California Independent
System Operator Corporation

June 15, 2015

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. ER15- ___-000

Energy Imbalance Market Year One Enhancements – Phase 1

Dear Secretary Bose:

The California Independent System Operator Corporation ("CAISO") submits this tariff amendment to revise the CAISO tariff governing the Energy Imbalance Market. The proposed modifications, resulting from Phase 1 of the CAISO's Energy Imbalance Market Year One Enhancements initiative, enhance functionality, accommodate participation of additional Balancing Authority Areas, address issues encountered during the first year of operations, and comply with certain Commission directives in its order approving implementation of the Energy Imbalance Market. Specifically, the proposal (1) allows the use of available transfer capability for EIM transfers, (2) provides a cost based approach for greenhouse gas bidding by EIM participating resources and a means for such resources to avoid being dispatched to serve load in California, (3) aligns the EIM administrative charge with the grid management charge, and (4) includes additional elements for the evaluation of resource sufficiency.[1]

The CAISO requests that the Commission permit this tariff amendment to become effective October 1, 2015, except for the amendments to sections 29.17 and 29.32, for which the CAISO requests an effective date of September 15, 2015. NV Energy is scheduled to begin participating in the Energy Imbalance Market on October 1, 2015, and the earlier effective date for some provisions is necessary to support the planned period of parallel operation in September. Even if NV Energy's participation as an EIM entity were delayed, the proposed

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[1] The CAISO submits this filing pursuant to Rule 205 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.205 (2014) and section 205 of the Federal Power Act, 16 U.S.C. § 824d (2012).

effective dates would still apply to PacifiCorp's participation in the Energy Imbalance Market. The CAISO further requests that the Commission issue an order by September 1, 2015. The sooner the Commission can issue its order the sooner the CAISO and market participants will have certainty with respect to the rules in effect on September 15, 2015 and October 1, 2015.

I. BACKGROUND

The Energy Imbalance Market provides other balancing authority areas the opportunity to participate in the real-time market for imbalance energy that the CAISO operates in its own balancing authority area. PacifiCorp's two balancing authority areas were the first to join the Energy Imbalance Market. The CAISO's market rules went into effect on October 24, 2014, with the initial trading day of November 1, 2014.[2]

With one exception, the Energy Imbalance Market has functioned as expected.[3] The CAISO and PacifiCorp have estimated that the Energy Imbalance Market has yielded over $11 million in benefits since its implementation.[4] Three additional balancing authorities—NV Energy, Puget Sound Energy, and Arizona Public Service Company—have signed agreements under which they will become EIM entities and participate in the Energy Imbalance Market.[5] NV Energy will begin participation on October 1, 2015. Puget Sound Energy and the Arizona Public Service Company intend to join the Energy Imbalance Market on October 1, 2016.

Even before the Energy Imbalance Market commenced operations, the CAISO anticipated that the first year of actual operations would reveal potential market modifications to improve functionality as well as issues that the CAISO would need to address. For that reason, on October 28, 2014, the CAISO

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[2] *See Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,231 (2014) ("June 19 Order") (conditionally accepting tariff revisions to implement Energy Imbalance Market); *Cal. Indep. Sys. Operator Corp.*, 149 FERC ¶ 61,058 (2014) (order denying requests for rehearing, granting in part and denying in part requests for clarification, and conditionally accepting tariff revisions on compliance with regard to order listed above); Letter Order, 149 FERC ¶ 61,005 (Oct. 2, 2014) (order granting CAISO request to extend effective date of Energy Imbalance Market tariff revisions from September 23, 2014, to October 24, 2014, for trading day November 1, 2014).

[3] The exception involves infrequent anomalous pricing at times when the CAISO must relax transmission or power balancing constraints. The CAISO and other parties are addressing these issues in on-going proceedings in Docket Nos. ER15-861 and EL15-53.

[4] *See* April 30, 2015 Press Release.

[5] *See Cal. Indep. Sys. Operator Corp.*, 143 FERC ¶ 61,298 (2013); *Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,200 (2014), and *Cal. Indep. Sys. Operator Corp.*, 151 FERC ¶ 61,158 (2015).

announced an Energy Imbalance Market Year One Enhancements initiative. The CAISO is considering enhancements in two phases. This filing represents the completion of the first phase.

II. STAKEHOLDER PROCESS AND BOARD CONSIDERATION

As part of the Energy Imbalance Market Year One Enhancements initiative, the CAISO posted an issue paper and straw proposal on November 11, 2014,[6] and followed up with a stakeholder meeting on November 17, 2014. The CAISO conducted an online conference and stakeholder meeting on December 19, 2014, and January 8, 2014, respectively. The CAISO solicited comments after each of these events.[7]

On January 23, 2015, the CAISO issued a technical paper on energy transfer scheduling in the Energy Imbalance Market[8] and discussed it in a January 30, 2015 online conference. Subsequently, the CAISO solicited comments on the technical paper.[9] The CAISO issued a Draft Final Proposal on February 11, 2015,[10] and held a meeting on the proposal on February 18, 2015. The CAISO again solicited and considered stakeholder comments.[11]

The CAISO presented the proposal to its Board of Governors on March 26, 2015.[12] The CAISO's Department of Market Monitoring informed the Board of its support for the proposed enhancements.[13] The Board unanimously approved the proposal.[14]

Following Board approval, on April 14 and 21, 2015, the CAISO posted draft tariff language. Following the receipt of stakeholder comments,[15] the CAISO conducted an online conference to discuss the comments on May 4, 2015 and posted its responses to comments. The CAISO posted revised tariff

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6 Issue Paper and Straw Proposal – Energy Imbalance Market Year 1 Enhancements.

7 *See* comments on issue paper and straw proposal and comments on January 8, 2015 presentation.

8 Technical Paper – Energy Transfer Scheduling in the Energy Imbalance Market.

9 *See* comments on technical paper.

10 Draft Final Proposal – Energy Imbalance Market Year 1 Enhancements.

11 *See* comments on draft final proposal.

12 Board material included a memorandum and presentation.

13 Department of Market Monitoring Report – March 2015.

14 *See* motion approving proposed enhancements.

15 *See* comments on tariff language.

language on May 12, 2015.[16] The CAISO again reviewed the draft tariff language with stakeholders and received their comments on May 19 and May 26, respectively.[17] The proposed tariff language reflects input received in this process.

III. PROPOSED TARIFF REVISIONS

A. Use of available transfer capability for EIM transfers.

The initial implementation of the Energy Imbalance Market relied upon PacifiCorp's making available merchant transmission ownership and contractual rights to support EIM transfers. This is known as the PacifiCorp interchange rights holder mechanism and is as embodied in both the PacifiCorp OATT[18] and the CAISO tariff.[19] This mechanism worked well for the PacifiCorp implementation, but other EIM Entities have expressed an interest in making unused transmission capability under their OATTs eligible for EIM transfers. Accordingly, the CAISO and stakeholders developed a mechanism to allow EIM Entities to use available transfer capability, as defined under an EIM Entity OATT, to support EIM transfers if it is not being used by transmission customers. This mechanism provides all EIM Entities the opportunity to realize the benefits of participating in the Energy Imbalance Market by using unscheduled transmission in an efficient manner.

Using available transfer capability for EIM transfers is the essence of the CAISO's proposal. Because NV Energy will use available transmission capacity for EIM transfers (as opposed to PacifiCorp's use of transmission capacity provided by interchange rights holders), the CAISO must modify the EIM design to accommodate such an approach. NV Energy included the necessary supporting provisions in its OATT, and the Commission approved them.[20] The Commission expressly found that using available transfer capacity to support EIM transfers does not confiscate the rights of NV Energy's OATT customers.[21] Here the CAISO simply proposes to make a conforming change to its tariff to facilitate the use of available transfer capability for EIM transfers and effectively implement a general concept that the Commission has already approved.

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16 *See* revised tariff language.

17 *See* further comments on tariff language.

18 PacifiCorp OATT, Attachment T, section 5.2.

19 CAISO Tariff, section 29.17(f).

20 *NV Energy*, 151 FERC ¶ 61,131 at PP 116-18 (2015).

21 *Id.* at P 116.

1. EIM transfer limit constraints.

The EIM transfer limit ensures that imbalance energy transfers between EIM balancing authority areas are within the transmission capability made available to the Energy Imbalance Market. Currently, tariff section 29.17(f) limits EIM transfers according to the aggregate transmission rights made available to support EIM transfers. This limit was appropriate for transfers among the CAISO and PacifiCorp balancing authority areas because there is a single path between each balancing authority area. However, as more balancing authority areas participate in the Energy Imbalance Market, there will be multiple potential transfer paths among the balancing authority areas, and not all balancing authority areas will use the same interchange rights holder mechanism as PacifiCorp. For example, as noted, NV Energy will use available transmission capability over multiple intertie scheduling points to support EIM transfers between itself, the CAISO, and PacifiCorp East. The CAISO must modify its tariff to accommodate the approach approved for NV Energy in order to maximize the EIM transfers among balancing authority areas. Thus, the CAISO is proposing to revise section 29.17(f) to provide for consideration of EIM transfer limits separately for each intertie scheduling point. In order to accommodate NV Energy's participating in the Energy Imbalance Market in October 2015, the proposed changes are needed by that time.

Currently, in the fifteen-minute market and in the real-time dispatch, the CAISO enforces intertie scheduling limits to ensure energy schedules do not exceed each intertie's transmission capability. Under the proposed tariff revisions, the CAISO will similarly apply these intertie scheduling limits to interties used in the Energy Imbalance Market. In addition, the CAISO will continue to enforce EIM transfer limits to ensure that EIM transfers across EIM interties do not exceed transmission available to support EIM transfers (either through interchange rights or available transfer capability) and the intertie scheduling limit. All resources within the EIM footprint and at EIM interties compete equally to ensure the most economically efficient use of transmission up to intertie scheduling limits.

Generally, the CAISO will establish the EIM transfer limit based on information from the EIM entity. If two EIM Entities share an intertie, the CAISO will set the intertie scheduling limit equal to the lowest available transfer capability value, as determined by the EIM entity that submits the e-tag for the transfer on that intertie, and will enforce the individual EIM transfer limit for each EIM entity while allowing energy to wheel through the respective EIM entities based on the transmission made available for use in the Real-Time Market. The CAISO discussed the details of the procedure with stakeholders and will include them in the business practice manual for the Energy Imbalance Market.[22] These procedures appropriately belong in the business practice manual because they are mere implementation details.

Taken together, these rules ensure that EIM transfers, regardless of whether supported by interchange rights or available transfer capability, remain within path limits, are managed consistent with Western Electricity Coordinating Council scheduling practices, and only use the transmission capability made available to the Energy Imbalance Market.

2. EIM Transfer Parameter

In addition, because there may be multiple potential intertie scheduling paths for scheduling EIM transfers, the proposed tariff provisions enable the CAISO to include a de minimis transfer-related cost as a parameter in the optimization that will enable the optimization to function more effectively. Stated differently, because the optimization can account for EIM transfers on multiple paths with different transfer limits, the CAISO needs a parameter to determine efficiently on which E-tags to schedule the EIM transfer for accounting purposes. The objective of the EIM transfer parameter is not to recover transmission revenues between EIM balancing authority areas; rather, the optimization uses the cost to select the optimal path or paths for EIM transfers.

The CAISO will set the parameter, which is not an explicit cost, at a level that reflects the relative priorities of various paths for scheduling EIM transfers and will allow the market optimization to differentiate the value of scheduling on more optimal paths rather than less optimal paths. This will enable the calibration to produce a more robust solution. The CAISO will administratively determine the parameter costs and set them as low as possible while allowing various paths' priorities to be recognized; these costs will reflect efficiency gains of scheduling over the most optimal paths.

Although the transfer parameter cost will not be explicitly settled, it can affect locational marginal prices in two ways: (1) the transfer cost will be reflected in locational marginal prices if an individual EIM transfer limit is binding; and (2) the transfer parameter cost can influence the market dispatch and consequently affect locational marginal prices. Any impact on rates will be insignificant for the reasons discussed below.

Because the market optimization includes the transfer parameter cost, during market simulation prior to the effective date of the proposed tariff revisions, the CAISO will determine the appropriate level of the transfer cost by

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[22] *Supra,* n. 9 and 10.

balancing the benefits of including transfer costs with the impact to locational marginal prices. The CAISO will document the applicable transfer parameter costs for individual paths in the Business Practice Manual for the Energy Imbalance Market. In addition, in response to stakeholder concerns regarding the potential level of the transfer parameter cost, the CAISO proposes in new section 29.17(h) to cap the cost of any transfer parameter at $0.10 per MWh. Publication in the Business Practice Manual will ensure full transparency of the implementation detail, with the goal of implementing the lowest values possible, while producing a robust solution. The maximum transfer cost is not a rate *per se,* is not associated with a particular charge to ratepayers, is not associated with a particular cost, and its purpose is not cost recovery. Rather, its purpose is merely to ensure optimal and efficient use of and scheduling of EIM transfers in the market software.

With NV Energy and other balancing authority areas joining the Energy Imbalance Market, the number of intertie schedules to support EIM transfers will increase substantially, resulting in a large number of individual transfer paths. This will require a large number of transfer cost parameters that the CAISO will need to re-calibrate from time to time for reasons such as changes in network topology, changes in transmission rights, and seasonality. Under these circumstances, the CAISO needs flexibility. It would be administratively unwieldy, and unduly limit the CAISO’s ability to make timely and necessary changes to the transfer parameters, if the CAISO were to include each and every one of the specific transfer cost parameters in the tariff. Including a maximum transfer parameter value cost in the tariff will ensure that despite this increase in the number of transfer paths, the market can keep pace with changes and reach a unique and efficient solution that optimizes the use of transmission capability made available to the Energy Imbalance Market. Further, capping the potential level of any individual transfer cost parameter at $0.10 in the tariff ensures that any impact on rates will be *de minimis* because all individual path transfer cost parameters must be between $0.0001 cents and $0.10. Thus, the individual transfer cost parameters themselves cannot impact rates beyond what is specified in the tariff.

3. Financial Value of EIM Transfer in the Real Time Imbalance Energy Offset

The CAISO also proposes to revise section 11.5.4 to provide for the calculation of the financial value of EIM transfers that will be used as part of the financial settlement of the real-time imbalance energy offset for each balancing authority area in the Energy Imbalance Market. The CAISO does not settle EIM transfers explicitly because a transfer represents the imbalance energy of resources supporting the EIM transfer, which the CAISO settles with the applicable scheduling coordinators at its location. However, to calculate the real-time imbalance energy offset for a balancing authority area, the CAISO settlement calculations must consider the financial value of the EIM transfer in order to balance supply and demand settlements within the balancing authority area. The CAISO proposes to use the system marginal energy cost, which is a component of the locational marginal price, to represent the value of the energy of the EIM transfer. This is appropriate because the CAISO will already have settled the real-time congestion offset and real-time loss offset, leaving energy as the only component of the locational marginal price that remains and can cause a neutrality adjustment that will be settled through the real-time imbalance energy offset.

4. Flexible ramping constraint combinations.

Under current section 29.34(m), the CAISO calculates a flexible ramping requirement and enforces a flexible ramping constraint for each balancing authority area in the EIM area and for all combinations of such balancing authority areas. Currently, there are seven combinations among the CAISO and PacifiCorp balancing authority areas. As new entities join the EIM, however, the number of requirements and constraints will rapidly increase. The number of combinations will increase to fifteen with the addition of NV Energy, thirty-one with the addition of Puget Sound Energy, and then sixty-three with the addition of Arizona Public Service Company. The number will increase as the number of EIM entities increases further, resulting in an unmanageable number of combined constraints.

Therefore, the CAISO proposes to reduce the number of flexible ramping requirements and constraints to a manageable number. Under the proposed revision to section 29.34(m), the CAISO will only calculate a flexible ramping requirement and enforce a flexible ramping constraint for each individual balancing authority area and for the combination of all balancing authority areas in the EIM area. The individual balancing authority constraint is set to the individual balancing authority area's flexible ramping requirement minus the EIM transfer capability with other balancing authority areas in the EIM. If the EIM transfer capability exceeds the individual balancing authority area's flexible ramping requirement, the CAISO will not enforce the individual balancing authority area's constraint. As the transfer capability within the EIM area increases, the need to meet a balancing authority area's flexible ramping requirement with resources internal to its balancing authority area or a combination of EIM balancing authority areas is reduced. However, the CAISO must still maintain the individual balancing authority area constraint because if the balancing authority area fails the resource sufficiency evaluation, incremental EIM transfers are restricted and the flexible ramping requirement must be met by resources internal to the balancing authority area.

B. Greenhouse gas bidding by EIM participating resources.

Energy generated in California or imported into California is subject to California's greenhouse gas ("GHG") regulations. Current section 29.32 of the CAISO tariff allows EIM resources to include an adder in their bids to obtain compensation for costs incurred under California GHG regulations for energy transferred into California. In this way, GHG costs do not affect the locational marginal price in the balancing authority area of an EIM Entity outside of California. The GHG adder is not mitigated, and the only restriction is that the combined energy bid and GHG adder must be less than or equal to the $1000 energy bid cap.

The CAISO initially contemplated that EIM participating resources desiring to avoid being deemed to support EIM transfers into California could do so by submitting high bid adders to price themselves out of the market. The Commission did not accept this proposal and, in the June 19 Order, directed the CAISO to add a mechanism to allow an EIM participating resource scheduling coordinator to opt out completely from consideration for EIM transfer into the CAISO. In addition, the Commission directed the CAISO to implement a cost-based GHG bid adder mechanism.[23]

Proposed section 29.32 complies with this directive in a way that also provides some additional flexibility requested by stakeholders. Under the revisions, an EIM participating resource may submit a single MW quantity and single bid price on an hourly basis to express its willingness to serve as the source of an EIM transfer into the CAISO balancing authority area and be subject to California's GHG regulations. If the EIM participating resource does not submit a bid adder, or submits a bid adder with a zero MW quantity, the market will not deem the EIM participating resource delivered into CAISO.[24] Thus, although the CAISO is not proposing an explicit flag, an EIM participating resource, through its bid, can accomplish the same objective of not being considered for EIM transfers by bidding zero MW. This satisfies the Commission's directive in a way that provides enhanced flexibility to participants to transfer or not transfer energy into the CAISO.

To comply with the Commission's directive to implement a cost-based GHG bid adder, the CAISO proposes tariff revisions that allow an EIM participating resource scheduling coordinator to submit an hourly bid adder at or

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[23] June 19 Order at PP 239-40.

[24] The MW quantity is independent of the resource's energy bid curve; thus, only the output of the EIM participating resource up to the MW quantity bid is eligible for delivery to the CAISO balancing authority area.

below its daily maximum GHG cost cap as determined by the CAISO, but not less than zero.

The CAISO will calculate a daily maximum GHG cost using a process similar to the process the CAISO uses to calculate the GHG cost included in the default energy bids of CAISO resources.[25] This includes a variable cost option and a negotiated rate option. However, rather than calculating a cost curve as is done for default energy bids within the CAISO,[26] the CAISO will calculate a single daily maximum cap for the EIM participating resource.

Under the variable cost option, on a daily basis, the CAISO proposes to calculate each unit's maximum GHG cost based on the unit's maximum heat rate as registered with the CAISO, the applicable GHG allowance price, and the resource's emission rate. These are the same three components that the CAISO uses to calculate the greenhouse gas cost included in the default energy bid curves of CAISO resources. The standard GHG emission rate is documented in the US EPA Subpart C default emission factors.[27] Similar to the default energy bids of CAISO resources, the CAISO will apply a 10 percent adder to the calculated maximum cost.[28] The EIM participating resource scheduling coordinator must submit a GHG bid price equal to or less than the maximum GHG cap calculated under this approach, but not less than zero. This proposal complies with the Commission's guidance that the GHG bid adder be based on the expected cost of GHG compliance obligations.

Some stakeholders expressed concern that the proposed GHG bidding rules provide more flexibility than is necessary to comply with Commission's order and could limit EIM transfers into California. The CAISO has concluded that the flexibility will enhance, rather than deter, EIM transfers into California. The Commission did not dictate exactly how the CAISO was to comply with its

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[25] *See* section 39.7.1 of the CAISO tariff.

[26] Unlike energy bids which can use a ten segment bid curve, the GHG bid adder contains only one MW value and one bid price for the operating hour.

[27] CARB's regulation referenced these USA EPA figures as published in the Federal Register on December 17, 2010.

