Transitioning the California Market from a Zonal to a Nodal Framework: An Operational Perspective

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***Abstract*— The California ISO is in the process of migrating from a decentralized and zonal based market system to a centralized and nodal based market system. This is an effort motivated by the Standard Market Design proposed by the U.S. Federal Energy Regulatory Commission and by the operational problems encountered by the California ISO over the past five years using a zonal-based model. This paper explains why the California ISO has decided to move from the zonal market system to a nodal market system from an operational perspective.**

***Index Terms*— Electricity Market, LMP, Nodal Pricing, Power System Economics, Transmission Congestion, Zonal Pricing.**

I. Introduction

THE California Independent System Operator (ISO) assumed operational control of California's electricity transmission grid on March 31, 1998. The ISO is charged with maintaining reliability and providing equal access to 25,526 circuit miles of transmission lines to the market, while the transmission systems are still owned and maintained by individual utilities.

Since its establishment, the ISO has been operating a decentralized and zonal-based market system that provides transmission rights with scheduling priority. This market system worked adequately until the year 2000 when multiple factors caused the California energy crisis. The decentralized and zonal market design was perceived as one of the factors that contributed to the energy crisis. Shortly after the energy crisis was brought under control, the FERC issued a series of orders to direct the ISO to overhaul its current market design. In response to the FERC orders, the ISO launched a major market design initiative to drastically change the existing California electricity market structure [1]. In this new market design, the ISO will operate an integrated energy, ancillary service and transmission market in day-ahead, hour-ahead and real-time where financial transmission rights will be offered to hedge the cost of congestion. The integrated market will be conducted by a Security Constrained Unit Commitment (SCUC) program using a full nodal network model. The SCUC application will have the following features:

-- Perform simultaneous energy and A/S optimization subject to resource, network and inter-temporal constraints.

-- Minimize the total energy and A/S production (or bid) cost over a multi-day time horizon considering startup and shutdown cost, minimum load cost, energy bids, and AS bids.

-- Produce Locational Marginal Prices (LMPs) for each network node, load aggregation point, and trading hub.

-- Produce Ancillary Services Marginal Prices (ASMPs) for each AS provider and shadow prices on inter-ties to settle ancillary services.

Some stakeholders have questioned the new integrated market design. In fact, the debate between the zonal and the nodal approach can be traced back to the time before the CAISO was established. The parties that support the zonal approach believe that the zonal model balances equity concerns with efficiency goals, does not subject the Market Participants (MPs) to unnecessary complexity, facilitates the operation of the commercial market and it is far more transparent to grid users than the nodal model. Furthermore, they believe that the nodal model unnecessarily entangles the transmission service market and the generation market instead of unbundling them in order to facilitate market players' desire for flexibility, innovation and development of niche products. The parties that support the nodal approach claim that the nodal model is expected to promote efficient trading and reflect the opportunity costs of using the transmission paths. It can further facilitate the efficient use of the transmission system, the development of competitive power markets and send signals that are likely to encourage efficient location of new generation resources. It can also create incentives for transmission investment and promote greater efficiency than the prices currently being charged.

This paper focuses on the operational aspects of this debate only. It makes a compelling case about the operational problems the zonal model creates and explains the operational benefits of adopting an LMP, or nodal based market design. The paper is organized as follows. Section II describes briefly the original California market design that is still currently in use. Section III describes the problems associated with the zonal based congestion management. Section IV describes the problems associated with the market separation rule and the

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physical scheduling priority of Firm Transmission Rights (FTRs) currently offered in the market. Section V describes how the new market design addresses these problems. Section VI concludes the paper.

II. A Brief Review of the Existing Zonal California Electricity Market Design

The current market functions of the ISO include the following:

- The Day-Ahead (DA) Markets manage transmission congestion and procure ancillary services.
- The Hour-Ahead (HA) Markets manage transmission congestion and procure ancillary services.
- The Real-Time energy market maintains the power balance of the system.

In this market system, only a small fraction (less than 10 percent) [2] of the total wholesale energy is procured by the ISO in the real-time to balance the system. The ISO only uses the DA and the HA market to allocate transmission usage, and maintain operating reserves. In the forward markets, balancing the supply with demand is the responsibility of the Scheduling Coordinators (SCs) [3-4]. All market participants must participate in the California ISO's markets through the SCs. In real-time, the ISO balances the supply and demand by dispatching generation resources according to their real-time energy bids by merit order.

