWh (for energy transactions) were appropriate. The proposed Market Services billing determinant is the gross absolute value of MWh of energy cleared and MW per hour of ancillary service capacity awarded in the day-ahead and real-time markets. The proposed billing determinant for System Operations is the gross absolute value of MWh of real-time energy flows. The proposed billing determinant for CRRs is awarded MW per hour.

Q. WHY DID THE GMC TEAM PROPOSE THESE DETERMINANTS?

A. The GMC team selected these determinants based on the guiding principles discussed by Mr. Epstein and a comparison of other ISOs' service charges. In particular, the team's primary objective in designing the GMC was to allocate the costs of providing the ISO's core services to market participants in a manner that reflects each participant's use of and benefits received from the ISO's services as accurately as possible. The billing determinants described above are true to this objective.

In addition, in creating the three categories of services and their associated billing determinants, the team was particularly careful not to dilute the primary objective of recovering the ISO's costs of doing business – to be recovered through the GMC based on use of the ISO's services (cost causation) – with other concerns such as trying to reflect the impacts that participants have on the grid and the market. In particular, the team recognized that the GMC should not be used as a behavioral incentive or disincentive, but should simply and objectively allocate the ISO's costs of providing its services to those who use the services.

For example, although it is true that generator A might have a much greater impact on grid congestion than generator B, the costs associated with these impacts are reflected accurately in the locational marginal prices used for settlement of the energy schedules and energy flows of these two generators, and should not contaminate the design of the GMC. Other types of impacts on the ISO grid or markets are assessed through the allocation of uplift charges under the LMP market structure (which are also cost-causation based).

The ISO believes that the proposed billing determinants best achieve the objectives of the GMC rate design by reflecting each scheduling coordinator's use of the ISO's services and, consistent with the other guiding principles discussed by Mr. Epstein, are simple, transparent, predictable, and easy to forecast.

Q. DID THE ISO CONSIDER OTHER OPTIONS?

A. Yes. The GMC team considered other options such as per schedule charges, energy imbalance charges, and peak and off-peak rates. However, these alternatives did not fare well when evaluated against the guiding principles. For example, these alternatives are very difficult to forecast for both the ISO and the market participants, and it is difficult to assess whether these types of metrics will continue to reflect cost causation accurately when significant new market enhancements are implemented. The GMC team quickly realized that these types of metrics could easily lead the ISO back into a complicated GMC structure such as we have today and that adhering to the guiding principles established at the beginning of the redesign effort was the best way to achieve a GMC design that would achieve its purpose in the most accurate and practical manner.

The metrics MW per hour for ancillary service capacity awards and CRR awards, and MWh for energy schedules and flows, are extremely simple common denominators for allocating ISO costs, and they remain appropriate when new market enhancements and products are added. In other words, when the ISO designs and implements new features in its market structure, each market participant's total MWh of energy or MW per hour of ancillary service capacity still provide an accurate basis for allocating the costs of market services. In examining the approaches of the other ISOs and RTOs, the GMC team found that the others consistently use MW per hour and MWh as their primary quantities for creating per unit charges and billing determinants because they so accurately reflect each participant's volume of usage of the ISO's services.

Q. PLEASE ELABORATE ON THE MARKET SERVICES BILLING DETERMINANT.

A. The market services charge is designed to recover costs the ISO incurs for implementing and running the markets. Because the market systems process and validate all bids and then clear supply offers against demand bids to award energy schedules and issue dispatch instructions, supply bids and demand bids use equivalent market services and impose equivalent costs on the ISO. Accordingly, all MWh and MW awards for supply and demand should be treated equally from the perspective of the market software that determines the final awards. Moreover, a bid's use of market services is not dependent upon whether the bid is virtual demand, virtual supply, imports, exports, internal physical demand or internal physical generation. Thus the billing determinant used in the market services category denominator does not distinguish supply bids from demand bids or virtual bids from physical bids. The charge includes the gross awarded ancillary service capacity MW and the MWh schedules and dispatch instructions of generation, imports, load, and exports in the ISO's day-ahead market, hour ahead scheduling process, and real-time market.

Q. PLEASE ELABORATE ON THE SYSTEM OPERATIONS CHARGE.

A. The fundamental mission of system operations is to operate the transmission grid reliably at all times, 24 hours per day, under continuously varying conditions, as energy is injected into the grid by suppliers and withdrawn from the grid by load-serving entities. At all times the ISO operators must balance supply and demand to maintain reliability. Because reliable grid operation involves managing the flows of energy on the grid created by supply and demand, the system operations billing determinant is designed to capture the costs of flowing MWh in real time and is based on the settlement quality meter data that captures each participant's real-time supply and demand in each interval. Alternatively, it might be said that the end-user – whose consumption constitutes demand – is the primary beneficiary of reliability and therefore should pay the entirety of these costs. For this reason the GMC team considered (but ultimately rejected) allocating the system operations costs to demand only. The GMC team concluded that gross MWh of both supply and demand would be the more appropriate billing determinant for system operations because changes in grid conditions can result from both changes in supply and demand and the ISO operators must manage both components to maintain system balance at all times.

An additional consideration for this design decision was the recognition that demand will play an increasingly active participatory role in the ISO markets and in real-time operations in the future, with the expansion of new technologies that shift or reduce demand such as economic demand response, storage facilities, and electric vehicles. Thus demand is expected to provide services similar to those provided by generation in maintaining grid reliability. The GMC team therefore concluded that the GMC should be designed in a manner that results in comparable allocation of costs regardless of the technology or resource type that injects into or withdraws energy from the grid. This is consistent with the guiding principle discussed above, that is, to use the GMC to recover the ISO's costs of providing services as simply, transparently and objectively as possible, and not to confound this objective with an attempt to reflect the different impacts on the grid caused by different resource types or technologies. As explained earlier, these impacts are most appropriately and accurately reflected in market prices and the cost-causation-based rules for allocating uplift charges. Because both supply and demand resources have the same system operations GMC cost exposure, by including both in the System Operations charge billing determinant, the GMC remains true to its purpose of recovering the ISO's costs and does not become a factor to alter the competitiveness of different resource types in the ISO markets.

Q. PLEASE ELABORATE ON THE CRR CHARGE.

A. The CRR charge is the most simple. As discussed above, the CRR metric is based on awarded MW of CRRs applicable to each market trading hour. The CRR feature of the ISO's market structure is separate from both the market services activities, which are related to the day-ahead and real-time markets that are run every day and every hour, and from the system operations activities, which manage energy flows 24 hours a day. The CRR feature has its own market systems and business processes whereby the ISO awards CRRs to market participants. It interacts with the market services activities only for purposes of financial settlements, for which the CRR cost category includes an appropriate share of the market services cost category. The CRR feature has no interaction at all with the system operations activities. Thus, as three other RTOs and ISOs have determined, a separate cost category for CRRs is an entirely appropriate GMC design.

Q. HOW DID THE GMC TEAM DESIGN THE TRANSACTION FEES?

A. There are several administrative and transaction fees proposed for the new GMC design. The fees serve two purposes: they ensure that all parties utilizing certain transactions bear at least a portion of the costs of the ISO's provision of those transactions; and, they discourage market participants from engaging in unnecessary or inefficient quantities of these transactions. The ISO has sought to structure these fees in a way that allows each market participant to determine the extent to which it is willing to incur the costs associated with using the services in question, while not setting the fees so high as to discourage robust market participation. There are four fees: the bid segment transaction fee, the CRR nomination/bid transaction fee, the Inter-Scheduling Coordinator Trade transaction fee, and the Schedule Coordinator Identification administrative fee.

Q. PLEASE EXPLAIN THE DESIGN OF THE BID SEGMENT TRANSACTION FEE.

A. As the total volume of bid segments submitted to the market increases, the demands on the market software can increase dramatically, resulting in longer solution times and, in the extreme, inability of the software to reach an efficient solution within the time line according to which market participants need the results. Although the software systems are designed to manage large bid volumes, as a practical matter all such systems must set design limits to the quantities of bid segments they can process. At the same time, there are documented strategies whereby a market participant may submit an extremely large quantity of small MW bid segments as a way of "phishing" for locational price sensitivities. Such strategies can have adverse impacts on the ability of the software to clear the market in the required time, but have no demonstrated market efficiency benefits. The bid segment transaction fee is designed to deter strategies that involve the submission of high volumes of such "phishing" bids. The proposed fee is $.005 per bid segment and will be applied to all bid segments submitted. The rate of $.005 is a nominal charge that does not represent a significant expense to market participants under typical scheduling practices, but is enough to deter the submission of excessive bid volumes. The amount is similar to the rate used at the New York ISO.

The bid segment charge addresses concerns raised during the convergence bidding stakeholder process about potential bid proliferation if there were no incremental costs to participants who submit larger bid volumes. The ISO implemented the bid segment charge in February 2011 with the launch of the Convergence Bidding market feature. At the present time, however, only virtual bids are subject to the bid segment charge. With the new GMC design the ISO is now proposing to apply the bid segment charge to all bids including physical supply and demand bids.

A second purpose of the bid segment fee and other transaction fees is to collect revenue from participants who submit bids that are unsuccessful in clearing the market, but which nonetheless must be processed by the market software and thus have an impact on ISO costs. The revenue from this transaction fee will offset costs recovered through the market services cost category. Thus, if the number of unsuccessful bids increases, the market services rate for those bids that clear the market will decrease.

Q. PLEASE EXPLAIN THE DESIGN OF THE CRR BID TRANSACTION FEE.

A. The purposes of the CRR bid transaction fee are similar to those of the bid-segment fee. The fee will recover a portion of the CRR costs on a transactional basis. The CRR market has two methods whereby market participants can receive CRRs, allocation to eligible load-serving entities and auction processes open to all creditworthy parties. Both methods utilize the same software systems, and therefore the GMC team decided that both CRR acquisition methods should be treated the same with respect to this fee. Thus the fee will apply to the CRR nominations in the allocation process and CRR bids in the auction for the annual and monthly CRR release processes. Because nominations in the allocation process are single MW values with no price-quantity segments, whereas bids in the auction do have up to ten price-quantity segments, the GMC team decided on auction bids as the transaction fee basis instead of bid segments as used in the Market Services bid segment fee. The proposed rate is $1.00 per submitted bid, where a bid to a particular CRR market (defined by the combination of a season or a month with a time-of-use period, either on-peak or off-peak) is defined by a CRR source location, a CRR sink location, and a MW amount. The revenue from this transaction fee will offset costs recovered through the CRR services charge. Thus if the number of unsuccessful bids increases, the CRR services rate for those participants who cleared the market will decrease.

Q. WHY IS IT APPROPRIATE TO CHARGE CRR PARTICIPANTS A $1.00 BID TRANSACTION FEE IN ADDITION TO THE GMC CHARGE CODE THAT WILL BE APPLIED TO AWARDED CRRS?

A. Just as in the case of the market services bid segment fee, all submitted CRR bids or nominations impose costs on the CRR market systems, regardless of whether they clear the market or not. CRR nominations and bids that do not clear the market are still participating in the CRR allocation and auction processes and should be responsible for a portion of the costs. The proposed bid fee will collect approximately seven percent of the total CRR cost category.

During the stakeholder process, some stakeholders contended that the fee was too high and would discourage participation in the market. Some parties questioned what they saw as a disparity between the $1.00 per bid CRR bid fee versus the $0.005 per bid segment market services bid fee. The GMC team considered these arguments and concluded that the proposed fee is appropriate. The reason for the different fee levels has to do with the duration of the award the market participant receives when a bid clears the market, and hence the quantity of such fees a participant is likely to be exposed to. The market services bid fee will apply to bids submitted for every hour of every trading day, in order to buy or sell energy or capacity and obtain transmission services in the ISO spot markets. In contrast, the CRR bid fee will apply to CRR markets that are run only annually and monthly, yet will award CRRs that have settlement value in all hours of all trading days. The $1.00 CRR fee applied for each CRR allocation or auction process is therefore much less than if a fee comparable to the energy bid segment fee were applied for every hour an awarded CRR is valid.

In addition, there is no basis to assertions that the allocation of costs to CRR management activities is excessive, or that the use of the bid transaction fee will increase the total costs borne by CRR market participants. Tables 6-12 of Ex. No. ISO-2 demonstrate that over 80 percent of the costs attributable to CRR management reflect level 2 activities that are 100 percent devoted to CRR management. Any reduction in the costs allocated to CRR management would cause other market activities to subsidize the CRR market. Moreover, by design, the proposed CRR bid fee does not increase the costs that must be borne by CRR market participants; rather it only affects the manner in which those costs are recovered from those participants. Any decrease in the fee would simply increase the per MW/hour rate for CRR awards.

Q. PLEASE EXPLAIN THE DESIGN OF THE INTER-SCHEDULING COORDINATOR TRADE TRANSACTION FEE.

A. The inter-Scheduling Coordinator trade transaction fee is designed to recover costs directly related to the processing and settlement of inter-Scheduling Coordinator trades. The ISO's inter-Scheduling Coordinator trade feature is essentially a financial settlement service the ISO provides to market participants. Two willing and qualified counter-parties can submit inter-Scheduling Coordinator trades for any market trading hour. The ISO validates the parties' submissions and, if they are valid, settles the associated financial transaction between the two parties. Inter-Scheduling Coordinator trades do not figure into the clearing of the market in any way, and could be performed by the two parties outside of the ISO systems. Thus the inter-Scheduling Coordinator trade feature is an ISO service that benefits only the users of the service and is not needed for the performance of any other ISO market functions. It is therefore appropriate that the ISO recover the costs of this service from the parties that use it. The revenue from this transaction fee will offset costs recovered through market services. The proposed fee is $1.00 per party per inter-Scheduling Coordinator trade (i.e., $2.00 in total for each trade), and reflects the ISO's estimate of the administrative costs of providing this service.

Q. PLEASE EXPLAIN THE DESIGN OF THE SCHEDULING COORDINATOR IDENTIFICATION ADMINISTRATIVE FEE.

A. The Scheduling Coordinator Identification administrative fee is designed to limit the number of Scheduling Coordinator Identifications to those needed for legitimate ongoing business purposes and to discourage parties from maintaining lapsed or unnecessary Scheduling Coordinator Identifications. The ISO proposes to keep the charge at the current $1,000 per month per

Scheduling Coordinator Identification, and will assess the charge only to Scheduling Coordinator Identifications with non-zero settlements in the month. The revenue from this transaction fee will offset costs recovered through market services.

Q. HOW DO THESE PROPOSED ADMINISTRATIVE AND TRANSACTION FEES COMPARE TO SIMILAR FEES UNDER THE EXISTING GMC STRUCTURE?

A. The bid segment transaction fee for spot market bids (other than virtual bids) and the CRR bid fee are new charges being proposed under the revised GMC design. The inter-Scheduling Coordinator trade fee and the Scheduling Coordinator Identification fee are currently included in the ISO tariff. For 2011, the inter-Scheduling Coordinator trade fee is $1.3170, which is very close to the $1.00 level being proposed for the new GMC rate design. As I mentioned, the $1,000 Scheduling Coordinator Identification fee is the same as in the current tariff. In addition to continuing these charges and introducing two new ones, the ISO proposes to eliminate the current Station Power fee and the Participating Intermittent Resource Program Export fee. The GMC team determined that these fees could be eliminated because they both recover very insignificant amounts. Station power costs will be recovered through the Market Services charge, and Participating Intermittent Resource Program Export costs will be recovered through the System Operations charge. At the same time, the GMC team did decide to maintain the current fee of $0.10 per MWh on eligible intermittent resources (EIR) and resources participating in the Participating Intermittent Resources Program for the resource-specific forecast services these resources receive from the independent forecast service provider. The revenues the ISO receives from this fee will also contribute to the Market Services cost category. If in the future the ISO finds that a specific service benefits mainly its direct users and should be charged outside of the major cost categories, the new GMC design can easily accommodate a new, targeted fee upon approval by the Commission.

Q. YOU MENTION THAT THE PROPOSED GMC HAS SPECIAL PROVISIONS FOR TRANSMISSION OWNERSHIP RIGHTS AND CERTAIN SUPPLIERS. ARE THERE ANY OTHER PROVISIONS FOR SPECIAL TREATEMENT?

A. Yes. The ISO tariff allows Metered Subsystems to elect to operate their own generating resources to follow their load in real time and thus minimize their participation in the ISO real-time market. The revised GMC exempts Metered Subsystem Load-Following instructed imbalance energy from the Market Services GMC charge because this energy quantity reflects the Metered Subsystem's performance of its real-time load following function, and the costs associated with this function are recovered through the System Operation charge.

Q. DID THE GMC TEAM CONSIDER ANY OTHER RATEMAKING ISSUES?

A. Yes. Stakeholders asked the ISO to consider assessing the Market Services charge to real-time uninstructed energy deviations. The GMC team decided against this, however, for two reasons. First, although there is a GMC allocation to uninstructed deviations today, that charge is actually a residue of the ISO's former zonal market structure in which, for various reasons, uninstructed real-time deviations placed a considerable operational burden on the real-time operators of the grid. With the advent of the new ISO market structure in 2009, including the improved generator operating incentives that derive from locational marginal pricing and the substantial software upgrades to support real-time operation and congestion management, there no longer is the same cost-causation basis to argue that real-time uninstructed deviations should be responsible for a greater share of ISO operating costs than other real-time flows. Moreover, it would not be appropriate to use the GMC as a way to try to discourage real-time uninstructed deviations, as that would be counter to the guiding principles that Mr. Epstein described and that I discussed to some extent above. In particular, such an objective would violate the principle that the GMC should focus on recovering the costs associated with providing ISO services and should not address market participant behavior. Incentives for market participants to behave in ways that best support the efficiency of the ISO markets and the operational needs of the grid are best addressed through the market design itself, i.e., through exposure to real-time prices, eligibility for bid cost recovery, and responsibility for the different categories of market uplift charges.

<u>III.</u> <u>GRANDFATHERING OF CERTAIN SUPPLIERS</u>

Q. PLEASE EXPLAIN THE PROCESS THAT PROMPTED THE ISO'S PROPOSAL TO GRANDFATHER CERTAIN SUPPLIERS.

A. As Mr. Epstein discussed, after the GMC team established billing determinants and derived GMC rates based on historical data, we estimated the bill impacts of these rates on participating scheduling coordinators to determine whether the change in GMC rate structure would have a disproportionate impact on any particular customer classes. Under such circumstances, traditional utility ratemaking often includes bill impact mitigation techniques such as phasing-in revised rates or rate structures, or other approaches that could mitigate any dramatic changes in total charges.

Through this evaluation, we determined that although we had based the new rate design on cost causation principles and had followed the other guiding policies, the category of power suppliers would be disproportionately affected. By power suppliers I mean scheduling coordinators that primarily supply energy and capacity to the ISO markets and do not have load-serving responsibilities. Thus the category of power suppliers would not include municipal utilities or investor-owned utilities, because although these entities typically control supply resources that they bid into the ISO markets, they also have significant load-serving responsibilities. Under today's GMC, a supplier that injects the same volume of energy into the grid as a load-serving entity withdraws from the grid pays substantially less than the load-serving entity. For example, under the existing GMC, a base load generator pays $0.06 per MWh while an equivalent level of load pays $0.65 per MWh. Under the proposed GMC, the supplier and load-serving entity would pay the same amount. As a result a supplier that does not serve load will experience a dramatic increase in GMC charges under the proposed new GMC design, whereas a load-serving entity that also bids significant supply resources into the market would not see such a dramatic change.

Q. WHY IS THERE SUCH AN IMPACT ON SUPPLIERS?

A. The reason for this difference is that the current GMC does not charge supply resources for total energy flows, but rather charges them based on behavior, particularly real-time uninstructed imbalance energy or deviations. Thus a supply resource that does not significantly deviate from its forward schedule as modified by any ISO dispatch instructions would have a minimal GMC allocation under the current design. In contrast, under the proposed 2012 GMC structure the billing determinant for System Operations will be total energy flow MWh, without regard to whether the flows were forward scheduled, instructed or uninstructed. Thus suppliers that do not serve load will see dramatic increases in their GMC charges, as shown in the bill impact analysis presented on page 16 of Ex. No. ISO-3, the 2012 GMC Straw Proposal.

In contrast, a scheduling coordinator that represents both demand and supply will not experience this kind of increase in its GMC charges; although such an entity may see an increase in the charges associated with the supply resources it represents, that increase will be moderated by a decrease in the charges associated with its demand relative to the GMC charges demand pays today. As a result, the ISO determined that it would be appropriate to mitigate the impact of the 2012 GMC design on suppliers that do not serve load.

Q. IN LIGHT OF THE FACT THAT SUPPLIERS TYPICALLY PASS THEIR COSTS THROUGH TO CUSTOMERS, WHY WAS THIS A CONCERN?

A. Through the stakeholder comments and discussions, the GMC team learned that a few long-term energy contracts contain provisions that would prevent suppliers from passing GMC increases through to the energy purchasers (presumably load-serving entities who would be able to recover GMC cost increases through a retail rate mechanism). This outcome was not envisioned as the rates were being developed. And even if it had been envisioned, I believe that the ISO would have designed the new GMC structure so as to best conform to the guiding principles and then adopt short-term transition measures to mitigate any severe impacts, rather than compromise the design in order to accommodate such transitional concerns.

Q. WHAT PROVISIONS DID THE ISO DECIDE TO ADOPT TO ADDRESS THIS CONCERN?

A. Stakeholders offered comments suggesting that the ISO consider either grandfathering those supply resources with contracts of the type described above, or phasing in the new GMC charge structure to supply over a period of time. The GMC team reviewed these options and initially proposed phasing in the System Operations charge to suppliers over a three-year period. The GMC described this approach in its January 13, 2011 modifications to the GMC Straw Proposal, which is Ex. No. ISO-6. Upon further discussions with stakeholders and additional analysis, however, the GMC team concluded that the phase-in proposal, which would apply to all supply resources, would be too broad a measure compared to the much smaller set of resources that have the problematic contract provisions. The GMC team's analysis showed that phasing in the System Operations charges for all suppliers would have insufficiently mitigated the rate impacts on the suppliers most directly affected by the problematic contract provisions, would have provided benefits for suppliers that did not have contractual impediments to passing on the costs, and would have had a significant adverse impact on other customer classes by increasing the total volume of charges to be allocated to demand. The GMC team therefore abandoned the phase-in proposal in favor of grandfathering a limited number of existing contracts by exempting the energy associated with those contracts from the System Operations charge for the duration of the problematic contract provisions.

Q. HOW DOES THE GRANDFATHERING PROPOSAL BETTER ACCOMPLISH THE DESIRED MITIGATION.

A. By specifically targeting the affected contracts, the proposal mitigates the GMC cost impacts *only* for the energy flows associated with those resources subject to the contract limitations. This approach does not provide a benefit to supply resources not affected by this type of contract provision and thereby minimizes the total number of supply MWh that are excluded from the System Operations charge, as compared to the phase-in approach, and as a result does not impose any significant cost impacts on other participants. The proposed grandfathering provision would exempt from the System Operations charge only supply resources that meet certain criteria, set forth in the tariff, and only until the earlier of the first opportunity to renegotiate the contract or the contract expiration. To qualify for grandfathering, the contract must prevent the supplier from passing the System Operations charge on to the buyer, must be at least three years in duration, and must have been executed before the supplier had notice through the ISO's 2012 GMC design initiative that it would be subject to the System Operations charge. In view of the stakeholder process the ISO conducted for this initiative, the ISO proposes to establish this date as January 1, 2011. Thus, to qualify for grandfathering, the contract must have been executed prior to that date and must extend for at least three years after that date.

Q. THANK YOU. I HAVE NO FURTHER QUESTIONS.

DECLARATION OF WITNESS

I, Lorenzo Kristov, declare under penalty of perjury that the statements contained in the Direct Testimony of Lorenzo Kristov on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 5th day of July, 2011.

/s/ Lorenzo Kristov
Lorenzo Kristov

Exhibit No. ISO-10 –

Stakeholder Comments and ISO Response on 2012 GMC Rate Design Discussion

April 21, 2010

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

Stakeholder Comments on GMC 2012 rate design process discussed April 21, 2010

Please comment on the following

1. Process suggestions and improvements
2. Proposed calendar of events
3. SMCR allocation based on settlement charges
4. 35% of Core Reliability Services going to Energy Transmission Services, both Net Energy and Uninstructed Energy
5. 80%/20% split of Energy Transmission Services between metered load and uninstructed imbalance energy
6. Billing determinants
7. Other issues

Name	Comment	ISO Response
SCE	Southern California Edison submits these comments in response to the request of the ISO for stakeholder input regarding the 2012 Cost of Service Study for the 2012 GMC rates. The ISO specifically requested input on several issues, as follows with SCE's input: 1) Process suggestions and improvements. SCE does not have any suggestions to improve the process of conducting the 2012 Cost of Service Study. 2) Proposed calendar of events. The proposed schedule for completing the 2012 Cost of Service Study is reasonable. 3) SMCR allocation based on settlement charges. SCE is supportive of the current method of billing SMCR costs, where a given amount (currently $1,000 per month) is collected through a fixed charge from each SC that has activity in a month, and the remainder of costs is reallocated to other GMC charge buckets. It seems appropriate to have a fixed cost component of the GMC to represent that there are a certain amount of fixed costs that the ISO incurs in servicing an SC, regardless of its size (such as sending out a bill each month to each SC, and doing accounting on a per SC basis). Accordingly, SCE is not supportive of eliminating the fixed charge component of the SMCR charge. SCE is open to the possibility of billing the remainder of SMCR costs not collected through the $1,000 monthly charge in proportion to an SC's settlement charges, rather than reallocating the costs to other GMC cost buckets. This could be appropriate if it could be demonstrated that there is both a fixed cost component of servicing SCs, as well as a variable cost that is in some measure proportional to the amount of business that an SC does with the ISO. 4) 35% of Core Reliability Services going to Energy Transmission Services, both Net Energy and Uninstructed Energy. SCE is generally supportive of the current transfer of CRS costs to the ETS cost bucket. This transfer originated as a result of the settlement of the 2004 GMC case (ER04-115), and therefore in SCE's view represents a consensus among stakeholders that likely should be maintained. However, SCE would like to see more cost information	The issues, concerns and suggestions raised by SCE have been incorporated into the new proposed GMC rate design

Name	Comment	ISO Response
	before definitively supporting this cost allocation transfer. 5) 80%/20% split of Energy Transmission Services between metered load and uninstructed imbalance energy. SCE is supportive of maintaining the 80/20 split between the ETS costs that are recovered from metered load and costs that are recovered from uninstructed imbalance energy, assuming that the underlying relationship between metered load and uninstructed deviation energy have not changed since the original study. The original rationale for a split billing determinant of the ETS charge was that ETS costs are scalable costs that vary in proportion to the level of activity on the transmission system. Metered load and uninstructed imbalance energy are both measures of this scalable activity, and so both are appropriate as billing determinants. The 80/20 split was based on an analysis of the standard deviation of energy versus deviations. If this basic relationship has not changed much since the original study, SCE is supportive of keeping the 80/20 split. Additionally, SCE agrees that it is appropriate to allocate some ETS costs to uninstructed imbalance energy from an incentive perspective, in order to provide SCs with the incentive to minimize these deviations. 6) Billing determinants - SCE supports the current set of billing determinants. 7) Other issues.- SCE has no other issues to raise at this point.	
PG&E	PG&E proposes that the rate for the Settlements, Metering and Client Relations (SMCR) Charge Type be doubled, from the current $1,000 per month charge to $2,000 per month. CAISO cost studies have long established that the current SMCR charge recovers only a small fraction of the costs associated with SMCR activities. Increasing the monthly SMCR charge to $2,000 will move the charge, albeit minimally, closer to a cost-based rate. Regarding other GMC allocations, such as the allocation of certain Core Reliability Services (CRS) costs to Energy Transmission Services – Net Energy (ETS-NE), PG&E does not have enough information to formulate an opinion. PG&E will be able to formulate an opinion once quantitative analyses, such as cost-of-service or bill impact analyses, are available from the CAISO.	The issues, concerns and suggestions raised by PG&E have been incorporated into the new proposed GMC rate design

Name	Comment	ISO Response
MID / SVP	The Modesto Irrigation District ("MID") and the City of Santa Clara, California, doing business as Silicon Valley Power ("SVP"), thank the California Independent System Operator Corporation ("CAISO") for the opportunity to submit comments concerning the CAISO's Grid Management Charge ("GMC") for 2011 and Cost-of-Service study considerations leading up to a filing in 2012. MID's and SVP's comments concern the latter issue, the CAISO's development of a Cost-of-Service study over 2010-11, and for what purpose that study would be used for the GMC that would take effect January 1,2012. MID and SVP believe that the CAISO should, and is obligated to, file a full Federal Power Act ("FPA") Section 205 filing for 2012, which includes the information required in the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations in 18 C.F.R. 35.13, *et seq.* The CAISO has not submitted a GMC filing with full Section 35.13 support since its GMC filing aimed to take effect in 2004. Since that time, the CAISO has undergone a sea change in operations, business objectives and infrastructure, headlined by the Market Redesign and Technology Update ("MRTU"). In addition, the CAISO has undergone construction of a new building meant to meet the requirements of a rigorous Reliability Standard regime required as a result of the Energy Policy Act of2005. While it is understandable that the CAISO would not want to undertake a full Section 35.13 filing during the development and start-up of MRTU, it appears, particularly with the addition of new capital investments such as the CAISO headquarters, that the CAISO should file with the Commission, as soon as practicable, a full Section 35.13 filing. A full section 35.13 filing is, in MID's and SVP's view, what was intended by the Tariff language that arose from the settlement that requires the CAISO to file a Section 205 filing at the end of a GMC term. While stakeholders have agreed to extensions in the past, the only logical meaning for the language is that it would ultimately require a full Section 205 filing with Section 35.13 support. Section 35.13 filings fulfill important needs for both stakeholders and the Commission. A formulary approach makes it more difficult to determine whether the FERC rate regulated public utility is making reasonable forecasts. Even this year, we have found that the CAISO has had to use its Tariff rate adjustment authority twice. Whether or not factors are outside of the CAISO's control, a Section 35.13 filing under FPA Section 205, as opposed to Section 206, allows the Commission and stakeholders to determine whether expense projections were reasonable when made. Further, Section 35.13 support helps establish accurate cost allocations. As part of filing Section 35.13 support, the CAISO needs to perform and submit an updated Cost-of Service and use that Cost-of-Service to re-establish the allocation factors. One problem with the CAISO extension approach that has been used in the past is that the	The issues, concerns and suggestions raised by SVP and MIDISO regarding a rigorous cost-of-service study have been incorporated into the process. A cost-of-service analysis based on using Activity based costing and process mapping was undertaken. The resulting study was posted and presented at the October stakeholder meeting. Section 35.13 is triggered whenever the ISO makes a Section 205 filing to change rates in a "rate schedules, tariff or service agreement." Therefore, the ISO will comply with any Section 35.13 provisions that are applicable to the 2012 GMC changes that are submitted for approval. The ISO notes that many of the information categories described in Section 35.13 do not apply to the ISO and the calculation of the GMC.

Name	Comment	ISO Response
	stakeholders tend to walk through the motions rather than focusing on cost allocations to determine if they are updated and accurate. The CAISO is well aware of concerns that the allocation of Settlements, Metering and Client Relations ("SMCR") activity costs do not reflect actual cost causation principles. Moreover, a formulary rate shifts the burden on stakeholders and the Commission to question annual costs. At FERC, a concerned stakeholder would have to raise a complaint under FP A Section 206 to challenge CAISO costs, and the Commission would have to open an investigation under FP A Section 206 to undertake its own review. Further, the granularity of data may not be sufficient for full Commission review of CAISO costs. Cost containment concerns have been raised previously. A May 21, 2007 letter to the U.S. Government Accountability Office from Senators Lieberman and Collins noted that, "While the RTOs/ISOs have no profit motive, they also are not subject to the usual pressures or mechanisms to keep the rates charged for their services low." While the letter referred to lack of competitive pressure, owing to the fact that RTOs/ISOs have a monopoly over certain functions, one of the usual mechanisms that has been absent has been full cost-of-service review. Further, the GAO's subsequent report on electricity restructuring *(note 1 - GAO Report to the Committee on Homeland Security and Governmental Affairs, U.S. Senate, "Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance" at 36-43 (Sept. 2008) ("GAO Report").)* was concerned with FERC's lack of regular review of proposed RTO/ISO expenses. The GAO was aware of the extensions that deferred full review of the CAISO's expenses. *(note 2- See id. at 37.)* A full Section 205 filing with Section 35.13 support, whether or not resulting in certain revenue requirement adjustments, could cause an independent third party such as FERC Staff and other regulatory functions, to review CAISO costs and improve stakeholder confidence in both the CAISO's cost review processes and the administration of the CAISO's functions, particularly after the major capital expenditures of the past several years. While the revenue requirement cap has helped keep the annual rate down, the CAISO has been permitted to borrow debt, and market participants want to ensure that GMC rates decrease due to reduced debt payments as soon as practicable. MID and SVP urge other market participants to become more involved in the process of GMC review. Because CAISO GMC costs can be automatically passed-through by many market participants, there has been less incentive to undertake the exercise contemplated under Section 35.13. Nevertheless, given the current economic climate, MID and SVP urge heightened interest in reviewing costs and forecasts. On a separate issue of what substantively should be considered in the Cost-of-Service study, MID and SVP note that Ben Arikawa submitted testimony on the CAISO's Cost-of-Service in 2008. At that time, the CAISO's analysis and Cost-of-	

Name	Comment	ISO Response
	Service study appeared to be a conversion of the old CAISO Cost Centers to new CAISO Cost Centers and also included the CAISO Staffs initial thinking regarding how MRTU costs should be collected in GMC rates. MID and SVP believe that a more rigorous Cost-of-Service study should be undertaken. MID and SVP maintain that we do not fully understand the CAISO's costs and the CAISO's analysis of those costs without the benefit of Time Sheets and tracking. MID and SVP understand that the CAISO is implementing an Activity Based Cost method to track CAISO Staff time and their consultants - a method supported by MID, SVP and others. Further, MID and SVP request that the CAISO provide a further explanation of how it forecasts denominators in the GMC rate determination. While it is understood that weather and economic factors can affect the denominators through lower energy sales, it is important to MID and SVP that stakeholders understand how the CAISO develops its ongoing forecasts for those denominators, including ongoing consideration of all factors (weather, economic and otherwise).	

