Congestion Management Workshop

Presented to:

RTO West Congestion Management Work Group

Presented by Susan Pope, John Chandley, and Michael Cadwalader

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Congestion Management Workshop
Session One:
Why Congestion Management Matters

Agenda

- **Why Congestion Management Matters**
- **Congestion Management and Congestion Pricing**
- **Congestion Management and Balancing Markets**
- **What an RTO Must Do**
- **What an RTO Should Do**

Congestion Management and Order 2000

In Order 2000, the second of the seven minimum functions that FERC states an RTO must perform is to “create market mechanisms to manage transmission congestion.”

- **Is FERC placing too much emphasis on this issue?**
- **Is this mostly a concern that relates to markets in the East?**
- **Can development of market-based congestion management mechanisms be deferred because transmission congestion is only a minor concern in the Northwest?**

Congestion in Other Regions

Similar suggestions have been made in other regions.

- **In PJM, a postage stamp transmission tariff was initially used, under the assumption that transmission congestion in PJM was not significant.**
- **A postage stamp tariff was used in New England, based on a similar rationale.**
- **While the California market used zones, a postage stamp tariff was essentially used within each zone, under the assumption that transmission congestion within each zone should be minimal.**

In each case, the assumption that transmission congestion within the region (or in California, within the zone) was minimal has proved to be incorrect.

- **Rules to simplify congestion management, designed under the assumption that congestion was minimal, resulted in unforeseen consequences.**

What is Transmission Congestion?

We need a common understanding of what transmission congestion is.

- **Suppose that no transmission facility is operating at its limit. Is there transmission congestion?**
- **The answer may be yes.**

The key to determining whether there is transmission congestion is evaluating whether the system would have been scheduled and dispatched differently if unlimited transfer capability on all transmission facilities had been available.

- **If the schedule and dispatch would not have been affected, then there was no transmission congestion.**
- **If the schedule and dispatch would have been affected, then there is transmission congestion.**

Congestion Example

Therefore, there is transmission congestion if:

- **Transfer capability is limited for some reason.**
  - ***These limits may result from physical limitations or operating procedures.***
- **The system is re-dispatched in order to avoid exceeding those limits.**

To see this, consider the simple two-bus example below.

- **The line connecting Buses A and B is physically capable of carrying 100 MW.**
- **But operating practice is to keep the line flow at or below 80 MW.**

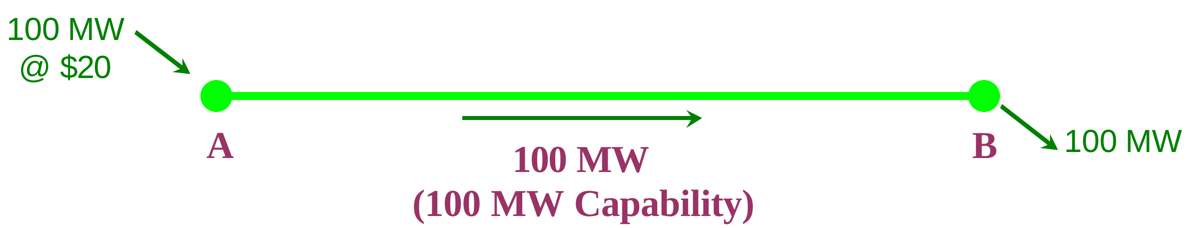
Congestion Example

In addition, suppose there is:

- **100 MW of load at Bus B.**
- **100 MW of $20/MWh generation at Bus A.**
- **50 MW of $30/MWh generation at Bus B.**

The line is physically capable of transmitting 100 MW from Bus A to Bus B, so if only the physical constraints were taken into account:

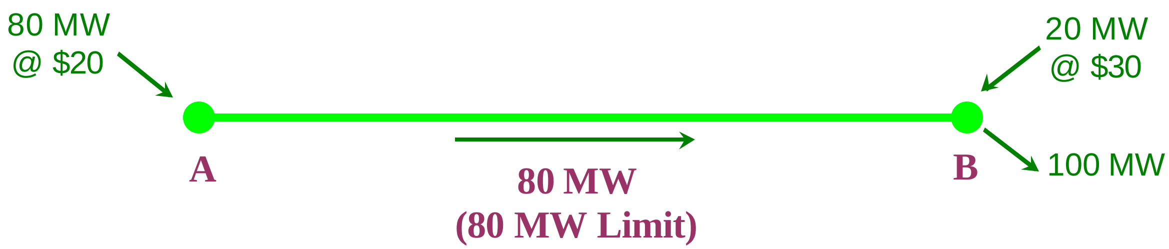
- **The generator at Bus A would generate 100 MW.**
- **There would be no transmission congestion, since the dispatch would not have been changed, even if transfer capability had been unlimited.**



Congestion Example

But the scheduling limit on that line is 80 MW.

- **As a result, the generator at Bus A is only dispatched to produce 80 MW.**
- **The generator at Bus B is dispatched to produce 20 MW.**
- **There is transmission congestion, since the transmission constraint forced 20 MW of out-of-merit generation at Bus B.**



In most cases, if there is out-of-merit generation, there is congestion.

Congestion and Physical Limits

In this simple example, we have not explained why the dispatcher has not used the full physical capability of the transmission line.

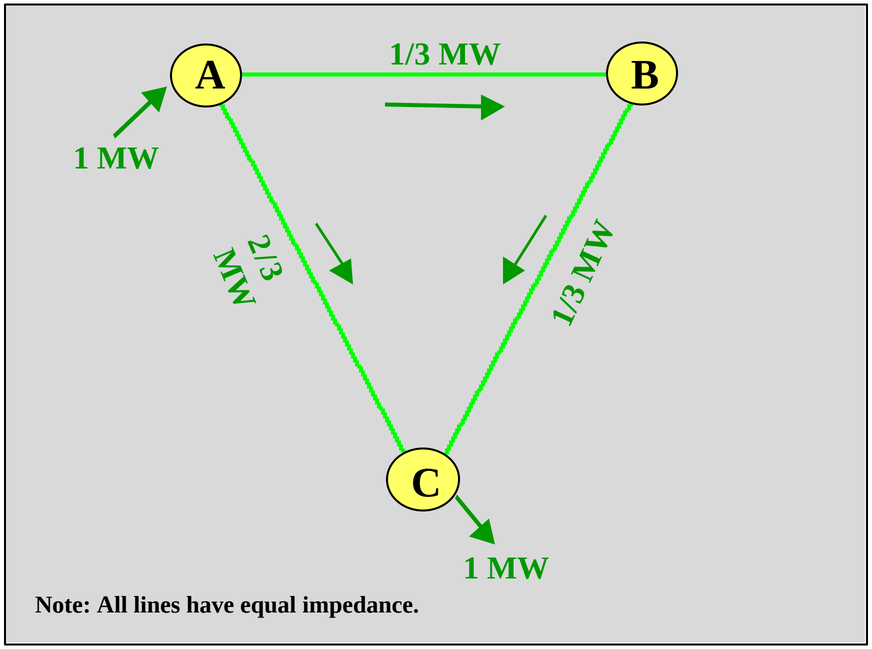
In practice, there are a number of reasons why this might occur. Facilities might not operate up to their physical limit in order to:

- **Leave room for fluctuations in load and generation, to ensure that those fluctuations do not cause flows over each facility to exceed its capability. (TRM)**
- **Ensure that facilities do not exceed their rated capabilities following the occurrence of a monitored contingency, such as the outage of another line.**
- **Ensure that flows over an interface do not exceed the capacity of that interface, since the precise locations where power will be injected and withdrawn on either side of that interface may not be known in advance.**

Parallel Flows

The last bullet can be better understood through an example.

- **As the diagram below shows, electricity will flow over all interconnected lines between source and sink.**
- **The flows over each path will be inversely related to the impedance of that path.**



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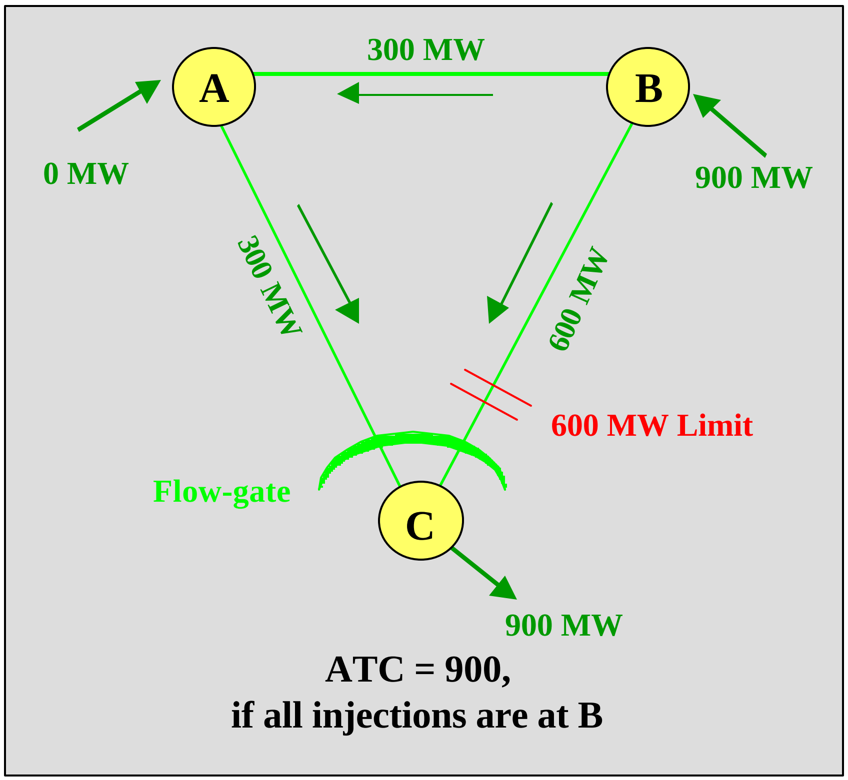
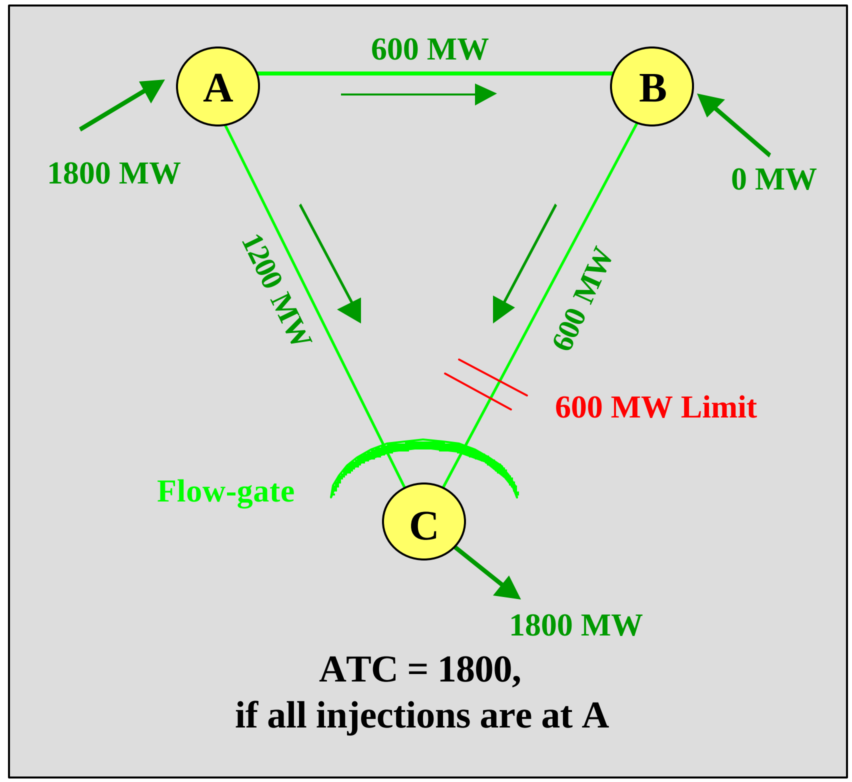
Determination of Flowgate ATC

As a result, the ATC of each flowgate is not fixed, even when all transmission elements are in service. The quantity of electricity that can feasibly cross a flowgate varies depending on the locations of injections and withdrawals.





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Conservatism in ATC Estimates

Because of parallel flow, system operators face difficult choices when allocating long-term physical transmission rights.

One way to ensure that each holder of a right across a flowgate will be able to use that right is to limit the number of physical rights to a very conservative estimate of ATC.

- **In most hours, this will mean that the firm transmission sold in advance to transmission customers will be less than the amount that is actually available.**

Operating Practices and Congestion

Congestion can also be disguised by other operating practices.

- **For example, utilities in some areas have practices of committing generators in some areas to operate during certain time periods.**
- **Often, transmission facilities would have been congested if those facilities had not been committed to operate.**
- **The willingness of entities to commit to operating more expensive generation in order to eliminate transmission congestion is likely to decrease as competition increases.**

And transmission congestion may become significant, even in locations where it is not significant today, in an open access market with decentralized investment and operating decisions.

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Ways to Manage Congestion

When congestion occurs on the transmission system, more entities will want access to the system than can be granted access.

- **One way to determine who gets access is to use a market-based procedure for managing congestion, which ensures that access goes to those who are willing to pay the most for it.**
- **Alternatively, non-market-based approaches can be used, which place restrictions on the activities of market participants in order to alleviate congestion.**

Ways to Price Congestion

There are also different ways to price transmission access.

- **Transmission access can be priced using market methods, charging a market-clearing price to users of transmission.**
- **Or transmission access can be priced through some other procedure.**

But the procedures used to determine who gets access and to determine how much they pay for that access must be consistent.

- **If transmission access is granted using market-based methods, it will be necessary to charge for that access using market-determined prices.**

PJM's Postage Stamp Tariff

As previously noted, rules designed to "simplify" congestion management that do not take the interaction between congestion management and pricing into account can have unanticipated consequences.

PJM's experience with a postage stamp tariff illustrates this.

- **In 1996, PECO proposed the use of a postage stamp tariff in PJM. PECO based its advocacy of a postage stamp tariff on its conclusion that congestion was not significant in the PJM area.**
- **While it considered the merits of locational marginal pricing, FERC directed PJM to implement the PECO proposal. It went into effect on April 1, 1997.**

PJM's Postage Stamp Tariff

Under this system, which was used through March 31, 1998:

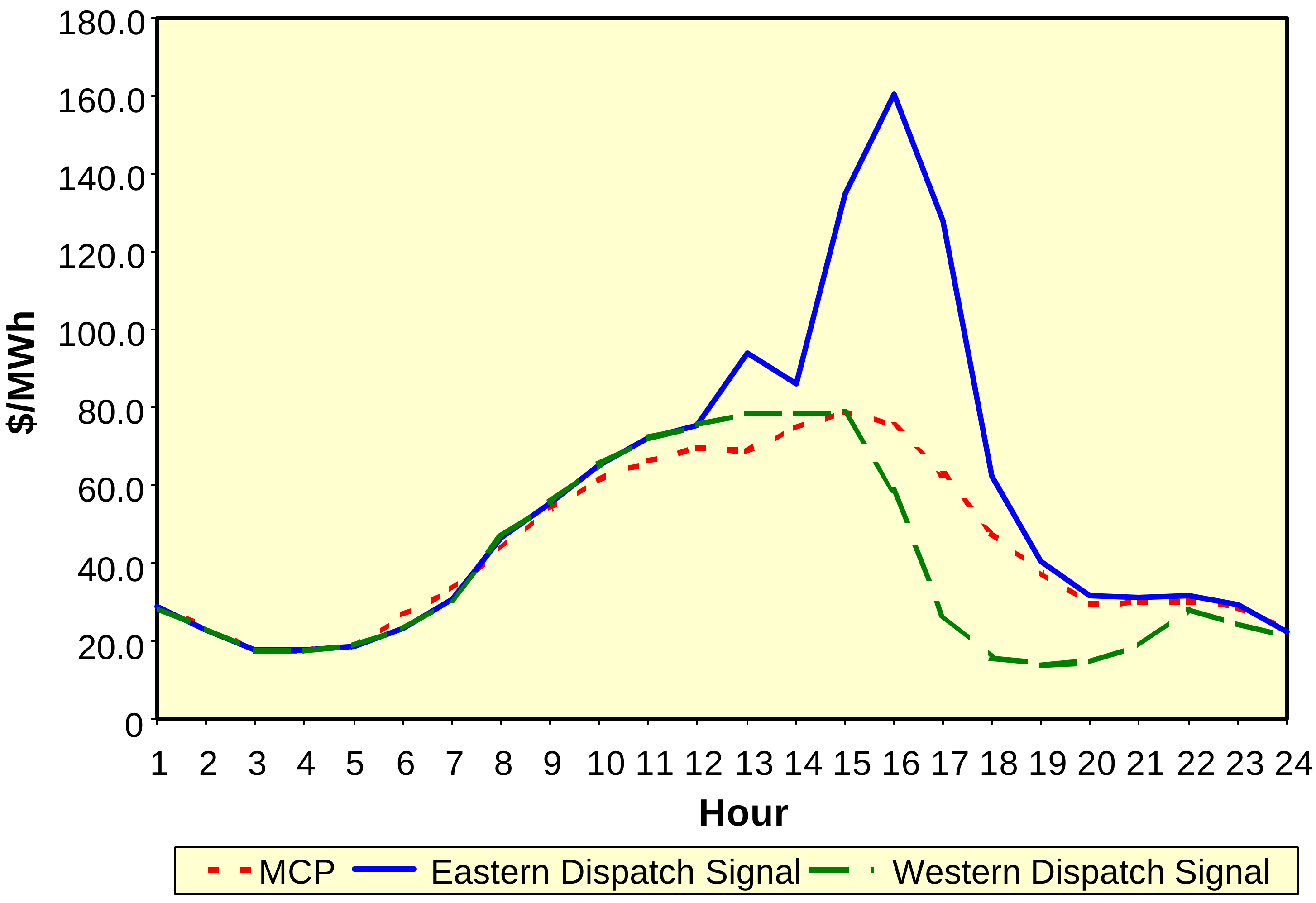
- **Loads and generators bought and sold energy in the imbalance markets at the hypothetical unconstrained price ("MCP").**
  - ***The MCP is the marginal cost of energy that would have existed if transmission constraints had been ignored in the dispatch.***
- **Constrained-on generators were paid the higher of the MCP or their bid.**
- **Constrained-off generators were paid nothing, even if the MCP exceeded their running cost bid.**
- **Non-firm transmission customers were allowed to "buy through" congestion by paying average re-dispatch costs.**

Allocating Access When There Is Congestion

The presumed benefit of this procedure was that a single price applied to all imbalances transactions.

