A Comparative Analysis of Congestion Management Schemes under a Unified Framework

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***Abstract*: The restructuring of the electricity industry has spawned the introduction of new independent grid operators or IGOs, typically called transmission system operators (TSOs), independent system operator (ISOs) or regional transmission organizations (RTOs), in various parts of the world. An important task of an IGO is congestion management (CM) and pricing. This activity has significant economic implications on every market participant in the IGO's region. The paper briefly reviews the congestion management schemes and the associated pricing mechanism used by the IGO's in five representative schemes. These were selected to illustrate the various CM approaches in use: England and Wales, Norway, Sweden, PJM and California. We develop a unified framework for the mathematical representation of the market dispatch and redispatch problems that the IGO must solve in CM in these various jurisdictions. We use this unified framework to develop meaningful metrics to compare the various CM approaches so as to assess their efficiency and the effectiveness of the market signals provided to the market participants. We compare, using a small test system, side by side, the performance of these schemes.**

***Keywords*: congestion management and pricing, optimum power flow, market dispatch, congestion redispatch, economic signals**

I. INTRODUCTION

The electricity industry is well along the road to become completely re-regulated in the presence of significant market competition. With the issuance of the FERC Order No. 2000, a major policy step has been taken in the US encouraging the development of efficient competitive markets [1]. During the debates that preceded Order No. 2000 and in the Order itself, the problem of transmission congestion management (CM) and pricing has been singled out as one of critical importance to the smooth functioning of competitive markets. In this paper, we use the term CM to include both the congestion relief actions and the associated pricing mechanisms. CM is the responsibility of the entity that operates and controls the interconnected transmission system. The various organizations that coordinate and control the usage of the transmission system or grid vary in several respects in the various implementations that have emerged as a result of electricity restructuring. Typically, the various existing organizations have grid control but no grid ownership. A common need, however, for the restructured industry is that of operating the grid independently of the various market players [1], [2]. So as to avoid confusion we use the term independent grid operator or IGO to refer to the generic system operator organization and include under it the independent system operator (ISO), ransmission system operators (TSO) and regional transmission organizations (RTO) structures

Congestion occurs whenever the system state of the grid is characterized by one or more violations of the physical, operational, or policy constraints under which the grid operates in the normal state or under any one of the contingency cases in a set of specified contingencies. Congestion is associated with a specified point in time. As such, the problem of congestion may arise during the day-ahead dispatch, in the day-ahead market, the hour-ahead dispatch, in the hour-ahead market or the real-time operations of the system, in the balancing market. In this paper we address the CM problem for the day-ahead and hour-ahead markets. Similar concepts to those used in these longer horizon markets may be extended for the real-time balancing markets.

In the old vertically integrated industry, the generation, transmission and distribution were, typically, owned, controlled and operated by a single entity, the vertically integrated utility (VIU). The central operator would dispatch the system having full knowledge of operational costs and constraints of the system. In this structure, the use of the grid by other entities was relatively limited and so congestion was not a term that was used. Typically, the problem was formulated as the optimization of some objective function subject to satisfying the various constraints considered. The optimal power flow or OPF tool was developed for its solution. The security constrained OPF was used to explicitly consider contingency conditions. The OPF optimum resulted in what economists call a *first-best* solution by maximizing the social surplus or minimizing the total production costs. The advent of a *common carrier* role for transmission, brought about by open access, results in very different uses of the transmission system than those for which it was originally planned and designed. The IGO is responsible for determining the necessary actions to ensure that no violations of the various grid constraints occur. It is this comprehensive set of actions or procedures that we refer to as CM. The actions in CM are principally the redispatch of the generation

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and load levels so as to establish a system state without constraint violations. The role of the pricing of congestion plays a major role in attaining such a state. In addition, the IGO may partition the grid into zones as a key step in removing congestion. A zone is defined as a subset of buses of a grid. Zones are interconnected by tie lines, whose end buses are in the different zones. Typically, there is no congestion or easily relievable congestion within the zones and so when zone partitioning is used the goal is to remove inter-zonal interface congestion.

The operation of a competitive electricity market takes place, typically, in two distinct stages. In the first stage, which we term *market dispatch* (MD), the participants of the markets submit forward market bids and offers as the basis for the determination of the generation and demand profiles for the market horizon. Scheduling coordinators (SCs), who are the bilateral contract administrators including the PX use their portfolios of resources and loads to prepare balanced supply-demand *preferred* schedules that are submitted to the IGO [4]. During this first stage, the IGO may partition the grid and the corresponding markets into zones. This partition may be performed for every market period, based on the forecasted operational and operator judgment.

When the market dispatch fails to provide a feasible operating state, i.e., a state with no constraint violations, the IGO invokes the second stage action *congestion redispatch* (CR). In this stage, the IGO aims to move from the infeasible to a feasible state and do so, usually, at *least cost*. The adjustments involved in this action may use market forces to greater or lesser extent. Sometimes, the CR, is also referred to as *out-of-merit* dispatch, due to the fact that the participants will not be dispatched solely based on the values of their adjustment bids and offers since the accommodation of transmission constraints is implicitly taken into account, or as buy-back, referring to the action of buying back power from the generators for congestion relief. The IGO may use zonal partitioning in this second stage just as in the MD [4].

