# Background on FTR Development

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# Topics

- Why were FTRs developed and why with the properties they have?
- Why were day-ahead markets developed?
- Why in markets with two settlement systems are FTRs settled in the day-ahead market, rather than at real-time prices?

# Conclusions

An important goal in implementing FTRs was to allow market participants entering into long-term bilateral contracts to hedge themselves against congestion risk in the much the same way as they did with firm transmission rights.

Important goals in implementing day-ahead markets were to support reliability and forward contracting by determining prices and financially binding schedules in the same time frame in which the unit commitment was determined.

These goals cannot be achieved, and large ISO revenue shortfalls avoided, unless FTRs are settled against day-ahead market prices.

# Why FTRs?

# Why FTRs

FTRs were developed primarily to replace physical firm transmission rights in markets based on economic dispatch and LMP pricing, thereby enabling load serving entities and generators to continue enter into long term contracts for power from resources located remote from load under the new market design.

- FTRs were designed to be financial, rather than physical, to avoid the use it or lose it properties of physical rights so they would support, rather than undermine, economic dispatch.



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# Why FTRs

In addition, the development and allocation of FTRs and ARRs could be used to allocate the value of the transmission system to the rate payers that were paying the embedded cost of the transmission system, while allowing open access to use of the transmission system.

- FTRs could also be allocated to reflect historical or contractual entitlements to use of, and payment of the embedded cost of, the transmission system, so as to avoid cost shifts among the rate payers of different transmission owners/ load serving entities.

# Why FTRs

Finally, FTRs provide a mechanism to distribute the congestion rents that would be collected by the system operator under a LMP market design, and do so in a way that would be consistent with the FERC's pricing rules at the time regarding "and" pricing, i.e. that the transmission provider could not charge transmission customers both the full embedded cost of the transmission system and congestion costs.

# Why FTRs

"Our perspective is on developing a framework for long-term contracts that define firm rights to the transmission system.  Experience suggests that investors in long-lived, fixed facilities of the type and scale of major electric power plants will be reluctant to make commitments with no more than a promise of being allowed to participate in a short-term spot market for transmission services. Practical development of long-term deals with the associated capacity and energy payments must include some form of firm right to power transmission.  Ideally there will be an associated usage pricing mechanism that reinforces the incentives for open access, economic dispatch, and efficient secondary markets for long-term firm rights.

In addition, any system for transmission rights must meet other equally important criteria. Foremost is preservation of the reliability of power system operations.  Any proposal for revising the current system must recognize and respect the real complications of day-today management of a power network."

William W. Hogan, “Contract Networks for Electric Power Transmission,” Journal of Regulatory Economics, September 1992 pp. 214-215.

# Why FTRs

"the Poolco least-cost dispatch would provide the foundation for a transmission contract that would serve essentially the same purpose as a physical right by defining a financial transaction that would not depend on matching physical flows in the actual dispatch. Transmission congestion contracts (TCCs) could be defined for a financial payment equal to the difference in congestion costs between locations. Such a transmission contract would allow a Genco to arrange a power contract with a distant customer and be assured of the delivered cost of the power. Through the Poolco dispatch, the system operator would collect congestion payments whenever the system was constrained, in turn disbursing the congestion payments to the holders of the transmission congestion contracts. The Poolco would keep none of the payments, and participants with long-term transmission contracts could fully protect the ability to deliver power at an agreed price, just as if there was the physical delivery from the source to the destination."

William W. Hogan, Electricity Transmission Policy and Promoting Wholesale Competition, Docket RM95-8-000, August 7, 1995 p. 52.

# Why FTRs

"The revenue that the Office of the Interconnection collects as a result of the differences in its receipts and payments constitute congestion cost payments which will be rebated to transmission users who have purchased firm network or point-to-point service (including the PJM Companies providing bundled requirements service). A firm transmission customer receives financial protection against its responsibility for congestion cost payments, thus assuring price certainty. The right to receive a share of congestion cost rebates will be represented by Fixed Transmission Rights (FTRs), which will be tradable, allowing transmission users another mechanism to obtain financial protection."

Brief of Supporting Companies, December 31, 1996, Docket OA97-261-000 p. 7.