Exhibit No. ISO-11 –

Stakeholder Comments and ISO Response on

GMC 2012 Cost of Service Study Discussion Paper, October 8, 2010

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California ISO
Your Link to Power

Responses to Stakeholder Comments on GMC 2012 Cost of Service Study Discussion Paper Issued October 8, 2010

1. Please comment on the design principles listed in the discussion paper, and suggest any others you believe should be considered.		ISO comments
SDG&E	SDG&E is pleased with the effort by CAISO staff in this attempt to define costs and tie cost responsibility with the appropriate function and groups at the various levels identified in this discussion paper. The design principles appear to be practical and allow for a workable methodology of determining how costs might be allocated appropriately except for guiding principle 2 which states that the focus of the redesign should be on 'use of ISO services, not market behavior". An example of why the CAISO needs to consider market behavior can be found when analyzing the modifications made to the Market Usage Forward Energy Charge during calendar year 2009. One of the reasons for eliminating the Inter SC transactions in determining this GMC charge was that the charge for IST participants was acting as a disincentive for using this feature of the market. This example demonstrates that GMC rate design does in fact need to consider market behavior when developing new rates.	We understand that costs drive behavior and have attempted to design rates that will not be a barrier while also attaching a cost to the transaction. For example Inter-SC trades were set at $1.00 per transaction, regardless of volumes. A nominal bid fee of $0.005 is proposed to deter SCs from submitting excessive volumes of "fishing bids"...
SCE	SCE is in agreement that the seven guiding principles set forth in the discussion paper are useful principles to guide the development of the 2012 GMC structure. These principles are: (1) Cost Causation, (2) Focus on use of ISO services, not market behavior, (3) transparency, (4) Predictability, (5) Forecastability, (6) Flexibility, (7) simplicity. Specifically, SCE agrees with the ISO that simplicity and transparency should be considered in developing the GMC rate structure, as that will allow customers to better understand how their market participation decisions may affect their GMC costs. SCE will caution however, that the focus on cost causation and the use of ISO services (and not market behavior) should not be absolute. Market behavior may be affected by GMC rates (which are prices from the perspective of market participants, and which therefore do affect their decisions). There should always be a final check on GMC rates, and a continuous monitoring, to ensure that GMC rates are not unduly negatively affecting market outcomes. Accordingly, an eighth principle should be added: (8) GMC rates should be designed to minimize adverse market outcomes.	We concur with SCE and have included it in subsequent discussion papers. The ISO agrees that a properly designed GMC should seek to do no harm (negatively affecting market outcomes) avoid imposing negative incentives (address negative market behavior such as deviations), and simply should be a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts.
PG&E	PG&E has no comments on this issue at this time.	Noted

Responses to Stakeholder Comments on GMC 2012 Cost of Service Study Discussion Paper Issued October 8, 2010

1. Please comment on the design principles listed in the discussion paper, and suggest any others you believe should be considered.		ISO comments
Dynegy	Dynegy supports the principles of cost causation, transparency, and predictability. In regards to focusing on the use of CAISO services, not market behavior – this topic warrants further discussion. For example, while the CAISO proposes per-bid fees to deter "spamming" or fishing" (submitting large numbers of bids), it processes those bids electronically, so that the level of incremental cost imposed by an additional bid is difficult to discern. Assuming, *arguendo,* that market prices, not GMC rates, should discipline market behavior, it's difficult to discern whether other things such as CAISO market prices are having the desired effects (e.g., in reducing levels of self-scheduling). In theory, designing GMC rates that recover costs, not manipulate market behavior, is probably a reasonable goal, but it is a discussion that is difficult to have without also discussing how other things affect market behavior. In regards to forecastability – which the CAISO defines as using billing determinants that can be easily forecasted by both the CAISO and market participants – it appears the CAISO may be moving towards withdrawal or injection MWh as a billing determinant that would apply to more, or larger, cost categories than under its current GMC rate structure. It's not apparent that accurate forecasts for these quantities, which seem appropriate billing determinants, are readily obtained or available for market participants to use. Reductions in throughput MWh over the last year have led to unanticipated and significant changes in GMC component rates. Nevertheless, it is probably much easier for market participants to forecast billing determinants like withdrawal and injection MWh than to forecast other billing determinants like the number of bids. In regards to simplicity – simplicity and cost causation are appropriate rate design principles that nevertheless may conflict. Dynegy looks forward to seeing how the CAISO balances the tension between simplicity and cost causation.	A bid fee is used by most other ISOs, or they are contemplating using one. We believe the design takes into consideration a charge that does not discourage activity but is in recognition that excessive bid volumes do impact ISO systems and process. The relationship between bid volumes and their direct impact on ISO systems is difficult to assess, but a nominal fee provides a signal to participants that there are costs associated with the participant's use of ISO systems. The proposed determinants are demand and throughput of energy in the ISO markets and Balancing Authority Area. These volumes are easier to forecast by both the participant and the ISO than most of the current determinants such as deviations, # of schedules etc. This should assist participants in their budgeting process.

California ISO
Your Link to Power

Responses to Stakeholder Comments on GMC 2012 Cost of Service Study Discussion Paper Issued October 8, 2010

1. Please comment on the design principles listed in the discussion paper, and suggest any others you believe should be considered.		ISO comments
MID/SVP	Further, the CAISO is aware of MID/SVP's concerns regarding a formula rate concept utilized over a long-period oftime. As illustrated from the CAISO's presentation, when debt service is retired, as is projected in 2013, or other expenses decrease, there is no effective protection to prevent spending up to the revenue requirement cap. MID/SVP's concerns are expressed in greater detail in their joint comments submitted to the CAISO on June 18, 2010.	4 of the 5 ISO/RTOs use a formula rate and PJM uses a fixed rate. The ISO has used a formula rate for many years and will propose continuing this method. We acknowledge the participants' concerns and point to the fact that the ISO implemented dramatic budget reductions in 2006 and has held the line on increases since that time. The ISO's management is dedicated to keeping costs reasonable and continually benchmarks our costs to ensure they are in line with other ISOs/RTOs.

2. Please comment on the use of ABC and the allocations into the 3 proposed GMC service categories		ISO comments
SDG&E	SDG&E supports the continued application of the Activity Based Costing model to the GMC 2012 Cost of Service study as described in the discussion paper. Cost category percentages for allocating Level 2 direct operating activities for partial responsibility between both Market Services and System Operations may require more study before additional comments may be offered	The comments are noted and will be considered in the final proposal.
SCE	SCE is supportive of the ISO's implementation of ABC. ABC should allow the ISO to better determine its cost of service associated with its activities and align its GMC rate structure with its underlying costs. The three GMC service categories (Market Services, System Operations, and CRR Services) are in SCE's view appropriate. However, it may be appropriate in some cases to have more than one billing determinant to recover the costs of one of these three service categories. This should be considered over the course of the stakeholder process.	The comments are noted and are being considered in the design.
PG&E	PG&E has no comments on this issue at this time.	Noted.

Responses to Stakeholder Comments on GMC 2012 Cost of Service Study Discussion Paper Issued October 8, 2010

2. Please comment on the use of ABC and the allocations into the 3 proposed GMC service categories		ISO comments
Dynegy	Dynegy appreciates that the CAISO has broken out CRRs into its own category. Dynegy regrets that this separation did not take place earlier, because Dynegy still perceives that the development and administration costs of this system, which does not benefit all market participants, and disproportionally benefits a few, were allocated broadly to market participants, while the development and administration costs of other systems that also had a limited set of beneficiaries were recovered specifically from those beneficiaries. Because the CAISO's market and system operation systems are, to a large extent, intertwined, there may be some unavoidable overlap between those two buckets. In Table 6, it's not apparent why 100% of market design and regulatory policy costs are allocated to market services, while 100% of the costs to develop State/Federal policy are allocated as an indirect cost. And while the opportunity to comment on other proposed allocations of activities to cost categories may be tempting, Dynegy expects that conversation may best be had after the bill impact statements are released	Noted. We believe that most of the costs of market design and regulatory policy are related solely to market services. On the other hand, the State and Federal regulation impacts both market design and current operations which is the reason for the indirect allocation.
MID/SVP	MID/SVP has no comments on this issue at this time.	Noted.

Responses to Stakeholder Comments on GMC 2012 Cost of Service Study Discussion Paper Issued October 8, 2010

3. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered.		ISO comments
SDG&E	SDG&E notes that the allocation of cost responsibility by ABC has only identified those customer categories having an impact on the various Level 1 and Level 2 direct operating activities, without specifically addressing the issue of just how a particular customer is, in fact, relating to these activities. For example, whereas Internal Load – UDC and Internal Generation – Merchant in Exhibit 2 are shown to have some relationship to the Level 2 activities for the development and running of the Day Ahead (Level 1 category 80005) and Real Time (Level 1 category 80006) market, the allocation of the actual costs must consider how the different customer types within the general categories of Load and Generation relate to these activities. If a customer is solely responsible for either the load or the generation resulting charges and payments, then it would appear reasonable to assume an allocation of costs based upon the metric (assuming MWh) for each. For UDC customers such as SDG&E who are participating in the markets on behalf of both Load and Generation, however, these direct operating activities are useful only so far as the net effect of providing incremental MWhs from the CAISO to balance supply and demand for the UDC customers. Opportunity for further discussion regarding the causes and impacts by and on customers (Scheduling Coordinators) will be important to come to the appropriate conclusions for cost allocation to users. In the process, it is hoped that the total number of charge codes currently in use for GMC charges may somehow be reduced. **SDG&E TOR issue:** SDG&E shares joint ownership of the Southwest Powerlink ("SWPL") with Arizona Public Service Company ("APS") and the Imperial Irrigation District ("IID"), in percentages defined by the SWPL Agreements, APS and IID have Transmission Ownership Rights (TOR) on SWPL. Furthermore, SDG&E, as the Scheduling Agent under the SWPL Agreements, submits TOR energy schedules to the CAISO for the APS/IID SWPL Transactions, and the CAISO assesses charges to SDG&E, as the Scheduling Coordinator under the CAISO Tariff for the APS/IID SWPL Transactions. Furthermore, it is also important to note that the ISO GMC costs assigned to this customer class and upon which the rate is derived should not have a full allocation of certain ISO functional costs as other rate classes must pay. SDG&E argued this position in the prior ISO GMC stakeholder meetings and explained why a full allocation of such costs is inappropriate. The TOR allocation needs to be based upon cost causation as otherwise this class will subsidize other classes. SDG&E looks forward to working with the CAISO and CAISO	We believe the various customer types were considered when the design was developed. The ISO looks forward to further discussions when the billing determinant discussion paper and billing impacts are presented. We acknowledge that TORs have been treated as "other supply and demand" in the initial development of the design and billing impacts. We will review other options in an attempt to accommodate TORs within the proposed GMC structure.

Responses to Stakeholder Comments on GMC 2012 Cost of Service Study Discussion Paper Issued October 8, 2010

3. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered.		ISO comments
SCE	The ISO has proposed several potential billing determinants for use in recovering the costs of the three service categories from customers: 1) Allocation to Demand: Establishing a metric and calculating the denominator by summing the energy withdrawals by load and exports. 2) Allocation to Supply and Demand: Establishing a metric and calculating the denominator by summing the injections by generation and imports and the withdrawals by load and exports. 3) Transaction Fees to Offset Total Cost: Transaction fees, such as bid segment fees, are set at an appropriate level to allow a market participant to make an economic decision whether to incur the added expense. The transaction fee creates a marginal cost that serves two purposes: (1) limits excessive usage by market participants, and (2) recovers costs of transactions that participate but do not result in a successful outcome (e.g., energy bids that do not clear the market). The costs recovered by transaction fees are used to offset the revenue requirement of the associated cost category. For example, a bid segment fee would offset the revenue requirement of the Market Services Cost Category. 4) Administrative Fees: Administrative fees are used to establish an appropriate cost to allow a market participant to make an economic decision whether to incur the added expense. For example, a SCID monthly fee can be used to manage the number of active/inactive SCIDs maintained in the system. The costs recovered in this manner are typically used to offset the revenue requirements of the other cost categories. SCE agrees that these potential billing determinants should be considered for use in determining the GMC rates. In general however, SCE would oppose the application of a System Operations GMC rate to supply. SCE is concerned that supply (generators) would simply incorporate that GMC rate into its bids, and raise the market price commensurately. And the benefits of reliable System Operation are accruing to demand. The Market Services service category may appropriately be recovered from both supply and demand, as both directly use that service. As the stakeholder process proceeds, SCE may have additional ideas for billing determinants.	The use of both supply and demand was considered in the design. As noted in both the billing determinant and billing impacts papers, since both load and generation will provide similar services, we recommend that the GMC be designed in a manner that provides symmetrical marginal costs regardless of the technology used to provide the service. The marginal cost of the underlying technology should determine its competitiveness in the ISO market, not a difference attributed to GMC rate differential.

Responses to Stakeholder Comments on GMC 2012 Cost of Service Study Discussion Paper Issued October 8, 2010

3. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered.		ISO comments
PG&E	PG&E would like to address the CAISO's proposed 2012 GMC Congestion Revenue Rights (CCR) charge. During the October 14, 2010 Stakeholder meeting, the CAISO seemed to indicate that the billing determinants for a 2012 GMC charge to recover Congestion Revenue Rights (CRR) Services costs would be "MW based." PG&E believes that the billing determinants for a GMC charge associated with CRR Services should be "transaction based." PG&E is unaware of any costs associated with CRR Services that vary with the MW amount awarded. Some may argue that CRR Revenue Adequacy is a function of the MW of awarded CRRs. However, the GMC charges being contemplated do not address CRR Revenue Adequacy. There is already a mechanism to address surpluses or deficiencies in the CRR Balancing Account. Instead, the proposed GMC charge attempts to recover system, labor and indirect costs associated with providing CRR Services. PG&E contends that the cost of providing CRR Services is a function of the number of CRRs nominated and awarded. Indeed, CAISO's actions in the recent past support this contention. CAISO needed to reconfigure their CRR Settlements Payload due to size constraints which were associated with the number of CRRs being included in the payload. Similarly, CAISO has encountered problems associated with the CRR Transfer/Load Migration Process resulting from the number of Load Migration CRRs being created each month. Given these issues, PG&E proposes that CAISO adopt a GMC charge for CRR Services which is based on the number of CRR awarded to each CRR market participant. In addition, market participants who nominate CRRs (but are not awarded any) impose a cost which should not be subsidized by market participants who are awarded CRRs. PG&E proposes that a GMC charge for CRR Services include the following: • A uniform charge assessed to each Registered CRR Holder • A charge for each CRR nomination in the allocation tiers and auctions • A charge for each CRR awarded in the allocation tiers and auctions • A charge for each ETC, CVR and TOR nomination in the allocation tiers • A charge for each CRR awarded as a result of load migration • A charge for each CRR transacted in the Secondary Registration System The relative size of each charge is undetermined but as an initial proposal, PG&E suggests that CRRs awarded in the Annual Processes be three times (3X) the GMC charge assessed to each CRR awarded in the Monthly Processes. In addition, PG&E suggests that CRRs awarded in the Long-Term Processes be nine times (9X) the GMC charge assessed to each CRR awarded in the Annual Processes. The relative size of the GMC charge assessed to load migration CRRs is an open question. CRR market participants can take actions to reduce nomination-based or transaction-based charges. In contrast,	The use of MWh volumes to collect revenue required to support CRRs is consistent with other ISOs/RTOs. The ISO provided details on costs associated with the CRR process and determined that it represents ~ $ 7 Million. We acknowledge that balancing cost causation with simplicity can be difficult. The ISO believes there are more impacts on ISO systems associated with the processing and maintaining 100 1MW CRRs than there are on processing 1 – 100 MW CRR and the ISO's proposal is a reasonable method for addressing this reality. We may to consider a high bid fee relative to the fee for a cleared CRR. On the energy side, the bid segment fee is $0.005 and the cleared schedule is $0.09. This would strike a balance – we recover more from bidding (nominating) in the market relative to received CRRs.

3. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered.		ISO comments
Dynegy	The CAISO has proposed four billing determinants: demand MWh, supply and demand MWh, transaction fees and administration fees. These all are reasonable ways to allocate costs. As noted above, transaction fees can serve a simultaneous function of allocating costs and encouraging or discouraging certain market behaviors, an aspect of GMC rates that the CAISO has indicated it wishes to discontinue. Other approaches, such as “capacity” based approaches (e.g., a MW, not MWh, “demand” charge) could be part of the discussion. Dynegy is intrigued by the CAISO’s proposed approach for simplifying the GMC rate structure and looks forward to further discussions. Clearly, how market participants feel about the CAISO’s proposed approach will largely depend on the billing impacts. Dynegy expects that the bill impact statements will stimulate more discussion about the details of the CAISO’s approach.	We believe these were considered when the design wasdeveloped. We look forward to further discussions when billing determinant discussion paper presented.

Responses to Stakeholder Comments on GMC 2012 Cost of Service Study Discussion Paper Issued October 8, 2010

<table>
<tr><td colspan="2">3. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered.</td><td>ISO comments</td></tr>
<tr><td>MID/SVP</td><td>MID/SVP have concerns regarding a proposal that would use SCIDs (active or inactive) as a billing determinant, as expressed on slide 17 of the CAISO's Oct. 14 presentation on the Cost-of-Service study. While there may be better solutions to allocating the costs that were attributed to the Settlements, Metering and Client Relations ("SMCR") bucket, which MID/SVP understand is proposed to be retired in the next rate design, MID/SVP are concerned with a potential continuation and expansion of the billing determinant used for SMCR. MID/SVP's concerns were realized earlier after reviewing the proposal submitted by Pacific Gas and Electric Company ("PG&E"), in PG&E' s June 18, 2010 comments in this stakeholder process. 1 PG&E expressed a preference to increase the SMCR charge to $2,000 per SCID per month. MID/SVP strongly oppose the proposal to increase per-SCID costs in the next rate design, and would support elimination of the use of such a per-SCID cost allocation method in the GMC altogether.

A per-SCID billing determinant is punitive toward smaller entities, as the same charge is assessed to differing entities irrespective of size. Also, an entity may elect to use one or more SCIDs, which does not necessarily reflect a greater proportion of business that such entity may conduct in comparison to a smaller entity. Further, entities may use separate SCIDs for specific, valid, business purposes, such as distinguishing sales transactions to different classes of entities. Emphasizing cost allocation on a per-SCID basis greatly discourages market participants from using SCIDs for such purposes. While MID/SVP have endured under this approach under the current rate design, MID/SVP do not want to see it increased or expanded.

MID/SVP also do not believe that a charge on inactive SCIDs is justified. MID/SVP have a hard time seeing how inactive SCIDs create significant work for the CAISO. Once an SCID is created, it would seem that the primary effort and expense in connection with such SCID would have passed. Thereafter, the CAISO's ongoing work with respect to SCIDs should be minimal, and this is even more the case with respect to inactive ones. For example, settlements as to inactive SCIDs should be relatively simple to produce, as there should be no transaction information to report and verify. Further, SCIDs can b inactive for relatively short periods of time, for example two-to-three months, and such short periods of inactivity should not warrant the same charge as if the SCID(s) were active. SCIDs can also be inactive for longer period’s oftime. If the CAISO is concerned about SCIDs remaining inactive for long periods of time, a better option (instead of levying a charge) would be for the CAISO to correspond with the holder of the SCID to discuss whether such SCID should be retired.</td><td>Based on current evaluation the treatment of the SCID fee will not change from the current method. This will mitigate the concerns addressed in this comment.</td></tr>
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Exhibit No. ISO-12 –

Stakeholder Comments and ISO Response on

GMC 2012 Straw Proposal issued November 11, 2010

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

1a. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **Market Services Charge and others combined**		ISO comments
EDF Trading	EDF Trading appreciates the opportunity to provide comments on the grid management charge straw proposal. EDF supports the principles used for the new GMC structure. However, we question the rates at which they are currently proposed. The GMC structure is "simply a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts." The ISO must balance its' cost recovery efforts with their impacts on the market. EDF feels that by setting the Market Services, CRR, and CRR Bid charges at their current levels, the negative impacts will outweigh the benefits to the market. The liquidity in the markets could be significantly lower should these charges be implemented at the proposed rates. **Market Services Charge** No other ISO has such a high market services charge. This charge will have a negative impact on the liquidity of the market and convergence of the Day Ahead and Real Time prices. By imposing high charges on market activities, it is likely the activity in the financial markets will be significantly lower which will counteract the benefits of implementing convergence bidding. EDF believes this charge should be significantly lowered or taken out of the proposal all together. . **CRR Charge on cleared MW** When comparing the straw proposal to other ISO's, PJM is the most appropriate since this is the most established and liquid market. The current CRR charge of .0126 per MWh is more than five times the rate of PJM of .0024 per MWh. EDF feels that this charge code should be brought down to a similar level as PJM. **CRR Bid Transaction fee** No other ISO charges such a high fee on CRR transactions. At the current level the CRR charge will successfully deter phishing bids, but will hinder the market by causing a lack of liquidity in the CRR market. PJM charges .0012 per bid segment submitted and ISO-NE charges .0065 per bid segment. EDF believes there is a rate somewhere between these two numbers that strikes a balance between cost recovery and market efficiency.	The cost structure is described in detail in the cost of service study and associated exhibits published October 7, 2010 and discussed in depth at the October 18, 2010 stakeholder meeting. The rates were developed to recover the revenue required to support each cost category. The cost catagories are based on functional assignment of labor, administrative support,and systems costs through activity based costing. The basis of the ISO's proposed GMC design changes are more fully described in the proposal papers. A comparison of fees charged by other ISO/RTOs for market services and CRRs indicates the Cal ISO is not significantly different on the % of revenue requirement for those cost categories or their rates, except for PJM rates where the variance relates to significantly higher footprint and volumes. The comparisons with other ISO/RTOs was included in the cost of service study filed October 7, 2010 and discussed in the stakeholder meeting October 14, 2010..
BPA	During the conference call this morning regarding the GMC straw proposal the ISO was discussing the transaction/administrative fee and they were discussing the Bid Segment Transaction fee of $.005 proposed. I knew that the ISO was proposing this fee for convergence bidding and then they said today that they were	Participants will be able to access information related to bid segments through SIBR. SIBR has

1a. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **Market Services Charge and others combined**		ISO comments
	now going to include it with all bid segments. Now for my question: **Bid segment fee** On the call they said, I believe, that this will be for all bid segments, not only for awarded schedules but for just putting bids into the system. Is that correct? How will the ISO present that value on the invoice for SCs to verify that the number of bid segments on the invoice match what we think they should be? Does the ISO have a system that actually counts each bid segment? This could become a very large dollar value if they do include all bid segments, awarded or not.	an API which allows participants to download information associated to their Cleaned Bids. The functionality to download Clean Bid information will be introduced with the implementation of Convergence Bidding. ISO systems will be configured to validate the number of bid segments for each SC.
NCPA	NCPA takes no position at this stage of the stakeholder process regarding the overall proposal to restructure the Grid Management Charge ("GMC") buckets, but rather focuses its comments on a specific detail of the CAISO proposal. In its straw proposal CAISO provides a list of billing determinates that will be used for billing each of the three proposed GMC buckets. The CAISO states that the Market Services charge code is designed to recover costs the CAISO incurs for running the markets. As such, the CAISO proposes this charge code will be applied to each Scheduling Coordinator's gross absolute value of awarded MWh of energy and MW per hour of ancillary services in the forward and real time market. The CAISO also describes each billing determinate that will be used to calculate the Market Services GMC charge. **Market Services Charge** Of the billing determinates listed by the CAISO NCPA believes that the billing determinate described as MSS Load Following should not be included and removed from the list of billing determinates used in the Market Services GMC charge code. As described in Section 34.12 (Metered Subsystems) of the CAISO Tariff, Load Following MSS Operators are required to submit an estimate of the number of MWs an applicable generating resource(s) will be generating over the next two hours in five-minute interval resolution to perform load following. The estimated number of MWs the MSS Operator may use to perform load following is submitted by the Scheduling Coordinator of the MSS Operator to the CAISO. This information is then processed by the CAISO and echoed back to the MSS Operator as a Load Following instruction. The MW amount submitted by the MSS Operator is always equal to the instruction provided by the CAISO. CAISO uses this information to supplement its dispatch in real-time. The estimate submitted to the CAISO by the MSS Operator, and the resulting Load Following instruction is different in nature than the other billing determinates listed. A Load Following instruction is not issued by the CAISO in response to a traditional market offer. This information is not provided to the CAISO as a Bid or Self-Schedule with the intent of being awarded energy or ancillary services, but rather is used as a mechanism to communicate and share information with the CAISO that is used to supplement CAISO's dispatch. NCPA does not require or have a need to receive Load Following instructions from CAISO to perform follow load. This is recognized in Section 34.12 of the CAISO Tariff, which	*Revised response:* The CAISO has considered this further and have determined that excluding the MSS Load Following instructed imbalance energy ,which is energy resulting from the MSS performing It's load following function, from the Market Services GMC charge is consistent the guiding principles and other aspects of the GMC proposal.

1a. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **Market Services Charge and others combined**		ISO comments
	states MSS Load following resources can deviate from the Dispatch Instructions in Real-Time to facilitate the following of Load. It is already recognized in the CAISO Tariff that Load Following instructions are not assessed GMC charges. Section 11.22.2.5.7 (Market Usage Charge) of the CAISO Tariff states the following: The Market Usage Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Part F. {For a Scheduling Coordinator for a Load following MSS, Instructed Imbalance Energy associated with Load following instructions will not be assessed the Market Usage Charge for Instructed Imbalance Energy and will be netted with Uninstructed Imbalance Energy for determining the Market Usage Charge for net Uninstructed Imbalance Energy.}	
SCE	Southern California Edison has the following comments on the "2012 Grid Management Charge Straw Proposal", dated November 11, 2010. As SCE stated in its prior comments submitted on the initial "2012 GMC Cost of Service Study Discussion Paper" dated October 8, 2012, SCE is in general agreement with the principles that the ISO has set forth to guide the development of the 2012 GMC, and that the three service categories the ISO proposes (Market Services, System Operations, and CRR Services) are the appropriate services for a GMC structure that will achieve the principles set forth by the ISO. In this latest discussion paper, the ISO has added details on how the ISO proposes to recover the costs allocated to these three service categories from market participants, by proposing billing determinants and also certain additional "administrative fees". **Market Services Charge** The Market Services charge is proposed to be assessed to gross amounts of "schedules and awards" in the ISO's markets. The discussion paper lists 18 specific quantities that would compose this billing determinant. SCE's preliminary review of these 18 quantities is that these seem to be proper. In the current GMC structure in SCE has taken the position that an analogous charge to the Market Services charge should be assessed using to net amount of participation in the ISO's markets. For example, the "Market Usage – Forward Energy" charge was assessed to net participation in the Forward markets until it switched on June 1, 2010 to a "max of gross" method. SCE believes that netting of supply-side quantities against demand-side quantities appropriately measures a Scheduling Coordinators use of and benefits from the ISO's markets. Accordingly, at this time SCE supports netting for the Market Services charge. **Systems Operation charge** The System Operations charge is proposed to be assessed to the "gross absolute value of actual real-time	**Market Services Charge** Although the ISO agreed to an alternative method in the MUFE settlement, the ISO clearly stated in that proceeding (and FERC agreed in its order), that this was an interim measure and that the preferred method should be based on total gross MW amounts. The approach proposed for the 2012 GMC is consistent with cost causation. An SC's use of the ISO market services is captured most accurately in the total gross MW of supply and demand, since under the ISO's market structure supply and demand bids are

1a. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **Market Services Charge and others combined**		ISO comments
	MWh energy flow". The ISO lists six specific quantities that would compose this billing determinant. SCE' preliminary review of these six quantities is that they seem to be proper. **CRR charge** The CRR charge is proposed to be assessed on each Scheduling Coordinator's total MW holdings of CRRs in each hour. SCE agrees that this proposed billing determinant is proper. **Other fees and charges** The discussion paper also proposes certain administrative fees, including: 1) a Bid Segment Transaction Fee; 2) a CRR Bid Transaction Fee; 3) an Inter-SC Trade Transaction Fee; and 4) an SCID Administrative Fee. SCE believes these proposed fees are in general appropriate. However, as SCE understands the SCID Administrative Fee, it would be assessed to SCs for any open SCID. Since settlement reruns may occur for a period of 36 months after the trading month, if an SC closed out an SCID the SC would continue to be assessed the $1,000 for a period of 36 months after it closed out the SCID. SCE is evaluating whether it supports this aspect of the SCID Administrative Fee. **TORs** The discussion paper acknowledges that the allocation of an administrative fee to TORs is an issue for further discussion and will be addressed during the stakeholder process to finalize the GMC design. SCE agrees that this should occur, as the cost impacts that TORs impose on the ISO are less than the cost impacts of energy scheduled in ISO markets and delivered over ISO-controlled transmission is lower than that over TORs. **PIRP charges** SCE is also interested in the ISO's plans for the GMC as it would be applied to PIRP participants. In the current GMC structure, the charge for Energy and Transmission Services – Uninstructed Deviations is assessed to monthly netted amounts of Uninstructed Deviations. Under the proposed GMC rate structure, where the charges are assessed to gross measures of use of Market Services or System Operations, it appears to SCE that there should be no analogous treatment for PIRP schedules. SCE looks forward to reviewing the GMC data to be distributed in early December and participating in the remainder of the GMC stakeholder process.	processed in the software systems and cleared in the market optimizations as distinct quantities. **SCID fee** After further review of the ISO's initial proposal and stakeholder comments, the ISO proposes that the current treatment of the SCID fee remain unchanged. **TORs** The treatment of TORs will be addressed after the initial proposal and impacts are reviewed. **PIRP charges** The ISO proposes that PIRP volumes be treated like any other volumes in the market or grid.
CDWR	The California Department of Water Resources State Water Project (SWP) welcomes this opportunity to submit comments specific to the 2012 Grid Management Charge Straw Proposal published by the CAISO on November 11, 2010. SWP's current comments are based upon its understanding of the straw proposal and the November 18, 2010 CAISO 2012 GMC teleconference call. In following the guiding principles used by the CAISO, SWP wish to bring attention to the following billing determinants that appears to have been omitted from the list presented in Section B.1. for the Market Services proposal. Inclusion of the following billing determinate will enable the list in Section B.1. to maintain consistency with the examples presented in the straw proposal and in the December 18 teleconference call.	The ISO agrees. A market participant should not be able to avoid the market services charge by not scheduling. Therefore the market services will be the greater of what was scheduled or what actually was delivered.

1a. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **Market Services Charge and others combined**		ISO comments
	Market Services Generation dispatch energy • Real-Time Instructed Imbalance Energy (IIE) • Real-Time Uninstructed Imbalance Energy (UIE) At this time, SWP does not have additional comments to the options presented. However, SWP does request the CAISO to consider the inclusion of a table that correlates the billing determinate being proposed to the CAISO Settlement Charge Code being used. SWP believes that this will assist with the SC validation process for these proposed GMC chargers. SWP also awaits the publication by the CAISO of the bill impact studies for each SC under the proposed GMC rate design and reserve future comments upon review of the study results.	

1b. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **PIRP**		ISO comments
California Wind Energy Association (CalWEA), the Large-scale Solar Association (LSA), and the Vote Solar Initiative (VSI)	CalWEA, LSA and VSI appreciate the opportunity to comment on the CAISO's November 11th 2012 Grid Management Charge Straw Proposal ("Proposal"). Our comments, described in more detail below cover two main topics: • General comments on the proposed design, including both positive elements and potential concerns; and • Our concerns about the proposed bill-comparison portion of the process. **Positive elements of proposed design** There are many attractive features of the proposed rate structure, e.g., that it would: • Simplify the overall GMC structure considerably; • Recognize that the services provided by both supply and demand may start to converge, as demand becomes more price sensitive (with new meters and rate structures) and begins to participate in CAISO markets more; and • Remove the billing determinant based on deviations from forward schedules (Uninstructed Imbalance Energy (UIE)). This billing determinant was costly to intermittent resources before recent changes allowing netting of such deviations on a monthly basis for generators participating in, and scheduling	For PIRP resources, CC4535 - Instructed Energy MWh, is the primary driver of their total GMC costs. The current rate for CC4535 is $0.5946 per MWh which is higher than the combined market services and system operations proposed rate of $0.3736 per MWh. PIRP resources do not participate in the day ahead market. Similar to other resources which actively participate in the real time market, PIRP resources should see a reduction in their GMC costs. In addition, the ISO has posted the Data Release Phase 3 Issue Paper which proposes to eliminate the $0.10 per MWh forecasting fee if the forecast

1b. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **PIRP**		ISO comments
	per, the Participating Intermittent Resource Program (PIRP). Intermittent resources cannot control output variations from lack of “fuel” (wind or sun), and most Power-Purchase Agreements (PPAs) provide for maximum possible output under most circumstances regardless of any forward schedules. Thus, removal of deviations from forward schedules may obviate the need for the special PIRP treatment in the GMC rate structure. (However, neither this change nor other GMC changes would provide compensation for potential elimination of PIRP netting treatment of imbalance energy, a concern we have expressed in comments in other stakeholder processes.) • Remove the current 10 cents per MWh intermittent-resource forecasting fee**.** Though this change was not explicit in the Proposal, we understand from recent discussions that it is part of the new design. If so, that would: ➢ Partly offset any bill increases from billing all metered energy (which, as noted above, might increase generator bills, especially for those in the PIRP program); and ➢ Remove a feature of the current design that we have believed was inequitable. The CAISO has never had a rational policy for when it does or doesn’t charge separately for certain services; for example, much more complex feature to accommodate different generation technologies, like the considerable software upgrades for Multi-Stage Generators (MSGs), have no associated extra charges, but intermittent-resource forecasting and Station Power services, which would appear to be far easier and cheaper to provide, have such charges. In the absence of such an overall policy, we favor elimination of this charge. **Potential concerns about the proposed design** We have two main concerns about the proposed design, from the information provided so far: • <u>Net impacts on intermittent resources:</u> While it appears that the proposed GMC rate applicable to real-time volumes would be lower than than that now applied to real-time deviations, the volumes it would apply to would be much more, particularly for PIRP participants. In other words, for most generators, it’s likely that total real-time production would exceed both real-time UIE or (for PIRP participants) net monthly UIE. This means that bill comparisons are particularly important to our constituents, to determine the net impact of the proposed changes. That issue is addressed further below. • <u>Charges assessed to suppliers:</u> We want to echo SCE’s concerns regarding allocation of GMC costs to suppliers; that concern was expressed with respect to System Operations charges but would also apply to any other GMC charges allocated to supply. SCE is concerned that generators would likely “simply incorporate that GMC rate into [their] bids, and raise the market price commensurately,” and states that	data is made available to all market participants.

1b. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **PIRP**		ISO comments
	"the benefits of reliable System Operation are accruing to demand" anyway. Certain forms of PPAs provide for Buyer coverage of GMCs, so allocating those costs to Sellers would effectively allocate them to demand anyway. Moreover, any GMCs that are the responsibility of the Seller would indeed cause sellers to raise their asking prices to compensate, for both the expected cost level itself and also uncertainty about future changes (which would be difficult to predict over the 10-30 year life of most PPAs). The original, one-charge CAISO GMC allocated costs only to demand for those very reasons. The CAISO should consider whether it makes sense to return to a demand-only allocation, or an allocation that moves in that direction, in this redesign process. **Concerns about the bill-comparison process** As is typical in these kinds of GMC stakeholder processes, the CAISO is proposing to post bill comparisons, based on historic usage data, for the current and proposed GMC rate structures. These bill comparisons would be posted for each Scheduling Coordinator Identification Number (SCID); the identity of the SCs would be masked, and the SCs would be told which data were theirs. This process would not provide sufficient information for CalWEA/LSA/VSI to determine the impact of the proposed changes on intermittent resources – their main concern – because the posted data: • Would only be based on historic data. Many of our members do not yet have generating facilities on-line and would receive no information through this process; this is especially true for large solar plants, since virtually none of those under development have yet achieved commercial operation, and for intermittent resources planned for areas where none currently exist. • Would not identify the generating technologies represented by the SCID. Because of the way that PPAs are typically written, there is usually a separate SCID for each merchant plant, but there will be no way to identify which SCIDs represent intermittent resources. • Would not break down the scheduling practices of any intermittent resources that are included. For example, it will be very important, in assessing the impact of the proposed changes, to determine impacts for periods when intermittent resources scheduled per their PIRP plant-specific forecast (and thus qualified for monthly netting of imbalances) and when they didn't. We urge the CAISO to work with us to modify its plans for bill comparisons in this stakeholder process, to ensure that sufficient information is available for a meaningful impact assessment for our members.	