Previous work on CM mechanisms aimed to define the rules for the emerging competitive electricity markets [3,4]. Two IGOs – the PJM ISO and the California ISO – have received considerable attention [4,5,6,7]. One important issue is the applicability of the OPF to competitive markets in light of problem characteristics such as a flat solution surface in the optimum neighborhood and the level of discretion of the central decision maker [10].

This paper looks at the different CM mechanisms using a common language and the same set of evaluation metrics. The paper presents a comparative assessment of the conceptual aspects of the schemes for CM used by the IGOs in five diverse jurisdictions: England and Wales, Norway, Sweden, PJM and California. These systems were selected to provide a representative sample of the various implemented IGO structures. We have developed a unified framework for the representation of the MD and CR problems. We use this framework to describe the five systems' CM schemes and we compare their performance on a test system. The numerical results for the test system are illustrative of the impacts produced by the different rules used in the various CM schemes and help in getting good insight into the economic consequences of those rules and the performance of the CM schemes.

The paper has four additional sections. Section II presents an overview of the CM schemes used by the different IGO's. Section III constructs the analytical framework for unifying the formulation of the CM problem for the various approaches. In section IV we present the numerical results used in the comparison of the five CM approaches. We discuss the conclusions in section V.

II. Description of the Five CM Schemes

We start our comparative study with a discussion of the five selected CM schemes of five IGOs. These selected schemes are representative of the range of CM schemes used around the world.

The ***England and Wales*** (E&W) market is an extreme case because only one zone exists and thus no constrained interfaces are considered for the MD. In this stage the zonal price is the so-called system marginal price (SMP) and is determined from the generators' offers [8]. The load is, in the original formulation, considered to be fixed. In the CR stage all constraints of the system are considered and every bus becomes a zone. Generators are commanded the adjustments by the IGO and they receive compensation for undertaking those actions. A plant that was scheduled to run in the unconstrained dispatch but was precluded, either totally or partially, from doing so due to system constraints is said to be "constrained-off" and is paid its lost profits. A plant that was not included in the unconstrained dispatch but is ordered to run in the constrained dispatch is said to be "constrained-on" and is paid its offer price. The loads do not participate in the CR. Since a unique zonal price results from the MD, all the participants are paid and charged for their production and consumption a uniform price. Consequently, there are no congestion charges in the MD. However, generators may receive compensation as a result of the CR. The resultant charges incurred by the IGO are passed on to the consumers as a part of the so-called uplift. The uplift is the component of the final price that is not directly related with the costs of energy production. It includes the costs for losses and ancillary services.

In the ***Pennsylvania-Jersey-Maryland*** (PJM), the IGO conducts a centralized MD for each time period in the scheduling horizon. This price-based dispatch is determined from the offers of the forward market participants. The conceptual basis of the dispatch is an optimization framework in which the nodal prices can be determined as dual variables corresponding to specific constraints. In actual implementation, the nodal price are computed using the state estimator data[12]. Each participant is paid and charged for its production and consumption according to its nodal price and, since there may be nodal price differences between any bus pair, these nodal price differences become the transmission usage charges that are applied to flows over the grid. We may view this market as the ultimate case of zonal partitioning, where each node is a zone with its own zonal price and every line is an inter-zonal interface. The *CR* stage is consequently not needed since all the constraints are implicitly handled in the MD stage.

In ***Norway*** (NOR), the IGO uses, for each hour of the scheduling horizon**,** the forecasted operational state of the grid to determine whether a partitioning of the grid into two or more zones is required [9]. The MD stage for each period determines the grid-wide or the zonal clearing prices, as the case may be. The different zonal markets are operated taking into account the export/import limits for each zone through the inter-zonal interfaces. During the CR stage, if needed, the participants are adjusted according to their adjustment bids and offers. In this second stage all the buses are considered to be in different zones.

The generators and the loads are paid and charged for production and consumption according to the zonal prices defined during the MD stage. All flows from one zone to another are through the interfaces and are charged the zonal price differences. Adjustment payments and charges may result from CR and these are done at uniform price. Upwards adjustment is paid the most expensive bid/offer price and downwards adjustment is charged the cheapest bid/offer price.

In ***Sweden*** (SWE), the IGO uses the same set of rules as the Norway IGO, with one substantial difference. In SWE, the IGO considers only one zone in the MD just as in the E&W market. Actually both Norway and Sweden along with Finland, and Denmark belong to the so-called NordPool that covers the wide-area market and the interconnected grids of all those countries.

Congestion management of the ***California ISO*** (CAL) uses the grid partitioning into a number of predefined zones [13]. The MD stage establishes the hourly market zonal prices for the next day markets. Theses auction-based results have no consideration of the transmission and they are the solution of the preferred schedules established by the several SCs in the bilateral markets. If the MD solution leads to congestion then its elimination is achieved using CR with zonal partitioning. This stage gives the zonal prices and also the transmission usage prices that are the dual variables associated with the interface flows. Consequently, participants are paid and charged according to zonal prices defined during the CR. Congestion charges are applied using the transmission charges in the inter-zonal interfaces.

One salient characteristic of this market is that the IGO maintains the separation between portfolios of the different SCs. Doing so, the IGO does not promote any implicit trade between them [4].