# Why FTRs

"given the potential for significant and long-tem changes in congestion, and thus in the price of transmission, generators and loads seeking to enter into term contracts for the purchase and sale of electrical energy (either in the form of physical bilaterals or contracts for differences (CFDs)) may value a mechanism that provides them with a degree of long-term price certainty for the transmission costs associated with these term contracts. Market participants therefore will likely seek either long-term rights to use the transmission grid or some long-term financial protection against variations in congestion costs. This is a function that FTRs can efficiently serve. Equally important, FTRs can easily perform the similar functions FERC intends for its capacity reservations tariffs (CRTs)."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97- 261-000 p. 49.

# Why FTRs

"The Supporting PJM Companies have addressed this need for transmission price certainty through a system of FTRs that entitle holders to receive credits for any transmission congestion costs between the points associated with the FTR.  Once a system of locational marginal prices is adopted for the pricing of electricity in the PJM control area, it is also possible to define a set of FTRs that hedge any transaction by payment of the congestion charges collected by the SO.  These FTRs will enable buyers and sellers to hedge either short-term or long-term fluctuations in the price of transmission (i.e., congestion).  FTRs thereby permit buyers and sellers to enter into any term bilateral contract at a delivered price without incurring potentially large price risks associated with changes in transmission congestion within the market."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97-261-000 p. 50.

# Why FTRs

"TCCs will provide transmission users with the financial equivalent of firm transmission service."

William W. Hogan, Report on the Proposal to Restructure the New York Electricity market,  January 31, 1997, Docket OA97-470-000, p. 23.

# Why FTRs

"FTRs provide a mechanism for distributing (or assigning ownership to) the congestion credits collected by the SO. Because congestion credits collected by the SO would be paid to FTR holders the mechanism also assures that the SO would not benefit from creating congestion or increasing the level of congestion credits.  The SO would be simply a conduit for the distribution of the congestion credits.  There would be no incentives for the SO to deviate from the economic dispatch or to create system congestion, because any increased congestion credits that would result from such behavior would be distributed to the holders of FTRs, with no residual congestion payments left for the SO.  The problem of supervising the SO and transmission grid owners would thereby be reduced."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97-261-000 p. 51.

# Why FTRs

" 'and' pricing cannot be a concern  under the Supporting Company Group's proposal because the combination of fixed transmission rights for firm transmission service and zero demand charges for non-firm transmission service prevents 'and' charges.  As explained above, a customer taking firm network or point-to-point service receives fixed transmission rights that allow it to receive a share of the congestion cost payments received by the Office of the Interconnection. Because revenues received from locational price differentials (i.e., congestion payments) are paid out to holders of these rights, a transmission owner will not receive more than its embedded cost of service."

Brief of Supporting Companies, December 31, 1996, Docket OA97- 261-000 p.15-16.

# Why FTRs

"Because FTRs would be purely financial instruments, they would impose no constraints on the actual dispatch.  Thus, unlike must-take power contracts, must-run generation or strict physical transmission rights, FTR ownership alone would not affect either line availability or transaction scheduling.  The economic dispatch consistent with the physical configuration of the grid would be determined by the SO without regard to FTR ownership."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97-261-000 p. 55. See also William W. Hogan, Report on the Proposal to Restructure the New York Electricity Market, January 31, 1997 Docket OA97-470-000, p. 24, for a very similar statement.

# Why FTRs

"If they choose, holders of FTRs could schedule bilateral transactions that match their FTRs.  In this sense, the dispatch would be affected by the schedule, not by ownership, of the FTR.  However, the FTRs, coupled with locational pricing, provide an economic incentive to avoid such inflexible schedules, since the FTR owner can realize the value of its transmission rights whether it actually schedules its generation or its loads are met by the SO's coordinated scheduling at lower cost."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97-261-000 p. 55.

# Why FTRs

"Well-defined property rights in the form of FTRs are vital to creation of a long-term transmission market.  Without FTRs, a locational spot pricing system would lack a mechanism to define and transfer the economic benefits of transmission to those paying for the transmission capacity, including expansions.  The traditional alternative to this market-driven procedure for transmission grid expansion would be to rely solely on regulator-determined grid expansion."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97-261-000 p. 60.