[28] In addition to approving a 10 percent adder for purposes of calculating default energy bids in the CAISO market, the Commission has approved 10 percent adders in other contexts. *See, e.g., San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services,* 96 FERC ¶ 61,120 at 61,519 (2001); *Public Serv. Co. of New Mexico,* 95 FERC ¶ 61,481 at 62, 714 (2001); *Niagara Mohawk Power Corp.,* 86 FERC ¶ 61,009 at 61,025 (1999); *Terra Comfort Corp.,* 52 FERC ¶ 61,241 at 61,841 (1990). The 10 percent adder can account for costs that are inexact or difficult to quantify, can serve as a margin of error, and can ensure cost recovery.

directives in the June 19 Order, and the CAISO's proposed approach is within the scope of compliance directives

The CAISO notes that the Department of Market Monitoring ("DMM") supports the CAISO's proposal for the GHG flag and cost-based bid adder. The DMM noted that some stakeholders expressed concerns about the need for flexibility to adjust the GHG flag on an hourly basis (rather than daily) and requested DMM to review this proposed design feature for potential gaming or other detrimental market impacts. DMM reviewed this issue and saw "limited value or need for this additional hourly flexibility" and did "not have any significant concerns about potential gaming or other detrimental impacts of this bidding flexibility."[29]

The CAISO notes that in the June 19 Order, the Commission recognized that any concerns about possible abuse of the GHG adder would be limited by competition among resources bidding into California.[30] Specifically, bids with high GHG adders will not be dispatched for sales in California unless their total bid price is less than the marginal price for energy on the CAISO system. The Commission also recognized that such competition would lessen concerns regarding any over-recovery of GHG compliance costs. The CAISO agrees that resources will be expected to bid below the cap because the compliance obligation is based upon the average annual emissions, which will always be less than the maximum emission rate, not on the emission in a given 15-minute or 5-minute interval. Finally, the Commission noted that its directive that the CAISO implement a cost-based GHG adder, which the CAISO proposes herein, would address any other concerns regarding over-recovery.[31] The Commission found the greenhouse gas adder component of the default energy bid to be just and reasonable and provide suppliers with a reasonable opportunity to recover their costs.[32] For similar reasons, the Commission should approve the proposed GHG adder for EIM.

C. EIM administrative charge.

The CAISO grid management charge is the mechanism by which the CAISO recovers ongoing operational costs from CAISO market participants. The EIM administrative charge is the mechanism the CAISO uses to recover ongoing operational costs from EIM market participants. The CAISO's objective in the

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29 Comments on Energy Imbalance Market Year 1 Enhancements Draft Final Proposal, Department of Market Monitoring, March 17, 2015.

30 June 19 Order at P 239.

31 *Id*.

32 *Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶61,237 (2012).

EIM administrative charge is to charge CAISO market participants and EIM market participants the same cost for similar real-time market services. Currently, the CAISO's grid management charge is made up of three components or services: (1) market services; (2) system operations; and (3) congestion revenue rights services. The market services charge encompasses all activities involved with clearing supply and demand in both the day-ahead and real-time markets. The system operations charge encompasses all activities associated with dispatching energy on the grid and balancing area activities such as transmission planning. The third component, congestion revenue rights services, encompasses activities involving congestion revenue rights.

When the CAISO implemented the Energy Imbalance Market, it charged EIM market participants an EIM administrative rate of $0.19/MWh applied to the sum of (1) the total gross absolute value of 15-minute market instructed imbalance energy, gross absolute value of real-time dispatch energy imbalance, and gross absolute value of uninstructed imbalance energy of the EIM market participant's supply; and (2) the gross absolute value of uninstructed imbalance energy of all the EIM market participant's demand. The CAISO derived the $0.19/MWh fee by determining the amount attributable to the real-time activities for the market services and systems operation cost components of the grid management charge. The EIM tariff also included a minimum EIM administrative charge to ensure that the CAISO was able to cover the costs of providing EIM service regardless of the quantity of instructed and uninstructed imbalance energy. Pursuant to tariff section 29.11(i)(2), the CAISO calculated the minimum EIM administrative charge by applying $0.19/Mwh to the sum of (1) five percent of the total gross absolute value of supply of all EIM market participants, plus (2) five percent of the total gross absolute value of demand of all EIM market participants. If the amount of the EIM administrative charges to the EIM market participants was less than minimum EIM administrative charges, the CAISO would assess the difference to each EIM entity scheduling coordinator.

During the initial months of the Energy Imbalance Market's operation, the CAISO assessed EIM market participants considerably more in EIM administrative charges than the CAISO had anticipated under the EIM administrative charge rate structure. The unanticipated amounts of EIM administrative charges that the CAISO assessed were inconsistent with the CAISO's and stakeholders' intent to design a charge that would bill EIM market participants an amount comparable to CAISO market participants using the same real-time services. In response, on January 14, 2015, the CAISO filed a tariff amendment, which the Commission accepted, [33] as an interim measure, under which the CAISO would no longer assess EIM market participants an

[33] *Cal. Indep. Sys. Operator Corp.*, 150 FERC ¶ 61,185 (2015) (Letter Order).

administrative charge based on volumes of imbalance energy and would instead only charge EIM scheduling coordinators the existing minimum EIM administrative charge pending redesign of the EIM administrative charge in the stakeholder initiative that resulted in the instant tariff amendment filing. The CAISO also noted that applying a single EIM administrative charge to all imbalances in the EIM balancing authority area, allocated cost to EIM market participants that is greater than the charge that would otherwise be allocated for the same services to CAISO market participants. This occurs because the billing determinant volumes used for the CAISO market services rate and system operations rate are lower than the EIM administrative rate determinant.

The CAISO proposes in this amendment to align the EIM administrative charge with the CAISO grid management charge. This will result in the CAISO charging CAISO market participants and EIM market participants the same rate for similar real-time services. Under revised tariff section 29.11(i), the EIM administrative charge will comprise two separate charges: the EIM market services charge and the EIM system operations charge. This is warranted because the billing determinants differ between the two charges. Each charge will consist of the product of the parallel CAISO charge (market services or system operations) and a real-time market percentage set forth in Appendix F of the CAISO tariff. The CAISO will allocate the EIM market services charge to gross instructed imbalance energy and allocate the EIM system operations charge to gross real-time energy flow, which is the absolute difference between the meter and the base schedule. These billing determinants for the two charges are consistent with the Commission-approved billing determinants for the market services and system operations components of the CAISO Grid Management Charge.

The CAISO proposes not to charge active EIM market participants a minimum charge because if CAISO costs or forecasted volumes change, the CAISO will update the EIM market services rate or EIM systems operations rate when it updates the CAISO grid management charge rates. The CAISO notes that, under the CAISO's existing tariff, it can update the rates for the CAISO market services charge and CAISO systems operation charge, as needed, on a quarterly basis if actual revenue collected changes by the greater of two percent or $1 million.

In the 2015 cost of service study underlying the CAISO's Commission-approved 2015 GMC, the CAISO calculated the percentage of costs that would apply to the energy imbalance market. The EIM portion of the CAISO market services rate is those costs attributable to the real-time market and not the day-ahead market. The EIM portion of the CAISO system operations rate is those costs attributable to the real-time market and not balancing authority area services. The CAISO calculates the EIM market services rate by multiplying the CAISO market services charge by the real-time market percentage which is 61%.

The EIM system operations rate is calculated by multiplying the CAISO system operations charge by the real-time market percentage of 45%. The cost support for this charge is included as Attachment C to this filing. This is the same type of data the CAISO has used to justify the market services and systems operations components of its grid management charge.

The CAISO now proposes to assess the existing minimum charge only if an EIM entity notifies the CAISO that is withdrawing from the Energy Imbalance Market and requests suspension of the Energy Imbalance Market in the EIM entity's control area. During the six month termination period following notification of withdrawal, the CAISO will allocate both the EIM market services charge and the EIM system operations charge to five percent of the EIM entity's load and exports plus five percent of its generation and imports. As discussed above, the tariff already includes a minimum charge. However, the CAISO now would only apply it to entities that are exiting the Energy Imbalance Market. This reflects that the CAISO will incur operating costs in connection with the EIM entity transferring out.

D. Resource sufficiency evaluation.

Section 29.34(m) of the CAISO tariff includes a resource sufficiency evaluation to ensure that each EIM balancing authority area has sufficient energy bid range from participating resources to meet the 15-minute net-load forecast and ramping requirements independently prior to the start of the operating hour. If a balancing authority area fails the resource sufficiency evaluation, incremental EIM transfers with other EIM balancing authority areas are not allowed. To provide equitable treatment among all EIM balancing authority areas, the CAISO proposes to revise section 29.34(m) so that it will also perform the resource sufficiency evaluation on the CAISO balancing authority area. The test will ensure there is sufficient ramping capability within the CAISO to meet 15-minute net load changes following the Hour Ahead Scheduling Process. In the event the CAISO fails the tests, additional EIM transfers into the CAISO above the last FMM interval of the preceding operating hour will not be allowed. This is the same treatment for all balancing authority areas in the EIM area.

In addition, the CAISO proposes to enhance the resource sufficiency evaluation by including the historical scheduling error of imports and exports included in the base schedules. The CAISO does not require hourly CAISO schedules from day-ahead and Hour Ahead Scheduling Process to be tagged until T-20. Likewise, the CAISO does not require hourly base schedules from EIM entities to be tagged until T-20. As a result, the assumed hourly schedules used in the resource sufficiency evaluation may differ from those that are actually tagged. When there is a difference, a balancing authority area may have insufficient upward or downward bid range from participating resources to meet its imbalance energy.

Failure to tag an hourly schedule at the base schedule amount will increase the need for imbalance energy. The CAISO proposes two additional mechanisms to ensure that differences between intertie schedules at T-40 and the final tagged schedule do not allow leaning on the EIM.

First, the CAISO proposes to calculate and publish, for each balancing authority area, the hourly scheduling error of imports and exports whose final tag schedules differ from either the EIM base schedule or CAISO hourly schedules. The CAISO will calculate this hourly scheduling error between the 15th day of the prior month and the 15th day of the current month and will include it in the hourly capacity test of the following month. This will ensure transparency across the EIM area regarding the difference between schedules considered in the hourly resource sufficiency evaluation and will allow the EIM entity to make necessary arrangements to increase the bid range of EIM participating resources prior to the start of the upcoming month. The CAISO considered calculating the hourly scheduling error on a rolling basis; however, this would provide insufficient time for the EIM entity to make business process or other changes to increase the bid range from participating resources which could result in additional failures of the resource sufficiency evaluation.

Second, under the proposed revisions, if a balancing authority area has historically high import or export schedule changes between T-40 and T-20, the CAISO will add an hourly block schedule difference to the capacity test of the resource sufficiency evaluation. The capacity test ensures that the bid range from participating resources can meet the 15-minute granular net load forecast for the operating hour. For example, assume a balancing authority area historically has 100 MW of imports which it has not tagged consistently with the base schedules. The balancing authority area would need to have a sufficient upward bid range of EIM participating resources to meet the load forecast, plus an additional 100 MW available to replace the potential 100 MW reduction in supply from imports.

On a monthly basis, according to procedures that the CAISO will set forth in the business practice manual for the Energy Imbalance Market, the CAISO will calculate for each EIM Entity Balancing Authority Area histograms of the percentage of the difference between imports and exports scheduled at T-40 and the final imports at T-20 based on the E-Tags submitted at T-40 and T-20. In addition, the CAISO will document the hours used to establish the histogram in the business practice manual for the energy imbalance market.[34] These are implementation details that do not significantly affect rates and, thus, appropriately belong in a business practice manual. Based on this information,

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[34] This is discussed further in the Draft Final Proposal at 25-26

the CAISO will calculate any additional incremental and decremental requirements for the capacity test component of the resource sufficiency evaluation and apply them prospectively.

E. Administrative Prices.

On December 18, 2014, the CAISO Board approved a pricing enhancements proposal stemming from a stakeholder initiative on administrative pricing rules[35] that includes revisions to the administrative pricing rules used during market disruptions. Because the Energy Imbalance Market is an extension of the CAISO real-time market, comparable administrative pricing rules should apply to the Energy Imbalance Market. The energy imbalance market year one enhancements approved by the CAISO Board in March 2015 include revisions to EIM tariff section 29.7, regarding the establishment of administrative prices in market disruptions, to conform the section with revisions to section 7 of the CAISO tariff adopted by the Board in December 2014 and in compliance with Commission directives. Because the CAISO has not yet filed the section 7 tariff revisions, revising section 29.7 would be premature. The CAISO will file the revision to section 29.7 when it files the revisions to section 7.

IV. Effective Date and Request for Waivers

The CAISO requests that the Commission permit all changes other than those to sections 29.17 and 29.32 to become effective October 1, 2015, *i.e.*, the day in which NV Energy is scheduled to begin participation in the Energy Imbalance Market. The CAISO requests that the Commission make the proposed amendment to sections 29.17 and 29.32 effective on September 15, 2015. In addition, because the requested effective date associated with sections 29.17 and 29.32 supports planned parallel operations with NV Energy and remain subject to implementation schedules, the CAISO commits to submit a further filing if the actual effective date slips by a few days to account for implementation planning.

In addition, because the proposed EIM administrative charge included in this filing is a formula rate, the CAISO 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), 35.13(d)(1), (2), and (5), and 35.13(h). These waivers are justified because the EIM administrative charge derives from the Commission-approved CAISO's grid management charge, which is based on a revenue requirement vetted through the budget process with stakeholders and trued up to actual costs. The CAISO has also provided details about the cost of service

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[35] *See* Administrative Pricing Rules Initiative.

analysis that is the basis for the EIM administrative charge. The Commission has previously granted waivers of the requirements to provide such data in a number of cases involving transmission formula rates.[36]

V. COMMUNICATIONS

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VI. SERVICE

The CAISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with scheduling coordinator agreements under the CAISO tariff. In addition, the CAISO has posted a copy of the filing on the CAISO website.

VII. CONTENTS OF FILING

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment

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[36] *See, e.g., PPL Elec. Utils. Corp.,* 125 FERC ¶ 61,121, at PP 40-41 (2008); *Pub. Serv. Elec. & Gas Co.,* 124 FERC ¶ 61,303, at PP 23-24 (2008); *Okla. Gas & Elec. Co.,* 122 FERC ¶ 61,071 (2008) at PP 6, 41; *Commonwealth Edison Co.,* 119 FERC ¶ 61,238, at P 94 (2007).

Attachment B	Red-lined document showing the revisions contained in this tariff amendment
Attachment C	Declaration of Michael Epstein and Cost of Service Discussion Papers

VIII. CONCLUSION

For the reasons set forth in this filing, the CAISO respectfully requests that the Commission grant waiver of its notice requirements and issue an order on an expedited basis that accepts the tariff revisions proposed in the filing effective as of September 15, 2015 and October 1, 2015, as set forth herein.

Respectfully submitted,

/s/ John C. Anders
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Attachment A – Clean Tariff Records

Energy Imbalance Market Year One Enhancements – Phase 1

California Independent System Operator Corporation

11.5.4 Imbalance Energy Pricing; Non-Zero Offset Amount Allocation

11.5.4.1 Real-Time Imbalance Energy Offset

(a) **Financial Value of EIM Transfers.** The CAISO will calculate the Real-Time Market financial value of EIM Transfers as the product of the MWh, either positive or negative, and the System Marginal Energy Cost.

* * *

29.11. Settlements And Billing For EIM Market Participants.

(a) **Applicability.** Section 29.11, rather than Section 11, shall apply to the CAISO Settlement with EIM Entity Scheduling Coordinators and EIM Participating Resource Scheduling Coordinators, except as otherwise provided, but not to other Scheduling Coordinators.

(b) **Imbalance Energy.**

(1) **FMM Instructed Imbalance Energy.**

(A) **Calculation.**

(i) **EIM Participating Resources.** The CAISO will calculate an EIM Participating Resource's FMM Instructed Imbalance Energy in the same manner as it calculates FMM Instructed Imbalance Energy under Section 11.5.1.1, except that references to the Day-Ahead Schedule in the relevant Appendix A definitions shall be deemed references to the EIM Base Schedule and that the CAISO will include any Energy from an EIM Manual Dispatch of the EIM Participating Resource in the FMM that is identified by the EIM Entity Scheduling Coordinator prior to the start of the FMM.

(ii) **Non-Participating Resources.** The CAISO will calculate the FMM Instructed Imbalance Energy of non-participating resources in an EIM Entity Balancing Authority Area in the same manner as it calculates FMM Instructed Imbalance Energy under Section 11.5.1.1, except that references to the Day-Ahead Schedule in the relevant Appendix A definitions shall be deemed references to the EIM Base Schedule and that the CAISO will include any Energy from an EIM Manual Dispatch of the EIM non-participating resource in the FMM that is identified by the EIM Entity Scheduling Coordinator prior to the start of the FMM.

(B) **Settlement.** The CAISO will settle-

(i) the FMM Instructed Imbalance Energy with the EIM Participating Resource Scheduling Coordinator for EIM Participating Resources; and

(ii) with the applicable EIM Entity Scheduling Coordinator for non-participating resources in an EIM Entity Balancing Authority Area.

(2) **RTD Instructed Imbalance Energy.**

(A) **Calculation.**

(i) **EIM Participating Resources.** The CAISO will calculate an EIM Participating Resource's RTD Instructed Imbalance Energy in the same manner in which it calculates RTD Instructed Imbalance Energy under Sections 11.5.1.2 and 11.5.5, except that the CAISO will include any Energy from an EIM Manual Dispatch of the EIM Participating Resource in the RTD that is identified by the EIM Entity Scheduling Coordinator.

(ii) **Non-Participating Resources.** The CAISO will calculate the RTD Instructed Imbalance Energy of non-participating resources in an EIM Entity Balancing Authority Area in the same manner in which it calculates RTD Instructed Imbalance Energy under Section 11.5.1.2 and 11.5.5, except that the CAISO will include any Energy from an EIM Manual Dispatch of the EIM non-participating resource in the RTD that is identified by the EIM Entity Scheduling Coordinator.

(B) **Settlement.** The CAISO will settle the RTD Instructed Imbalance Energy-

(i) with the EIM Participating Resource Scheduling Coordinator for EIM Participating Resources; and

(ii) with the applicable EIM Entity Scheduling Coordinator for non-participating resources in an EIM Entity Balancing Authority Area.

(3) **Uninstructed Imbalance Energy.**

(A) **EIM Participating Resources.**

(i) **Calculation.** For EIM Participating Resources and an EIM Entity Balancing Authority Area's dynamic import/export schedules with external resources, the CAISO will calculate Uninstructed Imbalance Energy in the same manner in which it calculates Uninstructed Imbalance Energy under Section 11.5.2.1.

(ii) **Settlement.** The CAISO will settle the Uninstructed Imbalance Energy with the EIM Participating Resource Scheduling Coordinator or the EIM Entity Scheduling Coordinator, as applicable.

(B) **Non-Participating Resources.**

(i) **Calculation.** For non-participating resources in an EIM Entity Balancing Authority Area, the CAISO will calculate Uninstructed Imbalance Energy in accordance with Section 11.5.2, except that the CAISO will treat an EIM Base Schedule as a Day-Ahead Schedule and the CAISO will treat an EIM Manual Dispatch as a Dispatch Instruction.

(ii) **Settlement.** The CAISO will settle the Uninstructed Imbalance Energy for non-participating resources in an EIM Entity

Balancing Authority Area at the applicable RTD Locational Marginal Price in accordance with Section 11.5.2.1 with the applicable EIM Entity Scheduling Coordinator and will treat EIM Balancing Authority Demand in the same manner as the CAISO treats CAISO Demand under that Section.

(C) **Non-Participating Load.**

(i) **Calculation.** For non-participating Load in an EIM Entity Balancing Authority Area, the CAISO will calculate Uninstructed Imbalance Energy in accordance with Section 11.5.2.2, except that the CAISO will determine deviations based on the EIM Base Load Schedule.

(ii) **Settlement.** The CAISO will settle Uninstructed Imbalance Energy for non-participating Load in an EIM Entity Balancing Authority Area at the applicable Default LAP Hourly Real-Time Price in accordance with Section 11.5.2.2 with the applicable EIM Entity Scheduling Coordinator and will treat EIM Balancing Authority Demand in the same manner as the CAISO treats CAISO Demand under that Section.

* * *

(f) **Real-Time Bid Cost Recovery.**

(1) **In General.** The CAISO will provide EIM Participating Resources RTM Bid Cost Recovery.

(2) **Calculation of Real-Time Bid Cost Recovery.** The CAISO will calculate Real-Time Bid Cost Recovery in accordance with Section 11.8.4, except that the CAISO will treat a non-zero EIM Base Schedule of an EIM Participating Resource as an IFM Self-Schedule and the corresponding intervals as IFM self-commitment intervals.

(3) **Application of Real-Time Performance Metric.**

The CAISO will adjust the RTM Energy Bid Cost, the RTM Market Revenues, and RTM Minimum Load Costs determined pursuant to Section 29.11(f)(2) by multiplying the Real-Time Performance Metric with those amounts for the applicable Settlement Interval pursuant to the rules specified in Section 11.8.4.4 and its subsections, except that the CAISO will treat an EIM Base Schedule as a Day-Ahead Schedule.

(4) **Allocation of EIM Entity RTM Bid Cost Uplift.**

(A) **Calculation of Charge.** The Net RTM Bid Cost Uplift will be determined for each EIM Entity Balancing Authority Area in accordance with the methodology set forth in Section 11.8.6.

(B) **Settlement.** The CAISO will assess the Net RTM Bid Cost Uplift calculated for each EIM Entity Balancing Authority Area to the applicable EIM Entity Scheduling Coordinator in accordance with Section 11.8.6.6.(ii).