III. A Unified CM Framework

We start by giving some definitions that characterize the properties and topology of the electric system. We call the set of buses $\mathcal{B} = \{1, 2, \ldots, N\}$. Each bus i is connected through direct lines to nodes in the set $\mathcal{H}_i \subset \mathcal{B}$. Let $\mathcal{L} = \{1, 2, \ldots, L\}$ be the set of lines. A line ℓ is defined by the pair of buses i and j which it connects: $\ell = \{i, j\} \in \mathcal{L}, \quad i, j \in \mathcal{B}$. In particular $\{i, \mathcal{H}_i\}$ is the subset of lines in $\mathcal{L}$ with bus i as an end node. We consider the network to consist of a set of zones $\mathcal{Z} = \{1, 2, \ldots, K\}$. Each zone $k \in \mathcal{Z}$ is characterized by its constituent lines and buses. For zone k we define the pair $\mathcal{Z}_k = \{\mathcal{B}_k, \mathcal{L}_k\}$. Here, $\mathcal{B}_k$ is the set of buses in zone k, with $\mathcal{B} = \bigcup_{k \in Z} \mathcal{B}_k$ and $\mathcal{B}_{k_1} \bigcap \mathcal{B}_{k_2} = \phi, \ \forall k_1, k_2 \in \mathcal{Z}, k_1 \neq k_2$, and $\mathcal{L}_k = \left\{ \ell : \ell = \{i, j\},\ i \in \mathcal{B}_k,\ j \in \mathcal{H}_i \bigcap \mathcal{B}_k \right\}$**.** The zone partitioning results in the set of interfaces $\mathcal{I} = \{1, 2, \ldots, I\}$. An interface between two zones is defined by the subset of lines connecting buses in each of the K zones. For an interface to exist between two zones there must be at least one line connecting a bus in one zone to a bus in the other zone. An interface is further characterized by its active power transfer capability on its lines. We denote an interface between zones k_1 and k_2 by $\mathcal{I}_{k_1, k_2} = \{\ell_1, \ell_2, \ldots\} \in \mathcal{I}$. By definition of $\mathcal{L}_k$, $\mathcal{L}_{k_1} \bigcap \mathcal{L}_{k_2} = \phi, \ \forall k_1, k_2 \in \mathcal{Z}, k_1 \neq k_2$, and $\mathcal{I} \bigcap \mathcal{L}_k = \phi, \forall k \in \mathcal{Z}$**.** Furthermore, $\mathcal{L} = \mathcal{I} \bigcup \bigcup_{k \in \mathcal{Z}} \mathcal{L}_k$**.**

A line $\tilde{\ell} \in \mathcal{I}_{k_1, k_2}$ is characterized by end buses i and j, with $i \in \mathcal{Z}_{k_1}$ and $j \in \mathcal{Z}_{k_2}$. The real power flow F_{ij} on line $\tilde{\ell}$ is defined to be non-negative and so is the flow F_{ji} from j to i. Thus F_{ij} is positive if the flow is from i to j; else, F_{ij}=0 and the flow F_{ji} is non-negative from j to i. The power flows associated with the line must satisfy $0 \leq F_{ij} \leq F_{ij}^{\max}$ and $0 \leq F_{ji} \leq F_{ji}^{\max}$.

Let us next examine the set of generators $\mathcal{G} = \{1, 2, \ldots, N_G\}$. We associate with each generator $g \in \mathcal{G}$ a triplet $\mathcal{C}_g(g)$ consisting of the connection bus b, the power generation range $[P_g^{\min}, P_g^{\max}]$ and the offer function $\rho_g(\cdot)$ expressed in marginal terms [14]. Thus, $\mathcal{C}_g(g) = \left\{ b, \left[P_g^{\min}, P_g^{\max} \right], \rho_g(\cdot) \right\}$ with $b \in \mathcal{B}$. For each zone we define the subset of generators $\mathcal{G}_k = \{g : b \ \ of \ \ \mathcal{C}_g(g) \in \mathcal{B}_k\}$. Note that $\mathcal{G} = \bigcup_{k \in \mathrm{Z}} \mathcal{G}_k$ with $\mathcal{G}_{k_1} \bigcap \mathcal{G}_{k_2} = \phi, \forall k_1, k_2 \in \mathcal{Z}, k_1 \neq k_2$. We denote by $\underline{\boldsymbol{P}}$ the vector of active power generation of $\mathcal{G}$.

We denote by $\mathcal{D} = \{1, 2, \ldots, N_D\}$ the set of loads in the system. With each load d we associate a triplet $\mathcal{C}_d(d)$ consisting of the connection bus b, the power consumption range $[D_d^{\min}, D_d^{\max}]$, and the bid function $\upsilon_d(\cdot)$ expressed in marginal terms. Thus $\mathcal{C}_d(d) = \left\{ b, \left[D_d^{\min}, D_d^{\max} \right], \upsilon_d(\cdot) \right\}$ with $b \in \mathcal{B}$. For each zone we define the subset of loads $\mathcal{D}_k = \{d : b \ \ of \ \ \mathcal{C}_d(d) \in \mathcal{B}_k\}$. Note that $\mathcal{D} = \bigcup_{k \in \mathcal{Z}} \mathcal{D}_k$ and $\mathcal{D}_{k_1} \bigcap \mathcal{D}_{k_2} = \phi, \ \forall k_1, k_2 \in \mathcal{Z}, \ k_1 \neq k_2$. We denote by $\underline{\boldsymbol{D}}$ the vector of active power consumption of $\mathcal{D}$.

