ATTACHMENT 4

Facilitating the Congestion Management Market in California

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Abstract

The Congestion Management process in California has been the subject of extensive discussions among many utilities in the world who are in the process of designing functional requirements of their Independent System Operator (ISO) and spot market or the Power Exchange (PX).

Congestion Management is a major function of any ISO and is the process which ensures the transmission system does not violate its operating limits. In the emerging world of the electric energy restructuring, the Congestion Management process is extremely important and if not properly implemented, it can impose a barrier to trading electricity.

This paper provides a perspective on market facilitation role of the California ISO through a complete discussion of the policy directives, design philosophy, and development of the congestion management process in California.

Keywords: Independent System Operator, ISO, Power Exchange, PX, Transmission System Overload, Operating Limits, Electric Utility Restructuring, Congestion Management, Electricity Trading

1. Purpose

California's new electric energy industry has been the subject of extensive discussions around the world and has been recognized as a bench mark and showcase for restructuring of a traditional regulated and vertically integrated electric utility industry.

The purpose of this paper is to provide an example of how the California Independent System Operator (ISO) facilitates its congestion management market in California's newly restructured electric energy industry. The market facilitation role of the ISO is articulated through in-depth discussion of the California Congestion Management process.

2. Introduction

California through an extensive stakeholder participation process elected to have an Independent System Operator (ISO) facilitate its transmission markets while operating the power grid in a secure and reliable manner. In addition, California chose to establish a separate entity, the California Power Exchange (PX) as a statewide or regional electricity spot market in which buyers and sellers can participate on a voluntary basis. The separation of the ISO and the PX is a unique characteristic of the restructuring process in California. Another unique characteristic of the restructuring process in California is that its three major utilities namely, Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric Company continued to own and maintain their transmission systems. In California, the ISO market participants are called Scheduling Coordinators (SCs). SCs are the sole point of contact with the ISO and coordinate all the scheduling activities.

Congestion management is one of the key functions of any ISO and is the process that ensures the transmission system does not violate its operating limits. Violation of operating limits has direct impact on reliability and security of any power grid. In the emerging world of competitive electricity, improper implementation of congestion management can impose a major barrier to free trading of electricity.

This paper provides a discussion of how the California ISO facilitates its congestion management market. In-depth discussion of historical background, design philosophy, development and implementation of the Congestion Management process provide a complete perspective on the facilitation role of the California ISO.

This paper is organized as follows:

Section 3 provides a perspective on the Bilateral and the Pool restructuring models,

Section 4 provides a discussion on the meaning of price and cost in both worlds of regulated and competitive electricity,

Section 5 outlines the policy directives that led to establishing roles and responsibilities for the California ISO,

Section 6 provides an introduction to understanding congestion, Section 7 describes participation in the California Congestion Management process,

Section 8 provides a brief discussion of congestion zones and zonal pricing,

Section 9 provides detailed description of Adjustment Bids,

Section 10 describes the Interzonal Congestion process,

Section 11 describes the Intrazonal Congestion process,

Section 12 describes the software approach and algorithm modification that is used in Interzonal and Intrazonal Congestion Management.

Section 13 provides simple congestion management examples under both the Bilateral and Pool models,

Section 14 summarizes the conclusions of the paper.

3. Bilateral vs. Poolco Model

The role of the transmission system within a power delivery system has been at the center of the restructuring debate ever since the California Public Utilities Commission (CPUC) issued its 1994 proposal to introduce competition into the State's electric energy industry.

Two models dominated this debate. One is referred to as the "Pool Model" and the other as the "Bilateral Model". There are fundamental differences between the two models and the exact differences depend on the particular version of either model that is under consideration.

The Bilateral model is based on the principle that a free market structure is the best way to harvest the benefits of competition for consumers of electricity.

This model has also been characterized as the most suitable in achieving the goal of providing "customer choice" or "direct access" where customers can freely select their preferred supplier of electric energy. In this model, suppliers and consumers independently arrange power transactions with one another according to their own financial terms. In the bilateral model, consumers via selection of their preferred supplier of electricity promote economic efficiency.

The Pool model or Poolco relies on the decision of a centralized command and control structure. Under this alternative, the pool receives bids for price and quantity from all generators and selects the most economic suppliers of electricity.

