UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Long Term Transmission Rights in Markets Operated by Regional Transmission Organizations and Independent System Operators

Docket No. AD05-7-000

NOTICE INVITING COMMENTS ON ESTABLISHING LONG TERM TRANSMISSION RIGHTS IN MARKETS WITH LOCATIONAL PRICING

(May 11, 2005)

The Commission invites all interested persons to file comments addressing establishing long term transmission rights in electricity markets operated by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs).

An important cost of transmission service is the congestion cost that customers incur when, due to the physical limitations of the grid, they are unable to obtain energy from the lowest cost generation resources. In markets with locational pricing, participants can hedge against congestion costs by holding Financial Transmission Rights (FTRs), which are generally allocated to historical users of the grid. Currently, the longest term FTR offered in any of the RTO or ISO markets is one year.

The Commission is aware of interest by some market participants and others to obtain transmission service at a known price for periods longer than one year in markets that use locational pricing. In response, the Commission staff has conducted informal outreach to get informal views on the need for, and issues raised by, establishing long term transmission rights. At this point, the Commission desires to obtain written comments by all interested parties. The Commission is particularly interested in comments that address the following:

- The need for long term transmission rights and the problems caused by the lack of them. Are such rights needed more by certain types of entities or in markets in certain regions?
- The impacts of introducing long term rights. What specific impediments or problems must be addressed?
- The plans of specific RTOs and ISOs to address long term transmission rights.
- Substantive and procedural options for the Commission to address long term transmission rights.

The Commission is aware that the adequacy of long term transmission rights may be an issue in markets that do not use locational pricing but believes that there are unique issues in markets with locational pricing that are best addressed separately.

A Commission staff document is available online at http://www.ferc.gov to assist parties in providing comments, but will not be published in the Federal Register. The staff document provides background on the need for long term transmission rights and the issues that must be addressed in introducing them into markets. The document also provides specific questions to address as well as general background on locational pricing and on FTR allocation methods in the existing RTOs and ISOs.

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The Commission encourages electronic submission of comments in lieu of paper using the “eFiling” link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the comment to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

All filings in this docket are accessible on-line at http://www.ferc.gov, using the "eLibrary" link and will be available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on June 27, 2005.

Linda Mitry
Deputy Secretary

Long-Term Transmission Rights Assessment
FERC Staff Discussion Paper

May 11, 2005

Introduction

In recent months, there has been an interest among various participants in the RTO and ISO[1] markets to obtain long-term rights for transmission usage; that is, rights with terms of more than one year. RTOs manage transmission congestion by using "locational" pricing, which establishes the transmission usage cost due to congestion (and possibly also transmission losses). Congestion costs can be highly volatile. In conjunction with congestion pricing, RTOs offer transmission rights which are financial instruments that entitle participants to a refund of congestion costs, resulting in a net zero congestion. These instruments are generally not made available for terms greater than one year, but are instead allocated again each year to eligible transmission users subject to availability.

Some market participants have concerns that sufficient transmission rights may not be available each year to adequately cover their congestion cost exposure. They argue that the combination of potentially volatile congestion costs, variability in the annual allocation, and the inability to secure a known quantity of transmission rights for multiple years introduces an unacceptable degree of uncertainty into resource planning and investment. As a result, some participants want the ability to obtain long-term transmission rights or service at a price certain.

Providing such long-term rights presents challenges. One such challenge is that to the extent that the RTO hands out transmission rights over multiple years but actual grid conditions are different than those anticipated, the RTO could collect insufficient congestion revenues to pay the FTR holders. Decisions must then be made regarding who will bear the revenue shortfall. As might be expected, the longer the instrument's term, the greater the probability that grid conditions will be different than forecast.

Long-term transmission rights could alternatively be created by exempting certain transmission users from the RTO's price-based congestion management system. These customers would retain the right to physically schedule their power but would not pay congestion charges nor receive financial transmission rights. Most RTOs have "grandfathered" some prior transmission rights in this fashion. This approach could

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[1] Henceforth, the term RTO will be used to refer also to ISOs, except when a specific ISO is being discussed.

provide the transmission customer with long-term price stability, but could also reduce economic efficiency and shift costs to those that remain within the RTO congestion pricing and financial transmission rights system.

Many market participants noted that in some regions, transmission infrastructure is insufficient to address their needs. The more robust the grid, the greater the potential for congestion hedges that have long-term stability. Although the staff team did not explore barriers to transmission investment, this was a recurrent theme that closely intersects with the issue of long-term transmission rights.

In short, long-term transmission rights can be established in RTO markets in various ways, but each of these requires trade-offs in cost and risk. A clear understanding of these trade-offs is necessary for making policy and market design decisions that support market competition, economic efficiency and system reliability.

The purpose of the paper is to elicit public comments on the need for longer term rights, the issues that need to be considered, and how the Commission should go about addressing these issues. The paper builds on the staff team's review of existing RTO market rules and informal dialogue with market participants, market operators, state regulators, and experts in market design and finance.

The paper is organized as follows. The first sections of the paper provide background on locational pricing and financial transmission rights, the interest in long-term rights, comparison of financial rights with the transmission rights that existed before the RTO markets, and impediments to implementation of long-term financial rights. We then examine some design issues that could be a consideration when offering long-term financial transmission rights, such as who is eligible for the rights, what term should they be, whether they should be obligations or options or both, whether they should be directly allocated or bought through an auction, and what the rules should be when the RTO's congestion revenues are not adequate to fully cover its payment obligations to rights holders. We also provide some initial views on the relationship of infrastructure financing and availability of long-term rights. Finally, we discuss alternative methods for providing transmission customers with long-term transmission scheduling rights in RTO markets. In most sections of the paper, we identify questions for public comment, but this list is not intended to be exhaustive.

Defining terms and design concepts is important, because parties' understanding of these can differ. To this end, Appendix A offers definitions and background on locational pricing and financial instruments, and the basic allocation and auction rules. This appendix also summarizes some of the differences among the existing RTO and ISO markets, because these differences will matter to how long-term rights are introduced. Appendix B then examines the individual RTO market rules in greater detail.

Locational Pricing and Financial Hedging Instruments

All RTOs approved by the Commission have implemented or planned for a congestion management system based on locational pricing of energy, mostly using locational marginal pricing (LMP), and the allocation or auction of financial transmission rights (FTRs).[2] Locational pricing establishes the difference in cost between purchasing energy at different locations in the spot market due to congestion and losses; in this paper we will concern ourselves only with congestion. The congestion charge associated with injecting power at one location (e.g., a generator) and withdrawing it at another location (e.g., a load) is equal to the difference in the LMPs at the two locations. If the price difference is zero, then there is no congestion charge. While the transmission user can estimate congestion charges ahead of time, the actual congestion charge is only known when the spot market locational prices are calculated.

An FTR is an instrument for returning the congestion charges collected by the RTO through LMP settlements to the market participants that hold the rights. FTRs thus can be used to hedge congestion charges associated with energy contracts or purchasing strategies. In other words, an FTR can refund all congestion charges faced by the holder of the FTR if the specification of the rights matches the transmission schedule. It is important to keep in mind, however, that the quality of the congestion hedge depends on the specification of the right (e.g., whether an option or obligation) and the rules for FTR market settlement. In general, FTRs are provided to load-serving entities (LSEs)[3] and others that pay fixed cost transmission rates, either through direct allocation or through an auction process in which the LSE is allocated auction revenue rights (ARRs) that can be used to purchase FTRs.[4] ARRs and FTRs can also be allocated to any party that invests in transmission upgrades or expansion. FTRs can also be traded in annual and monthly RTO auctions or on a bilateral basis by any entity.

As noted, RTOs currently offer ARRs and FTRs with terms of one year or less. LSEs that have met the RTO eligibility requirements have each year the right to nominate ARRs or FTRs up to some measure of their peak load. However, the quantities awarded of ARRs or FTRs may change each year due to factors outside the control of the LSE (such as changes in the network or the FTR nominations of other participants). We will

[2] We will use the term FTR to refer generally to the various types of financial transmission rights available in the RTO markets.

[3] An LSE is any entity that serves retail load.

[4] ARRs confer the right to collect revenues from the subsequent FTR auction. For example, the holder of an ARR between location A and location B knows that it will collect revenues equal to the market clearing price of an FTR between location A and location B. An ARR can exactly match an FTR, but does not need to; for details, see appendices A and B.

discuss some of the reasons for this in subsequent sections. Most RTOs do provide long-term transmission rights (i.e., rights with terms greater than one year) for transmission upgrades or expansion that increase transmission capability. These long-term transmission expansion rights merit extensive discussion in themselves, but the paper will focus on long-term rights to existing transmission capacity.