We consider the set $\mathcal{S} = \{1, 2, \ldots, S\}$ SCs. This set includes the power exchange(s) and all bilateral transactions. Let $\mathcal{G}^{s}$ and $\mathcal{D}^{s}$ denote the subset of generators and loads of SC s, each SC s is characterized by $\mathcal{S}^{s} = \{\mathcal{G}^{s}, \mathcal{D}^{s}\}$. By definition each SC must hold a balanced portfolio.

The MD problem is then to:

$$\min_{\underline{P},\underline{D}} \sum_{k\in\mathcal{Z}} \sum_{\substack{g\in\mathcal{G}_k \\ d\in\mathcal{D}_k}} [C_g(P_g) - B_d(D_d)] \qquad \text{(M1)}$$

subject to:

power balance for zone *k*

$$\sum_{\substack{g\in\mathcal{G}_k \\ d\in\mathcal{D}_k}} (P_g - D_d) \; - \sum_{\substack{\{i,j\}\in\mathcal{J}_{k,k'} \\ i\in\mathcal{B}_k \\ k'\neq k}} F_{ij} + \sum_{\substack{\{i,j\}\in\mathcal{J}_{k,k'} \\ i\in\mathcal{B}_k \\ k'\neq k}} F_{ji} = 0, \forall k\in\mathcal{Z} \qquad \text{(M2)}$$

interface power flows

$$F_{ij} = f_{ij}\;(\underline{P},\underline{D}),\ \forall\{i,j\}\in\mathcal{J} \qquad \text{(M3)}$$

separation of SCs' markets

$$\sum_{g\in\mathcal{G}^{s}} P_g - \sum_{d\in\mathcal{D}^{s}} D_d = 0, \quad \forall s\in\mathcal{S} \qquad \text{(M4)}$$

interface line transfer capability

$$0 \le F_{ij} \le F_{ij}^{\max},\ 0 \le F_{ji} \le F_{ji}^{\max}\ \ \forall\{i,j\},\{j,i\}\in\mathcal{J} \qquad \text{(M5)}$$

generation limits

$$P_g^{\min} \le P_g \le P_g^{\max}, \quad \forall g\in\mathcal{G} \qquad \text{(M6)}$$

consumption limits

$$D_d^{\min} \le D_d \le D_d^{\max}, \quad \forall d\in\mathcal{D} \qquad \text{(M7)}$$

The charges $C_g(\cdot)$ of a generator *g* [the benefits $B_d(\cdot)$ of a load *d*], are $\rho_g(\cdot)$ [$\upsilon_d(\cdot)$] and are given by [14]:

$$\frac{\partial C_g(\cdot)}{dP_g} = \rho_g(\cdot) \qquad \left[\frac{\partial B_d(\cdot)}{dD_d} = \upsilon_d(\cdot)\right]$$

The objective in (M1) is to the maximization of the social surplus [14], or equivalently the minimization of the social costs, for all the zones under the various constraints (M2)-(M7) of the model[1]. We refer to (M1)-(M7) as the MD problem or (MDP).

A general mathematical description of the CR problem in the second stage of CM, is:

$$\min_{\Delta\underline{P},\Delta\underline{D}} \sum_{k\in\mathcal{Z}} \sum_{\substack{g\in\mathcal{G}_k \\ d\in\mathcal{D}_k}} [\delta_g(\Delta P_g) - \eta\cdot\varepsilon_d(\Delta D_d)] \qquad \text{(R1)}$$

subject to:

power balance for zone *k*

$$\sum_{\substack{g\in\mathcal{G}_k \\ d\in\mathcal{D}_k}} (\Delta P_g - \Delta D_d) - \sum_{\substack{\{i,j\}\in\mathcal{J}_{k,k'} \\ i\in\mathcal{B}_k \\ k\neq k'}} \Delta F_{ij} + \sum_{\substack{\{i,j\}\in\mathcal{J}_{k,k'} \\ i\in\mathcal{B}_k \\ k\neq k'}} \Delta F_{ji} = 0, \forall k\in\mathcal{Z} \qquad \text{(R2)}$$

interface power flows

$$\Delta\underline{F} = \underline{\tilde{H}}\cdot(\tilde{\Delta}\,\underline{P} - \tilde{\Delta}\,\underline{D}) \qquad \text{(R3)}$$

separation of SCs' markets

$$\sum_{g\in\mathcal{G}^{s}} \Delta P_g - \sum_{d\in\mathcal{D}^{s}} \Delta D_d = 0, \quad \forall s\in\mathcal{S} \qquad \text{(R4)}$$

interface line transfer capability

$$0 \le F_{ij} + \Delta F_{ij} \le F_{ij}^{\max}, \quad \forall\{i,j\}\in\mathcal{J} \qquad \text{(R5)}$$

$$0 \le F_{ji} + \Delta F_{ji} \le F_{ji}^{\max}, \quad \forall\{i,j\}\in\mathcal{J}$$

generation limits

$$P_g^{\min} \le P_g + \Delta P_g \le P_g^{\max}, \quad \forall g\in\mathcal{G} \qquad \text{(R6)}$$

consumption limits

$$D_d^{\min} \le D_d + \Delta D_d \le D_d^{\max}, \quad \forall d\in\mathcal{D} \qquad \text{(R7)}$$

