115 FERC ¶ 61, 171
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

San Diego Gas & Electric Co.

v. Docket Nos. EL00-95-000

Sellers of Energy and Ancillary Services

Investigation of Practices of the California Independent System Operator And the California Power Exchange Docket Nos. EL00-98-000

ORDER ON ALLOCATION OF COST OFFSETS

(Issued May 12, 2006)

1. In this order we determine the appropriate methodology for allocating approved cost offset amounts for sellers into the California Independent System Operator, Inc. (ISO or CAISO) and California Power Exchange (PX) markets during the Refund Period.[1] Specifically, we require cost offset amounts to be allocated to buyers in proportion to the net refunds they are owed.

I. Background

2. On December 19, 2001, the Commission declared that it would provide an opportunity after the refund hearing for marketers and resellers of purchased power to submit cost evidence concerning whether the refund methodology results in an overall revenue shortfall for their transactions into ISO and PX markets during the Refund Period.[2] In the order issued May 15, 2002, this opportunity was extended to all sellers

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[1] The "Refund Period" runs from October 1, 2000 through June 20, 2001. The allowable cost offsets were approved in the January 26, 2006 Order on Cost Filings, 114 FERC ¶ 61,070 (2006) (January 26 Order).

[2] *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 97 FERC ¶ 61,275 (2001) (December 19 Order).

in California markets during the relevant time frame.[3] On August 8, 2005, the Commission established the framework and procedure for sellers to follow in preparing cost filings to demonstrate revenue shortfalls during the Refund Period.[4]

3. On September 28, 2005, the Commission granted requests to establish a schedule for filing comments on the methodology for allocating any approved cost offsets from refunds.[5] On January 26, 2006, the Commission determined which sellers had demonstrated overall revenue shortfalls for their transactions in California markets during the Refund Period.[6]

4. The offsets for revenue shortfalls are one of three categories of offsets from refunds permitted by the Commission. The other two categories of offsets are for emissions and the fuel cost allowance. The Commission has already determined the allocation methodologies for those offsets.

II. Procedure

5. According to the procedural schedule established by the September 28 Order, the deadline for submission of comments was October 31, 2005, and reply comments were due on November 7, 2005. The Competitive Suppliers Group (CSG),[7]

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[3] *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 99 FERC ¶ 61,160 (2002) (May 15 Order).

[4] *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 112 FERC ¶ 61,176 (2005) (August 8 Order).

[5] *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 112 FERC ¶ 61,344 (September 28 Order).

[6] January 26 Order, 114 FERC ¶ 61,070 at P 1. The Commission noted that the amount of offsets approved may change as the ISO and PX data was not final. *Id.* at n.1.

[7] CSG is comprised of: Powerex Corp.; IDACORP Energy LP; Avista Energy Inc.; TransAlta Energy Marketing (CA), Inc.; and TransAlta Energy Marketing (US), Inc.; Puget Sounds Energy, Inc.; Public Service Company of New Mexico; Constellation Energy Commodities Group, Inc.; Coral Power, LLC; and PPL EnergyPlus and PPL Montana LLC.

California Parties,[8] Salt River Project Agricultural Improvement and Power District (Salt River), Pinnacle West Capital Corporation and Arizona Public Service Company (Pinnacle West), Automated Power Exchange (APX), and Constellation NewEnergy (Constellation) filed timely comments. Timely reply comments were received by Salt River, the PX, Modesto Irrigation District (Modesto), Northern California Power Agency (NCPA), CSG, California Parties, Southern Cities[9] and the CAISO. On November 14, 2006, California Parties filed supplemental comments. On March 10, 2006, the CSG filed supplemental comments on the allocation of approved cost offsets. On March 27, California Parties filed an answer to the CSG's supplemental comments.

6. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2005), prohibits an answer to an answer unless otherwise ordered by the decisional authority. We are not persuaded to accept California Parties' supplemental comments, nor the CSG's supplemental comments and California Parties' answer to those supplemental comments, and will, therefore, reject them.

7. On February 17, 2006, the PX filed a Motion for Clarification of Implementation Issues Concerning the Offsets to Refund Obligations. The PX requests clarification of three issues: (1) whether the total amount of offsets per hour is limited by the amount of refunds in that hour; (2) whether, if in any hour the total offsets exceed the refund amount for a zone, the PX should apply any offsets for that hour to the same hour in other ones that have available refund amounts; and (3) in what order should the PX apply the fuel cost allowance, emissions and cost offsets.

8. Indicated Parties, Salt River and the APX responded to the PX's Motion for Clarification on March 6, 2006. Indicated Parties argues that it would be inappropriate for the Commission to address the issues raised by the PX until after ruling on the appropriate allocation methodology. They further assert that the Motion for clarification is premised on two erroneous assumptions: (1) that cost recovery claims can be allocated on an hourly basis; (2) that an allocation method could be adopted that would not allow sellers to be credited with their full amount of approved offsets. Salt River argues that the Commission should deny the PX's motion as

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[8] The California Parties are: the People of the State of California *ex rel. Bill Lockyer,* Attorney General; the California Electricity Oversight Board; the California Public Utilities Commission; Southern California Edison Co. (SCE) and Pacific Gas and Electric Co.