- **However, since it was a uniform price system, access in congested hours could not be granted to those who were willing to pay the most for it, because there was no way to determine who was willing to pay the most.**
- **Therefore, other measures were needed to allocate access to the transmission system when there was congestion.**

PJM Dispatch Signals and MCP, June 26, 1997



PJM's Dispatch Signals

PJM conducts a voluntary dispatch for generators in its control area.

- **It sends "dispatch signals" to those generators. The dispatch signal indicates the value of energy in a given location.**
  - ***Generators with running costs at the dispatch signal should operate at their current level.***
  - ***Generators with running costs below the dispatch signal should increase output.***
  - ***Generators with running costs above the dispatch signal should back down.***
- **When the system was congested, differences between dispatch signals for eastern and western PJM could be significant, as in the hours illustrated in the diagram above for June 26, 1997.**
  - ***These dispatch signals indicate that the PJM dispatcher was directing low-cost generation in the west to back down, replacing that generation with expensive eastern generation.***
  - ***Fundamentally, there was a demand for more transmission from west to east than could be accommodated.***

Incentives to Bypass Dispatch

At such times, there was a strong economic incentive for owners of generation in Western PJM to ensure that their generators were scheduled to produce energy.

- **Because the PJM dispatch signal was different from the price used to settle imbalances, sellers in PJM suffered an economic penalty if they followed the dispatch signal.**
- **The owners of constrained-off generators in the West responded to these incentives by withdrawing from the ISO's dispatch and self-scheduling their units.**
- **By self-scheduling constrained-off generators, LSEs in the East reduced their costs, because they reduced the amount of power they purchased at the MCP price, and replaced it with lower-cost generation.**

Self-Scheduling Reduces ISO's Ability to Control

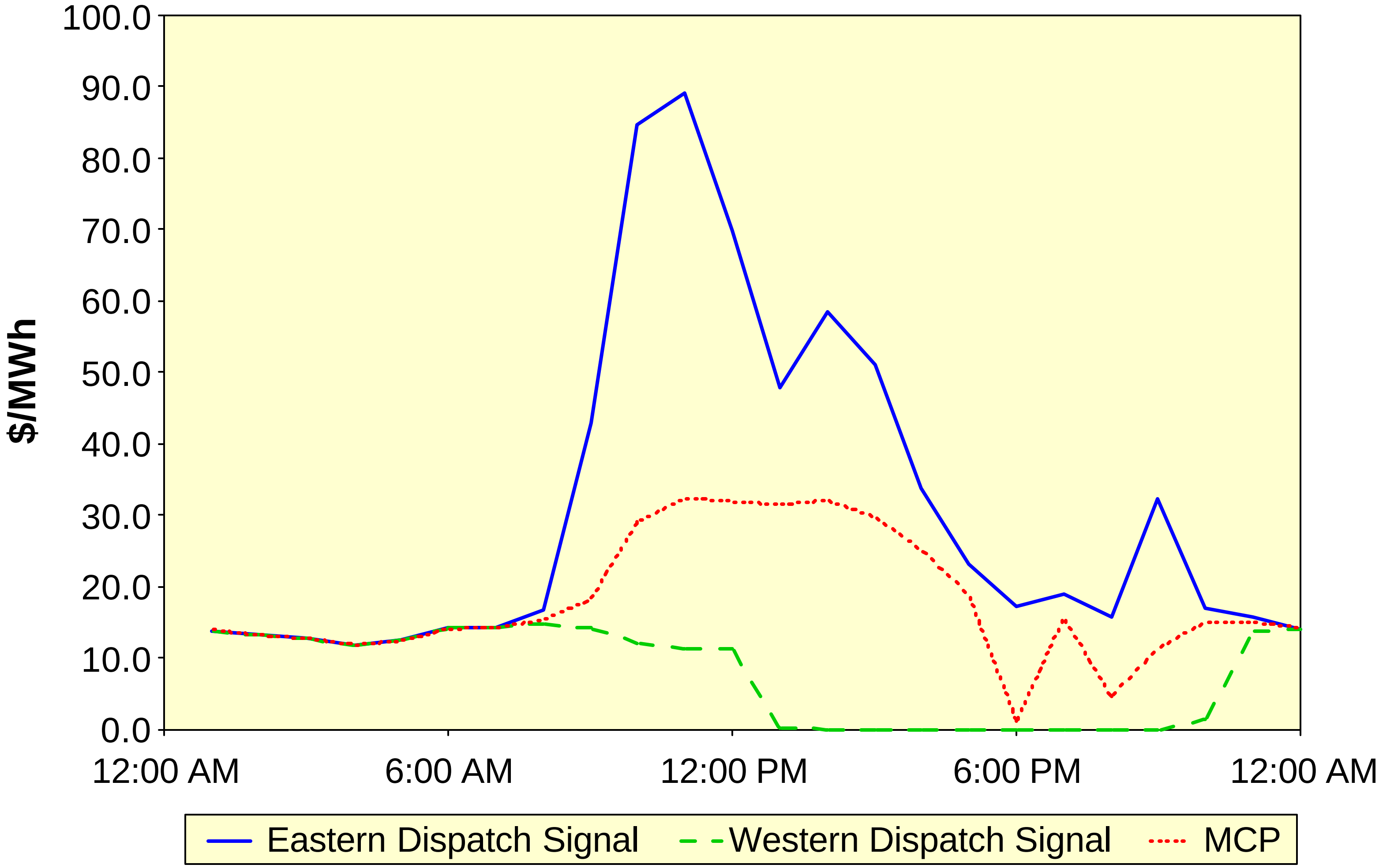
As self-scheduling under PJM's uniform pricing system grew, the operators' ability to control the system was reduced.

- **Fewer and fewer generators followed the dispatch signal.**

Eventually, the operators' inability to satisfy all of these requests for transmission led PJM to implement changes to the open access tariff on June 28, 1997 that restricted access.

- **These changes provided that non-firm transmission customers could not buy through congestion.**
- **Instead, they would be curtailed in favor of firm point-to-point and network service customers.**

PJM Dispatch Signals and MCP, August 22, 1997



A Hot August Day

But these tariff charges provided only a temporary respite.

- **The Western dispatch signal fell to zero on August 22 because LSEs self-scheduled transactions and bypassed the dispatch when transmission congestion existed.**
- **As a result, the OI needed to adopt non-price criteria to ration grid use. It was forced to declare a minimum generation emergency--during the daily peak on August 22, 1997!**

A Hot August Day

PJM's Systems Operations Overview described PJM's actions:

- **At approximately 11:00, PJM had dispatched all units in Central and Western PJM down to their economic minimum cost. No further units remained in the central or west to control the transfer limit. Additional generation in the East was still required. No generation in the central or west had been scheduled by PJM. All generation operating in these areas was self-scheduled by the owning company.**
- **At 11:21, PJM issued a minimum generation declaration for western and central PJM.**
- **At 11:21-11:30, PJM polled all companies affected by the minimum generation declaration to determine if any generation changes were anticipated. No generation changes were reported.**
- **At 11:30, PJM started curtailing spot market transactions from the west that were bid in at a price of zero. Approximately 1200 MW of energy was bid in at zero. Curtailments were made based on the timestamp of when the bids were received. The initial curtailment was for 574 MW to start at 11:45.**

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Transmission Access Restrictions

On this day, more people wanted access to the system than could be given access.

- **The failure to charge reflect congestion costs in charges for imbalances gave market participants incentives to circumvent the ISO's market-based process for congestion management.**
- **As a result, it was necessary for the ISO to adopt non-market-based procedures to manage congestion.**
- **In general, non-market congestion management procedures will require the RTO to:**
  - ***Restrict transmission scheduling in congested hours, to avoid problems such as those described that forced PJM to declare a minimum generation emergency in the middle of a hot day.***
  - ***Restrict access to the balancing market in congested hours, because selling and buying power at different locations in the spot market is equivalent to buying transmission.***

Short- and Long-Term Congestion Management Issues

Additionally, it is important to recognize that the problem of congestion management incorporates both short-term and long-term aspects.

- **Short-term remedies for transmission congestion include re-dispatch and schedule curtailment.**

- **Long-term remedies for transmission congestion include generation and load siting and transmission expansion.**

The use of non-market-based approaches for short-term congestion management has also led to non-market-based answers to these long-term congestion management issues.

Restrictions on Generator Entry and Expansion

Procedures for managing transmission congestion in NEPOOL, and intrazonal congestion in California, did not ensure that access would go to those who were willing to pay the most for it.

In order to ensure that the entry of new generation did not exacerbate these problems by causing additional congestion, both NEPOOL and California resorted to proposing restrictions on generation entry.

- **NEPOOL proposed that all new generators must pay half of the cost of all transmission upgrades that would be necessary for those generators to serve all NEPOOL load.**
- **California proposed to require new or expanded generators to foot the bill for intrazonal congestion attributed to their presence.**
- **FERC rejected both proposals as discriminatory and anti-competitive.**

Importance of Market-Based Congestion Management Mechanisms

Market-based mechanisms for congestion management are important to ensure that:

- **New generators have incentives to locate where the power they provide is most valuable.**
- **New loads have incentives to locate where the power they consume can be supplied least expensively.**
- **Entities that will be affected by transmission congestion have incentives to fund transmission expansions to reduce or eliminate that congestion.**

Summary

In summary, it will be important to develop a market-based system for congestion management for RTO West because:

- **Our discussions with market participants indicate that there may already be significant congestion in the Northwest.**
- **Changes underway in the market are likely to introduce additional congestion.**
- **This congestion must be managed and priced on a market basis in order to:**
  - ***Permit open access to the transmission system.***
  - ***Permit efficient decentralized operating and investment decisions.***
- **Failure to manage and price congestion on a market basis will encourage market participants to use the grid in ways that will increase congestion or create it where it does not currently exist, which will shift costs and undermine reliability.**

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Balancing Markets

While the topic of this workshop is congestion management, we will also devote a considerable amount of time to the discussion of imbalances markets.

- **Imbalances markets have been defined by FERC in the past as an ancillary service.**
- **So why isn't the discussion of imbalances markets taking place in the Ancillary Services Workshop?**

Managing Congestion and Managing Imbalances

Real-time congestion and imbalances are managed using the same resources.

- **When there is congestion in real time, it must be managed by re-dispatching generation (or load).**
- **When there are imbalances in real time, they must be managed by increasing or decreasing generator output (or load).**

Therefore:

- **Any discussion of imbalances management must discuss how imbalances will be managed when there is transmission congestion.**
- **And any discussion of congestion management must discuss how congestion will be managed when there are imbalances.**

Because these problems are so closely related, they need to be addressed together.

Pricing Congestion and Pricing Imbalances

It is also important to price congestion and imbalances consistently.

- **If prices for imbalances do not reflect the costs associated with congestion, the strategies for congestion and imbalances management that the RTO adopts would be undermined, just as PJM's congestion management procedures were undermined by its postage stamp tariff.**

Suppose, for example, that an approach that uses zonal pricing for congestion pricing is adopted, but the imbalances market charges a uniform price.

- **A load that is located in a relatively high-priced zone will have incentives to incur imbalances, since the amount it is charged for those imbalances will be lower than the congestion cost it would be charged for maintaining its schedule.**

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Order 2000

Another reason to implement a market-based approach to congestion management is that Order 2000 requires it.

- **What are the minimum standards that the RTO must meet to gain FERC's approval?**

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Market-Based Congestion Management

First, RTOs must manage congestion through market-based mechanisms that ensure that those who value access to the system most highly receive access.

- **"[T]raditional approaches to congestion management such as those that rely exclusively on the use of administrative curtailment procedures may no longer be acceptable in a competitive, vertically de-integrated industry. We thus concluded that efficient congestion management requires a greater reliance on market mechanisms…" (p. 333)**
- **"We proposed to allow RTOs considerable flexibility in experimenting with different market approaches to managing congestion through pricing. However, we stated that proposals should ensure that … limited transmission capacity is used by market participants that value that use most highly." (pp. 332-3)**

Regional Scope of Market

Second, the market must be regional. In other words, the scope of the area governed by the RTO must be sufficient so that it can effectively manage transmission within that area. Equally important, the RTO's congestion management procedures must manage congestion over the entire region.

- **"[T]he NOPR noted that efficient congestion management required regional actions, and that the current methods for managing congestion (e.g., Transmission Line Loading Relief procedures in the Eastern Interconnection), which do not attempt to optimize regional congestion relief, were cumbersome, inefficient and disruptive to bulk power markets." (p. 334)**

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Market Efficiency and Efficient Price Signals

Third, the market should ensure that congestion is managed efficiently, and it should send efficient price signals to all market participants.

- **"[P]roposals should ensure that … the generators that are dispatched in the presence of transmission constraints are those that can serve system loads at least cost…." (pp. 332-3)**
- **"[W]e will require the RTO to implement a market mechanism that provides all transmission customers with efficient price signals regarding the consequences of their transmission use decisions. We are convinced that efficient congestion management requires that transmission customers be made aware of the cost consequences of their actions in an accurate and timely manner, and we believe that this is best accomplished through such a market mechanism." (p. 382)**
- **"Market designs that base prices on the averaging or socialization of costs, may distort consumption, production, and investment decisions and ultimately lead to economically inefficient outcomes." (pp. 642-3)**

Tradable Transmission Rights

Fourth, it must provide tradable transmission rights that promote an efficient dispatch while hedging locational price differences:

- **"[W]e believe that a workable market approach should establish clear and tradable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices." (p. 333)**
- **"[E]very RTO must establish a system of congestion management that establishes clear rights to transmission facilities and provides market participants with price signals that reflect congestion and expansion costs." (p. 489)**

Authority to Order Re-Dispatch

Fifth, it must have authority to order re-dispatch as necessary to ensure reliability.

- **"Commenters generally agree that the RTO should have clear authority to order re-dispatch for reliability purposes…. We conclude here that the RTO should attempt to rely on market mechanisms…, [but] there may be times when even well-functioning markets fail to provide the RTO with the options it needs…. In such cases, the RTO must have the authority to curtail one or more transmission service transactions that are contributing to the congestion." (pp. 384-5)**

Real-Time Balancing Markets

And finally, each RTO must ensure that a real-time balancing market is created, and that market participants have access to this market on a non-discriminatory basis.

- **"[W]e conclude that an RTO must ensure that its transmission customers have access to a real-time balancing market that is developed and operated by either the RTO itself or another entity that is not affiliated with any market participant. We have determined that real-time balancing markets are necessary to ensure non-discriminatory access to the grid and to support emerging competitive energy markets." (p. 423)**
- **"In the NOPR, we noted that unequal access to balancing options can lead to unequal access in the quality of transmission service…. We conclude that control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market." (p. 425)**

Deadlines

Order 2000 does not require congestion management markets to be in place until one year after RTO start-up.

- **However, real-time imbalances markets must be in place as of RTO start-up.**
- **Therefore, real-time congestion management markets will need to be in place as of RTO start-up, since the same procedures and the same markets that are needed to manage real-time imbalances will also be needed to manage real-time congestion.**

Real-Time Responsibilities

The real-time responsibilities that Order 2000 assigns to RTOs center around the real-time dispatch.