Here a generator *g* (load *d*) may be adjusted by an amount ΔP_g (ΔP_d). We define $\Delta\underline{P}$ ($\Delta\underline{D}$) to be the vector of variations in the active power of the generators in $\mathcal{G}$ (vector of the variations in the active power consumption of loads in $\mathcal{D}$). η is a 0/1 parameter indicating whether or not loads may participate in the CR. The flows variations along the tie lines in $\mathcal{J}$ are arranged into $\Delta\underline{F}$ used in (R3). The components of $\Delta\underline{F}$ for each line *i*, *j* are given by ΔF_{ij} - ΔF_{ji}. $\underline{\tilde{H}}$ is the reduced matrix of the bus-branch power distribution factors for the intertie lines. To use this expression we need to express the augmented vector of adjustment of net active power generation at each element of $\mathcal{B}$. The term $\tilde{\Delta}\,\underline{P}$ $(\tilde{\Delta}\,\underline{D})$ is constructed from $\Delta\,\underline{P}$ $(\Delta\,\underline{D})$ by introducing zeros at those buses where there is no generation or load. We refer to (R1)-(R7) as the CR problem or (CRP).The objectives in (CRP) and (MDP) need not to be identical. For example, possible candidates in (CRP) are minimum shifts in power from the MD result or least-cost congestion relief actions. The economics associated with the change ΔP_g (ΔD_d) are expressed by $\tau_g(\sigma_d)$ with each $\tau_g \ge 0$ $(\sigma_d \ge 0)$.

The individual CM schemes for the different markets are summarized in tabular form: the entries in Tables 1 and 2 are obtained from the rules of the various schemes and represented within the unified framework. In the CAL approach we assumed that, during the unconstrained dispatch, congestion is detected and so zonal partitioning is undertaken. While actually this partitioning is part of the CR stage we consider that in the MD stage to keep consistency with unified framework. The existence of more than one SC was considered only for the CAL approach.

Table 1. MD representation in the framework

System	PJM	E&W	CAL	NOR	SWE
Zones	K=N	K=1	K=1	K<N	K=1
M1	✓	✓	✓	✓	✓
M2	✓	✓	✓	✓	✓
M3	✓		✓	✓	
M4			✓		
M5	✓		✓	✓	
M6	✓	✓	✓	✓	✓
M7	✓	✓	✓	✓	✓

Table 2. CR representation in the framework

System	E&W	CAL	NOR	SWE
Zones	K=N	K<N	K=N	K=N
Load redispatch	no	yes	yes	yes
R1	✓	✓	✓	✓
R2	✓	✓	✓	✓
R3	✓	✓	✓	✓
R4		✓		
R5	✓	✓	✓	✓
R6	✓	✓	✓	✓
R7		✓	✓	✓

The formulation here is for the operating state to be analyzed. A complete formulation requires the explicit

[1] The model does not take into account the impacts of firm transmission rights and in their presence the problem is further constrained since some of the interfaces could be reserved for the rights holders.

inclusion of the constraints associated with contingency cases, i.e., the set of specified contingencies under which the system security is analyzed. The framework is general enough to allow the inclusion of such constraints. However, in order to allow focusing on the comparative aspects, we omitted everywhere the inclusion of such constraints.

We include in the unified framework the definitions of the metrics that allow the economic evaluation of each CM scheme. These metrics provide consistency in comparing the performance of the two stages of a given scheme or across different schemes. They are the consumer surplus S^D, the producer surplus S^G, the merchandise surplus S^M, and the social surplus S^S [14]. For the (MDP), these metrics are defined by:

$$S^G(\underline{\boldsymbol{P}}) = \sum_{g\in\mathcal{G}} \left[\rho_g P_g - C_g(P_g) \right] \tag{M8}$$

$$S^D(\underline{\boldsymbol{D}}) = \sum_{d\in\mathcal{D}} \left[B_d(D_d) - \upsilon_d D_d \right] \tag{M9}$$

$$S^M(\underline{\boldsymbol{P}}, \underline{\boldsymbol{D}}) = \sum_{d\in\mathcal{D}} \upsilon_d D_d - \sum_{g\in\mathcal{G}} \rho_g P_g \tag{M10}$$

$$S^S(\underline{\boldsymbol{P}}, \underline{\boldsymbol{D}}) = S^D(\underline{\boldsymbol{D}}) + S^G(\underline{\boldsymbol{P}}) + S^M(\underline{\boldsymbol{P}}, \underline{\boldsymbol{D}}) \tag{M11}$$