[9] Southern Cities is comprised of the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California.

untimely because the issues should have been raised in comments filed in accordance with the September 28 Order's procedural schedule. Salt River further argues that the total amount of offsets should be limited by the amount of refunds for that hour; shifting excess costs from one zone to another will result in inequitable cost shifts that will produce unjust and unreasonable rates. It further asserts that the Commission has already determined that fuel cost allowance and emissions offsets should be applied prior to the cost offsets. APX asks the Commission to provide the guidance requested by the PX and to clarify that such guidance also applies the data processed by APX.

9. The PX's motion concerns not just cost filings, but all three categories of cost offsets. We find that, to the extent this order does not address issues raised by the PX's Motion for Clarification, such issues are beyond the scope of the September 28 Order's request for comments on allocation issues.

III. Discussion

10. Parties filed comments addressing two questions: (1) whether cost offset amounts should be allocated on a net or gross basis; and (2) whether cost offset amounts should be allocated to specific markets, scheduling intervals and time periods. In addition, several process issues were raised that we consider in the final section of this order. First, however, we review the allocation methodologies that the Commission determined were appropriate for the emissions and fuel cost allowance.

11. A June 19, 2001 Order required that the CAISO's new emission allowance be assessed against all in-state load served in the CAISO's system because "all customers within California benefit from cleaner air as a result of application of those mitigation fees."[10] The Commission further determined that emissions costs incurred by generators should be excluded from calculation of the mitigated market clearing price (MMCP) and recovered by generators as an adder in addition to mitigated prices.[11] The Commission later confirmed that, because of the reliability function served by the CAISO's markets, total gross load is the most appropriate method to use to allocate these costs.[12]

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[10] *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 95 FERC ¶ 61,418, at 62,562 (2001) (June 19 Order).

[11] *Id.* at 62,562.

[12] *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 105 FERC ¶ 61,066 at P 158 (2003) (October 16 Order) (citing *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 97 FERC ¶ 61,293, at 62,370 (2001)).

12. For the fuel cost allowance, the Commission permitted generators that justified actual fuel costs in excess of amounts otherwise collected through the MMCP to recover those costs in an offset to the refunds that they owe.[13] The Commission initially chose to apply the emissions allocation methodology to the fuel cost allowance as well. Upon reconsideration, however, the Commission recognized that differences between the two offsets warranted different treatment for the fuel cost allowance, or FCA:

> The FCA is part and parcel of the revised MMCP mitigation scheme and the FCA amounts should be incorporated into the final sales price for all mitigated purchases. To the extent any market participant, including generators, relied on the mitigated spot markets to purchase energy, we believe that such participant should thus bear a proportionate share of the total FCA amount. For example, a generator whose sales were mitigated should: (1) owe refunds and be eligible to file a FCA claim on its mitigated sales; and (2) receive refunds and owe an FCA amount on its mitigated purchases. Only the dollar amounts arising from these figures should be netted. We also note that this gross allocation of FCA amounts is consistent with our finding that refund liabilities and FCA claims are to be calculated based on gross sales.[14]

13. Subsequently, the Commission made a minor technical adjustment that the ISO requested to permit the netting of uninstructed energy, but otherwise denied rehearing of our determination to require that fuel cost allowance amounts be allocated based on gross purchases during mitigated intervals.

A. <u>Gross v. Net Allocation Methodology</u>

14. Given the manner by which the cost offsets were calculated, there are theoretically four possible ways to allocate them: (1) to gross refund dollars; (2) to gross MWh purchases; (3) to net refund dollars; or (4) to net MWh purchases. We note at the outset that parties filed comments supporting each of these four methodologies. In their comments, California Parties maintain that because cost offsets will reduce the refund liability of sellers (without accounting for their purchases), cost offset amounts should be allocated to buyers based on the gross

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[13] *See San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 102 FERC ¶ 61,317, at P 61 (2003) (March 26 Order).

