Alternatives to Implementing a Locational Marginal Pricing Market
by

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1. Introduction

We have supported the ISO's position over the last two years that a transition to a market design that employs Locational Marginal Pricing (LMP) would enhance the efficiency and reliability of California's electricity system. However, the seller's choice long-term contracts signed by the California Department of Water Resources have the potential to create a significant liability for California consumers under LMP. The resolution of this seller's choice issue and the development of an effective local market power mitigation mechanism--an issue we will address in more detail in a future opinion--are the two major obstacles to the transition to an LMP market. The staff of several California legislators has consistently emphasized the importance of these issues; we strongly concur that these two issues must be satisfactorily resolved before transitioning to an LMP market design. Given these two obstacles, there is an interest among California policymakers in developing alternatives to a LMP market design. We have been asked to comment on the ISO's Transitional Alternative Pricing and Settlement (TAPAS) proposal and some of the responses that have arisen to that proposal.

In summary, we would strongly prefer a successful transition to an LMP market design. In this opinion, we consider three alternatives to an LMP market design and ultimately conclude that we prefer them in the following order:

(1) The current market design with more reliability must run (RMR) units and an improved pre-dispatch process,

(2) TAPAS without constrained down payments, and

(3) TAPAS with constrained down payments.

The TAPAS proposal would develop and implement almost all of the features of the proposed Market Redesign and Technology Upgrade (MRTU), but would not implement nodal-pricing. Transmission congestion would be managed through a bid-based system, but generators and loads would not necessarily earn the prices their bids imply. In particular, the TAPAS proposal would recognize the existence of all transmission constraints when accepting bids for energy and ancillary services, but would pay zonal prices, with uplifts to generators whose bids exceed the zonal price but whose output is required to relieve congestion. The proposal would not pay generators to decrease their output if the network cannot accommodate this energy. As a result, the prices that generators will receive will often be inconsistent with their bids, because some bids that are less than the price will not be taken, while others that are greater than the price will be accepted. This mismatch between bid prices and the prices actually paid to market participants would certainly provide incentives to misrepresent costs through bids to the ISO and to violate operating instructions. The potential for distorting dispatch decisions is significant.

The most common solution to this incentive problem is to provide constrained-down payments to generation that is forced to curtail its output because of network constraints. However, if suppliers possess local market power these payments also give them an incentive to misrepresent their costs through extremely low bids that inflate their constrained-down payments. This is a serious concern because generation-rich areas tend to be dominated by one or two firms. Below, we discuss an alternative to the TAPAS and constrained-down payments alternatives: continuation of the current market design but with reliance upon an expansion of reliability must-run (RMR) contracts, or equivalent arrangements between load serving entities (LSEs) and generation. Regardless of the market design ultimately chosen for California ISO, more reliable real-time operations requires developing tools for system operators that provide for explicit representation of all network constraints. Real-time reliability would also benefit from the imposition of charges on real-time transactions that would discourage both load and generation from relying upon the real-time market. A market that does not fully represent all relevant network operating constraints in the real-time price each generation unit receives may require these charges to provide incentives for suppliers to schedule accurately and adhere to their schedules.

We have previously stated our strong support for the ultimate implementation of LMP because of its economic efficiency and reliability benefits.[1] However, it is important to understand that despite the desirable characteristics of LMP, it is possible to operate a reasonably efficient and reliable electricity market without it. Several variations of the alternatives to LMP described above can be found today in electricity markets around the world. While not perfect, in most places the performance of these alternatives has been at least satisfactory.

The remainder of this opinion first summarizes lessons from the US and other countries for a successful spot market design. The next section reviews TAPAS, a design that attempts to improve the performance of the California market with minimal changes in the current zonal design. The third section describes an alternative modification to the current design that uses the lessons from international experience to provide California ISO system operators with increased real-time locational pricing options to operate the system within the context of the current California ISO forward market.