where $\underline{\upsilon} = [\upsilon_1, ..., \upsilon_g, ...]$ and $\underline{\rho} = [\rho_1, ..., \rho_g, ...]$ are the vectors of the prices corresponding to the vectors of power $\underline{\boldsymbol{D}}$ and $\underline{\boldsymbol{P}}$ in the (MDP). The values of the variables at the optimum are denoted with * in the (MDP). The definition of the metrics for the (CRP) is carried out analogously. We make use of the change in cost (benefit) term $\Delta C_g (\Delta B_d)$ for each generator g (load d), where $\Delta C_g = C_g(P_g + \Delta P_g) - C_g(P_g)$ ($\Delta B_d = B_d(D_d + \Delta D_d) - B_d(D_d)$). The corresponding change in revenues (expenditures) $\Delta W_g (\Delta U_d)$ for each for each generator g (load d) are $\Delta W_g = \tau_g \Delta P_g$ ($\Delta U_d = \sigma_d \Delta D_d$). We denote the total change in costs (benefits) by $\Delta C = \sum_{g\in\mathcal{G}} \Delta C_g \left(\Delta B = \sum_{d\in\mathcal{D}} \Delta B_d \right)$ and we denote the total change in revenues (expenditures) by $\Delta W = \sum_{g\in\mathcal{G}} \Delta W_g \left(\Delta U = \sum_{d\in\mathcal{D}} \Delta U_d \right)$. The metrics for the (CRP) are expressed by:

$$\begin{aligned} S^G(\underline{\boldsymbol{P}}^* + \Delta\underline{\boldsymbol{P}}) &= \sum_{g\in\mathcal{G}} \left[\left(\rho_g^* P_g^* + \tau_g \Delta P_g \right) - C_g\left(P_g^* + \Delta P_g \right) \right] \\ &= S^G(\underline{\boldsymbol{P}}^*) + \Delta W - \Delta C = S^G(\underline{\boldsymbol{P}}^*) + \Delta S^G \end{aligned} \tag{R8}$$

$$\begin{aligned} S^D(\underline{\boldsymbol{D}}^* + \Delta\underline{\boldsymbol{D}}) &= \sum_{d\in\mathcal{D}} \left[B_d\left(D_d^* + \Delta D_d \right) - \left(\upsilon_d^* D_d^* + \sigma_d \Delta D_d \right) \right] \\ &= S^D(\underline{\boldsymbol{D}}^*) + \Delta B - \Delta U = S^D(\underline{\boldsymbol{D}}^*) + \Delta S^D \end{aligned} \tag{R9}$$

$$\begin{aligned} &S^M(\underline{\boldsymbol{D}}^* + \Delta\underline{\boldsymbol{D}}, \underline{\boldsymbol{P}}^* + \Delta\underline{\boldsymbol{P}}) = \\ &= \sum_{d\in\mathcal{D}} \upsilon_d^* D_d^* + \sum_{d\in\mathcal{D}} \sigma_d \Delta D_d - \sum_{g\in\mathcal{G}} \rho_g^* P_g^* - \sum_{g\in\mathcal{G}} \tau_g \Delta P_g \\ &= S^M(\underline{\boldsymbol{P}}^*, \underline{\boldsymbol{D}}^*) + \Delta U - \Delta W = S^M(\underline{\boldsymbol{P}}^*, \underline{\boldsymbol{D}}^*) + \Delta S^M \end{aligned} \tag{R10}$$

$$\begin{aligned} &S^S(\underline{\boldsymbol{P}}^* + \Delta\underline{\boldsymbol{P}}, \underline{\boldsymbol{D}}^* + \Delta\underline{\boldsymbol{D}}) = \\ &= S^D(\underline{\boldsymbol{D}}^* + \Delta\underline{\boldsymbol{D}}) + S^G(\underline{\boldsymbol{P}}^* + \Delta\underline{\boldsymbol{P}}) + S^M(\underline{\boldsymbol{P}}^* + \Delta\underline{\boldsymbol{P}}, \underline{\boldsymbol{D}}^* + \Delta\underline{\boldsymbol{D}}) \\ &= S^D(\underline{\boldsymbol{D}}^*) + S^G(\underline{\boldsymbol{P}}^*) + S^M(\underline{\boldsymbol{P}}^*, \underline{\boldsymbol{D}}^*) + \Delta S^D + \Delta S^G + \Delta S^M \end{aligned} \tag{R11}$$

These relations define explicitly the changes ΔS^D, ΔS^G, ΔS^M, ΔS^S in each surplus metric corresponding to $\Delta\underline{\boldsymbol{P}}$ and $\Delta\underline{\boldsymbol{D}}$ during CR. Whenever there is no congestion $S^M = 0$. A non zero value of S^M indicates congestion. The S^M arises due to the role of transmission and belongs consequently to the IGO. When total demand expenditures exceeds total supply revenues $S^M > 0$. In the reverse case, when $S^M < 0$, the IGO must subsidize the users of the transmission system to relieve congestion.

The coupling of the framework with the given rules of a specific market allow the assessment of the effectiveness and efficiency of each scheme for that market.

IV. COMPARISON OF CM APPROACHES

We illustrate the application of the unified framework to the comparison of the five CM approaches. We use the 7-bus test system described in Appendix A.