[14] *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 109 FERC ¶ 61,297, at P 30 (2004) *reh'g denied*, 110 FERC ¶ 61,293 (2005) (December 20 Order).

refund dollars owed to those buyers on account of their purchases (without accounting for their sales). California Parties note that while this allocation methodology is not identical to the methodologies for allocating other offset amounts, it flows from the same reasoning the Commission used in determining those allocations in that it is consistent with the way in which the offset was calculated. Arguing against netting, they cite the August 8 Order, which stated that, "California spot market purchases should not be netted with sales," and that "netting is inappropriate."[15]

15. Salt River argues that cost offset amounts should be allocated to all gross MWh purchases to ensure that all market participants bear their appropriate share of such offsets. It states that this methodology is consistent with the Commission's approach for calculating fuel cost allowance amounts by using gross sales. Salt River adds that "to the extent any of the cost offsets are based on losses that would have occurred even prior to mitigation, [the Commission] should allocate those offsets to the sellers that would have experienced such losses."[16]

16. Supporting a net allocation, CSG argues that cost offset amounts should be allocated so as to reduce the level of refund dollars that would otherwise flow to net purchasers over the Refund Period. CSG contends that if sellers with approved cost filings were to incur additional costs through a gross allocation, a confiscatory rate would result. CSG argues that this is the very situation that the cost filings were designed to prevent. CSG asserts that a "never-ending" iterative process would then be needed so that every time cost offset amounts are allocated back to sellers with approved cost filings, the sellers can revise their cost offset claim to reflect their higher costs. Instead of this, CSG proposes that MMCP-derived refunds, less cost offset amounts, be allocated ratably to the entities that were net purchasers during the Refund Period.

17. Constellation argues that cost offset amounts should be allocated on the basis of net MWh purchases throughout the Refund Period. Constellation submits that like the emissions and fuel cost allowance offsets, cost offset amounts should be allocated in a manner consistent with the nature and purpose of the offset itself. Constellation states that emissions amounts were found by the Commission to be related to the ISO's reliability function, and were thus calculated and allocated based on gross load. Constellation adds that fuel cost allowance amounts were incurred by sellers in connection with their ISO/PX spot sales and thus were allocated to purchasers who bought spot energy in order to meet their spot purchase requirements. Constellation states that in this respect, the cost offset and fuel cost allowance are similar.

[15] August 8 Order, 112 FERC ¶ 61,176, at P 89.

[16] Salt River Comments at 4-5.

Constellation asserts that unlike fuel cost allowance claims, however, a seller submitting a cost filing must demonstrate its net costs and revenues associated with its ISO/PX sales so that the seller cannot pick and choose transactions. It therefore concludes that cost offset amounts must be allocated on the basis of net purchases.

Reply Comments

18. California Parties argue that the Commission established a gross methodology for calculating cost offsets and that this methodology has significant impacts on the size and scope of cost offsets allowed. They conclude that the allocation methodology must necessarily correspond to the calculation methodology. California Parties cite as an example Powerex, who bought and sold large amounts of power in the ISO/PX markets, and who was in some hours not even a net seller, but can nonetheless claim a cost offset for its gross sales. They argue that Powerex should not be allowed to avoid an allocation of cost offset amounts, as they assert would happen under CSG's proposed net allocation methodology.

19. California Parties also argue against CSG's claim that a net purchaser allocation is necessary to avoid confiscation, contending that cost offsets calculated based on gross sales assures each seller that "the revenues from its ISO/PX sales will be sufficient to recover the costs the Commission has determined are associated with those sales."[17] They add that confiscation should be evaluated only at the company-wide level. California Parties assert that sellers claiming cost offsets typically did so based on high-priced power purchased from other sellers that are also claiming offsets.

20. Southern Cities argue that because the purpose of the cost offsets is to prevent a confiscatory result for sellers required to make refunds, the offset should be allocated in proportion to refunds. They conclude that California Parties' allocation methodology proposal "appears to be most consistent with the overall refund calculation method and the purpose for the cost recovery offsets."[18]

21. Salt River provides four reasons to oppose a net allocation: (1) it would be unjust, unreasonable, and unduly discriminatory to impose costs upon Salt River that were incurred to serve others; (2) the net allocation methodology is inconsistent with the Commission's gross calculation methodology for cost offsets; (3) a gross allocation methodology will not deny sellers the opportunity to recover the cost of

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[17] California Parties Reply Comments at 9.

[18] Southern Cities Reply Comments at 2.

selling power and only ensures they pay the costs incurred to serve them; and (4) net buyers would end up paying more than a just and reasonable rate for the services they received under a net allocation, which violates the Federal Power Act.

22. CSG reiterates that a gross allocation methodology would impose additional costs on sellers beyond that which has already been approved and trigger an iterative process to ensure that post-mitigation rates for a seller are not confiscatory. CSG concludes that the end result of such an iterative process could simply and more readily be achieved by using its proposed net methodology.

23. The ISO filed comments on its ability to efficiently and accurately implement each of the four proposals submitted. The ISO states it sees no problem with allocating cost offset amounts based on each purchaser's proportionate share of total gross refunds or gross purchases, as proposed by California Parties and Salt River, respectively.

24. The ISO also sees no problem with allocating cost offset amounts to net refunds or net purchases, as proposed by CSG and Constellation, respectively. The ISO adds, however, that it disagrees with CSG's specific proposal to allocate MMCP-derived refunds, less cost offset amounts, to net purchasers. To minimize any additional complication or time required to implement CSG's proposal, the ISO suggests that it could instead reflect cost offsets amounts as credits to entities making cost filings and allocate those amounts to purchasers as offsets to their refund amounts. In response to Constellation's proposal referencing spot sales, the ISO cautions that there is no way to differentiate between purchasers in the ISO markets based on spot/non-spot sales.