- **All real-time balancing markets flow from the real-time dispatch coordinated by a regional RTO.**
  - ***A real-time "balancing market" implies a market in which participants bid to buy and sell imbalance energy through the real-time dispatch, such as those conducted in or planned for PJM, New York, New England, California and Ontario.***
- **The RTO also must supply ancillary services in real time to those who have not previously self-supplied.**
- **The authority to re-dispatch to preserve short-run reliability also implies some control over the real-time dispatch.**

Operational Implications of Order 2000's RTO Requirements

A consistent and plausible interpretation of Order 2000 is that FERC wants an RTO to operate a regional, bid-based dispatch, which it uses to:

- **Provide an open real-time balancing market.**
  - ***Allowing traders to settle imbalances at market-clearing prices, as defined by participants' bids.***
  - ***Allowing participants to buy and sell energy on a "spot" basis, at these same market-clearing prices.***
- **Manage congestion as efficiently as possible by using participants' bids to re-dispatch generators.**
- **Coordinate all other ancillary services required to ensure short-run reliability, preferably via markets.**

Options with a Balancing Market

Structuring the RTO market around a bid-based dispatch/balancing market can accommodate:

- **Voluntary bidding; no one is required to submit bids.**
- **Balanced schedules (or not). Participants may choose to maintain perfectly balanced schedules on their own.**
  - ***Or they can use the balancing market to settle imbalances.***
- **Flexible bilateral transactions -- participants can arrange and schedule bilateral trades with the RTO.**
  - ***They can use the balancing market to settle any imbalances.***
  - ***They can use the balancing market to lay-off any uncontracted generation.***
  - ***They can use the balancing market to purchase spot energy to cover any uncontracted loads or supply shortfalls.***

Does Order 2000 Say This?

All of the operational ISOs that FERC has approved have these elements.

- **FERC is familiar with PJM, NY, NE, CA.**
- **FERC supports these elements in those markets**
- **FERC praises proposed ITCs with the same features (ComEd).**
- **It rejects RTOs (SPP) without them.**

It will be hard (impossible?) to construct an alternative interpretation that consistently meets all of the requirements, despite allowing "great flexibility".

Are Other Interpretations Consistent with Order 2000?

Suppose the RTO does not provide a regional, bid-based dispatch/balancing market.

- **Some other entity would have to provide a regional real-time balancing market. Who? How would it do it?**
  - ***FERC emphasized this RTO element is not optional.***
- **Another entity would have to exercise the authority to order re-dispatch to preserve reliability. Who? How?**
- **Another entity would coordinate and be provider of last resort for ancillary services. Who? How?**
- **Could TOs or current control areas meet FERC's rules for regional scope or independence?**
- **If not, what degree of RTO oversight and coordination of these control areas would be acceptable under Order 2000?**

Should the RTO Operate a Power Exchange?

A related question pertains to the following statement, taken from the Filing Utilities' Consensus Concerning RTO Form and Structure:

- **"The RTO shall not operate a Power Exchange."**

But this does not forbid the RTO from operating real-time markets for balancing and ancillary services.

- **The Consensus statement says so.**

What does it forbid?

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Power Exchanges: Mandatory or Voluntary?

There are (at least) two interpretations, both of which apply to RTO's involvement in forward markets.

- **It forbids the RTO from operating a forward market in which some market participants are *required* to participate, along the lines of the California PX.**
- **It forbids the RTO from operating any forward markets (probably excluding those necessary to ensure reliability, such as forward markets for some ancillary services), even if participation in those markets is voluntary.**

Reasons Why Some Market Participants Might Want a Voluntary PX

We will adopt the first interpretation in this workshop.

- **It might be in the interest of market participants to participate in an RTO-coordinated day-ahead market:**
  - ***The RTO may be able to determine a more efficient set of units to commit in order to serve the next day's load than individual market participants can identify through bilateral transactions.***
  - ***The ability to lock in transmission prices day-ahead may be attractive to market participants.***
- **Participants in other ISOs have found day-ahead markets to be attractive for these reasons.**
- **However, participation should be entirely voluntary.**
  - ***In particular, day-ahead power exchanges operated by parties other than the RTO would be permitted.***
  - ***The RTO would have no financial interest in its day-ahead market.***

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Fundamentals of Designing Competitive Markets

Most markets do not have to be designed.

- **Externalities in these markets are minor (or the impact of those externalities is regulated in some way).**
- **Time constraints are less critical than in electricity markets.**
- **As a result, we can rely on bilateral trading among market participants.**

However, in electricity, these conditions do not apply.

- **Interconnectedness leads to large externalities, because one participant's actions can significantly affect reliability for all.**
- **The need to balance generation and load at all times without violating transmission limits requires some degree of coordination.**

This means that a centralized market is required for at least some services. And that means that it is necessary to design that market.

Other Objectives

In addition to the requirements that the RTO comply with Order 2000, there are a number of other criteria that the congestion management and imbalances markets operating under the RTO should meet, some of which will be of great importance to many of you.

- **They should be efficient.**
- **They should ensure reliability.**
- **They should be open and non-discriminatory.**
- **They should not expose market participants to unpredictable and unhedgeable costs.**
- **They should be liquid.**
- **They should be sufficiently flexible to accommodate many forms of trading.**

Efficiency and the Advantages of Markets

The same benefits can result from establishing electricity markets that result from markets for other goods and services:

- **More efficient suppliers will be more profitable.**
- **Costs to end users will fall as the result of:**
  - ***Pressure on all competitors to lower their costs.***
  - ***Squeezing out less competitive suppliers.***
  - ***Increased gains to trade.***
  - ***Innovation in the supply of services.***

But in order to reap as much as possible of the rewards that flow from the creation of markets, these markets must be *efficient*.

Efficiency and the Advantages of Markets

If a market is efficient, then it supplies products to meet the needs of customers at the lowest possible cost.

Of course, no market is perfectly efficient, but some market designs give better incentives for efficiency than do others.

- **Efficiently functioning markets will do the most good for the greatest number of market participants.**
- **Efficiency is the foundation for most of Order 2000's directives for RTOs.**

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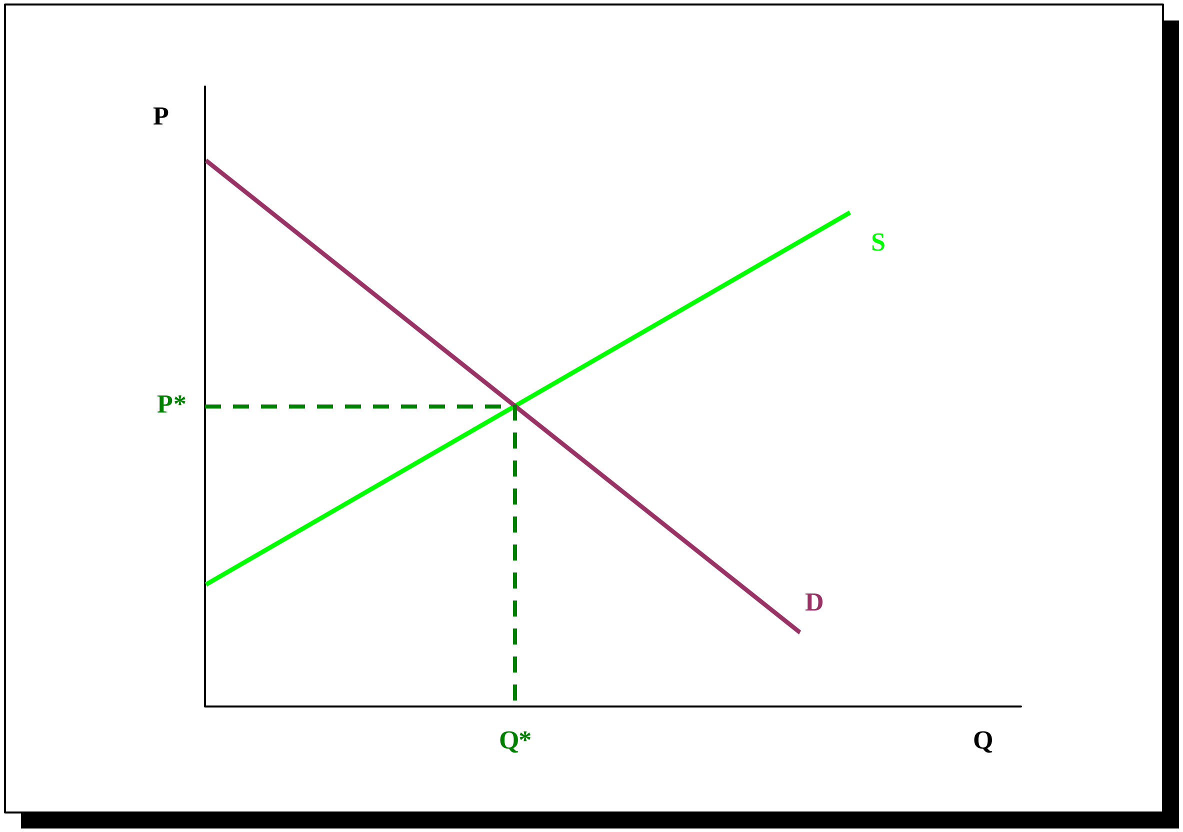
Efficiency and the Advantages of Markets

In markets that do not require central coordination, an equilibrium occurs at the intersection of supply and demand curves.



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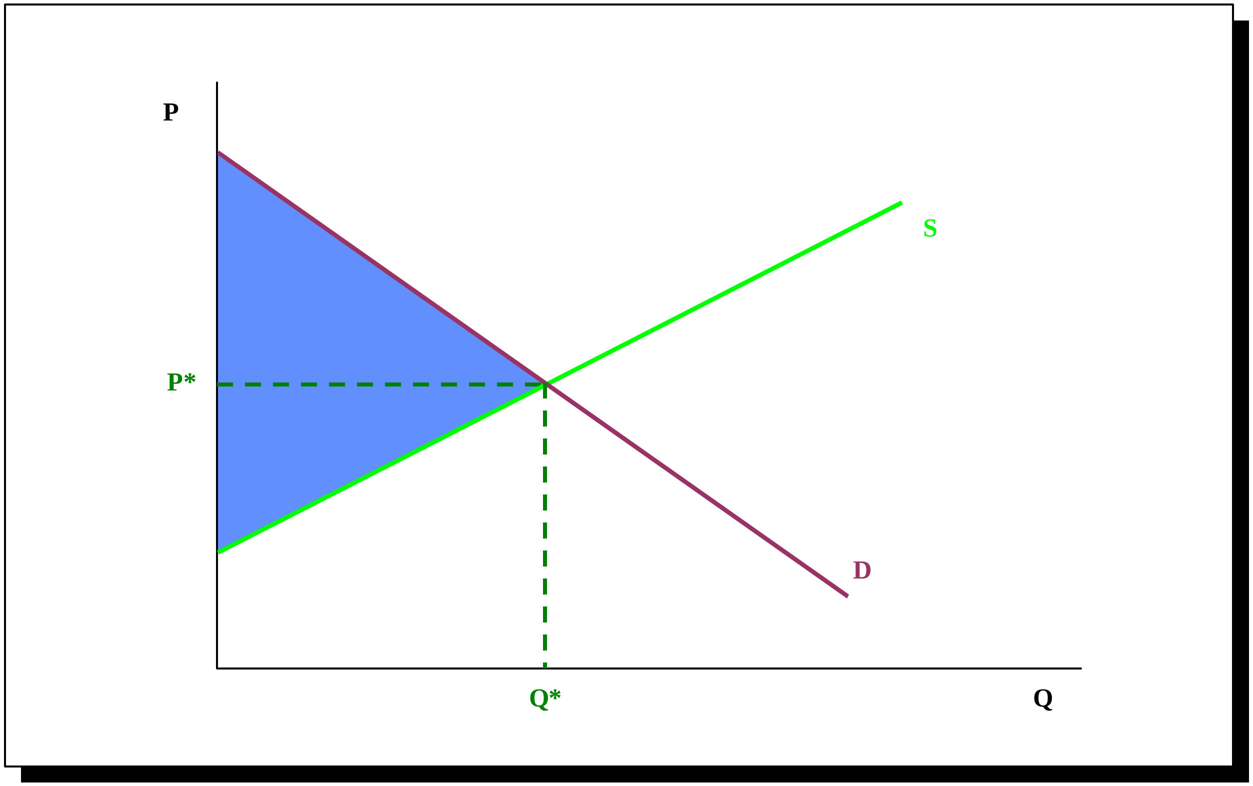
Efficiency and the Advantages of Markets

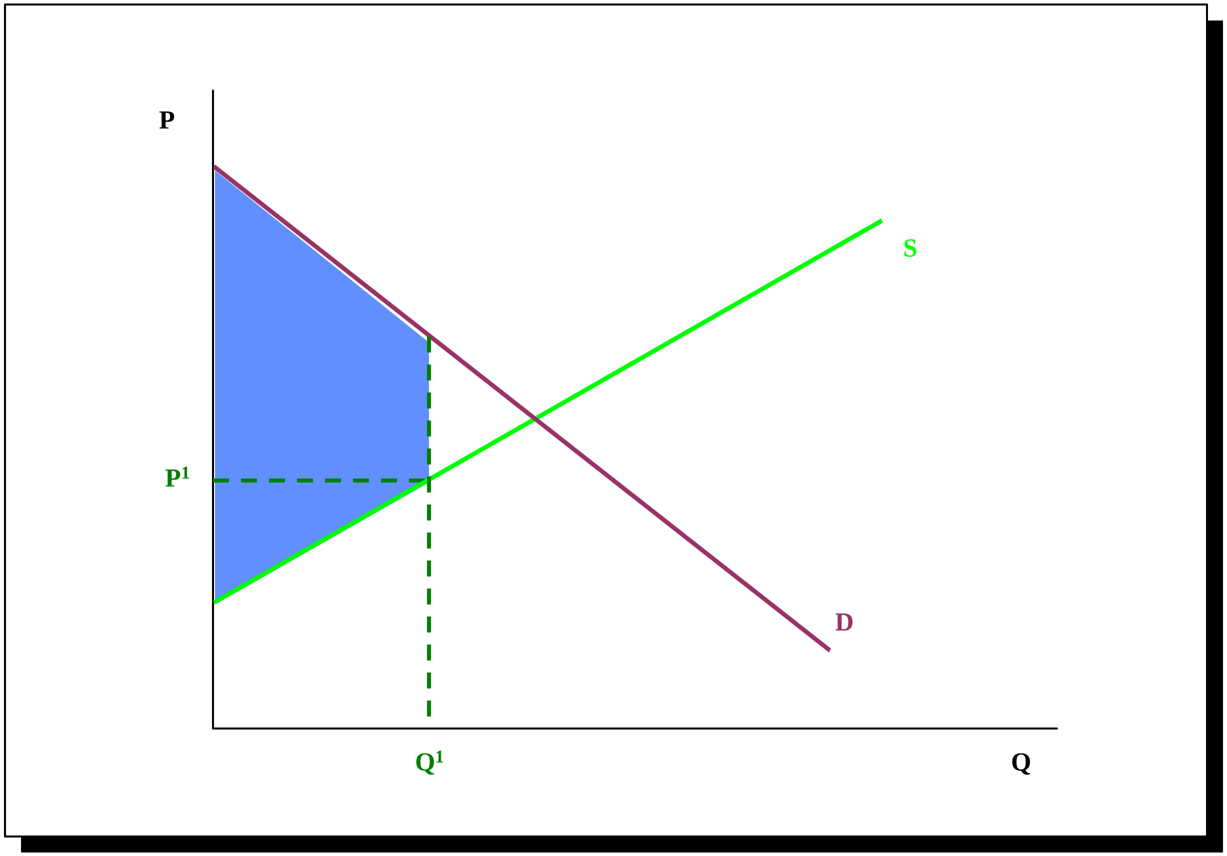
That price and that quantity maximize gains from trade.

- **Gains from trade are the amount consumers would have been willing to pay for the goods they purchased, less the amount that it actually cost producers to produce those goods.**



Efficiency and the Advantages of Markets

At any other price and quantity, gains from trade will not be maximized. It is still possible for market participants to make additional trades, to their mutual advantage.



Efficiency and the Advantages of Markets

Designers of markets attempt to encourage this competitive outcome.

- **If they fail to do so, resources will be wasted, and additional mutually beneficial (i.e., profitable) trades will not have been consummated.**

Beneficiaries of Efficient Markets

Efficiently functioning markets may not be in the interest of everyone in this room.

- **In fact, each representative of a market participant in this room may have a financial interest in making some part of this market inefficient--especially if the inefficiency would subsidize them, while spreading the cost across other market participants.**
- **However, efficiently functioning markets will do the most good for the greatest number of market participants.**

Accordingly, the key criterion by which to judge the design of a market, and the key criterion by which FERC will judge the design of markets that each RTO proposes, is the degree to which that design promotes efficiency in:

- **Minimizing the cost of meeting loads, given resources currently available.**
- **Providing appropriate incentives for capital investment.**

Reliability

The RTO must ensure that the ability of system operators to meet reliability criteria is not compromised.