* * *

(i) **EIM Administrative Charge.**

(1) **In General.** The CAISO will charge EIM Market Participants an EIM Administrative Charge consisting of an EIM Market Services Charge and an EIM System Operations Charge.

(2) **EIM Market Services Charge.** The EIM Market Services Charge shall be the product of the Market Services Charge for each Scheduling Coordinator as calculated according to the formula in Appendix F, Schedule 1, Part A, the Real-Time Market Percentage as calculated according to the formula in Appendix F, Schedule 1, Part A, and the sum of Gross FMM Instructed Imbalance Energy (excluding FMM Manual Dispatch Energy) and Gross RTD Instructed Imbalance Energy (excluding RTD Manual Dispatch Energy Standard Ramping Deviation, Ramping Energy Deviation, Residual Imbalance Energy, and Operational Adjustments).

(3) **EIM System Operations Charge.** The EIM System Operations Charge shall be the product of the System Operations Charge for each Scheduling Coordinator, as calculated according to the formula in Appendix F, Schedule 1, Part A, the Real-Time Market Percentage as calculated according to the formula in Appendix F, Schedule 1, Part A, and the absolute difference between metered energy and the EIM Base Schedules.

(4) **Minimum EIM Administrative Charge.** The CAISO will calculate the minimum EIM Administrative Charge as the product of the sum of the EIM Market Service Charge and the EIM System Operations Charge and—

(A) five percent of the total gross absolute value of Supply of all EIM Market Participants; plus

(B) five percent of the total gross absolute value of Demand of all EIM Market Participants.

(5) **Withdrawing EIM Entity.** If the EIM Entity notifies the CAISO of its intent to terminate participation in the Energy Imbalance Market and requests suspension of the Energy Imbalance Market in its Balancing Authority Area under Section 29.4(b)(4), the CAISO will charge the EIM Entity the minimum EIM Administrative Charge calculated under Section 29.11(i)(4) during the notice period.

(6) **Application of Revenues.** The CAISO will apply revenues received from the EIM Administrative Charge against the costs to be recovered through the Grid Management Charge as described in Appendix F, Schedule 1, Part A.

* * *

(o) **Application of Persistent Deviation Metric.**

The CAISO will modify the Bid Cost Recovery calculations described in Section 29.11(f) and Residual Imbalance Energy payments in Section 11.5.5 as described in Section 11.17, except that the CAISO will treat an EIM Base Schedule as a Day-Ahead Schedule.

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29.17 EIM Transmission System.

* * *

(f) **EIM Transfer Availability.**

(1) **In General.** The ISO will model individual constraints for each EIM Transfer limit submitted by each EIM Entity that makes transmission available on an EIM Internal Intertie.

(2) **Use of Interchange Transmission Rights.** The EIM Entity Scheduling Coordinator shall determine the EIM Transfer limit made available for use in the Real-Time Market through interchange transmission rights and communicate that limit to the CAISO prior to the start of the next Dispatch Interval in accordance with the procedures and timelines for submission and acceptance in the Business Practice Manual for the Energy Imbalance Market.

(3) **Use of Available Transfer Capability.** The EIM Entity Scheduling Coordinator shall determine the EIM Transfer limit made available to the Real-Time Market through available transfer capability in accordance with its tariff and communicate that limit to the CAISO prior to the start of the next Dispatch Interval in accordance with the procedures and timelines for submission and acceptance in the Business Practice Manual for the Energy Imbalance Market.

(4) **Multiple EIM Transfer Limits.** If there are two or more EIM Entity Balancing Authority Areas that share the same EIM Internal Intertie, the CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch will enforce the individual EIM Transfer limit for each EIM Entity Balancing Authority Area while allowing Energy to wheel through the EIM Entity Balancing Authority Areas based on the transmission made available for use in the Real-Time Market.

(5) **EIM Transfers and CAISO Scheduling Points.** EIM Transfers shall compete for Available Transfer Capability at interties that are an EIM Internal Intertie and a CAISO Scheduling Point.

(6) **EIM Transfer Limit Constraints.** The CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch shall enforce the EIM Transfer limit and the associated physical limit at each EIM Internal Intertie.

(g) **EIM Transfer Cost.** The CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch shall include a cost associated with EIM Transfers at each EIM Internal Intertie, not to exceed $0.10.

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29.32 Greenhouse Gas Regulation and EIM Bid Adders.

(a) **EIM Bid Adders.**

(1) **In General.** EIM Participating Resources will have an opportunity to recover costs of compliance with California Air Resources Board greenhouse gas regulations, which may include the cost of allowances, uncertainty on the final resource specific emission factor, and other costs of greenhouse gas regulation compliance.

(2) **EIM Bid Adder.**

(A) **Bid Submission.** EIM Participating Resource Scheduling Coordinators may submit an EIM Bid Adder as a separate hourly Bid component to recover costs of compliance with California Air Resources Board greenhouse gas regulations, which must include a price and quantity and the price portion of which must be equal to or less than 110% of the EIM Participating Resource's greenhouse gas maximum compliance cost as determined in accordance with section 29.32(a)(3).

(B) **Default Treatment.** If an EIM Participating Resource does not submit an EIM Bid Adder, the CAISO will assume that the EIM Participating Resource will not be selected for delivery to the CAISO Balancing Authority Area.

(3) **Determination of EIM Greenhouse Gas Maximum Cost.** Each day the CAISO will determine the greenhouse gas maximum compliance cost for each EIM Participating Resource as set forth in the EIM Business Practice Manual, based on—

(A) the EIM Resource's highest incremental heat rate; the applicable Greenhouse Gas Allowance Price; and the EIM Participating Resource's emission rate, as set forth in the applicable U.S. Environmental Protection Agency publication and registered in the Master File; or

(B) a price determined in accordance with the negotiated rate option procedures in section 39.7.1.3.1; or,

(C) with respect to, and only with respect to, Bids at EIM External Interties, the carbon dioxide equivalent emission rate of the resource with the highest such rate in the WECC region and the applicable Greenhouse Gas Allowance Price index.

(4) **EIM Bid Adder Price.** The price included in the EIM Bid Adder shall not be less than $0/MWh and the sum of the price component of the EIM Bid Adder and the Energy cost portion of the Bid cannot exceed $1000/MWh.

(b) **Consideration of EIM Bid Adders in Market Clearing.**

(1) **Dispatch of EIM Participating Resources with Nonzero Bid Adders.** The CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch shall take into account EIM Bid Adders in selecting Energy produced by EIM Resources outside the CAISO Balancing Authority Area for import into the CAISO Balancing Authority Area or other EIM Entity Balancing Authority Areas in California up to the associated MW quantity included in the EIM Bid Adder, but not when selecting EIM Resources to serve Load outside of the CAISO Balancing Authority Area or other EIM Entity Balancing Authority Areas in California.

(2) **Dispatch of EIM Participating Resources Bid Adders of Zero.** The CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch shall not dispatch EIM Participating Resources outside the CAISO Balancing Authority Area for delivery into the CAISO Balancing Authority Area or other EIM Entity Balancing Authority Areas in California if the MW quantity included in the EIM Bid Adder is zero.

* * *

29.34 EIM Operations

* * *

(m) **Flexible Ramping Constraint Requirement.**

(1) **Responsibility.** Each EIM Entity Balancing Authority Area and the CAISO Balancing Authority Area will be responsible for meeting its own portion of the combined Flexible Ramping Constraint capacity requirements for the next hour as determined by Section 29.34(m).

(2) **Nature.** The Flexible Ramping Constraint capacity requirement is a minimum requirement for each Balancing Authority Area in the EIM Area and on a system wide basis based upon the EIM Transfer limit between Balancing Authority Areas.

(3) **Determination.** Under the provisions of Section 29.34(m) and the procedures set forth in the Business Practice Manual for the Energy Imbalance Market, the CAISO will determine the Flexible Ramping Constraint capacity requirement using the CAISO Demand Forecast and CAISO Variable Energy Resource forecast for each Balancing Authority Area in the EIM Area and system wide.

(4) **Sufficiency Determination.**

(A) **Review.**

(i) **EIM Entity Balancing Authority Areas.** The CAISO will review the EIM Resource Plan pursuant to the process set forth in the

Business Practice Manual for the Energy Imbalance Market and verify that it has sufficient Bids for Ramping capability to meet the EIM Entity Balancing Authority Area Flexible Ramping Constraint capacity requirement, as adjusted pursuant to Sections 29.34(m)(4)(B), (C), and (E).

(ii) **CAISO Balancing Authority Area.** The CAISO will review the Day-Ahead Schedules in the CAISO Balancing Authority Area and verify that it has sufficient Bids for Ramping capability to meet the CAISO Balancing Authority Area Flexible Ramping Constraint capacity requirement, as adjusted pursuant to Sections 29.34(m)(4)(B), (C), and (E).

(B) **Pro Rata Reduction and Diversity Limit.** Each EIM Entity Balancing Authority Area Flexible Ramping Constraint capacity requirement shall be reduced by its pro rata share of the diversity benefit in the EIM Area as may be limited by the available net import EIM Transfer capability into that EIM Entity Balancing Authority Area.

(C) **Sufficiency of an EIM Entity Balancing Authority Area with a Net Outgoing EIM Transfer.** If an EIM Entity Balancing Authority Area has a net outgoing EIM Transfer (net export with reference to the EIM Base Schedule) before the Operating Hour, then the CAISO will apply a Flexible Ramping Constraint capacity requirement credit in determining the sufficiency of the Flexible Ramping Constraint capacity for that EIM Entity Balancing Authority Area equal to the net outgoing EIM Transfer before the Operating Hour.

(D) **Sufficiency of an EIM Entity Balancing Authority Area with a Net Ingoing EIM Transfer.** If an EIM Entity Balancing Authority Area has a net incoming EIM Transfer (net import with reference to the EIM Base

Schedule) before the Operating Hour; then the Flexible Ramping Constraint capacity for that EIM Entity Balancing Authority Area will be considered sufficient if it meets its own Flexible Ramping Constraint capacity requirement, irrespective of the incoming EIM Transfer that results from Real-Time Dispatch in the EIM Area.

(E) **Incremental Requirements.**

(i) **In General.** If the CAISO determines under the procedures set forth in the Business Practice Manual for the Energy Imbalance Market that an EIM Balancing Authority Area has historically high import or export schedule changes between T-40 and T-20, the CAISO will add to the EIM Entity's flexible capacity requirement an additional incremental requirement.

(ii) **Additional Incremental Requirement.** On a monthly basis, according to procedures set forth in the Business Practice Manual for the Energy Imbalance Market, the CAISO will calculate for each EIM Entity Balancing Authority Area histograms of the percentage of the difference between imports and exports scheduled at T-40 and the final imports at T-20 based on the E-Tags submitted at T-40 and T-20 and calculate additional incremental and decremental requirements for the capacity test component of the resource sufficiency evaluation.

5) **System Wide Constraint.** The CAISO shall determine the Flexible Ramping Constraint capacity requirement system wide, including requirements for individual Balancing Authority Areas in the system wide constraint, by reducing the total Flexible Ramping Constraint capacity requirement for each Balancing Authority Area by the total amount of EIM Internal Intertie import capability to that Balancing Authority Area from each Balancing Authority Area in the EIM Area.

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Appendix A

Master Definition Supplement

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- EIM Bid Adder

A Bid component composed of a MW quantity and price that provides EIM Participating Resources an opportunity to recover costs of compliance with California Air Resources Board greenhouse gas regulations.

Attachment B – Marked Tariff Records

Energy Imbalance Market Year One Enhancements – Phase 1

California Independent System Operator Corporation

11.5.4 Imbalance Energy Pricing; Non-Zero Offset Amount Allocation

11.5.4.1 Real-Time Imbalance Energy Offset

(a) **Financial Value of EIM Transfers.** The CAISO will calculate the Real-Time Market financial value of EIM Transfers as the product of the MWh, either positive or negative, and the ~~Locational Marginal Price of the pricing node at the corresponding EIM Internal Intertie~~System Marginal Energy Cost.

* * *

29.11. Settlements And Billing For EIM Market Participants.

(a) **Applicability.** Section 29.11, rather than Section 11, shall apply to the CAISO Settlement with EIM Entity Scheduling Coordinators and EIM Participating Resource Scheduling Coordinators, except as otherwise provided, but not to other Scheduling Coordinators.

(b) **Imbalance Energy.**

(1) **FMM Instructed Imbalance Energy.**

(A) **Calculation.**

(i) **EIM Participating Resources.** The CAISO will calculate an EIM Participating Resource's FMM Instructed Imbalance Energy in the same manner as it calculates FMM Instructed Imbalance Energy under Section 11.5.1.1, except that references to the Day-Ahead Schedule in the relevant Appendix A definitions shall be deemed references to the EIM Base Schedule and that the CAISO will include any Energy from an EIM Manual Dispatch of the EIM Participating Resource in the FMM that is identified by the EIM Entity Scheduling Coordinator prior to the start of the FMM.

(ii) **Non-Participating Resources.** The CAISO will calculate the FMM Instructed Imbalance Energy of non-participating resources in an EIM Entity Balancing Authority Area in the same manner as it calculates FMM Instructed Imbalance Energy under Section 11.5.1.1, except that references to the Day-Ahead Schedule in the relevant Appendix A definitions shall be deemed references to the EIM Base Schedule and that the CAISO will include any Energy from an EIM Manual Dispatch of the EIM non-participating resource in the FMM that is identified by the EIM Entity Scheduling Coordinator prior to the start of the FMM.~~as the sum of the Energy, if any, from EIM Manual Dispatch of the non-participating resource and any deviation from the EIM Base Schedule due to physical changes in any non-participating resource's output that the EIM Entity Scheduling Coordinator reports to the CAISO prior to the FMM.~~

(B) **Settlement.** The CAISO will settle-

(i) the FMM Instructed Imbalance Energy with the EIM Participating Resource Scheduling Coordinator for EIM Participating Resources; and

(ii) with the applicable EIM Entity Scheduling Coordinator for non-participating resources in an EIM Entity Balancing Authority Area.

(2) **RTD Instructed Imbalance Energy.**

(A) **Calculation.**

(i) **EIM Participating Resources.** The CAISO will calculate an EIM Participating Resource's RTD Instructed Imbalance Energy in the same manner in which it calculates ~~FMM~~ RTD Instructed Imbalance Energy under Sections 11.5.1.2 and 11.5.5, except that the CAISO will include any Energy from an EIM Manual Dispatch of the EIM Participating Resource in the RTD that is identified by the EIM Entity Scheduling Coordinator.

(ii) **Non-Participating Resources.** The CAISO will calculate the RTD Instructed Imbalance Energy of non-participating resources in an EIM Entity Balancing Authority Area in the same manner in which it calculates RTD Instructed Imbalance Energy under Section 11.5.1.2 and 11.5.5, except that the CAISO will include any Energy from an EIM Manual Dispatch of the EIM non-participating resource in the RTD that is identified by the EIM Entity Scheduling Coordinator~~as the Energy, if any, from EIM Manual Dispatch of the non-participating resource in the RTD that is identified by the EIM Entity Scheduling Coordinator~~.

(B) **Settlement.** The CAISO will settle the RTD Instructed Imbalance Energy-

(i) with the EIM Participating Resource Scheduling Coordinator for EIM Participating Resources; and

(ii) with the applicable EIM Entity Scheduling Coordinator for non-participating resources in an EIM Entity Balancing Authority Area.

(3) **Uninstructed Imbalance Energy.**

(A) **EIM Participating Resources.**

(i) **Calculation.** For EIM Participating Resources and an EIM Entity Balancing Authority Area's dynamic import/export schedules with external resources, the CAISO will calculate Uninstructed Imbalance Energy in the same manner in which it calculates Uninstructed Imbalance Energy under Section 11.5.2.1.

(ii) **Settlement.** The CAISO will settle the Uninstructed Imbalance Energy with the EIM Participating Resource Scheduling Coordinator or the EIM Entity Scheduling Coordinator, as applicable.

(B) **Non-Participating Resources.**

(i) **Calculation.** For non-participating resources in an EIM Entity Balancing Authority Area, the CAISO will calculate Uninstructed Imbalance Energy in accordance with Section 11.5.2, except that the CAISO will treat an EIM Base Schedule as a Day-Ahead Schedule and the CAISO will treat an EIM Manual Dispatch as a Dispatch Instruction.~~as the difference between the 5-minute Meter Data and the EIM Base Schedule or, if the EIM Scheduling Coordinator reported physical changes in a non-participating resource's output to the CAISO prior to the FMM, the FMM Schedule, less any EIM Manual Dispatch Energy of non-participating resources.~~

(ii) **Settlement.** The CAISO will settle the Uninstructed Imbalance Energy for non-participating resources in an EIM Entity Balancing Authority Area at the applicable RTD Locational Marginal Price in accordance with Section 11.5.2.1 with the applicable EIM Entity Scheduling Coordinator and will treat EIM Balancing Authority Demand in the same manner as the CAISO treats CAISO Demand under that Section.

(C) **Non-Participating Load.**

(i) **Calculation.** For non-participating Load in an EIM Entity Balancing Authority Area, the CAISO will calculate Uninstructed Imbalance Energy in accordance with Section 11.5.2.2, except that the CAISO will determine deviations based on the EIM Base Load Schedule.

(ii) **Settlement.** The CAISO will settle Uninstructed Imbalance Energy for non-participating Load in an EIM Entity Balancing Authority Area at the applicable Default LAP Hourly Real-Time ~~LAP p~~Price in accordance with Section 11.5.2.2 with the applicable EIM Entity Scheduling Coordinator and will treat EIM Balancing Authority Demand in the same manner as the CAISO treats CAISO Demand under that Section.

* * *

(f) **Real-Time Bid Cost Recovery.**

(1) **In General.** The CAISO will provide EIM Participating Resources RTM Bid Cost Recovery.

(2) **Calculation of Real-Time Bid Cost Recovery.** The CAISO will calculate Real-Time Bid Cost Recovery in accordance with Section 11.8.4, except that the CAISO will treat a non-zero EIM Base Schedule of an EIM Participating Resource as an IFM Self-Schedule and the corresponding intervals as IFM self-commitment intervals.

(3) **Application of Real-Time Performance Metric.**

The CAISO will adjust the RTM Energy Bid Cost, the RTM Market Revenues, and RTM Minimum Load Costs determined pursuant to Section 29.11(f)(2) by multiplying the Real-Time Performance Metric with those amounts for the applicable Settlement Interval pursuant to the rules specified in Section 11.8.4.4 and its subsections, except that the CAISO will treat an EIM Base Schedule as a Day-Ahead Schedule.

(4)~~(3)~~ **Allocation of EIM Entity RTM Bid Cost Uplift.**

(A) **Calculation of Charge.** The Net RTM Bid Cost Uplift will be determined for each EIM Entity Balancing Authority Area in accordance with the methodology set forth in Section 11.8.6.

(B) **Settlement.** The CAISO will assess the Net RTM Bid Cost Uplift calculated for each EIM Entity Balancing Authority Area to the applicable EIM Entity Scheduling Coordinator in accordance with Section 11.8.6.6.(ii).

* * *

(i) **EIM Administrative Charge.**

(1) **In General.** The CAISO will charge EIM ~~Entity Scheduling Coordinators~~Market Participants an ~~fixed~~ EIM Administrative Charge consisting of an EIM Market Services Charge and an EIM System Operations Charge.~~equal to the product of $0.19/MWh and the sum of—~~

(2~~A~~) **EIM Market Services Charge.** The EIM Market Services Charge shall be the product of the Market Services Charge for each Scheduling Coordinator as calculated according to the formula in Appendix F, Schedule 1, Part A, the Real-Time Market Percentage as calculated according to the formula in Appendix F, Schedule 1, Part A, and the sum of Gross FMM Instructed Imbalance Energy (excluding FMM Manual Dispatch Energy) and Gross RTD Instructed Imbalance Energy (excluding RTD Manual Dispatch Energy Standard Ramping Deviation, Ramping Energy Deviation, Residual Imbalance Energy, and Operational Adjustments).~~five percent of the total gross absolute value of Supply of all EIM Market Participants in the EIM Entity Balancing Authority Area; plus~~

(3~~B~~) **EIM System Operations Charge.** The EIM System Operations Charge shall be the product of the System Operations Charge for each Scheduling Coordinator, as calculated according to the formula in Appendix F, Schedule 1, Part A,~~,~~ the Real-Time Market Percentage as calculated according to the formula in Appendix F, Schedule 1, Part A, and the absolute difference between metered energy and the EIM Base Schedules.~~five percent of the gross absolute value of Demand of all EIM Market Participants in the EIM Entity Balancing Authority Area.~~

(4) **Minimum EIM Administrative Charge.** The CAISO will calculate the minimum EIM Administrative Charge as the product of the sum of the EIM Market Service Charge and the EIM System Operations Charge and—

(A) five percent of the total gross absolute value of Supply of all EIM Market Participants; plus

(B) five percent of the total gross absolute value of Demand of all EIM

Market Participants.

(5) **Withdrawing EIM Entity.** If the EIM Entity notifies the CAISO of its intent to terminate participation in the Energy Imbalance Market and requests suspension of the Energy Imbalance Market in its Balancing Authority Area under Section 29.4(b)(4), the CAISO will charge the EIM Entity the minimum EIM Administrative Charge calculated under Section 29.11(i)(4~~2~~) during the notice period.