Congestion management is a critical function of the ISO, which ensures that the transmission system is operated within its prescribed limits. The power transfer capability in California may become constrained on a variety of branches and transmission paths due to a variety of reasons. However, in order to reduce complexity and facilitate trade the California transmission network is represented by a zonal model, in which only the transmission limits on the inter-zonal paths (i.e., the paths between the zones) are enforced by the ISO. This decision was based on the assumption that congestion on the transmission branches or paths within a zone is infrequent and insignificant. The definition of insignificant is based on the cost of relieving the intra-zonal congestion over a year. If an intra-zonal path becomes frequently and significantly congested, new zones should be created.

In the forward markets, congested inter-zonal paths are used by the SCs who value them most. The willingness to pay is expressed by the "adjustment bids" submitted by the SC; the imputed value placed on the transmission path by an SC is the difference between the adjustment bids at the sink and the source. In other words, such difference in adjustment bids indicate the congestion price that the SC is willing to pay to use the transmission path. The schedules that are not willing to pay for the clearing price are curtailed. All SCs see the same price for transmitting energy across a congested inter-zonal interface, irrespective of the particular locations of their resources and loads within the zones. The ISO determines the prices for the use of congested inter-zonal interfaces using marginal costs. The ISO collects congestion charges from SCs for their use of congested inter-zonal interfaces. In the real-time, congestion is managed by conducting separate energy auctions in congested zones. Intra-zonal congestion is managed in real-time through uplifts.

Inter-zonal congestion can cause both curtailment of schedules and collection of congestion charges from schedules that use congested transmission paths. Congestion charges can be high, depending on specific conditions, relative to the cost of energy being transported. However, the occurrence of congestion and its associated charges cannot be easily predicted. Therefore, congestion charges are relatively unknown and pose a risk to energy traders. Therefore, they can hinder free trade of electricity across interfaces susceptible to congestion. To manage the risk, FTRs are offered in an annual auction. These FTRs entitle the right holders to receive physical scheduling rights and a stream of revenues from potential congestion charges across pre-established congestion zones. FTRs provide a means for transmission customers to manage the risks associated with the use of congested transmission interfaces in the forward markets.

III. Operational Problems With the Zonal Based Congestion Management

A. *Invalid Assumptions Meet Reality*

The zonal model is based on the assumption that intra-zonal congestion is infrequent and insignificant (in terms of financial consequences). This assumption turned out to be true only at the beginning of the ISO operation. As the actual dispatch pattern in the market environment evolved and new resources entered the market, intra-zonal congestion became very frequent and significant. At the same time the creation process for new zones lagged behind considerably. The new congestion pattern is caused by new generation in operation outside major load pockets mostly in Southern California coupled with new generation at the California/Arizona/Nevada border. These new, efficient and competitive resources started operation with little or no transmission upgrades to the current transmission system to aid in the transmission of new generation to load pockets.

Table 1 shows a comparison of the intra-zonal cost between year 2002 and 2003. As can be seen from Table 1, the cost of intra-zonal congestion (cost of real-time re-dispatch) increased tenfold from year 2002 to year 2003. Also, the RMR variable cost, mostly attributed to intra-zonal cost had increased 20% from 2002 to 2003 (from \$373 million in 2002 to \$449.6 million in 2003). Therefore, the major assumption of infrequent and insignificant intra-zonal congestion for the validity of the zonal model turned out to be incorrect in the long-term.

Table 1
Congestion Cost Comparison in 2002 and 2003

	2002	*2003*
Inter-Zonal	\$34,639,084	\$25,684,132
Intra-Zonal	\$4,327,625	\$46,536,772

B. Infeasible Forward Market Schedules

The current market system at the ISO accepts all schedules that are submitted, even if they violate current operating procedures across the grid in the forward market. As a result, there is an increase in real time re-dispatches that in turn, increase the probability of a path violation and additional costs to the consumer. Currently the ISO uses RMR units to resolve some of the congestion in real time and this escalated use of these units was not part of the original intent of RMR. Specifically, inter-zonal congestion is mitigated in the forward market (i.e., the DA and the HA markets) by considering inter-zonal constraints only and ignoring intra-zonal congestion in the forward market clearing process. The resources (i.e., generators, interchange, and load) in the same region are considered having the same effectiveness in mitigating an inter-zonal constraint. The resources within the zone that are used to mitigate an inter-zonal constraint are selected based on their energy adjustment bids. Consequently, a resource that is chosen to mitigate an inter-zonal constraint in the forward market may cause or worsen an intra-zonal congestion in real-time. The following example (example 1) illustrates the major flaws of the inter-zonal congestion management due to the fact that intra-zonal congestion is overlooked in the forward market. A simple 3-node DC network, as shown in Figure 1, is used in this example.