- **It should be in the economic interest of market participants to act in ways that support reliability, instead of undermining it.**
- **The market design should not simply assume that vital reliability functions will be performed by someone, without specifying:**
  - ***Who will perform those functions.***
  - ***Why they will perform them.***
- **It also should not complicate the the system operator's job to the extent that reliability is endangered.**

Non-Discriminatory Access

Another important factor is the degree to which the market facilitates comparable and non-discriminatory access.

- **The amount that each market participant is charged for use of the system or for a service, or the responsibilities placed upon a market participant, should not depend on who that market participant is.**
- **The ability of each market participant to schedule use of the transmission system should not depend on who that market participant is.**
- **Pricing should be as transparent as possible, and pertinent information (e.g., information on constraints) should be publicly posted.**
- **Participation by small entities should not be unnecessarily restricted.**
- **The market should not discourage entry of new competitors by treating entrants and incumbents differently.**

Exposure to Unhedgeable Costs

Market participants should not be exposed to unpredictable and unhedgeable costs.

- **It should permit market participants to lock in transmission costs in advance, using instruments that are not likely to be curtailed.**
- **It should incorporate mechanisms that will mitigate cost shifts.**
- **It should not expose market participants to any other significant costs that cannot be hedged, such as unreasonable uplift costs.**
- **It should not expose providers of last resort to unrecoverable costs.**

Liquidity

The congestion management and imbalances markets that operate under the RTO should be liquid.

- **They should permit the establishment of mechanisms such as trading hubs that permit markets to be more thickly traded.**
- **They should permit transmission rights to be traded and reconfigured as easily as possible, so that market participants can be flexible in the transactions they undertake.**
- **The market should be as seamless as possible. Barriers to trading between control areas within the RTO, and between the RTO and adjoining regions, should be eliminated to the extent possible.**

Flexibility

Finally, markets should be sufficiently flexible to accommodate many forms of trading.

- **The participation of entities such as independent power exchanges should be accommodated.**
- **At the same time, however, market participants should not be forced to use intermediaries (unless there is an economic basis for such requirements).**
- **The market structure should neither drive participants toward nor away from participating in independent power exchanges or in other bilateral transactions.**

Implementation Speed

Two final factors to keep in mind are speed of implementation and transitional issues.

While the deadlines that FERC set are important, they can be over-emphasized.

- **FERC will prefer a market that is consistent with Order 2000's objectives but which does not meet Order 2000's deadlines to a market that meets the deadlines but is inconsistent with its objectives.**
- **The schedule that FERC set forth in Order 2000 is very aggressive. Arguably, no region that was not operating a consolidated control area will be able to meet it.**

Interim Markets

It may be necessary to adopt interim market designs that differ from the end-state design.

- **The interim decisions must be made with the end-state design in mind.**
- **Radical shifts between interim design and end-state design will cause problems.**
  - ***In PJM, the shift from a postage stamp tariff to LMP caused problems for market participants who had entered into "seller's choice" contracts.***

Congestion Management Workshop
Session 2A:
Congestion Management Models

Objectives

Provide an introduction to market design

Present an overview of the basic alternatives for an RTO congestion management system

Describe the key market rules that define each model

Examine alternative market rules that would define alternative market models

Congestion Management Approaches

An RTO could consider several different approaches to congestion management. For example:

- **Regionally coordinated (and "conservative") scheduling to prevent most congestion from happening in the first place**
  - ***It requires an ability to examine the flows of each schedule throughout the region***
  - ***A last-resort curtailment procedure is still required***
- **Less (or un-)coordinated contract path scheduling**
  - ***It requires a method (TLR) to "unschedule" the grid to bring flows back within reliability/security limits***
  - ***Essentially the approach used in the non-ISO regions in the East***
- **Various "market" approaches -- this is what FERC wants RTOs to do. FERC has approved some approaches, and it promises to be flexible in letting RTOs develop other workable approaches**

Market-Based Approaches

Various market-based approaches are possible:

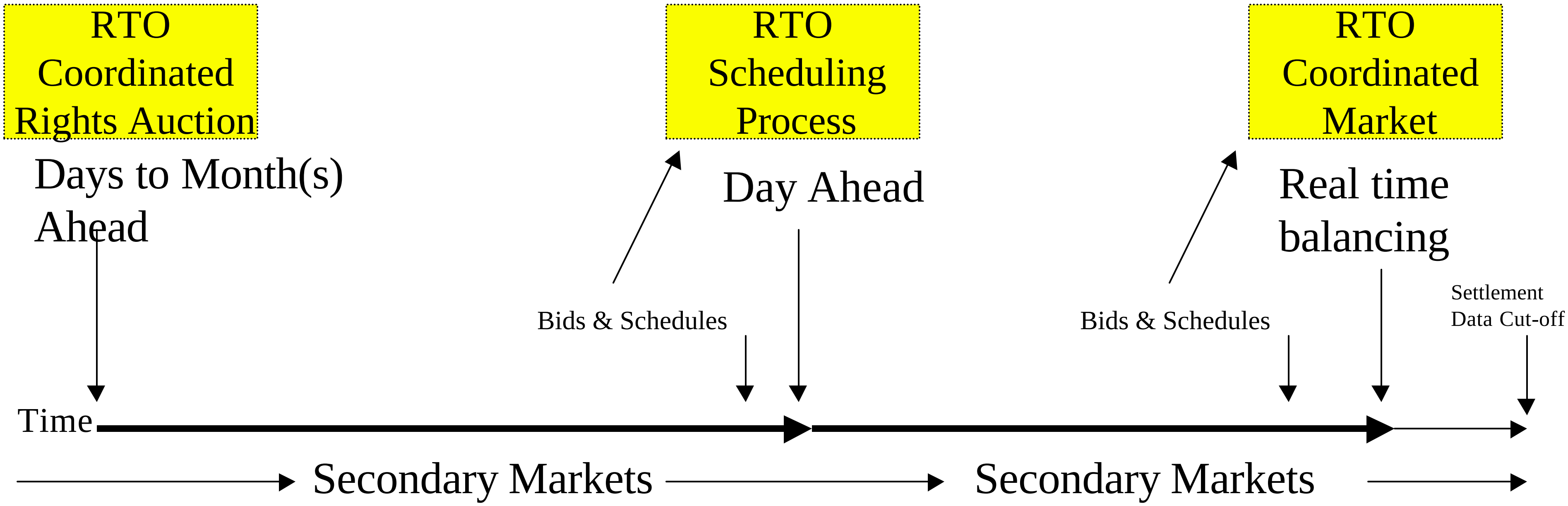
- **A system of tradable transmission rights can use markets to allocate transmission and help manage congestion in advance**
- **Bilateral markets and private exchanges can arrange schedules that will avoid and/or relieve some constraints**
- **An RTO can use voluntary bids to "redispatch" generation to solve congestion and also balance the system at least cost**

These approaches *all* have merit.

More important, *they are not mutually exclusive.* An effective RTO can use *all* of these approaches to give the market (and the RTO) maximum flexibility in managing congestion. The result can be a highly efficient market and a very reliable system.

We describe such *combined* market approaches in this session.

An RTO Congestion Management Model
One-Settlement System



This picture depicts the basic features of one possible RTO congestion management system. It combines multiple market approaches to manage congestion. Forward transmission and energy markets operate to allocate transmission and provide price certainty, and a real-time physical market operates to ensure reliability.

An RTO Market-Based Congestion Management System

In this system, the RTO holds periodic competitive auctions of transmission rights to allocate transmission well in advance of real time. Transmission is thus initially allocated efficiently, to those who value it the most.

Bilateral secondary markets and private exchanges operate continuously to allow participants to trade energy and to trade their transmission rights to support the energy transactions they are arranging in the forward period.

The RTO coordinates a bid-based real-time physical market for balancing and to provide any redispatch needed to resolve remaining congestion.

For market flexibility, efficiency *and* reliability, *every piece is important.*

An RTO Congestion Management System

Most trading occurs in *forward* secondary markets.

- **Parties arrange bilateral trades**
- **Parties trade transmission rights**
- **There may be one or more private exchanges to facilitate these markets**

The RTO's *real-time* physical market allows participants to reconcile and settle their positions.

- **Parties can use the real-time balancing market to buy and sell spot energy and transmission to balance their individual positions**
- **Parties settle their imbalances at market-clearing prices**
- **Parties pay for the transmission they used**
- **Parties are credited/paid for the rights they hold**

An RTO Congestion Management System

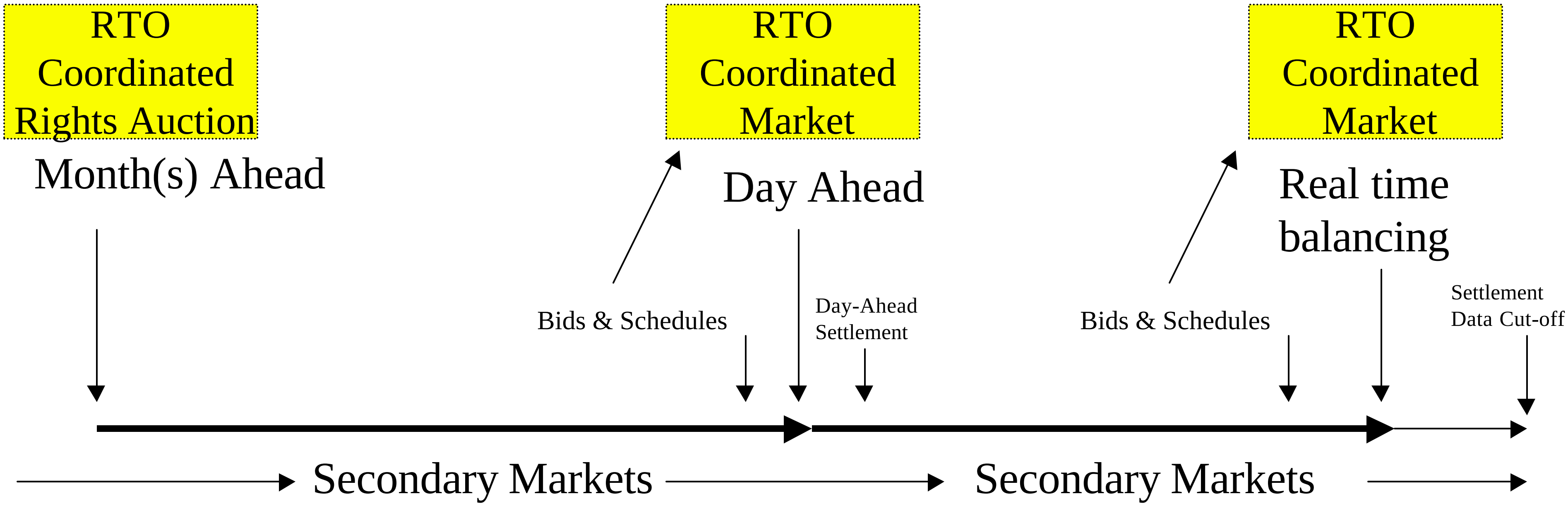
The features and operations of the secondary markets are defined by each of these markets.

- **Parties arrange their own bilateral trades; they define the terms**
- **Private power exchanges (e.g., APX) define their own bidding and settlement rules, hedging mechanisms, etc.**

The RTO's market rules must be specified and filed at FERC. For example, a set of RTO market rules could explain that:

- **The RTO coordinates a real-time physical market. Voluntary market bids and schedules are submitted day ahead up to near real-time**
- **The RTO uses the voluntary market bids to arrange a security-constrained economic dispatch -- *a dispatch that solves remaining congestion --* and balances the system at the lowest as-bid cost**
- **The RTO uses marginal cost principles to define market-clearing prices, which are used to settle the real time physical market**

An RTO Congestion Management Model
Two-Settlement System



A variation of the same model would include an RTO-coordinated *forward* market. The picture here shows a day-ahead market coordinated by the RTO.

1. This is the prevalent model in use or under development in the Eastern ISOs.

2. Private exchanges and other secondary markets function as before.

3. The RTO day-ahead market provides *another option* for exchanging rights and obtaining energy and transmission price certainty. Participation is voluntary *and* is not restricted.

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Generic Market Rules: RTO-Coordinated Bid-Based Markets

A fundamental feature of this model is that the RTO coordinates one or more bid-based markets. There are several reasons to consider this:

- ***FERC requires it*. The RTO must coordinate (or have an entity under its supervision coordinate) a real-time balancing market. The RTO must assure that all parties have open, non-discriminatory access to this market**
- ***It works*. The voluntary submission of price/quantity bids to the RTO has proven to be an effective mechanism to facilitate participation**
- ***It's fair*. A bid-based approach is non-discriminatory; it gives all participants equal and open access to the RTO-coordinated market**
- ***FERC likes it*. FERC has approved and praised this bid-based market approach in the four currently operating ISO markets**
- ***It's becoming common*. There are proposals to develop this basic approach in other regions**

Market Design Choices

Most of the basic features of this RTO congestion management system can be found or are under development in many places.

- **California**
- **Eastern ISOs -- PJM, NY, ISO-NE**
- **Parts of the Midwest and South (ComEd, Entergy/SPP, etc.)**
- **Ontario**
- **Mexico and several South American countries**
- **Australia, New Zealand, Singapore**

Important elements of this approach also appear in **Desert Star, Mountain West, and ERCOT**. However, there are several very important differences between all of these markets. The differences highlight the *design choices* each RTO has. This session explores these choices and their implications.

Market Design Choices: Bidding Rules

Voluntary. Participation in the physical market -- e.g, a bid-based dispatch/balancing market, and any bid-based day-ahead market (if there is one) is voluntary

- **Participants decide whether they want to participate by bidding**
- **Participants decide what prices/quantities they want to bid**
- **Participants can schedule bilateral transactions with or without bids**

Mandatory. Every generator must bid. Except where rules cap bid prices, the impact of this rule may not be what it seems:

- **Participants that want to be scheduled can simply bid prices that ensure they are dispatched**
- **Participants that want to avoid being scheduled can simply bid prices that ensure they aren't dispatched**
- **Bilateral participants bid accordingly**

Market Design Choices: Access to the Market

Unlimited. A companion rule to the voluntary bidding rule is that participants can choose how much they want to use the RTO-coordinated market.

- **There are no limits on how much they can use the RTO markets**
- **There are no financial penalties for using these markets, other than to accept settlements at market prices**

Limited. Alternatively, the RTO could impose rules that seek to limit access to RTO markets.

- **Require parties to submit and maintain balanced schedules (and/or discourage use of the RTO spot market)**
- **Penalize use of the balancing market outside some band**

The reasons for limiting access to *any* market should be carefully examined, since they can affect market efficiency and may not be consistent with Order 2000.

Market Design Choices: Dispatch Goals

Economic Dispatch. An important rule in most regions is that the RTO uses the bids from market participants to define an economic dispatch for those generators (and dispatchable loads) who voluntarily submit bids

- **The RTO uses all the generator bids from lowest to highest (merit order) to achieve the lowest as-bid cost for its dispatch**
- **If the RTO has to dispatch "out of merit" to relieve a constraint, it does so at the lowest cost, given the bids, the constraints and the relative effectiveness of different generators in relieving the constraints**
- **This is sometimes called a "security-constrained economic dispatch"**

Market Design Choices: Dispatch Goals (cont)

Alternative dispatch goals. In some markets (e.g., CAISO), RTO economic dispatch is not the goal. Other objectives determine the dispatch, and various rules limit the ISO's ability to find and implement a least-cost dispatch.

- **The ISO may not use an "inc" bid from one party and a "dec" bid from another party to clear congestion. As the ISO selects bids to relieve congestion, it must leave each party's portfolio balanced. The ISO cannot arrange the dispatch in ways that will result in "inter-party trading," even if it would be advantageous to the bidding parties and result in a lower cost dispatch.**
- **The ISO must stop considering lower-cost dispatches once it finds the minimal redispatch needed to relieve congestion**

In California, these are called "market separation" rules

Market Design Choices: Dispatch Goals (cont)

"Market-separation" rules are argued to be necessary and desirable to limit the ISO's participation in the market and to encourage innovation and bilateral trading.

The reasons for not allowing the RTO to implement an economic dispatch need to be explored and questioned, because they can lead to outcomes that are inconsistent with the bidders' economic preferences . . .

- **Generators willing to provide lower-cost energy are not dispatched**
- **Generators willing to back down if the market price is lower are still dispatched on**

And they run counter to Order 2000, which states ". . . proposals should ensure that (1) the generators that are dispatched in the presence of transmission constraints are those that can serve system loads at least cost . . ." (p. 332-3)

Market Design Choices: Consequences of Alternative Dispatch Goals

The California ISO has discovered that the market separation rules cannot be enforced all the time.

- **CAISO must ignore market separation rules to solve intra-zonal congestion in real time, because there may not be enough unrestricted inc/dec bids in the right locations to relieve congestion**
- **This problem will increase as more zones are created**
- **The participants have realized they are leaving money on the table; they've asked for voluntary inter-party trading coordinated by the ISO in the ISO markets (Amendment 29, pending at FERC)**

The restrictions have also had unintended consequences.