1c. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **CRRs**		ISO comments
SVP	If the CAISO goes forward with allocating a portion of GMC costs directly to CRR Holders, SVP supports the CAISO proposal to use allocated or auctioned CRR MW multiplied by the applicable hours as the billing determinant for apportioning most CRR related costs. Further, SVP requests that the CAISO clarify its CRR bid transaction fee proposal. The CAISO explains that this "fee will apply to the CRR nominations and the CRR allocations processes. The rate of $1.00 will be used for this fee." Straw Proposal at p. 10. It is not immediately clear to SVP whether the CAISO's proposal to allocate a dollar for every CRR auction bid applies to a single bid, or whether a CRR Entity could be charged more money if it submits multi-segment auction bids. SVP believes that the same charge should apply to single bids or multi-segment bids, based on cost causation principles (i.e., the cost to the CAISO of applying multi-segment bids is not likely to be a linear function of the number of bid segments).	The CRR bid fee is proposed to apply to an auction bid (no separate cost per bid segment) or nomination. Since a CRR nomination does not have segments, the ISO proposed a bid fee so that both nominations and auction bid would receive comparable treatment.
Mercuria Energy	We are opposed to the CRR billing determinants in the straw proposal paper. The reasons are as follows. 1. Regarding the proposed CRR bid fee of $1.00/bid. This fee in our opinion is too high compared to similar fees proposed for the convergence bidding process, which is $0.005/bid. We certainly understand the desire of the ISO to recover expenses incurred in processing the bids in CRR auctions, as well as in convergence bidding processes. However, since the ISO only processes the bids in one single CRR monthly auction, the amount of work load/expenses incurred should be in similar magnitude to that of convergence bidding. Certainly 200 times more ($1.00 vs. $0.005) seems excessive and inconsistent. 2. Regarding the proposed CRR charge of $0.0126/MWh, we believe the fee structure is not in line with the actual expense structure incurred in maintaining the CRR system. Namely, once a CRR bid is cleared, the amount of system maintenance cost to the ISO is neither a function of MW quantity nor number of hours of such contracts. A 1 MW path awarded takes up the same amount of resources to process/invoice as a 100 MW path. The number of hours the paths involved in should be irrelevant to the system maintenance cost by the same token. 3. Overall, the proposed structure is inconsistent with the cost recovery spirit of the initiative. This is especially true when we compare the proposed fee structure to the practices of other ISOs, in whose FTR/CRR markets we also participate. If adopted, it would force financial market participants like ourselves to re-align capital allocation among all the ISOs and risk significantly reduction in participation/liquidity in the CAISO CRR market. Therefore, we propose the following fee structure, 1. Adopt a lower CRR bid fee structure to truly reflect the amount of administrative work related to such activities, in line with that being proposed in convergence bidding, to $0.005/bid.	All ISOs have a separate GMC category for CRRs and take a similar approach. The proposed bid/nominate fee recognizes that there is a cost imposed on the ISO by market participants, regardless if they are successful or not. If the bid fee was lowered, the under-collection would have to be borne by market participants who successfully clear the market through a higher CRR MWh rate.

1c. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **CRRs**		ISO comments
	2. Adopt a CRR charge structure that is independent of both the MW quantity and number of hours of the related path. The exact amount can be determined by the ISO after consideration of the true cost involved in maintaining such paths.	
EMTRI	EMTRI believes that CRRs should not be separated into a separate bill determinate. Rather, they should be included into Market Services alongside DA schedules for Energy and Virtual Bidding as they are fundamentally a DAM instrument. EMTRI strongly believes that there should not be any significant difference between charges for CRRs and DAM Generation or Load bids, or virtual transactions. Especially egregious are the multipliers, proportional to the number of hours, thus making bidding for and holding CRRs unjustifiably expensive. The bid-block charge for CRRs does not need to be scaled by the number of hours in the month – time-of-use, since there is no incremental cost associated with the production of CRR allocations or awards for the subsequent 415 hours in addition to the first hour in the month – time-of-use in the CAISO's example on page 15. EMTRI proposes the removal of this scaling factor from the formula on page 15, thus making the CRR charge for 100 MW equal $1.26. Also, the CRR bid fee of $1 appears to be 200 times higher than the bid fee of 0.005 for Load or Generation DAM bids. It is not clear how CRR bids that do not clear add such a disproportional cost to the system as compared to Load or Generation DAM bids. EMTRI proposes that these charges be equalized by making the CRR bid charge the same as those for DAM load or generation block bid, i.e. $0.005 instead of $1. The CAISO paper correctly identifies cost causation as an important factor in cost allocation. However, this is not a complete picture as cost causation does not uniquely determine the billing determinants or charge codes proposed by the CAISO. Market efficiency can and does serve as an additional guide to choose between many options. High charges on CRRs, resulting from artificial scaling by CRR time-of-use hours that do not add additional costs, or artificially high bid costs as compared with Load or Generation DAM bids, will discourage participation, reduce volume and liquidity, and thus distort the price discovery of the true market cost of congestion. Other ISOs do not impose high charges on CRRs to avoid these undesirable results. EMTRI's proposed charges will ensure continued participation, preservation of liquidity, and market price discovery in the CAISO congestion market.	The ISO proposed a separate bucket for CRRs because it is a standalone market. There are many costs that are CRR specific and the ISO allocated some costs from shared market services items such as settlements. CRRs do require day ahead market results to calculate the CRR settlement, but CRRs are not considered in the clearing of the energy/ancillary services market. All ISO/RTOs that have CRR type products have separate market service and CRR charges.

1d. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered. – **Cost Allocations**		ISO comments
Dynegy	The CAISO's proposal to simplify its Grid Management Charge is intriguing. However, it is apparent that the	The causes of the difference in costs

1d. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered. – **Cost Allocations**	ISO comments

redesign will create winners and losers. Some market participants' GMC is going to go up, and some is going to go down. Individual market participants' bill impact statements will tell them how they are going to fare under the proposed new GMC as compared to under the existing GMC. While the chart on Page 16 of the CAISO's GMC Straw Proposal shows how much GMC cost is shifted from one class of market participants to another, that chart does not describe why the cost is being shifted. Dynegy asks that the CAISO qualitatively describe why the GMC costs go up for some market participants and go down for others under the proposed GMC structure. If the existing GMC structure is just and reasonable, it's not yet clear why the new GMC structure would necessarily be more just and reasonable.

While the CAISO agreed that allocating the Market Usage – Forward Energy charge on a gross basis was the right thing to do, the CAISO ultimately allocated that charge on a "max of" basis to mitigate the impacts on certain market participants.1 It therefore seems reasonable that the CAISO should be open to discussing mitigating the impacts of its proposed new GMC structure on market participants. The principle of re-designing its GMC charges to focus on how parties use CAISO services rather than on encouraging market behavior seems to be a reasonable principle. However, it also seems a bit naïve to assume that CAISO market outcomes, in and of themselves, are going to encourage the kinds of behavior that the CAISO wants to encourage – or in the case of self-scheduling, discourage. CAISO market prices have been low, and price volatility seems to be as much a consequence of software performance as of market fundamentals.

As a general matter, Dynegy is curious about the significant difference between the market services rate (nine cents per MWh) and the system operations rate (28.41 cents per MWh). It's not intuitive why there would such a marked difference in those rates.

As Dynegy understands, these are the cost components of how the market services and system operations rates were determined. (amounts in thousands)

	Market Services	System Operations	CRRs	Indirect	Total
Direct Activities	$11,474	$45,923	$1,500	$5,928	$ 64,825
ABC Support Activities	-	-	-	64,850	64,850
Non-ABC Support	450	450	100	32,020	33,020
Total O& M	$11,924	$46,373	$1,600	$102,798	$162,695

Could the CAISO explain what fundamental – personnel, equipment, other – leads to three times as much direct cost for system operations as market services? It seems that it is this difference – more than any difference between the billing determinants for the two categories – that contributes to the different rates.

ISO comments:

between market services and system operations are described in detail in the cost of service study and associated exhibits published October 7, 2010 and discussed in depth at the October 18, 2010 stakeholder meeting.

Whether one rate structure would be "more (or less) just and reasonable" than the existing structure is not a relevant consideration. Rather, under Section 205 of the Federal Power Act, the proposed GMC must be just and reasonable, and the ISO believes that the proposal meets this criteria. The ISO's proposed GMC design changes are based on the principles and objectives described in the proposal papers. In summary, stakeholders have requested a new cost of service study, the ISO market has significantly changed, cost tracking using Activity Based Costing has been implemented and the ISO is seeking to simplify the GMC structure and provide stakeholders with greater transparency as to applicable GMC charges.

1d. Please comment on the options the ISO has described for the billing determinants for allocating charge codes to users. Please describe any other options you believe should be considered. – **Cost Allocations**		ISO comments
	In any case, Dynegy looks forward to seeing the impacts of the proposed new GMC structure on its GMC, and to further explanation from the CAISO as to why the proposed new structure shifts costs among classes of market participants. Note 1 Amendment to Extend and Modify Grid Management Charge, submitted by the CAISO on October 30, 2009 in docket No. ER10-188, at 5 ("Although the ISO concluded that the gross option better reflected cost causation principles, it was concerned that applying the charge to "gross" energy schedules would result in substantial cost impacts to certain market participants.")	

1e. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **SCID charge**		ISO comments
WAPA	The CAISO is proposing to assess the $1000 GMC monthly charge to the SCs that have no market activity during the trade month. This charge (charge code 4575) is designed to recover the CAISO's costs associated with Settlements, Metering, and Client Relations. However, The CAISO's new proposal is contrary to cost causation principles. When a SC ID is inactive during the trade month, the SC does not have any settlement statements, does not submit meter data and does not require client relations support for that trade month. Therefore, Western recommends that the CAISO scrap that portion from its 2011 proposal.	After further review of the ISO's initial proposal and stakeholder comments, the ISO proposes that the current treatment of the SCID fee remain unchanged.
MID	For purposes of these comments, MID has two concerns it would like to raise. The first concern is the proposed administrative fee on all active Scheduling Coordinator IDs (SCIDs). The CAISO straw proposal states that "rather than applying the rate only to SCIDs with a positive or negative settlement, we propose to apply it to all active SCIDs." *See* Straw Proposal at 11. In MID's opinion, an SCID is not "active" unless its use causes charges or credits within the CAISO's systems. The CAISO should differentiate between "registered" SCIDs and "active" SCIDs in its straw proposal. MID concluded from the November 18, 2010 call/webcast that if an entity has registered two SCIDs, both SCIDs will each be charged the SCID fee, even if one does not have positive or negative settlement activity. Accordingly, an entity holding two SCIDs will be charged $2,000 per month for purposes of this administrative fee. While MID appreciates the CAISO's proposal to maintain the SCID charge at $1,000 per SCID per month, MID disagrees with the CAISO's proposal to expand the assessment of the charge to SCIDs that may not have positive or negative settlements. As noted in its October 21, 2010 joint comments with the City of Santa Clara, California dba Silicon Valley Power (SVP), MID believes that there is no cost justification for a charge on such SCIDs. Compounding this issue is the proposal to charge such SCIDs a minimum of 36 months of charges. Accordingly, an SCID, even if it had no settlement	After further review of the ISO's initial proposal and stakeholder comments, the ISO proposes that the current treatment of the SCID fee remain unchanged.

1e. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **SCID charge**		ISO comments
	activity, would be assessed the minimum charge of $36,000 LST UPDT: 10/7/10 - Final Page 2 ISO/Created by FINANCE over time. Any costs attributed to that SCID should be captured in an initial registration charge. Thereafter, MID cannot see where costs would be caused simply by having the SCID registered in the CAISO's systems. If the CAISO does follow through with these fees, MID proposes that SCs have the opportunity to retire, or "unregister" SCIDs they do not contemplate using before the effectiveness of the proposed CAISO SCID fees, such that they will not have to pay the proposed minimum $36,000 on those unused, or "inactive" SCIDs. MID understands that the proposed SCID fee is not derived from particular costs referenced in the cost-of-service study, and so is not linked to particular costs that need to be recovered. In addition, MID notes that the CAISO's treatment of the SCID fee contrasts with the CAISO's proposed treatment of Congestion Revenue Rights (CRRs). Specifically, an entity that is a CRR-Registered Entity, but does not acquire CRRs via allocation or auction, would not be charged the $1.00 bid transaction fee.	

1f. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **TORs**		ISO comments
SDG&E	The following comments apply to SDG&E as a Participating Transmission Owner (PTO) as they relate to the CAISO's 2012 Grid Management Charge Straw Proposal applicable to energy flows on the 500kV Southwest Power Link (SWPL) ownership share of Arizona Public Service (APS) and the Imperial Irrigation District (IID). **<u>Background</u>** 1. SDG&E owns a portion of the transmission capacity in SWPL and has turned over "only" this capacity portion to the CAISO via its Transmission Control Agreement (TCA). 2. APS and IID own part interest in the SWPL. Their ownership shares are not part of the CAISO Grid as these utilities have not transferred operational control of these facilities to the CAISO. 3. The load served by APS and IID by means of SWPL lies in their own Balancing Authority (BA). 4. Under SDG&E's SWPL Participation Agreement with APS and IID, which was signed years prior to the creation of the CAISO, SDG&E serves as the "Scheduling Agent" for APS's and IID's ownership rights on SWPL. This requires SDG&E to give effect to APS and IID schedules on SWPL. With the advent of the CAISO, this requires SDG&E to submit the APS and IID schedules on their respective SWPL ownership rights to the CAISO. 5. For such APS and IID SWPL schedules submitted to the CAISO by SDG&, the CAISO proposes to charge SDG&E GMC as shown in the ABC Level 2 Activities Straw Proposal.	The treatment of TORs will be addressed after the initial proposal and impacts are reviewed.

1f.	Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **TORs**	ISO comments
	SDG&E's Position on the CAISO's 2012 Proposal to Apply GMC to APS and IID TOR In the Guiding Principles of Cost Causation, the CAISO discusses the goal to properly allocate "caused costs" to specific categories and charged those who use or benefit. To the extent GMC is the cost to operate the CAISO in order to operate PTO assets put under the CAISO operational control via TCA's, including the balancing of Load and Resources, TOR schedules should not be charged GMC, as TOR's are not part of the CAISO. For SDG&E, as the Scheduling Agent for APS and IID TOR SWPL energy schedules, these schedules use APS and IID's SWPL Ownership. In particular, when reviewing the "Cost of Service Study Discussion Paper - Exhibit 1 ISO Business Process Framework Overview.xls", the CAISO provides a high level overview of the various Business Processes. As an example, for the process "Develop Markets (80002)", the CAISO says that these are the purpose of the process "Develop Markets": 1-Designs and implements value-added enhancements to the wholesale market design, 2-Improves the ISO's abilities to review and analyze the efficiency and quality of market results, and 3-Creates a framework that will accommodate demand response participation in the ISO market". Then, in reviewing the CAISO's "Cost of Service Study Discussion Paper - Exhibit 2 Mapping Customers to Operating Activities.xls", Existing TOR's, such as the SWPL TOR, are assigned to the following ABC Level 2 Activities: 1-BPM change management process, 2-Develop State / Federal regulatory policy, 3-Manage regulatory filings, and 4-Manage tariff amendments, and Market design & regulatory policy. It's not clear why the SWPL TOR causes costs for these level 2 activities. The same holds for many of the other ABC Level 2 Activities by Process. SDG&E looks forward to working with the CAISO on evaluating ABC Level 2 Activities by Process to determine what, if any, ABC Level 2 Activities apply to TOR energy schedules.	
MID	The Modesto Irrigation District (MID) thanks the CAISO for the opportunity to comment on the CAISO's proposed revised rate design. For purposes of these comments, MID has two concerns it would like to raise. Second, MID believes that there is reason to retain the reflection of the lower, relative costs of Transmission Ownership Rights (TORs) in the GMC. The CAISO's straw proposal states that, "The market services and grid operations charges presented in this paper applies to Transmission Ownership Rights (TORs). The ISO acknowledges that the allocation of administrative fees to TORs is an issue for further discussion and will be addressed during the stakeholder process to finalize the GMC design." *Straw Proposal* at 8. One of the guiding principles of the GMC rate design is cost causation. *See Presentation*, slide 5. The CAISO acknowledges that TORs create lower costs for the CAISO, including under MRTU: "As explained in the accompanying testimony of Mr. Ben Arikawa, the cost of providing reliability services to flows on TORs is lower than the cost of services provided to flows on facilities that comprise the CAISO Controlled Grid. This results in a reduction in the application of CRS ["Core Reliability Services"] costs to be applied to flows on TORs." CAISO GMC Filing, Docket No. ER08-585, Transmittal at 4 (Feb. 20, 2008). Mr. Arikawa explained that:	The treatment of TORs will be addressed after the initial proposal and impacts are reviewed.

1f. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **TORs**		ISO comments
	The one change in the Core Reliability Services is in the assessment of the CRS-Energy Exports charge on TOR exports. As I just explained, the CAISO reviewed the cost of service associated with TOR holders and determined that the CRS cost of service with respect to TOR exports is less than that for exports from the CAISO Controlled Grid. While the CAISO provides to the CAISO Controlled Grid the services of monitoring of transmission flows and emergency support, outage management and scheduling, transmission planning, Operations Engineering, Operations Support, determination of resource adequacy, dispatch of energy associated with Ancillary Services and load and resource balancing, the CAISO routinely provides only monitoring of transmission flows and emergency support, outage management and scheduling to flows on TORs. Because the level of Grid Reliability Services that the CAISO provides to these customers is lower than that for flows on the CAISO Controlled Grid, a separate service category with a reduced fee is appropriate. Accordingly, the CRS charge assessed to TOR exports will be less than that assessed to other exports. Note 1 - Arikawa Testimony, Exh. ISO-1 at 13 (ER08-585). Acknowledgement of TORs also was reflected as to Energy Transmission Services (ETS), such that the CAISO created a separate category, CRS/ETS-TOR, charged on MWhs usage of TORs at a separate rate. MID believes that continued acknowledgment of the relative costs of managing TORs should be reflected in the CAISO's proposed rate design. It would seem that a separate volumetric charge could be applied to MWh transacted over TORs to reflect the CAISO's lower costs of managing TORs. While MID can understand why the CAISO would want to reduce the number of GMC charges, granularity was another important principle that came out of the 2001 GMC litigation and stakeholder process that followed. *See California Independent System Operator Corp.*, 99 FERC ¶ 63,020 (2002) (Initial Decision of Judge McCartney).2 The relative burden of TORs on the CAISO system is one of those instances where greater granularity is a helpful principle to apply. *See* Arikawa Testimony, Exh. ISO-1 at 15 (ER08-585) ("A third change, consistent with the proposed change in the CRS-Energy Export charge, reflects the fact that the ETS cost of service with respect to TOR exports is lower than that for Metered Control Area Load in the CAISO Controlled Grid. Therefore, the ETS-Net Energy charge assessed to TOR exports will be adjusted relative to the ETS-Net Energy charge on other Metered Control Area Load."). Note 2 - Stating that the CAISO reaffirms that "unbundling the GMC is a work in progress; [that] the ISO remains committed to working with stakeholders to refine it, Exh. ISO-21 at 62:17-22," *Id.* At 65,084. Further, the FERC ALJ stated: *Nevertheless, I agree with the parties that serious consideration of further unbundling of the CAS is*	

1f. Please comment on the billing determinants listed in the straw proposal paper, and suggest any others you believe should be considered.- **TORs**		ISO comments
	appropriate. Throughout these proceedings, the ISO has repeatedly affirmed its position that it is not opposed to consideration of other ways to recover CAS costs. ISO I.B. at 48-49; ISO-34 at 4-5, 10-11 (Le Vine); Tr. 1538 (Le Vine). In this regard, I am directing that a full stakeholder review of the GMC be conducted in 2003 for [sic] this purpose; including, specifically, full stakeholder review of Dr. Kirsch's proposal and the suggestions made by the CPUC and EOB that the ISO should move from a pure energy-based (i.e., per kWh) charge for CAS to a mix of demand and energy-based charges. *Id.* at 65,086. Also, Judge McCartney urged review of the entire GMC, not just CAS: "as urged by DWR, the entire GMC should be examined in totality in a full stakeholder review process in 2003" *Id.* at 65,096. The stakeholder process directed by the FERC ALJ did occur, resulting in the GMC filed to take effect Jan. 1, 2004.	

Exhibit No. ISO-13 –

Stakeholder Comments and ISO Response on

GMC 2012 Bill Comparison Stakeholder Meeting, December 13, 2010

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

Responses to Stakeholder Comments on GMC 2012 Bill Comparison stakeholder meeting December 13, 2010

1. Charging system operations costs to supply		ISO comments
Coalition of Industrial cogeneration facilities	These comments are filed on behalf of a coalition of Industrial cogeneration facilities that provide thermal energy for industrial processes and generate electricity for sale to utilities pursuant to long-term contracts. The proposed grid management charge structure would impose a very significant increase in the grid management charge (GMC) for these generators, creating a severe financial constraint. This drastic increase seems due to two factors. First, the basic structure of the GMC has been changed so that generators are now charged for the energy they schedule and deliver to the grid. This fundamental change in the assessment of the GMC is unfair to suppliers that have existing contracts. Parties to existing contracts relied on the tariffs and regulations then existing to negotiate the financial responsibility for all expenses, including the GMC. The proposed GMC changes the assessment and the charge codes used for GMC, so any provisions of existing contracts related to GMC may become inapplicable. This financial risk imposed on long-term contracts is a particular disadvantage when compared with merchant plants, which make daily bids to sell their energy. Such merchant plants can adjust their bids to recover the additional costs of the new GMC. Suppliers with existing contracts may not be able to reach an accommodation with their buyers and would suffer a serious commercial disadvantage in competing with merchant plants. To resolve this penalty to existing contractual relationships, the new GMC structure should include a provision grandfathering transactions under existing contracts for some period of years. The GMC for such transactions would be assessed using the current methodology for the grandfathering period. At the expiration of the grandfathering period, the imposition of the new GMC would be phased in, perhaps transitioning from the existing methodology to the new one over three years. GMC billings may also significantly increase if the supplier had relatively low charges for schedule deviations under the current system. Some generators apparently historically accrued significant charges for deviations, and therefore, the imposition of new charges for delivered energy do not produce a significant net increase. But suppliers that did not have significant charges for deviations would now face an enormous net difference. These suppliers are in effect being penalized for their more accurate scheduling and operating behavior. In particular, industrial cogeneration, with its obligations to its steam host and its historically high capacity factor, should have minimal unscheduled deviations. The charges to individual suppliers for system operations should reflect the additional ISO activity required in real-time to balance deviations. Such activities by ISO staff are not related to the amount of MWh delivered, but the amount of deviation. ISO staff must perform far fewer scheduling actions to handle certain generators' compliant behavior than to compensate for another generator's deviations. The system operations charge should be disaggregated into two charges so that the costs of balancing the system can be properly allocated. Such a charge would not be a "penalty;" rather, it merely identifies and allocates the responsibility for the cost causation attributable to scheduling deviations.	Regarding RT deviations, the 2012 GMC proposal recognizes the fact that there really is no cost causation basis to assess additional GMC to such deviations under the new MRTU market design. This may not be well understood by all the market participants, but because of the new 5-minute economic dispatch using the full network model, which utilizes improved telemetry and a state estimator to provide accurate RT grid conditions, the impact of RT deviations on grid operators is nothing like what it was under the prior market system with zonal dispatch supplemented by operator-intensive out-of-sequence dispatch to mitigate local congestion. Indeed, an explicit objective of MRTU was to reduce the RT operational challenges of the old market system. With the new MRTU markets and systems it is no longer appropriate to assess additional GMC to RT deviations. Regarding the suggestion that existing contracts be grand-fathered, the ISO believes that the proposed 3-year phase-in period is a reasonable compromise to accommodate the transition to the new rate design.

Responses to Stakeholder Comments on GMC 2012 Bill Comparison stakeholder meeting December 13, 2010

1. Charging system operations costs to supply		ISO comments
Calpine	General Comments The CAISO has proposed to substantially change both the cost allocation and the rate design for collection of its nearly $200 million operating cost. The current rate design for GMC includes 17 charge types which makes the transactional cost difficult to interpret. In addition, the existing rate structure creates incentives for market behavior that the CAISO apparently finds unattractive. The new proposal greatly simplifies the rate design by lobbing most costs into one of two "buckets" and creates a third category for congestion hedges. Calpine supports the CAISO's effort to create simplifications and more transparency. However, the CAISO proposes to allocate GMC costs equally between supply and demand so one-half of the total costs of CAISO operations would be paid by supply. *(Note 1 - This is, by definition correct, but the CAISO has produced bill estimates that reflect the fact that a significant amount of supply is under the operational control of the state's 3 largest IOUs).* For the reasons identified below, Calpine does not support incremental allocations of GMC costs to generation and imports. If the CAISO is not inclined to charge all GMC costs directly to load, where they will ultimately reside in any case, Calpine offers alternatives. Calpine does not support charging indirectly that which could be charged directly The CAISO proposes to "variablize" its fixed cost of operation and design rates to charge 98 percent of its costs to loads, exports, generation and imports. The billing determinants are generally Mwhs or MWs per hour *(Note 2 - The CAISO breaks out two buckets, one for "awards" and one for "flows", but for simplicity, we lump them together)* for instance, for ancillary services. The average cost, when allocated this way will be roughly $0.40 per Mwh for every Mw of supply and every Mw of consumption. However, costs allocated to supply will not (for the most part) *(Note 3 - An unfortunate exception to this rule could be existing fixed-price contracts. We discuss them later)* remain with supply, as generation/import bids theoretically rise to cover the *expected value* of the actual GMC exposure. Thereby, the entire GMC cost will be allocated to loads – directly by the CAISO, and indirectly by generators and importers raising their supply bids. For a variety of reasons, suppliers will not know precisely what their GMC exposure will be. The simplicity of the new design does improve transparency and forecasting GMC exposure will be more accurate with this proposal than without it. Nonetheless, a supplier will not know *a priori* whether it will receive awards or what awards it will receive and what energy will flow and therefore, what GMC exposure it might have. In addition, since a single generator can provide multiple products, even if it could know with certainty the optimized IFM and RT outcomes, it is not feasible to differentiate each hourly bid of capacity by the specific allocation of expected GMC exposures.	Although it may be true that GMC cost will ultimately be passed to demand in some fashion, the objective of the GMC redesign is to align the ISO's allocation of its costs on the basis of cost causation, i.e., the extent to which each market participant utilizes the services the ISO provides. During the stakeholder process the ISO did consider the alternative of full allocation of System Operations costs to demand, but has concluded that the proposed approach of allocating both to supply and demand reflects better alignment with the cost causation principle, while still supporting the other design principles. Regarding the assertion that suppliers will not know precisely what their GMC exposure will be for incorporation into their market bids, the ISO believes this concern is addressed by the fact that the charges are applied at a per-MWh rate. The supplier will either pay both the market and the grid GMC for a MWh of scheduled and delivered energy, or only the market GMC for a MW of awarded AS, or only the grid GMC for a MWh of uninstructed energy. It seems straightforward to add the

Responses to Stakeholder Comments on GMC 2012 Bill Comparison stakeholder meeting December 13, 2010

1. Charging system operations costs to supply		ISO comments
	Rather than bidding the minimum-possible GMC, suppliers are more likely to bid the *expected value* – which could include a probabilistic view of the costs of awards, flows, ISTs, bid-segment fees and even possibly export fees. *(Note 4 - This expected value should also be in allowable in the Default Energy Bids which are used in LMPM*) This expected value would reflect the risk that GMC costs could be higher than the minimum possible exposure. So ultimately, loads could bear a risk-adjusted level of GMC costs that exceed the direct costs of CAISO operation. Charging the costs of GMC directly to loads and exports rather than indirectly to suppliers eliminates the payment of reasonable, but risk-adjusted supply bid costs. <u>The "Flow Through" theory is compelling, but not proven.</u> Parties have suggested that if all supply bids include the same GMC uplift, that dispatch order and infra-marginal revenue expectations for uncontracted assets should be unaffected. While some distortions will clearly occur, *(Note 5 – For instance, the average cost of non-spin for the month of November was less than the proposed GMC charges. The cost of non-spin would more than double with this change).* Calpine believes that if these assumptions are proven out, that generator and import revenue expectations would be unchanged. However, Calpine is predominantly an infra-marginal supplier. It does not control the resources that are generally on the margin and those who might control marginal resources will have a different *expected value* of risk and cost exposures that may influence their bid levels. Revenue compression for infra-marginal generation is a certain possibility if marginal generators (or those bidding marginal generation) face lower risk expectations. <u>Calpine agrees that the CAISO should "Seek To Do No Harm."</u> In the November Straw Proposal, the CAISO describes its "Guiding Policy and Ratemaking Principles" at page 4. In the discussion of the second principle, the CAISO confirms that "a properly designed GMC should seek to do no harm," and that it "is simply a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts". Calpine strongly endorses the concept that GMC should avoid market impacts and believes that allocations of GMC to generation and imports could and will affect market outcomes. In addition to mitigating effects on existing contracts, we offer several alternatives that could minimize the exposure to unnecessary costs or unintended consequences. <u>Calpine supports accommodations for pre-existing contracts</u> The "pass-through" theory clearly fails if the added costs of an increased GMC cost cannot be passed through to contractual counterparties. In this case, an allocation of the GMC cost to suppliers simply	estimated market GMC charge to AS bids and both the market and grid GMC charges to energy bids, to reflect the differential GMC costs of providing those products. Indeed, the GMC redesign process adopted the principles of transparency and predictability precisely to enable market participants to account easily for these charges in their bidding strategies and other business decisions. Therefore it is hard to see why there would need to be a risk premium on supplier energy or capacity bids to reflect GMC uncertainty. Regarding Default Energy Bids, it may be appropriate to consider including GMC costs, but this matter is outside the scope of this 2012 GMC redesign and should be pursued through the Market Initiatives Roadmap process that will occur later this year. Regarding the marginal/infra-marginal issue, the argument seems to be that marginal resources may include a smaller GMC risk premium on their bids than infra-marginal resources do, thus squeezing revenues for the infra-marginal. But this could just as well go the other way. If marginal resources use a larger

1. Charging system operations costs to supply		ISO comments
	increases their costs and provides a windfall to loads, as loads avoid costs of operating the CAISO. In particular, fixed-price, long-term contracts which split the SC responsibility between supply and load will not generally allow pass-through *(Note 6 - Of course, provisions of the underlying contract may allow pass-through)*. Calpine has long-term, fixed-price contracts *(Note 7 - Calpine is certainly willing to share these contracts confidentially with the CAISO, as long as such is allowed under the contract)* for base load energy where the cost of GMC (if allocated to supply as proposed) would increase by a fact of 10 from an aggregate GMC exposure of about $250,000 to over $2.5 million. Such a dramatic change in the allocation of GMC would not have been anticipated by reasonable negotiators when such a deal was struck. In addition, such a dramatic effect on market outcomes was probably not anticipated by those designing the new GMC structure. However, a theory of "do no harm" would require that such contracts be accommodated for the remaining tenure of the contract. Calpine is open to reasonable mitigation measures that continue to assess long-term, fixed-price contracts an allocation of GMC as long as it is consistent with historical, and not proposed rates. For instance, Calpine would accept a fixed-cost GMC annual payment (e.g. historical allocations reasonably escalated) or a substantially pro-rated volumetric charge (e.g. one-tenth of the per-mwh charge.) <u>Calpine proposes alternatives if the CAISO imposes GMC charges on supply</u> As a first principle, Calpine proposes that *if* the CAISO determines that it must charge supply, that imports and internal generation face precisely the same cost exposure. Differentiated pricing creates the unintended consequence of artificially favoring imports or internal generation. Calpine understands that the CAISO seeks to apply this same symmetry principle to all resources because "both load and generation will provide similar services". *(Note 8 - Straw Proposal* p7) Certain new technologies might need to be treated differently (e.g. DSM reductions should compete price-wise with incremental generation) but as discussed below, Calpine asserts that load is the major beneficiary of CAISO operational systems and should therefore bear most of the costs. Each of the options below decrease the risk that the CAISO could impose unrecoverable costs on supply or otherwise create harm or unintended market impacts. <u>Option 1 – Charge Supply only the Market Services Charge.</u> If the CAISO does impose costs on supply, Calpine supports the comments of SCE *(Note 9 - SCE's comments on the Discussion Paper, submitted October 21)* which suggest that generation pay the Market Services charges and not the System Operations charges. As SCE suggests "the benefits of reliable System Operations are accruing to demand." Indeed, the CAISO indicates that the "fundamental purpose of system operations is to balance supply and demand." Additionally, SCE is concerned with price distortions that	risk premium, then the infra-marginal resources would realize expanded revenues. Regarding the fixed-price contract issue, the ISO believes that the proposed 3-year phase-in should adequately address this concern. Regarding comparable charges to internal generators and import suppliers, the GMC proposal does this. Regarding the assertion that "load is the major beneficiary of CAISO operational systems," the ISO believes that although it may be argued that the raison d'être of the electricity sector is to provide electricity to end-use consumers, the ISO's provision of open, non-discriminatory transmission service and transparent spot markets provides benefits to all industry participants. Regarding the idea of a "conditional" transition to full application of charges to supply, the ISO points to the example of the energy bid cap transition under the MRTU design, where FERC approved a series of steps up to the $1000/MWh level, but did not make these steps

1. Charging system operations costs to supply		ISO comments
	arise as GMC bid adders are included in IFM results. Option 2 – Charge Supply, but on a pro-rated basis As with pre-existing contracts, supply could be charged a pro-rated charge (as a percent of Mwh or price) for both Market Services and System Operations that reflects the possibility that the "pass through" theory may fail. Option 3 – Charge Supply, with a conditional transition As an alternative to option 2, the CAISO could prescribe a transition plan in which supply's pro-rated share of the GMC would increase over, say 4-5 years. This transition period would allow bilateral contracts to expire and be reformed with a clear expectation of future risk. The annual escalation of the discount percentage could be made contingent upon a finding by an independent party that the "pass through" theory is supported.	conditional on other events or findings. This approach provides the market much better certainty – also a principle of the GMC design – than conditioning a subsequent phase-in step on some kind of finding. The ISO believes therefore that the same design is most likely to receive FERC approval for the GMC phase-in, i.e., a fixed timetable for the steps of the phase-in.

<table>
<tr><td colspan="2">2. CRRs</td><td>ISO comments</td></tr>
<tr><td>PG&E</td><td><u>General Comments</u>
Overall, PG&E supports the CAISO's 2012 GMC rate design proposal. Under the CAISO's proposed rate design, market participants will be assessed GMC based on how much they use CAISO-run markets and the CAISO-controlled transmission system. This will provide greater transparency than exists under the current GMC rate design and will allow market participants to more easily determine the "GMC impact" of any Market Services or System Operations transaction.

With respect to the CAISO's proposed GMC to recover the costs of managing the Congestion Revenue Rights (CRRs) market, as discussed further below, PG&E believes that the CRR charge is adequate for the time being, but future improvements are necessary.

<u>Improvements in the GMC CRR Charge</u>
PG&E supports the CAISO proposal for a CRR GMC based on both awarded MWHs and a Bid Transaction Fee. PG&E's support is tempered by the current lack of detailed cost data associated with CRRs. PG&E believes that a MWH-based charge does not accurately apply GMC to the market participants which cause costs to be incurred. However, lacking detailed cost studies, a MWH-based GMC charge meets several of the guiding policy principles for the new GMC structure, i.e., predictability, transparency, flexibility and simplicity. However, in PG&E's opinion the most important principle is cost causation and a GMC charge based on CRR MWH does not meet this criterion.

PG&E reiterates its prior comments that costs associated with CRR services are independent of the MWH awarded. CRR costs are a function of the number of allocation/auction nominations, the number of awarded CRRs, the number of CRRs transferred through the load migration process and the number of CRRs transferred through the secondary registration market. Of these cost drivers, only the cost associated with the nominations are addressed through a CRR Bid Transaction Fee, currently proposed to be $1 per nomination.

To appropriately assess fees associated with the aforementioned cost drivers, a detailed cost study is needed. Currently, the CAISO proposes to recover the costs of running its CRR market primarily through a MWH-based charge (proposed to be $0.01179/MWH). PG&E agrees that this is a reasonable and expedient initial rate structure. It is PG&E's recommendation that CRR cost studies be performed in the future so that improvements can be made to the CRR charge rate structure and the $/MWH billing determinant can be replaced by a transaction-based structure.