The Interest in Long-Term Transmission Rights

The interest in long-term transmission rights has arisen for a number of reasons. One general reason is that certain transmission users, particularly those with long-term generation resource commitments and load, perceive that LMP volatility has increased congestion risk. They believe that a long-term ARR or FTR will let them lock in a congestion hedge, whereas the uncertainty of annual FTR and ARR allocations leads to greater price risk. This perception appears to be more acute in some regions than in others.[5]

Another reason for interest in long-term rights is that some parties investing in new generation to serve load want to ensure a fixed quantity of transmission rights associated with the delivery of power from the new generator for a term equivalent to the expected term of financing for the investment or to the life of the asset. They contend that the lack of long-term transmission rights could be problematic for the firm's credit rating or for the ability to undertake project financing. The long-term right thus provides the certainty some participants believe is needed to support rational resource planning and acquisition.

Not all market participants agree that there is a pressing need for long-term transmission rights nor on what the appropriate term of such rights should be if they are offered. For such participants, there seems to be general satisfaction with the rights awarded through the annual allocation process in some RTO markets. However, if the benefits and costs are assigned appropriately so that the introduction of long-term financial rights does not create significant equity issues, most market participants consulted by the team were not opposed to them.

[5] For example, in the Midwest ISO there was some initial concern as the ISO began to model the transmission system and assign FTRs to market participants that the modeling was not reflective of how transmission rights had been sold historically and that as such the resulting FTRs did not protect historical transmission users. Many of those issues were addressed by the Commission in its orders on the Midwest ISO market design.

- What are the needs of market participants for long-term transmission rights in RTO markets? What has been the experience with congestion pricing and transmission rights of market participants in RTO markets? Have financial right allocations been sufficient to meet participants' needs for congestion hedging and long-term resource planning and acquisition?

Comparison of Prior Transmission Rights to Financial Rights

For some transmission customers seeking long-term transmission rights in RTO markets, the objective is to restore long-term transmission service that has scheduling, pricing and risk properties akin to the transmission service that they had before the start of the RTO market (with LMP and FTRs). Hence, to understand the expectations of such transmission customers, it is useful to review the characteristics of the prior transmission service and ask what the differences are with the current transmission rights and whether they are reconcilable.

Prior to the implementation of RTO markets, transmission service for customers in those regions was governed by either pre-Order No. 888 Open Access Transmission Tariff (OATT) contracts or the OATT.[6] Under the OATT, there are two types of transmission service – network integration transmission service (network service), which is a long-term firm transmission service, and point-to-point transmission service, which can be provided on a firm or non-firm basis and on a long-term (one year or longer) or short-term basis. Long-term firm transmission customers have the right to continue to take transmission service from the transmission provider when the contract expires, rolls over or is renewed (rollover right).

Point-to-point transmission service is for the receipt of capacity and energy at designated points of receipt and the transmission of such capacity and energy to designated points of delivery. A firm point-to-point transmission customer pays a monthly demand charge based on its reserved capacity.

Network service provides the customer with flexibility to integrate, economically dispatch and regulate its current and planned network resources (i.e., generation) to service its network load in a manner comparable to that in which the transmission provider utilizes its transmission system to serve its native load customers.[7] The network

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[6] Most pre-OATT transmission contracts were grandfathered into the RTO markets, hence will not be discussed further.

[7] A network customer must designate network resources, including all generation owned, purchased or leased by the network customer to serve its designated load. A network customer also must designate the individual network loads on whose behalf the

customer generally pays a monthly demand charge based on its load ratio share of fixed costs.

As a condition of receiving network service, a network customer agrees to redispatch its network resources as requested by the transmission provider pursuant to the terms of the OATT.[8] The transmission provider must plan, construct, operate and maintain its transmission system in order to provide the network customer with network service over the transmission provider's system, and must designate resources and loads in the same manner as any network customer. If the transmission provider needs to redispatch the system due to congestion to accommodate a network customer's schedule, the costs of redispatch are passed through to the transmission provider's native load and to network customers on a load-ratio basis. Transmission providers are not obligated to redispatch to accommodate a point-to-point customer's schedule.

If a curtailment on the transmission provider's system is required to maintain reliable operation of the system, curtailments are made on a non-discriminatory basis to the extent practicable and consistent with good utility practice, with firm service having the highest priority and non-firm generally having the lowest priority.

OATT transmission service greatly increased access to the transmission grid and hence facilitated the growth in wholesale power trading across the country. OATT service – typically provides long-term price stability. However, the Commission has noted problems of continuing undue discrimination by transmission providers outside RTOs.[9] Moreover, as usage of the grid has grown, in many areas curtailment of transmission schedules to manage congestion has resulted in growing market inefficiency.

Finally, OATT network integration transmission service is not readily tradable, whereas in many regions, especially those with retail competition and where vertically integrated utilities had divested their generation holdings to merchant operators, a tradable right would enable potential users of the grid to obtain rights from willing sellers.

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transmission provider will provide network service.

[8] Redispatch means that, due to congestion, the utility changes the output of its generators to maintain the energy balance. The output of some generators may be increased while the output of others may decrease.

[9] E.g., Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (February 25, 2000), FERC Stats. & Regs ¶ 31,092 (2000), petitions for review dismissed, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001). .

RTOs are essentially physical transmission scheduling entities on a much larger scale than a single public utility. RTO market participants that are serving load can schedule their generation and load through either the RTO day-ahead or real-time (dispatch) markets. In general, scheduling (or simply withdrawing power from the grid) in real-time can impose additional costs, such as the costs of generation that the RTO puts on stand-by when it forecasts that load has under-scheduled day-ahead. Unlike transmission providers in non-RTO regions, RTOs with LMP rely on price-based congestion management. That is, LMP makes explicit the cost of redispatch service. These features allow for a coordinated, efficient dispatch over a large region, and significantly reduce the need for curtailments as compared to those that occur when individual public utilities are scheduling transmission service on a non-price basis.

There are important differences between OATT transmission rights and FTRs. Unlike the OATT approach to transmission scheduling, which gives a scheduling priority to firm customers, in LMP markets all scheduling requests are treated as firm, but subject to congestion charges. FTRs are allocated to protect against congestion charges, but they are not required to physically schedule. Moreover, FTRs are settled financially whether the party that holds them physically schedules or not. That is, a party that holds an FTR from point A to point B does not have to schedule power between those points to collect FTR revenues (the incentive properties of such rights are discussed in Appendix A).

As has been discussed, all ISOs and RTOs began market operations with a one-year cycle of ARR or FTR allocations. With one exception, the terms of the financial rights were restricted to the one-year term or less, subject to renewal the next year.[10] This appears to have reflected the preference of market participants at the time. Market participants are allocated rights typically based partly on their historical uses of the system and also with some flexibility to choose among eligible transmission paths. The details vary by RTO, as reviewed in the appendices. Since the state of the system and market prices change from year to year, the market participants are allowed to re-configure their transmission rights requests each year, taking advantage of their market experience. The annual reconfiguration of rights also helps the RTO to manage exposure to situations of revenue shortfalls where payments to FTR holders exceed FTR revenues as a result of changes in the transmission grid or in the availability of generators that have a major impact on power flows. If such changes appear to be long-term, the RTO will adjust the quantity of rights handed out in the next annual cycle.

In conclusion, OATT transmission service, once obtained, appears to provide better long-term price certainty than the current RTO transmission service. But

[10] The exception is New York ISO, which offered FTRs with 2 year and 5 year terms during the Fall 2000 FTR auction. These multi-year rights were not offered subsequently. See discussion in Appendix B.

congestion management could be inefficient and network transmission rights are not easily traded and reconfigured, such that those who value them most highly can obtain them from willing sellers. The RTO transmission service greatly improves access, provides price-based congestion management that is generally efficient, and allows auctions and secondary markets for trade in transmission rights that are increasingly flexible in terms of locations and time periods covered. On the other hand, there are concerns that FTR allocations do not always offer long-term price stability, that is, adequate coverage of congestion charges. The policy issue is thus whether parties should be allowed to revert to some version of the prior OATT service within the RTO markets with LMP and FTRs or whether the FTR model can be modified to provide the type of congestion cost coverage that such parties seek.

Long-term Financial Transmission Rights

One avenue for providing less price uncertainty for transmission customers is to provide long-term financial transmission rights. A long-term right may be defined as either an FTR or an ARR with a term of more than one year. In general, long-term financial rights would decrease market participants' uncertainty about exposure to congestion costs over the period of the rights and for the quantity specified. In this section, we examine issues that may be raised by introduction of long-term financial rights. In a subsequent section, we examine the implications of other approaches to long-term rights in RTO markets.

Impediments to long-term financial rights in RTO markets

In discussions with market participants and RTO market operators, staff heard a number of reasons why multi-year financial rights have not heretofore been a standard component of the RTO transmission markets. Some of these impediments are a factor in providing long-term transmission service in markets without locational pricing, but they may pose greater challenges in markets with locational pricing.