Under the pool model, the prices that govern the transaction are based on the bids submitted by generators and adjustment made by the pool operator (which may be an ISO) to reflect the locational value of suppliers in terms of their contribution to the system losses and constraints. Another essential feature of the pool model is that all transactions made by consumers must be with the pool operator and not directly with the suppliers. The pool model is fundamentally different since the Market Participants bid their generation and load through a process that is controlled by the pool operator. The Market Participant's portfolio will be adjusted even if there is no congestion and finally determined through the same centralized process system.

The key difference between the two models is centered around the role of the ISO. Californians through an elaborate stakeholder process have chosen a bilateral model under which the ISO role is to facilitate the market while operating the power grid. The separation of the ISO and PX was recommended to the CPUC by a group of stakeholders representing independent power producer, large industrial customers and one utility. They considered this separation to be an essential element for competition in California. This separation ensures that direct access customers would receive truly comparable treatment in using the transmission system under the ISO control.

Under the Bilateral model in California, Market Participants or the Scheduling Coordinators manage their own portfolios (resources and loads), ensure that this portfolio is balanced and accept to participate in the congestion management system on a voluntary basis

4. Price vs. Cost in Competitive Electricity Markets

The foundation behind the operation of the traditional regulated electric utilities is vertical integration and single entity ownership and control. Under this setting, utilities concentrated on minimizing the total cost of power production and delivery. Traditional utilities could achieve economy since their costs were known and they had complete control of their power plants' production.

In the emerging world of competitive electricity, the cost of generation becomes an internal issue to its ownership and may be a confidential matter. Market Participants do not have intimate knowledge of production level and costs of other Market Participants. The fundamental difference is that the traditional relationship between the price and cost as known in the world of regulated utilities is no longer applicable.

The price that a Market Participant submits to the pool or in a bilateral contract will most likely be higher than its production costs. Under certain circumstances, the bid price can also be lower than the production cost depending on impending opportunities and the bidding strategy of the participant.

The paradigm shift here is that in the competitive electricity markets, bidding strategy of the participants will be driven by motivation for higher profits. There is no longer a direct relationship between price and cost. Economic efficiency is achieved by the markets in response to consumer selection of their preferred supplier of electricity. ISO (or the Pool operator) is simply a revenue neutral facilitator of the markets without motivation for profit.

5. Policy Directives

The Federal Regulatory Energy Commission (FERC) and the California Public Utilities Commission developed policies on restructuring California's electric energy industry. Reference [1] provides a comprehensive perspective on operation of the California ISO.

The role and responsibilities of the California ISO has been shaped by the following policy directives:

- Operate the power grid
- Facilitate the transmission markets
- Minimize involvement in forward energy markets
- Maximize efficient use of the transmission system
- Provide comparable prices to all participants
- Prevent discrimination
- Minimize gaming opportunities

The above directives were intended to ensure ISO's neutrality while maintaining its role as the facilitator of the markets.

The California ISO operates three markets, a Day-Ahead market consisting of 24 hourly schedules, a Hour-Ahead market pertaining to a specific operating hour and a real-time energy imbalance. Each market is operated independently and closed separately.

ISO purchases its need through an auction process for the following needs:

1. Real-Time energy
2. Ancillary Services
3. Congestion Management

Each hour, ISO publishes seven prices. five prices are published for various types of Ancillary Services, one for congestion and one for real-time energy.

Reference [2] provides an overview of characteristic of the California ISO.

6. Understanding Congestion

To understand how the California ISO conducts its Congestion Management process, it is important to concentrate some basic characteristics of electric power systems. Existence of network constraints characterizes a finite amount of power that can be transferred between two points on the power grid. The location of the generator and load as well as the presence of other loads and generation on the system can significantly influence the amount of power that may be transferred from a given generator to a given load. The presence of such network or transmission limitation is referred to as "congestion".

The constraints of a transmission system may include line flows, bus voltages, equipment ratings such as transformer tap limits, generation limits on active and reactive power, etc.

All of these constraints can affect system performance and may have to be recognized. In addition, power systems can undergo discrete changes in system configuration due to line or generator outages and have to be able to survive such contingencies. This may involve ensuring that relevant limits in the post-contingency system configuration are satisfied and that system dynamics performance meets specific stability criteria. In general, the power transfer limitations on a given transmission system are not always known with certainty and therefore, the problem has a probabilistic nature.