<u>PG&E Supports the CRR Bid Transaction Fee</u>
PG&E would like to see the CRR Bid Transaction Fee defined as precisely as possible. In various presentations and published documents, CAISO has defined the CRR Bid Transaction Fee differently. PG&E supports a fee assessed to each nomination bid in the annual, long-term and monthly allocations and the annual and monthly auctions. In the case of an allocation tier, a nomination bid is a submission by a market participant which</td><td>Regarding the concern about potential inequity between holders of allocated CRRs versus holders of auctioned CRRs, the ISO points out that the benefits all parties receive from the CRR element of the market structure are directly proportional to the total MW amounts of their holdings. It is therefore appropriate to recover the costs of the CRR processes and systems on this basis, irrespective of whether the CRRs were awarded through allocation or auction.

Regarding using MWh as the billing determinant: All guiding principles have similar weight overall in the recovery of ISO costs; however, their relative importance can change through the process. For example, cost causation is most important in the allocation of costs to each of the GMC cost category. Activity based costing is a pure form of cost causation and was utilized as part of the cost of service study is determining the total costs that must recovered by each GMC cost category. However, when establishing the billing determinant other guiding principles such as predictability and forecastability increase in relative importance.</td></tr>
</table>

2. CRRs		ISO comments
	specifies a source Pnode, a sink Pnode, the MW amount and the time-of-use period. For an auction, a nomination bid includes the data submitted in the allocation nomination in addition to the bid curve which specifies MW quantities and $/MW bids. Another suitable definition for a nomination bid is a submission which generates a Nomination ID in the CAISO CRR MUI. At the recent December 13, 2010 GMC Stakeholder Meeting, a market participant stated that a bid transaction fee does not reflect cost causation. PG&E disagrees. The CAISO's CRR systems were designed to handle a finite amount of allocation and auction bids. There are limits to how many nominations can be uploaded via the CRR MUI. A bid transaction fee better reflects cost causation than a $/MWH GMC. While there can be some debate as to whether $1 is the right amount to charge per nomination, the transaction-based structure is valid and appropriately reflects cost causation. PG&E notes that the proposed CRR Bid Transaction Fee recovers approximately $480 thousand, roughly 6.5% of the total CRR market cost of $7.5 Million. PG&E believes that this is an acceptable amount and PG&E would support an even higher percent recovery from a CRR Bid Transaction Fee. Going forward, PG&E would support expanding the CRR Bid Transaction Fee so as to reflect the term of the CRR being nominated. CRRs have three terms or durations: monthly durations (from the monthly processes), quarterly durations (from the annual process) and nine quarters (from the long-term allocation). Furthermore, PG&E believes that higher bid transaction fees would be appropriate for the annual and long-term process, compared to the monthly process. GMC Inequity Between Auction and Allocation Participants PG&E is concerned that the application of the CRR $/MWH charge and Bid Transaction Fee affects CRR allocation participants more than auction participants. Auction participants can adjust their bids to effectively recover all, or a portion of, the cost of the $/MWH charge and Bid Transaction Fee. That is, PG&E expects CRR auction clearing prices to reflect the new CRR GMC charge and fee. This will permit auction participants to pass such GMC costs through to the market, or else factor such GMC costs into their bids. CRR allocation participants do not have a similar mechanism at their disposal. PG&E would like CAISO to investigate this issue and consider alternative fee structures to address any inequities. Question Regarding the Timing CRR Bid Transaction Fee CAISO has not provided specifics regarding when the CRR Bid Transaction Fee will be assessed. The simplest method to assess the fees would be at the time the nominations are submitted. This means that the fee would be assessed from one month to nine years before the term of the CRR. PG&E asks CAISO to provide more details about the timing of the CRR Bid Transaction Fee.	One of the issues with the current GMC design that limits the ability for market participants in assessing their GMC exposure is applying solely cost causation to the establishment of billing determinants such as forward scheduling and imbalance energy. The selection of these billing determinants may have merit from a cost causation standpoint but do not reflect the relative benefit a market participant receives from the ISO service and is extremely difficult to forecast thus decreasing the predictability of the actual GMC rate. Regarding the CRR Nomination and Bid Fee: The Nomination fee applies per tier for each source sink pair and time of use. The Bid fee applies for each auction submission of source sink pair and time of use. Since the rate structure would not become effective until 2012 and the annual allocation / auction process occurs in late 2011 for 2012 CRRs, it does seem that for the annual 2012 process the $1.00 bid fee would not be in effect. In addition, the January 2012 monthly

2. CRRs		ISO comments
	<u>Questions Regarding the CRR Data Used in the 2012 GMC Customer Bill Impacts</u> The 2012 GMC Customer Bill Impact analyses used invoiced billing determinant quantities for the period June 2009 to May 2010. PG&E noticed that all the bids were characterized as "Auction Bids." Is this correct or do the quantities include Annual and Monthly Allocation Tier Nominations? In addition, did the bid count include nominations from two annual processes, *i.e.*, 2009 and 2010? Finally, it appears that no long-term allocation nominations were included. Can CAISO confirm if this is correct?	submission of bid/nominations would occur in 2011. Also, the February 2012 monthly process would have already begun but most likely nomination/bid submission would occur in 2012. So the bid/nomination fee will not impact all 2012 CRRs equally. The MWh portion would become effective for CRRs which are held in 2012, even though they cleared the market in 2011, because the corresponding settlements will occur after 1/1/2012. The CRR data only included transactions that would have gone through settlements for the period June 2009 to May 2010. The data is labeled as to which auction it refers.
Edison Mission	Please confirm that 2012 GMC will apply to grid activity effective Jan 1, 2012. For example: • 2012 GMC rates will not apply to CRR awarded positions prior to Jan 2012. • 2012 GMC rates are effective Jan 1, 20102 for awarded market position that settle on flow date Jan 1, 2012 and after	That is true - see comments to PG&E above
DC Energy	DC Energy submits these brief comments on the CAISO proposal to add a new charge to CRR holders associated with the 2012 Grid Management Charge (GMC) process. DC Energy believes that CRR market participants should bear an appropriate share of the GMC costs as CRR market participants share in the benefits of the CAISO markets. DC Energy agrees with the statements of SCE and CAISO in the November 2010 Straw Proposal: "there should always be a final check on GMC rates, and a continuous monitoring, to ensure that GMC rates are not unduly negatively affecting market outcomes. The ISO agrees that a properly designed GMC should seek to	The ISO believes that we have met our guidelines for this rate design and endeavor to provide lead time to participants to make changes in their business practices to incorporate these future GMC revisions.

2. CRRs		ISO comments
	do no harm (negatively affecting market outcomes) avoid imposing negative incentives (address negative market behavior such as deviations), and is simply a mechanism to recover ISO revenue requirements in a manner which minimizes market impacts.” DC Energy appreciates CAISO’s recognition of an appropriate transition period and introducing, for the first time, a CRR bid and award charge beginning in 2012. DC Energy also believes CAISO has met its stated goal of adhering to certain Guiding Principles *(note 1 - Cost causation, focus on use of services, transparency, predictability, forecastability, flexibility and simplicity),* as presented at the December 13th Stakeholder meeting.	

3. SCID charges and TORs		ISO comments
MID	The Modesto Irrigation District ("MID") thanks the California Independent System Operator Corporation ("CAISO" or "ISO") for the opportunity to comment on topics discussed at the December 13, 2010 stakeholder meeting on 2012 Grid Management Charge ("GMC") projected billing impacts. At the December 13 meeting, the CAISO discussed that it had two proposals it wished to make with respect to the 2102 GMC. The first proposal is to continue the CAISO's current treatment of SCIDs in the GMC charging $1000/month for its SCID fee only if there is any activity on the Scheduling Coordinators ("SC") invoice. While MID has not favored per-SCID charges, MID appreciates the CAISO's suggestion and believes it is a reasonable compromise. The second proposal is to exclude transmission ownership rights ("TORs") entirely from the market services charge. In addition, the CAISO proposes to exclude TORs from the System Operations charge 50% of the higher of supply or demand. If that is an accurate description of what the CAISO intends, then MID supports the proposal. MID went into detail in its November 24, 2010 comments as to why the GMC rate design should reflect the lower, relative costs of TORs. MID believes that the CAIS's December 13 proposal on TORs better reflects cost causation, and accordingly, MID supports it. However, MID understands that the CAISO intends to put in writing its proposal concerning TORs, and MID reserves the right to supplement or modify its position, if the CAISO's written proposal is different than what MID has noted above, or the proposal is subsequently modified or MID learns new information in the forthcoming stakeholder discussions.	Regarding SCID fees and TORs the proposals will be described in the paper to be issued January 13, 2011.

4. Cost shifts and customer category data		ISO comments
WPTF	WPTF offers some high-level comments and defers to its members' comments on more specific impacts or issues. WPTF supports the publishing of more sector-specific impact summaries, consistent with the requests of other parties made during the 12/13/10 meeting. WPTF is concerned that the CAISO's most recent GMC proposal would allocate the GMC – a charge historically collected from loads and exports – to new parties, creating significant cost shifts for some and potentially affecting market efficiency. WPTF requests that the CAISO comment on the merits of the cost shifts and address whether further consideration is required – for example on the CRR bid fee – to ensure market efficiency is not hampered.	The ISO published additional customer category to the GMC website on December 16, 2010 and will do the same for the modified proposal to be issued January 13, 2011. See responses to comments of Calpine, the coalition of industrial cogeneration facilities and PG&E above.

Exhibit No. ISO-14 –

Stakeholder Comments and ISO Response on

GMC 2012 Bill Comparison Stakeholder Call, January 13, 2011

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

Responses to Stakeholder Comments on GMC 2012 Bill Comparison stakeholder call January 13, 2011

1. Charging System Operations Charge to Metered Sub Systems (MSS)		ISO comments
City of Santa Clara	SVP is pleased that the CAISO has responded to stakeholder comments by proposing to exclude Metered Subsystem ("MSS") Load Following instructed imbalance energy from the Market Services charge. As the CAISO explains, the cost causation impacts of the function are appropriately recovered through the System Operations charge.	Noted

2. Treatment of CRR's		ISO comments
Mercuria Energy	As a follow up on our earlier comments about the proposed CRR bid charges for 2012, we believe the current fee structure proposed adds unnecessary hurdles to our participation in the CRR market and discourages market participants from providing liquidity that is much needed. We feel the number of bids submitted should not be a determinant of the transaction charges. We believe doing so only discourages financial participants from bidding extensively in the CRR market, hence decreases market liquidity as a result. We instead favor a fee structure that is proportional to the MW amounts awarded, at $0.005. We believe this should be sufficient enough to compensate for the resources ISO needs to clear the auctions without the disincentives caused by the proposed Bid Transaction Fee.	The proposed bid/nominate fee recognizes that there is a cost imposed on the ISO by market participants, regardless if they are successful or not. Since the CRR cost category must fully recover the allocated costs, if the bid fee was lowered, the under-collection would have to be borne by CRR market participants who successfully clear the market through a higher CRR MWh rate. The ISO sought to have comparable treatment between nominations and auctions. Since nominations do not have segments and the auction does have bid segments the ISO proposed a bid fee not based upon bid segments as is proposed in market services cost category. Bids for the energy market are submitted hourly whereas the shortest duration of a CRR auction is monthly. Assuming the number of hours a CRR is valid, the $1.00 bid fee is less than if an energy bid segment had been submitted for every hour the CRR is valid.

2. Treatment of CRR's		ISO comments
LDES	LDES believes that the $1 CRR bid charges are excessive and unreasonable due to the following reasons: 1. All the other ISOs either don't charge a bid fee or charge bid fee but in the range of several cents per bid. CAISO's proposal of $1 is way above the industry standards. 2. For DAM load and generators, the bid fee is only $0.005. CRR bid fee is unfairly high comparing to that standard. 3. The proposed $1 CRR bid charges will dramatically discourage the participation of the current CRR market. For example, LDES's charges will increase 7000% which is unreasonable by any standard. 4. Reduced market participation would dry up liquidity and would not promote efficient competitive marketplace. This may lead to other market power issues. LDES strongly urges CAISO to reconsider its $1 CRR bid charges and follows other ISOs' standard as a reference.	See ISO response to Mercuria Energy comments above.
EMTRI	EMTRI strongly believes that the currently proposed arbitrary CRR Bid Transaction Fee of $1 is excessive and should be equalized with the Bid Segment Transaction Fee for DAM Generation or Load bids, or virtual transactions (Bid Segment Transaction Fee). This CRR Bid Transaction Fee of $1 appears to be 200 times higher than the Bid Segment Transaction Fee of $0.005. EMTRI proposes that these charges be equalized by making the CRR Bid Transaction Fee the same as the Bid Segment Transaction Fee, i.e. $0.005 instead of $1. When CAISO designed its Bid Segment Transaction Fee of $0.005, it used the benchmarks of other ISOs and the outcome of the Convergence Bidding stakeholder process to set this Fee. It was a good and rational choice based on careful considerations. In its 2012 Grid Management Charge Straw Proposal dated November 11, 2010 CAISO noted that the charge of $0.005 "does not represent a significant expense to market participants under typical scheduling practices, but is enough to deter the submission of excessive bid volumes." The CRR Bid Transaction Fee of $1 appears arbitrary by this measure and considerations. No other ISO levies such a high charge. Artificially high CRR Bid Transaction Fee as compared with the Bid Segment Transaction Fee of $0.005, will discourage participation, reduce volume and liquidity, and thus distort the price discovery of the true market cost of congestion. Reduction of volume and liquidity will act counter to the CAISO asserted direction that "if the number of unsuccessful bids increases, the CRR services rate for those participants who cleared the market will be reduced." In fact EMTRI asserts that the number of bids will dramatically fall, thus significantly reducing the expected cash flow from the CRR Bid Transaction Fees and thus reducing the predictability and stability of the fees collected --- the very principles of the GMC process that CAISO is trying to uphold. Since no other ISO levies or ever levied such stratospheric CRR Bid Transaction Fees on market participants, it is impossible to find a direct parallel to this proposal in the history of ISO markets. However, ISOs experimented with different levels of bid charges on virtual transactions before converging on the current industry standards. In one example of such dramatic change ISO New England introduced previously absent, high bid charges of $0.584 on submitted virtual transactions in January 2004. As a result, the number of virtual transactions plummeted (See Fig. 2 in Sec. IV.B on p. 20 of the Report "Impact of Virtual Transactions on New England's Energy Market". The Report was submitted to and accepted by FERC	See ISO response to Mercuria Energy comments above. The study referenced by EMTRI is of virtual bidding and not CRRs. The CAISO submits that these are entirely separate vehicles and do not recognize the difference in frequency between energy bids and CRR bids.

2. Treatment of CRR's		ISO comments
	and is available at http://www.iso-ne.com/pubs/spcl_rpts/2004/virtual_transactions_report.pdf). Later the bid charges on submitted virtual transactions were reset to the level of $0.005, identical with the current Bid Segment Transaction Fee. Based on this experience alone it does not appear correct to infer future cash flows from the CRR Bid Transaction Fee based on the assumption of identical number of submitted bids prior to and after the proposed CRR Bid Transaction Fee. The proposed high CRR Bid Transaction Fee will lead to a significantly lower number of CRRs submitted with the accompanied decrease in liquidity and price discovery without the expected effect of increased cash flow from the CRR Bid Transaction Fee. This effect is not unlike the effect of tax increases that often lead to less tax collected, opposite to expectations. Here the change is dramatically amplified by going from zero CRR Bid Transaction Fee to a very high level of $1. A dramatic and not fully considered change can very well have unforeseen consequences. Such dramatic changes can certainly appear to be useful a-priori, but later become highly counter-productive. The industry standard of $0.005 strikes the right balance while increasing predictability and forecastability without the negative impact on market efficiency. EMTRI's proposed CRR Bid Transaction Fee of $0.005 will ensure continued participation, preservation of liquidity, and market price discovery in the CAISO congestion market.	
PG&E	PG&E wishes to respond to the various stakeholder comments regarding CAISO's proposed $1 per transaction fee for CRR nominations included in the CAISO's 2012 GMC rate design. PG&E reiterates its interim support of a $1 CRR nomination fee until CAISO conducts more detailed cost studies which better allocate CRR costs. PG&E would like to address stakeholder comments in order to avoid confusion or misunderstandings. **Bid Segment vs. Bid or Nomination** Stakeholders commented that IFM and convergence bids are charged $0.005. To clarify, the price unit is $0.005 per bid segment with a limit of 10 bid segments. So bids can have a maximum charge of $0.05 per bid. In contrast, CAISO CRR GMC proposal is $1 per nomination or per bid (without consideration of the number of segments). Furthermore IFM and convergence bids are accepted for 24 hours per day for each day of the month. CRR allocation tiers and auctions are divided into two time-of-use periods per month. Contrasting IFM and CRR nominations on a comparable basis, the $1 per CRR nomination is on the same order as $0.005 per bid segment. For example, to bid 100 MW into the IFM for 744 hours in any given (31 day) month would cost a minimum of: • IFM charge = 1 bid segment/hour x $0.005/bid segment x 744 hours = $3.72 To receive 100 MW CRR for 744 hours in any given (31 day) month would require two nominations: one for On Peak and one for Off Peak. • Proposed CRR GMC = 2 nominations x $1/nomination = $2.00 IFM and Convergence Bidding are Not Comparable to CRRs	Noted

2. Treatment of CRR's		ISO comments
	The analysis above shows that a $1 per nomination fee for CRR is comparable to $0.005 per bid segment for IFM and convergence bids. Beyond the dollar value comparability, PG&E finds this comparison questionable. IFM and convergence bids provide overall market efficiency benefits that partially offset associated CAISO support costs. CRRs are a completely separate market and its benefits are largely self-contained. The value of price discovery or extensive bids in the CRR auctions has limited value beyond the CRR markets. **Comments focused on the CRR Auction** The primary purpose of CRRs is to allow Load Serving Entities (LSEs), on behalf of their customers, a mechanism to hedge congestion risk. The needs and importance of the CRR 2 auction are secondary. This is evident in the order of the allocation tiers and auctions. Allocation participants are able to acquire CRRs before auctions are held. Although deep and liquid CRR auctions are desirable and beneficial, they have limited value within the context of the overall CAISO market design. A CRR auction provides a snapshot of expected congestion costs. The CRR process uses, by design, a simplified model of the IFM market. Modeling of outages, ancillary services and power flow are simplified in the CRR process. This gives limited value to CRR auction clearing prices as indicators of actual IFM congestion. This is reflected in the continued divergence of IFM congestion prices and CRR auction clearing prices. The benefits of price discovery resulting from numerous bids in the CRR auction would appear to accrue to the same limited set of bidders themselves. Even if the all auction participants equally benefit from price discovery, the concept of cost causation should require auction participants to cover their own costs. PG&E believes a nomination based charge best achieves this outcome. **Lack of Nomination-based Charges in Other RTOs** PG&E has not been able to confirm the fee structure of CRR equivalents in other RTOs. However, the lack of nomination based charges should not be a deterrent to CAISO implementing such a charge. CAISO has repeatedly asserted that the nature of California electricity markets and its own markets rules make operating the market more complex than other RTOs. PG&E can point to the complexities associated to load migration and auction credit requirements as two examples where CAISO's protocols appear to add cost and complexity to issues that are handled differently in other RTOs. These added costs need to be recovered and PG&E believes having a CRR nomination based charge is appropriate. **Nomination-based Charges are More Equitable than MW-based Charges** PG&E reiterates its stated position that MW based charges do not reflect the costs incurred by CAISO to operate and administer CRR markets. A $1 per nomination charge is a compromise position which only partially assigns charges based on incurred costs. PG&E notes that a CRR nomination (independent of MW amount) potentially incurs a range of costs beyond allocation or auction software costs. These include costs associated with credit calculation, credit holding, tracking, reporting, OASIS and settlement systems and personnel. All of these costs are independent of the MW amounts nominated or awarded. Given the	

2. Treatment of CRR's		ISO comments
	modest share a $1 nomination fee would generate as a percentage of total CRR revenue requirements, PG&E believes $1 is an appropriate (if not slightly undervalued) amount. Indeed, as more detailed cost studies are undertaken by CAISO, PG&E believes additional transaction based fees will be appropriate.	

3. Treatment of Station Power Charge		ISO comments
Dynegy	Dynegy supports the proposal to eliminate the separate station power charges. It has always been unreasonable to single out certain CAISO services with a limited number of beneficiaries for certain separately-billed charges (e.g., station power portfolio participants) but not assess separate charges for other services with a limited number of beneficiaries (e.g., CRR holders). Given that the CAISO has finally separated CRR services into its own separately billed category, it would be reasonable to continue to bill station power portfolio charges separately (assuming, of course, that all such CAISO programs with limited subsets of beneficiaries are so treated), but, given the CAISO's representation that these charges are de minimus, Dynegy supports eliminating the separate billing for them.	Noted

4. Treatment of PIRP Charge		ISO comments
Dynegy	Dynegy supports resolving the issues regarding the PIRP forecasting fee in the RIMPR stakeholder process rather than in the GMC process.	Noted
CalWea, LSA, Vote Solar Initiative and the Solar Alliance	After talking to the various renewable organizations about the GMC proposal, and reviewing the latest submitted stakeholder comments, we are going to save some $ by not submitting comments in this round and just authorizing you to say that CalWEA, LSA, Vote Solar Initiative, and the Solar Alliance are all in support of the latest GMC proposal, primarily because of its elimination of charges based on deviations from forward schedules. So, you can put that (or mention it) in your Board briefing this week.	Noted

5. Treatment of SMCR Charge		ISO comments
Dynegy	As Dynegy understands, the $1,000/month SCID fee is intended to ensure that market participants have some "skin in the game" in terms of covering the CAISO's overhead to provide client services. It does not seem inevitable that the CAISO would incur no support cost for a market participant who may have no market volume in that month. That market participant could still be using services from their account representative even if they had no market volume. The CAISO's proposal to waive the SCID fee if the market participant has no market volume may bear further refinement to account for all of the costs the CAISO may incur to provide services to that market participant.	CAISO believes that the determinants developed will catch most if not all activity. It is a low probability that a participant will have significant services and no charges.

6. Treatment of Transmission Ownership Rights (TORs)		ISO comments
SDG&E	The CAISO's latest GMC proposal presented on January 20, 2011, now includes distinct treatment for TORs. SDG&E believes this proposal more closely reflects cost causation, one of the guiding principles of this 2012 Grid Management Charge Initiative. SDG&E appreciates the CAISO's efforts in responding to our concerns related to the TOR issue.	Noted

6. Treatment of Transmission Ownership Rights (TORs)		ISO comments
CCSF	CCSF has actively monitored the stakeholder process examining the CAISO's 2012 GMC proposal and supports the Comments submitted by the Modesto Irrigation District on November 24, 2010 addressing treatment of TORs. The latest CAISO proposal (January 20, 2011 Presentation at page 7) setting forth changes from the initial Straw Proposal now excludes TOR transactions from application of any Market Operations charges. Further, it proposes to continue the current discounted rate to TOR holders in recognition of the reduced impact that transactions utilizing TORs have on the CAISO-controlled Grid. As such, the CAISO proposes to continue the discounted rate in its application of System Operations Charges to transaction utilizing TORs. CCSF strongly supports these proposals. The current discounted rate for TOR transactions appropriately recognizes the lesser impact of TOR transactions on Core Reliability Services as compared to those utilizing the CAISO-controlled grid facilities. Recognition that TOR transactions have less impact on CAISO operations gave rise to the current discounted rate. Accordingly, the TOR credit appropriately applies cost causation principles to the new GMC design and should continue for the term of the new GMC.	Noted
SCE	SCE is supportive of the proposed treatment of TORs and the proposed revenue requirement cap. It is appropriate to assess a lower GMC to TORs to reflect the limited services that TORs require from the ISO. SCE is also in agreement with the ISO on the proposed mechanics of assessing the GMC to TORs, by not assessing a Market Services charge and assessing the System Operations charge based on the minimum of supply or demand MWhs of energy.	Noted
Dynegy	While Dynegy understands the CAISO's rationale for proposing to exclude Transmission Ownership Rights from the Market Services Charge, Dynegy questions why the CAISO is proposing to allocate the System Operations charge on the minimum of the supply or demand MWh. If Dynegy understands the CAISO's initial proposal, both supply and demand will be assessed the System operations charge. As noted in the CAISO's initial proposal at page 7: The system operations category includes all flow quantities for generation, load, imports and exports (additional detail below). The fundamental purpose of system operations is to reliably balance supply and demand. Since both components (load and generation) are necessary to achieve balance, the ISO believes gross MWh is also appropriate for system operations. TORs would be provided a discount by excluding them from the Market Services Charge. They would be provided a second discount by assessing the System Operations charge on the basis of either supply, or demand, but not both. These two discounts seem reasonable in light of the reduced level of services that TORs require from the CAISO. However, it seems unnecessary to offer a third discount by assessing the System Operations charge on the minimum of supply or demand TOR MWh. Assessing the System Operation Charge on the maximum of supply or demand seems a more reasonable approach.	The confusion is that this method discounts TORs at 50% of the volume. For source to sink TORs the rate is assessed on 50% of the MWs. On source or sink only the TOR portion is excluded but the other side of the flow is assessed at the full 100% rate resulting in an overall 50% rate on the source to sink path. Thus there are only two discounts.

7. Phase in Approach		ISO comments
SCE	SCE opposes the phase in of the System Operations charge to supply. The ISO has proposed to assess the System Operations charge to both supply and load based on its determination that both supply and load contribute to the ISO's incurrence of costs allocated to the System Operations charge. From a cost causation perspective then, this System Operations charge should be assessed to supply and load on an equivalent basis without delay.	In response to stakeholder concerns, the CAISO has dropped the phase in proposal and is proposing instead a grandfathering of a few specific contracts. This revision was presented during the February 8, 2011 conference call.
PG&E	PG&E believes that the exemption from the System Operations MWh charge for 2/3 of supply minutes in the first year and 1/3 of supply minutes in the second year is overly broad and does not address the more narrow concerns expressed by certain generators. Second, the exemption of supply minutes in years 1 and 2 shifts too much of the GMC cost recovery responsibility to demand and thus to IOUs such as PG&E. The CAISO's initial GMC proposal was developed based on cost-causation principles. By contrast, the substantial, two-year GMC premium that PG&E would pay under the modified proposal is not cost-based and is unreasonable.	See ISO response to SCE above
Dynegy	First, as with other market participants, Dynegy's perspective on the CAISO's GMC is influenced by the bottom- line reality of how much it will have to pay. The initial bill impact data provided by the CAISO suggests that Dynegy is not as disadvantaged by the CAISO's proposal to fundamentally restructure its GMC as are other suppliers. Moreover, the CAISO's proposal to phase in assessing the System Operations charge to supply MWh over a three year basis greatly mitigates the impacts on Dynegy over that three-year phase-in period. On those bases, Dynegy does not object to the CAISO's proposed modifications. Dynegy understands that the holders of long-term contracts executed under the current GMC structure may be disadvantaged by being exposed to new GMC charges without a means to pass such charges along, and looks forward to further discussions about mitigating the impacts of the proposed new GMC structure on such market participants.	See ISO response to SCE above

8. Revenue Requirement Cap Proposal		ISO comments
CMUA	The California Municipal Utilities Association is pleased to have the opportunity to provide comments on the California Independent System Operator Corporation's ("CAISO") proposal for revisions to its Grid Management Charge ("GMC"), targeted to become effective January 1, 2012. At the outset, CMUA applauds the CAISO's ability, in recent years and under current leadership, to control expenditures and hence the GMC. CMUA does not believe the CAISO to be a profligate spender, and no concerns expressed herein should be thus interpreted. Nevertheless, the CAISO budget must reflect the times, and the current CAISO proposal does not.	The CAISO recognizes many of the stakeholders concerns over a long term rate ceiling with all the uncertainties facing the state, the industry and public power agencies. In that light the proposal will be cut back to three years which coincides with the retirement of the 2008

8. Revenue Requirement Cap Proposal		ISO comments
	CMUA is concerned about the structure and duration of the CAISO's revenue requirement cap that would go into effect January 1, 2012, and last for five years, increasing one percent per year. Under the CAISO's proposal, the cap which the CAISO could not exceed without filing cost justification at the Federal Energy Regulatory Commission ("FERC") would increase from $197 million in calendar year 2012 to approximately $205 million in calendar year 2016. The CAISO must view this proposal in light of continuing developments in the electric industry, of which the CAISO is a part. The economic downturn has significantly reduced electricity consumption and hence market volumes. CMUA members are reflecting these trends in their own revenue numbers. Moreover, there is no consensus, and quite a bit of skepticism, that historical load growth trends will return in the near future, or ever. This is because of fundamental changes to the California economy caused by the downturn, including the closure or permanent departure of significant large-load customers. Further, aggressive state-wide energy efficiency programs have the effect of lowering demand over the longer term. In this environment, CMUA cannot support a built-in increase in the revenue requirement cap. While CMUA understands that the CAISO intends to budget below the revenue requirement cap, and has made efforts to do so in the past, an escalating cap flies in the face of budget cutting in virtually every other sector of the industry and the state. The CAISO must be cognizant of this fact, and reflect it in its own budget process. CMUA is also concerned about the five-year locked in period in which parties would be forced to file a complaint at FERC to seek modifications to the GMC. With the significant financial milestone of 2008 Series bonds being retired within three years, proposing an increase over that period is counterintuitive and erodes the credibility and accountability of the budget process. CMUA members agree that some certainty with respect to the CAISO GMC in future periods is valuable. Also, mechanisms to decrease administrative and legal costs associated with preparation and examination of the proposed GMC are also valuable. CMUA does not object in principle for a revenue requirement cap of some duration, and one that reflects the retirement of the 2008 Series bonds. CMUA urges the CAISO to not proceed with its current 5-year, fixed escalator revenue requirement cap, which does not reflect the economic and industry environment in which the CAISO is operating, and erodes the credibility and accountability in budgeting that the CAISO has garnered over the last several years. Let's not return to the "old days" where the GMC was a major point of contention between the CAISO and those serving load through CAISO markets.	bonds and at which time stakeholders will be better informed about the future state of the economy. Additionally a percentage escalator appears unacceptable. As pointed out in the comments to MID in 8a below, the CAISO believes it will need a modest rise in the ceiling after 6 years at the current level. The ISO's revised request is for a 3 year cap with the existing level of $197 million for 2012 and a $2 million increase to $199 million for 2013 and 2014.
City of Santa Clara	SVP echoes other stakeholders' concerns that: (1) the five-year term is too long, as it does not adequately account for the uncertainty in level of expenses when debt service for MRTU is retired in 2014; and (2) the one percent-per year escalator is unjustified, particularly given the continued downturn in the economy.	See ISO response to CMUA

8. Revenue Requirement Cap Proposal		ISO comments
Modesto Irrigation District (MID)	MID is skeptical of and opposes the CAISO's revenue requirement cap proposal. MID's first objection goes to the built-in increases in revenue requirement. While MID understands that the CAISO intends to budget below the revenue requirement cap, and has made efforts to do so in the past, by proposing a one percent-per year increase, the CAISO signals that it does intend to spend up to the limit in place for a particular year. California's economy remains in a state that should dictate that increases in revenue requirement should be avoided whenever possible. The CAISO should make consideration of the consumer even more of a priority in this economic climate. While there have been some economic indicators that suggest some cause for optimism, it is premature to predict that the economy will improve significantly in the next couple years. California's unemployment rate increased to 12.5 percent in December, 2010. The rate for Stanislaus County, where MID is located, is higher, at 17.6 percent. (Employment Development Department, State of California – http://www.edd.ca.gov/About_EDD/pdf/urate201101.pdf). This figure does not include the underemployed. California is the third worst state in the nation in foreclosure rates, behind only Nevada and Arizona. One in every 203 housing units received a foreclosure filing in December, 2010 in California. (http://www.realtytrac.com/trendcenter/). The rate in Stanislaus County is worse, at 1 in every 104 housing units. (http://www.realtytrac.com/trendcenter/ca-trend.html). On top of those concerns, state and local budgetary issues remain far from resolved, and the impact of future cuts has not been reflected in the economy. Likewise, it is premature to project that trading volumes will increase measurably in the next couple years. Similarly, predicting significant load growth in the state is premature at this time. If trade volumes do not increase, it would be difficult to maintain GMC rates at an average $0.80/MWh level. If the economy does improve, and the CAISO's administrative costs increase, the CAISO would not be precluded from proposing a new revenue requirement at FERC to justify such costs. However, as evidenced by the Midwest Independent System Operator's ("MISO's") "rolled in" rates, if the economy does improve and California's load does increase, that should not necessarily merit an increase in costs for the CAISO. (MISO's "rolled in" administrative costs rate is approximately $0.40/MWh of load serving approximately double the load of the CAISO. (2010 ISO/RTO Metrics Report at p. 190 – http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3003829518EBD%7D/2010%20ISORTO%20Metrics%20Report.pdf)). When one extends the range covered by the proposal to four to five years, as the CAISO has done, projections regarding the economy and trading volumes become even more tenuous. A five year revenue requirement proposal, with a built-in escalator is problematic for other reasons. With the significant financial milestone of MRTU debt being retired within three years, maintaining a steady, revenue requirement increase is counterintuitive. MRTU is still relatively new, and the administrative costs of the CAISO in managing the grid are unpredictable at this point. The amount of enhancements to MRTU over the next five years is unpredictable. While some enhancements could be ordered by FERC or be seen as necessary, others are discretionary or leave room for flexibility, and the CAISO does not have to pursue each enhancement suggested by stakeholders. An example of an enhancement that was postponed was the initiative to further disaggregate the locational prices paid by load. This was an enhancement that FERC wanted within three years of the implementation of MRTU. However, with a majority of stakeholder	See ISO response to CMUA

8. Revenue Requirement Cap Proposal		ISO comments
	approval, the CAISO has asked FERC to further delay this enhancement requirement. As a compromise proposal, MID would not object to a three-year revenue requirement proposal with no percent escalator to the present cap. Such a proposal is a significant departure from MID's position voiced earlier in this process that traditional cost-of-service rate filings under Federal Power Act Section 205 are the appropriate means for gaining regulatory approval of the GMC.1 MID believes that Section 205 filings provide better protections for the consumer, as the burden is on the filing utility to show the proposed rate is just and reasonable, as opposed to a Section 206 complaint, where the burden is placed on the complainant to show that a rate is or has become unjust and unreasonable, and the expense and initiative is placed on the complainant for raising the concerns. A three-year limit would give the CAISO the opportunity to review the landscape after the retirement of MRTU debt and decide on a revenue requirement proposal that matches contemporary data. Further, if the CAISO finds, for example, in year two, that it is directed to implement a market enhancement, the revenue requirement cap would not preclude the CAISO from filing at FERC for recovery of a revenue requirement that would pay for the market enhancement.2 A slower, deliberate approach is consistent with the way the CAISO treated load granularity, and would be beneficial to the consumers of the CAISO's services when it comes to CAISO administrative costs. For these reasons, MID supports a more deliberate approach concerning the CAISO's revenue requirement.	
CPUC	**<u>The 1% increase of the revenue requirement cap should not be considered in the GMC 2012 stakeholder process</u>** The CAISO started the GMC 2012 stakeholder process on April 2010. At that time, the CAISO didn't bring up the proposed 1% annual increase of the revenue requirement cap (RRC) for 2012 to 2016. Only now, at the end of the stakeholder process, has CAISO raised this issue. The CAISO and the stakeholders should have more time to work on this, and, given the tight timeline, this issue should be parked for future consideration. The CAISO has proposed a 1% increase of the RRC every year from 2012 to 2016, and also to waive the 205 filing requirements during the same time period. With economic uncertainties in California in the future (six years look ahead), the CPUC staff does not believe that the CAISO should be granted the flexibility to spend this additional customer money without proper vetting by stakeholders. This proposal is premature and the 1% increase of the RRC should not be included in this stakeholder process. **<u>The $197 million revenue requirement cap is sufficient for year 2012</u>** The CAISO has asserted that the driver for the 1% increase of the RRC is mainly due to forecasted salary and benefit increases for its employees. However, with the current downturn of the economy many private businesses are facing employee layoffs and salary and benefit decreases. California's budgetary crisis speaks for itself. In this economic climate, it is difficult to see the rationale for increasing the salaries and benefits for the CAISO's employees. Looking ahead on a six-year time frame, what is the CAISO's confidence level in asserting the need of a 1% increase in the RRC? Did the CAISO conduct any studies or analysis to arrive at this number? If so, it would be helpful to share this information with stakeholders. The original $195 million RRC was an outcome of the 2004 GMC settlement and reflected stakeholder concerns over a perceived lack of budget control at the CAISO. Later, in response to MRTU development costs, the CAISO	See ISO response to CMUA