2. Congestion Management and Incentives

It is important to emphasize that zonal market designs are far more common than LMP designs internationally. A major lesson from international experience with electricity market design is that local market power problems arise in all wholesale electricity markets, regardless of the congestion management mechanism used. Local market problems arise in the wholesale market regime because the existing transmission network in virtually all parts of the US is very poorly suited to support the geographic extent of competition in electricity supply required to discipline the spot market bidding behavior of all market participants, given the concentration of generation capacity ownership in US wholesale markets.

Absent local market power mitigation in a LMP market, the bid of the unit or units with local market power would have to be accepted. This implies that the LMP at these locations in transmission network would be at or above the bids of these firms. Absent local market power mitigation in a zonal market design, the suppliers with local market power are, in essence, paid as-

[1] Market Surveillance Committee of the California ISO, “Comments on Locational Marginal Pricing and the California ISO’s MD02 Proposals”, April 7, 2003, http://www.caiso.com/docs/2003/04/07/2003040713192323878.pdf.

bid for the necessary energy. Which market design leads to higher overall wholesale energy costs to consumers depends on a number of factors, but there are two important points to emphasize. First, there are circumstances when a zonal market design would lead to lower wholesale energy costs, and there are other circumstances when a LMP market design would lead to lower costs. Second, because the greatest efficiency gains of competition will likely occur in the form of better investment decisions, no wholesale market design is likely to lead to significantly lower wholesale energy costs in the near term than the costs that existed under the vertically-integrated monopoly regime without an effective local market power mitigation mechanism. Given the configuration of the existing transmission network and the geographic distribution of generation capacity ownership in US wholesale markets, the frequency and magnitude of local market power implies that if left unmitigated, favorably situated suppliers could earn enormous profits by exploiting it.

Hence, effective local market power mitigation (LMPM) is a necessary component of any wholesale market design. For the same LMPM mechanism under a zonal versus nodal market design there is also no general conclusion about which market design yields lower average delivered prices of electricity. The New Zealand electricity market provides a graphic illustration of this point. New Zealand is the only LMP market currently operating outside of the US. During the periods June to September of 2001 and 2003 it experienced high wholesale electricity prices for much the same reason that California experienced very high prices during the period June to September 2000--insufficient forward contract coverage by a number of LSEs of their obligations to final consumers. These facts raise the question: What are the benefits from adopting an LMP market design?

An LMP market design provides the system operator with many more tools to operate the system in real time. Under an LMP design, the system operator has the ability to set a different price for electricity at each location in the transmission network. In contrast, under a zonal market design, the system operator can only set a single price for the entire zone. This flexibility is particularly valuable when the system operator needs to have certain generation units increase their output and others decrease their output within in the same time interval. This can be seamlessly handled in the LMP market by reducing the nodal prices for the units that the system operator needs to reduce their output and increasing the nodal prices for units that system operator needs to increase their output. How much the system operator must reduce or increase a nodal price is determined from the bid curves submitted by each generation unit.

In contrast, under a zonal market design, the system operator must resort to other means to move generation units in the same congestion zone in different directions within the same time interval. This can be accomplished in a number of ways. For example, all market participants could receive the zonal price for all of their output in the hour if they obey the dispatch instructions issued by the system operator within that hour. To provide additional incentives to obey dispatch instructions, market participants that are out-of-merit within the zone also could receive an uplift payment. For example, if all but one or two units in a zone are increasing their output within the hour, the two remaining units could be paid an administratively determined uplift payment to compensate for reducing their output to maintain system reliability. If congestion is severe, there are both short run and long run incentive problems with this system. In the short-run, local market power could lead to the "dec" game and inefficient commitment day-ahead.[2] In the long

[2]We have discussed this issue in a previous opinion (Market Surveillance Committee of the California ISO, "Managing Congestion Costs in the Miguel-Imperial Valley Region", January 13, 2004, www.caiso.com/docs/2004/01/14/2004011413564022018.pdf)

run, incentives for appropriate siting of new generation and energy-intensive industry are distorted. On the other hand, if congestion is sporadic, then such distortions are less of a problem, as experience in the England and Wales market and a number of other zonal markets have demonstrated.