The costs associated with necessary remedial measures (such as adjustment of schedules) to relieve congestion can increase to a level that could present a barrier to free trade of electricity. Therefore, it is not surprising that congestion management has been at the center of debate over facilitating greater competition in electric power industry.

7. Participation in Congestion Management

In California, market participants or SCs can participate in the process of Congestion Management through submission of " Adjustment Bids" which is described in section 9. SCs have maximum flexibility and choice in their scheduling decisions.

ISO eliminates transmission congestion before the real-time energy consumption by economic decisions and actions of the Market Participants or SCs. Generally, SCs as well as the PX operate independently of one another. Trades between these parties are arranged voluntarily and based on mutually agreed-upon terms. Due to competition, these parties are not generally compelled to trade with each other and their schedules are set independently. While each schedule may be individually acceptable to the power grid, the combination of schedules may violate the transmission limits.

ISO's Congestion Management process is accomplished in two time periods, a day before and two hour before the real-time. In both time periods, the ISO reschedules to eliminate potential problems and minimizes rescheduling to allow Market Participants to voluntarily seek their lowest cost of delivered energy. For example, ISO does not broker compulsory trades among participants except as last resort, to maintain transmission reliability.

The ISO Congestion Management process enables all participants to compete for scarce transmission capacity on a level playing field by providing accurate transmission marginal cost information. ISO allocates transmission capacity to the parties that can use it most cost effectively.

Overall, ISO's Congestion Management process recognizes and separates each SC's portfolio of generation and load from other SCs while finding the lowest rescheduling cost to maintain system reliability.

8. Congestion Zones

Through extensive stakeholder participation, California chose a congestion management process that uses zones or geographical locations to define electrical characteristics of the power grid and determine a financial value for the ability to serve its energy needs. Congestion management through zonal pricing follows the topography, operation and pricing of the transmission network.

Zones are defined as areas where congestion is infrequent and can be easily priced on an average cost basis. By definition, congestion within zones is infrequent and possibly difficult to predict. Therefore, financial rights will be difficult to auction and to resell in a secondary market. Congestion between zones is defined to be frequent with large impacts. Therefore, marginal cost pricing promotes its efficient use. Marginal Cost of transmission is the value that market participants place on congested transmission. Marginal Cost is based on scheduling and bidding information for hourly consumption in the relevant forward or spot market. Marginal cost pricing provides the economic incentives that promote the allocation of the limited transmission capacity to the most cost-effective users.

Since the transmission path between zones are not always a single long transmission line or group of transmission lines in a specific corridor, the California congestion pricing method uses the term "Interzonal" to describe congestion and pricing between zones (typically on a major artery), and the term "Intrazonal" to describe congestion and pricing within a zone.

The marginal cost of using a congested interzonal interface is defined as the incremental value of that interface to the marginal user. This marginal cost is paid by all SCs that want to use a congested interzonal interface. Intrazonal congestion pricing sets the congestion pricing per unit of energy to the average cost of relieving congestion within the zone. California ISO's Congestion Management process can define new zones if intrazonal congestion becomes frequent and inefficiently priced at average cost. Likewise, zones will be combined if interzonal congestion becomes infrequent and inefficiently priced at marginal cost.

The objective in Interzonal Congestion Management is to promote reliability and efficiency first since Interzonal capacity is a scarce resource. The objective of Intrazonal congestion management is to promote reliability and accommodate maximum customer choices since most customers are served in the zones, and the zones are highly networked with plentiful capacity.

Overall, Interzonal and Intrazonal congestion management have different objectives, network topography, operational impacts and price impacts. Therefore, the ISO's congestion management and pricing procedure differs for each of the two congestion types.