- **The lack of unrestricted bids forces the ISO to use non-market pricing and mandatory measures to relieve congestion and maintain reliability/system balance, but FERC has rejected some of these rules (Amend. 18 and 23)**

Market Design Choices: Relaxing the Market Separation Rule

There are two kinds of proposals to relax the CAISO market separation rules.

Voluntary *selective* approach: A scheduling coordinator (SC) may agree to allow the ISO to use its bids in conjunction with bids from another SC to relieve congestion, but only if each SC has agreed to allow the ISO to arrange "trades" *between them*.

Voluntary *non-selective* approach: Any scheduling coordinator may agree to allow the ISO to use its bids in conjunction with bids from any other SC (that has also agreed) to relieve congestion.

Market Design Choices: Relaxing the Market Separation Rule

The voluntary *selective* approach is intended to prevent the ISO from “forcing” any party to accept an ISO-coordinated “trade” with any party with whom it does not wish to trade.

- **It allows the party to selectively choose to do business with some, but not with others**
- **It requires the ISO to enforce these selections**
- **It is uncertain whether FERC would accept the concept of having the ISO enforce selective trading that may be motivated by market power or anti-competitive discrimination (must the ISO check?)**
- **The “forced trade” logic should be questioned**

The voluntary *non-selective* approach is simply a voluntary economic dispatch approach for those who choose it.

- **The ISO does not/cannot enforce selective trading preferences**

Market Design Choices: Pricing for Settlements

Market-clearing prices. The RTO would price and settle its coordinated market(s) at market-clearing prices.

- **This rule is market-based pricing based on marginal costs**
- **It sends efficient price signals**
- **It encourages generators to bid their marginal costs**
- **This is the basic rule in most RTO-type markets**

Pay as-bid prices. Alternatively, we could pay participants the prices they bid. Zonal systems use this for redispatched generators.

- **Any expected "savings" of this approach are elusive**
- **If generators are paid their bids and can bid any price, they will *change their bidding behavior* to capture market price**
- **Generators would set their offer prices at their expectations of the market-clearing prices; guesses could lead to inefficient dispatch**

Market Design Choices: Marginal vs Average Cost Pricing

Marginal cost pricing. An important rule in many markets is that the RTO uses marginal costs to define market-clearing prices for the markets it coordinates. This ensures efficient price signals.

- **Energy bought and sold in the RTO real-time balancing market is priced at marginal cost**
- **If the RTO coordinates a forward (day-ahead) market, energy bought and sold in that market is priced at marginal cost**
- **Transmission usage is priced at marginal cost, which means that**
- **Congestion is priced at marginal cost**
- **Pricing at marginal cost means some form of locational pricing -- nodal or zonal -- and not average or uniform pricing**

Average/Uniform pricing. We examine the features and merits of alternative pricing approaches in the next session.

Market Design Choices: Comparable Treatment

Consistent use of market clearing pricing ensures that all parties are treated comparably, without cost shifts, whether they:

- **Schedule and implement bilateral transactions**
- **Buy and sell energy in the RTO-coordinate market**
- **Do any combination of the two**

For purposes of settlements, these are treated comparably:

- **A sale at location "A" and purchase at location "B"**
- **A bilateral transaction scheduled from location "A" to location "B"**

Comparable treatment at prices based on marginal costs allows parties to move freely between bilateral and spot transactions without imposing cost shifts on another party. It allows maximum flexibility to participants.

Market Design Choices: The RTO's Role in Coordinating a Real-Time Physical Market

In many markets, an important element is the concept that the RTO will coordinate a real-time physical market for balancing and resolving congestion.

- **FERC is requiring an RTO-coordinated real-time balancing market**
- **Allowing any other party(ies) to operate the real-time market is problematic, given FERC's rules for scope and independence**

Alternative models in which the RTO does not appear to provide a real-time physical market are being proposed and developed. These efforts started before Order 2000.

- **Desert Star**
- **Mountain West ISA**
- **ERCOT**

Market Design Choices: RTOs Without Real-Time Physical Markets

Prospective RTOs without real time physical markets must eventually confront certain critical questions at FERC:

- **How does the system use markets to deal with real-time congestion and imbalances? What happens if a party's real-time operations don't match its schedules?**
- **How are parties charged for transmission they actually used that is in excess of, or different from, the transmission they originally scheduled (or for which they purchased rights)?**
- **How will system reliability be maintained (and by whom) if the RTO has no real-time dispatch function? If separate non-independent control areas balance their own systems, how do parties get non-discriminatory access to that service?**
- **If market participants participate in that service, how will they be charged and/or compensated for their participation?**

Congestion Management Workshop
Session 2B:
Congestion Pricing Approaches

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How Would Each RTO Price Congestion?

Under the RTO bid-based congestion management models, the RTO *could* use locational marginal pricing (LMP) to price energy and transmission bought and sold in the RTO-coordinated markets.

- **LMP is a method to price balancing energy at each location to reflect the system operator's marginal cost of redispatching to relieve congestion**
- **LMP also reflects the marginal cost of transmission usage, so it can support market-based transmission rights and their trading**

FERC's Order 2000 encourages RTOs to use locational marginal pricing (LMP), but it does not require it.

Alternatives to LMP

Because FERC has not mandated LMP, we need to consider alternative pricing methods. In this session we examine the principal alternative pricing approaches that have been tried by other ISOs or proposed for new RTOs.

We will first examine three basic alternatives to LMP:

- **A uniform pricing system**
- **A zonal pricing system**
- **A hybrid system that combines aspects of zonal pricing and "nodal" (LMP) pricing**

Option 1: Use a Uniform Price to Settle Transmission and Energy Imbalances

Uniform pricing systems apply a uniform transmission charge to all transactions and a uniform price to all energy purchases and sales in the RTO market, without regard to each transaction's impact on congestion.

- **The RTO settles all imbalances at the same uniform price, regardless of the location**
- **All costs the RTO incurs in redispatching generation to relieve congestion are charged to all customers (or all loads) as a uniform charge or "uplift." The uniform charge is usually imposed on a per kWh basis**
- **There is no attempt to use marginal cost pricing for energy or transmission**

Defining a Uniform Price

If an RTO uses a uniform price to settle transmission and/or energy imbalances, it must first define how it determines the uniform price for each period. There are at least two possible approaches:

- ***Unconstrained dispatch approach*. It could define the price as the bid price of the marginal unit in an unconstrained dispatch (U.K., PJM from 1997-98, Ontario)**
  - ***Construct a* hypothetical *dispatch based on the bids, but ignoring congestion and all security constraints***
  - ***Pick the price bid by the last unit/block used in that dispatch***
- ***Average price approach*. It could calculate the marginal cost prices (LMP) at each node, and find the weighted average price for all nodes in the region**
  - ***The nodal prices would be determined by the bids, given the* actual *dispatch and the actual constraints***
  - ***The RTO would use the average price as the region's uniform price***

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Features of a Uniform Pricing System

If the RTO used a uniform price for balancing, it would need other rules to deal with pricing effects:

- **Some generators would need to be paid constrained-off payments to get off, to relieve congestion on the RTO grid**
- **Some generators would need to be paid constrained-on payments to meet demand in constrained regions**
- **Rules would be needed to limit gaming -- because the interaction between the uniform price and the constrained-on/off payments would encourage strategic bidding**
- **Additional rules might be needed to limit access to the balancing market -- because the uniform balancing price shifts costs**
- **Additional rules might be needed to restrict new generator connections and/or control investments -- because prices would not provide good incentives**

Uniform Pricing Requires Side Payments for Redispatched Generators

When transmission congestion exists, some generators with bids above the uniform balancing price must generate and some generators with bids below the uniform price must be held down to relieve the transmission congestion.

Under a uniform pricing system, these constrained-on and constrained-off generators are usually compensated with side payments.

- **Constrained-on generators (Generator "N") are paid the higher of the uniform price or their bid**
- **Constrained-off generators (Generator "H") are paid their opportunity cost, which is the difference between the uniform balancing price and their bid**

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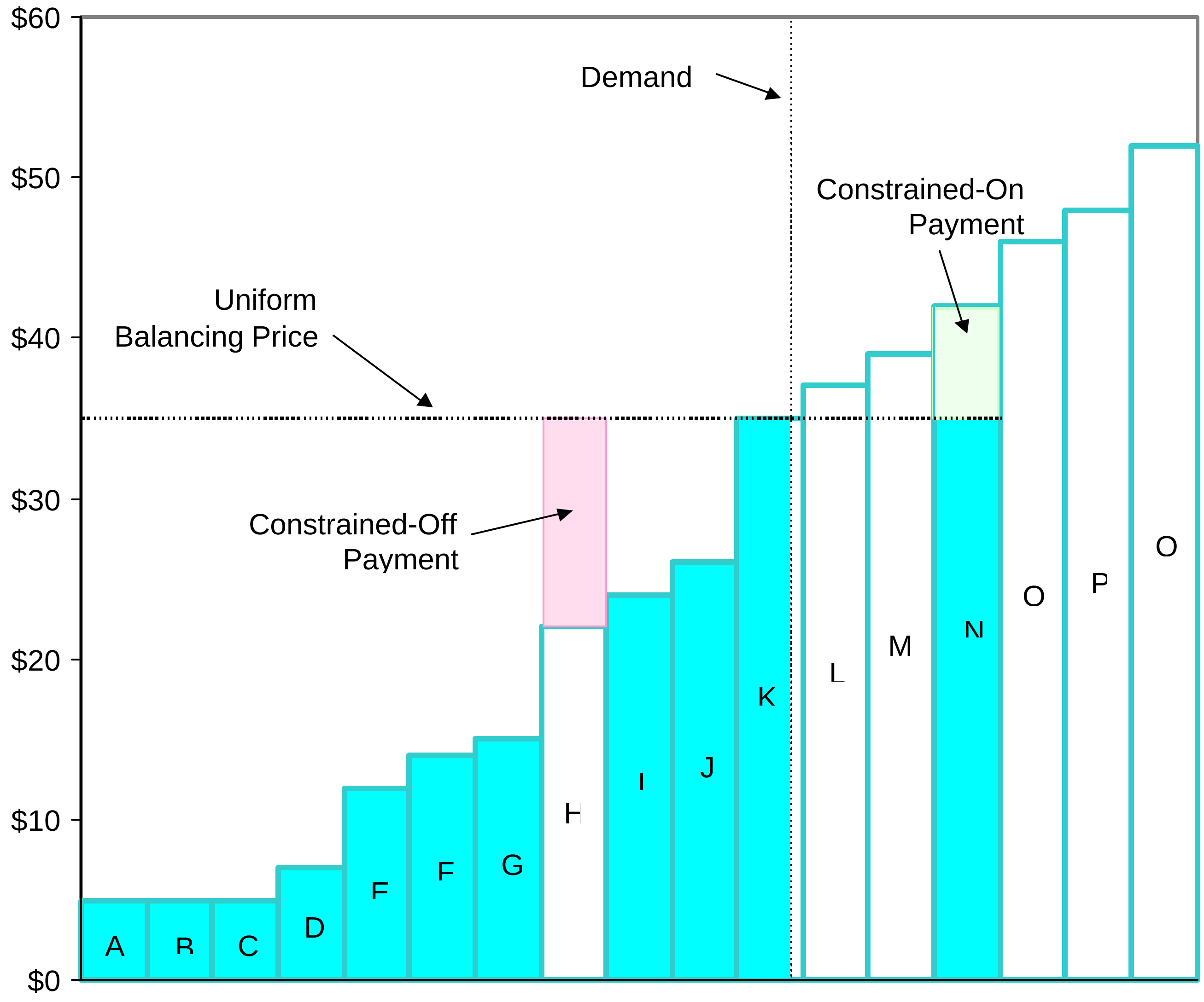
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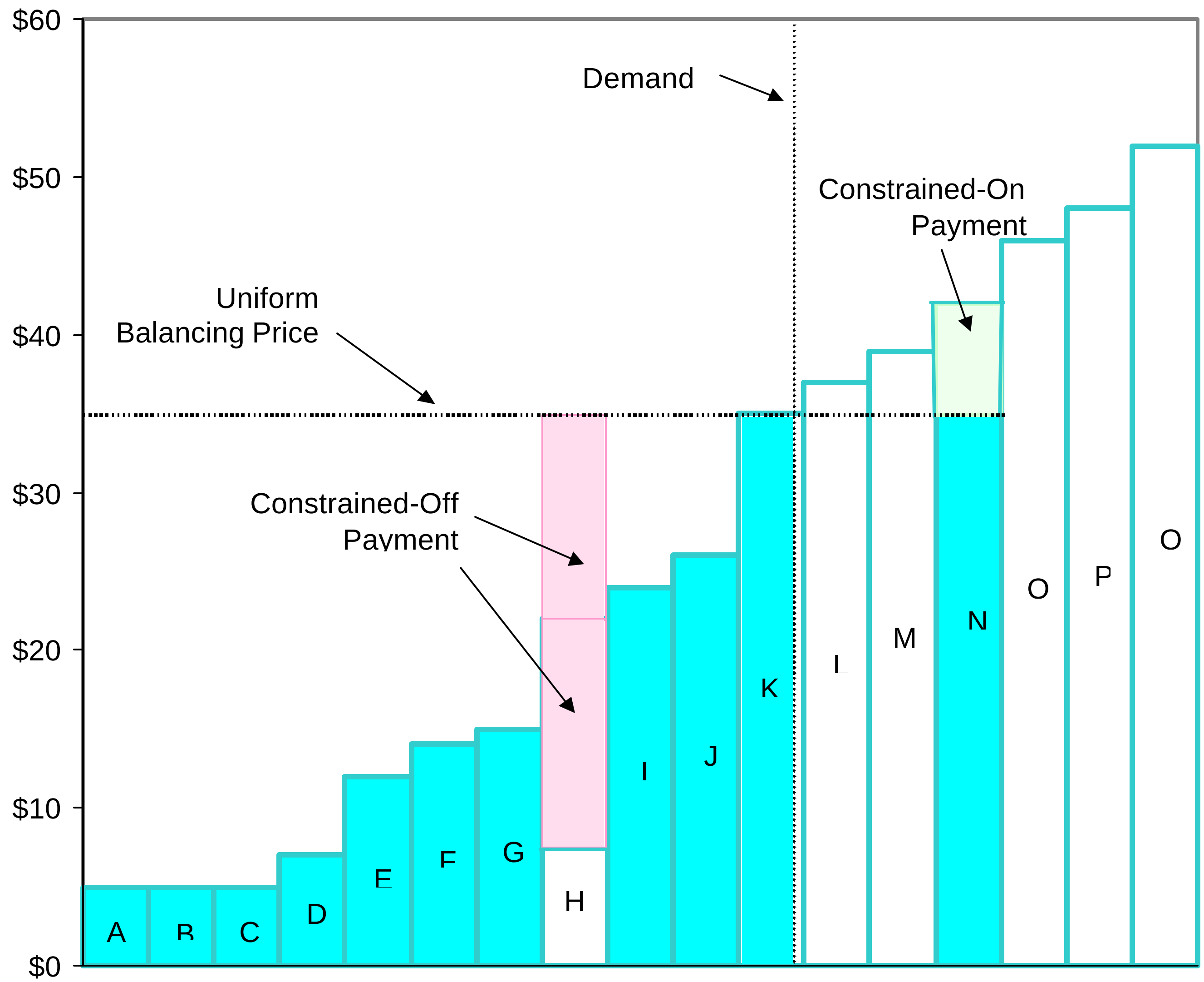
Under Uniform Pricing, Side Payments Encourage Bid Gaming: The "Dec Game"

If the rule for a *constrained-off* side payment is that the generator will be paid the difference between the uniform balancing price and its bid, then a generator has an incentive to *lower* its bid, even below its running costs.