First, as noted above, financial rights are currently allocated based on a snapshot of the transmission grid's capability for the year ahead. Uncertainty about future changes to the transmission network and to major generation resources make it difficult for the RTO to forecast accurately the available transmission many years into the future. Another source of grid uncertainty is changes in generation dispatch patterns over time. All of these factors affect the set of FTRs that are simultaneously feasible and thus the supply of FTRs.

Second, congestion prices and patterns in RTO markets have been difficult to predict and can change dramatically year to year. While this is not an impediment to issuing long-term transmission rights, it does make it difficult for participants to value such rights.

Third, given these uncertainties, there is the prospect for significant financial gains or losses associated with long-term financial rights. The creditworthiness of market participants that are allocated long-term financial rights or purchase them through an auction must therefore be ascertained by the RTO, although this will be difficult.

Fourth, in RTO regions with retail choice states, LSEs facing competition typically do not seek transmission rights beyond the terms of their energy contracts. New contracts could require a different set of FTRs. By tying up valuable hedging instruments over many years, allocating long-term transmission rights could become a barrier to entry.

Fifth, there are concerns that long-term FTRs will be less liquid than annual or shorter term FTRs, resulting in a less efficient market for congestion hedges.

Based on the staff team's discussions, it appears that these factors, rather than design or implementation, present the greatest impediments to introduction of long-term rights. Staff notes, however, that some of the impediments have not been analyzed in great detail. A clear understanding of the nature and significance of any impediments, as well as measures to mitigate their effects, are critical to evaluating the efficacy of long-term financial rights

- Have RTOs or market participants quantified the probability of significant changes in network topology over time due to transmission line outages or outages of major generators? Put another way, how stable are network topologies over time? What are the implications for revenue adequacy of long-term financial transmission rights? How significant is the role of changes in generation dispatch over time to the feasibility of long-term financial rights?

Market design issues

Market design refers to the rules governing transmission rights. Several aspects of market rules governing FTRs and ARRs will affect long-term financial rights. Based on the staff team's initial review and discussions, the following market design issues were identified as being of primary concern to market participants and market operators: eligibility criteria, the term of long-term rights, whether the rights are obligations or options, how the rights are initially awarded (allocation or auction), and what insurance the rights have under revenue inadequacy conditions.

Eligibility Criteria

All participants seeking ARRs and FTRs in the current RTO markets must meet basic eligibility requirements. Parties eligible for allocation of FTRs or ARRs must be transmission customers of the RTO; that is, those parties that pay the fixed costs of the transmission system through access charges. In general, an LSE is eligible only for rights up to its peak annual load (which is the usual billing determinant for transmission service). A point-to-point customer is typically eligible up to its transmission reservation.[11] Another requirement for participation in the FTR auctions is creditworthiness. This is to ensure that buyers and sellers in the auction have sufficient credit to cover their settlement obligations for the duration of the right. These basic eligibility requirements presumably would carry over to the allocation of long-term rights.

Some market participants and market operators have suggested that the allocation of long-term financial rights raises several eligibility issues. One is whether long-term rights are available to all market participants currently eligible for ARRs or FTRs in the RTO system or whether priority is given to some participants on the basis of historical contracts or resource usage. Priority might be a consideration when an equitable allocation of long-term rights is difficult to achieve for all parties simultaneously. For example, a priority in the allocation of long-term rights has been proposed for transmission customers that held long-term transmission rights before the RTO began operations.

Another approach to the problem of availability might be not to restrict access to long-term rights on the basis of historical contracts, but rather to adopt a basis for all RTO participants to qualify. For example, long-term rights might only be available to cover generation resources that were used as base-load over some prior period of time, or planned as base-load in future. Alternatively, long-term rights could be allowed for any resource but restricted to a percentage of a market participant’s total eligible number of rights. It should be noted that these types of eligibility criteria are difficult to implement in practice without greatly complicating the allocation process.

A second eligibility issue is whether all parties that request long-term rights should be subject to creditworthiness requirements for the life of the right and how such an assessment should be conducted. As the market operator, the RTO must evaluate the increased credit risk when selling long-term FTRs, especially for obligation FTRs that

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[11] Some RTOs have given network customers the first chance to obtain FTRs (as PJM did for several years), but recently the Commission has required that network and point-to-point rights be allocated on equal footing. Some RTOs give historical resources the first chance to obtain FTRs (e.g., PJM), while others set aside capacity for FTRs for native load (e.g., New York).

could have sustained periods of net payments (see discussion of obligation rights below and in appendix A). That is, if the payments become too large, the FTR holders could default and the RTO could have to recover those payments from other parties.

- Should there be eligibility criteria for allocation or purchase of long-term rights? Should some transmission customers have preferential access to such rights based on their historical transmission rights? Should such rights be reserved for particular generation resources, such as base-load plants? Should a limited quantity of the rights be offered? What should be the credit requirements for obtaining such rights?

Term

The term of long-term financial rights desired by market participants is likely to vary by the type of firm seeking the rights. LSEs seeking to hedge transmission charges associated with their own generation assets or long-term contracts and long-term load may desire terms on the order of decades. Other LSEs face retail competition and hence may seek terms of a few years at most to provide greater flexibility to change their transmission coverage when the location of load changes.[12] Yet other market participants may be entering the FTR market to maximize FTR revenues, and will thus seek FTRs in locations and for terms that fit their expectations about future congestion charges.

The staff team has heard of no software limitation in conducting an auction with multi-year ARRs or FTRs of various terms. The trend among RTOs is to offer more "granular"[13] terms for the current annual rights, with the shortest term currently being one month with the choice of daily peak or off-peak hours. The time increment could in theory be very granular and defined by the transmission user, within the term limits imposed by the RTO on the particular transmission user or on the market as a whole. Increased granularity could increase the ability to tailor long-term rights to long-term needs.

If there are limits on the terms of ARRs or FTRs, then they are likely to be the result of financial constraints and/or concerns about fairness, as discussed elsewhere in this section.

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[12] In general, the revenues from ARRs or FTRs will follow the load when it changes suppliers. The details of how this is done vary by RTO, as detailed in Appendix B.

[13] That is, shorter time periods or more choice in terms of hours of the day (e.g., off-peak and peak hours).

- What term of long-term rights is desirable? Should the available terms be defined on a standard basis by the RTO or should transmission customers define the terms that they desire (within the eligibility criteria and term constraints imposed by the RTO market)? How granular should long-term rights be (week, month, season, year)? Are there technical impediments to the modeling of long-term rights?

Obligations versus options

Obligation rights grant the holder the right to collect positive congestion revenues associated with the points of injection and withdrawal specified in the right, but also carry the obligation to pay negative congestion revenues. Negative congestion revenue occurs when the LMP at the right's injection location is higher than the LMP at the right's withdrawal location.[14] In contrast, option rights grant the right to collect positive congestion revenues, but not the obligation to pay negative congestion revenues. In general, the option right is a financially less risky instrument, but also reduces the total quantity of rights available on the system.[15] The option right is thus a more valuable right to the holder. For more discussion of these properties, see Appendix A.

In a long-term financial right, the financial risk associated with the obligation right can potentially become amplified. If the situation arises that the holder of an obligation right faces obligation FTR payments and cannot manage this exposure through generation or load, then holding such an instrument over a longer term becomes a greater potential liability than it might be for a right that expires after one year.[16] In the annual

[14] The obligation FTR holder's exposure to congestion changes will depend on whether it is operating a generator consistently with the FTR. If it can operate a generator at the source point of the FTR, then the obligation FTRs payment obligations will be equal to or less than the generator's LMP revenues.

[15] The basic reason why option rights reduce the amount of FTRs that can be allocated is because the RTO cannot assume that the financial "counterflow" payments embodied in the obligation FTR are available for revenue adequacy. Hence, these counterflows cannot be included in the allocation model.

[16] Consider the following hypothetical example. A utility that has built a remote generator in a low price location to serve load in a high price location holds a 20 year FTR obligation. In year 5, the utility decides to sell its remote generator because it has joined in a large new plant closer to its load. But it can't reconfigure its FTR, because the counterflows from the right are being used to support other parties' FTRs and they are not willing to reconfigure, nor can it sell its FTR, which regardless is still paying positive FTR revenues. However, in year 7, changes in fuel prices, generation locations and transmission expansion have reversed the prices at the locations in the FTR and it is now a liability. Because the utility no longer owns the remote generator, it cannot run it to

allocation cycle, such liabilities can be minimized by not requesting the FTR in the next allocation. A long-term obligation right, on the other hand, could be more difficult to return, reconfigure or sell if it became a liability.

Option rights are one way to address some of the risks of long-term obligation rights. However, as discussed above, option rights restrict the quantity of transmission rights that can be allocated; if bought through an auction, they are more expensive than obligation rights. Some utilities may have assets and load located in such a fashion that they would clearly benefit from holding options in the long-term, but others could find that as power flows change, their ability to hedge congestion charges is made less flexible year to year by the introduction of a long-term option right. As such, the RTO may have to establish rules that limit the allocation of option rights, if these are directly allocated rather than bought voluntarily through an auction.

