Comments on CAISO
CRR Auction and Allocation Issues

Prepared by
Scott M. Harvey*
William W. Hogan**

***LECG, LLC.**
Cambridge, MA

****Center for Business and Government**
John F. Kennedy School of Government
Harvard University
Cambridge, MA

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The California Independent System Operator (CAISO) has prepared a number of reports during the process of developing a new system of Congestion Revenue Rights (CRR) under its evolving market design (MD02) proposal. In general, the MD02 proposal includes a consistent market design with coordinated balancing and day-ahead markets, bid-based security-constrained economic dispatch, locational marginal pricing (LMP), and financial transmission rights in the form of CRRs. Here we address a few issues raised by our current understanding of the CRR allocations and treatment. We may have additional comments after further review of the answers recently provided by the CAISO to the clarifying questions we submitted to the CAISO.

I. LOAD HEDGING PRINCIPLES

The definition and purpose of CRRs follow from the larger context of the comprehensive market design. A feature of the market design is that it makes explicit terms and conditions that were previously implicit in normal operations. Hence, the CAISO has gone to lengths to define its terms and make sure that the pieces fit together in the larger context. Here we address a few issues that might benefit from further consideration or clarification.

A. Hedging Goal

The statement of purpose for CRR definition and allocation will be important in explaining the allocations and in guiding the implementation process. The CAISO describes its goal in allocating CRRs as "to allocate quantities of CRRs that are adequate to fully protect loads from congestion costs, provided these quantities are simultaneously feasible."[1] While much of what the CAISO proposes is reasonable, this goal statement is problematic if it is interpreted to mean assured access to low cost generation. We know that it has historically been necessary to

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[1] Amendment to Comprehensive Market Design Proposal, July 22, 2003 Filing letter, p. 74 (hereafter July 22 Filing Letter). California ISO, "Congestion Revenue Rights Preliminary Study Report," October 1, 2003 (hereafter CRR Study), pp. 5, 14.

dispatch generation out of merit to meet load in California and these costs were borne by rate payers both under utility operation and under CAISO operation of the transmission system. It would be unrealistic to hold out as a goal or even a standard, an objective of hedging all load to the lowest cost generation in the region, or even the lowest cost generation inside California.[2]

A goal of hedging all load relative to the cost of generation at some location is attainable (all load is actually met under almost all conditions). Thus, it would be possible to hedge all loads for particular patterns of system utilization (i.e., to some generator), provided these quantities were simultaneously feasible. However, this workable goal requires choices among participants in deciding on the usage patterns inherent in the definition and allocation of CRRs.

The description of the second CRR study introduces another allocation concept "adequate hedging of congestion costs over the course of the year, rather than trying to cover Load Serving Entity (LSE) schedules on a MW basis in each hour."[3] As explained in the February proposal this approach would attempt to allocate CRRs such that the expected congestion charges over the year would be equal to the expected CRR revenues. While this rule could be employed as a reasonable criterion for allocating CRRs, it should not be described in terms of hedging.[4] The purpose of hedging is to deal with the volatility ex post, not just the expected value ex ante. By design, CRRs provide a hedge under which net congestion charges associated with meeting load with specific generation resources do not vary as a result of changes in congestion patterns, such as those arising from variations in load patterns or changes in relative fuel prices. This is not the same as assigning CRRs such that the congestion charges will be offset by congestion revenues if congestion patterns are as expected.

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2 The CAISO's discussion of its decision to abandon its former goal of hedging all load net of local generation, suggests that the first interpretation of the CAISO goal is correct, but this goal is manifestly infeasible; see July 22 Filing Letter, p. 75, July 21 Proposal, Para 83.

3 "CRR Study 2 Proposed Processes, Input Data and Modeling Assumptions," February 5, 2004 (hereafter February CRR2 Proposal), pp.2, 3.

4 February CRR Proposal, p. 3, estimating "the quantities of CRRs that each LSE serving CAISO control area load will need to maximize the hedge against congestion costs over the course of a year and demonstrate that these sets of CRRs are simultaneously feasible," and pp. 15-17.

Conversely, the CAISO recommendation that LSEs designate CRR sources reflecting actual sources of supply used by the LSE to serve its load is consistent with CRRs that reduce risk by hedging congestion costs.[5]

Although the CAISO may be well aware of these details, market participants may not be as able to recognize the specifics intended by the general statements. The apparent lack of clarity in defining attainable goals or standards for the allocation process may give rise to problems as the CAISO proceeds to implementation and is required to make judgments based on its articulated goals.

Hence, the CAISO goal might be stated as "to allocate quantities of CRRs that achieve an appropriate balance across parties and would be adequate to protect a specified pattern of load and generation from net injection costs, provided these quantities are simultaneously feasible."

B. Load Switching CRRs

The conceptual basis for the CAISO's CRR allocation process – those who pay the embedded cost of the transmission grid are entitled to be allocated the economic value produced by that transmission grid[6] – is sound, but there are practical implementation issues that need to be considered in assessing how to achieve this objective. In particular, careful consideration needs to be given to whether this objective is most efficiently attained through the allocation of CRRs to load or the allocation of the market value of CRRs to load through a system based on auction revenue rights.

The CAISO proposes allocating CRRs to LSEs on behalf of loads and requiring that these CRRs be reallocated between LSEs so as to follow loads as customers switch between LSEs from month to month.[7] While this approach is consistent with the objective of assigning the economic value of CRRs to the loads that pay the embedded costs, the complexity of administering such a system in a retail choice environment should not be underestimated. As retail load moves from LSE to LSE from month to month the CRRs to be reassigned will likely

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[5] February CRR2 Proposal, p. 8.

[6] July 21 Proposal, Para 81.

be measured in fractional MW. In addition, each LSE serving load within a given load aggregation region may have CRRs from different sources. Thus, as each LSE gains and loses retail customers it could be gaining and losing distinct CRRs in some proportion. This could become unwieldy and expensive from an administrative standpoint for all concerned. This reassignment process will be particularly problematic if LSEs serving a given load aggregation zone are allocated CRRs with differing sources and sinks. Moreover, CRRs allocated on an annual or multi-year basis may be sold by the LSE prior to the time that load switches, requiring the assignment of negative CRRs to the losing LSE to offset the reallocated CRRs.

Some of the administrative difficulties can be illustrated with a simple example. Suppose that there were 12,000 MW of peak load priced at Load Zone B, and that the LSEs serving load at B were in aggregate assigned:

- 1,000 A-B CRRs
- 500 C-B CRRs
- 2,000 D-B CRRs
- 750 E-B CRRs
- 25 F-B CRRs

These CRRs could then be proportionately assigned to each LSE. Thus, the Blue, Red, Green and Yellow LSEs would be assigned CRRs as portrayed in Table A.

[7] July 21 Proposal, Para 81 "CRRs will follow the load if the consumer switches to a different LSE."

Table 1 Uniform CRR Allocation to LSEs						
	CRRs					
LSEs	**A-B 1,000**	**C-B 500**	**D-B 2,000**	**E-B 750**	**F-B 25**	**Load 12,000**
Blue	20.83333	10.41667	41.66667	15.625	0.520833	250
Red	62.5	31.25	125.0	46.875	1.5625	750
Green	875.0	437.5	1,750.0	656.25	21.875	10,500
Yellow	41.66667	20.83333	83.33333	31.25	1.041667	500
	1,000.0	500.0	2,000.0	750.0	25.0	12,000

If Blue gained 50 MW of load from Green and the CRRs followed the load, then Blue would gain CRRs as portrayed in Table 2 based on the same load ratio share used to assign CRRs in Table 1.