If the wholesale market has an effective LMPM mechanism, the additional flexibility afforded the system operator under an LMP market allows virtually any transmission network configuration to be reliably operated. The system operator only needs to vary the prices at each location in the network to ensure that all the generation units in the system are operated at the levels necessary for demand to equal supply at all locations in the network. The reduced locational pricing flexibility available to the system operator under a zonal market design limits the range of transmission network configurations that can be reliably operated without additional regulatory backstops either in the form of additional transmission capacity into the zone or reliability must-run generation units within the congestion zone. Attempting to run a zonal market design without these additional regulatory safeguards can inflate consumer costs and degrade system reliability.

It is important to emphasize that neither a nodal nor zonal market design eliminates the need to run expensive generation units for local or system-wide reliability reasons. The configuration of the transmission network and geographic location of available generation units and loads are important inputs into this decision. An LMP design explicitly minimizes the as-bid dispatch costs of meeting all locational energy needs, and price equals the marginal as-bid cost of meeting load in each location. By contrast, zonal designs typically pay out-of-merit suppliers (within the congestion zone) as-bid for decremental and incremental energy. There are circumstances when the LMP approach will lead to lower average prices to consumers and circumstances when the zonal market approach will lead to lower average prices. A major advantage of the LMP design is still the flexibility that it affords system operators in providing location-specific price signals to generation unit owners to provide the necessary energy at each location in the network to meet the geographic distribution of load throughout the transmission network. There are other operational advantages of an LMP market described in our previous opinion cited in footnote 1.

3. The TAPAS proposal

The ISO TAPAS proposal would implement virtually all of the operating systems and protocols of the MRTU package, while modifying some of its pricing features. The day-ahead market would incorporate a security-constrained unit-commitment (SCUC) process and a full network model in setting dispatch quantities. Unlike MRTU, the proposal would not pay nodal prices to generation to the extent those prices differ at nodes within three current congestion zones. Instead, generation that is needed but bid in at prices above the zonal price will be paid as-bid constrained-up prices (CUPs).

One of the most controversial aspects of the ISO's TAPAS proposal is that it does not make constrained-down payments (CDPs) to generation units that must have their schedules reduced due to intra-zonal congestions. As the report by Charles Rivers Associates points out, this practice is not incentive compatible. This means that some generators will have an incentive to under-represent their costs to the ISO in their bids, or to deviate from dispatch instructions. (The TAPAS proposal attempts to address the latter issue by appropriately sanctioning generators that deviate from dispatch instructions with uninstructed deviation penalties.)

In particular, generators with costs sufficiently below the zonal price will want to be in the day-ahead schedule to earn this price (or its equivalent value through a bilateral trade). However, in generation pockets (where nodal prices would be low under LMP), not all the suppliers that would like their generation units to be dispatched at the zonal price will able to be do so. Some will have to be constrained down. But none will want to be, as there is no compensation for it. The result will likely be a 'race to the bottom' of low energy bids from generators in constrained-off areas. Instead of the ideal, in which the ISO would relieve congestion in a least-cost manner by calling on the most efficient mix of generation, the ISO could instead be forced to assign its curtailments amongst a group of generation units that bid zero (or negative energy bids). Under these circumstances, an administrative rather than market process would be needed to determine which generation units would be dispatched and paid the zonal price, and which units would be constrained off.