- Should long-term transmission rights be obligations or options or both? If the rights are being allocated directly (i.e., not through an auction), on what basis should parties be eligible to nominate options and how should the RTO address fairness issues that may arise in the allocation?

Allocation and auction of rights

Each current RTO has slightly different rules for allocation of FTRs or ARRs and the subsequent FTR auctions. The differences in these rules will have implications for the properties of long-term rights introduced into the market. If long-term rights were introduced, then there are currently two basic approaches that would be used to allocate them: (1) direct allocation of FTRs, or (2) direct allocation of ARRs followed by auction of FTRs. In direct allocation of FTRs, the eligible market participants are given FTRs, typically in a series of allocation rounds that may give higher initial priority to historical resources. Alternatively, the participants could be directly allocated ARRs and would then have to purchase the FTRs that they want in the auction. There are somewhat different rules for these procedures in each RTO; these rules are reviewed in more detail in appendices A and B.

Direct Allocation of FTRs. In this approach, long-term FTRs would be directly assigned to market participants, based on eligibility requirements, such as those discussed above. The advantage of direct allocation of long-term FTRs is that it does not require the LSE receiving the rights to estimate their value and directly compete in an auction with other parties that may be seeking the same rights (although ARRs in most cases allow the holder to outbid any competitor if she chooses). This may suit parties that are

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offset the negative FTR revenues.

seeking a congestion hedge of a fixed amount for long-term resources and load.

There are also possible disadvantages to direct allocation. Some observers argue that it may not encourage FTR valuation among risk-averse holders of the rights and hence there may be a concern that the transmission users with the highest value uses of the grid will not be able to obtain transmission rights.

Allocation of ARRs with FTR auctions. Most RTOs currently allocate ARRs and then allow transmission customers and others to purchase FTRs through an annual auction. In general, the auction model is intended to prompt more careful valuation of FTRs than direct allocation of FTRs, and hence to promote market liquidity by bringing more sellers into the market. However, when considering long-term rights, especially those with terms longer than a few years, there may be considerable uncertainty over the long-term value of the FTR. Market participants have suggested to the staff team that this potentially creates an informational asymmetry that favors larger firms that can better internalize the risks of estimating FTR values over multiple years.[17]

Moreover, some transmission customers may seek a fixed long-term hedge regardless of its expected market value and are wary of the concept of having to compete for such rights in an auction, even with ARRs.[18] First, as with direct allocation of FTRs, direct allocation of ARRs may not give them the potential coverage of their transmission usage that they desire (i.e., ARRs themselves may be pro-rationed). Second, the outcome of an FTR auction, in terms of the quantity of rights allocated, will be entirely dependent on the bid and offer behavior of the auction participants and the resulting modeled power flows. Hence, as with the direct allocation of FTRs, some parties that seek long-term obligation rights may not obtain them via the auction process. For these reasons, some RTOs (e.g., PJM) allow parties to directly convert ARRs into FTRs, bypassing the auction.

- Should long-term FTRs be awarded through direct allocation? Should long-term FTRs be available through annual auctions? Are particular ARR allocation approaches (i.e., those taken by different RTOs) more suited to long-term rights than others? Are designs that allocate long-term rights to

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[17] For example, market participants noted that when the New York ISO offered 2 year and 5 year rights in the 2000 fall auction, only a few parties did well in the long-term auction, capturing valuable rights cheaply. For this reason, multi-year rights were not offered subsequently, although the ISO is planning to re-introduce such rights.

[18] The way in which the ARR is specified – i.e., point-to-point (e.g., PJM and New York ISO) or to a share of the transmission path from each of the RTO market generators to the customer's load (e.g. ISO New England) – may contribute to perceptions that the quantity of resulting FTRs may be uncertain.

some parties but require others purchase FTRs through an auction possible or desirable?

Rules for FTR payments when RTO is not revenue adequate

RTOs assign ARRs and FTRs to transmission users only to the extent that they are expected to be simultaneously feasible. This means that all the injections and withdrawals being modeled when assigning rights can take place simultaneously while respecting the physical and reliability limits on the network (as assumed in the RTO's "snapshot" of the period being modeled). As long as the aggregate set of ARRs and FTRs issued are simultaneously feasible in this analysis, the RTO is assured that it can collect at least enough congestion revenues from users of the grid to pay the holders of the rights when they are settled financially in the day-ahead market. This revenue adequacy holds as long as the network transfer capability does not change such that the RTO collects insufficient congestion revenues to pay the rights.

However, all RTOs experience transmission deratings or outages, changes in generator availability that affect the feasible power flow, and unexpected loop flow from contiguous RTOs or other balancing authorities. Such events that were not in the model used to identify the feasible set of rights can reduce congestion revenues collected below the level needed to pay existing FTR holders. When this happens, rules are needed to determine whether and how much FTR holders are paid. For example, PJM sets aside surplus congestion revenues each month (i.e., any congestion revenues left over after paying FTR holders) and uses this fund to pay FTR holders when the grid capability is reduced. When the fund runs out, FTR holders are paid a pro-rata share of their actual FTR entitlements. In contrast, New York ISO fully funds FTRs, and assigns any payments not covered through congestion revenues to transmission owners, which can then pass the costs through to their transmission customers through access charges. Different payment rules thus create hedges with different properties and have financial implications for cost assignment.

Because the probability of revenue insufficiency is likely to be greater with long-term financial rights, how such costs are assigned when the RTO is revenue inadequate could be more of an issue than in the annual allocation cycle.

- Should long-term financial rights be fully funded or subject to revenue shortfalls due to transmission network changes? How should potential revenue shortfalls be allocated?

- If long-term financial rights are awarded based on forecast grid conditions, but maintenance of the grid declines, resulting in future infeasibility, which parties should be responsible for maintaining the revenue adequacy of the rights?

Long-term financial rights and infrastructure financing

Our preliminary discussions with merchant generators, transmission-dependent utilities, credit rating agencies and financial advisors, allow a few observations to be made about the relationship between the availability of long-term transmission rights and financing of new infrastructure. These observations vary by type of firm and type of infrastructure project.

One concern raised by transmission dependent utilities is that not having a long-term transmission right could adversely affect their ability to finance new generation projects, specifically those remote to load (because of uncertainty from year-to-year about the cost of delivering the power to load). If such utilities finance investments by borrowing against the firm's overall assets and revenues (in contrast to project financing typically undertaken by merchant entities, in which the projected sales revenues are used to secure financing), then it appears that the unavailability of long-term FTRs may not have a direct impact on their ability to finance a new facility. Instead, the lack of long-term rights could have an impact on the overall credit risk profile of the utility, and thus their overall financial flexibility and ability to make the strategic decision to invest in new generation (instead of, for example, to purchase power through a contract).

For other types of firms, the availability of long-term FTRs is apparently less important in the financing decision. For example, staff's discussions suggest that, despite the fact that long-term hedging instruments are awarded in many RTOs in exchange for investments in transmission infrastructure, developers of merchant transmission may not consider long-term financial rights a reliable and sufficient source of revenue to obtain financing for new projects. FTR values are too difficult to forecast over a long period because of the challenges in accounting for changes to the generation resources and transmission system over time. In addition, new lines destroy a portion of the basis differentials that the FTRs reflect and are not therefore captured by FTR holders unless a contract party that benefits from the decline in basis pays in advance for them through a long-term contract.

Merchant generators in the current environment typically are able to obtain financing only if they have long-term power purchase or tolling contracts with credit-worthy counterparties, and may not have a strong interest in long-term FTRs. Because the long-term power purchase agreements that they typically enter into call for power delivery at (and pricing based on) the generator's interconnection point, such generators typically do not take transmission risk but leave it to their counterparties. When they considered accepting transmission risk as part of a contract, generators were more interested in obtaining short-term FTR options than in obtaining long-term FTR obligations.

Another source of uncertainty for merchants is regulatory policy. From the merchant perspective, market rules have changed sufficiently frequently in the existing RTO markets that long-term financial rights, particularly those with terms of decades, would not be seen as guaranteed revenue sources (regardless of the difficulty of valuation) when undertaking financial analysis. Again, particularly for project financing, the conclusion was that investors would be very conservative when factoring revenues from transmission rights into their lending decisions.

Other Approaches to Long-Term Transmission Rights in RTO Markets

There are ways to provide transmission customers in RTO markets with the long term stability of transmission service at a known price that do not require those customers to be exposed to congestion charges or hold financial transmission rights. For example, some transmission users in RTO markets have expressed interest in physical transmission scheduling rights akin to the Order 888 OATT rights.[19] Although there are various proposals for how to implement such rights under RTOs, in essence, such transmission customers would pay an RTO access charge and then, to the extent that they remain within their reserved transmission usage, they would not be subject to the uncertainties of hourly congestion charges and the annual allocations of FTRs.[20] However, in the presence of congestion, such customers could be subject to physical curtailment under rules similar to the rules outside RTO markets.[21] Alternatively, there could be rules specifying ahead of time the total redispatch charges that such a customer would be willing to pay. Unlike FTRs, such physical scheduling rights would not pay revenues when transmission is not scheduled, nor have payment obligations (apart from the initial charge for obtaining the rights).

