

Because the issue of multiple access charges is a rate issue, we discuss in detail the comments we received on this issue, the reasons for our conclusion, and the concepts of pancaked rates, license plate rates, and uniform access charges in Section III.G of this Final Rule addressing transmission ratemaking policy for RTOs.

## **2. Congestion Management (Function 2)**

In the NOPR, we proposed to include congestion management as a minimum function that an RTO must perform.<sup>464</sup> Specifically, we proposed to require the RTO to ensure the development and operation of market mechanisms to manage transmission congestion. We proposed that the RTO must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant. In carrying out this function, we stated that the RTO must satisfy certain standards or demonstrate that an alternative proposal is consistent with or superior to satisfying the standard. We further proposed that the market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions. We proposed to allow RTOs considerable flexibility in experimenting with different market approaches to managing congestion through pricing. However, we stated that proposals should ensure that (1) the generators that are

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<sup>464</sup>FERC Stats. & Regs. ¶ 32,541 at 33,741-43.

dispatched in the presence of transmission constraints are those that can serve system loads at least cost, and (2) limited transmission capacity is used by market participants that value that use most highly. We asked for comments as to what specific requirements, if any, may best suit these goals.<sup>465</sup>

We stated in the NOPR that traditional approaches to congestion management such as those that rely exclusively on the use of administrative curtailment procedures may no longer be acceptable in a competitive, vertically de-integrated industry. We thus concluded that efficient congestion management requires a greater reliance on market mechanisms, and stated our belief that a large regional organization like an RTO will be able to create a workable and effective congestion management market. We stated that while it is our intent to give RTOs considerable flexibility in experimenting with different market approaches to managing congestion, we believe that a workable market approach should establish clear and tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices.

The Commission invited comments on the requirement that RTOs must be responsible for managing congestion with a market mechanism, and posed the following

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<sup>465</sup>Id. at 33,754-55.

questions. Can decentralized markets for congestion management be made to work effectively and quickly? Can the RTO's role be limited to that of a facilitator that simply brings together market participants for the purpose of engaging in bilateral transactions to relieve congestion? If not, will these markets require centralized operation by the RTO or some other independent entity? How can an RTO ensure that enough generators will participate in the congestion management market to make possible a least-cost dispatch? Are there any special considerations in evaluating market power in a congestion market operated or facilitated by an RTO? In addition, we proposed to allow up to one year after start-up for this function to be implemented. We noted that market approaches to congestion management may take additional time to work out, and asked for comments on whether this additional implementation time period is warranted, and whether one year is an appropriate additional time period.

## **Comments**

### **Using Market Mechanisms to Manage Congestion**

Although opinions vary as to the proper role of the RTO in managing congestion, many commenters believe that efficient congestion management requires greater reliance on market mechanisms.<sup>466</sup> CSU believes that congestion management is uniquely

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<sup>466</sup>See, e.g., United Illuminating, CSU, Duke, NASUCA, Los Angeles, NYPP, DOE, SMUD, Otter Tail, PG&E, FirstEnergy, Mass Companies, Enron/APX/Coral Power, Nevada Commission.

amenable to a market solution. CSU states that there will be a continuing need for some type of market mechanism to address constraints and this mechanism is best established at the regional level and best placed with an entity independent of wholesale power market participants.

Some commenters emphasize that it is better to use market mechanisms to manage congestion than to rely on the physical interruption of power flows.<sup>467</sup> NERC contends that if the industry had in place more market-oriented mechanisms that dealt effectively with constraints, then the frequency of transmission loading relief (TLR) procedures would decrease. Professor Hogan claims that with efficient pricing, users have the incentive to respond to the requirements of reliable operation. He asserts that, absent such price incentives, market choices would need to be curtailed in order to give the system operator enough control to counteract the perverse incentives that would be created by prices that did not reflect the marginal costs of dispatch. PJM/NEPOOL Customers argues that, when faced with a transmission congestion circumstance, the RTO should redispatch generators to the extent possible.

Also, Statoil claims that the use of TLR procedures is inherently discriminatory. Statoil claims that most transmission owners serving retail load do not engage in interchange transactions or use the pro forma tariff at the same level as new competitive

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<sup>467</sup> See, e.g., NERC, Sithe, NASUCA, Cinergy, Professor Hogan, PJM, Dr. Ilic.

market entrants attempting to enter historically captive markets. Statoil thus argues that, even if TLR is applied in a comparable manner, it will still disproportionately and adversely affect new competitive market entrants.