9.Adjustment Bids

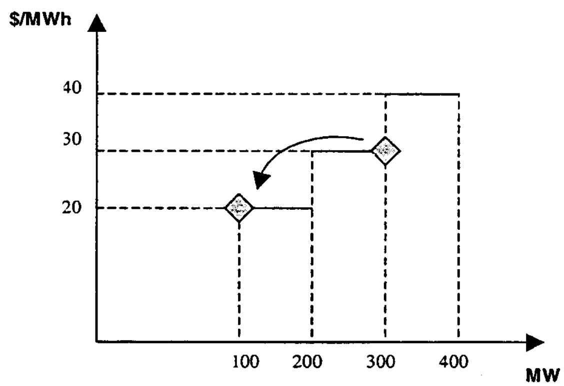
SCs provide preferred schedules for all their resources and demands in the hours of the relevant time frame for both the "Day-Ahead and "Hour-Ahead" markets. Each SC may bid the amount by which it is willing to increase energy output above its preferred schedule from one of its resources. The SC would also specify a cost that it would incur by increasing that resource's output. This is an incremental bid for that resource. Incremental bids may be similarly defined for demand bid. Conversely, each SC could bid the amount by which it is willing to decrease the output of its resource below the preferred schedule. The SC would also bid the savings that it would achieve by decreasing its resource's output.This is a decremental bid for the resource. Figure 1 provides a graphically demonstration.

The combination of incremental and decremental bids are referred to as Adjustment Bids and is used by the ISO to determine the most cost-effective allocation of transmission in a congested power grid.

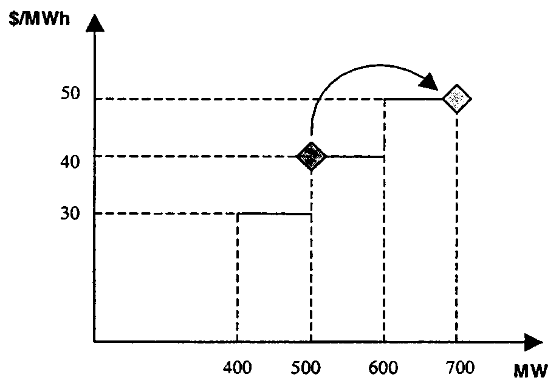
SCs are not required to provide adjustment bids for congestion management. If a SC does not provide adjustments bid (or if the ranges specified in the bid are too narrow), the SC is considered to be a "price taker". That is, the SC is willing to pay whatever congestion cost must be paid to receive transmission capacity to meet its preferred schedule.

To keep the transmission network within its limits, ISO reschedules only the SCs that provide adjustment bids.

Submitting adjustment bids enables the ISO to calculate the cost that the SC would incur if it were to shift the SC's resources to relieve the congestion. These bids allow the ISO to allocate interzonal transmission capacity to the SCs who value it the most. It also enables the ISO to set the marginal cost of using congested interzonal interfaces. All SCs using the congested transmission will be charged the marginal price. SCs will be paid the marginal cost for counterflow schedules on congested Interzonal path.



Decremental Bid



Incremental Bid

Figure 1

The incremental/decremental price bids are curves that define:

- The minimum MW output that the SC permits a resource to be redispatched
- The maximum MW output at which the SC permits a resource to be redispatched

The following describes some of the bid validation rules for the data submitted by the SCs:

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- SC's preferred operating point for the resource must be within the range of the curve. The minimum MW output level specified for each resource may be zero MW (in which case the ISO can effectively "decommit" the unit).
- Minimum and maximum MW output levels for each resource must be physically realizable by the resource.
- Minimum and maximum output levels for each resource must be as such that the resource will be capable of ramping from the preferred operating point to these levels within the scheduled hour.

The incremental/decremental bids are considered as options offers by SCs to be rescheduled for congestion management. The incremental amount of power and its cost does not have to be the same as the decremental amount and price of power. However, it is expected that the lowest incremental bid be greater than or equal to the highest decremental bid for the same unit.

In designing the incremental and decremental bids, SCs must take into account the following ways that their bid(s) may be used by the ISO in Interzonal or Intrazonal Congestion Management:

1) Incremental/decremental bids that are submitted for the Day-Ahead market and could be used two ways:
   a) To alleviate Interzonal congestion caused by SCs preferred schedules in the Day-Ahead market,
   b) To alleviate Intrazonal congestion in a zone in the Day-Ahead market.

2) The same or new incremental/decremental bids may be submitted for the Hour-Ahead market which can be used in the following three ways:
   a) To alleviate Interzonal congestion in a SC's preferred schedule during the Hour-Ahead market,
   b) To alleviate Intrazonal congestion in a zone during the Hour-Ahead market,
   c) To maintain reliability as an Ancillary Service in the real-time Imbalance market.