8. Revenue Requirement Cap Proposal		ISO comments
	proposed to increase the RRC from $195 million to $197 million in 2006. The CPUC staff commends the performance of CAISO in implementing the MRTU and understands that RRC increases were necessary to support start up efforts. However, it is unclear why RRC increases are needed going forward. The CAISO acknowledges that it does not need the same level of funding in developing market products and services as it did for MRTU development in past years. Therefore, it should be expected that the CAISO could operate under a smaller annual budget. The existing RRC of $197 million should be more than sufficient through 2012. Beyond 2012, the CAISO could submit a 205 filing to either extend the RRC, or to modify the RRC to reflect budget requirements at that time.	
SCE	The revenue requirement cap of $197 million in 2012, increasing at 1% per year for five years through 2016 is reasonable and SCE supports it. This cap provision provides that as long as the ISO maintains a revenue requirement under the cap in a given year, the ISO will not be required to submit its annual GMC under a Section 205 filing to the Commission. The ISO would have to make a 205 filing for a revised GMC effective January 1, 2017.	Noted
PG&E	PG&E supports the CAISO's proposal to increase its revenue requirement cap by 1% per year over the period 2012 to 2016. The cap, currently set at $197 million, provides a strong incentive for the CAISO to limit annual revenue requirement increases. If the CAISO exceeds the cap, it is required to make a full Section 205 cost of service filing with the Federal Energy Regulatory Commission to support its revenue increase. PG&E believes that the 1% annual escalation of the revenue requirement cap beginning in 2013 is reasonable and will obviate the need for the CAISO and Stakeholders to address this issue again until 2016.	Noted
Dynegy	Dynegy supports a revenue requirement cap but notes that the CAISO's proposal to allow for 1% increases would allow the revenue requirement to increase $8 million by 2016. Said another way, a 1% annual cap sounds very attractive – until one realizes that it could result in an $8 million increase over the proposed effective period. Dynegy looks forward to further discussion on this topic.	See ISO response to CMUA

8a.	Questions on Revenue Requirement Cap proposal by Sean Neal representing MID	ISO Response
1	There have been discussions on several occasions of retiring debt service to fund MRTU, the new building and other matters. a) Is it true that service of debt issued as of this date will be retired by 1Q 2014? If so, how much?	No. MRTU debt (i.e. 2008 bonds) will be paid off in the first quarter of 2014. The 2009 bonds issued to construct the ISO's new facility are 30 year bonds and will not be retired until the 1st quarter of 2039.
2	After current debt service is retired, is it the CAISO's intention not to take out more debt?	As noted in 1 above, the building debt is not retired until 2039. There are no financing plans during the revenue cap period of 2012-2016, other than to refinance the building debt if rates are favorable at the end of five years in 2014,

Responses to Stakeholder Comments on GMC 2012 Bill Comparison stakeholder call January 13, 2011

8a.	Questions on Revenue Requirement Cap proposal by Sean Neal representing MID	ISO Response
3	After current debt service is retired, is the CAISO intending to fund capital additions out of current budget (i.e., cash?). a) Is the CAISO doing so now? If the CAISO is doing so now, are capital additions funding projected to increase after debt service is retired? b) Are there any specific capital additions planned in the 2012-2014 time frame? c) For the 2015-2016 time frame?	When the existing bond funds are exhausted the CAISO intends to fund capital from out of pocket funds in the current revenue requirement. a) There are out of pocket funds available currently that the CAISO is utilizing. The revenue requirement proposals use capital project budgets of $23.5M in 2012, $20M in 2013 and $15M annually thereafter. b) And c) see answer to question 5 below. The 2011 budget document at the following .url lists projects under consideration that may occur in 2012 or later. http://www.caiso.com/2866/286671ed37f90.pdf
4	Has the CAISO projected the costs of renewable integration efforts? a) Does the CAISO know how many employees it will need to hire to meet the needs of this program?	No. The FTE level remains the same through the revenue cap period of 2012-2016 at 601 FTEs. a) It is initially thought to utilize existing positions but long term the FTE impact is not known.
5	Are there specific market enhancements proposed by stakeholders that have been proposed that would create capital costs for the CAISO that the CAISO is considering adopting? If so, what?	Yes, there are on-going stakeholder processes on market initiatives and enhancements. See web site at the following links Current initiatives: http://www.caiso.com/docs/2005/06/09/2005060910374912494.html Release planning: http://www.caiso.com/271e/271ea81869a90.html Market initiatives roadmap http://www.caiso.com/280d/280de3ee50bd0.html
6	Are salaries projected to increase over the next five years? If so, at what rate?	Total employee costs including burden are forecast to rise by 3% annually through the revenue cap period of 2012-2016
7	Is funding for employee benefits projected to increase over the next five years? a) If so, has the CAISO quantified by how much or at what rate?	Benefits are included in the 3% growth discussed above in #7. Health care and retiree health care costs could be substantially more than projected. The CAISO intends to keep its budgeted revenue requirement beneath the ceiling. If unforeseen costs threaten to drive the revenue requirement over the cap, a 205 filing would be required unless stakeholders agreed otherwise.
8	Has the CAISO seen any indicators that transaction volumes will increase over the year or several years?	Yes, this year's volume is coming back to pre-recession volumes so a 1% growth seems appropriate. That rate is the same growth rate we are proposing for the revenue requirement cap.

8a.	Questions on Revenue Requirement Cap proposal by Sean Neal representing MID	ISO Response
	a) What is the status of the centralized capacity market initiative and how will that be expected to affect transaction volumes?	a) There is no such initiative at present. The likely increase in volumes from such a market would be addressed as part of that initiative.

Exhibit No. ISO-15 –

Stakeholder Comments and ISO Response

on February 8, 2011 call on GMC Grandfathering

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

California ISO
Shaping a Renewed Future

Responses to Stakeholder Comments on February 8, 2011 call on GMC Grandfathering

Comments on proposal to grandfather certain generation units form system operations charges		ISO comments
Calpine	On a conference call Tuesday, February 8, 2011, the CAISO proposed a grandfathering of certain contracts in order to mitigate the substantial bill impacts of its primary proposal to reform the GMC cost allocation. Calpine supports the grandfathering in both concept and implementation. <u>CAISO Proposal</u> The CAISO has proposed that certain pre-existing contracts pay a reduced GMC for the remaining term of the contract. Specifically, the CAISO limits the contracts to those with the following characteristics: 1. remaining terms of 3 years or longer on 1/1/11 2. the generator is the SC, and 3. Where an officer of the Company will attest to the inability to recover incremental GMC costs. <u>The Proposed Criteria are Appropriately Narrow</u> The criteria proposed by the CAISO narrowly circumscribe the pre-existing contracts that will be most directly impacted by the GMC cost allocation change. Indeed, the criteria identify contracts in which the GMC charge increases would be "trapped" with the supplier. Based on the CAISO's analysis, there are only 5 contracts that would qualify for the exemption. <u>The Rate Impacts of the Proposal are not Material on Others</u> Given the narrowly prescribed exemption, it appears that between 3 and 7 Twh (1.5 percent) of energy will be grandfathered. This will cause a slight reallocation of costs which in which all transactions share, including non-grandfathered transactions by the SC representing the grandfathered contracts. <u>The GMC Costs of Grandfathered Contracts Still Increase Substantially</u> The grandfathered contracts will still be obligated to pay the Market Service rate on all volumes. Calpine estimates that these charges, alone, will double the exposure to GMC costs for the grandfathered contracts when compared with actual GMC costs today. <u>The Impact of the GMC Change was Not Reasonably Foreseeable</u> Calpine agrees that by negotiating term contracts, parties must envision and assume reasonable risk. Small changes in assumptions can be and are reasonably foreseen and included in commercial trade. However, in the case of GMC, no reasonable party would have expected the dramatic shift in cost allocation proposed by the CAISO, a shift that increases exposure to some contracts by as much as 1000 percent.	Noted

Comments on proposal to grandfather certain generation units form system operations charges		ISO comments
SCE	SCE is opposed to a grandfathering of certain suppliers so that their supply would not be assessed the System Operations charge for a certain amount of time. SCE has previously stated its opposition to a phase in of the assessment of the System Operations charge to supply. SCE has been supportive of the overall proposed new GMC structure, with its goals of simplification and cost causation, even though SCE will pay more under the proposed new GMC rate structure than under the current GMC rate structure. A phase in or grandfathering provision is in SCE's view unwarranted for the following reasons: 1. A grandfathering would blunt the cost causation effect of the new GMC rate structure. A major goal of the ISO in proposing the new GMC rate structure is that the charges to market participants reflect costs imposed by those market participants on the ISO. Waiving a charge that is cost-justified is clearly counter to that goal. 2. Grandfathering (or phasing in) results in costs that must be borne by others. Since the ISO's revenue requirement must be collected in total from market participants, any amount waived for one market participant must be collected from other market participants. Some of these market participants, as is the case with SCE, would already pay more under the proposed new GMC rate structure than under the current GMC. 3. The GMC rate structure has never been guaranteed to remain static. In fact, there have been two previous major redesigns of the GMC since the inception of the ISO. Market participants should anticipate this possibility in their contracting. In the most recent document "Modification to 2012 GMC Straw Proposal Grandfathering Provision", issued February 8, the ISO proposes certain criteria whereby a supplier may qualify for grandfathering. A grandfathered supplier would then be exempt from the System Operations charge until the underlying contract that the supplier has to sell its power expires, or reaches a point of renegotiation. The ISO lists six criteria that are intended to limit grandfathering, without opening up the grandfathering exemption to undeserving suppliers. SCE is concerned that additional suppliers may qualify for grandfathering that are not really deserving of the exemption, despite the ISO's best efforts to limit the qualification through these six criteria. In SCE's view, the complexity of determining which suppliers should qualify for grandfathering is yet another reason why grandfathering should not be considered. SCE urges the ISO to consider additional alternatives to the grandfathering proposal set forth in the "Modifications to 2012 GMC Straw Proposal Grandfathering Provision" prior to seeking Board approval of the GMC.	The ISO appreciates Edison's comments regarding the grandfathering proposal. Similar to the recent design change for the Market Usage-Forward Energy (MUFE), the ISO has proposed the contract grandfathering criteria to mitigate the impact of cost shifts associated with the proposed three bucket design. The ISO initially proposed a more broad based transition plan that would have been applied to all suppliers, but that proposal was overwhelmingly rejected by both suppliers and load serving entities. After further discussion with suppliers, the ISO determined the number of supply contracts that will be severely impacted by the new design are very limited in scope. The ISO recognizes SCE's assessment that grandfathering does not align with cost causation principles and could result in additional cost shifts to others that may also be facing cost increases. In addition, the ISO acknowledges SCE's point that market participants should factor future changes to GMC during contract negotiations. However, the ISO is also aware of the regulatory uncertainties associated with a GMC design that results in significant cost shifts to entities that are unable to recover the costs. The ISO believes that the grandfathering proposal is a reasonable compromise that achieves the goal of reasonable mitigation with minimal cost-shifting, and that the proposed grandfathering criteria achieve the rate impact mitigation goal. SCE urged the ISO to consider additional alternatives, but there have been no other alternatives proposed through the stakeholder process.

Comments on proposal to grandfather certain generation units form system operations charges		ISO comments
PG&E	PG&E supports adding the CAISO's proposed grandfathering provision to the 2012 GMC rate design straw proposal. By exempting generating units that meet a set of limited, specific criteria from the proposed MWh-based System Operations charge, the CAISO has addressed the concerns expressed by certain Stakeholders without broadly departing from its cost-based rate design principles. PG&E understands that, by proposing the grandfathering compromise, the CAISO seeks to limit or eliminate the issues FERC must resolve when the CAISO makes its 2012 GMC filing, and PG&E supports this aim.	Noted
Powerex	Powerex appreciates the opportunity to provide these brief comments on the CAISO's 2012 GMC Straw Proposal Grandfathering Provision. Based on the information provided to Powerex by the CAISO, Powerex believes that the grandfathering provision is a reasonable compromise to mitigate the rate impact from the 2012 GMC Straw Proposal for the limited number of contracts that do not have the ability to flow through the additional GMC costs. Powerex's acceptance of the grandfathering provision and the associated criteria is based on the information provided by the CAISO in regards to the volume of energy that would be grandfathered from the 2012 GMC rates. However, Powerex is concerned about the length of the grandfathering provision. The data provided to Powerex shows that certain units would be grandfathered through 2021. Powerex's concerns on the length of the grandfathering provision are fairly minor based on the volumes provided but Powerex suggests that if the volume of energy subject to grandfathering increases significantly, the CAISO should limit the length of time for the grandfathering (perhaps to a maximum of three to five years) or phase out the volume of energy eligible for grandfathering over a reasonable period of time.	Noted- There have been no additional contracts submitted to date by generators.
Midway Sunset	Midway Sunset strongly supports the grandfathering proposal the ISO has suggested.	Noted
DC Energy	DC Energy appreciates the ability to present these limited comments on the proposed modification to the 2012 Grid Management Charge Straw Proposal Grandfathering Provision as presented on the February 8th Stakeholder Call. DC Energy does not oppose the grandfathering provision presented, however there was one alternative suggested that DC Energy does oppose. Specifically the grandfathering proposal would exempt a limited number of generating units (that meet specific/limited criteria) from the System Operations charge until the first opportunity to renegotiate the contract or until the contract expiration. DC Energy is not a generation owner and does not benefit from this proposed modification. DC Energy agrees with the CAISO determination that the affect on the remaining participants that pay the	The grandfathering proposal is only applicable to the systems operations charge and no others.

Comments on proposal to grandfather certain generation units form system operations charges		ISO comments
	System Operations charge will be extremely small compared to the extremely large impact that would be placed on a small number of participants and therefore does not oppose this limited exemption. One participant on the call suggested that the amount of dollars that result from this exemption should be spread across all market participants. DC Energy opposes such socialization as it is contrary to cost causation principles that CAISO has determined an important principle in this cost allocation re-design and would further impact the large increase that certain participants (i.e., CRR holders) are absorbing with the 2012 GMC structure.	

Exhibit No. ISO-16 –

Stakeholder Comments and ISO Response

on February 22, 2011 call on the GMC Draft Final Proposal

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011

Responses to Stakeholder Comments on February 22 2011 call on the GMC Draft Final Proposal

Comments on general design		ISO comments
Powerex	Powerex believes the CAISO's GMC proposal meets with the Policy and Ratemaking Principles expressed by the CAISO at the start of this process. Powerex especially supports the cost causation principle used to set rates and believes the design process led to rates that are transparent, predictable, and simple.	Noted

Comments on proposal to grandfather certain generation units form system operations charges		ISO comments
Calpine	Calpine's comments throughout this GMC stakeholder process have been critical of the policy proposal of charging GMC costs indirectly to suppliers rather than charging them directly to load. The CAISO theory that all prices will rise – and therefore leave suppliers financially unaffected – is questionable and particularly flawed as it relates to certain pre-existing contracts. Calpine has, and continues to support the modification to the CAISO's proposal which addresses the pre-existing contract flaw. In comments submitted on February 11, Calpine highlighted and explained its support for grandfathering under the following headings: • The Proposed Criteria are Appropriately Narrow • The Rate Impacts of the Proposal are not Material on Others • The GMC Costs of Grandfathered Contracts Still Increase Substantially • The Impact of the GMC Change was Not Reasonably Foreseeable	Noted
Powerex	Furthermore, Powerex supports the grandfathering proposal as a useful transition for a certain number of limited generation contracts that mitigates the rate impact of the GMC re-design since parties could not have reasonably predicted the impact of this rate design on those contracts.	Noted
SCE	Southern California Edison ("SCE") submits these comments in response to the "2012 GMC Draft Final Proposal" dated February 22, 2011. SCE supports the proposed GMC rate structure as set forth in the proposal, with one exception. As SCE has stated in previous comments (see SCE's February 11 comments), SCE is opposed to the proposed grandfathering provision. If ISO management does decide to bring a grandfathering proposal to the Board for approval, SCE would urge the ISO to consider adding an additional limit: grandfathering should be limited to two years (2012 and 2013). An open-ended grandfathering provision (limited only by the contract expiration or "first opportunity for renegotiation") is in SCE's view unwarranted.	Noted - There have been no additional contracts submitted to date by generators.

Comments on proposal to exclude MSS load following instructed imbalance from Market services		ISO comments
NCPA	Northern California Power Agency ("NCPA") provides the following comments regarding CAISO's 2012 GMC Draft Final Proposal dated February 15, 2011. NCPA supports CAISO's determination that it is appropriate to exclude MSS Load Following instructed imbalance energy from the Market Services GMC charge. NCPA also supports CAISO's proposal to eliminate the three-year phase-in for the application of the System Operations charge to supply energy flows from the draft final proposal.	noted

Comments on CRR auction bid fee of $1		ISO comments
Mercuria	We are writing in response to the 2012 GMC Draft Final Proposal, specifically regarding the proposed CRR bid transaction fees. We have in the past twice submitted written comments objecting to the current proposed the scheme and would like to do so again.	The ISO believes that a bid/nomination fee is appropriate for the CRR cost category. Market participants that submit bids/nominations and are

Comments on CRR auction bid fee of $1		ISO comments
	First, we believe that during the stakeholder process, there were sufficient objections to the proposed CRR bid charges in the form of $1 flat rate CRR Bid Transaction Fees. However, we feel that the ISO didn't seem to take into sufficient consideration of the concerns raised by various stakeholders but rather chose to maintain the initial proposed scheme. We believe since it impacts the financials of all CRR market participants, especially the financial participants; it is prudent to take into consideration of all the concerns of and objections to the proposed fee structure, and not to rush to finalize the proposal. Also, as we emphasized in the previous correspondences with the ISO regarding this issue, we strongly feel that the current fee structure does not reflect the true cost burdens born by various CRR market participants proportionally and thus creates additional disincentives for financial players to actively participate in the CRR market and to provide necessary liquidity and price discovery. It therefore in the long run hurts the healthy development of the CRR market and all the market participants involved. Based on the abovementioned reasons, we strongly urge the ISO to reconsider the proposal before finalization and continue to balance the interests of different market participants to arrive at an equitable solution that is acceptable to all.	unsuccessful in clearing the market are participating in the CRR market and should cover a portion of the costs. The bid fee collects approximately 7% of the total cost category. Any decrease in the bid/nomination fee rate will result is an increase per MWh rate. The comparison to the bid fee rate for the market services cost category is not analogous. Energy bids are submitted on an hourly basis, whereas the lowest granularity for the CRR market is monthly. The bid/nomination fee and proposed rate is supported by the majority of CRR holders based upon MW.
EMTRI	Summary: The Draft Final Proposal for the 2012 Grid Management Charge (GMC) Stakeholder Process ignores the majority of stakeholders who commented at the different stages of the Process about the necessity to change or eliminate the proposed $1 CRR Bid Transaction Fees. In its current form, the Draft Final Proposal jeopardizes market efficiency and liquidity of the CAISO CRR market without bringing any predictable benefits. We continue to advocate the industry standard level of $0.005 CRR Bid Transaction Fee by the proper adoption of Bid Segment Transaction Fee for energy and convergence bids for CRR market. EMTRI continues to strongly believe that the proposed by CAISO arbitrary $1 CRR Bid Transaction Fee is excessive and unjustifiable. EMTRI also continues to recommend a $0.005 CRR Bid Transaction Fee by the proper adoption of Bid Segment Transaction Fee for energy and convergence bids instead. In its Draft Final Proposal on p. 17 CAISO provided the calculation that attempts to state the equivalence of the proposed $1 CRR Bid Transaction Fee and $0.005 Bid Segment Transaction Fee for energy and convergence bids. The problem with this argument comes from scaling $0.005 bid fees by the number of hours in a month for CRR Bid Transaction Fee. Such scaling is not appropriate for the following reasons. In the IFM, participants submit bids on an hourly granularity and CAISO needs to resolve each hour separately and then all hours together in order to come up with an hourly price as a part of unit commitment and dispatch process. The energy and convergence bids require the daily auction accompanied by RUC and then real-time process every day of the month / year. In contrast, there is no such variation across hours in the CRR market, just the two times-of-use (TOUs) which should be treated	See comments to Mercuria above and EMMT and DC Energy below. See also PG&E comments earlier that argued in favor of a $1 fee. EMTRI appears to attempt to draw similarities between the bidding and allocation structure proposed for CRRs and the per segment bid fee proposed for convergence bids or energy bids. The ISO has studied the two proposed fee structures and believes the differentiation is appropriate and justified as explained in the previous response to Mercuria and for the reason noted below. In addition, it should be highlighted that the energy bid fee is applied to both convergence bidding and physical bids. Using a $0.005 per bid segment fee will result in approximately $2,500 in revenue collection from CRR bid/nomination fees. $2,500 revenue

Comments on CRR auction bid fee of $1		ISO comments
	distinctly. One cannot bid each CRR hour separately and CAISO does not need to solve for each hour of a CRR. The CRR price does not vary across hours within each time of use and it is as easy to solve for an hour as it is for entire TOU as all hours within a time-of-use are identical. The proper application of bid fee is per bid block – per time-of-use in the CRR case which takes into account a very different reality of the CRR and energy markets. The hours-scaling argument, while trying to back-engineer the original CAISO-proposed $1 CRR Bid Transaction Fee, does not appear to be critically examined. The entire argument is copied essentially verbatim from the recent comments of the only market participant who specifically argued in support of $1 CRR Bid LST UPDT: 10/7/10 - Final Page 2 ISO/Created by FINANCE Transaction Fee. EMTRI continues to propose the true equalization of the IFM Bid Segment Transaction Fee and the CRR Bid Transaction Fee by charging $0.005 per bid segment per time-of-use. This would also bring the proposed CRR Bid Transaction Fee in line with industry standards. When CAISO designed its Bid Segment Transaction Fee of $0.005, it used the benchmarks of other ISOs and the outcome of the Convergence Bidding stakeholder process to set this Fee. It was a good and rational choice based on careful considerations. On p. 16 of Draft Final Proposal CAISO noted that the charge of $0.005 "does not represent a significant expense to market participants under typical scheduling practices, but is enough to deter the submission of excessive bid volumes." The proposed CRR Bid Transaction Fee of $1 appears arbitrary by this measure and considerations. No other ISO levies such a high charge. Majority of stakeholders who spoke on the issue of CRR Bid Transaction Fee spoke against the proposed $1 CRR Bid Transaction Fee and in favor of the more equitable $0.005 or similar bid fee. Unfortunately, their opinions and suggestions on this particular issue appear to have been disregarded. The adoption of high $1 CRR Bid Transaction Fees will cause the market disruption by significantly reducing the volume of submitted bids and thus drastically reducing liquidity, price discovery, and market efficiency to adequately price transmission. FERC uses impact of tariff charges on liquidity, price discovery, and market efficiency when reviewing requests for tariff changes. These bid fees also reduce the predictability and stability of the collected fees due to the significant impact of high bid fees on submitted volumes. In fact, they will result in less total revenue collected from decreased participation, as a side effect of excessive "taxation" on the market-efficient activity. EMTRI urges CAISO and its Board of Directors to reject this $1 CRR Bid Transaction Fee. EMTRI also urges CAISO to use $0.005 CRR Bid Transaction Fee instead, which, when properly applied, reflects the industry standard and ensures the continuation of price discovery and liquidity in the CRR market, allowing it to remain an efficient market. At the same time such change will increase predictability and the forecastability of collected revenue, the very principles CAISO set out in the beginning of the GMC process.	collection is considered de minimis and is not economically viable from an administrative perspective. As previously noted, the ISO forecasts that the proposed $1 bid/nomination fee will collect approximately 7% of the costs associated with the CRR process.

Comments on CRR auction bid fee of $1		ISO comments
EMMT	Edison Mission Marketing & Trading, Inc. supports the CAISO 2012 GMC proposal to charge a CRR bid fee.	noted
DC Energy	DC Energy submits these very brief comments on the CAISO 2012 Grid Management Charge (GMC) final proposal. These comments simply supplement and support comments DC Energy provided in December 2010 and February 2011. DC Energy believes the CAISO staff has done an excellent job process wise to reach this conclusion and final proposal. Such process started well in advance of the proposed January 1, 2012 implementation date and staff provided participants detailed explanation throughout (i.e., in its meeting materials, during the scheduled meetings as well as off-line one-on-one). This, well in advance process, was especially important as the 2012 GMC includes a new charge for CRR participants. DC Energy has throughout supported the CAISO's Guiding Policy and Ratemaking Principles (i.e., Cost Causation, Focus on use of ISO services, not market behavior, Transparency, Predictability, Forecastability, Flexibility and Simplicity). DC Energy presently participates in both the convergence bidding and CRR markets and believes: (a) market participants should bear an appropriate share of the GMC costs applicable to the markets in which they participate (as they share in the benefits of these markets); and (b) the rates proposed, while significant, are not overly onerous.	noted
SVP	The City of Santa Clara, California, doing business as Silicon Valley Power ("SVP") thanks the CAISO for the opportunity to submit comments concerning the CAISO's 2012 GMC Draft Final Proposal, posted February 15, 2011. SVP's understanding is that the CAISO proposes to recover, through the CRR Services charge code, revenues via charging for the amounts of awarded CRRs (via allocation or successful bids). The CAISO is also proposing to recover CRR-based revenues via the CRR bid transaction fee—so these revenues will supplement the revenues received via CRR Services charge code. The bid transaction fee will be applied to bids, whether they are successful or unsuccessful. This means that if CRR Entities are, on average, more unsuccessful than successful in their bidding, the CAISO will make up for the lost revenue under CRR Services charge code via the CRR bid transaction fee. SVP also requests that the CAISO monitor what percentage of the CRR bid transaction fee comes from successful versus unsuccessful bids. If the amount of successful bids starts to dwarf the amount of unsuccessful bids, then it would appear that the bid transaction fee could result in an over-collection of revenues—when considering the CRR Services fee already collects revenues from successful bids. If the CAISO monitors the collection of the fee (and shares the resulting findings with Market Participants) to see what proportion successful bidders' payment of fees contributes to the total offset the CRR auction bid fee makes to the revenues collected via the CRR Services charge, both the CAISO and Market Participants will be able to evaluate the necessity of this fee (or its current level) in the future.	Noted. CAISO will attempt to gather CRR bid data as part of the annual budget process commencing in 2013

Comments on proposal regarding Transmission Ownership Rights		ISO comments
Powerex	Powerex also has no objections to the proposed treatment of Transmission Ownership Rights or the Treatment of Metered Sub System Load Following Energy since the CAISO believes their proposal follows cost causation principles and will not unreasonably shift costs to other market participants.	noted

Comments on proposal revenue requirement cap		ISO comments
Powerex	Finally, Powerex believes the CAISO's proposal for a 3 year Revenue Requirement Cap of $197M, $199M, and $199M for 2012, 2013, and 2014, respectively, is reasonable. However while Powerex believes the proposal is reasonable, Powerex continues to encourage the CAISO to pro-actively seek efficiencies and opportunities to simplify its operations and tariff to reduce its annual budget below the Cap	noted
CMUA	The California Municipal Utilities Association ("CMUA") is pleased to have the opportunity to provide these brief comments on the California Independent System Operator Corporation's ("CAISO") proposal for revisions to its Grid Management Charge ("GMC"). CMUA's comments are limited to the issue of the CAISO's proposed changes to its revenue requirement cap. CMUA takes no position on the other proposed changes to the CAISO's GMC. In the previous round of comments, CMUA raised concerns with the CAISO's proposed revenue requirement cap and fixed escalator. The CAISO had proposed a five year revenue requirement cap that would automatically increase one percent each year. CMUA expressed its concern that five years is too long and that the automatic increase to the revenue requirement is out of step with the current economic realities. On February 15, the CAISO released its Final Draft Proposal, which included key changes on these two issues. Instead of a five year revenue requirement cap, the CAISO now proposes a three year revenue requirement cap. The CAISO also eliminated an automatic one percent annual increase. Instead, the revenue requirement will be increased once in 2013. CMUA supports these modifications to the GMC proposal, and appreciates the continued vigilance of the CAISO Management to ensure prudent expenditure of ratepayer dollars.	noted

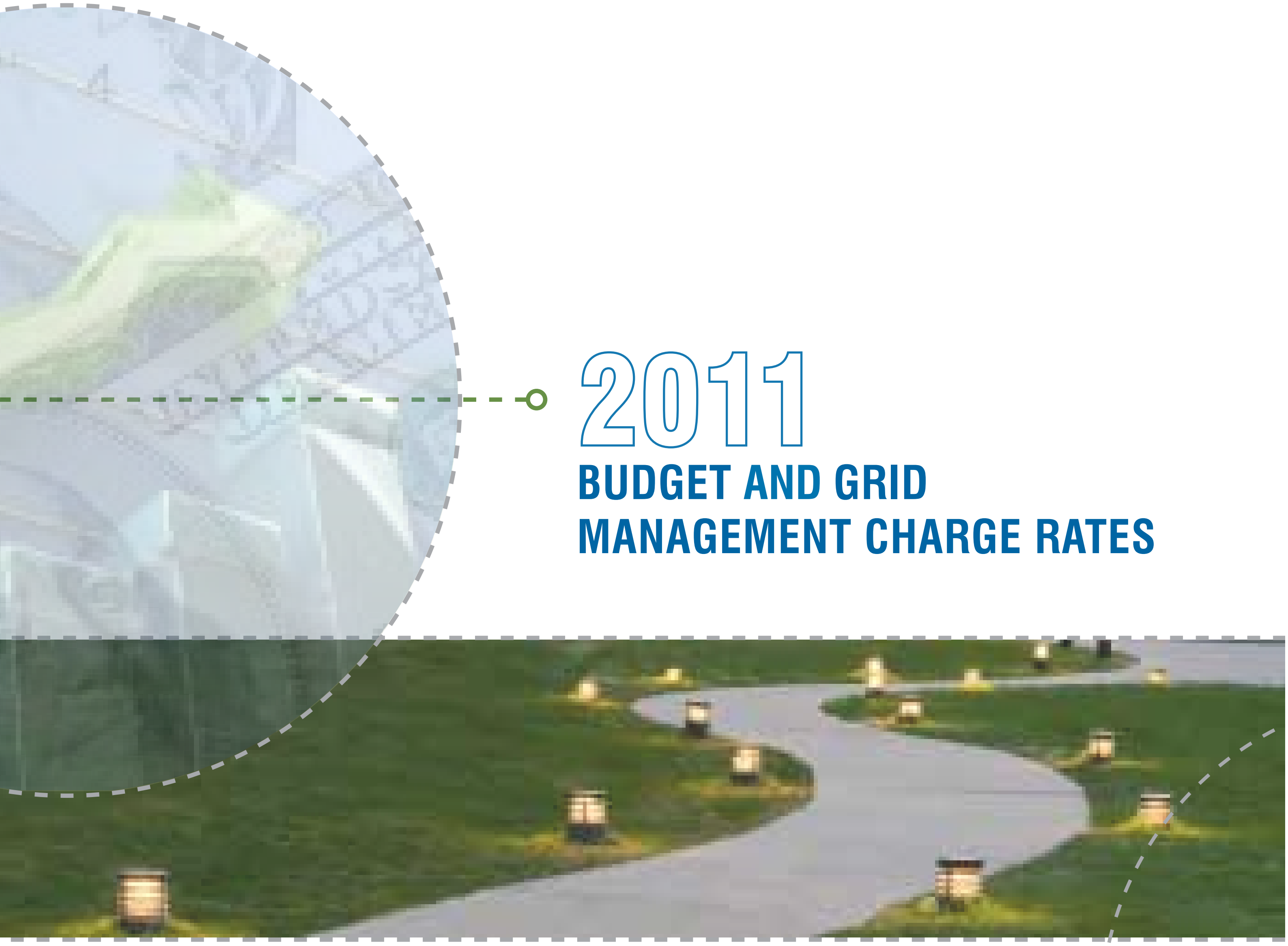
Exhibit No. ISO-17 – 2011 Budget and Grid Management Charge Rates

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

2012 Grid Management Charge Tariff Amendment

July 5, 2011



2011
BUDGET AND GRID MANAGEMENT CHARGE RATES

California ISO
Your Link to Power

Prepared by Department of Financial Planning
December 15, 2010

2011 Budget and GMC Rates

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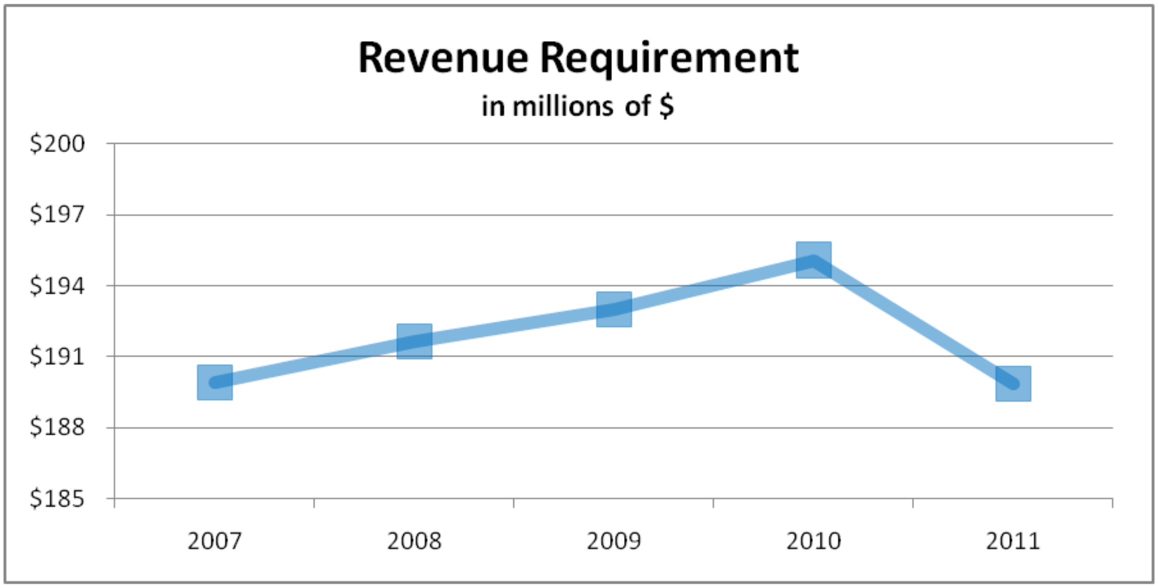
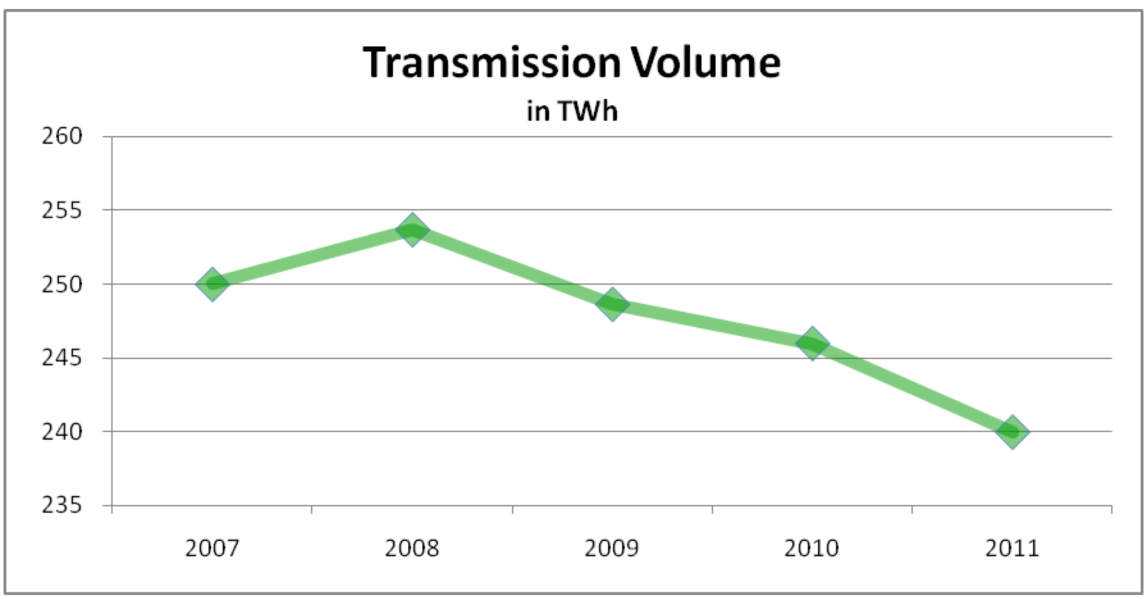
I. 2011 Revenue Requirement

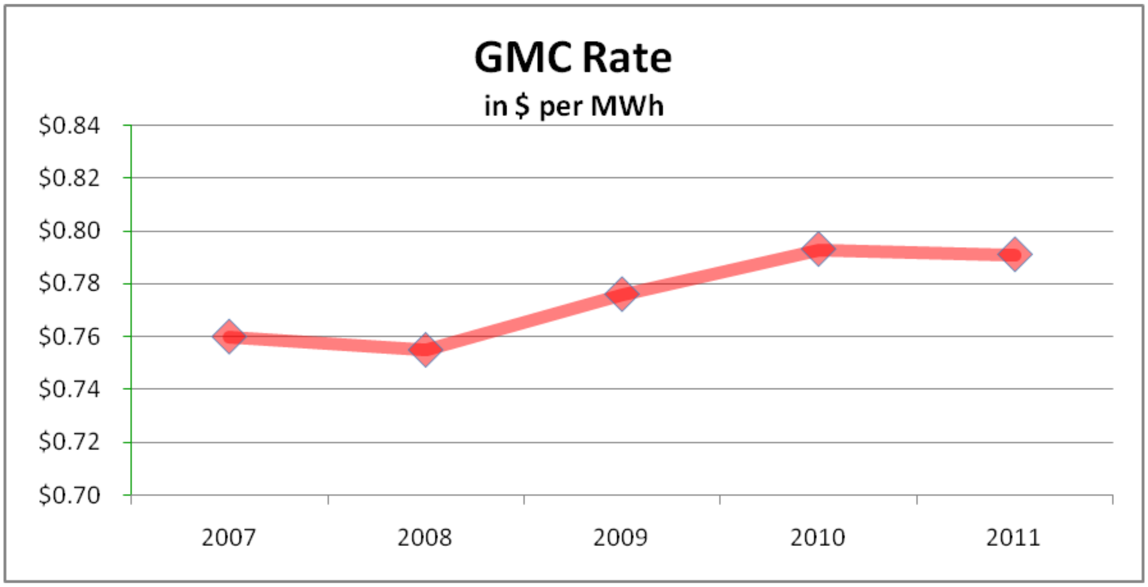
The 2011 budget provides for a revenue requirement of $189.8 million, $5.2 million lower than 2010 and at the same level as 2007. As further described in this document, the California Independent System Operator Corporation is increasing service levels through effective management and allocation of resources toward key corporate initiatives as outlined in the Five-Year Strategic Plan.