# Why Day-Ahead Markets?

# Why Day-Ahead Markets?

The concept of day-ahead markets grew out of discussions with utility operators in California regarding the role of the ISO. These operators strongly believed that an ISO could not be expected to reliably operate the system based on schedules it received only shortly before real-time.

- It was concluded to be essential for maintaining reliability that market participants provide accurate advance information regarding their real-time operating plans to the system operator.
- The day-ahead time frame for receiving operating plans was important because it allowed time for the commitment of steam generation if needed to maintain reliability.
- It was recognized in discussing solutions to these issues that simply requiring market participants to submit indicative schedules would invite the submission of inaccurate information in order to impact real-time prices.

# Why Day-Ahead Markets?

These concerns led to the idea of creating a financially binding day-ahead market that would incent market participants to provide the ISO with accurate information regarding their real-time intentions, because deviations from day-ahead market schedules would be settled at real-time prices.

This concept of a day-ahead market was discussed with the transmission owners in PJM and New York who agreed with the rationale and worked to refine the design concept.

# Why Day-Ahead Markets?

It was also recognized that implementation of a day-ahead market would enable generators and loads to lock-in energy prices in the day-ahead time frame in which prices would be less volatile and enable forward bilateral contracts to be settled in the same time frame in which the unit commitment was determined.

# Why Day-Ahead Markets?

Not all regions need day-ahead markets.  Regions with almost all coal and hydro generation alone or in combination with intermittent resources do not benefit much from the implementation of a day-ahead market.

- Coal units generally need more than a day to come on line and hydro units generally need much less than a day's notice to come on line.
- Intermittent resources such as wind and solar generation also generally have no commitment decision.

# Why Day-Ahead Markets?

Eastern PJM, California, New York and New England all had a material amount of slow starting gas or oil fired steam generation in the late 1990's.

- This resource mix made the development of a day-ahead market and commitment process desirable.
- In addition to providing day-ahead schedules for internal generation, day-ahead markets provide a binding financial commitment for the scheduling of imports and exports, reducing the potential for market participants to manipulate the unit commitment and real-time prices by scheduling imports or exports that would not flow in real-time.

# Why Day-Ahead Markets?

With the development of combined cycles and the retirement of much of the old gas- and oil-fired steam generation, there may be less need to commit generating units day-ahead in order to have them available to operate in real-time.

- The increased importance of gas only generation, however, has made it more important to schedule the gas needed to meet real-time load in day-ahead gas markets.
- Day-ahead power markets can help maintain reliability in this new environment by guiding day-ahead gas procurement decisions.

# Why Day-Ahead Markets?

"The system proposed by the Supporting PJM Companies is not a pure one-settlement system, as the SO reviews bids and schedules a day in advance and coordinates unit commitment. Hence, it could be described as a 'one-settlement system with commitment.'

The Supporting PJM Companies have chosen to begin the new market structure with this approach in order to simplify the initial transition from the current system and to allow the new structure to commence as soon as possible… the Supporting Companies are aware that various issues arise that must be addressed in any proposal for a one-settlement system. The first is the need for system operators to ensure that, in a competitive market with many participants, those who schedule and bid in the day-ahead market intend to implement their schedules in real time and have the incentive to do so. In the interest of reliability and because of the lead times required for some resources to be available, operators need some assurance that scheduled resources will be available to match actual loads."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97-261-000 p. 68.

# Why Day-Ahead Markets?

"In recognizing these issues, the Supporting PJM Companies are considering moving toward a two-settlement system.  In a two-settlement system, these issues are approached in a different way.  The day-ahead scheduling market is set up as a separate market that opens and then closes at a fixed point in time.  When this market 'closes', the confirmed schedules (which the SO will ensure are consistent with all transmission and reliability constraints) become binding financial obligations.  Generation and load scheduled with the SO become, in effect, forward sales and purchase contracts between the generators and loads.  These implicit contracts create a financial obligation to deliver or take power in the actual dispatch."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97-261-000 p. 69.

# Why Day-Ahead Markets?

"Generators can cover their obligation to deliver by operating or purchasing power through the SO in real time, while loads can cover their obligation to take by consuming power or selling power back through the SO in real time.  The important point, however, is that participants are now financially obligated to perform and are paid or charged at the market prices associated with the day-ahead market; this is the first settlement.  If conditions then change and the SO's real-time dispatch is different from the day-ahead schedule, then the SO will settle any deviations at the market-clearing price associated with the actual real-time dispatch.  This is the 'second' settlement.  In this system, the financial commitments at market-clearing prices provide, in effect, market-based 'penalties,' reducing the need for administratively determined penalties."