Against this unappealing picture, however, one must weigh the fact that in reality no electricity market has fully incentive compatible transmission pricing. Under an incentive compatible mechanism (or market design), generators find it most profitable to reveal (or bid) their true costs to the ISO rather than to misrepresent their costs. Aspects of a market design can create incentive incompatibility, as does the presence of market power. A supplier with market power has a unilateral incentive to bid higher than its minimum increment cost curve. By doing so, the supplier raises the price it receives by more than enough to compensate for the reduction in electricity sold as a result of this higher bid curve. Therefore, when a supplier possesses market power, an incentive compatible compensation mechanism would have to "buy out" the market power of the supplier in a way that makes it most profitable for the supplier to bid their true minimum incremental cost curve. An incentive compatible payment mechanism implies that, conditional on bidding its true minimum incremental cost curve, a supplier would receive profits that are as least as great as it could receive from exercising all available unilateral market power given the procedure used to determine the compensation paid to the supplier. Such an incentive compatible payment mechanism is likely to be extremely expensive.[3]

It is important to emphasize that LMP is not incentive compatible when individual firms are able to influence the price at a given node. Even if firms do not have substantial system-wide market power, it may be profitable for them to misrepresent their costs in order to capture some of the congestion rents that would otherwise accrue to the ISO or transmission rights holders. Under a zonal-pricing scheme with CDPs, generators have an incentive to bid a low price to collect a larger CDP if they can get away with it (in the sense that no other generator over-bids them and earns the CDP instead). In a wholesale electricity market with any local market power, a purely incentive compatible mechanism would have to compensate the generator fully for its locational rents, effectively buying out their market power. Policy-makers rightly consider this approach to be too costly and instead regulate a firm's ability to extract these rents through various forms of local market power mitigation (LMPM).

Whether zonal pricing with CDPs or zonal pricing without CDPs leads to fewer distortions in the dispatch depends upon the extent of market power in the nodes that are likely to be constrained-off. Thus the payment of CDPs becomes relatively more attractive when the nodes at which they might be applied are less likely to suffer from local market power. The incentive

[3] An actual example of the very high cost of buying truthful revelation is contained in B.F. Hobbs, M.H. Rothkopf, L.C. Hyde, and R.P. O'Neill, "Evaluation of A Truthful Revelation Auction in the Context of Energy Markets with Nonconcave Benefits," Journal of Regulatory Economics, 18, 5-32, July 2000.

compatibility advantages of paying CDPs are greatly reduced, if not eliminated, when the constrained-off nodes feature concentrated ownership of generation. Since generation pockets in California usually contain large thermal generators owned by a small number of suppliers, concentration in such locations is the rule rather than the exception, which argues against the ISO paying CDPs.

It should also be noted that whether or not CDPs are paid in a zonal system, the ISO will not rely completely upon the truthful bidding of generator costs for its redispatch decisions. There will continue to be some form of bidding restraints on dec bids, such as those currently applied in California. Similarly, redispatch under TAPAS could also utilize reference prices, rather than dec bids, to ration who gets left in the market and to decide who gets curtailed. We agree with the Charles River Associates report that resorting to such measures is a poor substitute for true incentive compatibility. However given the known local market power problems in a number of local areas in the ISO control area such as the Miguel interface; these measures seem inevitable under either approach. The need for LMPM measures that set reference prices for generation units may be more widespread if CDPs are not paid, as they would need to be applied even to competitive constrained-out locations -– if any exist.

While the payment of CDPs, absent substantial local market power, would probably increase the *efficiency* of the dispatch, such payments would also constitute a large transfer (or more accurately, a continuation of a large transfer) to generators located in constrained-down areas. This transfer would mostly come from the loads responsible for paying uplift charges that would cover those payments. We note that the recent cost of CDPs in the CAISO, specifically the cost of decremental energy, has been averaging on the order of tens of millions of dollars per month. Furthermore, uplift charges to loads to pay these CDPs can also distort retail market efficiency by exacerbating the difference between the prices consumers pay and the actual marginal cost of supplying electricity at the location where a retailer withdraws energy from the network. For these reasons, even with a local market power mitigation mechanism in place, we prefer TAPAS without CDPs.