Because of the economic conditions in California, the transmission volume is projected to be down 2.4% from 2010 and down 4.0% over the last five years. This results in a higher grid management charge, as noted below.



The bundled composite grid management charge (GMC) is expected to be $0.79 per MWh. The GMC rate is at the same rate as 2010, which was also higher than in previous years because of a drop in transmission volumes.



The revenue requirement has been reduced substantially since 2003, which highlights the ISO's firm commitment to maintain a grid management charge in the mid- to high 70 cent per MWh range for the next several years, consistent with the Five-Year Strategic Plan, and absent uncontrolled drops in transmission volume. The growth rate of the revenue requirement over the last five years has been under 0.7% while transmission volume has declined at a 1.0% rate, resulting in rate growth of 1.6% for the five-year period.

Components of 2011 Revenue Requirement

Transmission volumes in the state are projected to drop 2.4% or 6.0 TWh to 240.0 TWh for 2011 because of weak economic conditions. When combined with the reduction in the revenue requirement, this results in a pro-forma bundled GMC to $0.79 per MWh the same a 2010.

A summary of the 2011 revenue requirement compared to 2010 is as follows:

Revenue Requirement ($ in millions)	2011 Budget	2010 Budget	$ Change	% Change
Operating & Maintenance Budget	$162.5	$162.7	$(0.2)	(0.1)%
Miscellaneous revenue	(6.9)	(8.1)	1.2	14.8%
Subtotal net Operating & Maintenance	155.6	154.6	1.0	0.6%
Debt Service including 25% reserve	43.7	61.0	(17.3)	(28.4)%
Out-of-Pocket Capital Funding	23.5	15.0	8.5	56.7%
Subtotal before revenue credit	222.8	230.6	(7.8)	(3.4)%
Revenue Credit	(33.0)	(35.5)	2.5	7.0%
Total Revenue Requirement	**$189.8**	**$195.1**	**$ (5.3)**	**(2.7)%**
Transmission volume in TWh	**240.0**	**246.0**	**(6.0)**	**(2.4)%**
Pro-forma Bundled GMC per MWh	**$0.791**	**$0.793**	**$(0.002)**	**(0.2)%**

The revenue requirement is recovered through the unbundled grid management charges. Each unbundled service offering has corresponding rates paid by users of that service. These rates are calculated by determining the costs associated with each of these services, and then dividing those figures by the forecasted billing determinant volume for each service. The result is a rate per unit of use. Section X of this document outlines the determination of GMC rates.

II. Budget Overview

This budget package provides an overview of and detail about the ISO cost of service that for 2011 consists of the following:

- Operating and maintenance (O&M) budget
- Debt service costs (section VI)
- Project and capital funding (section VII)
- Other revenues and expense recoveries (section VIII)
- Revenue credit from operating reserve account (section IX)

The O&M budget is the largest of these components and is the primary focus of this report, which consists of the costs necessary for ongoing operations. The O&M budget of $162.5 million in 2011 was $200,000 less than 2010. The O&M budget is presented in three views:

- By process — such as support customers and stakeholders (section III)
- By resource — such as salaries (section IV)
- By division — such as the Operations Division (section V)

Debt service costs are the principal and interest payments related of the ISO's 2008 bonds and a 25% debt service reserve collection. In June 2008, the ISO issued fixed rate bonds that funded 2008 to 2010 capital expenditures and retired existing variable rate demand bonds. During 2009, the ISO issued bonds to build a new headquarters facility. Debt service during the building's development stage is funded from bond proceeds. Occupancy is planned for early 2011. Debt service costs on both bonds decreased by $17.3 million to $43.7 million in 2011, which reflects the 2008 and 2009 bond amortization and a 25% debt service reserve.

The revenue requirement contains direct funding for capital and other projects in 2011 amounting to $28.5 million. The source was primarily from an additional month's collection of the grid management charge in January 2010 arising from the implementation of the payment acceleration market software enhancement in November 2009. Direct funding avoids the additional costs of interest and the 25% debt service reserve. Total capital spending for 2011 is budgeted primarily for systems development related to expand market capabilities.

Other revenue and expense recoveries are various offsets to the revenue requirement, such as interest, scheduling coordinator application fees, Participating Intermittent Resource Program fees, training fees and the California-Oregon Intertie Path Operator fee.

The operating reserve credit is a reduction or offset to the ISO revenue requirement for 2011. In any year, that the ISO operating reserve account exceeds 15% of the prospective year's O&M budget, such excess is used to reduce the revenue requirement for the coming year. For 2011, the ISO forecasts a credit from the operating reserve account of $33.0 million. The operating reserve account is calculated separately for each grid management charge category.

Budget Guidance

Each year, division and departmental budget planners receive guidance on the expected overall budget outcome and the mechanics of how it will be prepared. Guidance provided for developing the 2011 revenue requirement called for each ISO division to develop an O&M budget consistent with the Strategic Plan and limiting increases to less than 3.0%.

Company-wide, the O&M budget will result in a revenue requirement under the $197 million threshold that triggers a review filing with federal regulators and a bundled grid management charge similar to 2010. In late July, ISO management met and refined the proposed budget to keep it at the same level as 2010. This included reducing headcount, contractors and consultants. The budget achieves the above goals and funds ISO operations and initiatives as set forth in the Strategic Plan.

The preliminary budget was presented to the Board in early September for feedback and was then posted to the ISO website for stakeholder review. The budget was discussed with stakeholders at a workshop held October 14 (discussion notes were posted on the ISO website). Stakeholders did not submit any additional questions.

Strategic Outlook

The ISO is fully engaged with state, regional and federal officials in shaping the power industry's transformation to one that is ready to meet the needs of modern society. Clean energy is already playing a critical role in meeting environmental goals with more than 3,000 MW of wind resources now connected to the ISO grid. The ISO sees the 2020 future grid, at which time utilities must have 33 percent of their resource portfolio in renewable energy, in three areas.

Demand:

- Growth in demand is tied to economic recovery, but is tempered by greater energy efficiency and rooftop solar.
- Retail electricity customers can reduce their use and sell those kilowatt-hour savings as demand response energy products into the wholesale market.
- Over one million electric vehicles will reduce harmful emissions creating new sources of demand.

Resources:

- Large utility scale renewable power plants contribute to resource diversification and help balance the grid while keeping costs in check.
- Energy storage and other smart grid technologies complement and support renewable resources while enhancing reliability.
- Closer and energetic collaboration with regional planning entities makes it possible to benefit from economies of scale and increases the sharing of resources in the West.

Transmission:
- o Building new transmission lines remains challenging but is aided by improved planning and siting processes.
- o New generation investment triggers new transmission investment.
- o Reductions in coal contracts free up capacity for renewable generation imports.

The ISO plays a leading role in providing policymakers with technical advice to aid them in their regulatory and policy deliberations, such as those calling for a 33% renewable portfolio standard. The ISO is also actively working with the California Air Resources Board to implement greenhouse gas curbs mandated by Assembly Bill 32 (California Global Warming Solutions Act of 2006).

Just as in 2010, the sluggish economy continues to affect the ISO, mostly through lower electricity volumes, and its customers. As most companies, the ISO is keeping its costs contained while improving services. This is accomplished in part by making sure staffing levels and skill sets efficiently meet current and future needs, scrutinizing expenses, and deftly managing investments and debt obligations.

Aligning with the Strategic Plan

The ISO is continuing in 2011 the focus begun in 2005 to contain or lower operating costs while improving services and enhancing the reliability of the California transmission grid. This includes, for instance, strengthening compliance efforts without adding costs. It also includes performing the increased responsibilities and planning needed to integrate 20% and 33% renewable portfolio standards.

The 2011 budget also represents another step taken in 2009 to align with the Strategic Plan, which is the primary roadmap for the ISO to achieve organizational and operational objectives and goals. The Strategic Plan this year is focusing on three key areas:

- System — initiatives that identify the requirements to ensure a stable and reliable foundation for grid and market operations as well as infrastructure planning;
- Environment — initiatives that promote and support environmental and regulatory policies and objectives; and
- Organization — initiatives that develop the people and processes needed to efficiently use resources to manage the rapid changes the industry is undergoing.

The Strategic Plan contains the refined vision of moving the corporation forward and is supported by the initiatives to further flesh out the ISO strategy, while the budget explains how the corporation funds and allocates its resources to support its business plans. ISO management and staff created a 2011 budget that supports the Strategic Plan with the right mix of talent, skills and financial resources to be successful.

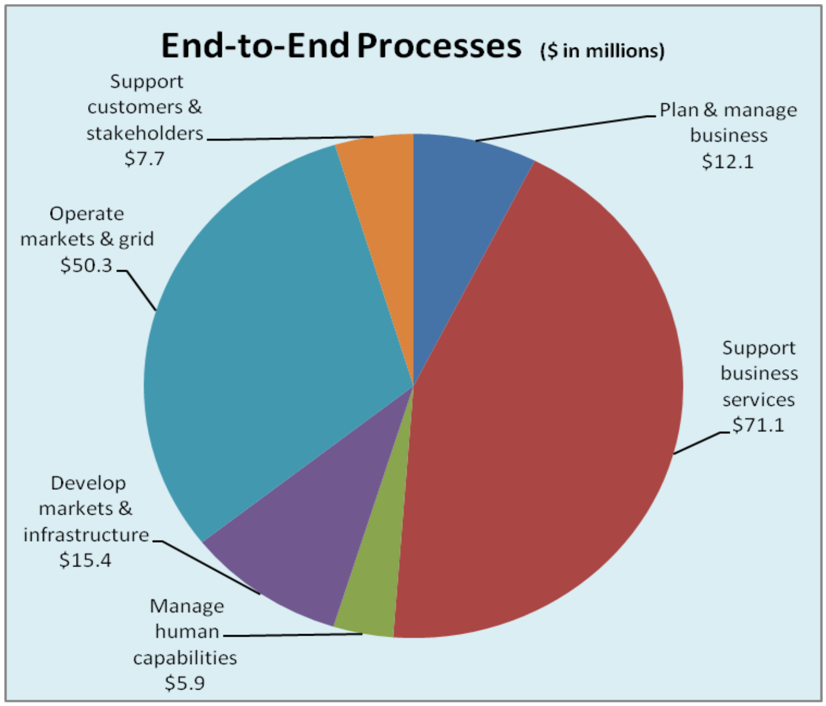
Aligning the strategic planning process more closely with budget planning reveals with greater transparency how ISO resources are used and the costs associated with business and operational activities. This, in turn, enables management to better assess the value of corporate projects and processes and determine whether they are under or over resourced. The ISO is also scrutinizing day-to-day expenses in an effort to ensure the most effective use of budgeted resources.

The highest levels of the ISO are actively involved with defining, creating and nurturing a culture of cost-consciousness as well as enhancing services while not adding costs. Stakeholders also participate in ISO governance by engaging in policy and tariff stakeholder processes that weigh and balance costs and reliability issues.

Not only is the ISO vigilant in containing costs, it also places a high emphasis on managing our resources in a smart and prudent manner.

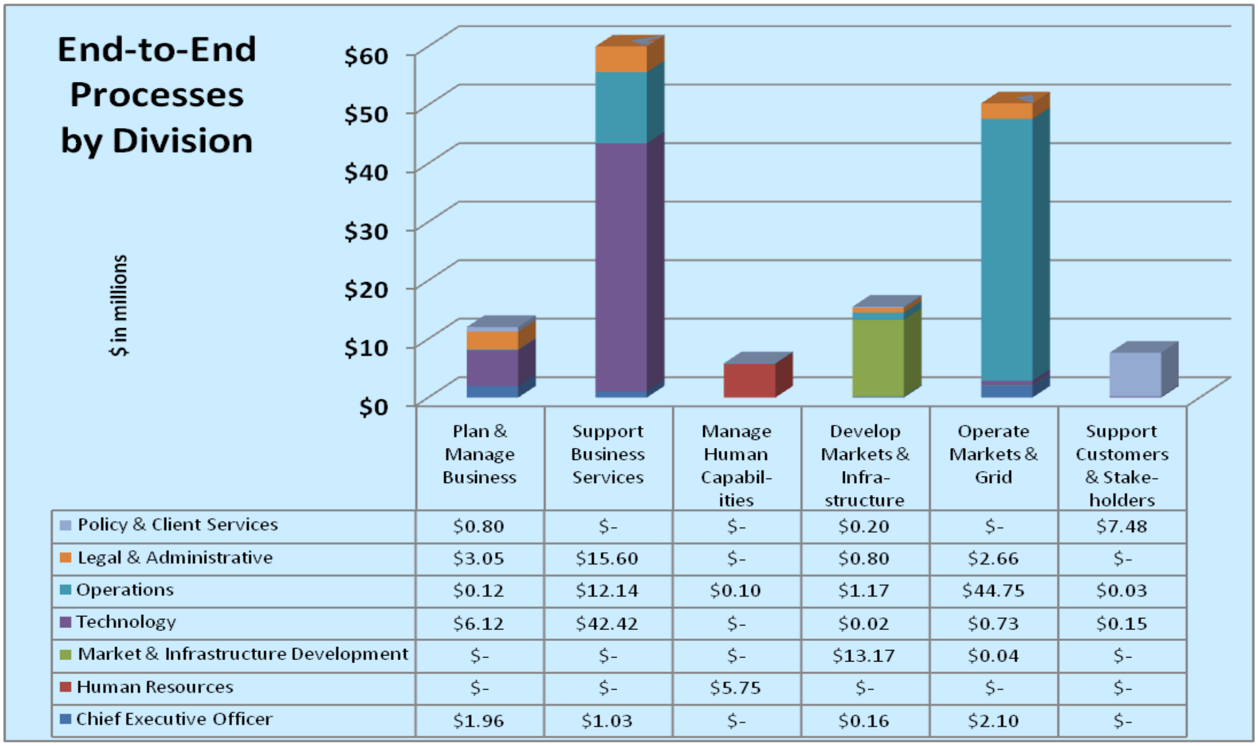
III. Process View

In the fall of 2009, we initiated activity based costing and in 2010, we further leveraged the system to provide greater transparency and granularity in how the budget supports business plans. We derived costs for the activities using an estimate of the percentage of time spent by each cost center on the end-to-end process. We then took the percentages and allocated them to the six summary activities described below. This budget reports the cost centers in the following buckets:



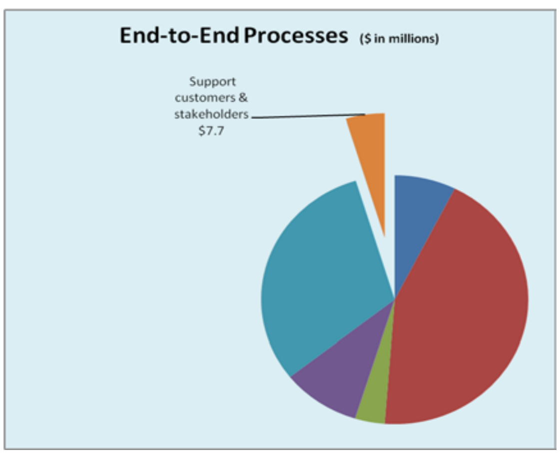
- Support customers and stakeholders – client, account and stakeholder processes, government affairs and communications;
- Develop markets and infrastructure – regulatory, market, policy and product design and transmission planning, grid asset reviews and interconnection studies;
- Operate markets and grid – manage and operate the markets including modeling, setup and settlements;
- Manage human capabilities – employee lifecycle, training and organizational development;
- Support business services – general, information technology, financial, legal and compliance support services; and
- Plan and manage business – strategic planning, governance, budgeting and project management.

The divisional make up of the end-to-end processes is as follows:



	Plan & Manage Business	Support Business Services	Manage Human Capabil-ities	Develop Markets & Infra-structure	Operate Markets & Grid	Support Customers & Stake-holders
Policy & Client Services	$0.80	$-	$-	$0.20	$-	$7.48
Legal & Administrative	$3.05	$15.60	$-	$0.80	$2.66	$-
Operations	$0.12	$12.14	$0.10	$1.17	$44.75	$0.03
Technology	$6.12	$42.42	$-	$0.02	$0.73	$0.15
Market & Infrastructure Development	$-	$-	$-	$13.17	$0.04	$-
Human Resources	$-	$-	$5.75	$-	$-	$-
Chief Executive Officer	$1.96	$1.03	$-	$0.16	$2.10	$-

Support Customers and Stakeholders



Support Customers and Stakeholders, amounting to $7.7 million and 37 staff, is made up of elements of two divisions, Policy and Client Services and Technology. The ISO is committed to provide the highest quality of service to its customers, market participants and stakeholders. This includes the timely resolution of customer issues and streamlined access to market information.

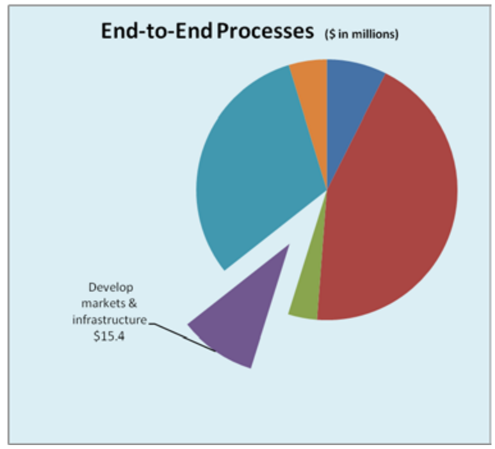
Primary Activities

This process has a variety of initiatives that directly promote improving customers' business experience with the ISO and disseminating clear and consistent corporate information for stakeholder and public consumption. Besides responding to inquiries quickly and encouraging quality dialogue between the ISO and its key customers, this activity provides the resources necessary to manage the stakeholder process that results in quality interactions.

In addition, supporting customers comprises robust government affairs activities that communicates the ISO position to government and regulatory bodies the advice and technical expertise to advance policies and mandates that also protect grid reliability.

Develop Markets and Develop Infrastructure

Develop Markets and Develop Infrastructure are two separate processes that cover the ISO activities in designing and implementing value-added enhancements to the market design and proactively planning and facilitating grid upgrades, especially those needed to integrate renewable resources.

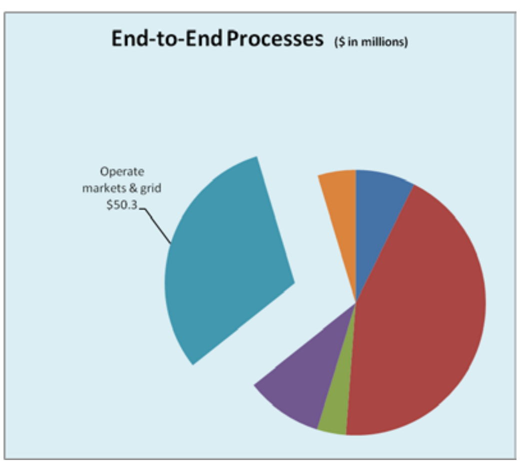


Develop Markets
Develop markets, amounting to $5.9 million and 47 staff, is comprised of elements from five divisions: the Market Monitoring department of the CEO division, Market Infrastructure and Development, Technology, Operations, and Legal and Administrative. This activity includes improving our abilities to review and analyze the efficiency and quality of market results, and identifying market design enhancements that solve issues and increase efficiencies and transparency.

Among the many initiatives under this banner are ones that are building the business and operational framework that accommodates demand response, renewable resources and storage technologies participation in the ISO market.

Develop Infrastructure Develop infrastructure, amounting to $9.6 million and 24 staff, is comprised of four divisions: Market Infrastructure and Development, Operations, Legal and Administrative, and Policy and Client Services. The budget continues to support a proactive approach to transmission planning that has resulted in reforming transmission planning into a comprehensive approach that considers reliability needs, implementing state and federal environment policies and renewable portfolio standards.

Operate Markets and Grid



There are four end-to-end processes that make up operate markets and grid: Manage Market and Reliability Data and Modeling, Manage Market Setup and Execution, Operate Real Time Market and Grid, and Manage Operations Support and Settlements.

Manage Market and Reliability Data and Modeling
Manage Market and Reliability Data and Modeling, amounting to $9.1 million and 39 staff, is comprised of primarily the Operations division with elements of the Chief Executive Office, Technology, and Legal and Administrative divisions. The ISO diligently checks and rechecks its network

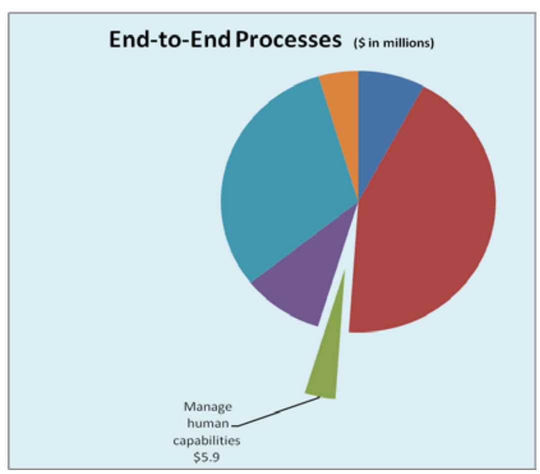
modeling policies and protocols to reduce as much as possible non-market energy dispatches, assure models reflect all grid constraints and produce timely and accurate prices results.

Manage Market Setup and Execution
Manage Market Setup and Execution, amounting to $9.6 million and 46 staff, is comprised of primarily the Operations division with elements of the Technology division. A difficult ISO responsibility is to manage transmission and generation outages, especially those that are unplanned, as it takes expertise honed in split-second decision-making situations to ensure continuous flow of power to all customers. Managing the market includes executing the day ahead market and interchange scheduling to make sure all local capacity requirements are met and the power is delivered with the least cost possible by avoiding congested areas.

Operate Real Time Market and Grid
Operate Real Time Market and Grid, amounting to $18.9 million and 78 staff, is comprised of primarily of the Operations division with elements of the Market and Infrastructure Development division. This is the fundamental process of the Company that ensures load is balanced to generation and the least cost generation is dispatched.

Manage Operations Support and Settlements
Manage Operations Support and Settlements, amounting to $12.6 million and 75 staff, is mostly comprised of Operations along with the Market Monitoring department of the CEO division, Technology division, and Legal and Administration division. The budget provides the resources that work to improve market efficiency. This effort includes lowering the financial risk of participating in the wholesale market that in turn lowers the cost of doing business with the ISO. The lower cost translates into less overhead for ISO customers who can pass the savings to ratepayers.

Manage Human Capabilities



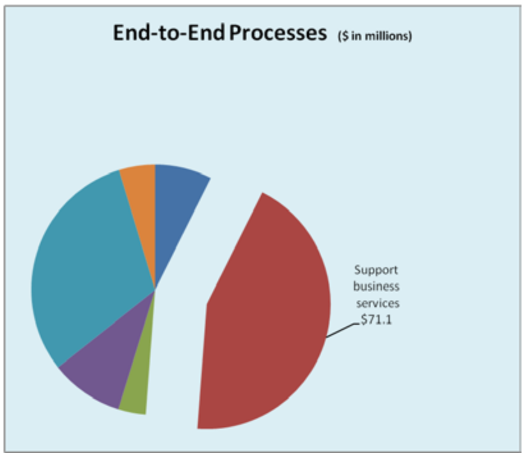
Manage Human Capabilities, amounting to $5.9 million and 17 staff, consists of five primary end-to-end processes that combine to ensure the ISO ability to attract and retain skills and talent necessary to achieve business objectives: compensation, benefits, recruitment, training and development, and employee relations.

With respect to compensation and benefits, the budget provides resources to support the ability to attract and retain uniquely skilled and highly sought-after professionals, and ensure that the menu of benefits offerings reflects creative cost containment measures while at the same time preserving the options needed to meet the needs of a diverse employee population.

Developing the next generation of ISO people equipped with the knowledge, skills and expertise to meet the challenges of today and the future remains a top priority. The budget provides resources to ensure employees not only grow in their jobs but also increase their value to the corporation.

In addition, the budget provides resources to support management and employees in maintaining a respectful and transparent workplace environment where employees are highly engaged and pursue their highest potential and the success of the corporation.

Support Business Services



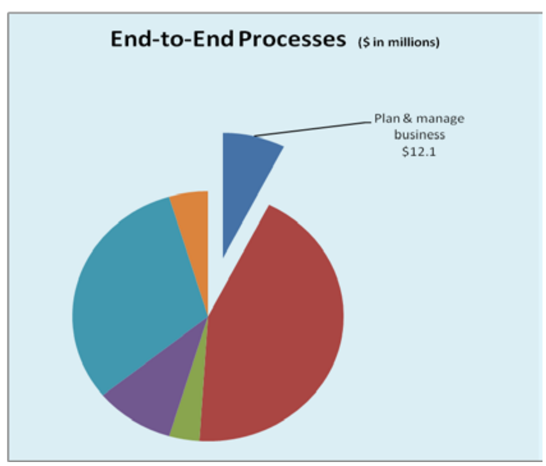
Support Business Services, amounting to $71.1 million and 207 staff, is comprised of elements of four divisions: Technology, Operations, Legal and Administrative, and the Market Monitoring Department of the Chief Executive Officer division.

This process provides the resources to improve upon the ISO's ability to effectively carry out its business duties by developing well defined, measured and controlled processes (workflow and information technology), nurturing disciplined business decision making, maintaining quality assurance and efficiently implementing enhancements.

In addition, this cost center supports the initiatives that improve and maintain a responsive and effective compliance culture.

Plan and Manage Business

The Plan and Manage Business process, amounting to $12.1 million and 31 staff, is comprised of five divisions: CEO, Technology, Legal and Administrative, Operations, and Policy and Client Services.

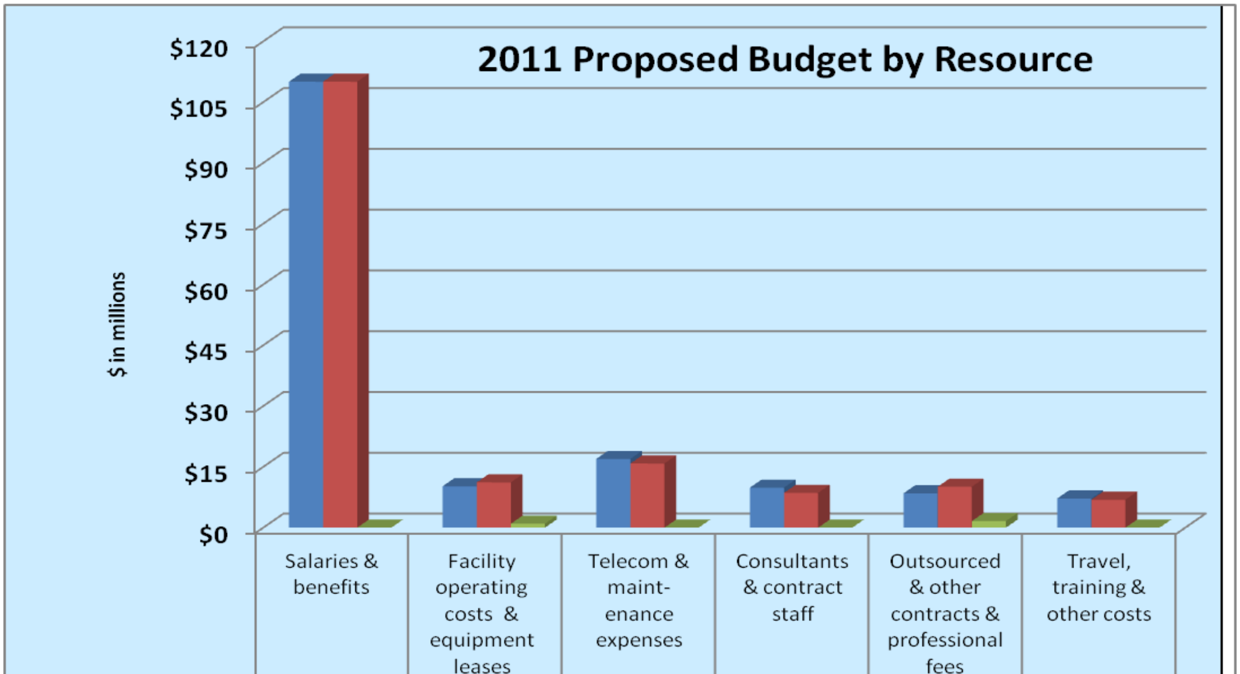


Every process, project or policy the ISO has or is considering is measured against the identified benefits. This activity in part is supported by aligning the strategic planning process with budget planning, as outlined in Section II: Aligning with the Strategic Plan.

It is the budget process that drives revenue requirement needs, which is translated into rates charged to scheduling coordinators and other market participants.

IV. ISO Resource Utilization

This section deals with the resources consumed by the ISO in its O&M budget to accomplish its strategic objectives and goals. The major resource components are outlined in the chart below. The O&M budget of $162.5 million in 2011 was $200,000 less than 2010. Changes in the 2010 budget components reflect reorganizations during 2010 although the total amount of the 2010 budget was not changed.



	Salaries & benefits	Facility operating costs & equipment leases	Telecom & maint-enance expenses	Consultants & contract staff	Outsourced & other contracts & professional fees	Travel, training & other costs
2010 Budget	$110.03	$10.20	$16.95	$9.86	$8.47	$7.19
2011 Budget	$110.03	$11.16	$15.82	$8.58	$10.08	$6.88
Change from 2010	$-	$0.96	$(1.13)	$(1.28)	$1.61	$(0.31)

Staffing

To operate the grid, the ISO depends on its highly educated employees, which makes staff a critically important resource with salaries and benefits comprising 68% of the O&M budget for 2010 and 2011.

The staffing plan premise is to attract and retain the best and brightest individuals in the industry and at times, the ISO will revise the organizational structure to accommodate such talent. The Company also makes periodic organizational changes to align resources to focus on the important matters identified in the Strategic Plan, and to better reflect end-to-end business processes.

The staffing level for 2011 is 598 employees and 3 trainees, 14 less than the budgeted 2010 staffing level. As of October 31, 2010, there were 587 full time employees; this amount includes three committed employees. As that equals 98% of the budgeted staffing level, no provision for vacancies was made to the 2011 budget. A summary of the budgeted headcount for 2011 and 2010 is as follows:

Projected Staffing Levels	2011 Budget	2010 Budget	Change
Chief Executive Officer	17	18	(1)
Human Resources	17	19	(2)
Market and Infrastructure Development	63	67	(4)
Technology	161	162	(1)
Operations	249	252	(3)
General Counsel and administration	55	56	(1)
External Affairs	39	41	(2)
Gross headcount	**601**	**615**	(14)
Less Program Office staff included in capital	(7)	(10)	3
Less vacancy factor	-	(15)	15
Net headcount	**594**	**590**	4

At $110.0 million, staffing costs remained the same in 2011 as they did 2010. The merit increases and elimination of the vacancy factor amounted to a $1.6 million increase in the 2011 budget over 2010, which was offset by a $1.6 million reduction stemming from a lower headcount. Anticipated overtime decreased $0.5 million or 8% to $5.6 million in 2011 from $6.1 million in 2010. The benefits burden went up by 1%, or $681,000, to cover the increased costs of employee health insurance. Other payroll costs decreased $170,000, or 13%, to $1.2 million in 2011 from $1.4 million in 2010.

Staffing Related to Capital

As in past years, the costs of ISO staff dedicated full-time to capital projects have been removed from the O&M budget, and will be charged to capital projects, which are funded separately. The capitalized staff amounted to seven full-time staff in the Program Office department of the Technology division. Other ISO staff engaged on capital projects are budgeted in their respective cost centers, but will be capitalized for the financial statements that are prepared in accordance with generally accepted accounting principles.

Compensation Structure

The 2011 compensation budget includes funding for employee base salaries, benefits and payroll taxes, as well as other compensation elements such as overtime and performance compensation, and related costs such as relocation and tuition reimbursement. The budget also includes funds for 2011 salary adjustments for merit, equity and market adjustments. These costs have been budgeted for each position.

In setting the annual merit, equity and market adjustments budget, the Human Resources division participates in multiple salary surveys that qualified third party vendors administer confidentially to obtain information on competitive market pay rates.