It is important to point out that forward energy prices as reflected in the SC's adjustment bids have no direct relevance to the ISO except for management of congestion.

10. Interzonal Congestion

ISO relieves congestion on an interzonal interface by reducing scheduled energy production on one side of the interface and increasing (or decreasing load) production on the other side. Interzonal congestion management keeps each SC's portfolio separate. Therefore, the ISO does not pay a SC for increased output in its revised schedule that results from the ISO's redispatch for interzonal congestion.

The increase in output from a SC's generator is used to offset a decrease in output from another generator for that SC. SC's power production is used only to serve that SC's loads and cover its losses. Each SCs generation is kept in balance with its load and losses. ISO does not buy or sell energy from and to the SCs. Rather; the ISO sells or buys interzonal transmission capacity. Consequently, the ISO will only charge and pay the SC according to their interzonal transmission use and the market participants' determination of the cost of usage for interzonal transmission.

ISO avoids interfering in the energy forward markets by keeping each SC's portfolio of generation and load separate and balanced as it adjusts schedules to alleviate congestion. The participants can arrange voluntary trades amongst themselves. However, the ISO will not force such trades as it alleviates interzonal congestion.

The process of Interzonal Congestion Management assigns transmission to its most cost-effective users. ISO determines the most cost-effective users of congested transmission with the incremental and decremental bids of the SCs that use the congested Interzonal interface. ISO uses marginal costs to charge SCs for their use of a congested Interzonal interface (or to pay other SCs that create transmission capacity with a counterflow on a congested Interzonal interface). ISO "clears the market" (assure that supply and demand are in balance) for transmission such that rational and consistent marginal costs can be calculated.

In the Day-Ahead market, which contains 24 hourly trading periods, the cost of relieving Interzonal congestion in each trading period will be minimized by modifying the SCs' schedules to produce the lowest total system cost while satisfying the Interzonal transmission limits and without ISO arranging trades between SCs.

The Interzonal Congestion procedure is designed to achieve several goals:

1. Unbundle transmission and energy markets,
2. Allocate congested transmission to the most cost effective uses,
3. Minimize the ISO's interference with the forward energy markets,
4. Clear the forward energy and transmission markets (assure that supply and demand are in balance),
5. Determine the marginal cost of congested transmission, and
6. Provide explicit transmission marginal costs to facilitate investment to build transmission or generation facilities.

Each SC administers its own forward energy market (including day-ahead and hour-ahead administration). Each SC manages a portfolio of generation and loads that participate in its forward market. Generation in the portfolio competes to serve loads in portfolio under the rules set forth by the ISO's transmission marketplace.

The ISO administers a forward market for interzonal transmission in which the various SCs will compete for transmission. The ISO does not participate in the forward energy markets when interzonal congestion occurs. The ISO does not compel different SCs to trade among each other and likewise, does not force least cost redispatch of all schedules with all SCs in a common Pool. Further, ISO does not engage in purchasing or selling energy.

11. Intrazonal Congestion Management

ISO alleviates Intrazonal congestion by rescheduling the resources within the zone using the SC's incremental and decremental bids.

Intrazonal congestion will be alleviated while considering the following two objectives:

1. Minimize disturbance to the SC's preferred schedules.
2. Alleviating congestion at a lowest actual cost by using the incremental/decremental bids.

ISO accomplishes the above objectives by determining a weighted minimum shift rescheduling with the weights based on the prices in the incremental/decremental bids. Actual costs are used to charge or to pay SCs that change their preferred schedules to alleviate intrazonal congestion. ISO pays a SC for increased output from its generators (or demand bids that are accepted). ISO charges a SC to replace energy from a generator whose output was reduced and is replaced with energy by the ISO. ISO buys energy from SCs and sell energy to SCs as it performs a bid-cost-weighted minimum change in preferred schedules to eliminate intrazonal congestion. Since ISO prices these trades on actual bids from SCs rather than marginal costs, it does not have to clear the entire energy market consisting of all parties in an integrated pool. Therefore, the ISO's Intrazonal Congestion Management process has a minimal impact on the energy markets.