William W. Hogan, Report on PJM Market Structure and Pricing Rules, December 31, 1996, Docket OA97-261-000 pp. 69-70.

# Why Day-Ahead Markets?

"This conversion of day-ahead schedules into dispatch commitments is a fundamental safeguard against market manipulation.  As proposed, the two-settlement system provides less opportunity for strategic behavior than a single settlement system because it requires market participants (PEs) to make financial commitments to their day-ahead schedules.  Systems that do not require a financial commitment to day-ahead schedules would provide the opportunity for individual market participants to schedule transactions a day ahead – which, due to transmission system interactions, affect the schedules of other parties – and then back away from the schedules in the actual dispatch without any potential financial consequence.  Market participants engaging in such behavior could potentially affect the LBMPs that sellers receive, the LBMPs paid by buyers, and the congestion costs paid for bilateral transactions."

William W. Hogan, Report on the Proposal to Restructure the New York Electricity Market, January 31, 1997 Docket OA97-470-000, pp. 59-60.

# Why Day-Ahead Markets?

"In contrast, the settlement of the dispatch commitments under the voluntary two-settlement system provides appropriate price signals for those that have chosen to make day-ahead financial commitments by scheduling with the ISO and wish to change their schedules in the hour.  In addition, if parties change their schedules, and adversely affect the cost or feasibility of the schedules of other parties due to network interactions, the settlement of the dispatch commitments provides the revenue for compensating those whose schedules are affected."

William W. Hogan, Report on the Proposal to Restructure the New York Electricity Market, January 31, 1997 Docket OA97-470-000, pp. 60.

# Why Day-Ahead Markets?

"The introduction of a two-settlement system in conjunction with locational marginal pricing will provide PJM grid users with additional flexibility in structuring transactions and will enable the OI to reduce reliance on administrative rules and penalties. The proposed changes would:

- Replace administrative penalties for non-performance with market driven performance incentives.
- Reduce the need for administrative rules intended to limit gaming by introducing market-driven pricing and financial commitments to schedules.
- Create a day-ahead market in which FTR owners can sell unneeded transmission rights and grid users lacking FTRs can lock in the cost of transmission day ahead.
- Allow generators and loads to lock-in energy prices in a day-ahead market."

Scott Harvey, A Multi-Settlement System for PJM under LMP, October 30, 1997 p. 2.

# Why Day-Ahead Markets?

"Generators with CFDs cannot hedge themselves under a one-settlement system by relying on the OI's day-ahead scheduling.

- Generators with CFDs that are not scheduled to run by the ISO (because of low forecast demand day ahead) would be exposed to price risk if real-time demand is above forecast.
- Generators with CFDs therefore must self-schedule themselves to run in order to hedge themselves against high real-time prices.
- Under a two-settlement system, a generator with a CFD can bid both its generation resource and its CFD obligation in the day-ahead market and thereby lock in the cost of covering its CFD whether it is scheduled to run or not."

Scott Harvey, A Multi-Settlement System for PJM under LMP, October 30, 1997 p. 18.

# Why Settle FTRs in Day-Ahead Markets?

# Why settle in the day-ahead market?

FTRs in PJM were initially settled at real-time prices because there was no day-ahead market when LMP pricing was implemented in 1998.

- When a day-ahead market is implemented, PJM and other ISOs have settled FTRs using day-ahead market prices.
- FTRs have to be settled against day-ahead market prices in a two settlements system. If FTRs and day-ahead market schedules were both settled at real-time prices, this would entail double payment of real-time congestion rents, while the ISO would collect one set of congestion rents calculated at day-ahead market prices (in the day-ahead market) and another set calculated at real-time prices (in real-time).

# Why settle in the day-ahead market?

The ISO can either settle FTRs against real-time prices or settle day-ahead market schedules against real-time prices, but it cannot settle both against real-time prices without creating the potential for revenue inadequacy on a massive scale whenever real-time prices are higher than day-ahead market prices.