In short, the relative merits of paying CDPs boils down to the empirical question of how competitive are the constrained-off nodes where CDPs are most likely to be paid. If these generation rich areas are fairly competitive, then not paying CDPs will create an additional incentive to distort bids that would otherwise not exist, potentially resulting in an inefficient dispatch. If, however, the constrained-off nodes are likely to be subject to mitigation of their bids anyway, not paying CDPs contributes only a marginal distortion to an already serious incentive problem. Our experience with generation pockets in the California ISO control area suggests that the concentration of generation ownership is sufficiently high that the vast majority of these generation-rich areas are likely to be subject to significant local market power. For this reason, we do not favor paying CDPs if the ISO decides to adopt the TAPAS market design.

4. Continuation with the Current Market Design

It is important to recognize that the TAPAS proposal does go farther than any other zonal market design in trying to capture all of the operating and network constraints in its day-ahead schedule. We believe it is important to move congestion management from real-time to day-ahead to the extent possible and therefore approve of this feature of TAPAS. The fact that the cost and revenue implications of those constraints are not included in prices under this proposal is the source of much of the incentive problems. Other zonal systems for the most part do not attempt to account for constraints in their advance schedules when those constraints are not used to calculate prices. In other words, the simpler prices are calculated using a simpler model of system operations. In attempting to capture detailed network constraints in the context of a simplistic pricing system, the TAPAS proposal is attempting something unique to electricity markets. This is an important reason for continuing with the current market design. All new electricity market designs have unintended consequences that can be very costly to correct, particularly during the initial stages of implementation. The risk of extremely costly unintended consequences can be avoided by continuing with current market design until an LMP market design can be implemented.

Given this fact, it is worth considering the motivations for adopting LMP in the first place. The performance of the California market design was satisfactory during 1998 and 1999. Even during the crisis years, intra-zonal congestion was not very prominent among the many problems experienced in the California market. It is only more recent problems created by the new entry of generation into now constrained areas that have led to the currently inefficient congestion management situation in Southern California. It is important to remember, however, that the lack of LMP during the initial years of the market no doubt contributed to the decision to site generation in these now unattractive locations.

Still, the fact remains that the short-run problems with intra-zonal congestion were manageable until rather recently. Currently, the problem is essentially that the LSEs schedule too much power from areas away from the California coastal population centers, while network constraints dictate that a large amount of the power needs to be sourced closer to these areas. Because these areas are all within the geographically broad SP15 zone, all of this is allowed under the current market rules. It is hoped that transmission upgrades will help to somewhat alleviate current problems with the Miguel and Sylmar interfaces. The problem is now dealt with through the denial of must-offer waivers and commitment of RMR units. Much of this ‘coastal’ energy must be dispatched too close to real-time for the comfort of ISO operators. The major problems with the current design are considered to be related to reliability: there is too much generation being dispatched in real-time.

LMP is widely acknowledged to be the desirable end-state, but the transition to LMP may be suspended until there is a satisfactory resolution of the seller’s choice contracts. Another way to approach the current situation, therefore, is to determine the minimum steps necessary for dealing with current problems as a transitional arrangement. We strongly recommend that a commitment to LMP follow at some point. However, the minimum steps necessary to deal with current intra-zonal congestion problems would involve a mechanism for increasing the feasibility of day-ahead schedules, which will improve the ability of ISO operators to deal with real-time redispatch. Depending upon how long a transitional mechanism may be in place, additional measures designed to promote the appropriate siting of new generation and construction of new transmission may also be necessary.

One way to accomplish these minimum requirements would be to increase the quantity of long-term energy and ancillary services supply contracts between LSEs and generation units local to their major load centers, particularly within the Southern California Edison territory. While these supply agreements could take the form of RMR contracts, long-term contracts for energy and/or ancillary services between LSEs and local generation units may provide more flexibility to both parties. However, we believe that the availability of a cost-based standard RMR contract is necessary to achieve reasonable terms for any directly negotiated contract because of the local market power of the generation unit owners near major California load centers. With more energy and ancillary services under contract, LSEs can hopefully be induced to submit forward schedules closer to what is needed to meet their actual load. The configuration of the transmission network implies that a substantial amount of generation located within the constrained areas must be operating; therefore, it is a question of getting it scheduled in advanced as opposed to through a somewhat ad-hoc redispatch process. These forward contracts will provide the necessary energy and ancillary services in advance of real time.