Table 2 Blue CRRs after Gaining Customers from Green						
	CRRs					
	A-B 1,000	**C-B 500**	**D-B 2,000**	**E-B 750**	**F-B 25**	**Load 12,000**
Initial CRRs	20.83333	10.41667	41.66667	15.625	0.520833	250
Gain from Green	4.166667	2.083333	8.333333	3.125	0.104167	50
Final Blue CRRs	25.0	12.5	50.0	18.75	0.625	300

If Blue LSE then lost 25 MW of load to Red and 10 MW of load to Yellow, the CRRs would again be reallocated using the same fractional allocation rule, as shown in Table 3. This reallocation method would therefore apparently require the CAISO billing and settlement to track and settle fractional CRRs on a daily basis. Load switching among LSEs presents enough challenges just in accounting for the power delivered to a customer at a fixed location. It would be a substantial increase in detail to have to match an increasingly complex pattern of CRRs from many possible generating points, especially when the resulting reallocation would not match the load's hedging preferences. The administrative cost to the LSEs of tracking and trading to assemble such fractional CRRs into useful hedges may exceed the hedge value of the

CRRs. In effect, the net result would be a complicated administrative procedure for tracking and reassigning the initially allocated CRRs, and to still require the LSEs or their customers to seek out different patterns of CRRs for hedging.

Table 3
Blue CRRs after Losing Customers to Red and Yellow

	CRRs					
	A-B 1,000	**C-B 500**	**D-B 2,000**	**E-B 750**	**F-B 25**	**Load 12,000**
Blue CRRs	25.0	12.5	50.0	18.75	0.625	300
Loss to Yellow	2.083333	1.041667	4.166667	1.5625	0.052083	25
Loss to Red	0.833333	0.416667	1.666667	0.625	0.020833	10
Final Blue CRRs	22.08333	11.04167	44.16667	16.5625	0.552083	265

Even so, the tracking process in this example is simplified by the feature that each LSE's holdings of each CRR would be proportional to its retail load. This simplifying feature arises because of the assumption that all LSEs are assigned the same proportion of each CRR. This symmetry will probably not exist under the CAISO's proposed CRR allocation methodology, as LSEs would be able to designate different sources for their CRRs. This ability to vary the sources would further complicate the tracking process.

Table 4 portrays an initial allocation in which various LSEs have selected CRRs with varying sources.

Table 4
Non-Uniform Designation of CRRs

	CRRs					
LSEs	**A-B 1,000**	**C-B 500**	**D-B 2,000**	**E-B 750**	**F-B 25**	**Load 12,000**
Blue	0	0	0	100	0	250
Red	250	0	0	0	0	750
Green	750	250	2,000	650	25	10,500
Yellow	0	250	0	0	0	500
Total	1,000	500	2,000	750	25	12,000

It is again assumed that Green LSE loses 50 MW of load to Blue LSE. Now, however, the reallocation of CRRs from Green to Blue is based on Green's unique allocation of CRRs. Table 5 shows that as in the first example it would be necessary for the CAISO to track and settle fractional CRRs. Now, however, the allocation of CRRs would not be a fixed function of load share but would be path dependent in terms of gains and losses of load between LSEs.

Table 5
Blue CRRs after Gaining Customers from Green

	CRRs					Load 12,000
	A-B 1,000	C-B 500	D-B 2,000	E-B 750	F-B 25	
Blue Initial	0	0	0	100	0	250
Gain from Green	75	1.190476	9.52381	3.095238	0.119048	50 Green-Blue
Final Blue CRRs	75	1.190476	9.52381	103.0952	0.119048	300

If Blue then lost load to Yellow and Red, it would lose a share both of the CRRs it was initially assigned and those it acquired in reassignments from Green as shown in Table 6. It is apparent that there would likely be an increased need to track and settle very small fractions of CRRs under this approach.

Table 6
Blue CRRs after Losing Customers to Yellow and Red

	CRRs					Load 12,000
	A-B 1,000	C-B 500	D-B 2,000	E-B 750	F-B 25	
Blue	75	1.190476	9.52381	103.0952	0.119048	300
Loss to Yellow	6.25	0.099206	0.793651	8.59127	0.009921	25 Blue-Yellow
Loss to Red	2.5	0.039683	0.31746	3.436508	0.003968	10 Blue-Red
Final Blue CRRs	66.25	1.051587	8.412698	91.06746	0.105159	265 Blue

The CAISO CRR allocation proposal would introduce a further degree of complexity in that different LSEs might also acquire varying amounts of CRRs with different sinks, introducing still more variation in the assignment of CRRs and magnifying the tracking problem.[8]

These complexities of the CRR allocation and reallocation process are potentially avoidable because the CAISO could account for load shifts by reallocating the economic value of a given set of CRRs (based upon the auction values). This would be consistent with the criterion for allocating the CRRs based on expected congestion revenues. For hedging purposes, this would allow market participants to choose which CRRs they want to acquire in an auction.

The ex ante economic value of CRR awards can be measured in the proposed monthly CRR auction. This would permit reliance on mechanisms for shifting the economic value of the CRRs to follow load through administratively simpler mechanisms, such as cash payments based on a proportionate share of the market value of the assigned CRRs.

C. Auction versus Allocation

We recommend that the CAISO in general allocate auction revenue rights (ARR) to LSEs, rather than allocating the actual CRRs. The distinction is in the treatment after allocation. The initial allocation of ARRs could look like the allocation of CRRs. The ARRs could be defined as point-to-point rights and follow the CRR allocation procedure outlined to match a particular pattern of generation with a simultaneous feasibility test. However, once the auction occurs, the ARRs define the allocation of the revenue but not the actual CRRs. The auction would put the CRRs in the hands of market participants and would not require administrative reallocation by the CAISO. As observed above, such a process of allocating and reallocating money as load shifts between LSEs would substantially reduce the administrative burden of tracking shifts in CRRs between LSEs.

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[8] The various CAISO market design proposals are unclear on whether CRRs allocated on an annual and monthly basis would be reallocated jointly or whether the monthly allocating would be reassigned first or some other procedure followed. Taking account of this distinction would further complicate the application of load following CRRs.

In addition, a somewhat subtle effect of rules providing for the allocation of CRRs, rather than CRR economic values, to LSEs is that they constrain the duration of forward auctions for CRRs. The conflict is simple – if CRRs must be retained by the CAISO for allocation to LSEs on an annual, biannual or monthly basis, then they cannot be sold in multi-year auctions. This limitation would be avoided if LSEs were allocated the financial proceeds of the auction (i.e., auction revenue rights), rather than CRRs, as long-term CRRs could then be sold in forward auctions with the revenues distributed to LSEs on a daily or monthly basis in the CAISO settlement system.

While it is likely reasonable to limit the duration of the CRRs sold in the initial CRR auctions, as market participants may not have a good basis for assessing CRR market values until an LMP market is actually in operation, it would be helpful to enable market participants to be able to acquire long-term point-to-load CRRs in an auction. For example, LSEs seeking to enter into long-term contracts to hedge their energy cost would likely want to be able to also acquire a long-term hedge of the congestion costs associated with energy deliveries under that contract. If there is no long-term auction, LSEs will have no means of acquiring such a long-term hedge other than by contracting with local generation.

Allocating auction revenue rights, rather than CRRs, to LSEs would simplify administration for both the CAISO and market participants and permit the CAISO to transition to the auction of longer-term CRRs. The allocation of point-to-point auction revenue rights would enable LSEs that wish to lock in CRRs matching their auction revenue right allocation to do so by submitting high bids for those CRRs that would be hedged by the allocation of auction revenue rights.

II. ETC TREATMENT

The approach proposed by the CAISO for accommodating Existing Transmission Contracts (ETC) in "CRR Study 2 Proposed Processes, Input Data and Modeling Assumptions," February 5, 2004, Section 2.7.1, p. 8, is a reasonable and workable approach. The advantages are substantial when compared with the likely alternatives.