Table 3. The MD results

	E&W	PJM	NOR	SWE	CAL
total consumption (MWh)	1073.3	1027.5	1033.7	1073.3	1044.2
Producer Surplus ($/h)	15544	14336	14555	15544	22979
Consumers Surplus ($/h)	18036	16185	16277	18036	9319.9
Merchandise Surplus ($/h)	0	2138	1576	0	0
social surplus ($/h)	33580	32659	32408	33580	32298
min. zonal price ($/MWh)	44.32	37.82	38.97	44.32	52.05
max. zonal price ($/MWh)	44.32	53.69	51.23	44.32	52.05
congested lines	3-6, 4-5	implicit	3-6	3-6, 4-5	3-6

Table 4. The CR modified MD results

	E&W	NOR	SWE	CAL
total consumption (MWh)	1073.2	1027.6	1027.6	1034.0
producer surplus ($/h)	18017	14872	15846	22831
consumer surplus ($/h)	18036	16498	18608	9622
social surplus ($/h)	31106	32659	32659	32143
merchandise surplus ($/h)	-4947	1289	-1795	-310
min zonal price ($/MWh)	30.14	50.51	42.56	46.55
max zonal price ($/MWh)	72.78	53.69	53.69	52.90

The system is divided into the three zones depicted in Figure A1. In the MD stage line flow limits are not considered and only the NOR scheme considers zone partitioning. For the CR stage each bus is a zone in the E&W, NOR, SWE schemes and so all the lines are tie-lines. For the

CAL scheme the network is partitioned into zones and the lines inter connecting the zone are considered to be tie-lines. For the sake of simplicity and to allow us to focus on the thrusts of our discussion we assume that the bid and offer schedules are the same for the MD and CR stages. Furthermore, we consider no contingencies in the numerical studies discussed here. The results are reported in Tables 3 and 4. In addition to the metrics discussed for the (MDP) and (CRP), we provide measures of the total demand and the maximum and minimum prices. Note that the E&W scheme is the single zone unconstrained market dispatch.

An examination of the results of Table 3 leads to the following observations:

- *Total consumption*: the E&W and the SWE schemes result in the maximum amount of power consumption.
- *Prices*: the prices are uniform for E&W and SWE schemes. Due to the constraints considered, the PJM, the NOR and the CAL schemes result in a non-uniform price.
- *Surplus metrics:* the value of S^S, which measures market efficiency, attains its maximum for the E&W and the SWE schemes. For these two schemes, no other constraints are considered, so that $S^M = 0$ and $S^S = S^D + S^G$. In the other schemes, the nonzero value of S^M indicates a loss of efficiency which reduces both S^G and S^D in the PJM and NOR schemes.
- *Congested lines*: these are identified and given in the last row of Table 3.

The CR stage is undertaken in all the schemes with the sole exception of PJM in which the MD solves implicitly any congestion. The results reported in Table 4 combine the changes arising from the solution of the (CRP) with the original (MDP) solution. A comparison of these results with those of PJM MD leads to the following observations in assessing the behavior of the different CM schemes:

- *Total consumption*: the only scheme in which total demand is not reduced and remains unchanged during CR is E&W, since the load is assumed to be inelastic. The reductions in NOR and SWE schemes are comparable to those of PJM.
- *Prices*: the PJM scheme, where each bus defines, in effect, its own zone, has the widest price variability. The NOR scheme has the narrowest variation due to the zone partitioning in the MD.
- *Surplus metrics:* the CR modifications results in the NOR and SWE schemes having exactly the same S^S values as that of PJM MD. The CAL approach CR, with the explicit consideration of the SC balance constraints, results in a lower S^S and its more askewed allocation among the generators and the load. The E&W scheme attains the lowest S^S and keeps unchanged the S^D in the CR stage, due to the inelasticity of the loads. In the NOR and CAL scheme, the S^M is positive when congestion is relieved as in the PJM scheme. S^M, in the SWE and E&W approaches, reflects the fact that no zone partitioning was done in the MD stage. In addition, the E&W scheme also reflects the lack of load participation in the CR.

The S^M signal may provide an improper incentive to the IGO in removing congestion. How S^M is used depends on the rules in place. For example, the PJM scheme allows the IGO to collect the positive S^M. If that money collected is kept by the IGO this represents an incentive to maintain congestion so as to continue collecting such funds. In the actual PJM implementation, that amount is used to refund the fixed transmission rights holder the congestion charges.

Similar conditions may occur in the NOR market rules. On the contrary, the CAL market rules provide that the positive S^M collected is passed to the transmission owners. On the other hand, the possibility of a negative S^M may provide strong incentives for removing congestion. This in the case of SWE market rules where the IGO uses its own funds to cover this subsidy. On the other end, the E&W rules allows the IGO to charge such expenditures for the transmission use in the so-called uplift.

The numerical results reported are applicable to the test system under the conditions we considered. Due to the particularities of each system and the time varying nature of system conditions, the generalization of these results is not possible. However, our extensive studies indicate that many of the observations above have wide generality.

V. Conclusions

This paper presents a comparative analysis of various schemes implemented to relieve congestion. The unified framework we developed provides the capability of evaluating the different CM schemes using a consistent set of metrics. The framework overcomes the problems of the use of different *language* and interpretation used in the description of those schemes.

The side-by-side comparison gives good insight on several aspects of the various CM schemes such a short term efficiency and appropriateness of the economic signals for congestion removal. The unified framework is a powerful construct for putting on a consistent basis the various CM schemes.