### **Role of the RTO in Congestion Management**

Commenters offer a variety of views concerning the proper role of the RTO in congestion management. Some advocate an active role for the RTO in operating an energy market that is highly centralized.<sup>468</sup> Others envision the RTO's role as being much smaller, perhaps limited to that of a facilitator that brings together market participants for the purpose of engaging in voluntary transactions to relieve congestion.<sup>469</sup> Still others, such as Southern Company and EEI, believe that RTOs are not necessary to make congestion management work. EEI argues that while congestion management does require a coordinated regional or interconnection-wide solution, it does not require the extensive infrastructure and responsibilities associated with what the Commission has proposed to define as RTOs. EEI notes that NERC's Congestion Management Working Group is exploring available options for congestion management, independently of whether RTOs exist.

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<sup>468</sup> See, e.g., PJM, Professor Hogan, CSU, Sithe, NERA, Duke, PJM/NEPOOL Customers, H.Q. Energy Services, Minnesota Power, FTC.

<sup>469</sup> See, e.g., APX, SPP, South Carolina Authority, Alliant Energy, WPSC, NSP, TANC, Williams.

PJM/NEPOOL Customers believes that an independent entity must operate any congestion management market. It believes also that that entity must have sufficient power and centralization to address congestion problems effectively and quickly. Consequently, it urges the Commission not to consider proposals that include a decentralized market for congestion management or that limit the RTO role to that of a facilitator of bilateral transactions to relieve congestion. In addition, it contends that the RTO must retain sufficient authority over generators that choose to make themselves available to ensure that those generators will participate in the congestion management market. Duke states that, eventually, decentralized markets may organize in a manner to accomplish effective congestion management, but at this time, the congestion management function should be centrally managed.

PJM claims that RTOs can facilitate efficient, broad-scale congestion management. PJM states that by combining multiple transmission systems over a large geographic region, an RTO can have an effective pricing system to price efficiently actual transmission flows in a region. PJM argues that not only should the Commission require that RTOs be responsible for managing congestion with market mechanisms, the Commission also should prohibit any other entity from acting in a manner that detracts from the RTO's ability to employ its market mechanisms.

Cleveland believes that an effective way to manage congestion may be to combine a market-based mechanism with a power exchange. It states that the RTO's redispatch function and the bidding process available through a power exchange should jointly operate to minimize the congestion.

H.Q. Energy Services contends that control over the management of congestion goes hand-in-hand with control over reliability. It believes that, ideally, an RTO should establish a congestion pricing system that manages congestion with minimal operator intervention. However, H.Q. Energy Services argues that, without control over reliability, an RTO will not be in the position to accurately and fairly allocate available transmission capacity because it cannot send the correct congestion pricing signals.

Sithe contends that the Commission should not allow overly decentralized systems whereby individual utilities in a region continue to manage congestion relief, especially if those utilities continue to own generation. Arkansas Consumers believe that the RTO's congestion management function helps provide a remedy for any anti-competitive activity on the part of generators or transmission owners. First Rochdale contends that only fully independent operation of an RTO is likely to lead to open markets in which all entities can compete freely. Duke asserts that there are no special considerations in evaluating market power in a congestion market operated or facilitated by an RTO.

Other commenters stress that the RTO's role in managing congestion using market mechanisms should be strictly limited. Indeed, the South Carolina Authority opposes a centralized arrangement for managing congestion as being unduly restrictive and perhaps anti-competitive. WPSC argues that the role of the RTO should be limited to acting as a clearinghouse so that market participants are aware of the range of alternatives available for dealing with congestion. WPSC contends that the market will then dictate which mechanisms are used in any particular instance. SPP suggests that the RTO can be a facilitator of congestion relief and that there is no need for the Commission to require that the RTO adopt a centralized approach, such as locational marginal pricing, for managing congestion. SPP states that it is a facilitator of congestion relief and intends to continue in that role under its new proposal. SPP states that it will identify which generators can relieve a constraint and the relative impact of redispatching those generators. It will then be the customer's responsibility to contract with the owner of these generators for redispatch services. SPP notes that this method relies on the market and bilateral contracts for the redispatch solutions. SPP claims that the market can also provide for price assurance and for long-term redispatch obligations. PG&E claims that with the proper information, bilateral market-based redispatch could be used within an hour of the occurrence of congestion on any part of the controlled system.

APX argues that the RTO should not conduct the trading process because it will impede the adaptation of trading to market conditions, which is essential for market development. APX claims that all competitive industries use decentralized trading through forward contracts, and no competitive industry uses a central bidding agent to create its market. Consequently, APX believes that the Commission should limit the RTO's role in congestion management to that of a provider of last resort. PG&E argues that although the RTO may administer certain market mechanisms such as congestion management, it is important that the RTO not view itself as responsible for energy pricing and other aspects of supply and demand interactions, all of which, PG&E contends, can be most effectively managed by the market unless material and lasting market flaws are present.

Similarly, Cinergy argues that the mechanism for price transparency in the commodity market should be developed and implemented by the market, not the RTO. Cinergy recognizes, however, that an economic congestion management system depends on a power market mechanism that provides price transparency for determining economic dispatch of generation. Consequently, Cinergy notes, RTOs will be confronted with issues of applying an economic dispatch valuation mechanism. Cinergy argues that such mechanism should evolve from the marketplace, not directly from the RTO. Cinergy proposes that the RTO would administer the congestion management system, but would

not be involved in the commodity market infrastructure unless its involvement was mutually agreeable among all stakeholders.