Such scheduling rights could apply only to a subset of the market or to the entire market. Regarding the latter case, SPP has recently proposed a market design in which parties with OATT rights are given FTRs on a daily basis, exempting them from congestion charges, and then settle imbalances using locational pricing.

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[19] It is important to note that in RTO markets, all transmission customers have the right to physically schedule subject to congestion charges. The difference here is that the customer would have the right to physically schedule but not be subject to congestion charges, although it might be subject to other congestion management rules, as discussed below.

[20] Because congestion costs are difficult to forecast, there is always the possibility that there would be some degree of *ex post* redispatch charges even under this type of scheme.

[21] Also, when such a transmission customer was out of balance, then it would pay the RTO market's congestion charges based on LMPs.

In this section, we discuss some of the implications of long-term physical scheduling rights with the general characteristics discussed above for the FTR market in the case that only a subset of the market participants is eligible for such rights. Details of the proposed SPP market design are provided in Appendix B.

Scheduling rights based on "carve-out"

A fundamental issue that the RTO faces if eligible parties elect to maintain (or revert to) an OATT-type physical scheduling rights in lieu of FTRs is how to allocate transmission capacity to those parties that nominate for FTRs. In this first approach, the RTO would reserve, or "carve-out", some percentage of the transmission capacity that would be used for scheduling entities with the pre-RTO scheduling rights when it allocates FTRs. For example, if a party elected OATT-type rights for scheduling 100 MW from a generator at location A to its load at location B, and this required 50 MW of power to flow on transmission line X in the direction of B, the RTO would reduce the available transmission capability assumed for line X in the appropriate direction when it considered how much transmission capacity might be available for LMP/FTR customers.

There are impacts on the market and other participants in the RTO markets that must be kept in mind when considering the "carve out" approach. In general, if only a subset of the market is eligible, then there is potentially an equity issue, because those parties could get the benefit of less uncertainty over physical delivery due to the RTO market redispatch but not share in the costs of such redispatch. Moreover, because the transmission capacity needed for the customer's service is removed from that available for FTRs, any counterflow service that might be enabled by using that capacity would not be considered feasible in the FTR model and thus fewer overall FTRs will be available to the market. This could result in less efficient use of the grid than possible and cost shifts to parties that would be exposed to LMP-based congestion charges. Parties with these OATT-type scheduling rights also may have less incentive to redispatch their generators through the RTO spot market because they are not exposed to congestion charges and thus may be less interested in buying from the RTO market. This could reduce the RTO's ability to redispatch the system through prices and increase the possibility that it will rely on physical curtailments to manage congestion. While these problems may be manageable by the RTO for some amount of long term OATT-type physical scheduling rights, there may be a limit beyond which the integrity of the price-based congestion management regime is too compromised.

Transmission customer is granted physical scheduling rights but financial rights are taken by seller of the historical transmission service

In this second approach, the transmission capacity needed for the customer's physical scheduling reservation is not excluded from the transmission capacity that is available for FTRs. As such, this method avoids the downsides of a carve-out described above. However, because the transmission customer is granted the right to schedule its transactions without exposure to congestion costs, some entity must take on the obligation to pay congestion costs and possibly hold FTRs. While the entity would bear the risk of paying any congestion not covered by the FTRs allocated, it would also receive any congestion revenues associated with the FTRs. An additional rate charged by the holder of the FTRs to the purely physical customer (in addition to the access charge) may be needed to compensate for the congestion risk undertaken.

One possible candidate for the risk bearing entity might be the transmission owner on whose system the FTRs are awarded. If the service for which the long term scheduling rights are awarded was provided before the start of the RTO market, the transmission owner committed to the service and managed the congestion risk in the past and should be able to manage it now.[22] If the service is new, the transmission owner may be in the best position of all the parties involved (customer, RTO, and transmission owner) to identify improvements in system operation or facility expansion to manage any congestion that could impact the service in question. On the other hand, transmission owners in the RTO market may not have the option that they had in the pre-RTO market of passing through redispatch costs into their rate base, hence may not find this approach equitable.

- Are purely physical scheduling rights necessary as an alternative to financial rights to ensure stable transmission prices over the long-term? If so, which model of such rights is the most appropriate to the RTO market context? What rules for transmission scheduling and RTO market participation should be required for holders of such rights?

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[22] In the Midwest ISO, the Commission did require this type of arrangement for "slice of system" purchase contracts that were in place prior to the RTO market. This was because in such contracts, the utility selling the system power controls the generators used to provide the power. If the buyer of the system power held FTRs but did not control the generators at the source points, it could not easily manage congestion risk.

APPENDIX A: Background on LMP and Transmission Rights

The rules for allocation and settlement of financial transmission rights vary among RTOs and ISOs. In each case, they reflect the market's historical starting point, market participants' views on management of congestion risk and insurance for the FTRs, and market changes that have taken place since restructuring. How long-term FTRs might be introduced in the context of the existing market rules, and their resulting properties as financial instruments, will thus also vary from market to market. This appendix reviews the general features of ARR and FTR allocation procedures and FTR auction markets, and highlights some alternative approaches. Appendix B describes the market rules of each RTO and ISO.

LMP and Congestion Pricing

Locational Marginal Pricing (LMP) is a pricing method for energy (both day-ahead and in real-time) that determines a price for energy at various locations (for example, "nodes" or zones) within the RTO market area. If there were no congestion or line losses, all prices would be the same. However, LMP yields a different market price at each location when transmission congestion or line losses cause the price of delivered power to be different at those locations. In this appendix, we will ignore the marginal cost of losses, which are generally small, and consider only marginal congestion pricing.

The explicit congestion charge associated with any set of injections and withdrawals in such a market is the difference between the price at the point of injection and the price at the point of withdrawal multiplied by the quantity injected and withdrawn. Note that, for buyers and sellers in the RTO energy market, neither side pays "congestion" explicitly; rather, the cost of congestion is reflected in what the RTO collects when it pays the market sellers less than what it receives from the buyers. If there is no congestion, and all prices are the same, the RTO receives from buyers exactly what it pays to sellers. If there is congestion, then the RTO will collect more from buyers than it pays to sellers. This "surplus" is used in part to pay holders of financial transmission rights.

The cost of congestion is *positive* if the price at the injection point is less than the price at the withdrawal point. For example, if the price at the generator's location is $15/MWh and the price at the load's location is $20/MWh, then the cost of congestion is $5/MWh. Conversely, the cost of congestion is *negative* if the price at the injection point is more than the price at the withdrawal point. For example, continuing with the same generator and load, if the price at the generator is $20/MWh and the price at the load is $15/MWh, then the congestion charge is a negative $5/MWh.

FTR Definition and Specification

An FTR is specified by means of a point of injection, a point of withdrawal, and a MW quantity. The points of injection and withdrawal are typically electrical busses designated as pricing locations for LMP. In general, 1 MW = 1 FTR. An FTR can be divided over multiple points of injection and withdrawal; these are sometimes called "zonal" or "hub" FTRs.[23]

There are two basic types of FTR: the obligation right and the option right. An obligation right entails the right to receive congestion revenues when congestion is positive (i.e., the price at the withdrawal point exceeds the price at the injection point), but also the obligation to pay congestion revenues when congestion is negative. Thus, if a market participant holds a given quantity of obligation FTRs, and injects that quantity of power at the point of receipt and withdraws the same quantity at the point of withdrawal, the obligation FTRs provide compensation (positive or negative) that exactly offsets the cost of congestion (positive or negative) that the market participant incurs. In contrast, the option FTR entails the right to collect positive congestion revenues associated with the FTR's point of injection and point of withdrawal, but not the obligation to pay negative congestion revenues.

In determining how many FTRs can be offered to transmission customers, the RTO will model its system assuming that, for a given quantity of obligation FTRs, the same quantity of power is actually injected at the point of injection and withdrawn at the point of withdrawal. In this way, the RTO can assume that "counterflows" will be present that would make other injections and withdrawals, and hence FTRs, feasible. The option FTR does not assume that the modeled power flow can be used for counterflow; put another way, the holder of the option FTR has the option not to inject or withdraw power, and as a result, the option FTR effectively encumbers a greater amount of system capacity than does the obligation FTR.

FTR Settlement

Regardless of how they are obtained (which is discussed next), FTRs are settled in the RTO day-ahead market at the prices associated with their points of injection and withdrawal. That is, for each hour of the relevant day, the FTR holder would receive (or pay, if applicable) congestion revenues equal to the difference in the prices for that hour multiplied by the quantity of FTRs that it holds.