Under the proposed approach, the Participating Transmission Owners (PTO) would submit schedules in the day-ahead market (DAM) reflecting the expected transmission usage of the ETC customer based on the transmission owner's assessment based on operating experience and any information provided to the scheduling transmission owner by the ETC customer. The PTO would then be financially responsible for any real-time imbalances between the day-ahead schedules it submits and the real-time transmission usage of the ETC.[9] The PTO would, however, be able to submit DAM schedules to hedge the expected real-time transmission usage of the ETC holder, based on both the information relayed by the ETC holder and other market information.[10]

This flexible scheduling, as opposed to some more rigid "physical" scheduling rule, would be necessary to allow the PTO to honor the terms of the ETC without taking unnecessary financial risks. The PTO will have an incentive to schedule efficiently given its responsibility for imbalance and congestion charges in the real time market.

In addition, CRRs hedging the ETC transmission service would be assigned to the PTO providing the transmission service to the ETC holder. The CRRs would serve as a congestion hedge for the transmission service provided to the ETC holder, and the economic value of any transfer capability not utilized by the ETC holder would accrue to the other transmission customers of the transmission owner as a credit against their cost of service (like CRR auction revenues).

In effect, the ETC contract would then be like any other contract outside the CAISO market and the necessary scheduling would be handled by the transmission owner within the CAISO market rules. The ETC holder would not have the ability to exploit differences between schedules it would submit to the CAISO under special terms and the actual conditions in the real-time market, because the day-ahead scheduling will be controlled by the PTO providing

9 Note that to the extent the ETC schedules are not feasible, this will assign the cost of counterflow to the entity that sold the infeasible transmission service.

10 This approach is consistent with the proposed reliance on the PTO to certify that schedules are consistent with contract terms under Paragraph 67 of the July 21 Proposal.

transmission service who would not be exempt form the costs of providing the service under the ETC.

The proposed approach preserves for the ETC holders the value of their contracts but should avoid providing the ETC holders with profit opportunities in the markets coordinated by the CAISO that are in addition to the value of the firm transmission to which the ETC holders are contractually entitled. These additional profit opportunities could arise if the ETC holders were permitted to a) participate without restriction in the CAISO DAM markets; b) take positions in the CAISO DAM markets reflecting their private information (in particular whether their ETC has or has not been reflected in the DAM bids); and c) schedule their transmission usage in real-time without cost. If the PTOs do not receive the CRRs and schedule the ETCs, and these rights were assigned directly to the ETCs with an obligation for the CAISO, rather than the PTO, to honor the scheduling terms of the ETC, the ability to participate in CAISO markets would potentially provide two benefits to an ETC holder beyond those they receive from their firm transmission rights absent CAISO markets. First, the ETC holder will be able to realize the full economic value of its ETC even if it cannot utilize the firm transmission service. Second, the ETC holder may be able to realize some additional arbitrage benefits in CAISO markets, arising from the ETCs ability to operate outside CAISO scheduling rules.

Each of these incremental benefits beyond the ETC can be more fully explained with a simple example. Suppose an entity has an ETC that entitles the holder to inject power at A and withdraw power at F without paying congestion, subject to whatever curtailment provisions are included in the contract. Since the transmission contract is physical, however, it does not entitle the holder to receive the economic value of the transmission right at times when there is congestion but the holder cannot utilize the transmission service. In effect, the existing physical right is a “use it or lose it” right.

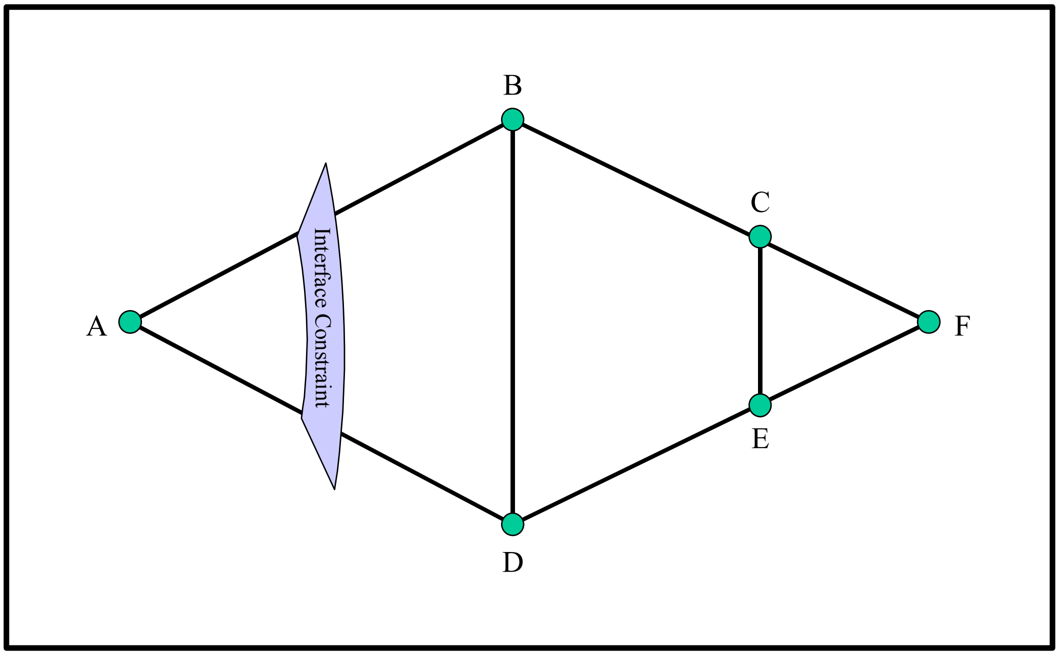
Permitting an ETC holder to convert the firm transmission right into a CRR would potentially benefit the ETC holder by enabling it to receive the economic value of the CRR even at times when the holder cannot utilize the transmission service. To the extent that transmission owners entered into the ETC counting on diversity of use in the portfolio, not all ETC rights are used at the same time. Hence, awarding CRR options to ETC holders actually implies an increase in the value of the ETC transmission rights. The PTO was utilizing the diversity in providing the ETC rights, and the ETC could not exploit a different set of rules under the CAISO.

Conversely, conversion of the ETC to a CRR would require the ETC holder to conform to CAISO scheduling rules which might be less advantageous than those provided for in the ETC contract.

The implementation of LMP markets in California, however, would potentially provide substantial benefits to ETC holders that do not convert their ETCs to CRRs but were permitted to participate fully in CAISO financial markets. The likely alternative to the CAISO proposal would be to shift responsibility of scheduling and compensation from the PTO to the CAISO. Thus, the ETC could schedule in the day-ahead market when congestion is anticipated but the full ETC is not needed to meet the load of the ETC holder. The ETC holder could then submit offer prices that ensure that the ETC transaction would be dispatched down or supplied via counterflow in real-time, with the imbalances between day-ahead financial schedules and real-time flows settled at real-time prices.

These potential effects of LMP on the economic value received by ETC holders if the CAISO were required to financially accommodate ETC schedules submitted outside the time frame of the day-ahead market coordinated by the CAISO can be illustrated using the simple grid portrayed in Figure 7. Suppose an entity has an ETC for 500MW of energy from A to F on the simple grid portrayed in Figure 7. This firm transmission right entitles the holder to inject power at A and withdraw power at F without paying congestion, subject to whatever curtailment provisions are included in the contract. It is further assumed that the ETC holder's generation at A has a generating cost of $30/MWh.