- **It will lower its bid down to the level at which the next likely constrained-off unit would bid. That unit will depend on its price and location -- i.e., on the relative cost and effect of its generation on relieving the constraint**
- **In the graph, if the next likely constrained-off unit to be chosen by the RTO is Generator "D," then Generator "H" has an incentive to lower its bid down to a level just above the bid from Generator D**

The "constrained-off game" (also called the "dec game") can be exacerbated if the generator owner has market power.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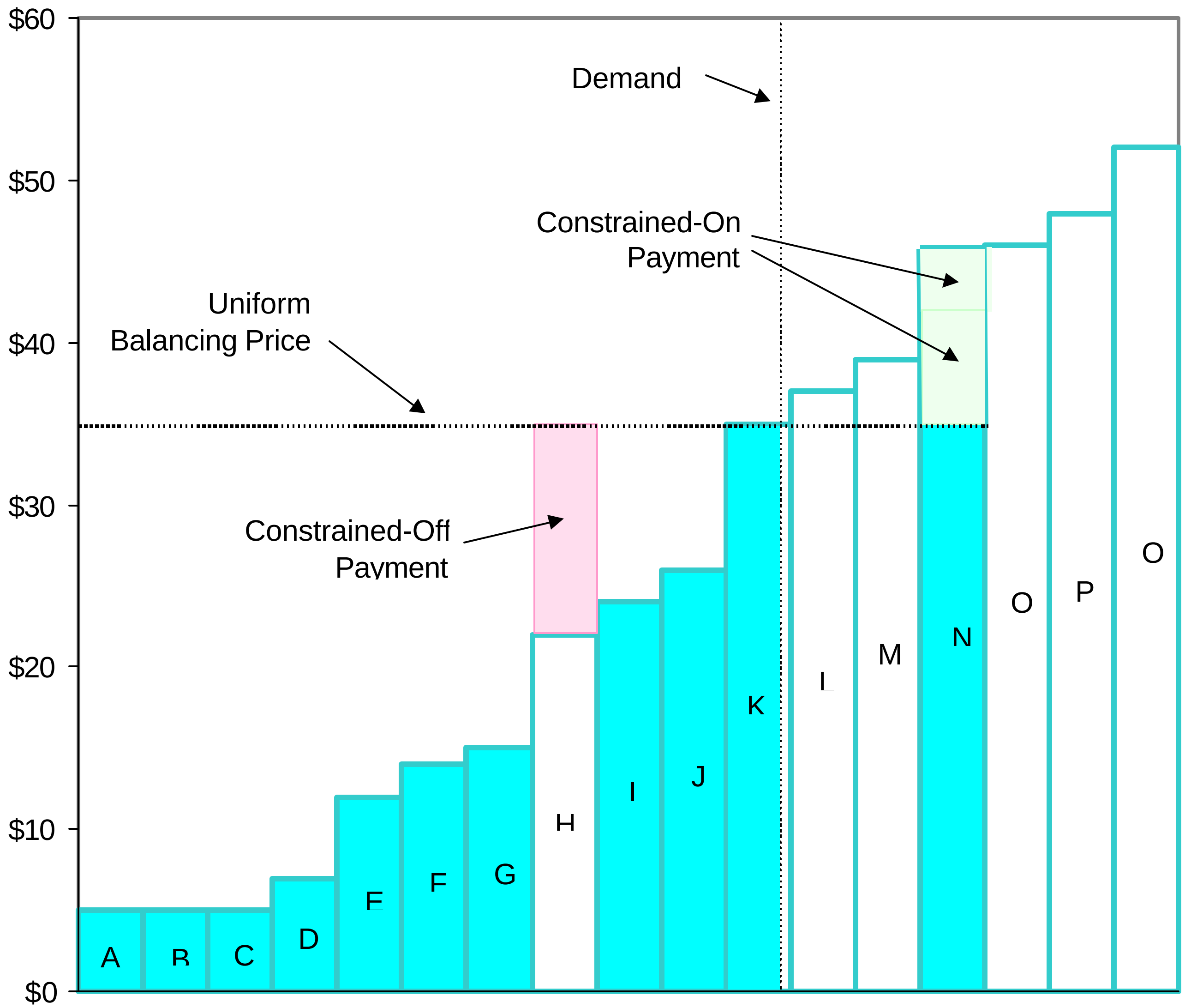
Under Uniform Pricing, Side Payments Encourage Bid Gaming: The "Inc Game"

If the rule for a *constrained-on* side payment is that the generator will be paid the higher of the uniform balancing price or its bid, then a generator has an incentive to *raise* its bid above its running costs.

- **It will raise its bid up to the level at which the next likely constrained-on unit would bid. That unit will depend on its price and location -- i.e., on the relative cost and effect of its generation on relieving the constraint**

- **In the graph, if the next likely constrained-on unit to be chosen by the RTO is Generator "O," then Generator "N" has an incentive to raise its bid up to a level just below the bid from Generator O**

The "constrained-on game" (also called the "inc game") can be exacerbated if the generator owner has market power.



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Uniform Pricing Systems Can Lead to Restrictions on Market Access

Because uniform pricing systems do not price congestion, they are sustained either by tolerating cost shifts or restricting access to transmission and the RTO's balancing market

- **Transmission access may be restricted because transmission users are not paying the marginal cost of transmission. The costs are being shifted to others who pay the uniform congestion (uplift) charge. The incentive is to overuse the grid.**
- **Balancing market access may be restricted because selling power at "A" and buying power at "B" is the same as using transmission between A and B (PJM in 1997-98)**
- **Participants can shift costs merely by using this market**
  - ***Generators in low cost regions can shift costs by selling (over-generating) imbalances and receiving the higher uniform price***
  - ***Generators in high-cost regions can shift costs by buying imbalance energy at the lower uniform price***

Uniform Pricing May Require Controls on Investment Decisions

Uniform pricing does not price energy or transmission at marginal costs. Participants thus receive incorrect price signals about where to locate new generation or loads and where to upgrade transmission.

- **Both New England and California ISOs proposed restrictions on new generation interconnections, because they feared that generators would locate in the "wrong" locations, thus worsening congestion**
- **FERC rejected these rules for their anti-competitive effects**
  - ***ISO NE has since decided to implement LMP and has just filed revised tariffs at FERC proposing LMP, FTRs, and a two-settlements system***
  - ***FERC ordered CAISO to undertake a comprehensive reevaluation of its congestion management system. That process is still ongoing***

Some Form of Average Pricing is Probably Necessary for Most Loads

In virtually every market, including those using LMP, some form of averaging is used to charge most loads.

Average pricing for loads is driven by metering limitations.

- **Most end-use customers do not have interval meters that can distinguish hourly energy use and hourly pricing**
- **These customers receive monthly bills that effectively average prices anyway**

Average pricing is also driven by political and transition issues.

- **Regulators are reluctant to expose smaller end-use customers to market prices all at once**
- **In PJM and NY, the ISO determines the average LMP price for each utility's service area. Customers without interval meters are charged these average prices**

Option 2: Zonal Pricing

Zonal pricing is a form of locational pricing. It is also a form of marginal cost pricing. It recognizes that the price of energy will differ between locations when the grid is congested.

In a system with zonal pricing:

- **Energy prices are allowed to differ between zones, which are regions connected by transmission facilities that are expected to be congested frequently**
- **Energy prices within zones are set at a uniform price, on the assumption that**
  - ***There is no significant congestion within the zone to cause locational prices to differ within the zone***
  - ***The congestion between the zones does not cause locational prices within a zone to be significantly different***

Goals of Zonal Pricing

Zonal pricing is intended to balance potentially conflicting goals.

- **Use markets to manage *important* congestion by recognizing the *commercially significant* locational differences in prices**
- **Achieve commercial simplicity by avoiding “too many” prices.**
- **Avoid seriously compromising the need to have prices reflect marginal costs**
- **Provide efficient price signals**

Inter-Zonal Pricing Uses Marginal Costs

In the CAISO zonal system, the RTO applies marginal cost pricing *between* zones. Market participants submit bids for transmission in the RTO market(s).

- **Given bids from various parties, the ISO allocates inter-zonal transmission to those who value it the most**
- **Given the bids, the ISO can define the marginal cost (from the bids of the marginal user) for using the inter-zonal transmission**
- **The marginal costs then define the usage charge that the ISO applies to all users of the inter-zonal transmission**

Intra-Zonal Pricing is Uniform Pricing

An important feature of any zonal pricing system is that *uniform pricing applies within each zone*. All of the additional rules and concerns that apply to a uniform pricing system also apply in a zonal system:

- **Constrained-on and constrained-off payments are needed**
- **The incentives for bid gaming are present**
- **The potential for cost shifts by those using the grid or using the imbalance market is present whenever congestion occurs**
- **The need for RTO controls on interconnections and investment decisions is present**

The assumption, however, is that congestion (or price differences) within each zone will be so infrequent and insignificant that these aspects of uniform pricing will not be a serious problem, *provided* the zones are correctly defined.

Inter-Zonal Pricing: Bidding for Transmission

Each party's bids are in the form of incremental and decremental adjustments to their schedules at various prices.

- **Suppose a party has a schedule from point A to point B, with an incremental bid at B and a decremental bid at A.**
  - ***An* incremental bid *of $40/MWh means that the party is willing to increase generation at point "B" if the RTO will pay the party $40/MWh for the additional energy***
  - ***A* decremental bid *of $30/MWh means that a party is willing to reduce its generation at point "A" and will pay the RTO $30/MWh for replacing this energy***
  - ***The* difference *between a party's incremental bid at one location and its decremental bid at another location ($40 - $30 = $10) indicates the value that the party places on using the grid between the two locations***

Assumptions Underlying Zonal Pricing

Zonal pricing depends on very important assumptions about the grid and the RTO's ability to predict its use:

- ***Some congestion is important.*** **We assume that:**
  - ***The RTO can accurately predict congestion that is likely to be more frequent and more costly to relieve***
  - ***The RTO can draw appropriate boundaries given these predictions***
  - ***Because this congestion is important, marginal cost pricing is needed to deal with it effectively and to send the right price signals.***
- ***The remaining congestion is unimportant.*** **We assume:**
  - ***The RTO can accurately predict congestion that is likely to be infrequent and doesn't cost much to relieve***
  - ***An average (uniform) pricing system will be good enough to deal with it; marginal cost pricing for unimportant congestion isn't needed***
  - ***Because this congestion is infrequent and unimportant, the price signals don't matter that much***

The Success of a Zonal System Depends on How Good the Assumptions Are

The success of any zonal pricing system depends on the degree that zone boundaries are based on accurate predictions of which constraints will actually cause congestion.

- **If the constraints have been correctly predicted and the zones have been drawn in such a way that prices within each zone are relatively uniform when those constraints bind, then the zonal system can function reasonably well.**
- **If these conditions are not met, then problems will arise that require RTO intervention.**
  - ***The RTO's average/uniform pricing within each zone will consistently send the wrong price signals***
  - ***Congestion within the zones will become increasingly more troublesome, as market participants respond to the wrong price signals***
  - ***If parties do not have to pay marginal costs for this congestion, the RTO will repeatedly have to intervene in the market to offset the effects of the wrong price signals.***

What Has Been the Experience for ISOs that Used Zonal and Uniform Pricing?

The experiences in PJM (pre-LMP), ISO NE and California illustrate the risks in these assumptions:

- **Predictions about the level of congestion have been consistently understated -- there has been a lot more congestion than expected**
  - ***Congestion increases as soon as the market starts and generators are free to respond to prices***
- **Predictions about where congestion would arise have not been accurate -- congestion has arisen in places that were not expected**
- **The costs of managing congestion (the uplift to cover constrained-on and constrained-off payments) have been much higher than expected (not counting higher A/S costs)**
  - ***In ISO NE, uplift costs have been averaging about $1 million per day***
  - ***The allocation of these costs has been on those with no assured cost recovery from their state regulators***

Experience With Zonal Assumptions

Importantly, several key assumptions about the zonal method have often been incorrect:

- **The assumption that an ISO can predict and distinguish between "important and frequent" congestion and "unimportant and infrequent" congestion has been shown to be suspect**
- **The assumptions that an averaging or uniform pricing system would be "good enough" for intra-zonal congestion and that the problems with wrong pricing signals would be minimal have proven to be *very wrong*:**
  - ***Every ISO has had serious problem trying to deal with operational decisions of generators following the wrong price signals***
  - ***Bid gaming encouraged by the constrained-on/off payments has proven to be a serious problem, especially in California***
  - ***Intra-zonal pricing has created new ways for generators to create artificial congestion and exploit market power***

Approaches to Improving Zonal Systems

The most obvious remedy for the adverse effects of intra-zonal (uniform) pricing is to apply inter-zonal (marginal cost) pricing to more congestion. There are two basic approaches:

- ***Create more zones*, and revise the zones more frequently**
  - ***The goal is to make sure that zones keep up with the actual and possibly changing patterns of congestion and virtually always capture the "important and frequent" congestion***
  - ***The criteria for new zone creation must be relatively easy to meet; they should not be a barrier to new zone creation***
  - ***The RTO must apply the criteria for creating new zones objectively and more or less automatically. Ideally, the process should try to avoid politically motivated delays or boundary gerrymandering***
- ***Move to nodal pricing* -- apply marginal cost pricing to all congestion, without trying to predict "important" vs "unimportant"**

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Issues in Creating More Zones

A small number of zones is easier to deal with, but only if the actual grid and congestion are also simple. If the actual grid/congestion conditions require more than a few zones, dealing with many zones may be complicated

- **More inter-zonal interfaces (and loops around these interfaces) means that there can be commercially important price differences within the zones; radial assumptions that may apply with only 2-3 zones will not work**
- **The administration of zone-to-zone or inter-zonal interface rights is more difficult; trading/exchanging rights when points of receipt/delivery change can become more difficult**
- **Transmission rights must be reconfigured/re-auctioned; contracts may have to be renegotiated**
- **Market separation rules must give way, because there may not be enough balanced bid options to allow the RTO to manage all the inter-zonal congestion. The RTO will need to make inter-party trades to maintain reliability.**

Desirable Features of a Zonal System

A successful zonal system may be achievable under certain conditions:

- **Zonal works best if only a few zones are enough to capture all commercially significant price differences caused by congestion**
- **Zonal pricing can be simpler if the zones are connected radially or by closed interfaces. If the interface is open (loops around the interface), congestion will cause price differences within a zone**
- **The RTO criteria for defining and redefining zone boundaries should keep zones consistent with zonal assumptions:**
  - ***The criteria should be based on price differences within a zone. Where the price differences are commercially significant to market participants, the zone should be split and redefined***
  - ***The process should be as objective and automatic as practical***

If these conditions do not exist, other pricing options, including nodal or voluntary nodal/zonal, should be considered.

Option 3: Voluntary Zonal/Nodal Pricing

It is also possible to design a market that combines both zonal and nodal pricing and allows the market to solve the problem of keeping the zones consistent with the realities of grid congestion.

A central problem that arises in zonal markets is the inability of the ISO (or the market) to predict in advance how important congestion will be at each location. Because congestion is hard to predict, there can often be too few zones or zones with inappropriate boundaries.

If generators and appropriately metered loads could voluntarily choose to be settled at either their locational price or their zone price, the market could help solve the problem of inappropriate zone boundaries.

A Voluntary Zonal/Nodal System

In the voluntary approach, the RTO does the best job it can in defining zones, but it also determines nodal prices for every location. The zone price is the weighted average of nodal prices.

Generators are allowed to choose whether they wish to be settled at the zonal price or their respective locational (nodal) prices. (Interval-metered loads could also choose)

- **Each generator makes an election for a given settlement period (e.g., at the beginning of the monthly billing cycle)**
- **For generators that choose the zonal price for that month, their RTO trades and congestion charges are settled using the zonal prices**
- **For generators that choose the nodal price for that month, their RTO trades and congestion charges are settled using the nodal prices**

Implications of the Voluntary Approach

If there is minimal intra-zonal congestion within a zone, there will seldom if ever be any commercially significant price differences within the zone. No one will have any incentive to change from the "simpler" zonal pricing method to the nodal pricing method.

If there is significant intra-zonal congestion within a zone, there will often be differences in the zone's nodal prices. Where the difference between the zonal and nodal price for a given participant is commercially significant, the participant will have a clear incentive to choose the pricing approach in its interest

These choices will tend to *change the effective zonal boundaries* in ways that align the zones with the zonal assumptions.

Incentives Under the Voluntary Approach

Generators at lower-price locations (and loads at higher-price locations) will tend to choose the zonal price.

Generators at higher-price locations (and loads at lower-price locations) will tend to choose their nodal price over the zonal price.

- **As these parties leave zonal pricing, they change the zonal average price. The remaining differences in the locational prices within the zone will tend to become commercially insignificant**
- **As the zones are redefined by the market, there will be less incentive for anyone else to move from zonal to nodal pricing**

The incentives thus provide a natural correction for poorly-defined zones. The market will change zones by choosing nodal whenever the zone averages include commercially significant locational price differences. The market defines what is "commercially significant."

Relevance of the Voluntary Approach

The voluntary approach has been suggested in California as a way to allow the CAISO to retain and improve its zonal pricing system. Rather than abandon its zonal system and start all over with LMP, the CAISO can use the approach to improve the efficiency of the price signals it gets from zonal pricing, while harnessing market incentives to help improve zonal boundaries.

An RTO starting from scratch might also consider this approach if there is any significant uncertainty about its zonal assumptions.

The voluntary approach is presented here because it highlights the issues an RTO must face if it selects a zonal approach.

Pricing Option 4: Use Locational Marginal Pricing for Imbalances

An RTO could use LMP to price balancing energy at each location on the RTO-controlled grid.

- ***Each seller (generator) receives the LMP at its location for any sales (injections) at its location***
- ***Each buyer (load) pays the LMP at its location for any purchases (withdrawals) at its location (LSEs might pay an area weighted average of the locational prices)***
- ***Bilaterals are credited/debited for their imbalances at LMP, and pay congestion charges based on LMP differences***

Under LMP, balancing prices and congestion charges would reflect the marginal costs of redispatching the system to relieve congestion, given the market bids.

We will describe the LMP pricing approach in a later session.