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[23] For example, if a utility has decided to spread its FTRs over its 5 network generator resources based on an analysis of the annual usage of each resource, then for each 1 MW of FTR sourced in the zone, 40 % will be assigned to generator A, 30 % to generator B, 20 % to generator C, and 5 % each to generators D and E.

FTR Auctions

In addition to direct allocation, discussed below, RTOs typically make available FTRs through monthly and annual auctions. An FTR auction is organized as a uniform, second price (locational) clearing price auction in which buyers and sellers can bid for or offer FTRs between any two locations or aggregations of locations in the RTO network. A bid in an FTR auction is defined as the dollar value willingness-to-pay for the injection of a MW quantity at a location and the withdrawal of that quantity at another location. For example, Party A is willing to pay up to $5/FTR for up to 100 FTRs from a location in PJM West to a location in PJM East. Party B is willing to pay $4.25/FTR for the same FTRs. An offer in an FTR auction is defined as the dollar value minimum sale price for an FTR, again specified as the injection of a MW quantity at a location and the withdrawal of that quantity at another location. For example, Party C is offering for sale 100 FTRs at $4/MW from the same location in PJM West to the same location in PJM East. For any pair of injection and withdrawal points, the auction clears at a single price and the winning bids all pay the price bid by the second highest bid. In the example, the bidder willing to pay $5/FTR would win the FTRs and would pay $4.25/FTR. In an actual FTR auction, the physics of the power flows being modeled means that the clearing prices do not necessarily correspond exactly to particular offers and bids, but for any particular awarded right, they can never be higher than the prices in the winning bids or lower than the prices in the winning offers.

In an FTR auction, the type of FTRs being bought and sold – obligation or option – will have an impact on the market clearing FTR prices. This is because the option right does not include the "counterflow" assumptions that the obligation right does, as discussed above. In essence, the option right reserves more of the total transmission transfer capability than does the obligation right, and because of its financial settlement properties, the former is a higher quality right than the latter. As a result, option rights trade at higher prices than obligation rights and the auction typically produces fewer option rights than obligation rights in many RTO regions.

ARR Definition and Specification

An auction revenue right (ARR) is the right to the revenues from the sale of an FTR between a specific injection point and a specific withdrawal point in the RTO's FTR auction. Each ARR, like each FTR, is direction specific. Also like FTRs, ARRs are allocated to LSEs and others that pay the fixed costs of the transmission system. A market participant that wishes to purchase FTRs in the RTO's auction can use its allocated ARR revenues to fund these purchases. Thus, an ARR can reduce to zero the net cost of purchasing an FTR. In some instances (such as in PJM), an ARR can be converted directly into an FTR with the same injection and withdrawal points.

In sum, the procedure is as follows:

- ARRs are defined and allocated to parties
- Parties cash out their ARRs in an annual FTR auction
- The FTR auction results in awards of FTRs
- ARR proceeds are awarded on a monthly basis; FTRs are settled daily against day-ahead locational prices

Simultaneous Feasibility Test

When determining how many FTRs or ARRs it can allocate, the RTO must ensure that it will be "revenue adequate"; that is, it must ensure that it will collect enough congestion revenues to compensate the holders of the FTRs or ARRs. In general, this can be done by ensuring that the implied dispatch underlying the set of rights is physically feasible. This means that, in its modeling of the transmission network for the periods over which it is defining the rights, the RTO must establish that the injections and withdrawals being modeled for the rights do not violate system constraints. This is known as a "simultaneous feasibility test" (SFT). Performing this test guarantees that, as long as the network transfer capability is not reduced in a manner that violates the feasibility of the existing rights, the RTO will always collect at least enough congestion charges through locational pricing to pay the holders of FTRs. When the network <u>does</u> change in a manner that violates the feasibility of the existing rights -- e.g., if a major transmission line is removed from service -- the RTO may not have enough congestion revenues to pay the existing rights. In that case, the RTOs have rules to determine how the available revenues are distributed to FTR holders, or how the shortfall is to be made up, as discussed below.

Allocation of Rights to Existing Transmission Capacity

There are two general models for allocation of rights to existing transmission capacity, and within each model, several variations.

<u>Direct Allocation of FTRs</u>. The first model uses an administrative process to directly allocate FTRs to LSEs on an annual basis. This was the approach first adopted by PJM (1999) and later by MISO (2005). The FTRs are not allocated on the basis of value or willingness to pay (i.e., congestion revenues they are expected to collect), but on the basis of an administrative determination of eligibility. LSEs with network rights are typically eligible to receive FTRs between network resources and network loads. Parties with point-to-point rights are eligible to receive FTRs corresponding to the points of injection and withdrawal in their rights.

<u>Direct Allocation of ARRs with FTR auction</u>. The second model uses an administrative process first to directly allocate ARRs, but then allows parties to choose how to "spend" their ARRs in an FTR auction. A party receiving ARRs is not limited to purchasing FTRs that correspond to the party's ARR points. Instead, it has a choice: it

may use its ARRs to purchase FTRs that hedge its expected transactions or schedules, or it may use its ARRs to purchase FTRs that it considers valuable rights to hold.

Reconfiguration

The holder of a right from point A to point B may prefer to hold the right from point C to point D, or the holder may want to change the MW quantity of the right. RTOs allow market participants to reconfigure their FTRs by submitting appropriate bids and offers in the monthly auctions. The RTO will permit the reconfiguration as long as it does not affect the simultaneous feasibility of all other outstanding rights.

Current Rules for Allocation of Rights to New Transmission Capacity

When a market participant pays for an expansion of the transmission system, the RTO will allocate to the market participant the FTRs that are made possible by the capacity expansion. Although the specific rules for these allocations vary among RTOs, the FTRs that are awarded typically are of longer duration than those available from existing capacity. The market participant may be able to decline the award of any FTRs whose value is negative, and it may be able to turn back FTRs if their value becomes negative in the future.

Rules for FTR Settlement When the RTO is Not Revenue Adequate

In general, if the RTO accurately models the transmission network when it assigns FTRs and ARRs, and if the configuration of the network does not change for the duration of the rights, then the RTO will always collect sufficient congestion revenues to pay holders of the rights. When the network configuration does change in a way that makes the existing rights no longer simultaneously feasible, then the RTO may not collect sufficient congestion charges to pay the holders of the rights. Rules for addressing this revenue shortfall vary among RTOs. One approach is simply to allocate the available revenues to FTR holders on a prorated basis according to the MW quantity of the FTR holdings. A second approach is to provide each FTR holder with a payment equal to its full entitlement, and make up the resulting revenue shortfall by assessing an administrative "up-lift" charge to market participants or transmission owners. These rules obviously affect the hedging properties of the rights, because holders of the rights may be exposed to additional charges after the fact (*ex post*).

Creditworthiness Requirements

When FTRs are offered through auction, creditworthiness becomes an important requirement of the transmission rights market. In general, auction participants must establish credit limits with the RTO prior to buying and selling through the RTO auctions.

Rules for ARRs/FTRs in Retail Choice States

In regions where states have implemented retail choice programs, a retail customer typically is allowed to switch its retail energy provider on relatively short notice. If retail energy providers could obtain FTRs or ARRs only through infrequent allocations or auctions, they might find it difficult to compete with incumbent utilities to serve retail customers, and competition in retail markets could suffer as a result. Consequently, all RTOs that serve states with retail choice programs have established rules that allow ARRs or FTR to follow the movement of retail customers from one retail energy provider to another on a daily basis. These rules are designed to reduce financial risk for retail energy providers and thereby increase competition in the retail markets.

APPENDIX B: Review of Current and Proposed RTO/ISO Rules for Financial Transmission Rights

This appendix provides a summary of the current rules for allocating, auctioning and trading transmission rights in the current RTO and ISO markets. In most cases, these markets use a common framework of a day-ahead energy market with locational marginal pricing (LMP). The principal exception is the California ISO, which currently uses zonal pricing and zone-to-zone transmission rights. The re-designed California ISO market will implement LMP.

As readers will observe, each market uses slightly different terms for financial transmission rights. The fundamental properties of the financial rights remain the same, but differences in rules can affect the value of the rights.

PJM RTO

PJM began its cost-based LMP market with Fixed Transmission Rights (FTRs) on April 1, 1998; the energy market became bid-based on April 1, 1999. Until 2003, obligation FTRs with an annual term were allocated directly to network customers; any remaining FTRs were made available to point-to-point customers. Customers were allowed to refuse any FTRs allocated to them. A monthly FTR auction was then established for the sale of FTRs on any residual transmission capacity and for reconfiguration and trade of allocated FTRs. On June 1, 2003, PJM made the transition to an annual allocation of Auction Revenue Rights (ARRs) with an annual FTR auction of all transmission capacity. Also in 2003, PJM introduced option FTRs as an alternative to obligation FTRs.