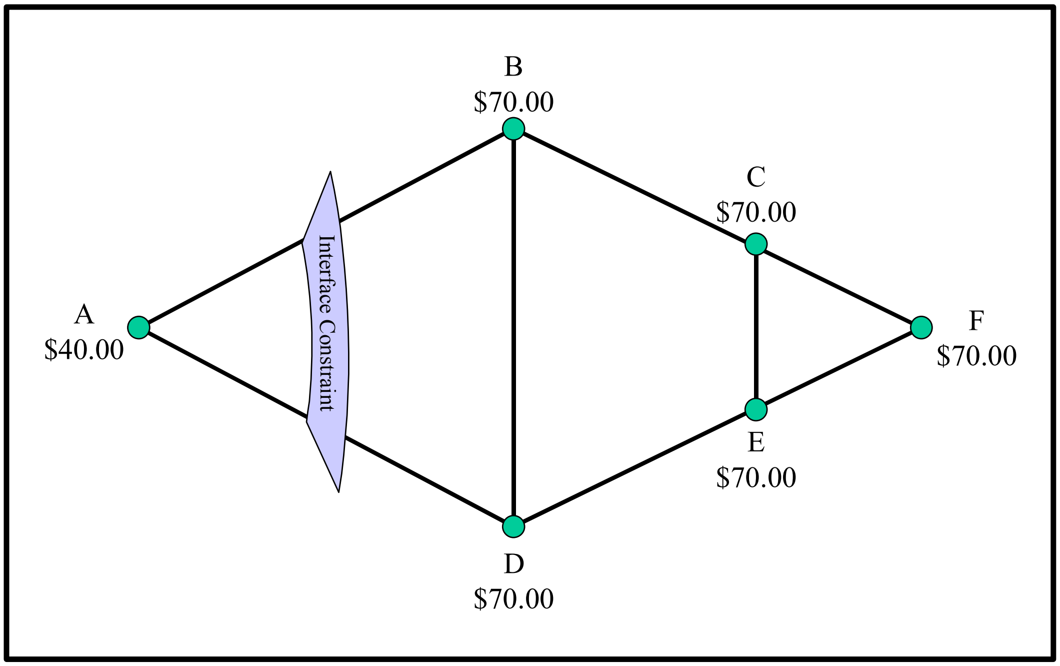
Figure 7
Illustrative Grid



If the ETC only has load of 450 MW during hour h, its ETC would enable the ETC holder to meet its load at an average cost of $30/MWH using its generation at A. In addition, if the market price of power at A were $40/MWh, the entity could realize an additional $10/MWh margin on the sale of its unused 50 MWh of generation in the spot market at A.

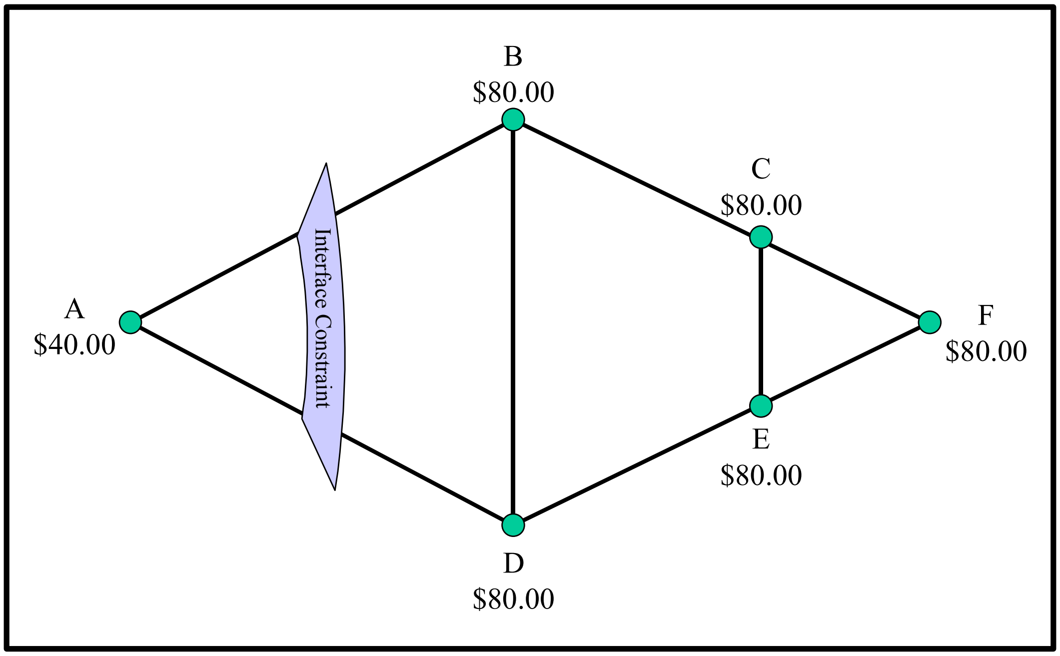
Suppose, however, that LMP is implemented and that as a result of the interface constraint the expected real-time LMP prices are as portrayed in Figure 8. In this situation, it would be profitable for the ETC holder to fully schedule its ETC right in the day-ahead market and then settle imbalances between its day-ahead schedule and actual real-time injections and withdrawal at real-time prices.

Figure 8
Expected Real-Time Prices



Scheduling 500 MW of transmission usage from A to F might result in prices east of the constraint of $80/MWh, producing an apparent $40/MWH of congestion as shown in Figure 9. The ETC holder, however, would be able to schedule its transaction without paying congestion, just as would a CRR holder.

Figure 9
Day-Ahead Prices with 500 MW Schedule



In real time, the ETC holder would only withdraw 450 MWh at F and would settle its imbalances against its day-ahead schedules, selling back 50 MWh of energy at F at a price of $70 (the real-time price in Figure 8), netting $40/MWh rather than $10/MWh by realizing the financial value of its transmission right in real-time. This bidding and scheduling strategy would enable the ETC holder to realize value that otherwise would have accrued in the CRR congestion account, reducing uplift or helping to offset congestion rent shortfalls attributable to transmission outages.[11] The additional profit opportunities of the ETC holders in CAISO financial markets that would arise if the CAISO were required to honor ETC schedules at no cost and outside the time frame of the CAISO day-ahead market, however, would not only reduce the congestion rents collected by other market participants, they would have the potential to also manifest themselves in revenue inadequacy in the CAISO DAM, and uplift costs that must be borne by other CAISO market participants.

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[11] It should be noted that the differences between day-ahead and real-time prices in the example help the intuition of the example but are not important to the conclusion. Even if market participants perfectly anticipated the overscheduling by the ETC in the day-ahead market, causing day-ahead and real-time prices to be equal, the ETC holder would be able to capture the full financial value of the ETC.

The kind of bidding patterns by ETC holders under such preferential scheduling rules that could raise the value of ETC contracts to the holder but raise costs and create uplift for other market participants could be as follows. For days during which the ETC holder would intend to fully utilize its ETC transmission rights, the ETC holder would not submit any transmission schedules in the day-ahead market explicitly using these ETC rights. The ETC holder would, however, submit day-ahead bids and offers for purchases and sales in the CAISO market that would be financially equivalent to their ETC rights (transmission service is equivalent to selling at the point of injection and buying at the point of withdrawal) in an amount that is less than the ETC rights it intends to utilize in real-time. In real-time the ETC holder would fully utilize its ETC rights to meet its load (paying no congestion costs) and would settle its day-ahead financial position at real-time prices.

To the extent that the ETC holder's failure to schedule its ETC rights in the day-ahead market and its full use of these rights in real-time raise real-time prices relative to day-ahead prices, the ETC holder would not only realize the full value of its ETC rights, it would also realize arbitrage profits.[12] The difference between day-ahead and real-time congestion charges that gives rise to ETC profits would also give rise to real-time uplift costs for other market participants. The ability of other market participants to arbitrage this kind of behavior by the ETC would be limited by their lack of knowledge as to ETC scheduling intentions as well as by the fact that other market participants would be required to settle deviations from day-ahead schedules at real-time prices.

In this case, let us assume that the ETC holder expects real-time prices as portrayed in Figure 9 and expects to fully utilize its ETC. Instead of scheduling its ETC in the day-ahead market coordinated by the CAISO, however, the ETC holder buys 400 MW of energy at F. The ETC holder's failure to schedule its ETC in the day-ahead market reduces demand in the East by 500 MW, 400 MW of which is replaced by the day-ahead energy purchase at F.