A major reliability concern of the ISO operators with the existing market design is the need to re-dispatch a significant number of generation units and MWs between the close of the day-ahead market and real time. Consequently, if the quantity of long-term contracts between LSEs and local generation units is expanded, then it is extremely important to make the most effective use of these units to limit the number of generation units and total MWs that must be re-dispatched between the close of the day-ahead market and real time. This can be accomplished by the ISO pre-dispatching RMR units before the start of the day-ahead scheduling process according to the following algorithm. The ISO operators should schedule enough of this contracted capacity and RMR energy in each congestion zone so that the remaining generation units located in each congestion zone are approximately equally effective at meeting the remaining load to be served in each congestion zone. To facilitate the short-term procurement process of the LSEs, the ISO should make available to all market participants, the hourly pre-dispatch quantities of energy from each of the RMR units before the opening of the day-ahead congestion management process. This will allow the LSEs to plan their short-term procurement of energy and ancillary services knowing how much RMR energy will be produced in real-time from each RMR unit and the amount of energy and ancillary services they have from the local generation units they have under contract, and thereby limit the extent to which day-ahead energy and ancillary services schedules are physically infeasible. If the ISO signs up sufficient RMR capacity and the LSEs have an increased quantity of forward energy and ancillary service contracts with local suppliers, this pre-dispatch and information provision mechanism should address the ISO operators' reliability concerns with the current design.

Another way to achieve the goal of moving transactions out of the real-time market is to increase the cost of real-time transactions to both load and generation. The England and Wales electricity market currently operates under a single zone day-ahead system that appears to provide strong incentives for loads and resources to avoid the balancing market. This market also provides the system operator with the flexibility to pay and charge generation units at different locations in the network different prices within the same settlement interval. This is accomplished by paying all instructed deviations (up or down) from a generation unit's day-ahead schedule as bid. Loads consuming more energy than they are scheduled to consume in real time and generators supplying less than they are scheduled to provide in real time pay the quantity-weighted average price paid to upward real-time dispatch instructions. Generators supplying more energy than they are scheduled to provide in real time and loads consuming less than they are scheduled to consume in real time are paid the quantity-weighted average price collected from generation units receiving downward real-time dispatch instructions. This balancing market is quite expensive for all entities that are unexpectedly out of balance. The high cost of participation in this "balancing mechanism" provides strong incentives for both loads and generation unit owners to submit physically feasible schedules in the day-ahead market and to stick to these schedules, including any additional dispatch instructions received from the ISO.

This mechanism could be modified to make the real time market participation expensive whether it is because of an instructed or uninstructed deviation, by instituting a $/MWh trading charge on all purchases or sales in the real-time market. This has the advantage of making the "dec game" more expensive for suppliers to undertake, because even instructed reductions in output in the real-time market would have to pay this $/MWh charge. The ISO could exempt a certain total quantity of MWh—both incremental and decremental energy relative to a generation unit or load's final schedule--from this trading charge each hour for each supplier to account for reasonable deviations due to demand or unit-level output uncertainties. We note, however, that there have been criticisms that mechanisms which increase the cost of real-time transactions such as the England and Wales imbalance mechanism have harmed renewable generation and have resulted in inefficient loading and ramping of generation units. Therefore, very high charges for real-time transactions are not a panacea or a desirable long-term alternative to LMP. However, the real-time locational pricing flexibility this type of mechanism provides to the ISO operators and the strong incentives it provides for feasible forward schedules may make it a useful transitional measure to a LMP market.

Even with the above modifications to the existing design, it may still be necessary to redispatch generation in real time. One current problem with the redispatch process is that even the real-time market operating system does not explicitly incorporate the full network model. Operators are forced to make ad-hoc judgments based upon their considerable experience with the transmission network. It seems advisable that at least one aspect of MRTU, the development of a real-time system that explicitly models all network constraints, be adopted to help mitigate the reliability pressures created by real-time redispatch operations if the ISO decides to continue with the existing market design.