Congestion Management Workshop Session 3A: Tradable Transmission Rights

Objectives

Define a system of tradable transmission rights to support the RTO congestion management models

Describe the key features and market rules that define how the transmission rights would work

Vary the features and/or market rules in ways that would define alternative transmission rights models

Examine each rights model by considering:

- **Incentive properties of the model's rules**
- **How well it supports a competitive market**
- **How well it meets FERC's Order 2000 RTO requirements**
- **Flexibility, simplicity/complexity, and so on**

Existing Contract Rights Are Assumed

It is assumed here that existing contract rights at the time the RTO is formed could continue in some form. In the next session, we discuss how:

- **They might be grandfathered**
- **Some of them might be converted to the new rights system**

The transmission rights models discussed here would be based on the remaining capacity of the RTO-controlled grid, after the existing contract rights are accounted for in some manner.

The treatment of existing contracts and the possibility of some pre-market allocation of rights for equity purposes well be covered in another session.

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Consistency with the RTO Congestion Management Models

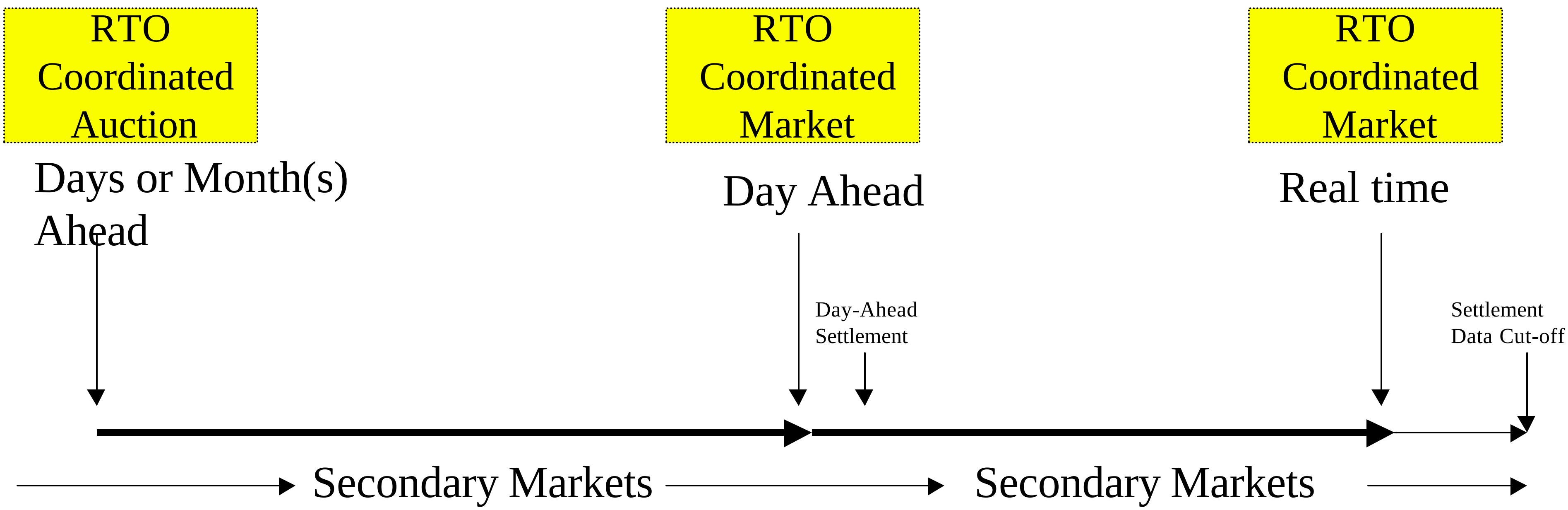
The transmission rights described here are designed to support the RTO congestion management models described in the previous session.

Recall that there were two versions of this model:

- ***A one-settlement system*, in which the RTO coordinates only a real-time balancing market. The RTO settles the real-time market at the real-time prices**
- ***A two-settlement system*, in which the RTO also coordinates a day-ahead forward market, in addition to its real-time balancing market. The RTO settles the forward market first at the forward market-clearing prices. The RTO use real-time prices to settle the real-time market based on deviations from the forward market**

The transmission rights model could work with either a one- or two-settlement system. We describe the case of the two-settlement system in this session.

Tradable Transmission Rights Model



The picture shows a framework for transmission rights, premised on a two-settlement system. Three key questions help define how the rights work.

1. Must participants acquire a right to get access to transmission? How and when do they do this?

2. If participants don't schedule or use a right, what happens to that right?

3. If a participant doesn't use a right, is the participant compensated?

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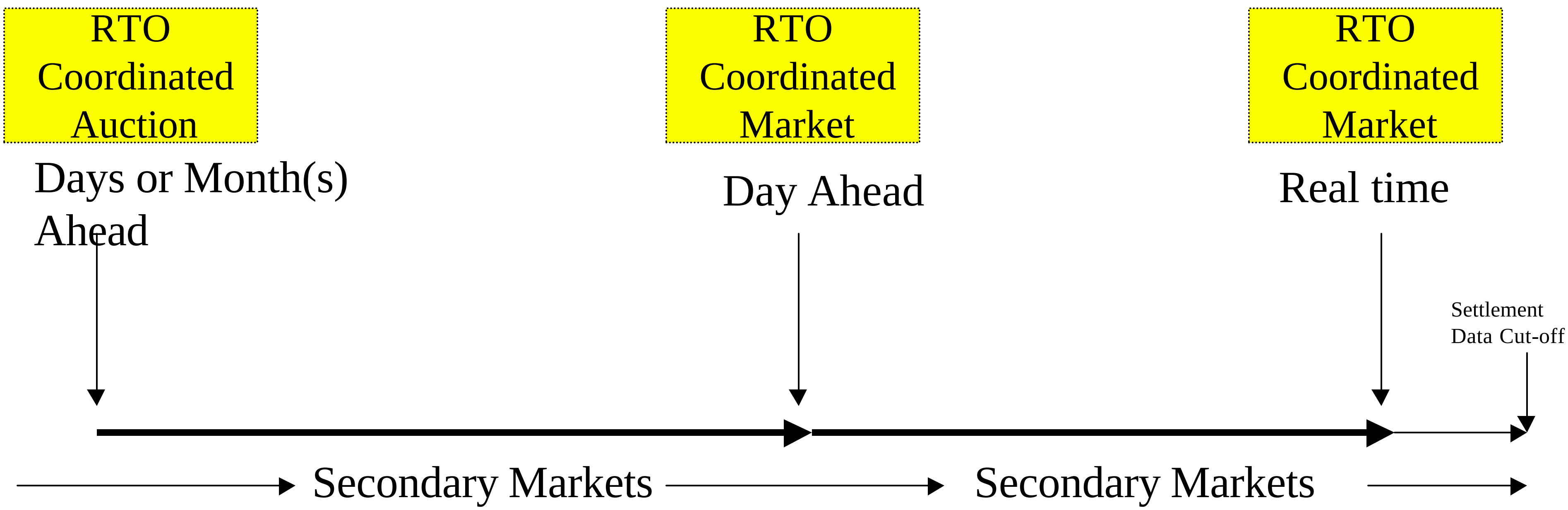
Tradable Transmission Rights Model



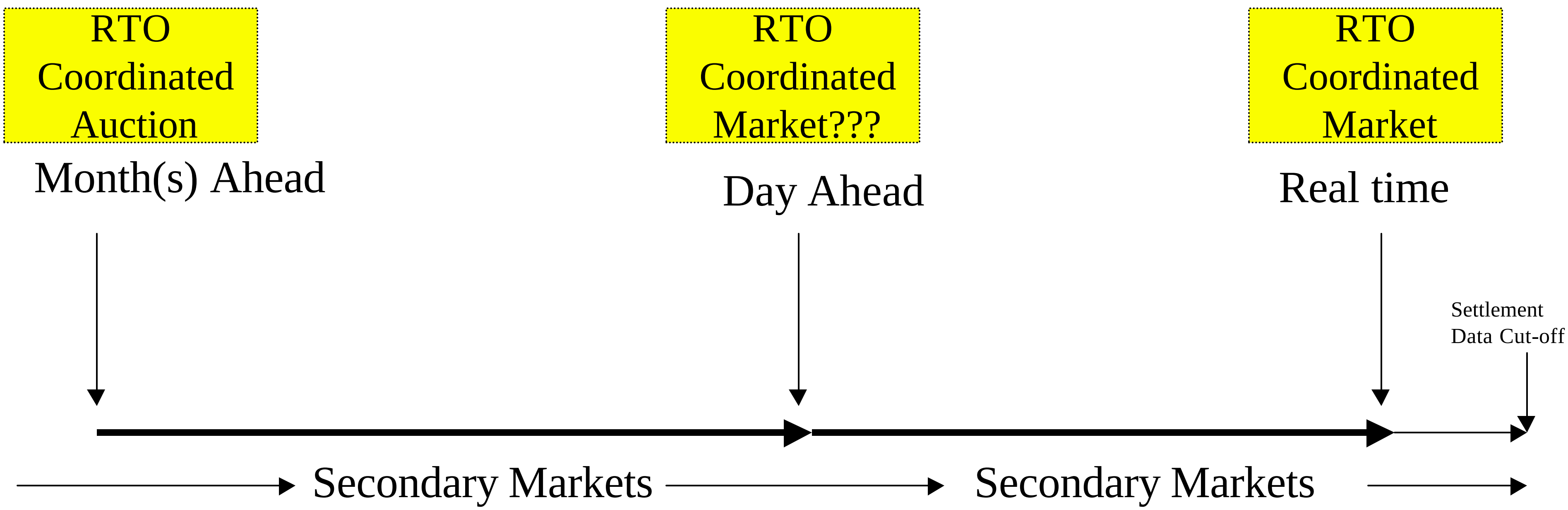
In one possible model, we could answer these questions in the following way:

1. A party must *eventually* purchase the right(s) for its transaction, but *it need not have the correct right(s) at the time it schedules a transaction*. It has many options in choosing how and when to purchase the right(s) it needs. Rights can be purchased in the RTO auction, in secondary markets, or in RTO coordinated markets.

2. If a party has a right, but does not schedule its right in the day-ahead market, *that right is surrendered to the RTO* for that scheduling period for sale to others in the RTO's coordinated Day-Ahead Market.

3. *The RTO will compensate the original owner of a right surrendered in the DA market*. The party will receive the market-clearing price defined by the bids/offers in the Day-Ahead market.

An Alternative Transmission Rights Model



An alternative model would define each of these three rules somewhat differently, and would produce a different market outcome and different incentives. E.g:

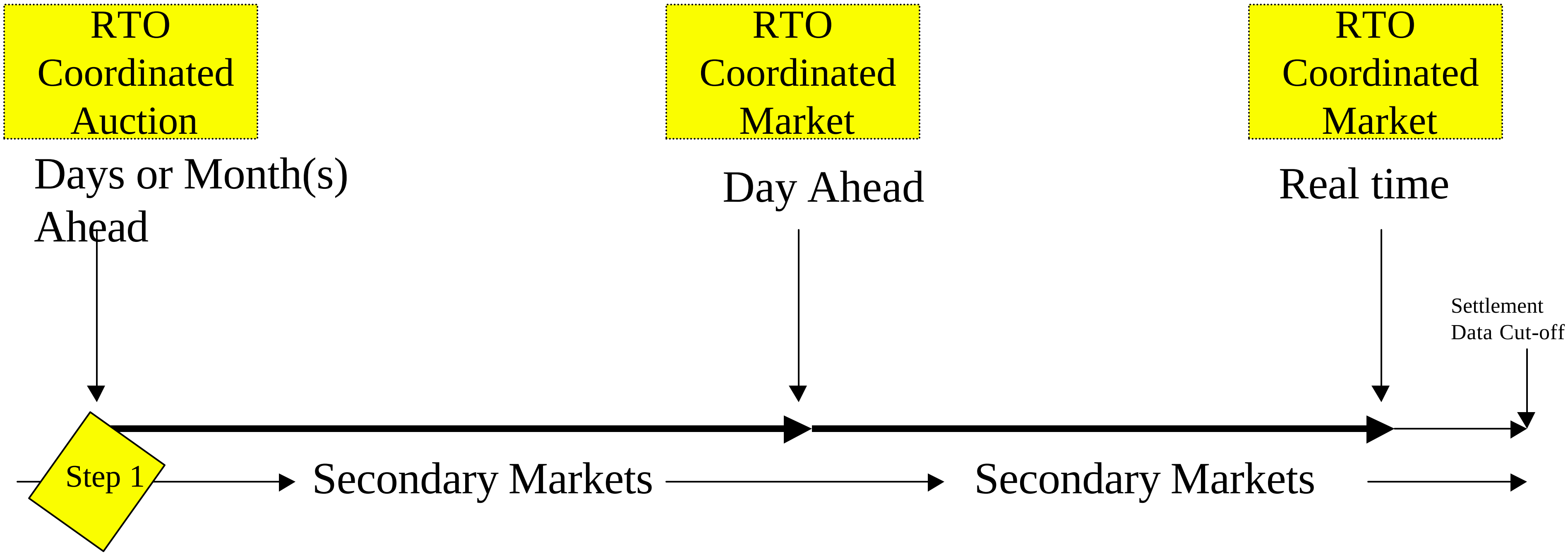
1. A party must purchase a right **before it schedules a transaction**. E.g., by the scheduling deadline for the Day-Ahead (DA) or Real-Time market. Variations would include a DA market or not.

2. If a party does not schedule its right by the scheduling deadline, **it loses that right**. ("use it or lose it")

3. The original owner of a right that "loses" its unused right **will not be compensated** for that right.

We will examine this model more closely later, after we describe how the first set of rules works.

Tradable Transmission Rights Model



Step 1: Get the transmission rights into the market.

The RTO would allocate transmission rights through a bid-based market auction. Participants would bid to buy rights at market-clearing prices. Participants with previously allocated rights could offer to sell their rights in this same auction market. Frequent auctions (at least monthly) are becoming the norm.

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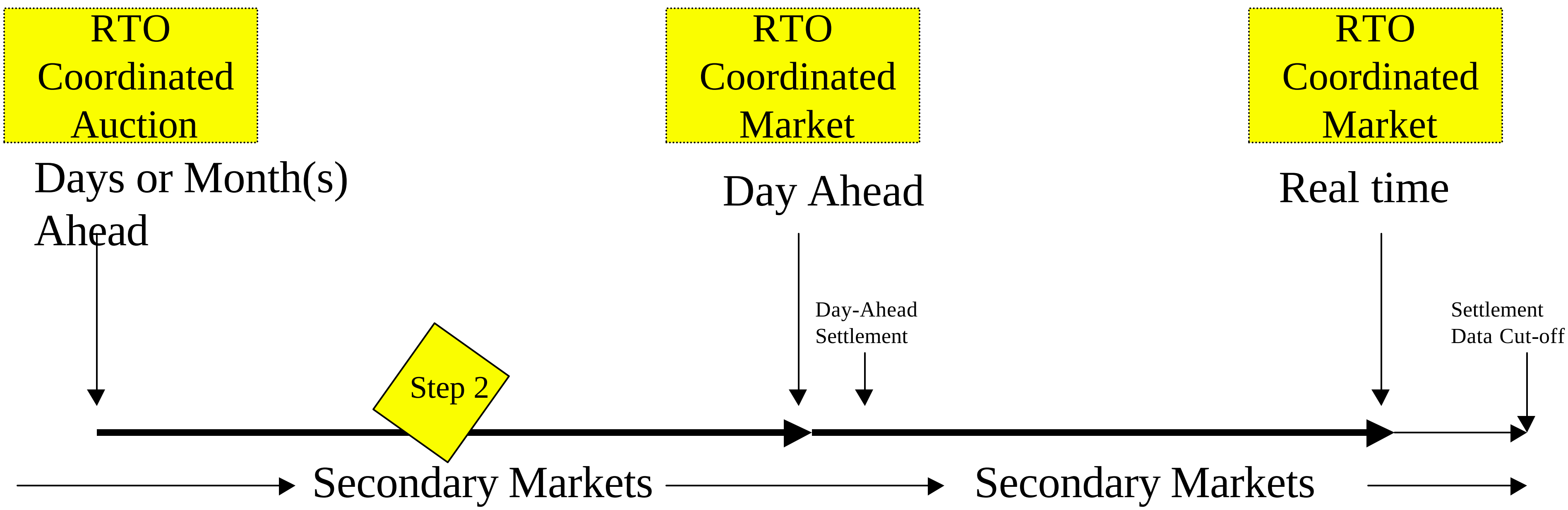
Tradable Transmission Rights Model



Step 2: Allow secondary market trading of these rights.

Once a set of rights is in the market, market participants would be free to trade these rights in secondary markets. The RTO would not coordinate these markets. Private entrepreneurs could run their own rights market or "exchange." Prices would be determined by the market, either bilaterally or in the private exchanges.