(6~~2~~) **Application of Revenues.** The CAISO will apply revenues received from the EIM Administrative Charge against the costs to be recovered through the Grid Management Charge as described in Appendix F, Schedule 1, Part A.

* * *

(o) **Application of Persistent Deviation Metric.**

The CAISO will modify the Bid Cost Recovery calculations described in Section 29.11(f) and Residual Imbalance Energy payments in Section 11.5.5 as described in Section 11.17, except that the CAISO will treat an EIM Base Schedule as a Day-Ahead Schedule.

* * *

29.17 EIM Transmission System.

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(f) **EIM Transfer Availability.**

(1) **In General.** The ISO will model individual constraints for each EIM Transfer limit submitted by each EIM Entity that makes transmission available on an EIM Internal Intertie. ~~The EIM Transfer limit available for use in the Real-Time Market shall be determined by~~

(2) **Use of Interchange Transmission Rights.** ~~t~~The EIM Entity Scheduling Coordinator shall determine the EIM Transfer limit made available for use in the Real-Time Market through interchange transmission rights and communicate~~d~~ that limit to the CAISO prior to the start of the next Dispatch Interval in

accordance with the procedures and timelines for submission and acceptance in the Business Practice Manual for the Energy Imbalance Market.

(3) **Use of Available Transfer Capability.** The EIM Entity Scheduling Coordinator shall determine the EIM Transfer limit made available to the Real-Time Market through available transfer capability in accordance with its tariff and communicate that limit to the CAISO prior to the start of the next Dispatch Interval in accordance with the procedures and timelines for submission and acceptance in the Business Practice Manual for the Energy Imbalance Market.

(4) **Multiple EIM Transfer Limits.** If there are two or more EIM Entity Balancing Authority Areas that share the same EIM Internal Intertie, the CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch will enforce the individual EIM Transfer limit for each EIM Entity Balancing Authority Area while allowing Energy to wheel through the EIM Entity Balancing Authority Areas based on the transmission made available for use in the Real-Time Market.

(5) **EIM Transfers and CAISO Scheduling Points.** EIM Transfers shall compete for Available Transfer Capability at interties that are an EIM Internal Intertie and a CAISO Scheduling Point.

(6) **EIM Transfer Limit Constraints.** The CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch shall enforce the EIM Transfer limit and the associated physical limit at each EIM Internal Intertie.

(g) **EIM Transfer Cost.** The CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch shall include a cost associated with EIM Transfers at each EIM Internal Intertie, not to exceed $0.10.

* * *

29.32 Greenhouse Gas Regulation and EIM Bid Adders.

(a) **EIM Bid Adders.**

(1) **In General.** EIM Participating Resources will have an opportunity to recover costs of compliance with California Air Resources Board greenhouse gas regulations, which may include the cost of allowances, uncertainty on the final resource specific emission factor, and other costs of greenhouse gas regulation compliance.

(2) **EIM Bid Adder.**

(A) **Bid Submission.** EIM Participating Resource Scheduling Coordinators may submit an EIM Bid Adder as a separate hourly Bid component to recover costs of compliance with California Air Resources Board greenhouse gas regulations, which must include a price and quantity and the price portion of which must be equal to or less than 110% of the EIM Participating Resource's greenhouse gas maximum compliance cost as determined in accordance with section 29.32(a)(3).

(B) **Default Treatment.** If an EIM Participating Resource does not submit an EIM Bid Adder, the CAISO will assume that the EIM Participating Resource will not be selected for delivery to the CAISO Balancing Authority Area.

(3) **Determination of EIM Greenhouse Gas Maximum Cost~~Cap on Bid Adder~~.** Each day the CAISO will determine the greenhouse gas maximum compliance cost for each EIM Participating Resource as set forth in the EIM Business Practice Manual, based on—

(A) the EIM Resource's highest incremental heat rate; the applicable Greenhouse Gas Allowance Price; and the EIM Participating Resource's emission rate, as set forth in the applicable U.S. Environmental Protection Agency publication and registered in the Master File; or

(B) a price determined in accordance with the negotiated rate option procedures in section 39.7.1.3.1; or,

(C) with respect to, and only with respect to, Bids at EIM External Interties, the carbon dioxide equivalent emission rate of the resource with the highest such rate in the WECC region and the applicable Greenhouse Gas Allowance Price index.~~The sum of the EIM Bid Adder and the Energy cost portion of the Bid cannot exceed $1000/MWh.~~

(4) **~~Minimum~~ EIM Bid Adder Price.** The price included in the EIM Bid Adder shall not be less than $0/MWh and the sum of the price component of the EIM Bid Adder and the Energy cost portion of the Bid cannot exceed $1000/MWh.

~~(5) **Limit on Use of Bid Adders.** An EIM Participating Resource Scheduling Coordinator may submit no more than one Bid Adder per day for an EIM Resource.~~

(b) **Consideration of EIM Bid Adders in Market Clearing.**

(1) **Dispatch of EIM Participating Resources with Nonzero Bid Adders.** The CAISO's ~~shall modify its~~ Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch shall ~~to~~ take into account EIM Bid Adders in selecting Energy produced by EIM Resources outside the CAISO Balancing Authority Area for import into the CAISO Balancing Authority Area or other EIM Entity Balancing Authority Areas in California up to the associated MW quantity included in the EIM Bid Adder, but not when selecting EIM Resources to serve Load outside of the CAISO Balancing Authority Area or other EIM Entity Balancing Authority Areas in California.

(2) **Dispatch of EIM Participating Resources Bid Adders of Zero.** The CAISO's Security Constrained Economic Dispatch in the Real-Time Unit Commitment and Real-Time Dispatch shall not dispatch EIM Participating Resources outside the CAISO Balancing Authority Area for delivery into the CAISO Balancing Authority Area or other EIM Entity Balancing Authority Areas in California if the MW quantity included in the EIM Bid Adder is zero.

* * *

29.34 EIM Operations

* * *

(m) **Flexible Ramping Constraint Requirement.**

(1) **Responsibility.** Each EIM Entity Balancing Authority Area and the CAISO Balancing Authority Area will be responsible for meeting its own portion of the combined Flexible Ramping Constraint capacity requirements for the next hour as determined by Section 29.34(m).

(2) **Nature.** The Flexible Ramping Constraint capacity requirement is a minimum requirement for each Balancing Authority Area in the EIM Area and on a system wide basis~~each combination thereof~~ based upon the EIM Transfer limit between Balancing Authority Areas.

(3) **Determination.** Under the provisions of Section 29.34(m) and the procedures set forth in the Business Practice Manual for the Energy Imbalance Market, the CAISO will determine the Flexible Ramping Constraint capacity requirement using the CAISO Demand Forecast and CAISO Variable Energy Resource forecast for each Balancing Authority Area in the EIM Area and system wide.~~each combination thereof.~~

(4) **Sufficiency Determination.**

(A) **Review.**

(i) **EIM Entity Balancing Authority Areas.** The CAISO will review the EIM Resource Plan pursuant to the process set forth in the Business Practice Manual for the Energy Imbalance Market and verify that it has sufficient Bids for Ramping capability to meet the EIM Entity Balancing Authority Area Flexible Ramping Constraint capacity requirement, as adjusted pursuant to

Sections 29.34(m)(4)(B), ~~and~~ (C), and (E).

(ii) **CAISO Balancing Authority Area.** The CAISO will review the Day-Ahead Schedules in the CAISO Balancing Authority Area and verify that it has sufficient Bids for Ramping capability to meet the CAISO Balancing Authority Area Flexible Ramping Constraint capacity requirement, as adjusted pursuant to Sections 29.34(m)(4)(B), (C), and (E).

(B) **Pro Rata Reduction and Diversity Limit.** Each EIM Entity Balancing Authority Area Flexible Ramping Constraint capacity requirement shall be reduced by its pro rata share of the diversity benefit in the EIM Area as may be limited by the available net import EIM Transfer capability into that EIM Entity Balancing Authority Area.

(C) **Sufficiency of an EIM Entity Balancing Authority Area with a Net Outgoing EIM Transfer.** If an EIM Entity Balancing Authority Area has a net outgoing EIM Transfer (net export with reference to the EIM Base Schedule) before the Operating Hour, then the CAISO will apply a Flexible Ramping Constraint capacity requirement credit in determining the sufficiency of the Flexible Ramping Constraint capacity for that EIM Entity Balancing Authority Area equal to the net outgoing EIM Transfer before the Operating Hour.

(D) **Sufficiency of an EIM Entity Balancing Authority Area with a Net Ingoing EIM Transfer.** If an EIM Entity Balancing Authority Area has a net incoming EIM Transfer (net import with reference to the EIM Base Schedule) before the Operating Hour; then the Flexible Ramping Constraint capacity for that EIM Entity Balancing Authority Area will be considered sufficient if it meets its own Flexible Ramping Constraint capacity requirement, irrespective of the incoming EIM Transfer that results from Real-Time Dispatch in the EIM Area.

(E) **Incremental Requirements.**

(i) **In General.** If the CAISO determines under the procedures set forth in the Business Practice Manual for the Energy Imbalance Market that an EIM Balancing Authority Area has historically high import or export schedule changes between T-40 and T-20, the CAISO will add to the EIM Entity's flexible capacity requirement an additional incremental requirement.

(ii) **Additional Incremental Requirement.** On a monthly basis, according to procedures set forth in the Business Practice Manual for the Energy Imbalance Market, the CAISO will calculate for each EIM Entity Balancing Authority Area histograms of the percentage of the difference between imports and exports scheduled at T-40 and the final imports at T-20 based on the E-Tags submitted at T-40 and T-20 and calculate additional incremental and decremental requirements for the capacity test component of the resource sufficiency evaluation.

5) **~~Combinations~~ System Wide ~~of~~ Constraint~~s~~.** The CAISO shall determine the Flexible Ramping Constraint capacity requirement system wide, ~~for all possible combinations of sufficient Balancing Authority Areas in the EIM Area,~~ including requirements for individual Balancing Authority Areas in the system wide constraint~~each combination~~, by reducing the total Flexible Ramping Constraint capacity requirement for each ~~group of~~ Balancing Authority Area~~s~~ by the total amount of EIM Internal Intertie import capability to that Balancing Authority Area ~~group~~ from each Balancing Authority Area in the EIM Area.~~outside the group.~~

* * *

Appendix A

Master Definition Supplement

* * *

- EIM Bid Adder

A Bid component composed of a MW quantity and price that provides EIM Participating Resources an opportunity to recover costs of compliance with California Air Resources Board greenhouse gas regulations.

Attachment C– Declaration of Michael Epstein and Cost of Service Discussion Papers

Energy Imbalance Market Year One Enhancements – Phase 1

California Independent System Operator Corporation

California ISO

2015 GMC Update
Cost of Service Study

April 2, 2014

Table of Contents

Executive Summary

The revenue requirement limit established by the ISO and developed with stakeholders during the 2012 grid management charge (GMC) stakeholder initiative and budget process will expire on December 31, 2014. According to tariff section 11.22.2.5, the ISO is required to seek Federal Energy Regulatory Commission (FERC) approval of another revenue requirement maximum for the period beginning January 1, 2015. To determine whether changes should be made to the revenue requirement cap or the GMC structure, the ISO has updated its 2012 cost of service analysis, which was based on 2010 costs, for 2015 and beyond.

By way of background, the ISO implemented activity based costing (ABC) in 2010, which was utilized for the 2012 cost of service study to restructure the GMC rate design. The new GMC design was vetted through a comprehensive stakeholder process and approved by the ISO Board of Governors (ISO Board) and FERC in 2011 to be effective on January 1, 2012. The structure contains three cost categories: market services, system operations and congestion revenue rights (CRR) services and percentages that are applied to the revenue requirement to determine the amount in the three cost categories upon which rates are set. The market services charge code is designed to recover costs the ISO incurs for running the markets. The system operations charge code is designed to recover costs the ISO incurs for reliably operating the grid in real time. The CRR charge code recovers costs the ISO incurs for running the CRR markets.

The updated 2015 cost of service analysis uses 2013 data to determine the percentages for the three cost categories, as reflected in the table below and is summarized in Exhibit 2. This cost of service analysis also updated the energy imbalance market (EIM) and transmission ownership rights (TOR) rates. The ISO has posted the EIM rate update development and the TOR rate update development in the other papers posted at the same time as this cost of service update.

Summary of Cost Category Percentages

Cost Category Percentages from Cost of Service Studies	2010 Study effective for 2012	2013 Study to effective for 2015	Change
Market Services	27%	**27%**	-
System Operations	69%	**70%**	1%
CRR Services	4%	**3%**	(1%)

The 2012 Cost of Service Study Overview and Activity Based Costing (ABC)

On September 30, 2011, FERC approved the ISO's redesigned GMC with an effective date of January 1, 2012.[1] As part of the 2012 GMC stakeholder initiative that led up to the FERC submission, the ISO conducted a cost of service study based, for the first time, on the recently implemented Activity Based Costing (ABC) model (2012 cost of service study), using 2010 ISO costs.[2] The ISO then used the 2012 cost of service study to calculate the cost allocation percentages assigned to the three cost of service "buckets": market services, system operations and CRR services, as well as the associated fees including the TOR fee.

This 2015 cost of service study uses the same ABC modeling and cost allocation methodology used to calculate the cost allocation percentages and TOR fee. However, the 2015 cost of service study updates the 2012 analysis by using 2013 data and also incorporates changes to the level 1 and 2 ABC processes that the ISO has made since the 2012 cost of service study. As discussed in more detail below, the ISO in 2011 completed its implementation of all ABC level 2 processes. At the start of 2013, ABC encompassed nine level 1 processes that align with the ISO's core business processes (see chart below). These processes were then broken down into 153 level 2 activities that align with a level 1 process and are a granular breakdown of the core business functions. See Exhibit 1 for a description of the ISO business process framework overview.

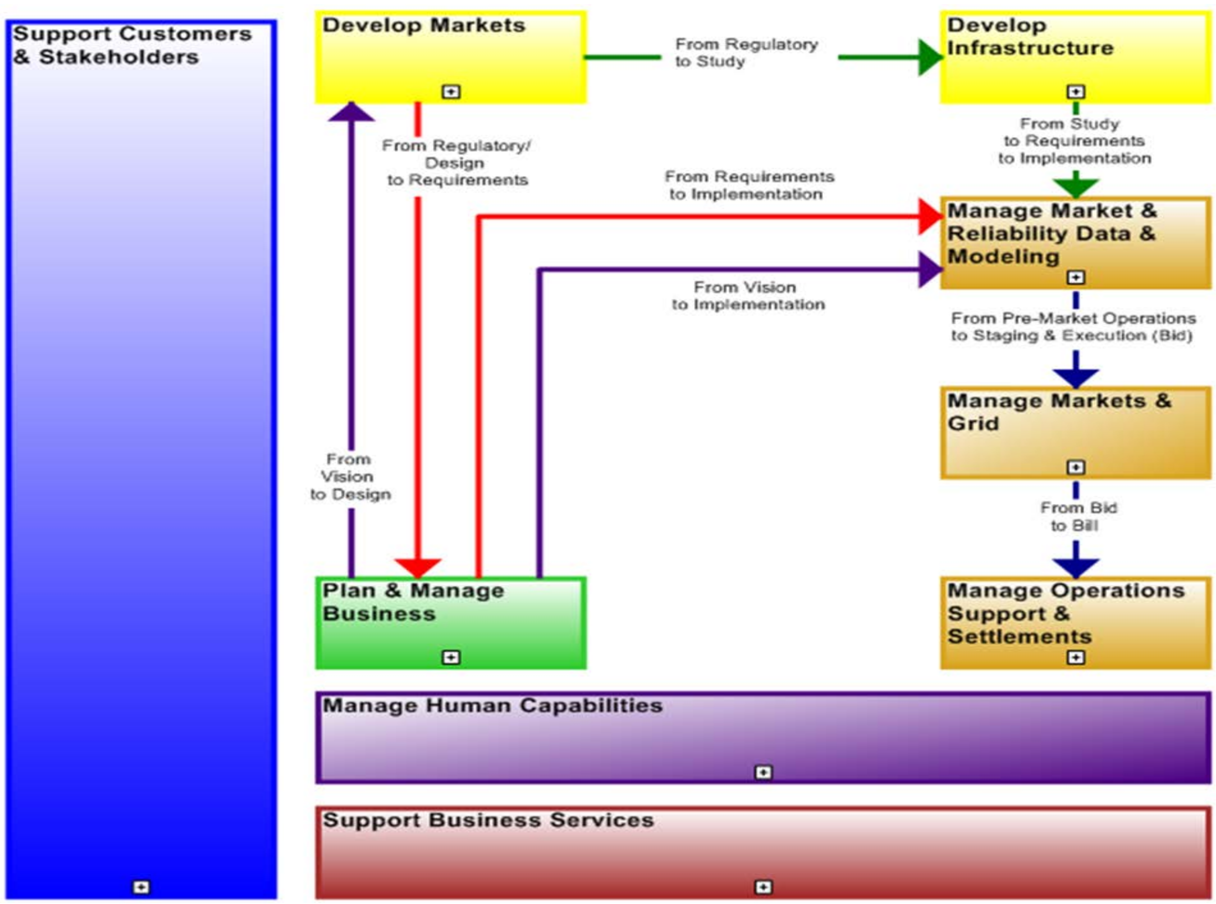
[1] See *California Independent System Operator Corp.*136 FERC ¶61,236 (2011).
[2] The 2012 cost of service study can be found at: http://www.caiso.com/Documents/2012Cost-ServiceStudyDiscussionPaperwithExhibits.pdf

Application of ABC to GMC Structure

When the ISO, in 2010, conducted the 2012 cost of service study, time reporting for ABC level 1 activities had just been implemented. Full level 2 reporting, using activity codes and time sheet reporting, commenced in 2011 and has now been completed. This process is continually being reviewed and developed, and changes in definitions and levels have occurred since the 2012 cost of service study.

Currently, the ABC analysis has disaggregated the ISO into nine core processes (level 1 activities). Each of the core activities were further broken down into major processes (level 2 activities) that were mapped to the level one activity.

Mapping of ISO Core Business Processes



The level 2 processes discussed in this study are mapped and defined as of January 1, 2013. 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) support or 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 activity codes	Level 1 Charge Code
Develop Infrastructure	Direct operating cost	11	80001
Develop Markets	Direct operating cost	9	80002
Manage Market and Reliability Data and Modeling	Direct operating cost	21	80004
Manage Market and Grid	Direct operating cost	13	80005
Manage Operations Support and Settlements	Direct operating cost	19	80006
Support Customers and Stakeholders	Direct operating cost	11	80010
Plan and Manage Business	Support costs	15	80008
Support Business Services	Support costs	46	80009
Manage Human Capabilities	Support costs	8	80003

Mapping of ABC Direct Operating Activities

These activities are defined, linked to specific processes, and measurable. Using the three GMC 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%).