- Hence, ISOs like PJM that coordinate day-ahead markets must settle FTRs against day-ahead prices to avoid taking on a large unhedged short position in the real-time market.

# Why settle in the day-ahead market?

Market participants clearing day-ahead market schedules that use the same transfer capability as their FTRs are in effect rolling their FTRs over into real-time.

- FTR holders that want to reserve the transfer capability associated with their FTRs for possible use to hedge real-time transactions can do so by submitting virtual bids at the source and sink of the FTR.
- FTR holders that do not want to use or reserve the transfer capability associated with their FTRs, settle them in the day-ahead market, thereby making that transfer capability available to support the day-ahead market schedules of market participants that do not hold FTRs.

# Why settle in the day-ahead market?

A day-ahead market schedule in effect rolls a FTR over into real-time and the source and sink of the day-ahead market schedule are in effect a real-time FTR that settles at real-time prices, rather than day-ahead prices.

- This applies to both the day-ahead schedules of physical generators and loads, and the day-ahead market schedules of virtual traders.
- Critically, if an FTR is rolled over into a day-ahead market schedule and then settled at real-time prices, there is only one set of schedules that settles at real-time prices, the day-ahead market schedules.

# Why settle in the day-ahead market?

If the ISO settled FTRs against real-time prices instead of against day-ahead market prices, market participants would similarly need to settle their bilateral contracts against real-time schedules in order hedge those contracts against congestion costs with FTRs.

- Settling contracts against real-time prices would expose generators entering into forward contracts to price risk in committing their units because they would have to decide day-ahead whether to commit their unit to cover their real-time contract.
- One of the goals in implementing day-ahead markets was to reduce this risk by enabling bilateral contracts to be settled day-ahead in the same process that determines the unit commitment.

# Why Settle FTRs in the Day-Ahead Market?

"Some have suggested that the ISO should both make day-ahead commitments and settle the TCCs at the balancing market prices. Although this idea may have some initial appeal, it would create an inherent contradiction. Specifically, the TCCs are a complete set of claims for using the transmission system. Likewise, the day-ahead schedules become dispatch commitments and represent a second complete set of claims for using the transmission system. Under the first settlement of a two-settlement approach, the TCC claims are extinguished at the time of the day-ahead auction and replaced by a follow-on set of dispatch commitments. In contrast, if both TCCs and dispatch rights were settled in the balancing market, the TCC claims and the dispatch-right claims effectively would co-exist during the period between the day-ahead and hourly markets. Such an idea cannot be made to work without imposing unacceptable financial risks on the ISO."

William W. Hogan, Report on the Proposal to Restructure the New York Electricity Market, January 31, 1997 Docket OA97-470-000, p. 64.

# Why Settle FTRs in the Day-Ahead Market?

"if TCCs were settled at the second settlement prices in the balancing market, the ISO effectively would be required to sell transmission at the day-ahead prices and then to buy it back by settling TCCs at the balancing prices.  If the balancing prices reflect more transmission congestion than was anticipated in the day-ahead market, transmission prices will be higher and the ISO would incur a financial loss by having to buy transmission (i.e., settle TCCs) at a higher price than the previous day's selling price."

William W. Hogan, Report on the Proposal to Restructure the New York Electricity Market, January 31, 1997 Docket OA97-470-000 p. 65.

# Why Settle FTRs in the Day-Ahead Market?

"Under locational marginal pricing and a two-settlement system, network service customers that do not schedule use of their FTRs (or who are not, in effect, scheduled to use them by the OI's dispatch), in effect, sell the use of this transmission capacity in the day-ahead market.

Importantly, the OI's day-ahead scheduling process will, in effect, reconfigure FTRs to meet the needs of other customers."

Scott Harvey, A Multi-Settlement System for PJM under LMP, October 30, 1997, p. 16.

# Conclusions

An important goal in implementing FTRs was to allow market participants entering into long-term bilateral contracts to hedge themselves against congestion risk in the much the same way as they did with firm transmission rights.

Important goals in implementing day-ahead markets were to support reliability and forward contracting by determining prices and financially binding schedules in the same time frame in which the unit commitment was determined.

These goals cannot be achieved, and large ISO revenue shortfalls avoided, unless FTRs are settled against day-ahead market prices.

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