For intrazonal congestion, a SC is paid the actual cost of the ISO's intrazonal congestion management actions as measured by the SC's bids. If a SC has its generation output increased, then ISO pays that SC for its energy at its as-bid price for incremental generation times the increase in output. If a SC has generation output decreased, then that SC pays the ISO for replacement energy at its as-bid price for decremental generation times the decreased in output. Any difference between the amount paid by the ISO to the SCs and the amount charged to the SCs will be collected from all SCs in a zone as part of the Grid Operations Charge. This part of the Grid Operations Charge will be allocated among the SCs based on their zonal load and net zonal export.

Intrazonal congestion charges are based on the actual cost of rescheduling to relieve Intrazonal congestion for the following reasons:

Intrazonal congestion is expected to be infrequent and have small impact. If intrazonal congestion occurs frequently with large impact, a new zone will be created. The ability to create new zones when intrazonal congestion reaches a limit means that any pricing inefficiency caused by as-bid pricing and not paying for counterflow schedules will be small and self-correcting (through new zone creation and marginal cost between the new zones).

The Intrazonal Congestion Management process may compel SCs to engage in energy trades with other SCs in a zone. Because of the localized nature of intrazonal congestion, the SCs may not have sufficiently diverse portfolios that would permit the ISO to keep each SC's portfolio in balance as it reschedules to alleviate intrazonal congestion. Although small and infrequent, these forced trades are needed to maintain reliability. However, to minimize the impact on the SC's individual forward energy markets, the ISO will perform Intrazonal Congestion Management with an algorithm that offers a minimum change in schedules needed to alleviate intrazonal congestion. It will not compel the SCs to make all of trades amongst themselves that would be needed to clear the combined and totally integrated forward energy market. Consequently, accurate marginal costs will not be available from intrazonal congestion.

References [3] and [4] provides a comprehensive discussion of the algorithm used by California ISO for Interzonal as well as Intrazonal Congestion Management.

12. Software Approach

The objective of the California Inter-Zonal Congestion is to:

Minimize: Cost of changes to preferred schedules
Subject to: 1. Balance each SC's portfolio
2. Enforce all interzonal constraints

By solving this optimization problem, the ISO allocates congested transmission to the most cost effective users. It simutaneouly clears each SC's forward energy market individually as well as the forward transmission market. Since each market clears, the ISO can determine the marginal costs that will be needed to price congested interzonal interfaces. The ISO determines each SC's use of interzonal interfaces. SCs pay the marginal cost for using a congested interzonal interface. The payment may also be calculated from an SCs generation and load in each zone and its zonal marginal costs. SCs that provide counterflows to interzonal congestion are paid the marginal cost of the congested interzonal interface. Such counterflow schedulers are obligated to provide counterflows or else pay back to the ISO the cost of replacement energy at the real-time price.

Optimal Power Flow (OPF) is used to determine a minimum cost resource schedule, marginal costs and energy movement in the California transmission network.

Available OPF technology can calculate real power marginal costs and enforce real and reactive power constraints. To achieve the objectives of the California ISO, the following modifications were made to a DC OPF:

1. Minimize the cost of alleviating congestion
2. Disable total rescheduling of all scheduled generation so that voluntary trades can take place (allowing the marketplace to determine least cost rescheduling)
3. Reschedule only as far as needed to relieve congestion while observing network constraints
4. Determine marginal costs for interzonal congestion
5. Determine actual costs for intrazonal congestion
6. Add constraints that separate each SC while performing interzonal congestion management
7. Add constraints that prohibit SC portfolio optimization within zones
8. OPF shall minimize cost for interzonal congestion while not arranging trades between SCs

The California Congestion Management process recognizes the treatment of different types of congestion management:

1. In Interzonal Congestion Management, the main constraints will be thermal or stability constraints that are modeled as limits on interzonal interface megawatt flows.
2. In Intrazonal Congestion Management, the OPF mostly enforces equipment operating constraints that are modeled as MVA or ampere flow limits.

13. Examples

Congestion financial obligations under the California bilateral model are best demonstrated by a simple example. Consider the 2-bus network shown in Figure 2. In this example, we have two separate traders represented by SC1 and SC2. If the line from A to B is not constrained, each SC can serve its 100 MW of load at B using its the less expensive generation at A. SC1 would use G1 at a price of 2 cents/kWh while SC2 would use G3 at a price of 2.5 cents/kWh. This would amount to energy costs of $2000/h for SC1 and $2500/h for SC2.