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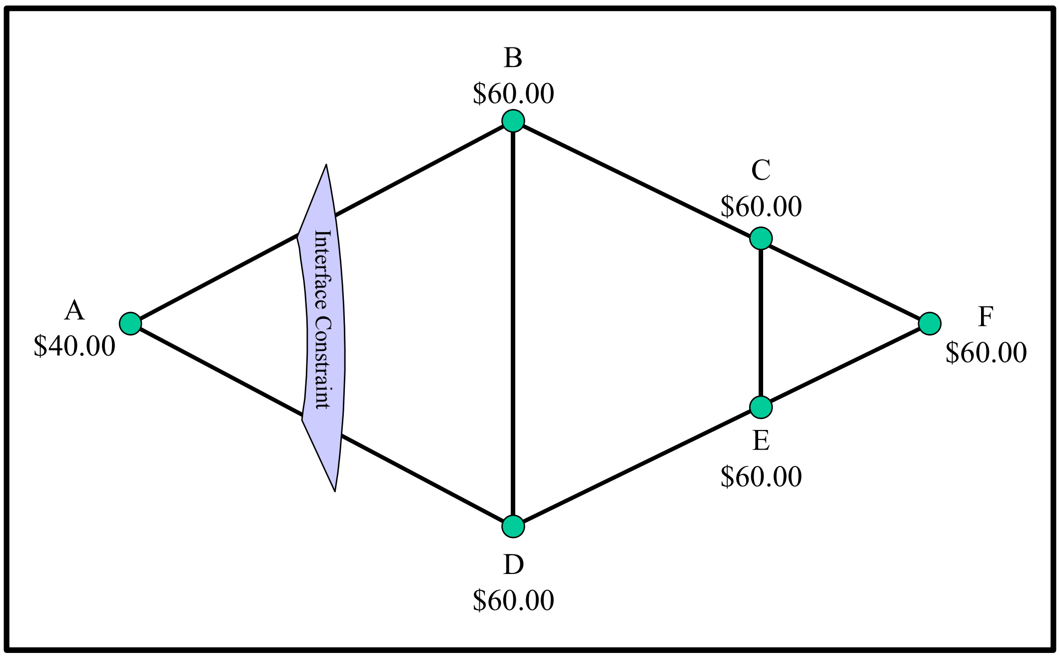
12 In this example, the disequilibrium between day-ahead and real-time is important to the conclusion.

For the purposes of the example, we will assume that the scheduling of only 400 MW of load in the east reduces the prices in the CAISO day-ahead market to only $60/MWh as shown in Figure 10. The net cost of the ETC holders purchases are therefore $24,000/hour.

Figure 10
Day-Ahead Prices with 400 MW Schedule



In real-time, the ETC holder schedules 500 MW of power from its generation at A to meet its load at F, and the real-time price rise to the level shown in Figure 9 with 500 MWh of load at F. The ETC holder then settles its 400MW purchase in the day-ahead market financially, selling back the energy at the real-time price of $80. The ETC holder will then net an arbitrage profit of $20 ($80-$60) times 400 MW per hour. The CAISO on the other hand would be revenue inadequate because it would in effect have to buy back 500MW of transmission from West to East to cover the ETC schedule at real-time prices, having sold the ETC capacity at day-ahead prices. Because day-ahead congestion costs would be lower than real-time congestion costs, the CAISO would be revenue inadequate.

These disequilibrium arbitrage profits are in principle subject to arbitrage by other market participants. The ability of other market participates to arbitrage these profits are constrained, however, by two factors attributable to the special position held by the ETC holders under such an approach. First other market participants would not know when submitting their day-ahead offers whether the ETC holder has over or under scheduled its true load in the DAM. Second, other market participants do not have the ability to cover their real-time position without cost if they fail to schedule it day-ahead, while the ETC holder would have this ability if is not subject to CAISO scheduling requirements.

While the ETCs are entitled to the benefits conferred by their existing contracts over the contract term, it is less clear that they are entitled to remain outside the CAISO market design for some purposes, while also being permitted to earn profits by imposing costs on other market participants through unrestricted participation in the CAISO markets with whose terms and scheduling deadlines they are not required to comply.

In the presence of the CAISO market, the most direct way to preserve the ETC rights would be as the CAISO proposes. The contracts are between the two parties, the PTO and the transmission service customer. To the extent that the actual schedules of the ETC deviate from the expected schedules, or congestion costs arise, the PTO would retain the responsibility to redispatch or absorb any costs outside the contracts. The ETCs would function like any other contract, and be subject to the same rules and market oversight under the CAISO framework.

III. LOAD ZONE ISSUES

Real-time operations must respect the actual configuration of the grid and the actual distribution of injections and withdrawals. Hour-ahead and day-ahead schedules should be as consistent as possible with real-time operations to avoid creating artificial arbitrage opportunities that would both complicate operations and produce unintended payments that would be socialized in uplift costs. A principal area of concern is any system of zonal aggregation. Whatever the merits of zonal aggregation, it necessarily creates gaps between real time operations and the representations in the zones. The larger the zones, the larger the gaps. The potential difficulties can be easily underestimated. Here we identify a few issues, but this list is not exhaustive as the CAISO continues to develop new rules to deal with the problems as they appear.

A. Load Zone Definition

The description of load aggregation in the July 21 Proposal[13] suggests that the Load Distribution Factors (LDFs) used to define aggregate load zones for the purpose of the CRR Simultaneous Feasibility Test (SFT), to settle the day-ahead market, and to settle the real-time market will potentially be different. These differences will likely give rise to congestion rent shortages and surpluses in the day-ahead and real-time markets. If these differences are unpredictable, they have the potential to average out over time so that there would be a relatively minor net impact on ISO settlements. To the extent that the large zonal definitions give rise to predictable differences, however, they will give rise to arbitrage transactions that would lead to congestion rent shortfalls that would not average out over time.

The potential for congestion rent shortfalls is particularly problematic between day-ahead and real-time markets if the load weights used in the day-ahead market are different than those used for real-time settlements and these differences can be predicted by market participants. The July 21 proposal refers to day-ahead load weights based on differences in day of the week and high load versus low load hours but not for other day-to-day differences, such as for expected weather patterns. Given the size of the large load aggregation zones, differences in weather conditions across those zones will likely give rise to predictable day-to-day differences in real-time load distributions. If the day-ahead load weights are not based on the best possible forecast of the actual real-time distribution of load within the large load aggregation zones, then market participants will be able to use information regarding predictable weather driven differences in real-time load distribution to arbitrage these artificial differences between the day-ahead load zone weights and price and the real-time load zone weights and price, whether through virtual demand and supply bids or through bids by physical loads that are higher or lower than real-time load. With such artificial arbitrage opportunities, congestion rent shortfalls and surpluses in the real-time market will not average to zero but will instead result in a congestion rent shortfall in real-time settlements. The CAISO's response to Sempra's February 4, 2004 questions clarifies that it is the CAISO's intent to progressively improve the methodology utilized to forecast the

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[13] Paragraphs 62-64.

distribution of load utilize in the day-ahead market so that the distribution of load "resembles expected real-time load conditions as closely as possible." This is an appropriate objective.

These difficulties discussed above would be avoided under a full nodal pricing system for load. Alternatively, basing wholesale market settlements on narrower load zones would also reduce the magnitude of these potential problems, particularly during the period in which the CAISO is developing its load forecasting capabilities, by reducing the extent to which there would be predictable differences in load patterns across the load zone.

B. Load Area Disaggregation

In the initial CRR allocation study, the CAISO broke down some large load aggregation regions into smaller load group regions for the purpose of the SFT.[14] It is proposed that this would also be done in the second study.[15]This is a reasonable approach if there are transmission constraints within the large load aggregation regions. We agree that failing to take this step could cause the SFT to materially understate the number of CRRs that could be awarded to hedge load within the smaller load aggregation regions.