5. Concluding Comments

The strength of an LMP market is that the system can be reliably operated and under a wider range of procurement policies and transmission expansion policies. However, there is a considerable risk that the costs to California consumers will be extremely high without regulatory intervention by FERC to address the seller's choice contracts liability. We believe that the most desirable outcome is that the seller's choice contract issue is settled by the contracting parties and that MRTU be implemented on schedule.

However, if the seller's choice contracts issue cannot be resolved, there are at least three alternatives to LMP that can be considered. The first is the TAPAS proposal put forward by the ISO. The second is the TAPAS proposal with the addition of constrained-down payments. The third is a continuation of the current market design, supported by improved operations software that would reflect the full network model and perhaps by surcharges to both load and generation on real-time transactions. Under any of these options, it is advisable that the ISO pursue an expansion of RMR contracts, or equivalent direct arrangements between LSEs and generation. Additional incentives to submit feasible forward schedules and avoid participation in the ISO's real-time market may also be necessary. The presence of these arrangements will help to minimize the need for redispatch generation to address the intra-zonal congestion problems that would be a potential concern under any of these zonal schemes.

It is important to emphasize that zonal market designs are far more common than LMP designs internationally. Zonal designs exist in the three markets where consumers have achieved the greatest benefits from wholesale electricity market re-structuring—the United Kingdom, Australia, and the Nordic countries. Because of geography, the legacy of the former state-owned monopoly regime, and a regulatory framework that encourages transmission expansion (particularly in the

United Kingdom), these markets have met the criteria of having sufficient transmission capacity within each congestion zone to make all generation units in that zone approximately equally effective at meeting loads in that zone a large fraction of the hours of the year. These markets provide strong empirical evidence that any of the alternative market designs described above can provide California consumers with significant benefits without having to incur the substantial costs of implementing a LMP market, so long as California policymakers recognize the need for procurement policies and transmission expansion policies that support these market designs, and the public believes that the construction of necessary transmission capacity is acceptable. The markets in these countries had the benefit of starting with what many observers would argue was excess transmission capacity, something that is clearly not the case in any US wholesale markets.

Between these options one must consider at least two sets of trade-offs. The TAPAS proposal creates some savings to LSEs by ending the practice of transferring constrained-down payments to generators in constrained-off areas. These savings may come at the cost of increased inefficiency in the dispatch of generation units stemming from the incentive problems created by not paying CDPs. The relative merits of paying CDPs depend upon the extent to which the constrained down areas will be subject to local market power. The continuation of the current market design holds the potential attraction of deferring investments in new hardware and software systems, both on the part of the ISO and on the part of market participants. However, to make the current system operate more reliably, it would be desirable to make some investments in new systems so that ISO operators have the tools to manage intra-zonal congestion in a fashion that is more consistent with the real physical constraints of the network. To the extent that the hardware and software systems upgrades deemed necessary for reliable operations comprise a large share of the MRTU transition costs, the savings from a continuation of the current market become minimal.

We have the following ranking of the three alternatives. Our first choice is to continue with the current market design, adding more RMR units and the pre-dispatch process described above. To the extent the ISO operators believe they need greater real-time locational pricing granularity, the imbalance pricing mechanism described above could be implemented. Our preference for the existing market design over either TAPAS proposal is based on performance of the California during first two years of operation when there was significantly more RMR capacity available to the ISO operators and because of our concerns about the risk of unintended adverse consequences associated with implementing a new market design. As noted earlier, if the ISO decides to move forward with TAPAS we favor not paying CDPs, because the past three years have convinced us that in virtually all generation pockets there are significant local market power problems, so we believe the efficiency benefits of paying CDPs are likely to be swamped by the transfers from consumers to producers associated with paying CDPs.