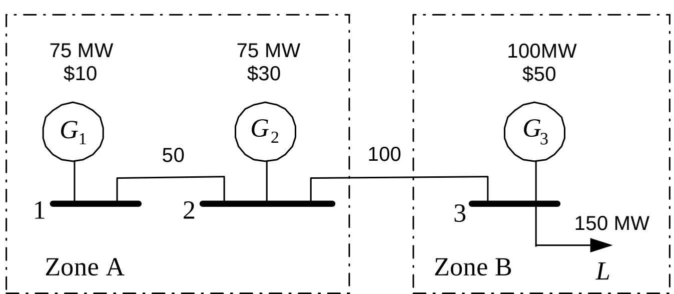

Figure 1 A 3-node 2-zone DC network

- The network has 2 transmission constraints. The inter-zonal path from Node 2 to Node 3 is rated at 100 MW in both directions. The intra-zonal path from Node 1 to Node 2 is rated at 50 MW in both directions.
- It is assumed that generators G_1 and G_2 are located in Zone A and each has 75 MW of preferred schedule. The adjustment bid prices for G_1 and G_2 are $10/MW and $30/MW, respectively. Generator G_3 is located in Zone B with an adjustment bid of $50/MWh for the 100 MW.
- The load L has a fixed schedule of 150 MW in Zone B.
- It is assumed that there is only one SC; therefore, the market separation rule is not enforced. This rule ensures that congestion management does not perform trades between SCs. Each SC's portfolio will be kept in balance, i.e., its generation will still match its load after the congestion adjustments have been completed.

Since G_1 and G_2 have initial preferred schedules of 75 MW to meet the 150 MW fixed load, the total resulting flow on Branch 2-3 is 150 MW, which exceeds the inter-zonal path limit of 50 MW. Since the zonal model is used, the intra-zonal limit of branch 1-2 is ignored. To relieve the congestion on Branch 2-3, the final energy schedules for G_1, G_2 and G_3 are 75 MW, 25 MW and 50 MW, respectively.

However, such final energy schedules are practically infeasible because the 75 MW output of G_1 would overload the intra-zonal path from Node 1 to Node 2, causing a congestion problem in real-time.

C. Inefficient Intra-Zonal Congestion

Under the zonal model, intra-zonal congestion is mitigated only in real-time by adjusting the most effective resources with respect to intra-zonal congestion. However, the most effective resources for mitigating intra-zonal congestion may not be the most economic resources available for dispatch in the merit order of the real-time energy bids. The operator has to dispatch such resources out of sequence of the merit order of the energy bids. Such dispatch is referred to as "Out Of Sequence" dispatch, i.e., the OOS dispatch.

The OOS dispatch is by and large a manual process although the effectiveness of generators for mitigating any foreseeable intra-zonal congestion is predefined in the operating procedures. Nevertheless, the OOS dispatch becomes difficult when several intra-zonal constraints need to be mitigated and the most effective generator for mitigating one intra-zonal constraint may worsen another intra-zonal constraint. Essentially, the operator is placed in a time-critical and stressed situation to come up with an Optimal Power Flow (OPF)-like solution based on his/her experience without the aid of the sophisticated optimization computer tools that are usually needed in order to determine an optimal solution. The following example (example 2) illustrates how the current protocol can lead to sub-optimal results due to the inefficiency of the intra-zonal congestion management process. Let us continue with the result of Example 1. Assume that the real-time bids for all the generators remain the same. Since the 75 MW output of G_1 would overload the intra-zonal path from Node 1 to Node 2, G_1 is reduced to 50 MW. To meet the 150 MW of load, either G_2 or G_3 has to increase by 25 MW. The optimal energy schedules should be 50 MW for all three generators. However, the operator may choose to increase $G3$ to 75 MW instead of increasing G_2 to 50 MW because of the lack of a formal intra-zonal congestion management process.