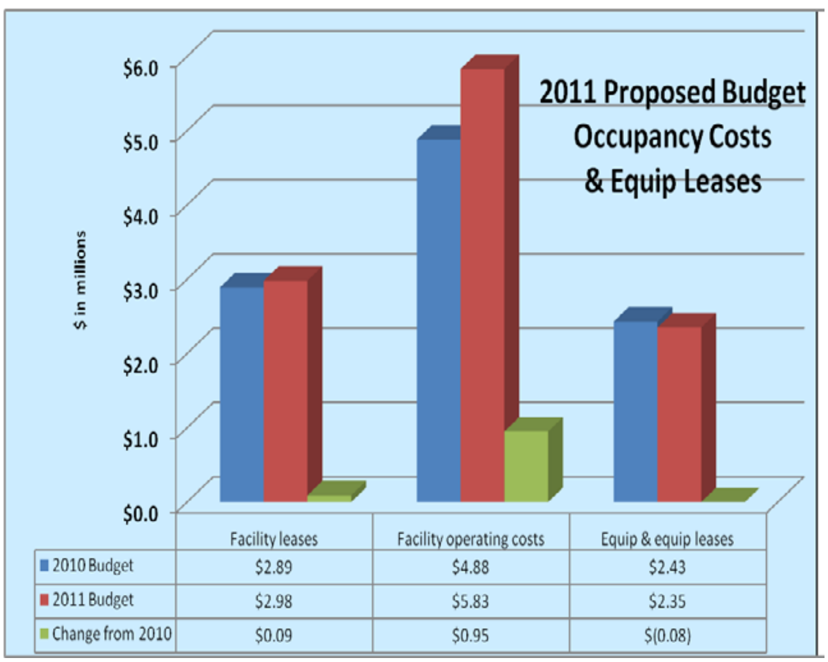
The ISO ability to attract and retain talent with the necessary skills and knowledge is directly linked to our ability to maintain competitive pay practices. The total compensation package provided to employees includes performance compensation with payouts in the subsequent year based on individual and corporate performance.

Employee benefits are budgeted at 36% of salary costs to fund the benefits summarized in the table below. Benefits increased 1% from 2010 primarily related to increases in health insurance portion of health benefit plans. Management will enter into contracts with selected vendors to ensure these benefits are available to eligible employees with the costs primarily depending on employee population levels and participation.

The 36% benefits burden is broken down as follows:

Benefit Obligation	ISO Cost Components	Rate
Health and Welfare plans Medical, Dental and Vision	Medical, dental and vision; life, accidental death and long-term disability insurance; state unemployment insurance; and worker's compensation	13%
Retirement Benefit Plans	Retirement Savings Benefit Plan 401(k); Federal social security and Medicare; executive retirement plans; and Retiree Medical Benefit Plan	22%
Other obligations	Administration related costs	1%
Total Burden		**36%**

Occupancy and Equipment Leases



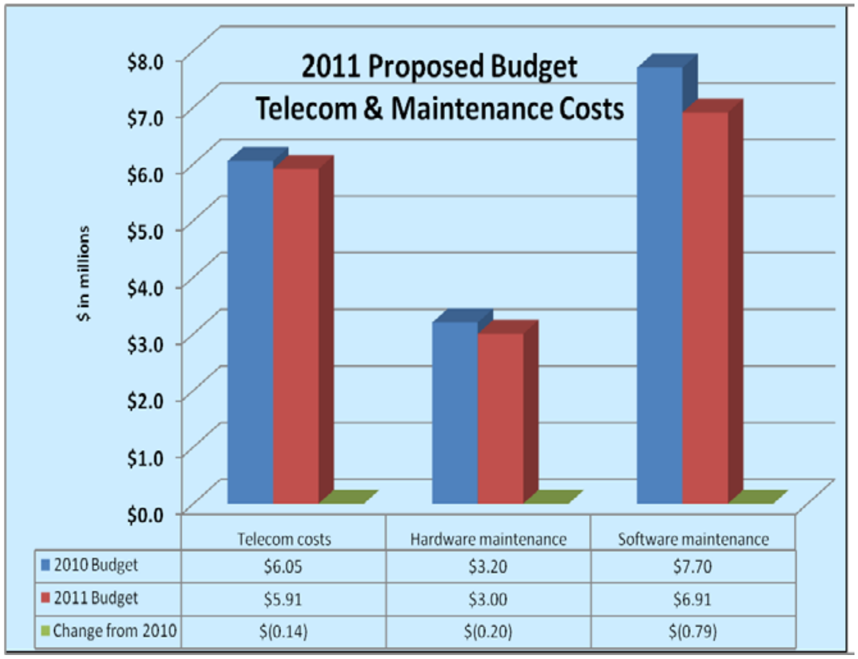
Occupancy and equipment lease costs increased by $963,000 for the 2011 budget to $11.2 million from $10.2 million in 2010 and make up approximately 7% of the 2011 and 2010 budget.

Facility costs increased by $1.0 million, or 13%, to $8.8 million in 2011 from $7.8 million in 2010. The increase is primarily related to the addition of the new headquarters building in 2011 while still maintaining the leased facility in Folsom through 2012.

Equipment leases held steady from 2010 at $2.4 million.

Telecommunications and Hardware and Software Maintenance Costs

Telecommunications and hardware and software maintenance costs decreased $1.2 million, or 7%, for the 2011 budget amounting to $15.8 million compared to $17.0 million in 2010. These costs make up approximately 10% of the 2011 and 2010 budgets.



Telecommunication costs decreased $140,000, or 2%, for the 2011 budget amounting to $5.9 million compared to $6.1 million in 2010.

Hardware maintenance costs decreased $199,000, or 6%, to $3.0 million in 2011 from $3.2 million in 2010.

Software maintenance costs decreased $788,000, or 10%, to $6.9 million in 2011 from $7.7 million in 2010. Maintenance contracts to support the new market software were not as high as originally anticipated.

Consultants and Contract Staff

Consulting and contract staff costs declined by $1.3 million, or 13%, in 2011 to $8.6 million from $9.9 million in 2010 and make up approximately 5% of the 2011 budget and 6% of the 2010 budget.

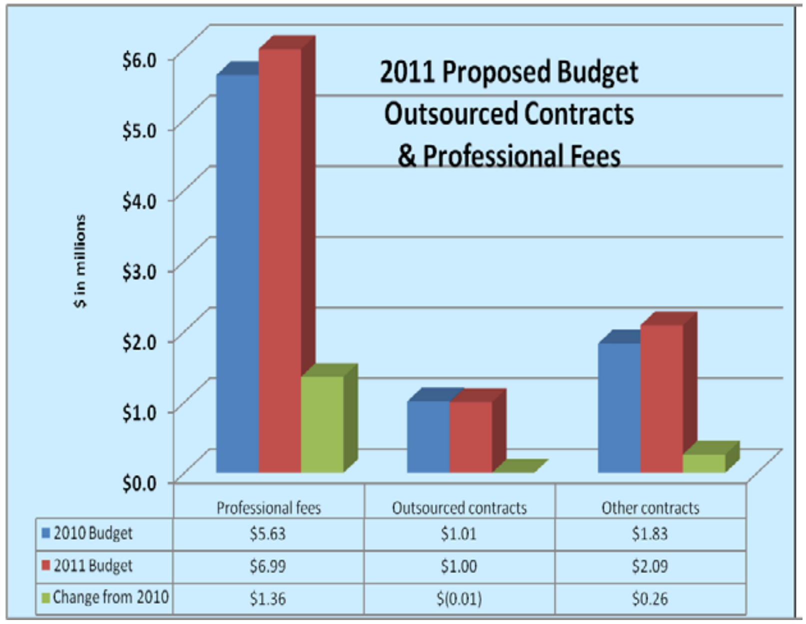
The Market and Infrastructure Development and Operations divisions accounted for a majority of the reductions with $465,000 and $858,000 respectively while the remaining divisions had a combined increase of just $51,000.

The ISO evaluates on an ongoing basis how to fulfill its responsibilities in a manner that is cost effective while providing the highest service quality, whether this is through hiring full-time employees or using outside resources (contractors, consultants, or temporary staff). At times, the Company may bring in-house work previously performed by contractors when the work is of an ongoing nature and can be performed at lower overall cost and with the same or better service quality.

Outsourced Contracts and Professional Fees

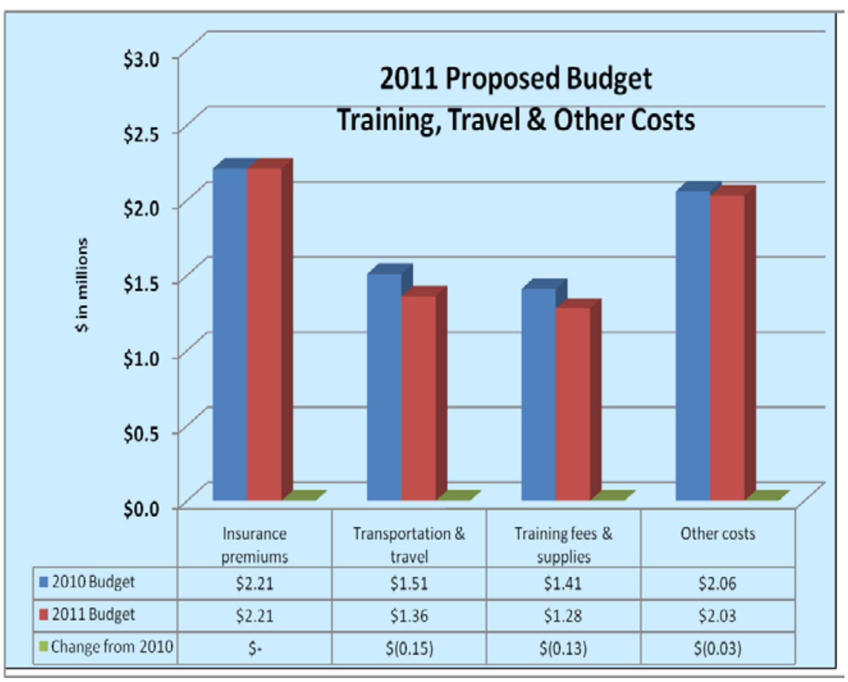
Outsourced contracts and professional fees increased $1.6 million, or 19%, in 2011 to $10.1 million from $8.5 million in 2010. The budget category makes up approximately 6% of the 2011 budget and 5% of the 2010 budget.

Professional fees increased $1.4 million, or 24%, to $7.0 million in 2011 from $5.6 million in 2010. The increase is a result for the need of additional outside legal counsel and audit services.



Outsourced and other contracts increased $249,000 to $3.1 million, or 13%, in 2011 from $2.8 million in 2010. Major outsourced contracts are security certificate management, locational marginal price validation, weather and wind forecasting, and credit rating services.

Training, Travel and Other Costs



Training, travel and other costs decreased $310,000, or 4%, to $6.9 million in 2011 from $7.2 million in 2010. These costs make up approximately 4% of the 2011 and 2010 budgets.

Insurance premiums remained the same at $2.2 million in 2011 and 2010.

Transportation and travel decreased $147,000, or 10%, to $1.4 million in 2011 from $1.5 million in 2010.

Training fees and supplies decreased $131,000, or 9%, to $1.3 million in 2011 from $1.4 million in 2010.

The remaining costs (primarily office, office supplies and meeting costs) decreased $34,000, or 1%, to $2.0 million in 2011 from $2.1 million in 2010.

Reconciliation with 2010 O&M Budget

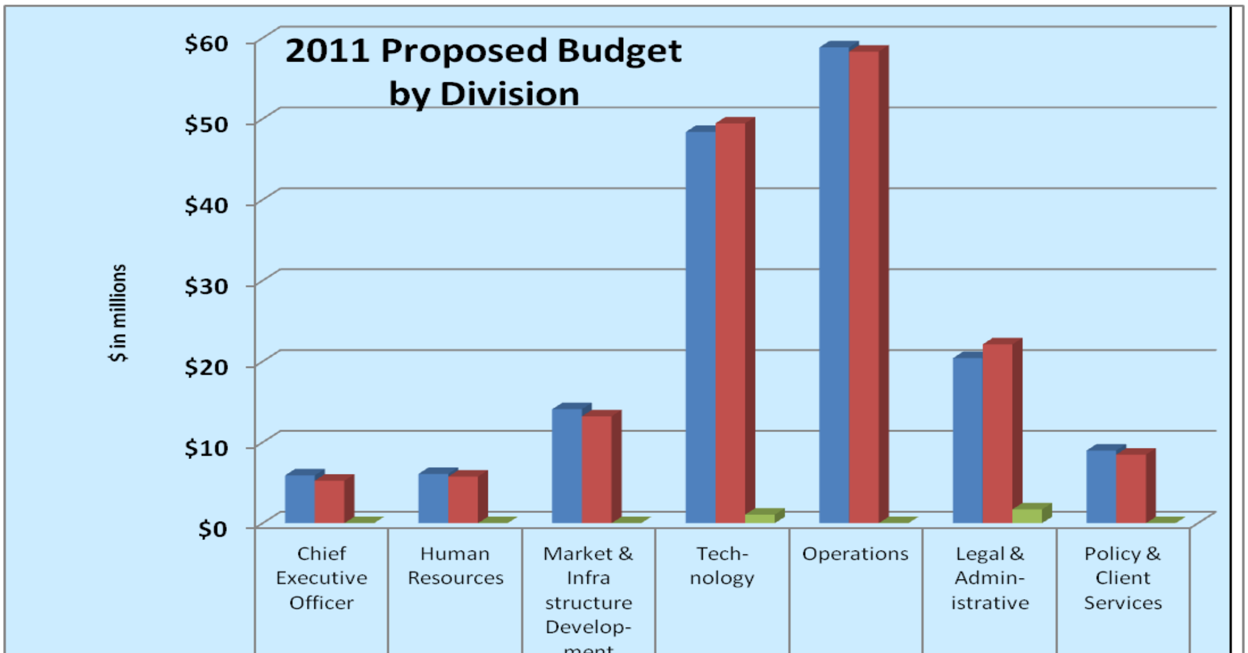
The O&M budget decreased by $200,000 or 0.1% to $162.5 million in 2011 compared to $162.7 million in 2010. A reconciliation of the change follows ($ in millions):

2010 Operations and Maintenance Budget	**$162.7**
Increases in the budget	
Merit increases and elimination of vacancy factor	2.2
Increase in facility operating costs as both Folsom locations will be maintained for 2011	1.0
Increase level of professional fees for outside counsel and audit fees	1.4
Increase in other contract services for weather forecasting and credit rating	0.2
Net increases in the budget	**4.8**
Decreases in the budget	
Lower compensation due to reduced headcount and other personnel related costs	1.6
Reduction in overtime	0.5
Lower hardware and software maintenance costs	1.0
Lower telecommunication costs	0.2
Reduction in consultants and contract staff	1.3
Reduction in transportation and travel	0.2
Other decreases	0.2
Net decreases in the budget	**5.0**
2011 Operations and Maintenance Budget	**$162.5**

V. ISO Divisional Budget Overviews

Each corporate division provides a description of their department, functions, staffing, and proposed budget. The divisions are presented in the following order:

- Chief Executive Officer
- Human Resources
- Market and Infrastructure Planning
- Technology
- Operations
- Legal and Administrative
- Policy and Client Services



	Chief Executive Officer	Human Resources	Market & Infra structure Develop-ment	Tech-nology	Operations	Legal & Admin-istrative	Policy & Client Services
2010 Budget	$5.90	$6.10	$14.09	$48.38	$58.83	$20.41	$8.99
2011 Budget	$5.25	$5.75	$13.21	$49.44	$58.31	$22.11	$8.48
Change from 2010	$(0.65)	$(0.35)	$(0.88)	$1.06	$(0.52)	$1.70	$(0.51)

The 2011 proposed budget of $162.5 million is $200,000 or 0.1% lower than the 2010 budget of $162.7 million. The Operations and Technology divisions accounted for 36% and 30%, respectively, of the 2011 O&M budget while the Legal and Administrative division comprised 14%. The Market and Infrastructure Development division accounted for 8%, the Policy and Client Services division accounted for 5% and the Human Resources and Chief Executive Officer divisions made up 4% and 3%, respectively. Staffing decreased by 14 to 601 from 615.

A restructuring of the executive team was the most notable corporate change in 2010. The reorganization was in response to filling the executive position left open with the resignation of the long-serving vice president of Operations and other needs. Some responsibilities of five divisions were transferred to more directly align the divisions with

ISO core missions. For instance, all technology-related departments were combined to form a new division, Technology. Staff dealing with renewable integration and smart grid technologies have been reassigned to the Technology Division as well, which will also be responsible for the full end-to-end testing of new market applications.

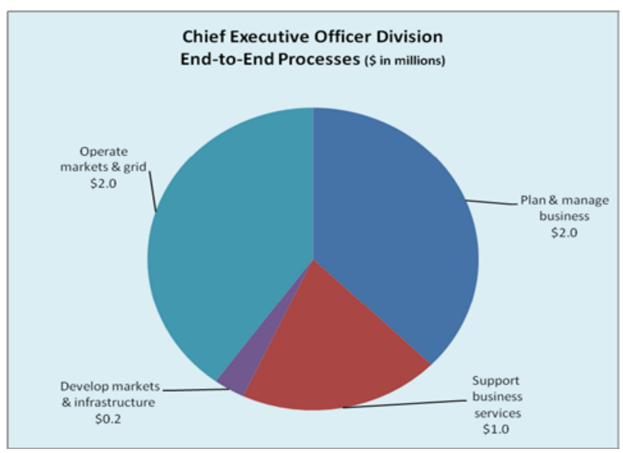
In addition, the financial planning, accounting and procurement departments were combined under the General Counsel and Chief Administrative Officer, who also serves as the Chief Compliance Officer and Corporate Secretary. While Legal is maintaining its corporate compliance function, the organizational changes also included creating a Director of Operations Compliance and Control position with supporting staff that reports to the Vice President of Operations and Chief Operating Officer.

Other organization realignments in 2010 include decommissioning the Organizational Effectiveness department because its mission of creating a strategic framework business plan ended with the divisions and departments now taking direct responsibility for implementing strategic planning initiatives.

The 2010 budget reflects these changes to be comparable with the 2011 budget.

Chief Executive Officer Division (including Department of Market Monitoring)

The division comprises the office of the Chief Executive Officer and the Department of Market Monitoring.

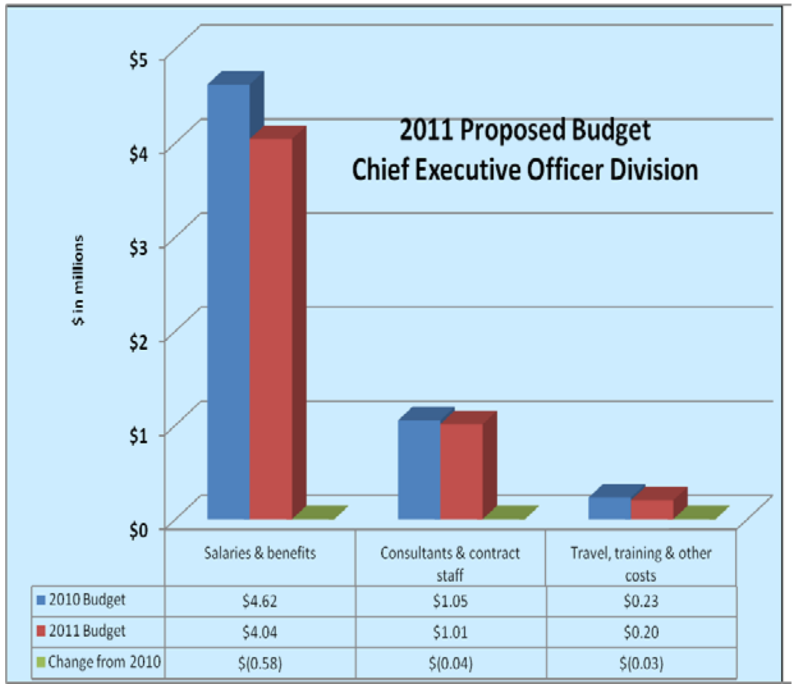


The Department of Market Monitoring provides independent oversight and analysis of the ISO markets by identifying market design flaws, potential market rule violations and market power abuses.

The department is staffed with a highly skilled group of analysts with advanced degrees in engineering and economics who publish quarterly and annual reports on market issues and performance as well as periodic ad-hoc reports. The market monitor is active in shaping policies to help ensure provisions are in place to mitigate the exercise of market power, especially with new market features and services that facilitate the integration of renewable resources.

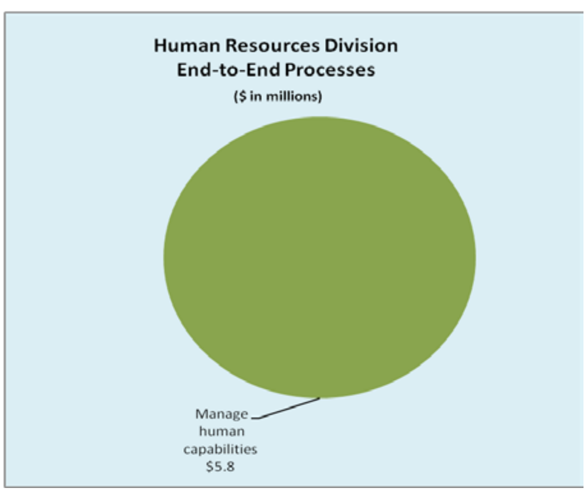
Discussion of Proposed Budget

The 2011 proposed budget of $5.2 million compares with the 2010 budget of $5.9 million, which is a decrease of $646,000, or 11%. Staffing remained the same at 17. Personnel costs decreased $578,000 while other costs decreased $68,000.



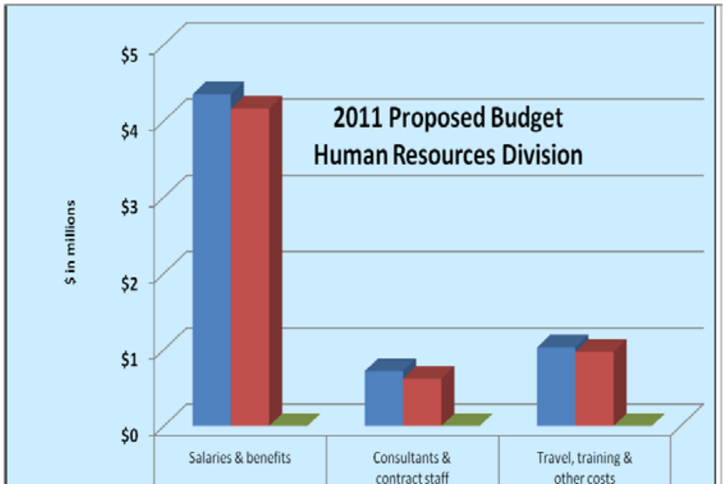
Human Resources Division

The Human Resources division establishes the policies, programs and "people" strategies that enhance the Corporation's ability to attract and retain the uniquely skilled and highly talented professionals needed to operate the Company and meet its objectives.



In addition to managing the division with the best industry practices, Human Resources will advance the corporate focus on developing the next generation of ISO people. Driven in part by the United States Department of Labor's continued prediction of diminishing resource pools in engineering and other technical fields, Human Resources will leverage the ISO Academy to advance the technical skills and capabilities of selected employees in engineering, operations, markets, economics and business.

Retention and succession development takes center stage in 2011 as the initiative to develop the next generation of ISO people matures. Our focus is on ensuring that key employees gain hands-on experience, situational awareness, coaching and mentoring in critical areas. Additionally, the President's Leadership Academy will continue to challenge employees with people-management responsibilities to grow leadership capabilities in areas such as collaboration, mentoring and developing others, interpersonal skills, and team building.



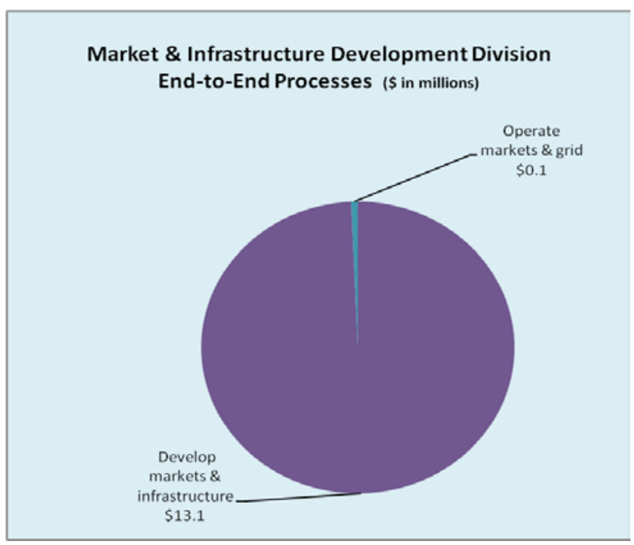
	Salaries & benefits	Consultants & contract staff	Travel, training & other costs
2010 Budget	$4.35	$0.72	$1.03
2011 Budget	$4.16	$0.62	$0.97
Change from 2010	$(0.19)	$(0.10)	$(0.06)

Discussion of Proposed Budget

The 2011 proposed budget of $5.8 million compares with the 2010 budget of $6.1 million, which is a decrease of $349,000, or 6%. Staffing decreased by two in 2011 to 17 from 19 in 2010. Personnel costs decreased $189,000, while consulting costs fell $105,000 and other costs dropped $55,000.

Market and Infrastructure Development

The division develops a forward-looking, comprehensive and fully compliant transmission plan that incorporates initiatives that facilitate a robust market, support the state's Resource Adequacy program, generator interconnection studies and renewable resource integration analysis. Other responsibilities include performing seasonal operating studies, maintaining operating procedures, supporting real time operations, and coordinating with surrounding control area operators on engineering issues.



Ongoing duties include developing policy positions on regulatory issues and responsibility for over 1,700 ISO regulatory contracts, including their negotiation, drafting and administration.

This division provides subject expertise and regulatory support to policymakers developing state initiatives such as greenhouse gases, increasing demand response participation in the wholesale market and setting capacity requirements. It also provides technical support to Market Services (Operations division) on congestion revenue rights and to Market Operations (Operations division) on full network modeling capabilities.

The Market and Infrastructure Policy Department is responsible for the design of market rules and mechanisms including those mandated for enhancement, such as convergence bidding, expanded functionality for demand response participation in the wholesale markets, real-time dispatch and pricing rules for constrained generation and decremental generation bidding rules.

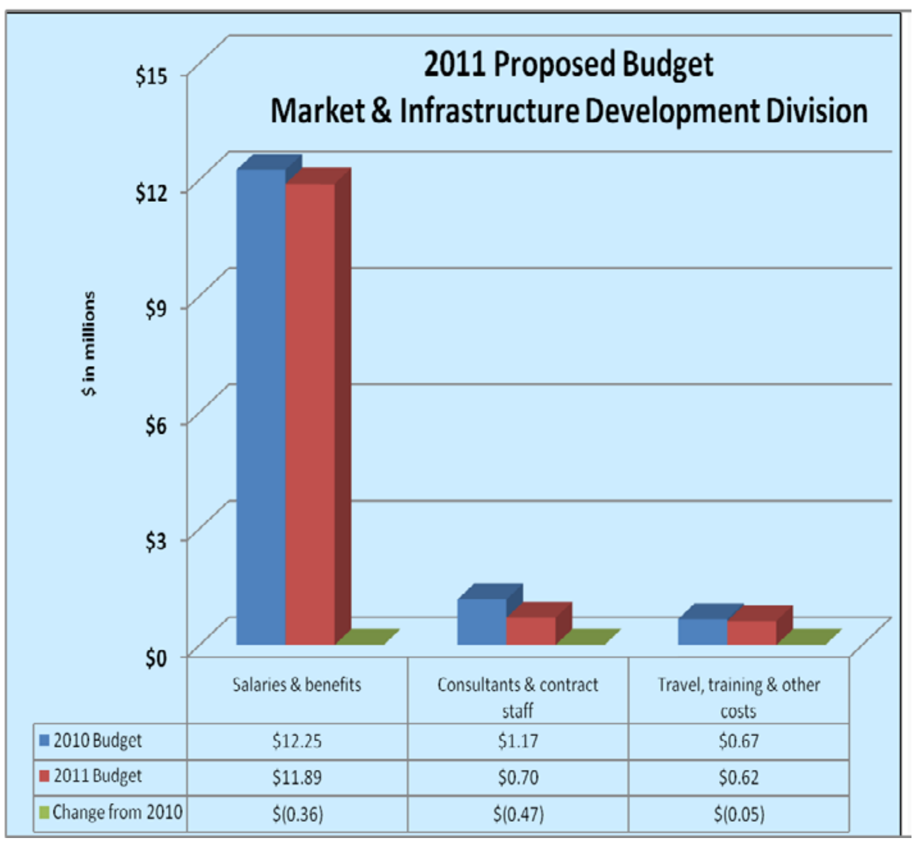
The Market Analysis and Development Department monitors the market and identifies systemic issues that may need attention. When it identifies issues, the department develops conceptual solutions to address them. The department holds a stakeholder Web conference about every six weeks that provides updates and observations on market performance with an emphasis on coordinating plans with stakeholders to implement market enhancements, services and features. The outreach is reflective of the ISO efforts to improve its communications with stakeholders and encourage feedback.

The division as a whole is focusing a substantial amount of resources to developing the rules and mechanisms to integrate renewable resources. Progress is being made on several related initiatives that include completing an important study on interconnecting 20% renewable generation and reforming the transmission planning process so that infrastructure upgrade plans include meeting state renewables portfolio standard targets as well as reliability needs.

Also, the ISO was fully engaged in 2010 with investor and municipal owned utilities via the California Transmission Planning Group in establishing the metrics that led to publishing a conceptual statewide transmission plan that fed into the ISO regulatory compliant 2011 transmission planning process.

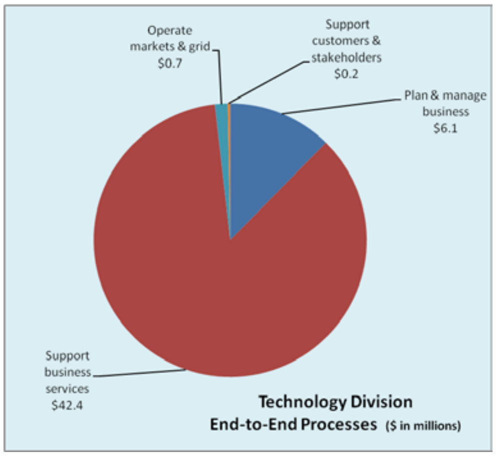
Discussion of Proposed Budget

The 2011 proposed budget of $13.2 million compares with the 2010 budget of $14.1 million, which is a decrease of $889,000, or 6%. Staffing decreased by 1 to 63 from 64. Personnel costs decreased $366,000, while consulting costs fell $465,000 and other costs dropped $58,000.



Technology

The Technology division encompasses Information Technology and the Project Office. Technology provides reliable, low-cost and world-class services and innovation through technologies that delivery exceptional system availability and new functionalities that support corporate goals and objectives.



The division's priorities in 2011 are as follows:

- to make incremental technology improvements, especially for market and reliability operations
- to proactively identify system problems and to fix them
- to predict system vulnerabilities and strengthen them before they become problems

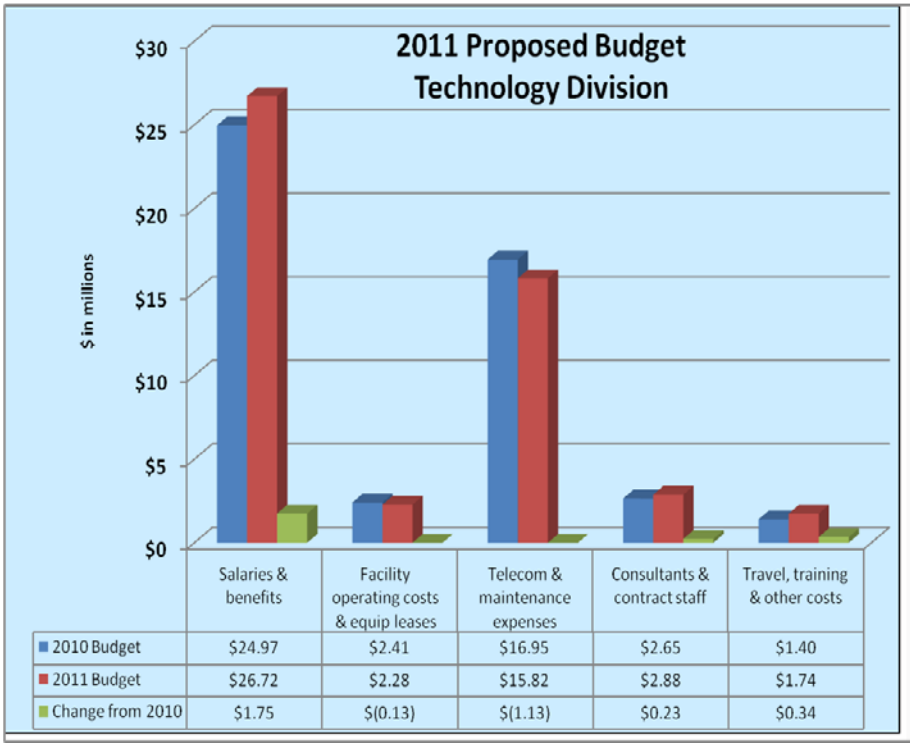
The Technology division is a lynchpin in managing the many changes needed to support renewable integration and has several initiatives directly related to facilitating new generation and transmission construction in California.

In the mid- to long-term future, the division is developing plans to make architectural changes so that ISO systems are easier to maintain, reduce maintenance costs and leverage technologies to improve cost effectiveness.

The Program Office Department leads and manages key initiatives and projects that focus on enhancing customer service and processes. Core functions include release planning, program management for the Strategic Plan and the market initiatives roadmap, and providing project delivery via a standardized program lifecycle approach. All Program Office efforts have a strong process and quality focus based on Project Management Institute and Capability Maturity Model Integration standards.

The Smart Grid Technologies and Strategy Department leads the ISO effort to identify emerging technologies, which also includes new uses for mature technologies that enhance grid efficiencies and monitoring capabilities. These technologies are critical in enabling the ISO to interconnect and manage the intermittency of renewable resources.

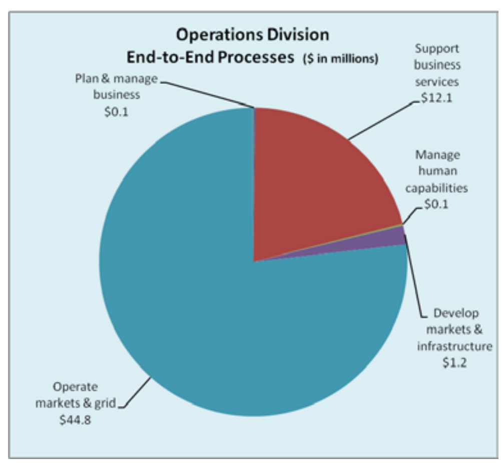
The Power Systems Technology Development Department is responsible for the functional testing related to market-related projects. Working with the Program Office, the department makes sure that project implementation plans are feasible. This department leads the advanced technology applications development efforts such as voltage stability and dynamic stability applications projects.



Discussion of Proposed Budget

The 2011 proposed budget of $49.4 million compares with the 2010 budget of $48.4 million, which is an increase of $1.1 million, or 2%. Staffing decreased by 1 to 161 from 162. Personnel costs increased $1.8 million, which reflected merit increases, the elimination of the vacancy factor and overtime. Hardware maintenance costs decreased $200,000, or 6%, to $3.0 million in 2011 from $3.2 million in 2010. Software maintenance costs decreased $788,000, or 10%, to $6.9 million in 2011 from $7.7 million in 2010. Maintenance contracts arising out of the new market software were not as high as originally anticipated. Consultants and contract staff costs increased $227,000, or 9%, to $2.9 million in 2011 from $2.7 million in 2010. Other costs increased $85,000.