Table 2 — Mapping of ABC Direct Operating Activities to Cost Categories

Mapping of ABC level 2 Direct Operating Activities to Cost Categories						
ABC Level 2 Activities	**Cost Code**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
		% of cost to allocate to category				
Definitions used in allocation		100%				the costs are entirely to support the market results and function resulting in a financially binding schedule or ancillary servicer award
			100%			the costs are entirely to support system operations
				100%		the costs are entirely to support the CRR process
					100%	Attributes are not distinguishable 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)						

Mapping of ABC level 2 Direct Operating Activities to Cost Categories							
ABC Level 2 Activities	**Cost Code**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
		% of cost to allocate to category					
Regulatory contract procedures	201				100%	Attributes are not distinguishable to any specific category
Manage generation interconnection project (GIP) agreements	202		100%			managing the building and maintaining of the grid thus the costs are entirely to support system operations
Manage GIP	203		100%			
Long-term transmission planning	204		100%			
New transmission resources	205		100%			
Transmission maintenance studies	206		100%			
Load resource data	207		100%			
Seasonal assessment	208		100%			
Queue management	209		100%			
Annual delivery assessment	210		100%			
Develop Markets (DM) (80002)						
Manage tariff amendments	227				100%	Attributes are not distinguishable to any specific category
Post-order rehearing comp	228				100%	
State / Federal regulatory policy	229				100%	
Business process manual change management process	230				100%	
Develop infrastructure policy	231		100%			managing the building and maintaining of the grid thus the costs are entirely to support system operations
Perform market analysis	232	100%				the costs are entirely to support the market results & function
Develop market design	233	100%				
Regulatory contract negotiations	234				100%	Attributes are not distinguishable to any specific category
Manage Market and Reliability Data and Modeling (MMR) (80004)						
Manage full network model (FNM) maintenance	301	50%	50%			the costs support equally both market and system operations
Plan and develop operations simulator training	302	20%	80%			significantly more operational procedures, thus the costs are predominantly operational flow based but have some market relationship
ISO meter certification	303		100%			measuring flows on the grid thus the costs are entirely to support system operations
Energy measure acquisition and analysis (EMMAA) telemetry	304		100%			measuring flows on the grid thus the costs are entirely to support system operations
Metering system configuration for market resources	305		100%			
Manage CRRs	307			100%		the costs are entirely to support the CRR process
Manage credit and collateral	308	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Resource management	309	50%	50%			resource attributes that support both thus the costs support equally both market and system operations
Manage reliability requirements	310		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage operations planning	311		100%			
Manage WECC seasonal studies	312		100%			
Participating intermittent resource projects (PIRP)	313	20%	80%			significantly more operational procedures, thus the costs are predominantly

Mapping of ABC level 2 Direct Operating Activities to Cost Categories						
ABC Level 2 Activities	**Cost Code**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
		% of cost to allocate to category				
Manage & facilitate procedure maintenance	314	20%	80%			operational flow based but have some market relationship
Procedure administration and reporting	315	20%	80%			
Plan and develop operations training	316	20%	80%			
Execute and track operations training	317	20%	80%			
California Electric Training Advisory Committee (CETAC) activities	318		100%			relates to actual system operations thus the costs are entirely to support system operations
Provide stakeholder training	320				100%	Attributes are not distinguishable to any specific category
SC management	321				100%	
Manage Markets and Grid (MMG) (80005)						
Manage day ahead (DA) market support	352	100%				the costs are entirely to support the market results & function
Operations real time (RT) support	353	50%	50%			the costs support equally both market and system operations
Outage model and management	355		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage DA market	358	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 pre and post scheduling	359		100%			relates to actual system operations thus the costs are entirely to support system operations
Manage operations engineering support	362	20%	80%			based on support of DA and RT thus the costs are predominantly operational flow based but have some market relationship
RT market – shift supervisor – manage post DA and pre RT	363	50%	50%			the costs support equally both market and system operations
RT Operations – generation and RT renewables coordinator (GRC) desks - maintain balancing area and manage RT pre dispatch	364	20%	80%			based on support of DA and RT thus the costs are predominantly operational flow based but have some market relationship
RT Operations – transmission desk – manage transmission and electric system	365		100%			relates to actual system operations thus the costs are entirely to support system operations
RT Operations – scheduling desk – manage RT interchange scheduling	366		100%			
Manage Operations Support and Settlements (MOS) (80007)						
Manage price validation & corrections	401	50%	50%			related to proper outage allocation thus the costs support equally both market and system operations
Manage dispute analysis & resolution	402				100%	Attributes are not distinguishable to any specific category
Manage the market quality system (MQS)	403	50%	50%			portion of MQS relates to operational flows thus the costs support equally both market and system operations
Manage data requests	404				100%	Attributes are not distinguishable to any specific category
Manage regulation no pay & deviation penalty calculations	405		100%			measuring actual performance thus the costs are entirely to support system operations
Manage rules of conduct	406				100%	Attributes are not distinguishable to any specific category

Mapping of ABC level 2 Direct Operating Activities to Cost Categories						
ABC Level 2 Activities	**Cost Code**	**Market services**	**System Operations**	**CRR services**	**Indirect**	**Comments**
		% of cost to allocate to category				
Periodic meter audits	407		100%			measuring actual performance thus the costs are entirely to support system operations
ISO remote intelligence gateway (RIG) engineering	408		100%			
Manage energy measurement acquisition & analysis	409		100%			
Manage market clearing	411	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage market billing & settlements	412	45%	45%	10%		
Manage reliability must run (RMR) settlements	413		100%			Supports reliability on the grid thus the costs are entirely to support system operations
Manage settlements release cycle	414	45%	45%	10%		this is a 50/50 split after a minimum allocation to CRRs
Manage market performance	417	50%	50%			the costs support equally both market and system operations
Manage dispute analysis and resolution	418				100%	Attributes are not distinguishable to any specific category
Perform market validation	419	50%	50%			the costs support equally both market and system operations
Support Customers and Stakeholders (SCC) (80010)						
Represent ISO externally	539				100%	Attributes are not distinguishable to any specific category
Client inquiries	601				100%	
Account management	602				100%	
Stakeholder processes	603				100%	
Develop participating transmission owners	605		100%			managing the building and maintaining of the grid thus the costs are entirely to support system operations
Service new clients	606				100%	Attributes are not distinguishable to any specific category
Government affairs	609				100%	Attributes are not distinguishable to any specific category
Communications and public relations	610				100%	

Allocation of Debt Service and Capital

Debt service is the aggregation of principle, interest, and a 25 percent debt service reserve on the 2008 and 2009 bonds. The debt service is the capital spent on projects over the last six 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. The 2009 bonds funded the corporate headquarters so the debt service was allocated 100 percent to indirect. The revenue requirement also includes cash funded capital. The funds raised from the GMC go to maintaining a long term capital reserve fund, which varies from the capital project budget for that year. The number of and cost for capital projects vary significantly from year to year. The annual budget approves the spending limits for capital but not the projects themselves. A proposed listing is provided but the actual projects are subject to review and approval by an internal management committee as needed during the year. Because of the uncertainty of the actual projects coming on line, 100 percent of the cash funded capital will be allocated to indirect.

Table 3 — Allocation of Debt Service and Capital to GMC Cost Categories

Allocation of Debt Service and Capital to GMC cost categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
2008 Bond Debt Service					
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
CRR			100%		the costs are entirely to support the CRR process
DMM & compliance tools (SAS MARS)	50%	50%			the costs support equally both market and system operations
Energy Management System (EMS)		100%			the costs are entirely to support system operations
Existing Transmission Contracts Calculator (ETCC)		100%			This is a balancing authority responsibility
FNM / State estimator	50%	50%			Needed for market and system operations thus the costs support equally both market and system operations
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
MQS	50%	50%			aligns with direct operating process thus the costs support equally both market and system operations
Master file	50%	50%			
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
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
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%			
Process Information System (PI)		100%			the costs are entirely to support system operations
RT markets	20%	80%			support & provide actual dispatches to balance system thus the costs are predominantly operational flow based but have some market relationship
HA Scheduling Protocol (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
RMR application Validation Engine (RAVE)	50%	50%			
Scheduling & Logging for ISO CA (SLIC)	50%	50%			

Allocation of Debt Service and Capital to GMC cost categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
Control Area Scheduler (CAS)		100%			This is a balancing authority responsibility
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 and 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 and Fixed Assets					
Client relations & engineering analysis tools				100%	Attributes are not distinguishable to any specific category
Local Area Network (LAN), WAN & monitoring (Tivoli)				100%	
Office automation desktop laptop (OA)				100%	
Oracle Corporate Financials				100%	
Security External Physical & ISS (CUDA)				100%	
Storage (EMC symmetrix)				100%	
Land and feasibility studies				100%	
NT servers and WEB servers				100%	
New system equipment				100%	
Office equipment, physical facilities software, furniture & leasehold improvements				100%	
2009 Bond Debt Service					
Iron Point headquarters				100%	Attributes are not distinguishable to any specific category
Cash Funded Capital					
Capital Project fund				100%	Amounts and projects vary yearly thus attributes are not distinguishable to any specific category

Allocation of Non-Payroll Support Costs

For the next step, significant non-payroll costs were pulled out of the operations and maintenance budget and allocated to buckets based on specific charge codes or to indirect costs. (see Table 4 next page)

Table 4 — Allocation of Non-Payroll Support Costs to GMC Cost Categories

Allocation of Non-Payroll Support Costs to GMC Cost Categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
Technology Division					
Hardware and software maintenance and leases				100%	Attributes are not distinguishable to any specific category
Communications (AT&T)				100%	
Occupancy costs				100%	
Operations Division					
PIRP forecasting costs	20%	80%			Use 80004 activity 313
General Counsel and Administrative Services Division					
Outside legal fees, financial audits and bank fees				100%	Attributes are not distinguishable to any specific category
SSAE 16 audit	45%	45%	10%		Use 80007 activity 412
Operational assessment	TBD	TBD			To be based on total % for 80005
Insurance				100%	Attributes are not distinguishable to any specific category

Allocation of ABC Support activities

The ABC support activities were allocated to indirect.

Table 5 — Allocation of ABC Support activities to GMC Cost Categories

Allocation of ABC support activities to GMC Cost Categories						
System	**Cost Code**	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category					
Plan and manage business	80008				100%	Attributes are not distinguishable to any specific category
Support business services	80009				100%	
Manage human capabilities	80003				100%	

Allocation of Other Income and Operating Reserve Credit

The remaining revenue requirement components, other income and operating reserve credit, were then analyzed and allocated to buckets based on specific charge codes or to indirect costs.

Table 6 — Allocation of Other Income to GMC Cost Categories

Allocation of Other Income to GMC Cost Categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
SC application fee				100%	Hardware and software maintenance and leases
MSS penalties				100%	
SC training fees				100%	
PIRP forecasting fees	20%	80%			Use 80004 activity 313
LGIP study fees		100%			Use 80001 activity 203
Interest				100%	Hardware and software maintenance and leases
COI path operator fees	TBD	TBD			To be based on total %s from 80005

Table 7 — Allocation of Operating Reserve Revenue Credit to GMC Cost Categories

Allocation of Operating Reserve Revenue Credit to GMC Cost Categories					
System	**Market services**	**System operations**	**CRR services**	**Indirect**	**Comments**
	% of cost to allocate to category				
Change in operations and maintenance budget				100%	Hardware and software maintenance and leases
25% debt service reserve on 2008 bonds	TBD	TBD	TBD	TBD	Based on %s from 2008 bonds debt service allocation
25% debt service reserve on 2009 bonds				100%	Hardware and software maintenance and leases
Revenue changes				100%	
Expense changes				100%	

Indirect Costs

Indirect costs are aggregated and then allocated proportional to direct costs. After this mapping is completed it can be applied to the ISO revenue requirement to derive the related cost of service.

Costing the 2013 Revenue Requirement

The allocation matrix of level 2 activities and software was applied to the ISO's 2013 revenue requirement (based on the budget approved by the ISO Board in December 2012) to determine the costs associated with three categories: market services, system operations and CRR services. The 2013 revenue requirement data and employee hours are the most recent information available to both determine the GMC cost category percentage updates and the updated revenue requirement for the ISO's 2015 GMC tariff filing.

Table 8 — Components of the 2013 revenue requirement:

Revenue Requirement	2013 Budget ($ in thousands)
Operating and maintenance costs	$ 162,907
Debt service 2008 bonds	24,666
Debt service 2009 bonds	17,847
Cash funded capital	24,000
Other income	(7,900)
Operating reserve	(25,492)
Total Revenue Requirement	**$ 196,028**

Completing the analysis required the following steps:

1. Breaking out non-ABC Operating and maintenance (O&M) support costs and applying cost category percentages to these costs;
2. Mapping the ABC direct and support O&M costs into two components: level 2 activities and support costs. This process involved:
    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;
3. Mapping remaining revenue requirements to cost categories and applying cost category percentages to these costs;
4. Aggregating costs and allocating indirect costs to cost categories based on percentage of direct costs, allocating fees to the three buckets and determining resulting cost category percentages; and
5. Dividing resulting costs by estimated volumes to determine 2013 rates using revised cost category percentages.

Step 1: Breaking Out Non-ABC Support 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. The significant non-ABC support costs were removed from the divisions and allocated separately.

Table 9 — Mapping Costs to ABC Activities and Non-ABC Support Costs

Mapping Costs to Direct and Support Activities and Non-ABC Support Costs		2013 Budget ($ in thousands)		
Division		**Total**	**ABC Activities**	**Non-ABC**
Chief Executive Officer	2100	$ 4,589	$ 4,589	$ -
Market and Infrastructure Development	2200	13,991	13,991	
Technology	2400	58,653	38,319	20,334
Operations	2500	42,724	42,021	703
General Counsel and Administrative Services	2600	27,070	19,234	7,836
Market Quality and Renewable Integration	2700	5,871	4,887	984
Policy and Client Services	2800	10,009	10,009	
Total		**$ 162,907**	**$ 133,050**	**$ 29,857**

These budgeted costs were allocated using the percentages shown in *Table 4 — Allocation of Non-Payroll Support Costs to GMC Cost Categories.*

Table 10 — Allocation of Non-ABC Support to Cost Categories

Allocation of Non-ABC support costs									
Non-ABC support costs	**Market Services**	**System Operations**	**CRRs**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRRs**	**Indirect**
	% of costs allocated to activity				**Cost of category $ in thousands**				
Technology Division									
Hardware and software maintenance and leases				100%	$ 8,941	$ -	$ -	$ -	$ 8,941
Communications (AT&T)				100%	5,952				5,952
Occupancy costs				100%	5,441				5,441
Operations Division									
PIRP forecasting costs	20%	80%			1,687	337	1,350		
General Counsel and Administrative Services Division									
Outside legal fees, financial audits and bank fees				100%	5,180				5,180
SSAE 16 audit	45%	45%	10%		539	243	243	53	
Operational assessment	17%	83%			200	34	166		
Insurance				100%	1,917				1,917
Total					**$ 29,857**	**$ 614**	**$ 1,759**	**$ 53**	**$ 27,431**

Step 2: Allocation of O&M Costs

For activity related O&M costs, the recent ABC structure was utilized to allocate costs between the cost categories. ISO activities have been broken out into nine level 1 ABC activities as shown in *Table 1 — Level 1 ABC Activities*. For those direct operating level 1 activities, the associated level 2 activities were mapped to one of the three cost categories as shown in *Table 2 — Mapping of ABC Level 2 Direct Operating Activities to Cost Categories.* The level 1 support activities were allocated to ABC support costs.

The O&M budget is comprised of approximately 103 cost centers. As discussed above, ISO staff has been coding their time to ABC level 1 and level 2 activities since 2011. The time for 2013 was collected and the percentage breakdown of each cost center by the level one and level 2 direct activities was determined. The percentage was applied to the activity budget for the cost center to allocate the cost center activity budget by dollars to the level one and level 2 direct operating activities.

ABC Direct Operating Activities

Table 11 — Mapping Division Hours to Direct Operating Activities

Mapping Division Hours to Direct Operating activities	Percentage of time related to direct operating activities					
	Develop infra-structure (DI)	Develop markets (DM)	Manage market and reliability and data modeling (MMR)	Manage markets and Grid (MMG)	Manage operations support and settlements (MOS)	Support customers and stake-holders (SCS)
Organization Name	**80001**	**80002**	**80004**	**80005**	**80007**	**80010**
Chief Executive Officer (CEO)						
Market and Infrastructure Development (MID)	74%	20%	2%			
Technology (Tech)			4%	3%	1%	
Operations (Ops)			21%	53%	18%	
General Counsel and Administrative Services (GCAS)		2%	4%		1%	
Market Quality and Renewable Integration (MQRI)	3%	46%	3%	6%	33%	
Policy and Client Services (PCS)			7%			87%
Total	**8%**	**4%**	**9%**	**19%**	**7%**	**6%**

The hours were aggregated by level 2 activity.

Table 12 — Mapping Division hours to level 2 activities

		ISO Divisions							
ABC Level 2 Activities	Cost Code	CEO 2100	MID 2200	Tech 2400	Ops 2500	GCAS 2600	MQRI 2700	PCS 2800	Total
Develop Infrastructure (DI) (80001)									
Regulatory contract procedures	201		100%						4%
Manage GIP agreements	202		100%						8%
Manage GIP	203		98%			2%			27%
Long-term transmission planning	204		100%						42%
New transmission resources	205		100%						3%
Transmission maintenance studies	206		100%						4%
Load resource data	207		100%						3%
Seasonal assessment	208		100%						3%
Queue management	209		100%						6%
Annual delivery assessment	210		100%						
Total			99%			1%			100%
Develop Markets (DM) (80002)									
Manage tariff amendments	227					100%			6%
Post-order rehearing comp	228		100%						1%
State / Federal regulatory policy	229		86%		14%				10%
Business process manual change management process	230		15%					85%	1%
Develop infrastructure policy	231		100%						14%
Perform market analysis	232						100%		28%
Develop market design	233						18%		38%
Regulatory contract negotiations	234		82%						2%
Total			59%		1%	6%	34%		100%
Manage Market & Reliability Data & Modeling (MMR) (80004)									
Manage FNM maintenance	301			74%	22%		4%		14%
Plan and develop operations simulator training	302			10%	90%				3%
ISO meter certification	303				100%				4%
EMMAA telemetry	304				100%				1%
Metering system configuration for market resources	305				100%				1%
Manage CRRs	307				100%				5%
Manage credit and collateral	308					100%			6%
Resource management	309				96%		4%		9%
Manage reliability requirements	310		38%		57%		5%		9%
Manage operations planning	311				96%		4%		13%
Manage WECC seasonal studies	312				100%				1%
PIRP	313				100%				
Manage & facilitate procedure maintenance	314				100%				8%
Procedure administration and reporting	315				100%				
Plan and develop operations training	316				95%		5%		7%
Execute and track operations training	317				97%		3%		13%
CETAC activities	318				100%				1%
Provide stakeholder training	320							100%	3%
SC management	321							100%	2%
Total			3%	12%	72%	6%	3%	4%	100%
Manage Markets and Grid (MMG) (80005)									

		ISO Divisions							
ABC Level 2 Activities	**Cost Code**	**CEO 2100**	**MID 2200**	**Tech 2400**	**Ops 2500**	**GCAS 2600**	**MQRI 2700**	**PCS 2800**	**Total**
Manage DA market support	352			94%	6%				
Operations RT support	353			57%	20%		23%		5%
Outage model and management	355				100%				11%
Manage DA market	358				100%				10%
Manage pre and post scheduling	359				100%				4%
Manage operations engineering support	362				100%				4%
RT market – shift supervisor – manage post DA and pre RT	363				100%				8%
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364				100%				24%
RTO – transmission desk – manage transmission and electric system	365				100%				19%
RTO – scheduling desk – manage RT interchange scheduling	366				100%				15%
Total				3%	96%		1%		100%
Manage Operations Support & Settlements (MOS) (80007)									
Manage price validation & corrections	401			20%	80%				2%
Manage dispute analysis & resolution	402			2%	98%				10%
Manage MQS	403			13%	87%				16%
Manage data requests	404				100%				2%
Manage regulation no pay & deviation penalty calculations	405				100%				
Manage rules of conduct	406				100%				2%
Periodic meter audits	407				100%				
ISO RIG engineering	408				100%				5%
Manage energy measurement acquisition & analysis	409				100%				12%
Manage market clearing	411					100%			2%
Manage market billing & settlements	412				96%	4%			17%
Manage RMR settlements	413				100%				
Manage settlements release cycle	414				100%				11%
Manage market performance	417						100%		3%
Manage dispute analysis and resolution	418							100%	
Perform market validation	419			1%	14%		85%		17%
Total				3%	78%	2%	17%		100%
Support Customers and Stakeholders (SCC) (80010)									
Represent ISO externally	539		16%	40%	1%	29%	7%	7%	3%
Client inquiries	601							100%	14%
Account management	602							100%	10%
Stakeholder processes	603							100%	7%
Develop participating transmission owners	605							100%	
Service new clients	606							100%	3%
Government affairs	609							100%	43%
Communications and public relations	610							100%	20%
Total						1%		98%	100%
Direct O&M			**19%**	**5%**	**57%**	**2%**	**6%**	**11%**	**100%**

Cost of Direct Operating Activities

These costs were inputs into the allocation matrix shown in *Table 2 — Mapping of ABC Level 2 Direct Operating Activities to Cost Categories* to get the costs to the cost categories.

Table 13 — Allocation of Division Costs to Direct Operating Activities

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 and reliability and data modeling (MMR)	Manage markets and Grid (MMG)	Manage operations support and settlements (MOS)	Support customers and stake-holders (SCS)	Direct operating activities
Organization Name	**80001**	**80002**	**80004**	**80005**	**80007**	**80010**	**Total**
Chief Executive Officer (CEO)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market and Infrastructure Development (MID)	9,726	3,340	352		3	37	13,458
Technology (Tech)	26		1,305	802	215	99	2,447
Operations (Ops)	3	79	7,491	24,689	5,509	4	37,775
General Counsel and Administrative Services (GCAS)	62	355	583		153	65	1,218
Market Quality and Renewable Integration (MQRI)	176	1,997	293	286	1,229	16	3,997
Policy and Client Services (PCS)		28	452		24	8,965	9,469
Total	**$ 9,993**	**$ 5,799**	**$ 10,476**	**$ 25,777**	**$ 7,133**	**$ 9,186**	**$ 68,364**

The costs were aggregated by level 2 activity.