As shown by the CAISO's comments, the determination of the number of CRRs than can be awarded under the SFT can be sensitive to load aggregation. It is therefore important that all load zones be sufficiently disaggregated for the purpose of the SFT to assure that the award of CRRs is not limited by constraints internal to the Aggregate Load Zones and that all load zones be treated symmetrically. It appears, however, that the PG&E load zone was disaggregated into 26 zones averaging less than a fifth the size of the SDGE aggregate load zone which was not disaggregated.[16] It also appears that the same disaggregated load zones will be employed in the second study. This asymmetric treatment of disaggregation between aggregate load zones may affect the relative award of CRRs across load zones.

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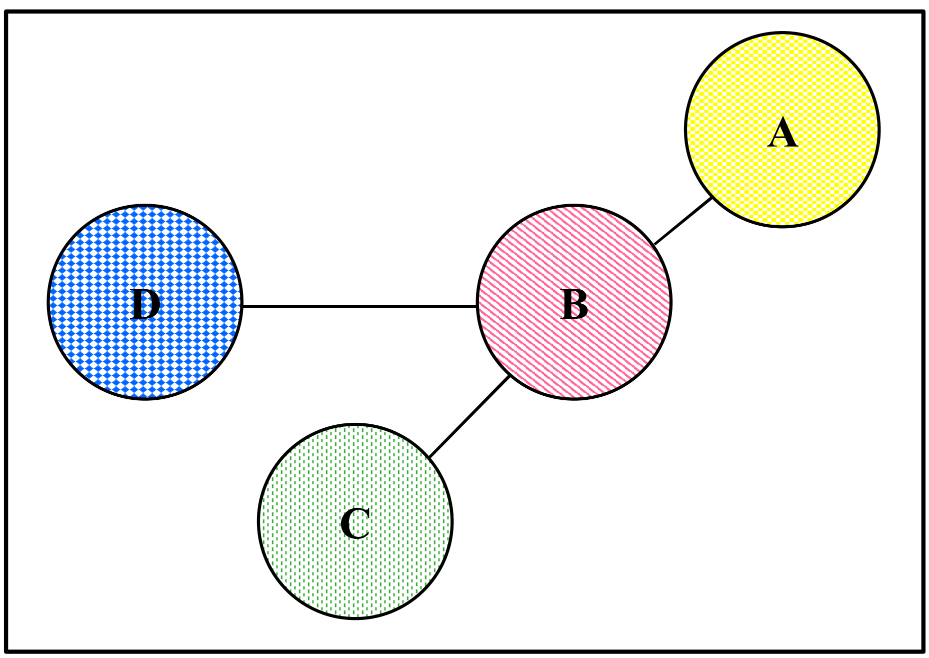
14 CRR Study, p. 28.

15 CRR Study, p. 14.

16 The CRR study states that "After each of the four load aggregation areas were broken down into smaller load groups, " but it does not appear that the SDGE load aggregation area was broken down into smaller regions.

Another subtle feature of the allocation of CRRs to aggregate load zone sinks is that this approach can make it difficult or impossible to assign all of the congestion rents to loads if there are transmission constraints within the aggregate load zones. This is illustrated by Figure 11. Suppose the aggregate load zone includes regions A, B, C and D, and that CRRs were awarded from C to the aggregate load zone, and in addition from C to B, C to A and C to D subject to the SFT. Such an allocation might well not exhaust the transfer capability from B to A, yet there could be congestion between generation in region B and load in region A. The CAISO could define additional B to aggregate load zone CRRs to utilize this capability, but there might be little incentive to hold such CRRs as they might have little or even negative value if defined as obligations.[17]

Figure 11
CRR Allocation to Aggregated Load Zones



These difficulties could be avoided if the CRRs whose economic value is assigned to load are defined to sinks based on a relative disaggregate set of load zones.

[17] The aggregation of regions A, B, C and D into the aggregate load zone gives rise to the possibility that the expected price in region A could exceed the expected price in region B, yet the price at B could exceed the aggregate load zone price.

On the other hand, it is only load within the smaller load aggregation regions that can be hedged by these CRRs. The CAISO comment in the initial study that "The resulting cleared bids were subsequently 'reassembled' to arrive at the total quantity of cleared bids form the original source to the original load aggregation areas" leaves some ambiguity as to what was done and whether the final awards would satisfy the simultaneous feasibility test. It needs to be clarified whether this reassembly is to be limited to the extent that the there were sufficient cleared bids to each of the smaller load aggregation composing the larger areas with some CRRs defined with the smaller load aggregation areas as sinks or whether all of the awards for the smaller load aggregation regions are in some manner transformed into awards to the larger load aggregation regions.

The CAISO's response to Sempra's February 4, 2004 clarifying questions (question 11) appears to indicate that the CAISO intends to award source to aggregate load zone CRRs for CRRs that are in fact infeasible if defined to the aggregate load zone, rather than to the smaller load zone regions. The infeasibility arises whenever there is a difference between the LDF for the aggregate load zone and the distribution of the local CRRs. In terms of Figure 11, the proposed disaggregation rule would award A to C and A to D CRRs if A to B CRRs were feasible. If this is the CAISO's intent, it is important to understand that this approach could potentially result in the award of material quantities of CRRs that are in fact infeasible, leading to a substantial revenue inadequacy in CRR settlements. Preservation of revenue adequacy in the award of CRRs requires that if the SFT is applied to CRRs defined to disaggregate load zones, then the CRRs awarded are also defined to these same disaggregate load zones.

C. Aggregate Load Zones and Metered Subsystems

The reliance on aggregate load zones for pricing has the potential to give rise to more serious difficulties in the context of metered subsystems of LSEs serving load with internal generation or LSEs allocated CRRs from local generation to load. The fundamental source of these difficulties is that the use of aggregate load zones causes the pricing point for the generation and load to be different, even when the electrical location is essentially the same. Pricing options A and B both appear likely to give rise to inefficient arbitrage incentives for such LSEs due to the load zone aggregation.

The underlying issue is that because the pricing point for the generation and load is different, although the physical location is the same, the LSE operating the metered subsystem needs to be allocated CRRs from its generation to the load zone pricing point in order to be hedged against congestion charges, even though the generation and load are actually at the same location with no congestion charges between them. Some of these CRRs will have expected positive values and others expected negative values. The need to designate CRRs between locations that are actually identical will create trade offs between hedging congestion costs and avoiding cost shifting that may be insolvable.

In addition, the separate pricing and scheduling points for MSS generation and load has the potential to give rise to artificial constraints and infeasibilities that may both hinder hedging and give rise to inefficient bidding and scheduling incentives that shift costs onto other market participants.

To illustrate these issues let us suppose that the locations A and D in Figure 11 are both metered subsystems with 1,000 MW of peak load, 1,000 MW of generation, and 250 MW of transfer capability from B to A and B to D. While peak load can in principle be met without relying on imports, the import capability allows the LSEs at A and D to take advantage of low cost energy available on the spot or term market, as well as to conduct generation maintenance and meet load when generation is not available due to forced outages. In addition we assume that there is 2,500 MW of peak load in region B, 3,000 MW of peak load in region C and transfer capability of 1,500 MW from C to B; see Table 12. There is a single LSE serving regions B and C.

Table 12
Scenario I Nodal Payments by Load

Scenario I	Load	Price	Total
A	1,000	45	45,000
B	2,500	42	105,000
C	3,000	40	120,000
D	1,000	80	80,000
	7,500		350,000

Table 13 portrays a simple set of assumptions regarding generation costs, with high cost generation required at the margin to meet load in regions A and D, determining nodal prices for generation in the four regions, which are for simplicity of the example assumed to be radially connected.

Table 13
Scenario I Generation Costs

	Capacity (MW)	Generation (MW)	Price/MW	Total Cost
A	500	250	45	11,250
	500	500	40	20,000
Total A	1,000	750		31,250
B	500	250	42	10,500
	500	500	40	20,000
	750	750	35	26,250
Total B	1,750	1,500		56,750
C	2,500	2,000	40	80,000
	2,500	2,500	35	87,500
Total C	5,000	4,500		167,500
D	500	250	80	20,000
	500	500	60	30,000
Total D	1,000	750		50,000
Total Production	8,750	7,500		305,500

The resulting generation revenues and regional prices are summarized in Table 14.