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BIOGRAPHIES

Ettore Bompard (M'99) received his Ph.D. degree in Electrotechnical Engineering in 1994. In May 1997 he joined the faculty of the Politecnico di Torino, Italy, where he is an Associate Professor. His research activities include power systems and distribution systems analysis, electricity markets, industry restructuring and power quality.
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George Gross (F' 88) is Professor of Electrical and Computer Engineering and Professor, Institute of Government and Public Affairs, at the University of Illinois at Urbana-Champaign. His current research and teaching activities are in the areas of power system analysis, planning, economics and operations and utility regulatory policy and industry restructuring. His undergraduate work was completed at McGill University, and he earned his graduate degrees from the University of California, Berkeley. He was previously employed by Pacific Gas and Electric Company in various technical, policy and management positions.
Mikael Amelin received his M.Sc in Electrical Engineering from the Royal Institute of Technology, Sweden, in November 1997. He is now a Ph.D. student at the Dept. of Electric Power Engineering at the same institute. His current research concerns the value of inter-area transmission capability.

APPENDIX

The one line diagram of the test system is depicted in Figure A1 with the network data given in Table A1. The three zones are demarcated on the figure. There are two SCs SC1 and SC2. The generator bus and the load bus set associated with SC1 (SC2) are {1,3,4} ({5,7}) and {1,2,3,7} ({4,5,6}), respectively.

Even though each market may have specific ways in which offers and bids are expressed, for the purposes of the comparison we adopt the same price and value schedules in quadratic forms for all markets.

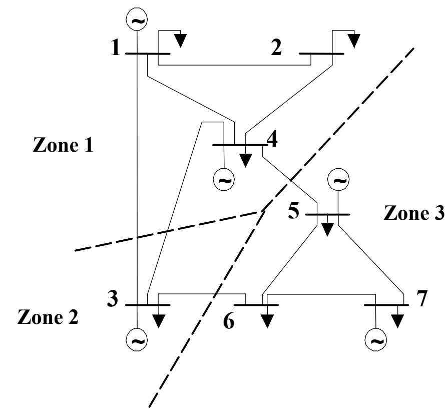

Figure A1. Test system configuration

We use a generalized formulation of the loads in which consumers are characterized by a responsiveness to prices defined as load elasticity [15]. The functional forms are:

$$C_g\left(P_g\right)=\alpha_{2,g}\cdot\left(P_g\right)^2+\alpha_{1,g}\cdot P_g+\alpha_{0,g} \qquad (\$/h) \qquad \text{(A1)}$$

$$B_d\left(D_d\right)=\beta_{2,d}\cdot\left(D_d\right)^2+\beta_{1,d}\cdot D_d \qquad (\$/h) \qquad \text{(A2)}$$

The parameters tabulated in table A2.

Table A2. Price and value schedule parameters

Generator (*g*)	*Price schedules* $\alpha_{2,g}$ (*\$/MW²h*)	$\alpha_{1,g}$ (*\$/MWh*)	$\alpha_{0,g}$ (*\$/h*)	*load* (*d*)	*value schedules* $\beta_{2,d}$ (*\$/MW²h*)	$\beta_{1,d}$ (*\$/MWh*)
1	0.05	13.0	0	*1*	- 0.12	70.0
-	-	-	-	*2*	- 0.13	72.0
3	0.07	16.0	0	*3*	- 0.11	75.0
4	0.06	14.0	0	*4*	- 0.14	68.0
5	0.08	18.0	0	*5*	- 0.10	80.0
-	-	-	-	*6*	- 0.08	84.0
7	0.09	19.0	0	*7*	- 0.09	82.0

For the CR problem the objective is to minimize the costs incurred by the IGO for the adjustments. The charges for the supply generator adjustments are $\delta_g(\Delta P_g)$ and for loads adjustments are $\varepsilon_d(\Delta P_d)$:

$$\delta_g\Big|_{P_g^*}(\Delta P_g)=C_g\left(P_g^*+\Delta P_g\right)-C_g(P_g^*) \qquad \text{(A3)}$$

$$\varepsilon_d\Big|_{D_d^*}(\Delta D_d^*)=B_d(D_d^*+\Delta D_d)-B_d\left(D_d^*\right) \qquad \text{(A4)}$$

Here η =1. The transmission losses are neglected and a flat voltage profile was adopted. Simple linear equations are used to represent the power flows on the lines using the D.C. power flow model. Thus the relations in (M3) are expressed simply as:

$$f_{ij}(\underline{P},\underline{D})=-b_{ij}\left(\theta_i-\theta_j\right), \quad \forall\{i,j\}\in\mathcal{T} \qquad \text{(A5)}$$

where θ_i (θ_j) is the voltage angle at bus *i (j)* and b_{ij} is the susceptance of line connecting buses *i* and *j*.

Table A1. Line parameters (Base quantities: 100 MVA , 345 kV)

Line	1-2	1-3	1-4	2-4	3-4	3-6	4-5	5-6	5-7	6-7
X [*p.u.*]	0.0576	0.0920	0.1700	0.0586	0.1008	0.0720	0.0625	0.1610	0.0850	0.0856
P_{max} [*p.u.*]	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0