If the line from A to B is constrained at 150 MW, 50 MW of generation at A must be replaced by more expensive generation at B. If SC1 were to substitute its generation at B for its generation at A, it would replace 50 MW from G1 which costs it 2 cents/kWh with 50 MW from G2 which costs it 4.5 cents/kWh. Therefore the transmission from A to B is worth 2.5 cents/kWh to SC1 (4.5 – 2 cents/kWh). If SC2 were to substitute its generation at B for its generation at A, it would replace 50 MW from G3 which costs it 2.5 cents/kWh with 50 MW from G4 which costs it 3.5 cents/kWh. Therefore the transmission from A to B is worth 1 cent/kWh to SC2 (3.5 – 2.5 cents/kWh). Since the available transmission is more valuable to SC1, the ISO allocates transmission first to SC1 then any remainder to SC2. SC1 is allocated 100 MW of transmission while SC2 is allocated the remaining 50 MW. SC2 is the marginal user of transmission from A to B and it sets the marginal cost of congested transmission at the incremental value of transmission to SC2, namely 1 cent/kWh. The process of predicting the need for and subsequently arranging the out-of-merit dispatch of resources is called congestion management.

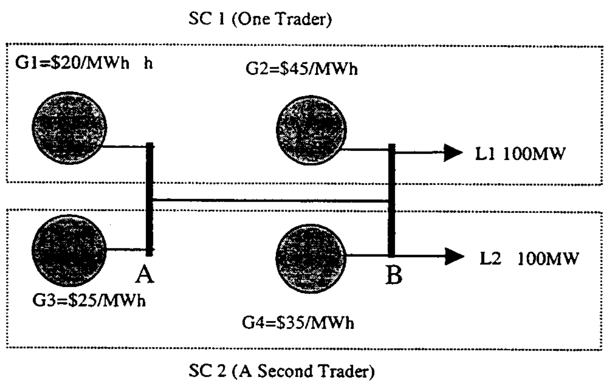

Figure 2 - Bi Lateral Model

In SC1's market, the marginal cost of energy at A is 2 cents/kWh. The marginal cost of energy in SC1's market at B is just its marginal cost at A plus the ISO's marginal cost of transmission, namely 2 cents/kWh plus 1 cent/kWh or 3 cents/kWh. In SC2's market, the marginal cost of energy at A is 2.5 cents/kWh. The marginal cost of energy in SC2's market at B 3.5 cents/kWh.

Each trader is free to set its own pricing structure for its energy purchases and sales, while the ISO prices transmission capacity at its marginal value. For the purposes of the example illustration, we will assume that each trader prices energy at the marginal cost of energy within its separate energy market at each location. That is, SC1 and SC2 both price energy at their individual zonal marginal costs.

Figure 3 depicts the financial transactions that occur during congestion management in the 2-bus example. The entity that coordinates the process of congestion management is assumed to be the ISO.

This model unbundles energy and congestion cost, congestion costs shown in the dashed lines (congestion cost is $10/MWh). The energy charges are handled separately by the SCs which are shown on the solid lines. This is fundamental to the California model as it gives clear signal of congestion cost, (i.e. transmission cost) and energy cost separately since essentially they are separate markets.