Table 14 Scenario I Generation Revenues			
	Generation (MW)	Price/ MW	Generation Revenues
A	750	45	33,750
B	1,500	42	63,000
C	4,500	40	180,000
D	750	80	60,000
Total	7,500		336,750

Finally, it is assumed that the LSEs at A and D are assigned 250 MW of CRR from C to A and C to D respectively, while the LSE serving regions B and C is assigned 1,000 C to B CRRs, with the values shown in Table 15 under peak load conditions.

Table 15 Scenario I Nodal CRR Values			
Carrier	CRRs	$/MW	CRR Revenues
A	250 C to A	5	1,250
B	1,000 C to B	2	2,000
C	0	0	0
D	250 C to D	40	10,000
Total			13,250

The net cost of load, the cost of generation plus the cost of purchased power, plus congestion charges less CRR revenues is shown in Table 16.

Table 16 Net Cost to Loads – Nodal Hedging					
	Payments by Load	CRR	Generation Revenues	Generation Costs	Net Cost to Load
Net Cost to A	45,000	-1,250	-33,750	31,250	41,250
Net Cost to D	80,000	-10,000	-60,000	50,000	60,000
Net Cost to BC	225,000	-2,000	-243,000	224,250	204,250
Total	350,000	-13,250	-336,750	305,500	305,500

Exactly the same cost of meeting load can be replicated under a system of zonal price aggregation in which all LSEs pay a load zone price, based on the load weighted average nodal price, as portrayed in Table 17. The LSEs at A, B and C pay higher zonal prices than under a disaggregated pricing system while receiving the same price for their generation (i.e., they incur congestion charges in delivering their power from their generation to their load, even though their generation and load are electrically at the same location).

Table 17
Scenario I Load Zone Price

Scenario I	Load	Price/MW	Payments at Locational Prices	Payments at Load Zone Price	Load Zone LDF Weights
A	1,000	45	45,000	46,666.67	0.133333
B	2500	42	105,000	116,666.7	0.333333
C	3,000	40	120,000	140,000.0	0.4
D	1,000	80	80,000	46,666.67	0.133333
Total	7,500	46.66667	350,000	350,000	1.0

The effect of the artificial congestion charges arising from the zonal price aggregation can be offset, however, by assigning these LSEs additional CRRs from their generation to the aggregate load zone as shown in Table 18.

Table 18 Scenario I CRR Values			
Carriers	**CRRs**	**$/MW**	**CRR Revenues**
A	250 C to Zone	6.666667	1,666.667
	750 A to Zone	1.666667	1,250
Total A	1,000		2,916.667
B	1,000 C to Zone	6.666667	6,666.667
	1,500 B to Zone	4.666667	7,000
Total B	2,500		13,666.67
C	3,000 C to Zone	6.666667	20,000
D	250 C to Zone	6.666667	1,666.667
	750 D to Zone	-33.3333	-25,000
Total D			-23,333.3
Grand Total	7,500		13,250

The cost of generation is unchanged by the zonal cost aggregation, so the net cost of meeting load is summarized in Table 19 and it can be seen that the cost is identical for each LSE to the costs under a disaggregated pricing system.

Table 19 Net Cost to Loads					
	Payments by Load	**CRR**	**Generation Revenues**	**Generation Costs**	**Net Cost to Load**
Net Cost to A	46,666.67	-2,916.67	-33,750	31,250	41,250
Net Cost to D	46,666.67	23,333.33	-60,000	50,000	60,000
Net Cost to BC	256,666.7	-33,666.7	-243,000	224,250	204,250
Total					305,500

Unfortunately, the impacts of zonal price aggregation are more problematic than suggested by this happy outcome. The first problem is that this zero cost shifting outcome only exists for the state in which the actual load equals the peak load for which the zonal price hedges were allocated. At any other load level, even if the load weights are perfect, the zonal price aggregation will lead to cost shifts. To illustrate this, let us assume that the load in each region is 80 percent of the load assumed in the first scenario, as portrayed in Table 20.

Table 20 Scenario II Nodal Payments by Load			
Scenario II	**Load**	**Price/MW**	**Total Cost**
A	800	45	36,000
B	2,000	40	80,000
C	2,400	40	96,000
D	800	80	64,000
Total	6,000		276,000

The generation needed to meet load is reduced as shown in Table 21 and there is no congestion between regions B and C, with the cost of meeting load of $40 in both regions.

Table 21 Scenario II Generation Costs				
	Capacity (MW)	**Generation (MW)**	**Price/MW**	**Total Cost**
A	500	50	45	2,250
	500	500	40	20,000
Total A	1,000	550		22,250
B	500	0	42	0
	500	250	40	10,000
	750	750	35	26,250
Total B	1,750	1,000		36,250
C	2,500	1,400	40	56,000
	2,500	2,500	35	87,500
Total C	5,000	3,900		143,500
D	500	50	80	4,000
	500	500	60	30,000
Total D	1,000	550		34,000
Total Production	8,750	6,000		236,000

Generation revenues are portrayed in Table 22.

Table 22 Scenario II Generation Revenues			
Carriers	**Generation (MW)**	**Price/MW**	**Generation Revenues**
A	550	45	24,750
B	1,000	40	40,000
C	3,900	40	156,000
D	550	80	44,000
Total	6,000		264,750

Finally, CRR revenues are impacted by the change in regional clearing prices and are portrayed in Table 23.

Table 23 Scenario II Nodal CRR Values			
Carrier	**CRRs**	**$/MW**	**CRR Revenues**
A	250 C to A	5	1,250
B	1,000 C to B	0	0
C	0	0	0
D	250 C to D	40	10,000
Total			11,250

The cost of meeting load is therefore reduced as shown in Table 24.

Table 24 Scenario II Net Cost to Loads					
	Payments by Load	**CRR**	**Generation Revenues**	**Generation Costs**	**Net Cost to Load**
Net Cost to A	36,000	-1,250	-24,750	22,250	32,250
Net Cost to D	64,000	-10,000	-44,000	34,000	44,000
Net Cost to BC	176,000	0	-196,000	179,750	159,750
Total					236,000

Now let us calculate the cost of meeting load for each LSE under a system of zonal price aggregation. The zonal price and payments by load are portrayed in Table 25.

Table 25 Scenario I Load Zone Price					
Scenario I	**Load**	**Price/MW**	**Payments at Locational Prices**	**Payments at Load Zone Price**	**Load Zone LDF Weights**
A	800	45	36,000	36,800	0.133333
B	2,000	40	80,000	92,000	0.333333
C	2,400	40	96,000	110,400	0.4
D	800	80	64,000	36,800	0.133333
Total	6,000	46	276,000	276,000	1.0

Given this load zone price and the generation prices from Table 21, Table 26 shows the value of the aggregate load zone CRRs.

Table 26 Scenario I CRR Values			
Carriers	**CRRs**	**$/MW**	**CRR Revenues**
A	250 C to Zone	6	1,500
	750 A to Zone	1	750
Total A	1,000		2,250
B	1,000 C to Zone	6	6,000
	1,500 B to Zone	5	9,000
Total B	2,500		15,000
C	3,000 C to Zone	5	18,000
D	250 C to Zone	6	1,500
	750 D to Zone	-34	-25,500
Total D			-24,000
Grand Total	7,500		11,250

The cost of meeting load for each LSE is then portrayed in Table 27. Table 27 shows that the system of zonal price aggregation reduces the cost of meeting load for the LSEs at A, B and C and raises the cost of the LSE in the high cost region D, relative to a less aggregate pricing system. This result is likely at first unintuitive as the LSE that loses is the LSE whose wholesale price is reduced by the aggregation. The reason for this is that the zonal price aggregation system requires allocation of CRRs to hedge the congestion costs at peak load between generation and load that are actually at the same location (i.e., the A to load zone, and B to load zone CRRs). The CRRs required by the fictional pricing system, however, are also valuable at low load levels when the generation they hedge is not being dispatched.