Commission Determination

25. We determine that cost offsets should be allocated to net refund recipients in proportion to their net refunds because this is the most efficient and equitable allocation methodology, and one that will avoid a confiscatory result for sellers with approved cost offsets. Cost offsets are calculated on a net dollar basis, and cost offset amounts should be allocated on a net dollar basis as well.

26. The underlying purpose of the refund proceeding is to compensate fairly those who participated in California markets during the Refund Period, without overcharging buyers on the one hand,[19] and without under-compensating sellers on

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[19] *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 105 FERC ¶ 61,065 (2003) (citing May 15 Order, 99 FERC ¶ 61,160, at 61,655) (October 16 Order).

the other hand.[20] Consequently, as to the former, the Commission developed the MMCP refund methodology to determine the amount sellers should refund buyers who paid unjust and unreasonable prices for energy purchased from California markets during the Refund Period. In addition, as to the latter, the Commission also established the cost filing process to provide individual sellers the opportunity to demonstrate that the MMCP refund methodology does not allow them to recover their costs of selling power into ISO/PX markets during the Refund Period.

27. Sellers who successfully demonstrated that they have a revenue shortfall because the refund methodology does not allow them to recover their costs of serving ISO/PX markets during the refund period have approved cost offsets.[21] These cost offsets indicate the amount by which those sellers are under-compensated by the refund methodology because their actual costs of selling power into ISO/PX markets during the refund period are higher than the revenue they recover after application of the MMCP. In other words, sellers who, after the MMCP is applied, have un-recovered costs, were not fairly compensated by the MMCP.

28. We conclude that the most equitable approach is to allocate the cost offset to those buyers who are compensated by the MMCP refund methodology through receiving refunds. We further find that because the cost offsets will serve to reduce sellers' net refund liability, cost offset amounts should be allocated to buyers in proportion to the net refunds they are owed. This is consistent with our determination in the January 26 Order that an entity that does not have refund liability has no liability to offset.[22]

29. To determine sellers' refund liability, the MMCP was developed and applied on a 10-minute interval basis throughout the entire Refund Period, consistent with the California ISO's market pricing rules. To prevent sellers from cherry-picking only their highest power cost, we required sellers submitting cost filings to net all of their mitigated and unmitigated revenue from Refund Period ISO/PX markets with the

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[20] *Id.* at P 22 (citing May 15 Order, 99 FERC ¶ 61,160, at 61,656).

[21] *See generally,* January 26 Order, 114 FERC ¶ 61,070, at P 161, *et seq.*

[22] *Id.* at P 129. This allocation methodology also minimizes the risk, as SCE notes, of the "perverse result" that provides a "net negative refund to a buyer owed net refunds prior to cost filings." (SCE Cost Filing Submission at 8, Docket Nos. EL00-95-155 and EL00-98-142, September 14, 2005).

costs they incurred to produce those revenues.[23] Consistent with cost causation principles, the resultant cost offsets should be allocated to net refund recipients, or load. Load should ultimately incur the cost of serving the market because load ultimately benefited from the use of the power. We find that allocating more costs to sellers is inconsistent with cost causation. Accordingly, we find it just and reasonable, as well as equitable, to allocate cost offsets to net refund recipients in proportion to their net refund dollars.

30. The alternatives to this approach are no more equitable, in part due to the complexity inherent in otherwise trying to calculate refunds and offsets for a market in which market participants were both buyers and sellers. If offsets are allocated on a gross refund basis, as California Parties and Southern Cities' advocate, since all buyers and sellers have gross refunds, including those sellers with cost offsets, this would result in allocation of a portion of cost offset dollars back to sellers with cost offsets. This would trigger an iterative process whereby, to avoid confiscation, sellers with approved cost offsets that are allocated costs from other sellers' as well as their own cost offsets would reapply to the Commission to recover compensation for these additional costs. This second cost offset, if again allocated back to such sellers, would prompt return to the Commission to demonstrate need for yet another cost offset.[24] This cycle would continue to repeat itself until converging on a final dollar amount, but the process would end up almost identical to a net allocation where refund recipients are allocated cost offsets. California Parties assert that, through approval of sellers' cost offsets, the Commission has already determined the sufficient level of revenue needed to recover sellers' associated costs, so allocation of cost offsets to gross refunds would not be confiscatory. This assertion fails to consider the fact that reallocation of costs back to sellers with cost offsets would diminish that rock bottom level of revenue the Commission has determined. In sum, it is not possible to implement a gross refund allocation methodology without producing a confiscatory result for sellers with cost offsets, or multiple rounds of cost offset calculations.[25]

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[23] August 8 Order, 112 FERC ¶ 61,176, at P 37 (Netting revenues from the costs of all mitigated and non-mitigated transactions will ensure there is no cherry-picking among transactions).