D. The DEC Game

The key flaw that exposed the weaknesses of the zonal model is the "DEC" game. In this game, a resource in a constrained generation pocket submits a relatively high bid in the forward market and a low bid in the real-time. In the forward market, the resource is paid a relatively high price based on its high bid; in the real-time, the resource is dispatched out of sequence to reduce its output due to intra-zonal congestion and charged as bid based on the low bid. By getting paid high price for a forward schedule and dispatched down, i.e., DEC'ed, out of sequence in real-time, the resource pockets the difference without generating much energy. The "DEC" game became part of a complicated strategic bidding behavior by many SCs during the California energy crisis.

From an economic perspective, the "DEC game" revealed that the zonal pricing system is vulnerable to gaming because (1) intra-zonal congestion was not addressed in the DA market, and thus (2) those SC who caused congestion could profit from being paid for re-dispatch to alleviate it. From an engineering perspective, it is (1) that is instructive. Markets cannot allocate resources efficiently when some scarce resources are not recognized, and experience has shown vividly that power markets are especially vulnerable to gaming that exploits such deficiencies. Now that power systems rely on markets, an important engineering task is to identify explicitly the scarce resources. This is the first step in designing mechanisms to allocate these resources efficiently. The mechanism adopted might be a market, but depending on circumstances, it might be some other rationing scheme, such as assignment (or sale) of priorities.

The following example (example 3) illustrates the "DEC" game based on the result of Example 1. Assume that the real-time bid for G_1 is changed to –\$250/MW. The real-time energy bids for the other two generators remain the same. Since the 75 MW output of G_1 would overload the intra-zonal path from Node 1 to Node 2, G_1 is reduced to 50 MW. Since G1 is dispatched "out of sequence," G1 is charged –\$250/MW, i.e. G1 is paid \$250/MW for each of the 25MW schedule reduction. The net profit to G_1 for scheduling 25 MW more than it can deliver is:

25 MW * (Forward Market Price + \$250/MW)

IV. Problem with Physical FTR and Lack of ISO Forward Energy Market

The zonal model is based on the assumption that intra-zonal congestion is infrequent and insignificant (in terms of financial consequences). Once it is identified that a certain intra-zonal constraint becomes congested frequently with substantial financial consequences, new zones must be defined. However, the precise definition of "infrequent" and "insignificant" becomes difficult to quantify and its applicability in a stakeholder process with diverse interests and for a meshed physical network difficult to manage. Moreover, the fact that the ISO does not operate (after the energy crisis) a forward energy market fundamentally limits the way new zones can be created.

Since the ISO does not operate a forward energy market and only performs the congestion management for the forward market, the participants are required to submit balanced supply and demand schedules through the SCs. The ISO will keep each SC's energy portfolio balanced in the congestion management process by introducing a "market separation constraint" for each SC in the congestion management optimization. The FTRs currently auctioned over inter-zonal paths give the FTR holders special physical scheduling rights which eliminate FTR holders' incentive for providing economic adjustment bids. The physical scheduling priority for FTRs and the market separation protocol together seriously limit the feasibility of creating new zones that introduce loops in the network model. The following example (example 4) illustrates the problem. Specifically, this example illustrates the effect of enforcing the "market separation rule" and the physical scheduling priority for FTR in the congestion management under a looped network model. A simple 3-node DC network, as shown in Figure 2, is used. Each node represents a zone.

- The network has 3 branches with identical impedance. Branch 1-2 and branch 2-3 are rated at 50 MW in both directions. Branch 1-3 is rated at 100 MW in both directions.
- It is assumed that there are two Scheduling Coordinators, SC1 an SC2, whose initial balanced portfolios are as follows:

SC1: G_1 has 50 MW of preferred DA schedule balanced with 50 MW of load at Node 3, without adjustment bids. G_3 has 0 MW preferred DA schedule and an adjustment bid of \$50/MWh for 100 MW. The schedule is not associated with any FTR.

SC2: G_2 has 100 MW of preferred DA schedule balanced with 100 MW load at Node 3. The schedule is associated with 100 MW of FTR from Node 2 to Node 3.