Annual ARR Allocation

Auction Revenue Rights are allocated to customers with network resource integration service up to their total annual load and to customers with firm point-to-point service up to the quantity specified in the transmission reservation and for the period of the reservation. ARRs are defined as a point of injection, a point of withdrawal and a quantity, which can be specified to the nearest 0.1 MW. ARRs are nominated by eligible transmission customers and their award is subject to a simultaneous feasibility test.[24]

The ARR allocation is implemented in two stages. In Stage 1, load serving entities (LSEs) are eligible to nominate ARRs from generation resources that historically served load in each transmission zone. In Stage 2, market participants are not restricted

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[24] As with FTRs, allocation of ARRs may be prorated. For example, in PJM's 2003 ARR allocation process, 28,933 MW of ARRs were allocated, which represents 73 percent of the 39,888 MW requested.

to historical resources. There are four rounds in which 25 percent of the remaining transmission capacity is allocated in each round. Participants can assign priorities, from 1 to 4, for the ARRs nominated in these rounds. They can also view the results of each round before proceeding to the next round.

FTR Auctions

PJM conducts both annual and monthly FTR auctions. In the annual auction, FTRs with terms of one year are traded. These can be obligations or options and can be specified for the daily off-peak hours, the daily peak hours or all 24 hours. The annual auction has four rounds in each of which 25 percent of the feasible transmission capacity is made available. A participant that purchases an FTR in one round may offer it for sale in subsequent rounds.

Holders of ARRs have the option to convert them directly to FTRs by “self-scheduling” them in the first round of the annual FTR auction. Holders of ARRs are not required to bid for FTRs on the transmission paths associated with the ARR; they may bid on alternative paths or alternative products. For example, they may use an obligation ARR to purchase an option FTR.

Annual auction revenues are distributed to holders of ARRs. ARR revenues may be prorated. The annual auction settlements and the corresponding ARR settlements take place on a monthly basis.

Monthly auctions are conducted for any residual transmission capability not sold through the annual auctions for FTRs offered for sale. The monthly auctions sell monthly FTRs.

Market participants must establish an auction credit limit prior to participating in an auction and their bids in the auctions cannot exceed this limit. ARR revenues are taken into account in determining credit limits.

Incremental ARRs for Network Upgrades and Transmission Expansion

Incremental, multi-year ARRs are assigned for transmission expansions associated with generator interconnections and merchant transmission projects. The term of the ARRs is thirty years or the life of the facility or upgrade, whichever is less. The ARRs are awarded in three rounds in each of which the party requesting the rights can nominate a different point-to-point path if it chooses. The ARRs nominated by the third round become final.

Market participants awarded such multi-year ARRs have a one-time option to switch to an annual allocation of their eligible ARRs. They may also turn back any multi-year rights that they no longer desire to hold, as long as this does not affect the feasibility of the ARRs of other parties.

New York ISO

New York ISO began market operations in November 1999 with an LMP energy market and point-to-point obligation FTRs that are called Transmission Congestion Contracts (TCCs). New York ISO was the first organized market to introduce an annual auction for financial rights.

Before the first TCC auction took place in September 1999, several kinds of existing rights had to be translated into the new system. The holders of existing transmission rights, including Transmission Wheeling Agreements and Transmission Facilities Agreements, were given the opportunity either to retain grandfathered rights or to convert them into Grandfathered TCCs which remain active until the time the original right would have expired. Transmission owners that had obligations to serve load were allocated Existing Transmission Capacity for Native Load (ETCNL) rights. Before each bi-annual Initial Auction, a portion of these ETCNL rights can be converted to ETCNL TCCs (6-month TCCs). ETCNL rights that are not converted are sold in the Initial Auctions and function like Auction Revenue Rights in that they entitle the owner to the revenues resulting from the sale of the corresponding TCCs in the New York ISO-run auctions. Any remaining transmission capacity was allocated to transmission owners as Original Residual Capacity.

Bi-Annual TCC Allocation

Prior to each Initial (bi-annual) Auction, New York ISO allocates Residual Capacity Reservation Rights (RCRR) to transmission owners taking into consideration existing grandfathered rights, ETCNL rights, and valid TCCs. Transmission owners can then convert a portion of their RCRRs to 6-month TCCs and sell the remaining rights into the Initial Auction.

TCC Auctions

The New York ISO holds a number of auctions each year to facilitate the liquidity of the TCC market. At Initial Auctions, held twice a year, the NYISO releases TCCs, including non-converted ETCNL rights, Original Residual Capacity and RCRRs, plus expired grandfathered rights, for sale in two stages of multi-round auctions. During the first stage, a certain percentage of all the TCCs for sale are released in each of the four rounds. The second stage allows TCC holders to resell rights they purchased through the first stage. Currently the effective period of the auctioned TCCs is determined by the ISO, and is either 6 months or one-year. At the discretion of the New York ISO, multi-year TCCs are offered, with the longest being five years. The price is determined by the lowest winning bid for a particular TCC point-to-point pair in a specific round. The New York ISO also holds monthly Reconfiguration Auctions in which TCC holders can offer to sell their TCCs for the subsequent month.

TCCs for Network Upgrades

Parties who invest in transmission expansion are entitled to 20-year Expansion TCCs, commencing when the new transmission facility begins operation. The Expansion TCCs consist of only the new TCCs made feasible as a result of the transmission expansion.

ISO New England

ISO New England began market operations on May 1, 1999. The initial phase of the energy market relied on a congestion management system using a redispatch algorithm that resulted in a two-part pricing system under which "in-merit" generators were paid a single New England market clearing price and "out-of-merit" generators – those dispatched to a higher output level due to congestion – were paid their offer price, after market power mitigation had been taken into consideration. Today, ISO New England implements a market design with LMP, ARRs and an FTR auction. The ARR methodology is unique to New England.

Annual ARR Allocation

ARRs are allocated monthly first to the entities that pay for transmission upgrades that increase transfer capability on the NEPOOL transmission system, making possible the award of additional FTRs in the FTR auction. The remaining auction revenues are allocated to each congestion-paying LSE in proportion to its load ratio share.[25] Any ARRs assigned that have negative values in the FTR auctions are eliminated. The remaining ARRs are reduced proportionally[26] until a solution is reached in which all the ARRs are simultaneously feasible given the other rights, including the excepted transactions, NEMA rights, and Quality Upgrade Awards, which are discussed below. In general, an entity receiving ARR revenues does not know its ARR position before the FTR auctions are held, as the dollar value of its ARR allocation is contingent on the MW

[25]For example, assume a load (Load Z) has a demand of 100 MW, which is 5 percent of the total network load of 2000 MW. If there were 400 MW and 300 MW of generation at nodes A and B, respectively, Load Z would be assigned ARRs from each generation node to its load node (z) proportional to the amount of generation.

[26] Reductions are based on which constraint whose relief would require the largest proportionate reduction in all the ARRs.

amounts resulting from the four stage ARR allocation process and the auction clearing prices associated with the ARR paths.

ARRs are made available on a long-term basis to certain entities, such as holders of Excepted Transactions (grandfathered contracts) and “NEMA” (Northeast Massachusetts) contracts. Excepted Transactions are given the option to receive ARRs from the generator to the specified load location. The Excepted Transactions consist primarily of transmission agreements for certain point-to-point wheeling transactions across or out of the network and are assigned either to entities serving load to which energy is delivered or to entities making an external sale. To date, about 0.5 percent of the ARR revenues have gone to entities with rights associated with Excepted Transactions.

ARRs for Network Upgrades

Auction revenues are made available on a long-term basis to entities that construct transmission upgrades that increase the transfer capability of the NEPOOL transmission system. These are referred to as “Qualified Upgrade Awards” (QUAs). Qualified Upgrades, which normally are new expansions to the transmission system, are awarded rights to receive FTR auction revenues. The FTR bids and revenues are first determined with the upgrade and then without each upgrade. The difference in revenues between the two (which can be interpreted as the value the upgrade brings to the system) is awarded to those entities which provided the upgrade. Qualified Upgrade payments are made as long as the entity is paying for the upgrade, or for the life of the asset, whichever is shorter. To date, approximately 1.5 percent of the total FTR revenues have been assigned to Qualified Upgrades.

FTR Auctions

New England holds FTR auctions for peak and off-peak periods. Fifty percent of the total transmission capacity is made available in an annual month auction, and the residual transmission is sold in monthly auctions. The ISO’s FTR auction maximizes the total value to the bidders, subject to the FTRs being simultaneously feasible, given previously allocated FTRs and transmission constraints. The recipient of each FTR pays a clearing price which is the marginal opportunity cost of the FTR being awarded.

Midwest ISO

The Midwest ISO (MISO) Day 2 market started on April 1, 2005. FTR allocation was a contentious issue in the development of the market design, in part because the existing pre-OATT and OATT transmission rights in the MISO footprint did not appear to convert easily into FTRs that market participants believed would be sufficient to hedge their long-term contracts or investments. A larger percentage of the network than in other RTOs was also set aside for grandfathered rights.