Table 14 — Allocation of Division Costs to Level 2 activity

		ISO Divisions							
ABC Level 2 Activities	**Cost Code**	**CEO 2100**	**MID 2200**	**Tech 2400**	**Ops 2500**	**GCAS2 2600**	**MQRI 2700**	**PCS 2800**	**Total**
Develop Infrastructure (DI) (80001)									
Regulatory contract procedures	201	$ -	$ 378	$ -	$ -	$ -	$ -	$ -	$ 378
Manage GIP agreements	202		818						818
Manage GIP	203		2,251	26	3	62			2,342
Long-term transmission planning	204		4,273						4,273
New transmission resources	205		376				176		552
Transmission maintenance studies	206		499						499
Load resource data	207		268						268
Seasonal assessment	208		223						223
Queue management	209		615						615
Annual delivery assessment	210		25						25
Total			**9,726**	**26**	**3**	**62**	**176**		**9,993**
Develop Markets (DM) (80002)									
Manage tariff amendments	227					355			355
Post-order rehearing comp	228		30						30
State / Federal regulatory policy	229		485		79				564
Business process manual change management process	230		5					28	33
Develop infrastructure policy	231		829						829
Perform market analysis	232		2				1,602		1,604
Develop market design	233		1,847				395		2,242
Regulatory contract negotiations	234		142						142
Total			**3,340**		**79**	**355**	**1,997**	**28**	**5,799**
Manage Market & Reliability Data & Modeling (MMR) (80004)									

		ISO Divisions							
ABC Level 2 Activities	**Cost Code**	**CEO 2100**	**MID 2200**	**Tech 2400**	**Ops 2500**	**GCAS2 2600**	**MQRI 2700**	**PCS 2800**	**Total**
Manage FNM maintenance	301			1,274	377		73		1,723
Plan and develop operations simulator training	302			31	269				300
ISO meter certification	303				416				416
EMMAA telemetry	304				100				100
Metering system configuration for market resources	305				70				70
Manage CRRs	307				574				574
Manage credit and collateral	308					583			583
Resource management	309				875		35		910
Manage reliability requirements	310		352		535		44		930
Manage operations planning	311				1,262		59		1,322
Manage WECC seasonal studies	312				71				71
PIRP	313				1				1
Manage & facilitate procedure maintenance	314				841				841
Procedure administration and reporting	315				11				11
Plan and develop operations training	316				679		35		714
Execute and track operations training	317				1,336		47		1,384
CETAC activities	318				73				73
Provide stakeholder training	320							286	286
SC management	321							167	167
Total			**352**	**1,305**	**7,490**	**583**	**293**	**453**	**10,476**
Manage Markets and Grid (MMG) (80005)									
Manage DA market support	352			107	8				115
Operations RT support	353			695	250		286		1,231
Outage model and management	355				2,921				2,921
Manage DA market	358				2,564				2,564
Manage pre and post scheduling	359				974				974
Manage operations engineering support	362				1,148				1,148
RT market – shift supervisor – manage post DA and pre RT	363				2,021				2,021
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364				6,093				6,093
RTO – transmission desk – manage transmission and electric system	365				4,956				4,956
RTO – scheduling desk – manage RT interchange scheduling	366				3,754				3,754
Total				802	24,689		286		25,777
Manage Operations Support & Settlements (MOS) (80007)									
Manage price validation & corrections	401			31	125				156
Manage dispute analysis & resolution	402			16	709				725
Manage MQS	403			150	992				1,142
Manage data requests	404				97				97
Manage regulation no pay & deviation penalty calculations	405				8				8
Manage rules of conduct	406				165				165
Periodic meter audits	407				4				4
ISO RIG engineering	408				332				332
Manage energy measurement acquisition & analysis	409				926				926
Manage market clearing	411					111			111
Manage market billing & settlements	412				1,160	42			1,202
Manage RMR settlements	413				10				10

ABC Level 2 Activities	Cost Code	ISO Divisions CEO 2100	MID 2200	Tech 2400	Ops 2500	GCAS2 2600	MQRI 2700	PCS 2800	Total
Manage settlements release cycle	414				807				807
Manage market performance	417						208		208
Manage dispute analysis and resolution	418							24	24
Perform market validation	419		3	18	175		1,020		1,216
Total			3	215	5,510	153	1,228	24	7,133
Support Customers and Stakeholders (SCC) (80010)									
Represent ISO externally	539		36	88	3	65	16	16	224
Client inquiries	601							1,318	1,318
Account management	602							889	889
Stakeholder processes	603				1			665	666
Develop participating transmission owners	605							8	8
Service new clients	606							299	299
Government affairs	609			10				3,979	3,989
Communications and public relations	610							1,793	1,793
Total			**36**	**98**	**4**	**65**	**16**	**8,967**	**9,186**
Direct O&M			**$ 13,458**	**$ 2,447**	**$ 37,775**	**$ 1,218**	**$ 3,997**	**$ 9,469**	**$ 68,364**

For direct operating activities the costs were aggregated at level 2 and allocated to the cost category identified in *Table 2 — Mapping of ABC Level 2 Direct Operating Activities to Cost Categories.*

Table 15 — Mapping ABC Direct Operating Activities to Cost Categories

ABC Direct Operating Activities										
ABC Level 2 Activities	**Cost Code**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
		% of costs allocated to activity				**Cost of category $ in thousands**				
Develop Infrastructure (DI) (80001)										
Regulatory contract procedures	201				100%	$ 378	$ -	$ -	$ -	$ 378
Manage GIP agreements	202		100%			818		818		
Manage GIP	203		100%			2,342		2,342		
Long-term transmission planning	204		100%			4,273		4,273		
New transmission resources	205		100%			552		552		
Transmission maintenance studies	206		100%			499		499		
Load resource data	207		100%			268		268		
Seasonal assessment	208		100%			223		223		
Queue management	209		100%			615		615		
Annual delivery assessment	210		100%			25		25		
Total DI						**9,993**		**9,615**		**378**
Develop Markets (DM) (80002)										
Manage tariff amendments	227				100%	355				355
Post-order rehearing comp	228				100%	30				30
State / Federal regulatory policy	229				100%	564				564
Business process manual change management process	230				100%	33				33
Develop infrastructure policy	231		100%			829		829		
Perform market analysis	232	100%				1,604	1,604			
Develop market design	233	100%				2,242	2,242			
Regulatory contract negotiations	234				100%	142				142

ABC Direct Operating Activities										
ABC Level 2 Activities	**Cost Code**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
		% of costs allocated to activity				**Cost of category $ in thousands**				
Total DM						**5,799**	**3,846**	**829**		**1,124**
Manage Market & Reliability Data & Modeling (MMR) (80004)										
Manage FNM maintenance	301	50%	50%			1,724	862	862		
Plan and develop operations simulator training	302	20%	80%			300	60	240		
ISO meter certification	303		100%			416		416		
EMMAA telemetry	304		100%			100		100		
Metering system configuration for market resources	305		100%			70		70		
Manage CRRs	307			100%		574			574	
Manage credit and collateral	308	45%	45%	10%		583	262	262	59	
Resource management	309	50%	50%			910	455	455		
Manage reliability requirements	310		100%			931		931		
Manage operations planning	311		100%			1,321		1,321		
Manage WECC seasonal studies	312		100%			71		71		
PIRP	313	20%	80%			1		1		
Manage & facilitate procedure maintenance	314	20%	80%			841	168	673		
Procedure administration and reporting	315	20%	80%			11	2	9		
Plan and develop operations training	316	20%	80%			714	143	571		
Execute and track operations training	317	20%	80%			1,383	277	1,106		
CETAC activities	318		100%			73		73		
Provide stakeholder training	320				100%	286				286
SC management	321				100%	167				167
Total MMR						**10,476**	**2,229**	**7,161**	**633**	**453**
Manage Markets and Grid (MMG) (80005)										
Manage DA market support	352	100%				115	115			
Operations RT support	353	50%	50%			1,231	616	615		
Outage model and management	355		100%			2,921		2,921		
Manage DA market	358	50%	50%			2,564	1,282	1,282		
Manage pre and post scheduling	359		100%			974		974		
Manage operations engineering support	362	20%	80%			1,148	230	918		
RT market – shift supervisor – manage post DA and pre RT	363	50%	50%			2,021	1,011	1,010		
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364	20%	80%			6,093	1,219	4,874		
RTO – transmission desk – manage transmission and electric system	365		100%			4,956		4,956		
RTO – scheduling desk – manage RT interchange scheduling	366		100%			3,754		3,754		
Total MMG						**25,777**	**4,473**	**21,304**	**-**	**-**
Total MMG %						**100%**	**17%**	**83%**		
Manage Operations Support & Settlements (MOS) (80007)										
Manage price validation and corrections	401	50%	50%			156	78	78		
Manage dispute analysis & resolution	402				100%	725				725
Manage MQS	403	50%	50%			1,142	571	571		
Manage data requests	404				100%	97				97
Manage regulation no pay & deviation penalty calculations	405		100%			8		8		

ABC Direct Operating Activities										
ABC Level 2 Activities	Cost Code	Market Services	System Operations	CRR Services	Indirect	2013 Budget	Market Services	System Operations	CRR Services	Indirect
		% of costs allocated to activity				Cost of category $ in thousands				
Manage rules of conduct	406				100%	165				165
Periodic meter audits	407		100%			4		4		
ISO RIG engineering	408		100%			332		332		
Manage energy measurement acquisition & analysis	409		100%			926		926		
Manage market clearing	411	45%	45%	10%		111	50	50	11	
Manage market billing & settlements	412	45%	45%	10%		1,202	541	541	120	
Manage RMR settlements	413		100%			10		10		
Manage settlements release cycle	414	45%	45%	10%		807	363	363	81	
Manage market performance	417	50%	50%			208	104	104		
Manage dispute analysis and resolution	418				100%	24				24
Perform market validation	419	50%	50%			1,216	608	608		
Total MOS						**7,133**	**2,315**	**3,595**	**212**	**1,011**
Support Customers and Stakeholders (SCC) (80010)										
Represent ISO externally	539				100%	224				224
Client inquiries	601				100%	1,318				1,318
Account management	602				100%	889				889
Stakeholder processes	603				100%	666				666
Develop participating transmission owners	605		100%			8		8		
Service new clients	606				100%	299				299
Government affairs	609				100%	3,989				3,989
Communications and public relations	610				100%	1,793				1,793
Total SSC						**9,297**		**8**		**9,297**
Total Direct O&M						**$ 68,364**	**$ 12,863**	**$ 42,512**	**$ 845**	**$ 12,144**
Direct O&M %						**100%**	**19%**	**62%**	**1%**	**18%**

ABC Support Activities

The same process yielded the following percentages for the three support activities.

Table 16 — Mapping Division Hours to Support Activities

Mapping support activities	Percentage of time related to support operating activities		
	Manage human capabilities (MHC)	Plan and manage business (PMB)	Support Business Services (SBS)
Organization Name	**80003**	**80008**	**80009**
Chief Executive Officer	0%	14%	86%
Market and Infrastructure Development	0%	0%	3%
Technology	0%	9%	83%
Operations	0%	1%	8%
General Counsel and Administrative Services	21%	7%	64%
Market Quality and Renewable Integration	0%	2%	7%
Policy and Client Services	0%	0%	5%
Total	**2%**	**5%**	**40%**

These costs were inputs into the allocation matrix shown in *Table 5 — Allocation of ABC Support activities to GMC Cost Categories* to get the costs to the cost categories.

Table 17 — Mapping Division Costs to Support Activities

Mapping support activities	Percentage of time related to support operating activities			
	Manage human capabilities (MHC)	Plan & manage business (PMB)	Support business services (SBS)	Support activities
Organization Name	**80003**	**80008**	**80009**	**Total**
Chief Executive Officer	$ -	$ 1,838	$ 2,751	$ 4,589
Market and Infrastructure Development			533	533
Technology		4,911	30,961	35,872
Operations	5	1,109	3,132	4,246
General Counsel and Administrative Services	4,918	1,891	11,207	18,016
16Market Quality and Renewable Integration		213	677	890
Policy and Client Services	1	11	528	540
Total	**$ 4,924**	**$ 9,973**	**$ 49,789**	**$ 64,686**

For support activities the costs were aggregated and allocated as shown in *Table 5 — Allocation of ABC Support activities to GMC Cost Categories.*

Table 18 — Mapping ABC Support Activities to Cost Categories

Allocation of ABC Support Activities									
ABC Level 1 Activities	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
	% of costs allocated to activity				**Cost of category $ in thousands**				
Manage Human Capabilities (80003)				100%	$ 4,924				$ 4,924
Plan & Manage Business (80008)				100%	9,973				9,973
Support Business Services (80009)				100%	49,789				49,789
Total					**$ 64,686**				**$ 64,686**

<u>Step 3 — Allocating Remaining Revenue Requirements to Cost Categories</u>

Debt Service and Cash Funded Capital

The allocation of costs is based on the percentage allocation in *Table 3 — Allocation of Debt Service and Capital to GMC Cost Categories.* (see Table 19 below)

Table 19 — Mapping Debt Service and Cash Funded Capital to Cost Categories

Debt Service and Capital									
System	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
	% of costs allocated to activity				**Cost of category $ in thousands**				
Operations Related Software									
ADS		100%			$ 30	$ -	$ 30	$ -	$ -
ALFS	50%	50%			79	40	39		
CRRs			100%		855			855	
DMM & compliance Tools	50%	50%			478	239	239		
EMS		100%			1,923		1,923		
ETCC		100%			5		5		
FNM / State estimator	50%	50%			182	91	91		
IFM	50%	50%			6,365	3,183	3,182		
MQS	50%	50%			1,013	506	507		
Master file	50%	50%			409	205	204		
MDAS		100%			15		15		
NRI	20%	80%			219	44	175		
OASIS	50%	50%			66	33	33		
OMAR		100%			96		96		
PIRP	20%	80%			45	9	36		
Portal	50%	50%			473	236	237		
CMRI	50%	50%			411	206	205		
PI		100%			137		137		
RT market	20%	80%			1,271	254	1,017		
HASP	505	50%			1,270	635	635		
Resource Adequacy	50%	50%			43	21	22		
RAVE	50%	50%			5	3	2		
SLIC	50%	50%			295	147	148		
CAS		100%			47		47		
SIBR	50%	50%			1,801	900	901		
SaMC	15%	75%	10%		3,407	511	2,555	341	
Total operations related software					**20,940**	**7,263**	**12,481**	**1,196**	
General Software and Fixed Assets									
Client relations & engineering analysis tools				100%	154				154
LAN, WAN & monitoring				100%	650				650
OA				100%	80				80
Oracle Corporate Financials				100%	606				606
CUDA				100%	99				99
Storage				100%	889				889
Land & feasibility studies				100%	238				238
NT servers and WEB servers				100%	232				232
New system equipment				100%	400				400
Office equip, furniture and leasehold imp				100%	378				378
Total general software and fixed assets				**100%**	**4,204**	**239**	**239**		**3,726**
Total 2008 bond debt service $					**$ 24,666**	**$ 7,263**	**$ 12,481**	**$ 1,196**	**$ 3,726**
Total 2008 bond debt service %					**100%**	**29%**	**51%**	**5%**	**15%**

Debt Service and Capital									
System	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
	% of costs allocated to activity				**Cost of category $ in thousands**				
2009 Bond debt service									
Iron Point headquarters				100%	**$ 17,847**				**$ 17,847**
Cash Funded Capital									
Capital Project fund				100%	**$ 24,000**				**$ 24,000**

Miscellaneous Revenue

The components of other revenue were reviewed and all revenues allocated pursuant to *Table 6 — Allocation of Other Income to GMC Cost Categories.*

Table 20 — Mapping Miscellaneous Revenue to Cost Categories

Allocation of Miscellaneous Revenue									
Type	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
	% of costs allocated to activity				**Cost of category $ in thousands**				
SC application fee				100%	$ 100	$ -	$ -		$ 100
MSS penalties				100%	250				250
SC training fees				100%	150				150
Intermittent resource forecasting fee	20%	80%			1,600	320	1,280		
LGIP study fees		100%			2,000		2,000		
Interest				100%	1,800				1,800
COI path operator fees	17%	83%			2,000	340	1,660		
Total miscellaneous revenue					**$ 7,900**	**$ 660**	**$ 4,940**		**$ 2,300**

Operating Reserve Credit

The components of the operating reserve credit were reviewed and allocated pursuant to *Table 7 — Allocation of Operating Reserve Revenue Credit to GMC Cost Categories.* (see Table 21 below)

Table 21 — Mapping Reserve Credit to Cost Categories

Allocation of Operating reserve credit									
Type	**Market Services**	**System Operations**	**CRR Services**	**Indirect**	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
	% of costs allocated to activity				**Cost of category $ in thousands**				
Decrease in 15% reserve for O&M				100%	$ 21	$ -	$ -	$ -	$ 21
25% debt service reserve 2008 bonds	29%	51%	5%	15%	5,680	1,647	2,897	284	852
25% debt service reserve 2009 bonds				100%	3,570				3,570
Revenue changes				100%	9,266				9,266
Expense changes				100%	6,955				6,955
Total					**$ 25,492**	**$ 1,647**	**$ 2,897**	**$ 284**	**$ 20,664**

Step 4 — Aggregating Revenue Requirement into Cost Categories

The individual revenue requirements were aggregated and indirect costs allocated based on the total of direct costs. See Exhibit 2 for a summary of the cost of service study.

Table 22 — Mapping Revenue Requirement to Cost Categories

Revenue Requirement ($ in thousands)	**2013 Budget**	**Market Services**	**System Operations**	**CRR Services**	**Indirect**
Direct O&M $	$ 68,364	$ 12,863	$ 42,512	$ 845	$ 12,144
Support O&M $	64,686				64,686
Non-ABC support O&M $	29,857	614	1,759	53	27,431
Total O&M	**162,907**	**13,477**	**44,271**	**898**	**104,261**
Debt Service 2008 bonds	24,666	7,263	12,481	1,196	3,726
Debt Service 2009 bonds	17,847				17,847
Debt Service 2008 bonds	24,000				24,000
Total debt service and capital	**66,513**	**7,263**	**12,481**	**1,196**	**45,573**
Other income	(7,900)	(660)	(4,940)		(2,300)
Operating reserve	(25,492)	(1,647)	(2,897)	(284)	(20,664)
Total before allocation of indirect	**196,028**	**18,433**	**48,915**	**1,810**	**126,870**
Allocate indirect based on direct cost %		27%	70%	3%	
Allocate indirect		34,255	88,809	3,806	(126,870)
Total Revenue to Collect $	**$ 196,028**	**$ 52,688**	**$ 137,724**	**$ 5,616**	
Total Cost Category percentages	**100%**	**27%**	**70%**	**3%**	

Step 5 — Calculation of 2013 Rates Using New Cost Category Percentages

Although not necessary to determine the cost category percentages, the rates are needed to determine the EIM fee are covered in a separate paper and summarized in Exhibit 2. The GMC rates are determined by first estimating fees as shown in the following table.

Table 23 — Estimation of Fee Revenue and mapping of Fees to Cost Categories

Fee	Estimated 2013 volumes	Rate	Revenue (in thousands)	Cost Category
Bid segment fees	40,659,200	$0.005 per bid	$ 203	Market Services
Inter-SC trades	2,750,910	$1.00 per trade	2,781	
SCID fees	173	$1,000 per month	2,079	
TOR charges	3,679,322	$0.27 per MWh	993	System Operations
CRR auction bid fee	186,318	$1.00 per bid	186	CRR Services
Total Fees			**$ 6,242**	

Then the fees are deducted from the revenue requirement resulting in the remaining revenue requirement to collect. The remaining amount to collect is divided by the estimated volumes of billing determinants for each cost category to determine the respective rates.

Table 24 — 2013 GMC Rates Using Revised Cost Category Percentages

Revenue Requirement	2013 Budget	Market Services	System Operations	CRR Services
Revenue Requirement in thousands of $	**$ 196,028**	**$ 52,688**	**$ 137,724**	**$ 5,616**
Less Fees				
Bid segment fees	(203)	(203)		
Inter-SC trade fees	(2,781)	(2,781)		
SCID fees	(2,079)	(2,079)		
TOR charges	(993)		(993)	
CRR auction bid fees	(186)			(186)
Total fees	**(6,242)**	**(5,063)**	**(993)**	**(186)**
Remaining revenue requirement to collect	**$ 189,786**	**$ 47,625**	**$ 136,731**	**$ 5,430**
Estimated volumes in thousands of MWh		514,168	474,712	566,649
Less grandfathered contracts			(7,179)	
Estimated volumes		**514,168**	**467,533**	**566,649**
2013 rates using revised percentages		**$ 0.0926**	**$ 0.2925**	**$ 0.0096**

Summary of Cost Category Percentages

The results of the cost of service analysis for the cost category percentages that will go into effect in 2015 are as reflected in the following table.

Summary of Cost Category Percentages for 2015

Category	Percentage
Market Services	27%
System Operations	70%
CRR Services	3%

California ISO

2015 GMC Update
Energy Imbalance Market Cost of Service Study

April 2, 2014

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Executive Summary

The ISO and PacifiCorp in early 2013 agreed to form a new Energy Imbalance Market (EIM). The EIM provides entities with the opportunity to leverage the ISO's existing real-time market platform to facilitate five minute economic dispatch. The EIM provides reliability and economic benefits to both existing market participants and new EIM entities by utilizing the ISO's 15-minute market and real-time dispatch. The EIM relies on the ISO's existing real time portion of the market services activities and system operations activities. The EIM fee for 2014 was developed in collaboration with stakeholders and was based on the ISO's 2010 cost of service study. This fee was approved by the ISO Board of Governors (ISO Board) and will be filed with the Federal Energy Regulatory Commission (FERC) in 2014. Conceptually, EIM participants will pay the same rate as existing customers but only for the real time market and real time dispatch activities specifically related to the EIM. The purpose of this paper is to describe the development of the EIM fee that will be proposed for approval and will be effective in 2015 as part of the updated grid management charge (GMC) and ISO revenue requirement.