[24] In addition, at some point in this iterative process, the MMCP could become confiscatory towards sellers without cost offsets because the allocation of additional costs to these sellers may cause their costs to become greater than their revenues from serving ISO/PX markets during the Refund Period.

[25] We also find that the August 8 Order has addressed California Parties' argument that a confiscatory standard must be evaluated at the company-wide level. August 8 Order at P 32-38. We see no reason to revisit this argument here. Similarly,

(continued)

31. Allocating cost offsets to net MWh purchases, as Constellation advocates, is similarly problematic. The mere fact that a market participant purchased more MWh of electricity than it sold does not indicate the price at which the market participant purchased that electricity, nor the proportion of those purchases that were mitigated sales. If a net purchaser happened to purchase primarily unmitigated power sold in California markets, neither its gross nor net refund would include much of the costs attributable to sellers' cost offsets. Simply netting MWhs, without taking into account dollars per MWh, yields an incomplete picture.

32. Parties opposing a net allocation methodology argue that the allocation methodology should match the gross methodology by which the offset was calculated. However, we find that the cost offset is not calculated on a gross basis, but rather a net dollar basis. The August 8 Order directed sellers to calculate their cost offsets by determining their cost of energy available for resale into the ISO/PX markets. California Parties and Salt River correctly note that the order prohibits sellers from netting MWhs from sales with MWhs from purchases when calculating their cost offsets. However, the August 8 Order prohibited the netting of MWhs, because such netting would conceal the underlying costs and mitigated revenues associated with sales and purchases.[26] Sellers could have earned additional revenues from sales that would not have been accounted for under a net MWh methodology if that seller happened to have made a low-cost purchase. Such netting could shield the true revenue position of the seller. Instead, the August 8 Order directed sellers to net only the aggregate dollar amounts from total sales revenue with the seller's total cost of energy to calculate a total revenue shortfall, or cost offset.[27] Simply put, mitigated and unmitigated revenues are netted with costs to produce those revenues.

33. California Parties further argue that offsets must be allocated to gross refunds because each market participant must bear its fair and proportionate share of the cost offset amounts. This argument begs the question of what is a fair and proportionate share of the cost offset amounts. While the Commission's chief concern throughout the refund proceeding has been to remedy buyers who may have paid rates that are above just and reasonable levels, the purpose of the cost offsets is to ensure that the

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California Parties' reiteration of their prior contentions that cost filers are claiming cost offsets based on high-priced power purchased from other cost filers is beyond the scope of this order; the issue at hand is limited to whether the ISO/PX sales revenues that a seller earns is sufficient to meet the costs associated with those sales. *Id.*

[26] August 8 Order, 112 FERC ¶ 61,176, at P 89.

[27] *Id.* at P 37.

refund methodology does not result in a confiscatory rate for any individual seller. The refund methodology is not complete without the offsets, including the cost offset. We disagree with Salt River's assertion that, if allocation is not done on a gross basis, then net buyers will end up paying more than a just and reasonable rate. Since the refund methodology is not complete without the offset that ensures that no individual seller pays more than a just and reasonable refund, allocating these offsets to net refund recipients will not produce a refund below the zone of reasonableness.[28]

34. We note that the net allocation methodology adopted in this order for cost offsets is different than the allocation methodologies for emissions and fuel cost allowances. However, we find that the emissions and fuel cost allowance are sufficiently distinct from cost offsets to justify differing allocation methodologies. Emissions costs are allocated on a gross load basis because, as we have previously found, all California customers benefit from cleaner air, and it is thus appropriate to socialize these costs more broadly.[29] Fuel cost allowances are generally calculated on a gross basis to take into account differences in heat rates and fuel costs that generators faced in peak versus non-peak hours. Consequently, fuel cost allowances are allocated on a gross purchaser basis.[30] In contrast, the cost offset here (which does not include any emissions or fuel cost allowances) will be calculated on a net dollar basis, netting all mitigated and unmitigated revenues from Refund Period ISO/PX market transactions with the costs to produce those revenues. Refunds as well are calculated on a net dollar basis, netting each market participant's refund obligation (amount of energy sold at prices above the MMCP) with its refund receipt (amount of energy purchased at prices above the MMCP). Therefore, since the MMCP refund methodology caused certain sellers to have net costs, it is reasonable to allocate these costs to buyers, who, through the same methodology, receive net refunds.

35. We also accept the CAISO's proposed mechanism to implement our allocation methodology. The CAISO should reflect cost offset amounts as credits to entities with approved cost filings and allocate those amounts to purchasers as offsets to their already calculated net refund amounts.

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[28] We note that we have previously determined that the MMCP provides "an appropriate surrogate for the *upper end* of the zone of a just and reasonable market price," October 16 Order at P 23 (emphasis added), which makes it less likely that allocating cost offsets would yield refunds that fall below the zone of reasonableness.