Initial FTR Allocation

FTRs are allocated directly to existing users of the transmission network. In the stakeholder process on market design, a number of different approaches were assessed including an ISO proposal to assign a certain percentage of the FTRs based on historical uses of network resources, and a stakeholder proposal that all FTRs be nominated voluntarily by market participants between their eligible points of injection and withdrawal. The market rules that were finally approved by the Commission set out a "compromise proposal" for the annual allocation, developed in consultation with market participants and with substantial input from the Organization of Midwest States (OMS). The compromise allows parties to voluntarily nominate FTRs between their eligible points of delivery and receipt. However, all parties remain eligible to receive a full allocation of nominated FTRs from resources they use to serve base load (with criteria to determine base load). To the extent that this full allocation is not achieved in the flexible phase of the allocation, counterflow FTRs are assigned (to parties providing existing transmission service) to ensure that the base load FTRs are "restored." This restoration process is described further below.

FTRs can be nominated from Network Resources based on the Forecast Peak Load served under Network Integration Transmission Service, and from the points of delivery and receipt in Point-to-Point Transmission Service of annual duration or longer. The maximum quantity eligible for nomination is the sum of these existing entitlements for network service and the total quantity in each point-to-point service.

The FTR allocation process takes place over four successive and cumulative tiers. In each tier, a Market Participant is allowed to nominate up to a percentage of its maximum nomination eligibility less the FTRs awarded in the prior tier. The cumulative Tier Factors are: Tier I, 35 percent; Tier II, 50 percent; Tier III, 75 percent; and Tier IV, 100 percent.

For a period of five years following the start of the Day 2 market, any eligible FTRs that were prorated in the first two tiers are eligible to be restored. Eligibility requires that, if the nominated FTR is from a network resource, that network resource has an average historical capacity factor of at least 70 percent, and if the nominated FTR is to convert existing point-to-point service, that service has a historical scheduling factor of at least 70 percent. To restore the prorated FTRs, the Midwest ISO will define Counter Flow FTRs sufficient to make the eligible nominated FTRs simultaneously feasible. Counter Flow FTRs are defined as eligible base-load FTRs that were either not nominated by a Market Participant or not awarded in the first two tiers, but if assigned, would provide counterflow in the FTR model for restoration of other nominated FTRs. The Midwest ISO will choose the minimal set of Counter Flow FTRs needed for restoration. The Counter Flow FTRs are allocated directly to the Market Participant that was eligible to nominate them. They are settled like other FTRs, except in the event of a unit outage, in which case they are not settled. (That is, if the unit is not physically available to provide counter flow, it will not be held financially responsible.) Any resulting shortfall in congestion revenues will reduce payments to FTR holders on a pro-rata basis.

MISO market participants were concerned that insufficiency of FTRs would have a particular impact on parties that are within persistent load pockets and hold existing transmission contracts to support imports from generators outside the load pocket. In MISO, such load pockets are called “Narrow Constrained Areas” (NCAs) and are defined as locations in which imports were affected by a transmission constraint for 500 hours or more in the prior year. The Commission determined that parties in NCAs, to the extent that they hold existing firm transmission contracts for imports, should be allocated sufficient FTRs to cover those contracts for a five-year period. In other words, they would be held harmless from congestion charges. This rule would extend to any NCA defined within the first six months of MISO market operations.

FTRs for Network Upgrades

Under its current tariff, MISO directly allocates incremental FTRs for network upgrades. Entities can select FTRs from any set of injection and withdrawal points in the network as long as the quantity reflects the incremental capacity that has been made available and the FTRs are jointly feasible with the outstanding FTRs. The maximum term of such awards is one year. In each subsequent allocation, the FTRs are re-evaluated based on any changes in the incremental transmission capacity created by the upgrade. When there are monthly differences in the incremental capacity, MISO may issue some incremental FTRs for only the months in which the capacity is available.

When multiple parties contribute to a transmission upgrade, FTRs are awarded in proportion to their financial share of the upgrade costs. The parties are encouraged to agree beforehand on their relative contributions.

Planned Changes in FTR Markets

There will be a number of major changes in the Midwest ISO transmission markets over the coming years. First, after five years, the provisions for non-voluntary assignment of counterflow FTRs are due to expire. Second, Midwest ISO plans to begin development of ARRs after the start of the Day 2 markets. Third, the Commission has required Midwest ISO to begin planning for allocation of long-term rights.

<u>California ISO</u>

The CAISO has been in operation since April 1998. FTRs were first made available to market participants in an auction in 1999 to take effect on Jan 1, 2000. All FTRs have been options, not obligations. In defining FTRs, the CAISO has made available 100 percent of Available Transmission Capacity at a 99 percentile availability level in each direction of an interface, net of grandfathered existing contracts. As grandfathered contracts expire, the quantity of FTRs made available to the market is likely to increase. Until recently, no FTRs were available on Path 15, one of the major constraints within the CAISO.

FTR Auctions

The CAISO has held annual auctions for FTRs since 1999, with FTR term lengths of one year and in some cases 13 or 14 months. All auctions have used a multiple round format with FTRs defined on inter-zonal interfaces and on interties with external areas. There have been roughly 10,000 MW of FTRs sold annually with annual auction revenues approaching $100 million in recent years. Auction revenues are credited back to transmission owners who use them to offset transmission access charges.

Planned Changes in FTR Markets

The CAISO is currently redesigning its markets to incorporate a nodal LMP approach where FTRs will be closer to the point-to-point design used by eastern RTOs. The LMP market is currently expected to start in 2007. In the new market, FTR allocations will be for 12 months of monthly FTR quantities, with both peak-hour and off-peak-hour varieties and potentially different quantities for each month to enable parties to hedge time-of-use and seasonal variation in expected congestion costs. For the purpose of the annual release, the CAISO would limit total quantities to 75 percent of available transmission capacity. In addition, there would be monthly "true-up" allocation or auction processes, conducted before the start of each month, in which the remaining transmission capacity could be released to parties based on their revised estimates of their needs and accounting for planned transmission outages. Long-term FTRs are likely to be considered after the start of the new market.

<u>Proposed SeTrans</u>

Prior to withdrawing their proposal to form the SeTrans RTO, the SeTrans participants had developed a comprehensive proposal for long-term financial rights. Staff reviewed this proposal to identify design concepts that may be of use to existing ISOs and RTOs.

Multi-Year FTR Allocation

SeTrans proposed to conduct a one-time, initial allocation of Long Term FTRs at the start of its Day Two market. The purpose of this initial allocation was to identify who is currently obligated to pay for the existing transmission system, and to ensure that these parties will continue to receive the economic value of the transmission grid. In this initial allocation certain parties would be allocated “R-FTRs,” or reserved FTRs, that could then be nominated in subsequent years. These R-FTRs would have an unlimited term, meaning they would never expire. Parties eligible to receive R-FTRs were: network load (which would be required to designate the network resources they are relying on), entities that have existing long term point-to-point transmission service, and any remaining grandfathered service customers that had not converted to point-to-point service.

The one-time Long Term Allocation would have consisted of 10 rounds that represent 10 years of load growth on the existing transmission system. The first round would attempt to replicate current system usage patterns of the three entities identified above, and allocate R-FTRs up to each entity’s current peak load or contracted generation (to account for counter-flow), while remaining simultaneously feasible. In subsequent rounds, each entity’s peak load would be increased by the forecasted amount, and an attempt would be made to cover the peak load of all entities with R-FTRs. FTRs would be prorated to ensure simultaneous feasibility. FTRs from previous rounds or FTRs from grandfathered rights would not be subject to prorating.

Annual FTR Allocations and Auctions

The proposal would have required the following annual process to convert R-FTRs into FTRs for each year. First, the owners of R-FTRs would nominate which of those rights (allocated to them through the one-time auction) they wished to hold as FTRs for that year. Next, the FTRs not nominated would be awarded to any new long-term firm transmission customers. Finally, FTRs not nominated by their owners or allocated to new transmission customers would be released into yearly or monthly auctions, where anyone could bid to buy the rights. Original R-FTR owners would be able to specify a positive strike price, below which they would not sell their right; they would also be able to specify a negative price they are willing to pay in order to rid themselves of an obligation right. For any rights sold, the R-FTR owner would receive the auction clearing price.

FTRs for Network Upgrades

Expansion of the transmission system results in an increase in the number of transmission rights available. In SeTrans, these Incremental FTRs, or I-FTRs, would have been allocated to the investors in the expansion only if the expansion made the I-

FTRs possible and feasible. The proposed transmission expansion would be monitored for potential degradation of the quantity of existing FTRs, which either would not be allowed or would require compensation payments. Under this proposal, a transmission expansion that resulted in economic degradation, or a decrease in the value of an FTR, would not necessarily be prohibited.