Currently, the GMC is made up of three components or services: market services, system operations and congestion revenue rights (CRR) services.[1] The market services charge encompasses all activities related to the processing of bids to issuing schedules in both the day ahead market and real-time market. The system operations charge encompasses all activities related to the dispatch of energy in support of grid conditions and balancing area activities, such as transmission planning. The third component, CRR services charge encompasses activities surrounding congestion revenue rights. Real time activities occur in market services for the real time market and in system operations for real time dispatch. The ISO has used the cost of service analysis for 2015 described in a separate discussion paper, posted at the same time as this update, to develop the updated EIM fee that is the subject of this paper.

To determine the updated EIM fee, using the 2015 cost of service study, the ISO identified

[1] The GMC also comprises several fees, in addition to the EIM fee, which are not relevant to the development of the revised EIM fee. See separate cost of service study discussion paper.

and aggregated the real time activity costs allocated to the two main cost categories. Indirect costs were then allocated to the categories based on the proportion to direct costs. The respective real time cost proportions were then applied to the respective rates for market services and system operations. For the final step, these two real time rates were added to derive the updated EIM rate (see Exhibit 2).

Table 1 – Summary of EIM Rate

Category	Net costs ($ in thousands)	Cost of real time activities	Percentage share of costs	Pro forma 2013 rate	EIM rate
Market Services	$47,625	$28,911	61%	$0.09	$0.06
System Operations	136,731	60,932	45%	$0.29	$0.13
CRR Services	5,430	-	-	$0.01	-
Total	**$189,786**	**$89,843**	**47%**		**$0.19**

The costs include the EIM share of all components of the ISO's revenue requirement such that EIM participants will pay the same rate as existing customers for the real time activities they are using.

Application of ABC to EIM Structure

As discussed in the 2015 cost of service study paper, the ABC analysis disaggregated the ISO's primary business functions into nine core processes (level 1 activities). Each core activity was then divided into major processes (level 2 activities) that were mapped to the corresponding level 1 activity. The first step was to allocate the two cost category activities to the corresponding real time components. The market services component relates to either the real time market or the day-ahead market. The system operations component relates to either real time dispatch or balancing authority services.

Level 2 activities were mapped as one of the following: 1) all in one category or not in the category (100 percent or 0 percent); 2) a split between two categories (50 percent / 50 percent); or 3) partially in one category or another (80 percent or 20 percent). If the activity was identified as indirect or the attribute was not distinguishable to any specific category, it was not included in the initial steps of the allocation process but rather allocated at the end of the process based on percentages of direct allocable costs.

Mapping of Market Services to EIM activities

This mapping only addresses those level 2 activities that are mapped to market services, which then in turn were mapped to either the real time market (RTM) or the day ahead market (DAM). The direct ABC level 2 activities mapped to market services is taken from *Table 2 – Mapping of ABC Direct Operating Activities to Cost Categories* in the 2015 cost of service study paper.

Table 2 – Mapping of Market Services ABC Direct Operating Activities

Mapping of Market Services ABC level 2 Direct Operating Activities to EIM activities					
ABC Level 2 Activities	**Cost Code**	**Market services**	**RTM**	**DAM**	**Comments**
% of cost to allocate to category					
Definitions used in allocation			100%		the costs are entirely to support the RT market
				100%	the costs are entirely to support the DA market
			50%	50%	the costs support equally both RT and DA markets
			80%	20%	the costs are predominantly RT market related but have some DA market relationship
			20%	80%	the costs are predominantly DA market based but have some RT market relationship
ABC Direct Operating Activities					
Develop Markets (DM) (80002)					
Perform market analysis	232	100%	50%	50%	Market analysis and design encompasses both markets
Develop market design	233	100%	50%	50%	
Manage Market and Reliability Data and Modeling (MMR) (80004)					
Manage FNM maintenance	301	50%	50%	50%	The full network model encompasses both markets
Plan and develop operations simulator training	302	20%	100%		The grid is operated in real time
Manage credit and collateral	308	45%	50%	50%	Credit and collateral required for all markets
Resource management	309	50%	80%	20%	Transmission resource & operational characteristics are reflected in RT market
PIRP	313	20%	100%		Scheduling option for intermittent resources is in RT market
Manage & facilitate procedure maintenance	314	20%	100%		The grid is operated in real time
Procedure administration and reporting	315	20%	100%		
Plan and develop operations training	316	20%	100%		
Execute and track operations training	317	20%	100%		
Manage Markets and Grid (MMG) (80005)					
Manage DA market support	352	100%		100%	Applies to DA market
Operations RT support	353	50%	100%		Applies to RT market
Manage DA market	358	50%		100%	Applies to DA market
Manage operations engineering support	362	20%	50%	50%	Ensures system conditions accurately reflected in markets
RT market – shift supervisor – manage post DA and pre RT	363	50%	100%		Applies to RT market

Mapping of Market Services ABC level 2 Direct Operating Activities to EIM activities					
ABC Level 2 Activities	**Cost Code**	**Market services**	**RTM**	**DAM**	**Comments**
% of cost to allocate to category					
RT operations – Generation and RT renewables (GRC) desks - maintain balancing area and manage RT pre dispatch	364	20%	100%		Applies to RT market
Manage Operations Support and Settlements (MOS) (8007)					
Manage price validation & corrections	401	50%	50%	50%	Price corrections occur in both markets
Manage MQS	403	50%	80%	20%	Process to feed correct data into settlements (base EIM schedules are equivalent to DA schedules)
Manage market clearing	411	45%	80%	20%	Predominantly real time activity
Manage market billing & settlements	412	45%	80%	20%	
Manage settlements release cycle	414	45%	80%	20%	
Manage market performance	417	50%	50%	50%	Market performance and validation encompasses both markets
Perform market validation	419	50%	50%	50%	

This mapping was also applied to the software costs underlying the debt service portion of the revenue requirement. This market services mapping is taken from *Table 3 – Allocation of Debt Service and Capital to GMC to Cost Categories* in the 2015 cost of service study paper.

Table 3 – Allocation of Market Services Debt Service to RT Categories

Allocation of Market Services Debt Service to EIM activities				
System	**Market services**	**RTM**	**DAM**	**Comments**
		% of cost to allocate to category		
2008 Bond Debt Service (see spelled out abbreviations in cost of service discussion paper)				
ALFS	50%	100%		Load forecast is used in RT market
DMM & compliance Tools (SAS MARS)	50%	50%	50%	ISO market monitoring covers all markets
FNM / State estimator	50%	100%		Used to initialize the RT dispatch
IFM	50%		100%	Applies to DA market
MQS	50%	80%	20%	Use 80007 activity 403
Master file	50%	100%		Stores resource operating characteristics
RIMs	20%		100%	Balancing authority responsibility
OASIS	50%	100%		Posts market results
PIRP	20%	100%		Use 80007 activity 313
Portal	50%	80%	20%	Enables participants to input and receive market information
CMRI	50%	80%	20%	
RT markets	20%	100%		Applies to RT market
HASP	50%	100%		
Resource Adequacy	50%		100%	ISO process to implement resource adequacy
RAVE	50%		100%	ISO process to implement RMR
SLIC	50%	100%		Required for recording outages in RT market
SIBR	50%	50%	50%	Required for submitted bids
SaMC	15%	80%	20%	Based on RT and DA charge codes

The market services related non-payroll support costs were mapped from *Table 4 – Allocation of Non-Payroll Support Cost to GMC to Cost Categories* in the cost of service discussion paper.

Table 4 – Allocation of Market Services Non-Payroll Support Costs

Allocation of Market Services Non-Payroll Support Costs to EIM activities				
Type	**Market services**	**RTM**	**DAM**	**Comments**
		% of cost to allocate to category		
Non-Payroll Support Costs				
Operations Division				
PIRP forecasting costs	20%	100%		Use 80004 activity 313
General Counsel and Administrative Services Division				
SSAE 16 audit	45%	80%	20%	Use 80007 activity 412
Operational assessment	17%	To be based on %'s from 80005 between RTM and DAM		

The remaining market services other income from *Table 6 – Allocation of Other Income to GMC to Cost Categories* and operating reserve credit from *Table 7 – Allocation of Operating Reserve Credit to GMC to Cost Categories* in the 2015 cost of service study paper were then allocated to real time and day ahead components.

Table 5 – Allocation of Market Services Other Income

Allocation of Market Services Other Income to EIM activities				
Type	**Market services**	**RTM**	**DAM**	**Comments**
		% of cost to allocate to category		
Other Income				
PIRP forecasting fees	20%	100%		Use 80004 activity 313
COI path operator fees	17%	To be based on %'s from 80005 between RTM and DAM		

Table 6 – Allocation of Market Services Operating Reserve Credit

Allocation of Market Services Operating Reserve Revenue Credit to EIM activities				
Type	**Market services**	**RT Market**	**DA Market**	**Comments**
		% of cost to allocate to category		
Operating Reserve Credit				
25% debt service reserve on 2008 bonds	29%	To be based on %'s from 2008 bonds debt service between RTM and DAM		

FEES

Market service fees from *Table 23 – Estimation of Fee Revenue and mapping of Fees to Cost Categories* in the 2015 cost of service study paper are allocated as follows.

Table 7 – Allocation of Market Services Fees

Allocation of Market Services Other Income to EIM activities				
Type	**Market services**	**RTM**	**DAM**	**Comments**
		% of cost to allocate to category		
Fees				
Bid segment fees	100%	50%	50%	Bidding in both markets
Inter-SC trades	100%		100%	All in forward market
SCID fees	100%	50%	50%	Participate in both markets

Costing the Market Services EIM activities

The amounts from the 2015 cost of service study were applied to the market services categories to derive the direct costs of the real time and day ahead markets.

Table 8 – Components of the 2013 Market Services Revenue Requirement:

Revenue Requirement ($ in thousands)	2013 Market Services Budget
Direct O&M	$ 12,863
Non-ABC support O&M	614
Debt service 2008 bonds	7,263
Other income	(660)
Operating reserve credit	(1,647)
Allocation of Indirect costs	34,255
Revenue Requirement before fees	**53,028**
Fees	(5,063)
Total Market Services Revenue Requirement	**$ 47,625**

Completing the analysis required the following steps:

1. applying EIM activity percentages to non-ABC O&M support costs;
2. applying EIM activity percentages to ABC direct O&M costs;
3. applying EIM activity percentages to debt service costs, other income and operating reserve credit;
4. aggregating costs and allocate indirect costs to EIM activities based on percentage of direct costs and allocation of fees to EIM activities to determine the resulting EIM activity amounts and percentages; and
5. applying the EIM activity percentage to market services rate to determine the EIM market services component.

Step 1: Applying EIM activity percentages to non-ABC O&M support costs

The non-ABC support costs from *Table 10 – Allocation of non-ABC Support Costs to Cost Categories* in the 2015 cost of service study paper were allocated using the percentages shown in Table 4 above.

Table 9 – Allocation of Market Services Non-ABC Support Costs

Allocation of Market Services Non-ABC support costs to EIM Activities						
Non-ABC support costs	Market Services	RTM	DAM	2013 Market Services Budget	RTM	DAM
		% of costs allocated to activity			Cost of activity $ in thousands	
Non-ABC Support Costs						
Operations Division						
PIRP forecasting costs	20%	100%		$ 337	$ 337	$ -
General Counsel and Administrative Services Division						
SSAE 16 audit	45%	80%	20%	243	194	49
Operational assessment	17%	66%	34%	34	22	12
Total				**$ 614**	**$ 553**	**$ 61**

Step 2: Applying EIM activity percentages to ABC direct O&M Costs

The ABC direct O&M costs from *Table 15 – Mapping ABC Direct Operating Activities to Cost Categories* in the 2015 cost of service study paper were allocated using the percentages shown in Table 2 above.

Table 10 – Allocation of Market Services ABC Direct Operating Costs

Allocation of Market Services ABC Direct Operating Costs to EIM Activities							
ABC Level 2 Activities	Cost Code	Market Services	RTM	DAM	2013 Market Services Budget	RTM	DAM
			% of costs allocated to activity			Cost of activity $ in thousands	
ABC Direct Operating Costs							
Develop Markets (DM) (80002)							
Perform market analysis	232	100%	50%	50%	$ 1,604	$ 802	$ 802
Develop market design	233	100%	50%	50%	2,242	1,121	1,121
Total DM					**3,846**	**1,923**	**1,923**
Manage Market & Reliability Data & Modeling (MMR) (80004)							
Manage FNM maintenance	301	50%	50%	50%	862	431	431
Plan and develop operations simulator training	302	20%	100%		60	60	
Manage credit and collateral	308	45%	50%	50%	262	131	131
Resource management	309	50%	80%	20%	455	364	91
Manage & facilitate procedure maintenance	314	20%	100%		168	168	
Procedure admin & reporting	315	20%	100%		2	2	
Plan and develop operations training	316	20%	100%		143	143	
Execute and track operations training	317	20%	100%		277	277	
Total MMR					**2,229**	**1,576**	**653**
Manage Markets and Grid (MMG) (80005)							
Manage DA market support	352	100%		100%	115		115
Operations RT support	353	50%	100%		616	616	
Manage DA market	358	50%		100%	1,282		1,282

Allocation of Market Services ABC Direct Operating Costs to EIM Activities							
ABC Level 2 Activities	Cost Code	Market Services	RTM	DAM	2013 Market Services Budget	RTM	DAM
			% of costs allocated to activity			Cost of activity $ in thousands	
Manage operations engineering support	362	20%	50%	50%	230	115	115
RT market – shift supervisor – manage post DA and pre RT	363	50%	100%		1,011	1,011	
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364	20%	100%		1,219	1,219	
Total MMG					**4,473**	**2,961**	**1,512**
Total MMG %					**100%**	**66%**	**34%**
Manage Operations Support & Settlements (MOS) (80007)							
Manage price validation and corrections	401	50%	50%	50%	78	39	59
Manage MQS	403	50%	80%	20%	571	481	120
Manage market clearing	411	45%	80%	20%	50	33	8
Manage market billing & settlements	412	45%	80%	20%	541	427	107
Manage settlements release cycle	414	45%	80%	20%	363	374	94
Manage market performance	417	50%	50%	50%	104	71	70
Perform market validation	419	50%	50%	50%	608	298	298
Total MOS					**2,315**	**1,743**	**756**
Total Direct O&M					**$ 12,863**	**$ 8,508**	**$ 5,327**
Direct O&M %					**100%**	**61%**	**39%**

Step 3 – Allocating the remaining market service revenue requirements

Debt Service

The debt service costs from *Table 19 – Mapping Debt Service and Cash Funded Capital to Cost Categories* in the 2015 cost of service study paper were allocated using the percentages shown in Table 3 above.

Table 11 – Allocation of Market Service Debt Service Costs

Allocation of Market Services Debt Service Costs to EIM Activities						
System	Market Services	RTM	DAM	2013 Market Services Budget	RTM	DAM
		% of costs allocated to activity			Cost of activity $ in thousands	
2008 Bonds Debt Service Costs						
Operations Related Software						
ALFS	50%	100%		$ 40	$ 40	$ -
DMM & compliance Tools	50%		100%	239	120	119
FNM / State estimator	50%	100%		91	91	
IFM	50%		100%	3,183		3,183
MQS	50%	80%	20%	506	405	101
Master file	50%	100%		205	205	
NRI	20%		100%	44		44
OASIS	50%	100%		33	33	
PIRP	20%	100%		9	9	

Allocation of Market Services Debt Service Costs to EIM Activities						
System	Market Services	RTM	DAM	2013 Market Services Budget	RTM	DAM
		% of costs allocated to activity			Cost of activity $ in thousands	
Portal	50%	80%	20%	236	189	47
CMRI	50%	80%	20%	206	165	41
RTMA split off 50% into HASP	20%	100%		254	254	
HASP	50%		100%	635	635	
Resource Adequacy	50%		100%	21		21
RAVE	50%		100%	3		3
SLIC	50%	100%		147	147	
SIBR	50%	100%		900	450	450
SaMC	15%	80%	20%	511	409	102
Total 2008 bond debt service				**$ 7,263**	**$ 3,152**	**$ 4,111**
Total 2008 bond debt Service %				**100%**	**43%**	**57%**

Miscellaneous Revenue

The miscellaneous revenue from *Table 20 – Mapping Miscellaneous Revenue to Cost Categories* in the 2015 cost of service study paper was allocated using the percentages shown in Table 5 above.

Table 12 – Allocation of Market Services Miscellaneous Revenue

Allocation of Market Services Miscellaneous Revenue						
Type	Market Services	RTM	DAM	2013 Market Services Budget	RTM	DAM
		% of costs allocated to activity			Cost of activities $ in thousands	
Miscellaneous revenue						
Intermittent resource forecasting fee	20%	100%		$ 320	$ 320	$ -
COI path operator fees	17%	66%	34%	340	224	116
Total miscellaneous revenue				**$ 660**	**$ 544**	**$ 116**

Operating Reserve Credit

The operating reserve credit from *Table 21 – Mapping Operating Reserve Credit to Cost Categories* in the 2015 cost of service study paper was allocated using the percentages shown in Table 6 above.

Table 13 – Allocation of Market Services Operating Reserve Credit

Allocation of Market Services Operating reserve credit to EIM Activities						
Type	Market Services	RTM	DAM	2013 Market Services Budget	RTM	DAM
		% of costs allocated to activity			Cost of activities $ in thousands	
Operating Reserve Credit						
25% debt service reserve 2008 bonds	29%	43%	57%	$ 1,647	$ 708	$ 939
Total				**$ 1,647**	**$ 708**	**$ 939**

Step 4 - Aggregating revenue requirement into cost categories and allocating fees

The individual revenue requirements for each category were aggregated, indirect costs were allocated based on the total of direct costs and fees were allocated using the factors in Table 7 - Allocation of Market Services Fees.

Table 14 – Mapping Revenue Requirement to Cost Categories

Revenue Requirement ($ in thousands)	2013 Market Services Budget	Real Time Market	Day Ahead Market
Direct O&M $	$ 12,863	$ 8,075	$ 1,788
Non-ABC support O&M $	614	553	61
Debt Service 2008 bonds	7,263	3,152	4,111
Other income	(660)	(544)	(116)
Operating reserve	(1,647)	(708)	(939)
Total before allocation of indirect	**18,433**	**10,528**	**7,905**
Allocate indirect based on direct cost %	100%	57%	43%
Allocate indirect	34,255	19,525	14,730
Total Revenue requirement	**52,688**	**30,053**	**22,635**
Less Fees			
Market bid fees	(203)	(102)	(101)
Inter-SC bid fees	(2,781)		(2,781)
SCID fees	(2,079)	(1,040)	(1,039)
Total fees	**(5,063)**	**(1,142)**	**(3,921)**
Revenue requirement to collect	**$ 47,625**	**$ 28,911**	**$ 18,714**
% applicable to EIM activities	**100%**	**61%**	**39%**

Step 5 – Calculation of the EIM component of the 2013 market services rates

The percentages from Table 14 above were applied to the market services rate from *Table 23 – 2013 GMC rates Using Revised Cost Category Percentages* in the 2015 cost of service study paper.

Table 15 – EIM Component Rates of Market Services

Revenue Requirement	Market Services	Real Time Market
2013 Market Services rate	**$ 0.09**	
Revenue requirement to collect	$ 47,625	$ 28,911
% of costs applicable to EIM activities		61%
2013 rates of EIM activities		**$ 0.06**

Mapping of System Operations to EIM activities

This mapping only addresses those level 2 activities that are mapped to system operations that are in turn mapped to the real time dispatch (RTD) or the balancing authority services (BAS). The direct ABC level 2 activities mapped to system operations is taken from *Table 2 – Mapping of ABC Direct Operating Activities to Cost Categories* in the 2015 cost of service study paper.