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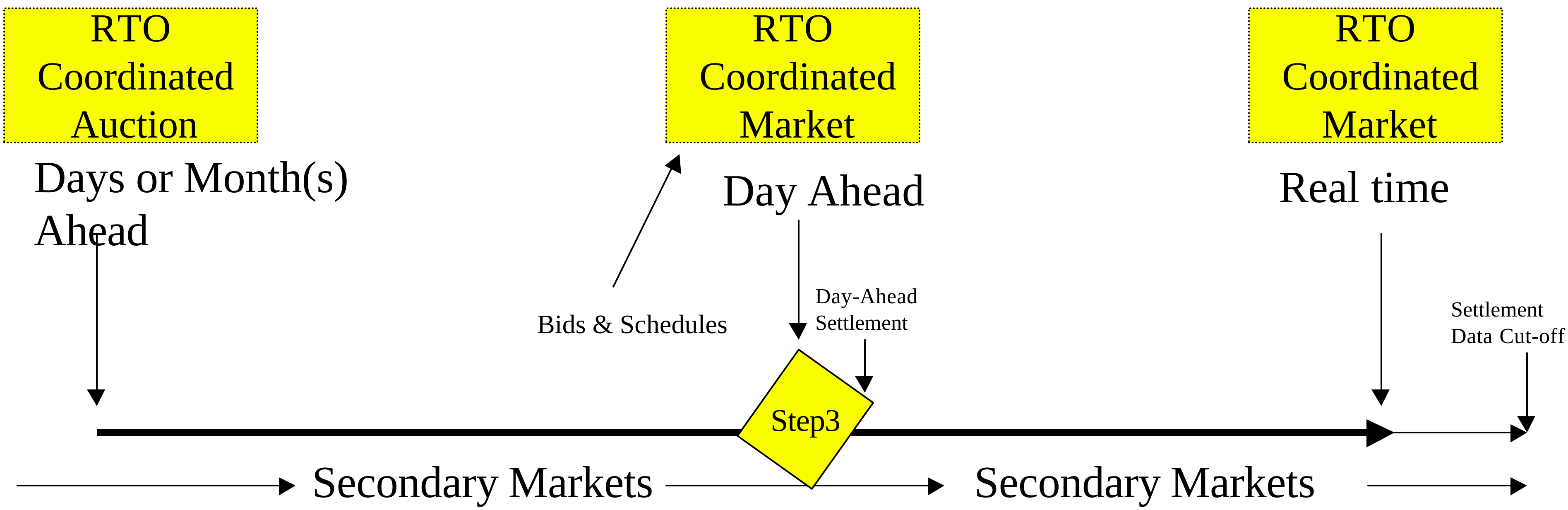
Tradable Transmission Rights Model



Step 3: The RTO coordinates a bid-based day-ahead market to allow participants to buy additional rights or sell unwanted rights.

Additional rights could come from: (1) any capacity not allocated in the auction because no one bid for it, (2) capacity not allocated in the auction because it was not assumed to be available at the time of the auction, (3) rights offered or surrendered for sale by rights holders, (4) capacity created by counterflows, and (5) rights created by parties willing to pay for redispatch.

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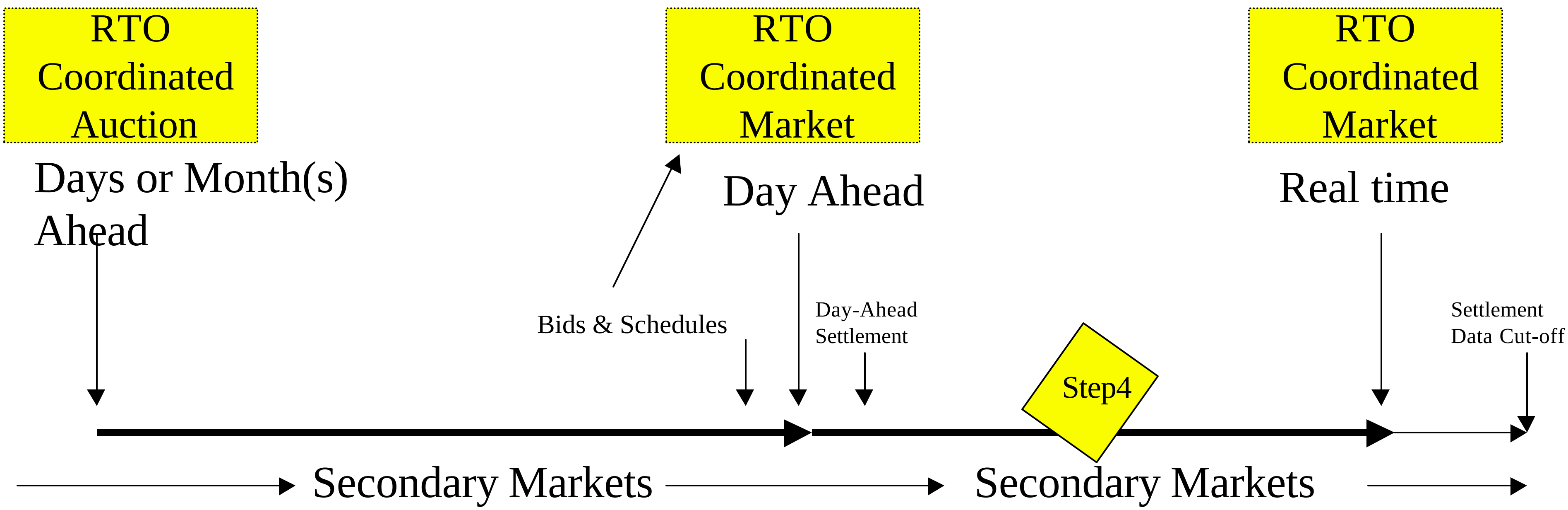
Settlements in the Day-Ahead Market

In the RTO-coordinated day-ahead market, all purchases and sales are settled by the RTO at bid-based market-clearing prices, based on marginal costs.

- **Parties who sold energy or transmission rights in the day-ahead market receive market-clearing prices. This includes parties who held rights coming into the day-ahead market but did not schedule them**
- **Parties who purchased energy or transmission rights in the day-ahead market pay market-clearing prices. This means that parties who scheduled transactions in the day-ahead market are settled at day-ahead market-clearing prices for the transmission they scheduled**

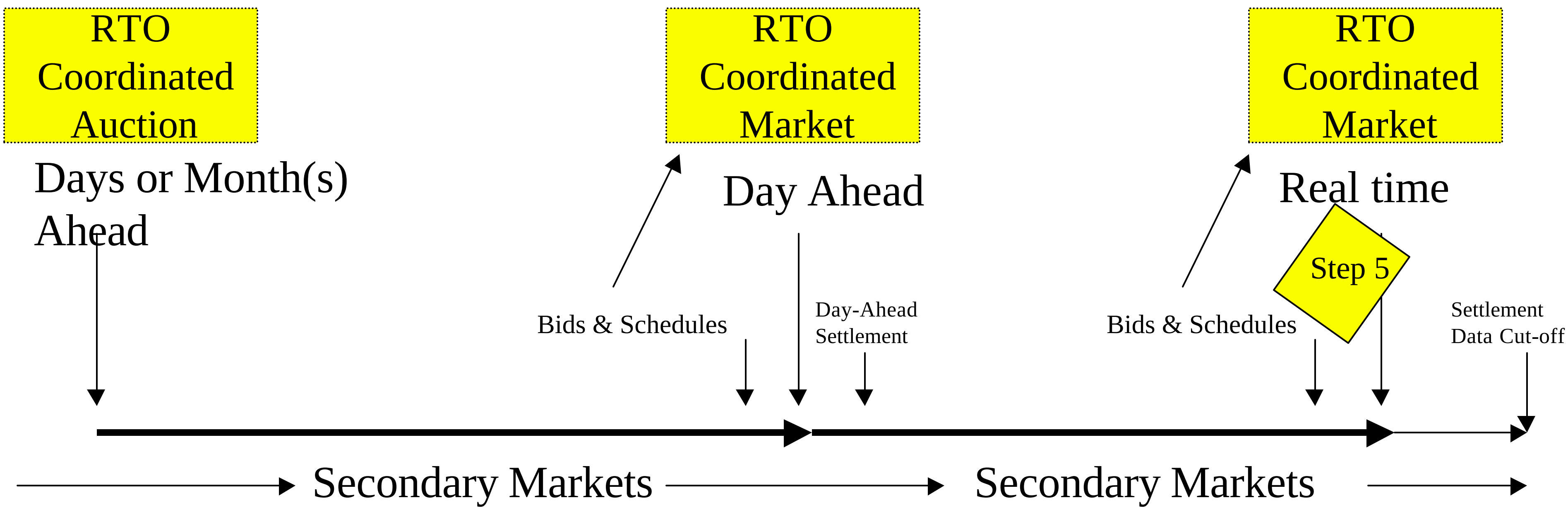
Tradable Transmission Rights Model



Step 4: Parties continue to trade rights in secondary markets.

Bilateral and "exchange" trading continue. Parties trade for many reasons: (1) they want to better match their rights to their expected trades, (2) they want to acquire more valuable rights or see a profit opportunity in additional hedges, (3) they want to sell rights they no longer want.

Tradable Transmission Rights Model



Step 5: The RTO coordinates the real-time market.

Parties that did not acquire the rights for the trades they actually implemented in real time effectively "buy" them at this time, by agreeing to pay for actual transmission usage. In settlements, they pay the market-clearing prices defined by the bids/offers into the RTO's real-time market. They are compensated for any rights they previously acquired but did not use.

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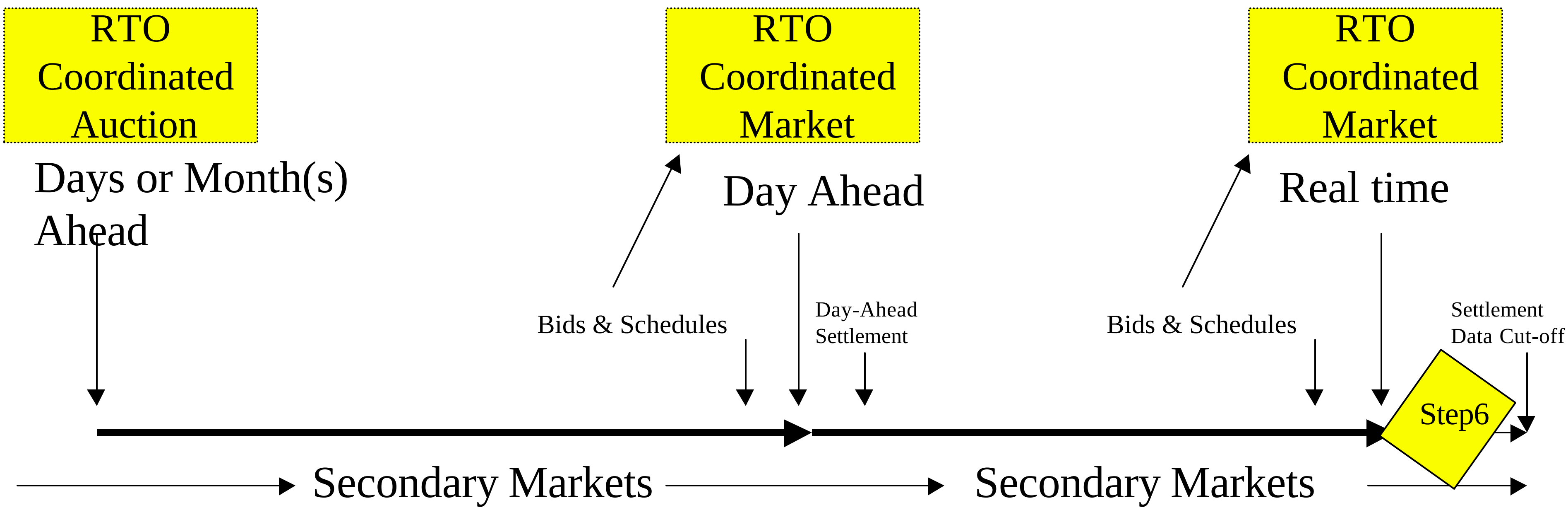
Tradable Transmission Rights Model



Step 6: The RTO settles the real-time market at the real-time prices.

Note that parties can continue to trade their rights in secondary markets up until the deadline for submitting settlement data to the RTO settlement system, which may be the day after. In settlements: *(1) Parties are credited for the rights they held. (2) Parties are charged for the transmission they used.* (Matched rights and transmission use means a zero settlement.) Market-clearing settlement prices reflect the marginal cost of transmission use.

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Pricing Rules: Transmission Use is Priced At Marginal Cost

A rule in this tradable rights model is that transmission usage is priced at marginal cost. There are different ways of saying *the same thing*. The marginal cost of transmission usage for a given transaction is:

- **The marginal cost of redispatching the system (bid-based economic dispatch) to accommodate the flows of the transaction within the security limits**
- **The market-clearing price for transmission, or the price offered by the marginal transaction that can be accommodated on the grid**
- **The difference in locational marginal (energy) prices between the point of injection (receipt) and the point of withdrawal (delivery)**

Pricing transmission usage at marginal cost ensures that transmission use is allocated efficiently, to those who value it the highest.

We Can Change the Rights Model by Changing the Key Market Rules

First Model

- **You must *eventually* acquire a right for the transaction you implement. Acquiring also means "pay the marginal cost of usage"**
- **Use it, or surrender it: If you don't schedule a right by the scheduling deadline, you surrender the right for resale by the RTO**
- **RTO *will* compensate you for the right you surrender at the market-clearing price**

Alternative Model

- **You must acquire the right that matches your transaction *before* you schedule that transaction**
- **Use it or lose it: If you don't schedule a right by the scheduling deadline, you lose the right for resale by the RTO**
- **RTO *will not* compensate you for the right you "lose"**

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Market Design Choices: Requiring a Right Before Scheduling

Such a rule has the potential to keep the number of transactions that are scheduled below the number of transactions the grid can accommodate

- **If parties did not bid for rights to all the capacity available in an auction, the remaining capacity could not be used to schedule transactions**
- **The auction/allocation may be "conservative," such that additional capacity may become, or often be, available. This capacity could not be used to schedule transactions**
- **Schedules that create "counter-flows" should be permitted; they would make other rights feasible**
- **Similarly, if schedules can be submitted by parties willing to pay for redispatch, new rights would become feasible**
- **The "use-it-or-lose-it" rule means that some unused rights may be surrendered to the RTO for reallocation to other parties. A strict rule would not permit schedules by those willing to purchase these rights**

These points show that *the scheduling process itself creates new rights that parties can use*. A strict rule might prevent those uses.

Market Design Choices: Requiring a Right Eventually

An alternative rule would be more flexible in allowing market choices, while supporting full, efficient grid use.

- **Parties must *eventually* acquire or pay for the rights to match their transaction, but they need not acquire the rights they need *before* they schedule**
- **Parties have wide latitude in deciding when, where and how to acquire or pay for the needed rights/transmission**
- **Full grid capacity is unknowable in advance, but trading can be expanded and changed by flexible RTO scheduling**
- **Parties can choose to either acquire the rights they need in one or more markets or acquire the rights they need by agreeing to pay the marginal cost of transmission usage. *Either choice is acceptable***
- **By deciding when and how to acquire their rights, market participants can decide when and how much they wish to be hedged against transmission price uncertainty**

Rationale for a Use-it-or-Lose-it Rule

A rule that allow others to use rights that aren't scheduled serves important functions:

- **It prevents any party from hoarding rights, and thus preventing others from using the grid or leaving the grid under-utilized**
- **It may mitigate market power that a participant might have**
- **It ensures that unused rights are made available to the market, in a more or less timely manner**

If unscheduled rights can be used by others, there should not be incentives for parties to schedule a transaction they do not plan to undertake, merely to preserve the option to undertake it.

- **The party cannot be compelled to undertake the transaction**
- **If it does not undertake the transaction, that capacity may be unused or under-used.**

Should the RTO Compensate Those Who Lose/Surrender Their Rights?

A use-it-or-lose-it rule with no compensation is usually justified as a necessary inducement to encourage those who do not schedule their rights to sell them *in non-RTO markets* before the scheduling deadline.

- **Some think the rule is needed to ensure that those who wish to purchase unused rights have a ready supply of rights to purchase**
- **The "no-compensation" rule discourages use of the RTO-coordinated market and encourages parties to use private bilateral markets**

Others think that a no-compensation rule is not desirable and is not needed to ensure liquid trading.

- **There is a natural, non-mandatory market incentive for parties to sell their unused rights in advance -- the desire to reduce risks**

Rationale for a Compensation Rule

Prior rights owners have a natural market incentive to sell their unused rights in advance.

- **They can set their selling price, reducing price risk**
- **Buyers will also be seeking price and supply certainty; they may often be willing to pay a premium for rights bought in advance**
- **If they wait until the RTO market, pricing is less certain; traders must accept the market-clearing price (whatever it is)**
- **A market price compensation rule thus captures the normal market dynamics between forward and spot markets**

The RTO will be selling unused, newly created, and left-over rights at (spot) market-clearing prices.

- **This seems the logical price to pay those who sell rights**
- **It compensates the owner fairly**