[29] *See San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 114 FERC ¶ 61,313, at P 20 (2006) (citing June 19 Order at 61,418).

[30] December 20 Order at P 30.

36. Finally, we find unconvincing CSG's contention that there would be no risk of confiscatory rates if the Commission adopted a cost offset allocation methodology that reduces the level of net refunds that would otherwise flow to purchasers. The CAISO has yet to allocate fuel cost allowance amounts to all gross purchases, including mitigated purchases that cost filers made. As a result, these sellers will still incur additional costs beyond that which the Commission has already approved in the January 26 Order.[31] Accordingly, we direct the ISO to: (1) add fuel cost allowance amounts that are allocated to sellers with approved cost filings to those sellers' cost offsets; and then (2) allocate the aggregate cost offset amounts to purchasers that are due net refunds, as discussed above. This is consistent with our statutory obligation to ensure that the refund methodology does not result in a confiscatory rate for individual sellers.

B. Allocations to Separate Markets, Scheduling Intervals and Time Periods

37. In comments filed, APX argues that because of the market-wide effect of an approved cost offset, the ISO and PX should not settle the cost offsets on a bilateral basis with each scheduling coordinator that made a cost filing, or with those market participants within a scheduling coordinator ID that submitted cost filings. Specifically, APX contends that the cost filings submitted by APX participants should not be offset against only the refund amounts of other APX participants.

38. Salt River argues that the allocation methodology should precisely match transactions by market and scheduling interval. For example, it states that offsets based on costs incurred to provide service in a particular ISO market should be allocated solely to that particular ISO market and not allocated to any PX market; similarly, any costs incurred to provide service in one particular hour or scheduling interval should not be allocated to other hours or scheduling intervals.

39. California Parties argue that the cost offsets and resulting allocations should be split into a pre-CERS period (October 2, 2000 to January 17, 2001) and a CERS period (January 18, 2001, to June 20, 2001).[32] They submit that there were significant changes in markets and market participants that occurred when CERS began purchasing the net short position of the California IOUs on January 18, 2001 that

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[31] We note that emission amounts will be allocated to gross load, which will not affect approved cost filers.

[32] CERS is the California Energy Resources Scheduling division of the California Department of Water Resources, which began purchasing energy in January 2001.

warrant such a division. California Parties point out that prior Commission orders found there were significant differences between market participants in these two time periods and that mixing dollars among pre-CERS and CERS periods was therefore inappropriate.[33]

Reply Comments

40. California Parties argue that individual APX participants' cost offset amounts should be assessed against other APX participants rather than the market at large. They submit that this would avoid the incorrect result where APX participants collectively are granted offsets in excess of any refunds collectively owed by APX participants.

41. The PX urges the Commission to carefully consider any allocation mechanism that combines ISO and PX markets. It states that even with the same data, the two different markets treat data differently. For example, the PX states that uninstructed energy in the ISO market settles on net basis by scheduling coordinator while the PX settles on a gross basis within its scheduling coordinator ID. The PX adds that if the markets are to be treated separately, it is important to avoid double-counting any basis for allocation; for example, if megawatts of load are used, the ISO should only count megawatts that differ from the schedule for the PX scheduling coordinator ID.

42. The ISO disagrees with Salt River's proposal to allocate cost offset amounts to specific markets and intervals, arguing that matching specific transactions would be very labor-intensive and time-consuming. California Parties add that the cost offset is determined on a period-wide, market spanning aggregation, and it is thus appropriate to allocate on the same basis. CSG also disagrees, asserting that it is not possible to precisely match all cost offsets by market and scheduling interval.

43. Salt River reiterates that the costs incurred to provide service to buyers in the ISO market should not be allocated to buyers in the PX market, and *vice versa*. Salt River suggests that the information in the cost filings should be sufficient to allocate offsets precisely by market hour and scheduling interval.

44. The ISO states that to implement California Parties' proposal to establish a pre-CERS period and a CERS period, the ISO must receive offset data which clearly identifies which offsets are associated with which periods.

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[33] California Parties' Comments at 10 & n.20 (citing *California Independent System Operator Corp.,* 98 FERC ¶ 61,335 at 62,432-34 (2002), *reh'g denied*, *California Independent System Operator Corp.,* 101 FERC ¶ 61,241 (2002)).

Commission Determination

45. We reject an allocation of cost offset amounts to separate markets, scheduling intervals or time periods. The allocation methodology should be consistent with the manner in which cost offsets are calculated. A review of the August 8 Order shows that the Commission directed sellers to calculate their cost offsets by netting all revenues with all associated costs, including netting across all markets, scheduling intervals and time periods. We also fail to see how cost offset amounts could be allocated according to scheduling interval, given that the cost offset is calculated based on sales revenues netted with associated costs; Salt River does not suggest how to allocate, for example when in some intervals, a seller's revenues are greater than its costs. In addition, the cost filing template[34] does not establish separate entries for cost offsets disaggregated according to the breakdowns requested, and parties have not justified the delay that would be needed to recalculate and resubmit the cost filings. Accordingly, cost offset amounts should be allocated across all markets, scheduling intervals and time periods.