Operations



The division's main mission is the reliable operation of the power grid, markets and operations support and it is comprised of Systems Operations, Operations Engineering Services, Market Services, and Operations Compliance and Control, as well as the Campus Operations Department.

The power system is evolving to accommodate an increasing amount of renewable resources connecting to the grid, rising levels of imports and exports, and the participation of demand resources in the wholesale market. In addition, new applicable reliability standards may impact how the ISO reliably operates the grid. With advanced tools, the division will proactively manage the changing profile and characteristics of the power system, which includes managing the intermittency of renewables.

A new state-of-the-art control center (as part of the headquarters construction project) staffed by industry leading professionals will enable the ISO to provide a more transparent view into the status of the real-time grid and market and solve potential reliability problems well in advance of real time. The Systems Operations Department operates the forward and real-time markets in a manner that minimizes the cost of delivering energy to California consumers.

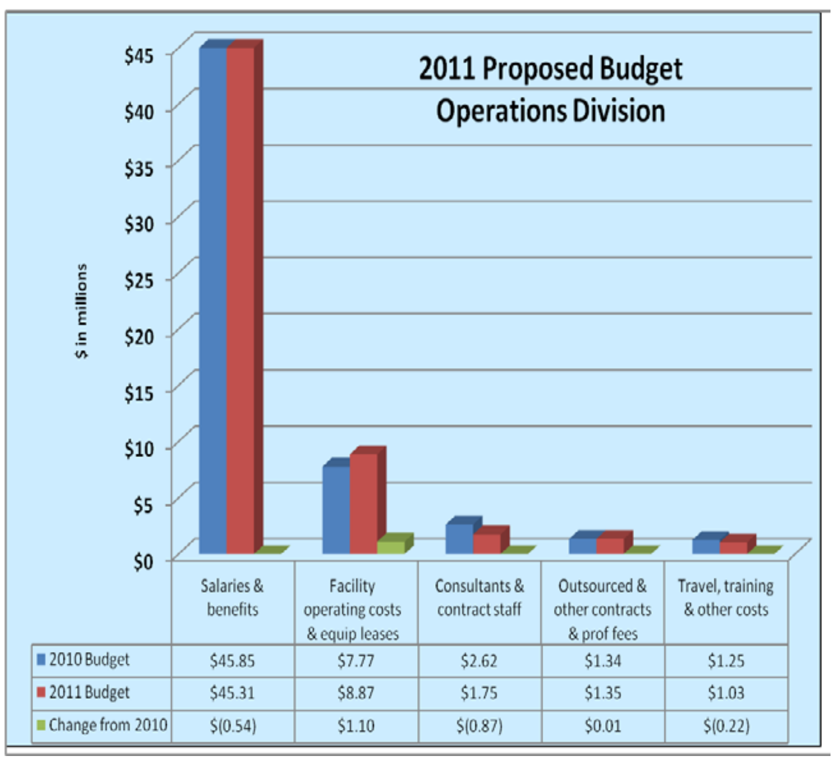
The Systems Operations and Operations Engineering Services Departments are becoming a center of excellence by further developing a professional staff that is highly skilled using the advanced technologies and tools necessary to reliably operate the grid and facilitate efficient markets in complex environments.

The Market Services Department performs the market settlement function as well as metering. It supports implementing market enhancements that facilitate transparent, consistent, and efficient operations as well as ones that reduce the settlement timeline to achieve efficient market outcomes.

The Operations Compliance and Control Department further develops and implements cross-training, market based training, forward analysis simulation training and individual career progression programs in order to empower our people to operate in a more complex, technical and challenging operating environment.

The Campus Operations Department manages the ISO building and infrastructure that supports a safe, efficient and comfortable work environment.

Discussion of Proposed Budget



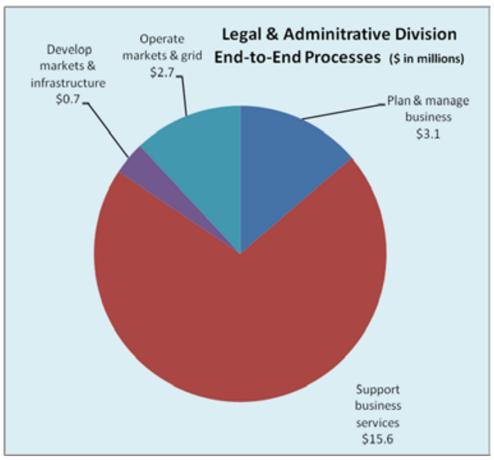
	Salaries & benefits	Facility operating costs & equip leases	Consultants & contract staff	Outsourced & other contracts & prof fees	Travel, training & other costs
2010 Budget	$45.85	$7.77	$2.62	$1.34	$1.25
2011 Budget	$45.31	$8.87	$1.75	$1.35	$1.03
Change from 2010	$(0.54)	$1.10	$(0.87)	$0.01	$(0.22)

The 2011 proposed budget of $58.3 million compares with the 2010 budget of $58.8 million, which is a decrease of $504,000, or 1%. Staffing decreased by 2 to 249 from 251. Personnel costs decreased $534,000. Facility costs increased by $1.1 million, or 14%, to $8.9 million in 2011 from $7.8 million in 2010. The increase is primarily related to the addition of the new headquarters building in 2011 while still maintaining the leased facility through 2012. Consulting and contract staff was reduced $869,000 while other costs decreased $207,000 primarily related to transportation and travel.

General Counsel and Chief Administrative Officer

The Legal and Administrative Division is comprised of the legal, compliance, internal audit, corporate secretary, finance, accounting and procurement departments. The legal division is staffed by a highly skilled, highly ethical team of professionals sought after by other ISO divisions and departments for their sound judgment, ability to solve problems, as well as its ability to add value in the legal and other areas of the company's business.

The legal division has four departments. The Corporate Counsel Department is responsible for key vendor contracts and other agreements, as well as providing counseling on regulatory contracts, corporate, employment, intellectual property, finance, tax, governance, and other general legal matters including conflicts and ethics advice.



The Regulatory Counsel Department oversees legal and regulatory functions (including tariff amendments), regulatory matters, and litigation. Its duties include working closely with policy development teams to create market services and features that conform to existing tariffs or work in parallel to draft tariff additions and modifications.

This work was especially important in 2010 in reforming the ISO transmission planning process and enhancing current rules on integrating renewables, storage technologies and demand response.

The Tariff Compliance Department is primarily responsible for tariff interpretations, maintenance and compliance.

The Litigation and Mandatory Standards Department oversees all state and federal court litigation and appellate work and handles adversarial proceedings. The duties also include providing advice to the corporate compliance team.

The Corporate Secretary Department coordinates Board-related matters, including communications, setting meeting agendas, and reviewing and coordinating the submission of Board documents. This department is also responsible for maintaining the official corporate record. The Paralegal and Office Administration Department is responsible for providing paralegal, and administrative and technical assistant support to the legal division.

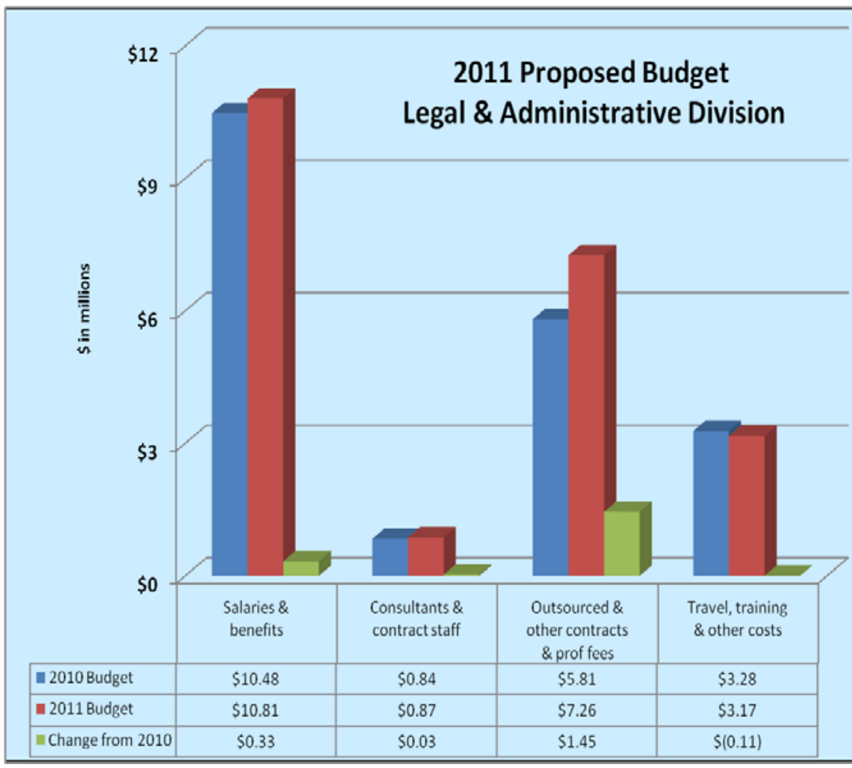
Corporate Compliance is the department that assesses and ensures business unit readiness for implementing new and revised mandatory reliability standards and ensuring a framework for tariff compliance as well as a corporate culture of compliance with all laws and corporate policies. This department is also responsible for corporate records management. The Internal Audit Department is responsible for developing and implementing the annual internal plan and conducting audits to evaluate the effectiveness of management practices and controls. This department also has the responsibility for the annual risk management assessment that feeds into the organization’s initiatives to mitigate identified risks.

The Accounting Department is responsible for implementing internal control policies, general accounting and financial reporting, and payables and receivables.

The Treasury and Credit Department is responsible for credit management and investments. Financial Planning is responsible for debt, financial administration of capital projects and financial planning, budgeting and rates.

Procurement and Vendor Management Department supports cost containment policies by purchasing goods and services through competitive vendor selection and cost management.

Discussion of Proposed Budget

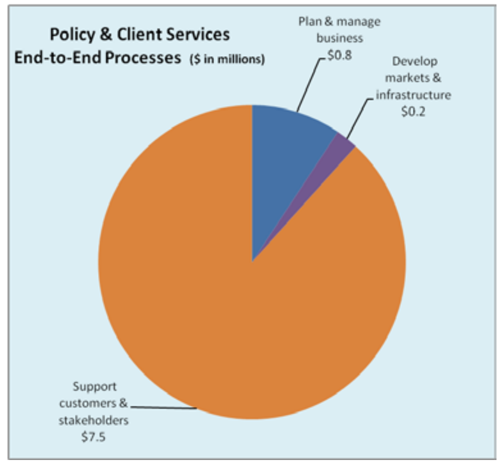


The 2011 proposed budget of $22.1 million is $1,700,000, or 8%, higher than the 2010 budget of $20.4 million. Staffing decreased by 6 to 55 from 61.

Personnel costs increased $324,000, which was primarily related to merit increases and the elimination of the vacancy factor. Professional fees increased $1.4 million, or 25%, as a result for the need of additional outside legal counsel and audit services. Consultants and contract staff increased $25,000, or 4%. Travel, training and other costs decreased $110,000, or 3%.

Policy and Client Services

The Policy and Client Services Division builds high quality collaborative relationships with a wide variety of stakeholders, regulators and consumer groups. It strives for excellence by providing timely and accurate information for public dissemination, fostering value added customer service, anticipating and addressing issues in a timely manner, and advancing objectives benefiting consumers and the electric industry. The division works toward these goals by collaborating across the ISO to quickly resolve customer issues, improve communication with stakeholders and effectively represent the ISO before state agencies, regional organizations and federal energy regulators.



The division is also responsible for key aspects in facilitating the integration of renewable resources by clearly explaining ISO positions and grid needs to technical and non-technical audiences. This has included such things as developing the "green pages" on the external ISO website and producing fact sheets that recast high technical grid terms and concepts into easily understandable language.

The division also performs important work to update and manage the ISO Business Practice manuals, which contain the information underlying tariffs and is critical in giving stakeholders and ISO customers the information they need to interconnect and operate renewable facilities, among other things.

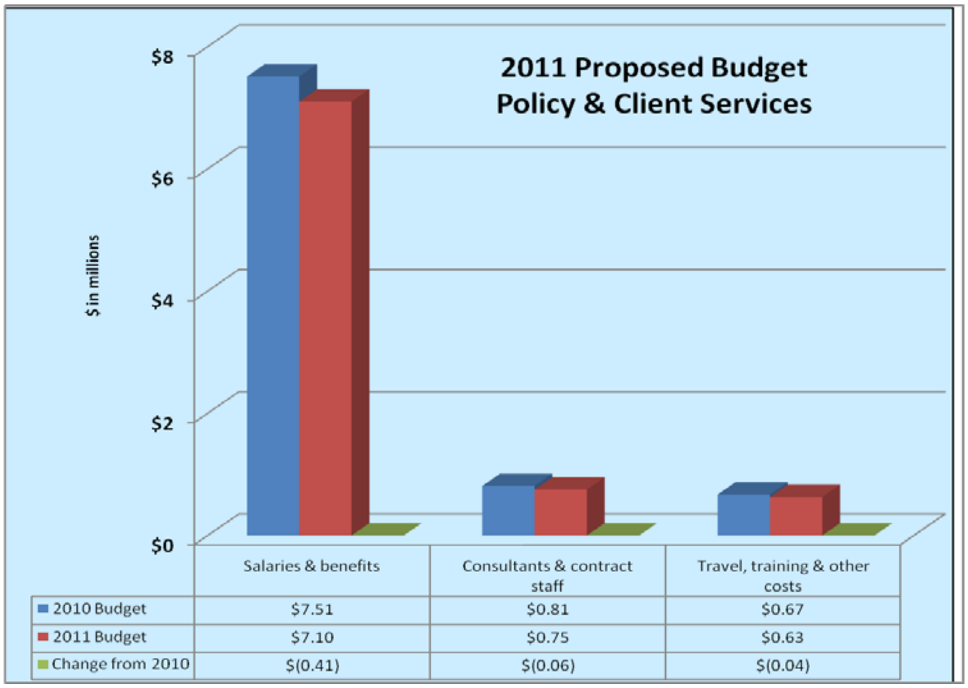
The Communications and Public Relations Department manages internal and external communications, including all Web communications, and employee and media relations. The department also issues stakeholder communications and develops new information products and services that add value to customer and stakeholder businesses.

The external affairs departments (federal, state and regulatory) oversee interactions with the state legislature and governor's office regarding matters that could impact ISO. The activities include building and maintaining relationships with regulatory agencies including the California Public Utilities Commission, the California Energy Commission, and the California Air Resources Board, and monitoring and managing federal legislative and regulatory matters that could influence ISO practices and policies. The ISO collaborated closely with the Air Resources Board as it developed the rules to implement California's landmark greenhouse gas emissions reduction law, Assembly Bill 32. The departments work with the state legislature to advise and educate lawmakers that are introducing new or modified statutes that impact the power system.

The Customer Services and Industry Affairs Department is the primary business interface between ISO and its clients and stakeholders. It was able to cut the amount of time it takes to resolve customer enquiries by 50% in 2009. The department has initiatives that continue in 2011 implementing a customer relations management system.

Discussion of Proposed Budget

The 2011 proposed budget of $8.5 million compares with the 2010 budget of $9.0 million, which is a decrease of $511,000, or 6%. Staffing decreased by two from 41 in 2010 to 39 in 2011. Personnel costs decreased $412,000, or 5%, and other costs decreased $99,000.



VI. Debt Service

Debt service budgeted for inclusion in the 2011 revenue requirement includes principal and interest on the ISO's outstanding Series 2008 and 2009 bonds. The 2008 bonds will be retired in full by February 2014, bear interest at 5%, as summarized below:

Amortization schedule for 2008 bonds ($ in millions)	Principle	Interest	Proceeds from debt service fund	Total
2011	$42.3	$6.5	$(0.7)	$48.1
2012	25.1	4.3	(0.7)	28.7
2013	36.0	3.0	(0.7)	38.3
2014	23.5	1.2	(20.2)	4.5
Total	**$126.9**	**$15.0**	**$(22.3)**	**$119.6**

In 2009, the ISO issued debt to finance building a new facility in Folsom on land owned by the ISO. The 2011 revenue requirement includes a portion of debt service costs related to this offering, as a portion of the interest carrying costs would be funded from the proceeds of the offering (as capitalized interest). The structure of the bonds is a fixed rate debt at rates from 4.5% to 6.25% with a term of 30 years. Lease payments on current facilities in Folsom will expire at the end of 2012. Amortization of the 2009 bonds is shown below:

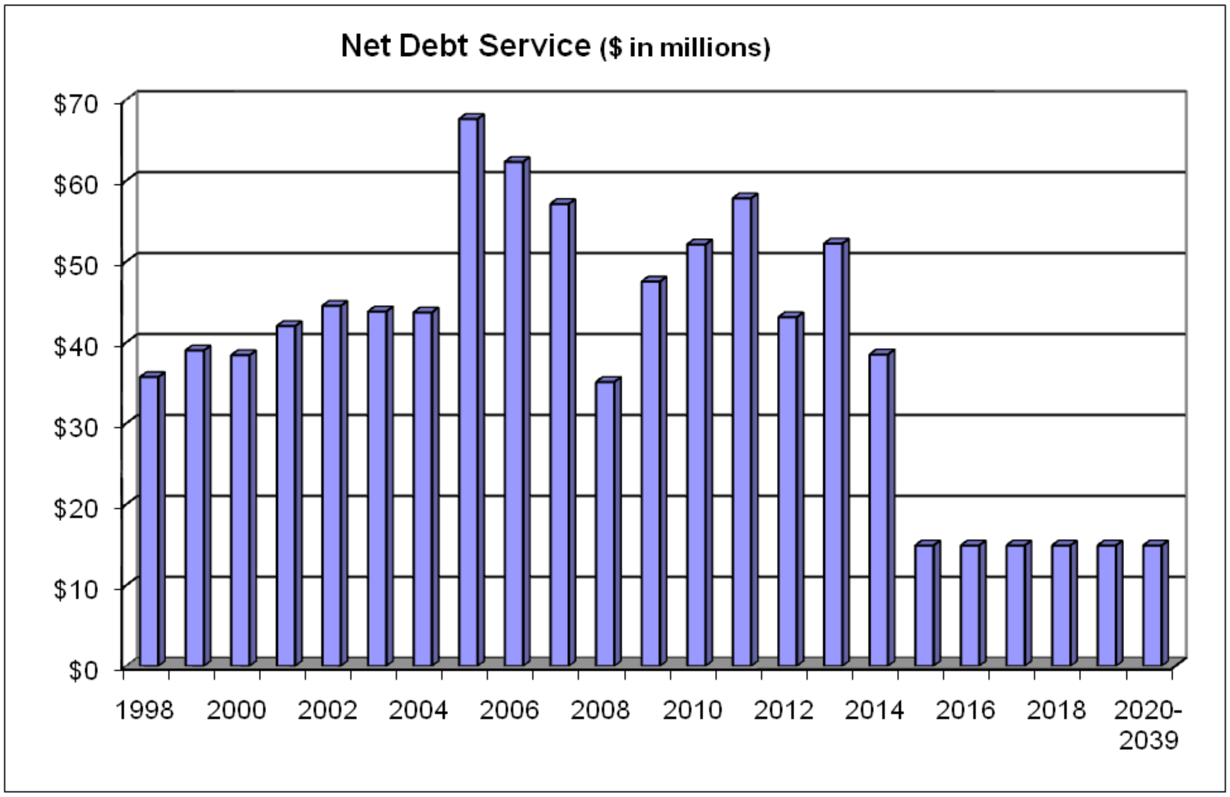
Amortization schedule for 2009 bonds ($ in millions)	Principle	Interest	Proceeds from debt service fund	Total
2011	$ -	$11.3	$(11.3)	$ -
2012	3.5	11.3	(8.5)	6.3
2013	3.6	11.2	(0.5)	14.3
2014	3.7	11.1	(0.5)	14.3
2015	3.8	11.0	(0.5)	14.3
2016	4.0	10.8	(0.5)	14.3
Thereafter	181.4	158.3	(11.3)	328.4
Total	**$200.0**	**$225.0**	**$(33.1)**	**$391.9**

The collection for the bonds in the revenue requirement occurs the year before the bond payments are made. Principle payments occur in February and interest is paid semiannually in February and August.

A summary of debt service is as follows:

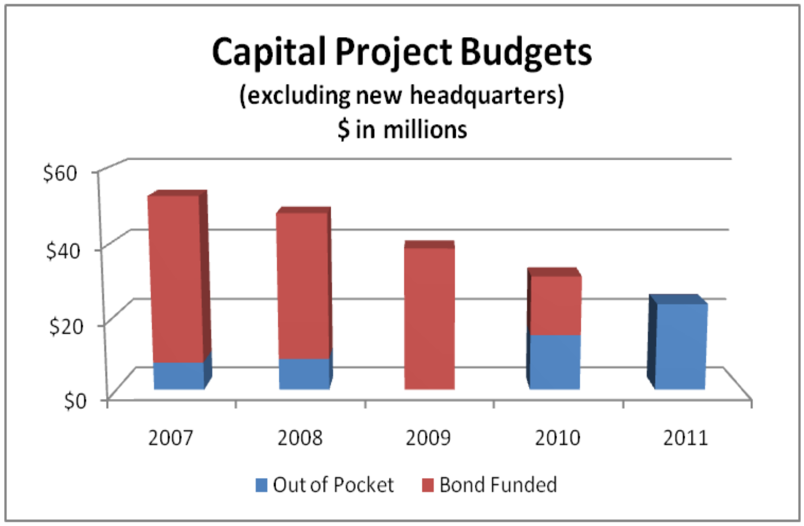
Debt Service ($ in millions)	2011 Budget	2010 Budget	Change
Principle payments on 2008 and 2009 bonds	$28.6	$42.3	$(13.7)
Interest payments	15.6	6.5	9.1
Less amounts from debt service reserve	(9.2)	-	(9.2)
Subtotal	**35.0**	**48.8**	**(13.8)**
25% Debt Service Reserve	8.7	12.2	(3.5)
Total	**$43.7**	**$61.0**	**$(17.3)**

Net debt service from ISO inception is shown below:



VII. Capital Project Budget

The planned 2011 capital budget of up to $23.5 million will fund projects as detailed on the following pages. All of it will be funded out of operating funds. Additional assessment of capital spending needs will continue over the coming months. The current project list excludes the ISO facility of $160.0 million, which is funded separately from the 2009 bonds.



Capital / Project Budget Development Process

The 2011 capital budgeting process will be held August – November of 2010. Throughout the year, the Program Office collaborates with the internal business units and maintains a list of projects. The list is based on the Five-Year Strategic Plan, the Information Technology roadmap, and the ISO market initiatives roadmap. On a monthly basis, strategic initiative owners and managers, along with an advisory committee, review the progress of active projects, identify issues and risks, and approve changes to the master project listing. During the budgeting process, the information technology roadmap items are combined with the strategic projects scheduled for the following year and a budget is developed. A prioritization and ranking process is evoked in the event that the budget amount is exceeded

Capital Project List

The list of projects put forward is consistent with the proposed funding level, and provides an indication of the projects to be initiated during 2011. This year's list includes renewable integration projects to help California reach the state mandated 20% and 33% renewable energy goals, as well as projects to help with identifying, proving and leveraging smart grid technologies. Also included are items mandated for implementation within three years after the new market launch (March 31, 2009) by the Federal Energy Regulatory Commission. All projects identified for 2011 will be subject to additional review before funding is approved, including further consideration of project need, a cost-benefit analysis and completion of a project plan. Specifically, the Corporate Management Committee made up of the Chief Executive Officer, Chief Financial Officer and General Counsel (with Chief Technology Officer attending) reviews and approves all projects considered for funding in 2011. The priorities set forth for 2011 may change depending on developments during the second half of 2010.

Proposed Capital Projects for 2011	Amount
Alignment (Customer, Stakeholder, External)	
Renewable integration market products and studies	medium
Smart Grid projects and studies	medium
Enhanced forecasting tools (congestion management display, short term event predictor and ramp planning tool)	small
Day ahead scheduling of intermittent resources	small
Rules to encourage the dispatch of wind and solar resources	small
Customer relationship manager - phase 2	small
Total	**2,200,000**
Operational Excellence (Process)	
Year three mandated items (load aggregation point, bid in demand, export of ancillary services and two tier real time uplift)	large
Operational improvements to market systems	large
Implement enterprise model management systems	medium
Voltage stability analysis — look ahead and real time (includes flow-gate capacity)	medium
Bid cost recovery for units running over multiple operating days	medium
Outage management system enhancements	medium
Phasor measurement infrastructure and wide area monitoring and	medium
Energy management system: grid operations training simulator	medium
Aggregation of pumps and pump storage	medium
Implement network application tools — dynamic stability	small
Operational meter analysis and reporting new features, corrections and automation	small
Replacement requirement for resource adequacy resources planned outages	small
Congestion revenue rights enhancements	small
Changes in commitment costs	small
Standard capacity product — phase 3	small
Multi-day unit commitment and 72 hour residual unit commitment	small
Ancillary services substitution	small
Multi hour block bidding in residual unit commitment	small
Simultaneous residual unit commitment and integrated forward market	small
Interim capacity procurement methodology and exceptional dispatch bid mitigation	small
Ancillary services for non generation resources	small
Market information data release — phase 3	small
California Energy Commission phasor project	small
Total	**13,700,000**

Proposed Capital Projects for 2011	Amount
Institutional Sustainability (People/Technology)	
Consolidation of multiple overlapping applications to improve efficiency	medium
Implement a standard graphical user interface for all tools	small
Efficiency and performance enhancements for settlement systems	small
Integration — common information model standards alignment and enterprise architecture implementation	small
Test automation tools	small
Total	**2,500,000**
Reasonable Cost and Essential Projects (Financial)	
Hardware, software and office equipment	large
Capitalized labor for portion of project office	large
Upgrades to Oracle eBusiness suite software — human resources, finance, procurement and market clearing	medium
Facilities — furniture purchases	small
Total	**5,100,000**
Total Proposed Capital Projects for 2011	**$23,500,000**

Note: The costs of the individual projects are not shown but are categorized by size as follows: small projects under $500,000, medium projects from $500,000 to $1 million and large projects over $1 million. The actual projects completed during 2011 will vary, including the potential addition of projects not on this list, the deferral of projects on this list to future years, or the elimination of projects on this list if no longer necessary.

VIII. Miscellaneous Revenue

Miscellaneous revenue for 2011 is budgeted at $6.9 million, a $1.2 million decrease from 2010 primarily to reflect lower earnings on the investment portfolio. The details of this category are as follows:

Miscellaneous Revenue ($ in millions)	2011 Budget	2010 Budget	Change
Scheduling Coordinator application and training fees, metered sub-system deviation fees, station power and wind forecasting and other fees	$0.5	$0.5	$ -
Interest earnings	2.6	3.8	(1.2)
Large generation interconnection fees	1.8	1.8	-
California-Oregon Intertie path operator fees	2.0	2.0	-
Total	**$6.9**	**$8.1**	**$(1.2)**

IX. Reserve Credit from 2010

The operating reserve credit is a reduction or offset to the ISO revenue requirement for 2011. In any year that the ISO's operating reserve account exceeds 15% of the prospective year's O&M budget, the excess goes toward reducing the revenue requirement for the coming year. For 2011, the ISO forecasts a credit from the operating reserve account of $33.0 million. The principle change was the collection of an extra month's grid management charges in January 2010 arising from the implementation of the payment acceleration market software enhancement in November 2009. The collection of an extra month's grid management charge will allow the expenditure for capital projects without the associated borrowing costs and 25% interest reserve. The reserve credit is calculated separately for each grid management charge category. A summary is below.

Reserve Credit from prior year ($ in millions)	2011 Budget	2010 Budget	Change
Increase in 15% reserve for O&M budget	$-	$(0.9)	$0.9
25% debt service collection from prior year	12.2	11.9	0.3
Collection of additional months grid management charges from implementation of payment acceleration	15.9	15.4	0.5
True-up of actual to forecast revenues and expenses and in 2009 a reduction in interest owed on generator fines arising from FERC ruling in 2001 refund case.	4.9	9.1	(4.2)
Total	**$33.0**	**$35.5**	**$(2.5)**

X. Unbundled Grid Management Charge Calculations

The ISO recovers its costs through separate grid management charges to market participants. Service categories and billing determinants are listed on the following page.

Rate Calculation

The rate for each service category is calculated as follows:

$$\frac{\text{Costs Allocated to Service Category}}{\text{Billing Determinant Volume}} = \text{Grid Management Charge Rate}$$

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Components of Grid Management Charge

The numerator for the above equation has been determined by summing ISO components of the revenue requirement for each service category, as the following:

- Operating and maintenance costs
- Miscellaneous revenue
- Debt service costs
- Cash funded capital project expenditures
- Operating reserve account credit

Changes to Grid Management Charge

In 2010, the structure for the Market Usage Forward Energy (MUFE) was changed to be based on the maximum MW of supply or demand scheduled in the day ahead market. The structure became effective June 1, 2010. Convergence bidding is planned for implementation in February 2011 and there will be two charges associated with this new functionality. The first is a bid charge of $0.005 per bid segment. Proceeds from this charge will offset the next year's costs for the convergence bidding MWh charge. The second charge will be applied to the gross MWh of supply and demand awarded in the day ahead market. The revenue requirement for this category will be nine percent of the sum of the costs associated with the market usage forward energy and forward scheduling categories.

Billing Determinants

The billing determinants for the rate structure are as follows:

GMC Rate Structure			
Function	**Rate Name**	**Bill Determinant**	**Charge Code**
Core Reliability Services (CRS)	CRS-demand (peak)	Monthly non-coincident peak (NCP) hour ending (HE) 7 – HE 22	4501
	CRS-demand (off-peak)	Monthly NCP all other hours	4502
	CRS-energy export	MWh of exports, excluding exports on transmission ownership rights (TOR)	4503
Energy Transmission Services (ETS)	ETS-net energy	MWh of metered control area load, excluding load on TORs	4505
	ETS-uninstructed deviations	MWh of uninstructed imbalance energy (UIE) netted over the settlement interval (except UIE associated with Participating Intermittent Resource Program PIRP)	4506
CRS/ETS	TOR	Metered control area load MWh on TORs	4508
Forward Scheduling (FS)	FS	Count of hourly schedules (including awarded RUC schedules)	4511
	FS-inter-Scheduling Coordinator (SC) trades	Count of hourly trades (including trades of Integrated Forward Market uplift obligations)	4512
	FS-PG&E-PGAB inter-SC trades	Count of hourly trades for PG&E-PGAB	4513
Market Usage (MU)	Purchases and sales of ancillary services (AS)	Day ahead and hour ahead scheduling process and real time MWh	4534
	Instructed energy (IE) (real time)	MWh of IE	4535
	Net uninstructed deviations, (Real Time)	MWh of UIE netted over the settlement interval (except UIE associated with PIRP)	4536
	Forward Energy	Maximum MWh of supply or demand scheduled in day ahead market	4537
Convergence Bidding	Bid charge	Bid charge of $0.005 per bid segment	4520
	Volumetric charge	Gross amount of MWh of supply or demand awarded in day ahead market	4533
ETS/MU	Monthly netted deviations – PIRP	MWh of IUE netted over the month for PIRP	4546
Settlements, Metering, and Client Relations (SMCR)	SMCR	Monthly customer charge of $1,000 per business associate ID	4575

Component Rates

The rates that result from the budget are as follows:

Net Revenue Requirement by Service Category ($ in millions)

Charge Code	Service component	2011 Budget	2010 Budget	$ Change	% Change
4501	CRS – demand (peak)	$32.2	$35.0	$(2.8)	(8.0)%
4502	CRS – demand (off-peak)	1.0	0.9	0.1	11.1
4503	CRS – energy exports	8.3	8.7	(0.4)	(4.6)
4505	ETS – net energy	68.7	75.2	(6.5)	(8.6)
4506	ETS - deviations	11.8	13.0	(1.2)	(9.2)
4508	CRS / ETS - TOR	0.9	0.9	-	-
4511-13	Forward Scheduling	12.0	22.2	(10.2)	(45.9)
4534-38	MU – AS and real time energy	34.3	16.9	17.4	103.0
4537	MU – forward energy	16.0	20.5	(4.5)	(22.0)
4533	MU – convergence bidding	2.8	-	2.8	new
4575	SMCR	1.8	1.8	-	-
Total		**$189.8**	**$195.1**	**$(5.3)**	**(2.7)%**

Billing Determinant Volume Forecast (in thousands of Units)

Charge Code	Service component	2011 Budget	2010 Budget	Unit Change	% Change
4501	CRS – demand (peak) - MW months	424.7	445.6	(20.9)	(4.7)%
4502	CRS – demand (off-peak) – MW months	19.5	16.3	3.2	19.6
4503	CRS – energy exports – MW of exports	5,122.9	7,439.7	(2,316.8)	(31.1)
4505	ETS – net energy – MW of load	232,168.8	239,426.8	(7,258.0)	(3.0)
4506	ETS – deviations – MW of net uninstructed energy	9,620.3	11,247.2	(1,626.9)	(14.5)
4508	CRS / ETS – TOR – MWh of exports	3,808.6	4,003.8	(195.2)	(4.9)
4511-13	FS – number of hurly schedules and awarded AS bids	9,136.1	12,999.7	(3,995.9)	(30.7)
4534-38	MU – AS and real time energy – MWh of awarded AS, IE and net UE	76,426.4	73,672.6	3,863.6	5.4
4537	MU – Forward energy – MWh of net purchases and sales in day ahead market	325,186.8	325,186.8	-	-
4533	MU – convergence bidding	44,975.3	-	44,975.3	new
4575	SMCR – Customer months	1.8	1.8	-	-

Grid Management Charge (Rate per Unit) (note rate calculations may vary due to rounding)

Charge Code	Service component	2011 Budget	2010 Budget	$ Change	% Change
4501	CRS – demand (peak)	$75.90	$78.51	$(2.61)	(3.3)%
4502	CRS – demand (off-peak)	50.10	51.82	(1.72)	(3.3)
4503	CRS – energy export	1.63	1.17	0.46	39.3
4505	ETS – net energy	0.29	0.31	(0.02)	(6.5)
4506	ETS - deviations	1.22	1.16	0.06	5.2
4508	CRS / ETS - TOR	0.23	0.23	-	-
4511-13	FS	1.32	1.71	(0.39)	(22.8)
4534-38	MU – AS and real time energy	0.45	0.23	0.22	95.7
4537	MU – forward energy	0.05	0.06	(0.01)	(16.7)
4533	MU – convergence bidding	0.06	-	0.06	new
4546	ETS/MU - Monthly netted deviations – PIRP	1.67	1.39	0.28	20.1
4575	SMCR	1,000.00	1,000.00	-	-

The following table provides comments on the changes in grid management charge rates from 2010 to 2011 for those charges that make up more than 5% of the revenue requirement. The overall rate change is attributable to two components:

- Changes in the components of the revenue requirement (O&M budget, debt service, other revenue and operating reserve credit) attributed to each grid management charge service category and
- Changes in the billing determinant volume estimates.

Comments on Changes in Grid Management Charge Rates

Charge Code	Service component	Change in Rate $	% of Revenue Require-ment	Comments on Change
4501	CRS	$(2.61)	17.0%	Decrease in 2011 revenue requirement
4505	ETS – net energy	(0.02)	36.2	Decrease in 2011 revenue requirement
4506	ETS - deviations	0.06	6.2	Increase attributable to drop in estimated volumes
4511-13	FS	(0.39)	6.3	Under collection in 2009 increased revenue requirement for 2010. Condition did not occur in 2010 leading to lower revenue requirement in 2011.
4534-38	MU - AS and real time energy	0.22	18.1	Over collection in 2009 reduced revenue requirement for 2010. Condition did not occur in 2010 leading to higher revenue requirement in 2011.
4537	MU – forward energy	(0.01)	8.4	Structure changed in 2010 as result of FERC settlement
	Total %		92.2%	