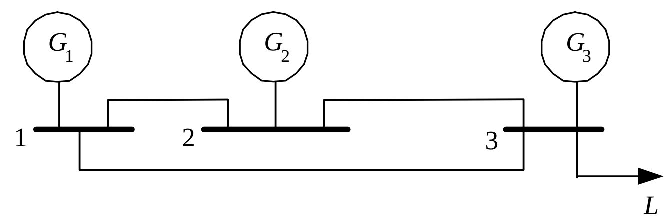

Figure 2. A 3-node DC network

Since the three branches have identical impedance, to supply each MW of power from G_1 to L, 2/3 MW goes through Branch 1–3; and 1/3 MW goes through Branches 1–2 and 2–3. To supply each MW of power from G_2 to L, 2/3 MW goes through Branch 2–3; and 1/3 MW goes through Branches 2–1 and 1–3. The flows on the three branches based on the preferred schedules are as follows:

Branch 1-3 flow = 2/3 G_1 + 1/3 G_2 = 75 MW

Branch 1-2 flow = 1/3 G_1 - 1/3 G_2 = 0 MW

Branch 2-3 flow = 1/3 G_1 + 2/3 G_2 = 75 MW *>50 MW limit*

As can be seen, the Branch 2-3 flow exceeds the branch limit of 50 MW. To relieve the congestion on Branch 2-3, the following happens:

- Since SC1's schedule does not have FTR scheduling priority, the output of G_1 is curtailed first to 0 MW. The output of G3 is increased to 50 MW to balance the 50 MW of load in SC1's portfolio.
- Then the output of G_2 is curtailed to 75 MW in order to relieve the congestion. Now since the SC2's schedule must be kept balanced, when G_2 is curtailed by 25 MW, the load at Node 3 is also curtailed by 25 MW.

Hence, the final DA energy schedules for G_1, G_2 and G_3 are 0 MW, 75 MW and 50 MW, respectively. The flows on the three branches are as follows based on the final schedules:

Branch 1-3 flow = 2/3 G_1 + 1/3 G_2 = 25 MW

Branch 1-2 flow = 1/3 G_1 - 1/3 G_2 = –25 MW

Branch 2-3 flow = 1/3 G_1 + 2/3 G_2 = *50 MW limit*

There are at least two problems with this congestion management outcome:

- First, the load is curtailed by 25 MW in the DA market unnecessarily because of the market separation rule associated with exercising the FTR physical scheduling priority. If the DA scheduled load represents load forecast, the curtailed 25 MW of load, if not met in HA, will rely on the ISO to find supply in real-time, which increases the risk of energy shortage and high prices in real-time. Even if the 25 MW load is scheduled subsequently in the HA, without any network change, the 25 MW of load will have to be supplied by G_3 (a less economic resource) instead of G_1 because the DA schedule of G_2 has higher priority in using Branch 2-3. Moreover, since G_3 is in SC1's portfolio and the 25 MW of load is in SC2's portfolio, an inter-SC trade has to be arranged, increasing the complexity and transaction cost. However, the inter-SC trade mechanism is cumbersome and it is rarely used by the SCs.
- Second, the resulting outcome is inefficient; it does not maximize the use of the transmission system. Without the market separation rule and the physical FTR scheduling priority, the final energy schedules for G_1, G_2 and G_3 would be 75 MW, 37.5 MW and 37.5 MW, respectively. In this case, the flows on the three branches would be as follows:

Branch 1-3 flow = 2/3 G_1 + 1/3 G_2 = 62.5 MW

Branch 1-2 flow = 1/3 G_1 - 1/3 G_2 = 12.5 MW

Branch 2-3 flow = 1/3 G_1 + 2/3 G_2 = *50 MW limit*

In this case, without market separation and physical FTR, the transmission system would allow more power to be delivered from G_1 and G_2 to L.

One may argue that the inefficient outcome of the market separation rule could be reduced or eliminated if additional market iterations between the SCs and the ISO were allowed, during which the SCs could submit revised schedules. Further, the SC could line up additional generation within its own portfolio to serve the curtailed load in the HA. The debate along this track cannot lead to any consensus because various assumptions can be made on the availability and the location of generation in the SC's portfolio. What is certain is that the market separation rule together with the physical scheduling priority prevents the most effective unit from relieving the congestion and the most efficient unit from providing the energy in a looped network.

Although the problem shown in this example was not prevalent in the current ISO's radial network, this problem has become an obstacle in creating new zones that could lead to a looped zonal network.

V. How Existing Zonal Problems Are Addressed by the New California Market Design

A. Full Network Model

The new proposed California Market Design will use a full network model. The full network model will model all the nodes and network constraints in and around the ISO control area. Therefore the problems inherently associated with the zonal network model, as described in Section III, are eliminated. Specifically, all scarce transmission resources will be enforced in the forward market and the intra-zonal congestion will be eliminated. Furthermore, all forward market schedules will be feasible and the "DEC" game will be eliminated.