46. We disagree with California Parties' contention that dividing the allocation into pre-CERS and CERS periods is consistent with prior Commission orders and would prevent cross-subsidies and inequities. California Parties do not explain the relevance of the orders they cite, which directed the ISO to apply CERS payments to invoices incurred as a result of CERS' transactions. We also find their allegations of potential cross-subsidies as unsubstantiated. Finally, we see no reason to provide preferential treatment to CERS, nor delay this proceeding so that sellers could recalculate their cost filing submissions.

47. We note that the PX cautions against combining markets when allocating the cost offset amounts, while the CAISO argues that allocating to specific markets would be laborious and time-consuming. We urge the PX and ISO (together with the APX) to coordinate their efforts in allocating according to the methodology established in this order.

C. Miscellaneous

1. Processing of Offsets

48. APX asserts that in processing the cost offsets and publishing the results, the ISO and PX should: (1) clearly show the amount of charges and payments related to

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[34] See Staff Suggested Cost Filing Template, Docket Nos. EL00-95-000 and El00-98-000 (August 26, 2006).

the cost offset and not aggregate the payments and charges with other offsets; (2) establish unique charge types for payments and charges related to each offset; (3) publish new records for scheduling coordinators to process the various offsets; (4) provide interval level settlement data for each unique charge type; and (5) flag interest adjustments (payments and charges separately) that result from implementation of cost offsets.[35] The APX argues that these measures would increase transparency, facilitate review of the data and minimize potential disputes. Finally, APX argues that the cash clearing for approved cost offsets should occur simultaneously with other offsets. APX states that this will reduce its risk of having to pay out market participants of approved cost offsets prior to collecting back any monies owed by the same market participants.

49. In response, the ISO and PX oppose APX's suggestion to develop unique charge types for each offset, arguing that this would require significant time and resources. The ISO states that it intends to include in the settlement statements comment fields which indicate to market participants which specific charges are associated with the various offsets, as well as distribute to parties CDs pertaining to each offset. The ISO adds that it will provide a detailed explanation of how it allocates the cost offsets, along with other offsets or adjustments, as part of its compliance filing to be made at the close of the financial adjustment phase. The ISO states that it has no objection to publishing new records for scheduling coordinators to process offsets/adjustments, or to the flagging of any interest adjustments resulting from the cost offsets.

Commission Determination

50. We find that the ISO has adequately addressed APX's transparency concerns regarding the processing of the cost offsets and the publishing of the results. We further agree with the ISO that its proposal to use comment fields with specific offset charges is just as effective as and more efficient than APX's proposal to establish unique charge types. Accordingly, we will not require the ISO and PX to establish unique charge types for each offset. However, the ISO must maintain and provide upon request information sufficient for parties to be able to duplicate their calculations. Regarding APX's request that cash clearing for approved cost offsets occur simultaneously with other offsets, we refer APX to our prior order, which found that:

[35] APX states that this last point is only a concern if the cost offsets impact interest payments.

> [I]t is also a settled matter that amounts owed both by and to parties, as determined in this proceeding, will be offset against each other and only the net result of this offset will flow to or from parties.[36]

2. **Global Settlements**

51. California Parties contend that any refund allocation methodology should reflect the impact of the global settlements between them and various sellers. They reason that none of the sellers' approved cost offsets should be allocated to the California Parties and that these sellers should be able to recover a proportionate share of their cost filings from non-settling parties only. Salt River adds that to the extent a seller has settled its transactions, the seller cannot now recoup additional costs for transactions which have been settled with other parties.

52. On reply, Salt River states that to the extent California Parties want the El Paso settlement[37] reflected in the allocation process, California Parties should file the settlement for approval in this proceeding.

Commission Determination

53. The Commission has assured parties that those who elect not to join in a global settlement will not be affected by the settlement.[38] Accordingly, cost offsets and refund amounts must reflect an allocation to all parties, settling and non-settling, so that the correct proportion is assigned. We note that the CAISO states that it intends to submit its compliance filing after the completion of the financial adjustment phase[39] and before the CAISO makes any further adjustments to invoices based on

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[36] October 16 Order*,* 105 FERC ¶ 61,066, at P 180.

[37] Salt River's Rely Comments at 7 & n. 20 (citing Joint Settlement Agreement, Docket No. RP00-241, (filed June 4, 2003), and Master Settlement Agreement, Docket No. RP00-241 (filed for information purposes on June 27, 2003)).

[38] *See, e.g., San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 113 FERC ¶ 61,308 at P 19 (2005).