Table 27
Scenario II Net Cost to Loads

	Payments by Load	CRR	Generation Revenues	Generation Costs	Net Cost to Load
Net Cost to A	36,800	-2,250	-24,750	22,250	32,050
Net Cost to D	36,800	24,000	-44,000	34,000	50,800
Net Cost to BC	202,400	-33,000	-196,000	179,750	153,150
Total					236,000

The other side of this is that the D to load zone CRRs are actually counterflow FTRs under zonal price aggregation and have large negative values. While these negative values are offset by counterflow revenues for the generation at high load (i.e., the difference between the high price paid for the generation and the low aggregated price paid by load) this is not the case at lower load levels when less generation is dispatched

At high prices LSE D's load is met at lower zonal aggregation prices, but the quantity of CRRs from high cost generation to the load zone is fixed, raising the cost of meeting load.

This anomalous result suggests the next difficulty with the zonal aggregation approach to metered subzones, which is the implicit assignment of counterflow CRRs. It is noteworthy that in both Scenario I and II the CRRs from D to the Aggregate Load Zone have negative values, even though the generation is by definition at the same location as LSE D's load. As a result, LSE D would be much better off if it did not take these CRRs and if given a choice presumably would not because the cost of accepting the congestion hedge would likely exceed any risk reducing value.

This leads to a further problem in that these counterflow CRRs are necessary not only to the simultaneous feasibility of the C to D CRRs but also of the C to A and C to B CRRs, because of the zonal aggregation. Table 28 shows the implied shift factors of the various generator to Aggregate Load Zone CRRs in the SFT for the Aggregate Load Zone CRRs. For example, because 1/7.5 of the load for the Aggregate Load Zone is in region A, a CRR from generation at A to the Aggregate Load Zone would produce counterflows across the B to A constraint of .8667 MW per MW of CRR from A to the Aggregate Load Zone. With the assumed allocation of CRRs, the flows across each of the constraints, B to A, B to D and C to D, associated with the CRRs is less than each of the limits so the allocation satisfies the SFT. Table 28 also shows that the D-Load Zone CRRs provide counterflow on constraints B to A and C to B, as well as on B to D.

Table 28
SFT with Counterflow

LSE	CRR	B to A Constraint		B to D Constraint		C to B Constraint	
		CRR Shift Factor	Flows	CRR Shift Factor	Flows	CRR Shift Factor	Flows
A	250 C-Zone	0.133333	33.33333	0.133333	33.33333	0.6	150
	750 A-Zone	-0.86667	-650	0.133333	100	-0.4	-300
D	250 C-Zone	0.133333	33.33333	0.133333	33.3333	0.6	150
	750 D-Zone	0.133333	100	-0.86667	-650	-0.4	-300
C	3,000 C-Zone	0.133333	400	0.133333	400	0.6	1,800
B	1,000 C-Zone	0.133333	133.3333	0.133333	133.3333	0.6	600
	1,500 B-Zone	0.133333	200	0.133333	200	-0.4	-600
Total			250		250		1,500

The D to Aggregate Load Zone CRRs would likely have negative values, however, so the LSE at D would prefer not to accept such CRRs, being better off if it were unhedged. Table 29 shows the SFT test for the remaining CRRs if LSE D could choose not to accept the D to Aggregate Load Zone CRRs, It shows that the allocation of CRRs in Table 18 would substantially overload the B to D and C to B limits, absent the counterflow provided by the D to Aggregate Load Zone CRRs.

Table 29 Infeasible SFT – No Counterflow							
		B to A Constraint		B to D Constraint		C to B Constraint	
LSE	**CRR**	**CRR Shift Factor**	**Flows**	**CRR Shift Factor**	**Flows**	**CRR Shift Factor**	**Flows**
Limit			250		250		1,500
A	250 C-Zone	0.133333	33.33333	0.133333	33.33333	0.6	150
	750 A-Zone	-0.86667	-650	0.133333	100	-0.4	-300
D	250 C-Zone	0.133333	33.33333	0.133333	33.3333	0.6	150
	750 D-Zone	0.133333	0	-0.86667	0	-0.4	0
C	3,000 C-Zone	0.133333	400	0.133333	400	0.6	1,800
B	1,000 C-Zone	0.133333	133.3333	0.133333	133.3333	0.6	600
	1,500 B-Zone	0.133333	200	0.133333	200	-0.4	-600
Total Flow			150		900		1,800

Revenue adequacy could be restored by proportionately prorating down the remaining CRRs but Table 30 shows that very substantial prorationing of CRR allocations would be required to satisfy the SFT and the number of congestion hedges available to the LSEs at A, B and C would be dramatically reduced relative to the earlier example. As a result, the LSEs would be exposed to substantial congestion risk as well as cost shifting.

LSE	CRR	B to A Constraint		B to D Constraint		C to B Constraint	
		CRR Shift Factor	Flows	CRR Shift Factor	Flows	CRR Shift Factor	Flows
Limit			250		250		1,500
A	69.44444 C-Zone	0.133333	9.259259	0.133333	9.259259	0.6	41.66667
	208.3333 A-Zone	-0.86667	-180.556	0.133333	27.77778	-0.4	-83.3333
D	69.44444 C-Zone	0.133333	9.259259	0.133333	9.259259	0.6	41.66667
	0 D-Zone	0.133333	0	-0.86667	0	-0.4	0
C	833.3333 C-Zone	0.133333	111.1111	0.133333	111.1111	0.6	500
B	277.7778 C-Zone	0.133333	37.03704	0.133333	37.03704	0.6	166.6667
	416.6667 B-Zone	0.133333	55.55556	0.133333	55.55556	-0.4	-166.667
Total Flow			41.66667		250		500

Table 30

SFT – No Counterflow: Reduced CRR Allocation

The proposed approach to zonal price aggregation has the potential to lead to a variety of SFT and cost shifting problems in the day-ahead market as well as the CRR related problems discussed above. First, if LSE loads are mapped to the aggregate load zone based on LDFs, underbidding by a particular LSE will cause the load scheduled in the day-ahead market to decline across the load zone, not just in the region served by that LSE. This could lead to anomalous outcomes as the load modeled in constrained regions is reduced or increased by the load bidding decisions of LSEs serving other regions, while generation scheduled by an LSE to serve its load in the constrained region may appear to be greater than or less than load modeled in the day-ahead market because of the bidding decisions of LSEs in other regions. This has the potential to introduce a level of chaos into the CAISO's day-ahead market that would be better avoided. These potential problems are avoided if the CAISO defines CRRs to less aggregated load zones and in particular, that metered subsystems be priced on zonal basis that is no larger than the metered subsystem with CRRs defined to this same location.

[i] Scott Harvey is a Director with LECG, LLC. William W. Hogan is the Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University and a Director of LECG, LLC. The preparation of these comments has been supported by Constellation, Coral, Mirant and Sempra Energy. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. The author are or have been consultants on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Australian Gas Light Company, Avista Energy, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, Calpine Corporation, Central Maine Power Company, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, Conectiv, Constellation Power Source, Coral Power, Detroit Edison Company, Duquesne Light Company, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GWF Energy, Independent Energy Producers Assn, ISO New England, Maine Public Advocate, Maine Public Utilities Commission, Midwest ISO, Mirant Corporation, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario IMO, Pepco, Pinpoint Power, PJM Office of Interconnection, PP&L, Public Service Electric & Gas Company, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Corporation, Sempra Energy, SPP, Texas Utilities Co, TransÉnergie, Transpower of New Zealand, Westbrook Power, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the authors. (Related papers can be found on the web at www.whogan.com).