B. ISO-Operated Forward Energy Market

The ISO will operate a central energy pool where trades for forward energy will be conducted in an optimal manner [5]. In each forward market, an SC can buy or sell energy optimally with other SCs through the ISO markets. In general, SCs do not have to submit balanced energy schedules, and even if they elect to submit balanced preferred schedules, there is no guarantee that their final schedules will remain balanced. Fixed bilateral trades for energy at the same location (i.e., node or hub) will also be supported; both trading SCs must submit the same amount of energy schedules. Such bilateral trade is purely financial and will not affect the optimization because they produce zero net injection at the same location.

Since the ISO will operate a central energy pool to balance supply and demand, there is no need for the SCs to submit balanced portfolio. The elimination of the market separation rule eliminates the congestion management inefficiency associated with this protocol as described in Section IV.

C. Simultaneous Optimization and Congestion Management

The new forward market will use a SCUC application to optimize ancillary service provision and energy output for each participating resource. If necessary, the SCUC application will commit additional resources besides the resources that are already committed previously or self-committed as indicated by the energy schedules in order to meet the load and the ancillary service requirements. Based on the results of the commitment and dispatch decisions, the SCUC produces for each hour the Locational Marginal Prices (LMPs) for energy settlement and the Ancillary Service Marginal Prices (ASMPs) for paying ancillary service providers.

In addition to optimal procuring ancillary services and energy, the SCUC application will optimize the use of the transmission network at the same time. The use of the congested transmission network is first allocated to those SCs which value the transmission network most according to their energy bids. Ancillary service bids compete explicitly for the use of transmission network only on inter-ties; the further, regional procurement of ancillary services will ensure that sufficient reserves are available to meet local reliability needs inside the control area.

D. Financial Congestion Revenue Rights

The Firm Transmission Rights are replaced by the Congestion Revenue Rights (CRRs). There are two types of CRRs:

- CRR Options and
- CRR Obligations.

CRR Option holders receive positive congestion revenue according to their entitlements. CRR Obligation holders receive positive or negative congestion revenue according to their entitlements.

CRR rights are defined by sinks and sources, i.e., point-to-point CRRs. Both CRR options and CRR obligations are purely financial rights; they give their holders no physical scheduling priority on either the demand side or the supply side under congestion management.

By eliminating the physical scheduling priority associated with the FTRs, the CRRs do not affect congestion management. Therefore the problems associated with FTR physical scheduling priority, as described in Section IV, are eliminated.

VI. Concluding Remarks

The California ISO is in the process of migrating from the decentralized zonal market system to a centralized nodal market system. This paper has presented the advantages of using a nodal model in the new proposed ISO market design from an operational point of view. The specific problems with the zonal model, which is currently in use, are summarized as follows:

- The zonal model is based on the assumption that intra-zonal congestion is infrequent and insignificant, which has been proven untrue.
- The zonal congestion management creates infeasible forward market schedules because it ignores intra-zonal congestion that needs to be dealt with in real-time. As a result, the current market design does not perform a complete reliability evaluation of all scheduled resources in the forward market.
- The real-time intra-zonal congestion management that is based on "out of sequence" dispatch not only is inefficient and results in non-optimal solutions, it also unduly places the burden of simultaneously resolving multiple intra-zonal constraints on the real-time operator.
- The zonal-based forward market provides the opportunity for exercising the "DEC" game, with onerous financial consequences for the consumers.
- Markets cannot allocate resources efficiently when scarce resources are not recognized, and experience has shown vividly that power markets using the zonal model are especially vulnerable to gaming that exploits such deficiencies. The prevalence of these strategies and their severe effects on system reliability, have shown that power systems cannot rely on individual market participants to ensure overall physical feasibility. Indeed, the clear conclusion is that financial incentives and gaming opportunities can easily thwart the engineers' attempts to maintain reliable operations.
- The market separation rule and the scheduling priority for the FTRs lead to inefficient market outcomes and furthermore, prevent the ISO from creating new zones, which is another important assumption that the zonal model relies on.

The new California market design based on the centralized optimization using a full nodal network model is expected to improve the efficiency of the market as well as the reliability of the grid.

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