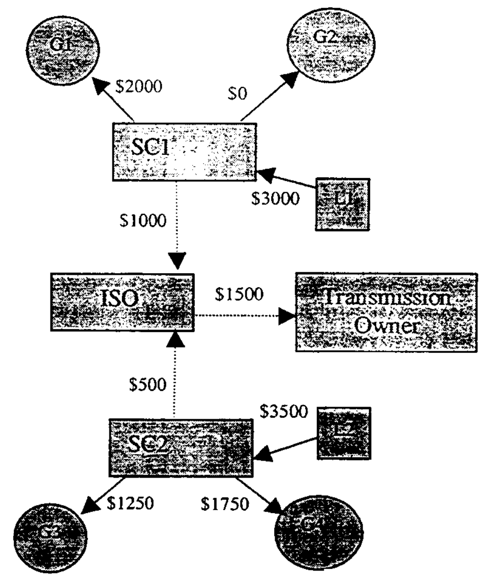

Figure 3

For the sake of completing discussion, it is important to see what would have happened if California had chosen a Pool model for its structuring. The next example compares the congestion management approach under the California bilateral model with pool pricing. Pool pricing does not separate congestion management from the basic price of energy. It also does not enable the different traders to run their energy markets separately. Once any congestion exists, the ISO would redispatch the system as a pool. The ISO would then arrange the energy trades and set the energy prices. It relies on the use of nodal prices defined for all locations that include the energy price and the congestion charge together (in addition to a loss component, which we will ignore here). In the 2-bus example shown in figure 4, the pool would schedule 150 MWh from G1 and 50 MWh from G4. Therefore, the marginal cost of energy at A is $20/MWh while the marginal cost of enrgy at B is $35/MWh. Thus, payments from loads are $7000 (as opposed to $6500 in the previous example). The generators are paid a total of $4750 (as opposed to $5000). See figure 5. This creates a merchandising surplus or network revenue that is left with the ISO who pay this to the transmission owners.

In this example, the congestion revenue is $2250, i.e. the parties pay an additional $$750 over what is needed for congestion management in the bilateral example. Also, L1 pays an additional $500 for its energy.

Pool Model

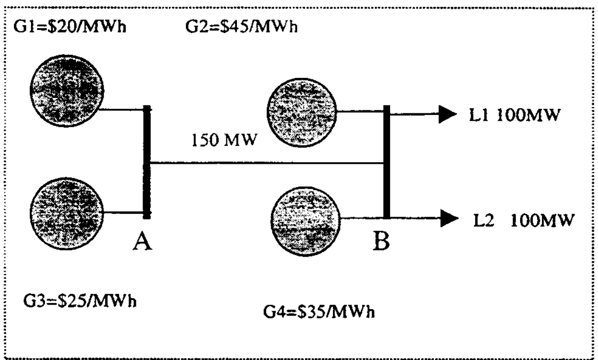

Figure 4: Congestion in a 2-bus system. Nodal prices at A and B are $20 and $35/MWh respectively.

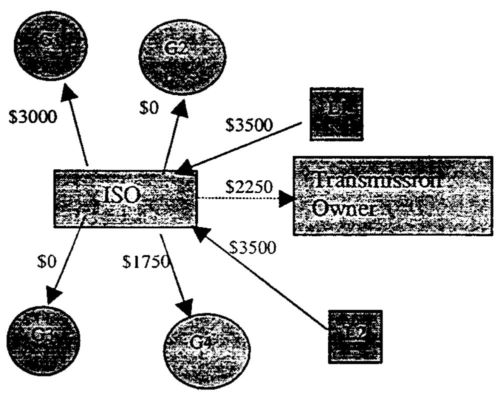

Figure 5: Financial transactions in 2-bus example with congestion under nodal pricing. All energy transactions are done with the Grid Operator

15. Summary and Conclusions

This paper provided necessary background on the alternative market structures (namely Poolco and Bilateral) that were considered in deregulation of California's 21 billion-dollar electric energy industry. In addition, some of the unique characteristics of California's restructured electric energy industry were presented.

Focus was placed on the role of the ISO as facilitator of its transmission market and operator of the power grid. The market facilitation role of the California ISO was articulated through an in-depth discussion of California's Congestion Management process.

A simple examples provided a clear perspective on financial transactions roles and responsibilities of the Market Participants and the ISO in scheduling. In addition, a second example further articulated how the roles and responsibilities and financial transactions would have changed had California chosen a Pool model for its energy industry structure.

In summary, the role of ISO as the facilitator of its Congestion Management market can be summarized as follows:

1. Minimal role in the forward energy markets.
2. Clear market rules and process
3. Preservation of competitive markets
4. Continuous dissemination of relevant information
5. SCs empowered with maximum scheduling flexibility
6. Reliance on markets to value and alleviate congestion
7. SCs participate voluntarily in congestion management
8. All SCs compete equally for transmission
9. Allocation of transmission to most cost effective users
10. No forced trades, except as a last resort for reliability.
11. Recognition and separation of SC portfolios
12. Minimum rescheduling to alleviate congestion
13. Creation of market opportunity through payment for counterflow schedules

In conclusion, the California ISO facilitates its Congestion Management process while provides maximum flexibility such that the market participants recognize, value and strategize to relieve congestion on the California power grid.

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