Table 16 – Mapping of System Operations ABC Direct Operating Activities

Mapping of System Operations ABC level 2 Direct Operating Activities to EIM activities					
ABC Level 2 Activities	**Cost Code**	**System Operations**	**RTD**	**BAS**	**Comments**
			% of cost to allocate to category		
Definitions used in allocation			100%		the costs are entirely to support RT dispatch
				100%	the costs are entirely to support BA services
			50%	50%	the costs support equally both RT dispatch and BA services
			80%	20%	the costs are predominantly RT dispatch related but have some BA relationship
			20%	80%	the costs are predominantly BA services based but have some RT dispatch relationship
ABC level 2 Direct Operating Activities					
Develop Infrastructure (DM) (80001)					
Manage GIP agreements	202	100%		100%	This is a balancing authority responsibility
Manage GIP	203	100%		100%	
Long-term transmission planning	204	100%		100%	
New transmission resources	205	100%		100%	
Transmission maintenance studies	206	100%		100%	
Load resource data	207	100%		100%	
Seasonal assessment	208	100%		100%	
Queue management	209	100%		100%	
Annual delivery assessment	210	100%		100%	
Develop Markets (DM) (80002)					
Develop infrastructure policy	231	100%		100%	This is a balancing authority responsibility
Manage Market and Reliability Data and Modeling (MMR) (80004)					
Manage FNM maintenance	301	50%	100%		The grid id operated in real time
Plan and develop operations simulator training	302	80%	100%		The grid id operated in real time
ISO meter certification	303	100%		100%	The EIM entity is responsible for ensuring that their resources meet metering requirements.
EMMAA telemetry	304	100%		100%	
Metering system configuration for market resources	305	100%	100%		Ensure meter telemetry data is reflected in the real time market
Manage credit and collateral	308	45%	100%		Relates to billing for market transactions
Resource management	309	50%	20%	80%	Transmission resource and operational characteristics for management of the balancing area
Manage reliability requirements	310	100%		100%	This is an ISO process to implement resource adequacy
Manage operations planning	311	100%		100%	This is a balancing authority responsibility

Mapping of System Operations ABC level 2 Direct Operating Activities to EIM activities					
ABC Level 2 Activities	**Cost Code**	**System Operations**	**RTD**	**BAS**	**Comments**
			% of cost to allocate to category		
Manage WECC seasonal studies	312	100%		100%	
PIRP	313	80%	100%		Scheduling option for intermittent resources in real time market.
Manage & facilitate procedure maintenance	314	80%		100%	This is a balancing authority responsibility
Procedure administration and reporting	315	80%		100%	
Plan and develop operations training	316	80%	100%		The grid is operated in real time
Execute and track operations training	317	80%	100%		
CETAC activities	318	100%		100%	This is a balancing authority responsibility
Manage Markets and Grid (MMG) (80005)					
Operations RT support	353	50%	100%		Applies to real time market
Outage model and management	355	100%		100%	This is a balancing authority responsibility
Manage DA market	358	50%	80%	20%	DA schedules in ISO are equivalent to EIM base schedules
Manage pre and post scheduling	359	100%		100%	This is a balancing authority responsibility
Manage operations engineering support	362	80%	100%		Ensures system conditions accurately reflect real time market
RT market – shift supervisor – manage post DA and pre RT & manage emergency operations	363	50%	20%	80%	Manages ISO grid reliability and ensures real time market dispatch after reflecting system conditions and man
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364	80%	100%		This is the preparation for running the real time market
RTO – transmission desk – manage transmission and electric system	365	100%		100%	This is a balancing authority responsibility
RTO – scheduling desk – manage RT interchange scheduling	366	100%		100%	
Manage Operations Support and Settlements (MOS) (8007)					
Manage price validation & corrections	401	50%	100%		Price corrections are in real time
Manage MQS	403	50%	100%		Process to feed correct data into settlements (base EIM schedules are equivalent to DA schedules)
Manage regulation no pay & deviation penalty calculations	405	100%		100%	This is a balancing authority responsibility
Periodic meter audits	407	100%	100%		Validated meter data for settlement purposes
RIG engineering	408	100%		100%	This is a balancing authority responsibility
Manage energy measurement acquisition & analysis	409	100%	100%		Validated meter data for settlement purposes
Manage market clearing	411	45%	100%		Predominantly real time or market activity
Manage market billing & settlements	412	45%	100%		
Manage RMR settlements	413	100%	100%		
Manage settlements release cycle	414	45%	100%		
Manage market performance	417	50%	100%		Market analysis and validation encompasses both markets
Perform market validation	419	50%	100%		
Support Customers and Stakeholders (SCC) (80010)					
Develop participating transmission owners	605	100%		100%	This is a balancing authority responsibility

This mapping was also applied to the software underlying the 2008 bond debt service portion of the revenue requirement. The system operations mapping s taken from *Table 3 – Allocation of Debt Service and Capital to GMC to Cost Categories* in the 2015 cost of study discussion paper.

Table 17 – Allocation of System Operations Debt Service

Allocation of System Operations Debt Service to EIM activities				
System	**System Operations**	**RTD**	**BAS**	**Comments**
		% of cost to allocate to category		
2008 Bond Debt Service				
ADS	100%	100%		Used to send dispatch instructions to participating resources.
ALFS	50%	100%		Load forecast is used in real time
DMM & compliance tools	50%	100%		Market monitoring
EMS	100%		100%	This is primarily a balancing authority responsibility with some real time as the balancing authorities communicate with each other
ETCC	50%		100%	This is a balancing authority responsibility
FNM / State estimator	50%	100%		This is used to initialize the real time dispatch
IFM	50%	100%		
MQS	50%	100%		Process to feed correct data into settlements (base EIM schedules are equivalent to DA schedules)
Master file	50%	100%		Stores resource operating characteristics
MDAS	100%	100%		Receives meter data for settlement purposes
RIMs	80%		100%	This is a balancing authority responsibility
OASIS	50%	100%		Market results include EIM results
OMAR	100%	100%		Receives meter data for settlement purposes
PIRP	80%	100%		Scheduling option for intermittent resources in real time market
Portal	50%	100%		Enables EIM participants to input and receive market information
CMRI	50%	100%		
Pi	100%		100%	This is a balancing authority responsibility
RT markets	80%	100%		Includes the hour ahead, real time dispatch and fifteen minute market
HASP	50%	100%		
Resource Adequacy	50%		100%	This is a process to implement resource adequacy
RAVE	50%		100%	This is a process to implement RMR
SLIC	50%	100%		Required for reflecting outages in the real time
CAS	50%		100%	This is a balancing authority responsibility
SIBR	50%	100%		This is required for submitted bids
SaMC	75%	100%		Based on day ahead and real time charge codes

Next the system operations related non-payroll support costs were mapped from *Table 4 – Allocation of Non-Payroll Support Cost to GMC to Cost Categories* in the 2015 cost of service study paper.

Table 18 – Allocation of System Operations Non-Payroll Support Costs

Allocation of System Operations Non-Payroll Support Costs to EIM activities				
Type	**System Operations**	**RTD**	**BAS**	**Comments**
		% of cost to allocate to category		
Non-Payroll Support Costs				
Operations Division				
PIRP forecasting costs	80%	100%		Use 80004 activity 313
General Counsel and Administrative Services Division				
SSAE 16 audit	45%	100%		Use 80007 activity 412
Operational assessment	83%	To be based on %'s from 80005 between RTD and BAS		

The remaining system operations other income *Table 6 – Allocation of Other Income to GMC to Cost Categories* and operating reserve credit *Table 7 – Allocation of Operating Reserve Credit to GMC to Cost Categories,* both in the 2015 cost of service study paper, were then allocated to their RTD and BAS components.

Table 19 – Mapping of System Operations Other Income

Allocation of System Operations Other Income to EIM activities				
Type	**System Operations**	**RTD**	**BAS**	**Comments**
		% of cost to allocate to category		
Other Income				
PIRP forecasting fees	80%	100%		Use 80004 activity 313
LGIP study fees	100%		100%	Use 80001 activity 203
COI path operator fees	83%	To be based on %'s from 80005 between RTD and BAS		

Table 20 – Mapping of System Operations Operating Reserve Credit

Allocation of Market Services Operating Reserve Revenue Credit to EIM activities				
Type	**System Operations**	**RTD**	**BAS**	**Comments**
		% of cost to allocate to category		
Operating Reserve Credit				
25% debt service reserve on 2008 bonds	51%	To be based on %'s from 2008 bonds debt service between RTD and BAS		

FEES

Transmission ownership rights charges were allocated 100 percent to real time dispatch.

Costing the System Operations EIM activities

The amounts from the 2015 cost of service study were applied to the system operations categories to derive the direct costs of the RTD and BAS.

Table 21 – Components of the 2013 System Operations Revenue Requirement:

Revenue Requirement **($ in thousands)**	**2013 System Operations Budget**
Direct O&M	$ 42,512
Non-ABC support O&M	1,759
Debt service 2008 bonds	12,481
Other income	(4,940)
Operating reserve credit	(2,897)
Allocation of Indirect costs	88,809
Revenue requirement before fees	**137,724**
Fees	(993)
Total System Operations Revenue Requirement	**$ 136,731**

Completing the analysis required the following steps:

1. applying EIM activity percentages to non-ABC O&M support costs;
2. applying EIM activity percentages to ABC direct O&M costs;
3. applying EIM activity percentages to debt service costs, other Income and operating reserve credit;
4. aggregating costs and allocate indirect costs to EIM activities based on percentage of direct costs and allocating fees to EIM activities to determining resulting EIM activity amounts and percentages; and
5. applying EIM activity percentage to market services rate to determine the EIM market services component.

<u>Step 1: Applying EIM activity percentages to non-ABC O&M support costs</u>

The non-ABC support costs from *Table 10 – Allocation of non-ABC Support Costs to Cost Categories* in the 2015 cost of service study paper were allocated using the percentages shown in Table 18 above.

Table 22 – Allocation of System Operations Non-ABC Support Costs

Allocation of System Operations Non-ABC support costs to EIM Activities						
Non-ABC support costs	**System Operations**	**RT Dispatch**	**BA Services**	**2013 System Operations Budget**	**RT Dispatch**	**BA Services**
		% of costs allocated to activity			**Cost of activity $ in thousands**	
Non-ABC support costs						
Operations Division						
PIRP forecasting costs	80%	100%		$ 1,350	$ 1,350	$ -
General Counsel and Administrative Services Division						
SSAE 16 audit	45%	100%		243	243	
Operational assessment	83%	36%	64%	166	60	106
Total				**$ 1,759**	**$ 1,653**	**$ 106**

Step 2: Applying EIM activity percentages to ABC direct O&M Costs

The ABC direct O&M costs from *Table 15 – Mapping ABC Direct Operating Activities to Cost Categories* in the 2015 cost of service study paper were allocated using the percentages shown in Table 16 above.

Table 23 – Allocation of System Operations ABC Direct Operating Costs

Allocation of System Operations ABC Direct Operating Costs to EIM Activities							
ABC Level 2 Activities	**Cost Code**	**System Operations**	**RTD**	**BAS**	**2013 System Operations Budget**	**RTD**	**BAS**
			% of costs allocated to activity			**Cost of activity $ in thousands**	
ABC Direct Operating Costs							
Develop Infrastructure (DI) (80001)							
Manage GIP agreements	202	100%		100%	$ 818	$ -	$ 818
Manage GIP	203	100%		100%	2,342		2,342
Long-term transmission planning	204	100%		100%	4,723		4,723
New transmission resources	205	100%		100%	552		552
Transmission maintenance studies	206	100%		100%	499		499
Load resource data	207	100%		100%	268		268
Seasonal assessment	208	100%		100%	223		223
Queue management	209	100%		100%	615		615
Annual delivery assessment	210	100%		100%	25		25
Total DI					**9,615**		**9,915**
Develop Markets (DM) (80002)							
Develop infrastructure policy	231	100%	100%		829		829
Total DM					**829**		**829**
Manage Market & Reliability Data & Modeling (MMR) (80004)							
Manage FNM maintenance	301	50%	100%		862	862	
Plan and develop operations simulator training	302	80%	100%		240	240	
ISO meter certification	303	100%		100%	416		416
EMMAA telemetry	304	100%		100%	100		100

Allocation of System Operations ABC Direct Operating Costs to EIM Activities							
ABC Level 2 Activities	**Cost Code**	**System Operations**	**RTD**	**BAS**	**2013 System Operations Budget**	**RTD**	**BAS**
			% of costs allocated to activity			**Cost of activity $ in thousands**	
Metering system configuration for market resources	305	100%	100%		70	70	
Manage credit and collateral	308	45%	100%		262	262	
Resource management	309	50%	20%	80%	455	91	364
Manage reliability requirements	310	100%			931		931
Manage operations planning	311	100%			1,321		1,321
Manage WECC seasonal studies	312	100%			71		71
PIRP	313	80%			1	1	
Manage & facilitate procedure maintenance	314	80%		100%	673		673
Procedure administration and reporting	315	80%			9		9
Plan and develop operations training	316	80%	100%		571	571	
Execute and track operations training	317	80%	100%		1,106	1,106	
CETAC activities	318	100%			73		73
Total MMR					**7,161**	**3,203**	**3,958**
Manage Markets and Grid (MMG) (80005)							
Operations RT support	353	50%	100%		615	615	
Outage model and management	355	100%		100%	2,921		2,921
Manage DA market	358	50%	80%	20%	1,282	1,026	256
Manage pre and post scheduling	359	100%		100%	974		974
Manage operations engineering support	362	80%	100%		918	918	
RT market – shift supervisor – manage post DA and pre RT	363	50%	20%	80%	1,010	202	808
RTO – GRC desks - maintain balancing area and manage RT pre dispatch	364	80%	100%		4,874	4,874	
RTO – transmission desk – manage transmission and electric system	365	100%		100%	4,956		4,956
RTO – scheduling desk – manage RT interchange scheduling	366	100%		100%	3,754		3,754
Total MMG			**36%**	**64%**	**21,304**	**7,635**	**13,669**
Manage Operations Support & Settlements (MOS) (80007)							
Manage price validation and corrections	401	50%	100%		78	78	
Manage MQS	403	50%	100%		571	571	
Manage regulation no pay & deviation penalty calculations	405	100%		100%	8		8
Periodic meter audit	407	100%	100%		4		4
RIG engineering	408	100%		100%	332		332
Manage energy measurement acquisition & analysis	409	100%	100%		926	926	
Manage market clearing	411	45%	100%		50	50	
Manage market billing & settlements	412	45%	100%		541	541	
Manage RMR settlements	413	100%	100%		10	10	
Manage settlements release cycle	414	45%	100%		363	363	
Manage market performance	417	50%	100%		104	104	

Allocation of System Operations ABC Direct Operating Costs to EIM Activities							
ABC Level 2 Activities	**Cost Code**	**System Operations**	**RTD**	**BAS**	**2013 System Operations Budget**	**RTD**	**BAS**
			% of costs allocated to activity			**Cost of activity $ in thousands**	
Perform market validation	419	50%	100%		608	608	
Total MOS					**3,595**	**3,255**	**340**
Support Customers and Stakeholders (SCS) (80010)							
Develop PTOs	605	100%		100%	8		8
Total SCS					**8**	**-**	**8**
Total Direct O&M					**$ 42,512**	**$ 14,093**	**$ 28,419**
Direct O&M %					**100%**	**33%**	**67%**

Step 3 – Allocating remaining system operations revenue requirement components

Debt Service

The debt service costs from *Table 19 – Mapping Debt Service and Cash Funded Capital to Cost Categories* in the 2015 cost of service study paper were allocated using the percentages shown in Table 17 above.

Table 24 – Allocation of System Operations Debt Service Costs

Allocation of Market Services Debt Service Costs to EIM Activities						
System	**System Operation**	**RTD**	**BAS**	**2013 System Operations Budget**	**RTD**	**BAS**
		% of costs allocated to activity			**Cost of activity $ in thousands**	
Debt Service Costs						
ADS	100%	100%		$ 30	$ 30	$ -
ALFS	50%	100%		39	39	
DMM & compliance Tools	50%	100%		239	239	
EMS	100%	20%	80%	1,923	385	1,538
ETCC	50%		100%	5		5
FNM / State estimator	50%	100%		91	91	
IFM	50%	100%		3,182	3,182	
MQS	50%	100%		507	507	
Master file	50%	100%		204	204	
MDAS	100%	100%		15	15	
NRI	80%		100%	175		175
OASIS	50%	100%		33	33	
OMAR	100%	100%		96	96	
PIRP	80%	100%		36	36	
Portal	50%	100%		237	237	
CMRI	50%	100%		205	205	
PI	100%		100%	137		137

Allocation of Market Services Debt Service Costs to EIM Activities						
System	System Operation	RTD	BAS	2013 System Operations Budget	RTD	BAS
		% of costs allocated to activity			Cost of activity $ in thousands	
RT markets	80%	100%		1,017	1,017	
HASP	50%	100%		635	635	
Resource Adequacy	50%		100%	22		22
RAVE	50%		100%	2		2
SLIC	50%	100%		148	148	
CAS	100%		100%	47		47
SIBR	50%	100%		901	901	
SaMC	75%	100%		2,555	2,555	
Total 2008 bond debt service				**$ 12,481**	**$ 10,555**	**$ 1,926**
Total 2008 Bond debt Service %				**100%**	**85%**	**15%**

Miscellaneous Revenue

The miscellaneous revenue from *Table 20 – Mapping Miscellaneous Revenue to Cost Categories* in the 2015 cost of service study paper was allocated using the percentages shown in Table 19 above.

Table 25 – Allocation of System Operations Miscellaneous Revenue

Allocation of System Operations Miscellaneous Revenue						
Type	System Operations	RTD	BAS	2013 System Operations Budget	RTD	BAS
		% of costs allocated to activity			Cost of activities $ in thousands	
Miscellaneous revenue						
Intermittent resource forecasting fee	80%	100%		$ 1,280	$ 1,280	$ -
LGIP study fees	100%		100%	2,000		2,000
COI path operator fees	83%	36%	64%	1,660	598	1,062
Total miscellaneous revenue				**$ 4,940**	**$ 1,878**	**$ 3,062**

Operating Reserve Credit

The operating reserve credit from *Table 21 – Mapping Operating Reserve Credit to Cost Categories* in the cost of service discussion paper was allocated using the percentages shown in Table 20 above.

Table 26 – Allocation of System Operations Operating Reserve Credit

Allocation of System Operations Operating reserve credit to EIM Activities						
Type	**System Operations**	**RTD**	**BAS**	**2013 System Operations Budget**	**RTD**	**BAS**
		% of costs allocated to activity			**Cost of activities $ in thousands**	
Operating Reserve Credit						
25% debt service reserve 2008 bonds	51%	85%	15%	$ 2,897	$ 2,462	$ 435
Total				**$ 2,897**	**$ 2,462**	**$ 435**

Step 4 – Aggregating revenue requirement into cost categories and allocating fees

The individual revenue requirements for each category were aggregated, indirect costs were allocated based on the total of direct costs and fees were allocated as described above.

Table 27 – Mapping Revenue Requirement to Cost Categories

Revenue Requirement ($ in thousands)	2013 System Operations Budget	Real Time Dispatch	Balancing Authority Services
Direct O&M $	$ 42,512	$ 14,093	$ 28,419
Non-ABC support O&M $	1,759	1,653	106
Debt Service 2008 bonds	12,481	10,555	1,926
Other income	(4,940)	(1,878)	(3,062)
Operating reserve	(2,897)	(2,462)	(435)
Total before allocation of indirect	**48,915**	**21,961**	**26,954**
Allocate indirect based on direct cost %	100%	45%	55%
Allocate indirect	88,809	39,964	48,845
Total Revenue requirement	**137,724**	**61,925**	**75,799**
Less TOR charges	(993)	(993)	
Revenue requirement to collect	**$ 136,731**	**$ 60,932**	**$ 75,799**
% applicable to EIM activities	**100%**	**45%**	**55%**

Step 5 – Calculation of EIM component of 2013 system operations rates

The percentages from Table 27 above were applied to the system operations rate from *Table 23 – 2013 GMC rates Using Revised Cost Category Percentages* in the 2015 cost of service study paper.

Table 28 – EIM Component Rate for System Operations

Revenue Requirement	System Operations	Real Time Dispatch
2013 System Operations rate	**$ 0.29**	
Revenue requirement to collect	$ 136,731	$ 60,932
% of costs applicable to EIM activities		45%
2013 system operations rate for EIM activities		**$ 0.13**

Summary of EIM Rate

The results of the cost of service analysis for the EIM fee that will go into effect in 2015 are as reflected in the following table:

Summary of EIM Rate for 2015

Category	Net costs ($ in thousands)	Cost of real time activities	Percentage share of costs	Pro forma 2013 rate	EIM rate
Market services	$ 47,625	$ 28,911	61%	$ 0.09	$ 0.06
System Operations	136,731	60,932	45%	$ 0.29	$ 0.13
CRR services	5,430	n/a		$ 0.01	
Total	**$ 189,786**	**$ 89,843**	**47%**		**$ 0.19**

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER15 ___-000**

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

I, Michael K. Epstein, state as follows:

1. I am employed as Director of Financial Planning for the California Independent System Operator Corporation (the "CAISO"). My business address is 250 Outcropping Way, Folsom, California 95630. I am responsible for the CAISO's budget preparation and management; long term planning; accounting for the FERC refund case; market cash settlements; and audit coordination for all the CAISO's settlement and operations activities. As part of my duties at the CAISO, I oversee the development of the CAISO's grid management charge.

2. The foregoing "California ISO – 2015 GMC Update Cost of Service Study – April 2, 2014" and "California ISO – 2015 GMC Update Energy Imbalance Market Cost of Service Study – April 2, 2014" were prepared under my supervision.

3. To the best of my knowledge, the "California ISO – 2015 GMC Update Cost of Service Study – April 2, 2014" and "California ISO – 2015 GMC Update Energy Imbalance Market Cost of Service Study – April 2, 2014"

are true and accurate descriptions and estimates of the costs that the CAISO will incur in operating the ISO Controlled Grid and the Energy Imbalance Market in 2015 for each billing unit identified.

I hereby certify under penalty of perjury that the foregoing statements are true and correct to the best of my knowledge, information, and belief:

Executed on: June 15, 2015

/s/ Michael K. Epstein
Michael K. Epstein