[39] In the financial adjustment phase the CAISO will make adjustments to its refund rerun settlement data to account for fuel cost allowance offsets, emissions offsets, cost offsets, and interest on amounts unpaid and refunds.

written instructions from settling parties.[40] We find that this process will provide transparency to all parties as to the effect of the global settlements, and accordingly, see no need to reflect the impact of these settlements in the allocation methodology.

3. Shortfalls

54. Salt River asserts that any refund shortfalls that result from the cost offsets should be allocated through the revenue neutrality and cash shortfall mechanisms contained in the ISO and PX tariffs that were in effect at the time such transactions occurred. Salt River identifies section 11.2.9 of the ISO's tariff that allows the ISO to levy additional charges to ensure that a trial balance of zero is reached during the settlement process, and Schedule 2, section 5.3 of the PX tariff for payment shortfalls.

55. California Parties and CSG disagree in their reply comments, arguing that there should be no shortfall after the cost offset is allocated. CSG adds that nothing in previous Commission orders suggests that there might be any minimum level of refunds available to purchasers, as implied by Salt River's discussion of shortfalls.

Commission Determination

56. Salt River has not adequately explained why it believes that a shortfall might exist as a result of the cost offset allocation. It is our expectation that MMCP-derived refunds, as adjusted after allocation of the offsets, will be distributed in full to recipients. Accordingly, we see no need to prescribe a shortfall allocation methodology.

4. The *Bonneville* Decision[41] and Requests for Delay

57. Pinnacle West states that the *Bonneville* decision could dramatically alter the equities in the refund proceeding and argues that the Commission consider not only the allocation of cost offsets, but the allocation of refunds in its entirety. Pinnacle West questions in particular whether jurisdictional sellers should be required to make any refunds to non-jurisdictional sellers, at least until jurisdictional sellers are paid refunds they are owed.

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[40] *See, e.g.,* CAISO Twenty-First Status Report on Settlement Re-run Activity, Docket No. EL00-95-081 (October 11, 2005).

[41] *Bonneville Power Administration v. FERC*, 422 F.3d 908, 926 (9th Cir. 2005) (*Bonneville*). In *Bonneville,* the United States Court of Appeals for the Ninth Circuit found that Commission does not have authority to order refunds from non-jurisdictional sellers in the ISO and PX markets during the Refund Period.

58. Salt River, Modesto, NCPA and Southern Cities respond that Pinnacle West's comments on the *Bonneville* decision should be rejected because they are outside the scope of comments to be filed at this stage of the proceeding. Modesto and NCPA add that governmental entities are not excluded from the benefits of regulation of jurisdictional entities under Part II of the Federal Power Act.[42]

59. Pinnacle West further asserts that the Commission should simply delay its decision on an allocation methodology. It maintains that with many outstanding refund issues pending before the Commission and the United States Court of Appeals for the Ninth Circuit, it is impossible to determine how cost offsets should be allocated among market participants. California Parties support Pinnacle West's position that the Commission delay any final decision on the allocation methodology until after resolution of outstanding cost recovery issues.

Commission Determination

60. We agree with Salt River and other governmental entities that discussion of the impact of the *Bonneville* decision on refunds in general is beyond the scope of comments requested. Furthermore, the United States Court of Appeals for the Ninth Circuit did not stay Commission decisions concerning the refund methodology, nor has it issued its mandate making the *Bonneville* decision final. Accordingly, because the Court has not issued a mandate enabling the Commission to act on remand, the Commission cannot at this time revisit its final orders concerning the refund methodology. Since the refund proceeding has not been stayed, the Commission must determine the proper allocation of cost offsets, and move the refund proceeding closer towards completion, as Congress has asked us to do. Nevertheless, it is important to note that, if governmental entities ultimately have no refund liability, just like any other entity lacking refund liability, they correspondingly have no refund liability to offset and, therefore, no possible cost offset to allocate to other net refund recipients. This is consistent with the September 13, 2005 notice granting governmental entities a deferral from having to submit cost filings on the basis that the *Bonneville* decision, if final, rendered governmental entities' need to submit cost filings moot.[43]

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[42] Modesto's Reply Comments at 4 (citing *California Electric Power Co. v. FPC,* 199 F.2d 206, 208-209 (9th Cir. 1952)).

[43] Notice of Extension of Time, Docket Nos. EL00-95-000 and EL00-98-000 (September 13, 2005).

<u>The Commission Orders</u>:

(A) We direct the ISO to allocate cost offsets to buyers on a net dollar basis, in proportion to the net refunds owed to such buyers, consistent with the body of this order.

(B) We direct the ISO to allocate cost offset amounts across all markets, scheduling intervals and time periods, consistent with the body of this order.

(C) With respect to sellers with approved cost offsets, we direct the ISO to add any approved fuel cost allowance amounts they have to their cost offsets; and then allocate the aggregate cost offset amounts to purchasers that are due net refunds, consistent with the body of this order.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.