Williams claims that decentralized markets for congestion management, operating under the auspices of RTOs, can work effectively and quickly in an environment in which market participants have the correct incentives. Williams states that depending upon the geographic size of RTOs and the extent of congestion within each, zones for congestion management may have to be developed. Williams provides a detailed description of how a zonal approach to congestion management can be implemented.

Both CP&L and Enron/APX/Coral Power believe that the role of the RTO in congestion management should depend on the time frame in which the decisions are being made. These commenters prescribe different roles for the RTO in each of three different time frames.

### **The Direct Dispatch Authority of the RTO**

While supporting the use of pricing and other market mechanisms to manage congestion, a number of commenters state that an RTO must have authority to direct redispatch if necessary to ensure grid reliability.<sup>470</sup> For example, Otter Tail contends that the RTO should have direct authority to order redispatch of generation for purposes

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<sup>470</sup> See, e.g., Otter Tail, NERC, Allegheny, EME, NASUCA, East Kentucky, Williams, Minnesota Power, CSU. See also supra section III.D.3, which addresses the appropriate scope of the RTO's operational authority.

of relieving congestion and during system emergencies. Otter Tail states that this dispatch should be directed for the generating units that can most economically reduce the congestion. Otter Tail states that because there is a need for immediate, real-time response to system contingencies and to relieve transmission congestion, the RTO should have control of generating units. East Kentucky contends that to effectively manage congestion, the RTO must have absolute authority to order redispatch of all generators on the RTO transmission system. However, for this to work, East Kentucky states that the RTO will have to compensate the generator with firm transmission service for the additional out-of-pocket costs incurred due to the redispatch, plus an amount for lost margins on lost revenue. It suggests that generators with non-firm transmission service would have to redispatch as directed by the RTO but would have to bear their own costs.

NERC notes that market mechanisms may offer better ways of dealing with congestion management than does physical interruption of power flows, but asserts that it will always be necessary to have a non-market mechanism such as transmission loading relief in place to ensure that the stability of the grid is always maintained. However, EME believes that the extent of RTO control over dispatch of generation should be carefully circumscribed to ensure maximum development of competitive markets in wholesale power and ancillary services. Seattle contends that where transparent power supply markets exist, price differences are widely known to the market and congestion

can be resolved bilaterally with no intervention by an RTO. PJM notes that since implementing LMP, it rarely has needed to take emergency actions to alleviate transmission congestion.

Minnesota Power believes that RTOs must have the authority to require that all generators, existing and new, agree to redispatch as a condition of grid connection. Minnesota Power also believes that the RTO must have the authority to penalize generators who subsequently refuse a redispatch order, or claim a false unplanned outage. CSU asserts that generation redispatch is essential in Front Range Colorado, which can be expected to have an increasing population of gas-fired generation within the boundaries of the constraints. It contends that the inability to redispatch these units for any reason other than reliability would severely hinder the ability of an RTO to address capacity constraints.

MidAmerican states that, although congestion must be managed using pricing signals from the market, circumstances may occur where immediate actions are required and time does not permit normal bidding to allow the marketplace to respond. It contends that during such events, the RTO must be required to follow previously established procedures.

However, Seattle argues that the RTO should not have authority to redispatch generation to accomplish congestion management without unanimous consent of the

stakeholders. Seattle notes that many Northwest generating plant operators are subject to fishery-related hydroelectric dispatch constraints. Seattle states that because these constraints are particular to the owners of the generating facilities, these resources are not well suited to third party dispatch.

### **Managing Congestion by Eliminating It**

Some commenters contend that the ultimate goal of RTOs should be the elimination of congestion within their respective areas of control.<sup>471</sup> Powerex believes that it is better to eliminate congestion at its source through facilities upgrades, if economically and environmentally feasible, rather than attempting to manage congestion on a long-term basis through congestion pricing schemes. Salomon Smith Barney believes that the Commission has overemphasized congestion pricing as a vehicle to price the existing network rather than as a vehicle to induce investment when such investment is an economical alternative.

TDU Systems state that they do not want management of significant transmission congestion to become a long-term function of RTOs. They claim that minor congestion (i.e., congestion that is economically dealt with through redispatch of generators) will always be a feature of wholesale transmission markets, and an RTO should properly manage it. However, they argue that an RTO should deal with significant persistent

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<sup>471</sup>See, e.g., Williams, Powerex, Manitoba Board, Salomon Smith Barney.

transmission congestion by constructing (or having constructed) the appropriate transmission or generation facilities.

### **Desirable Attributes of Market Mechanisms**

Many commenters offer their views on the desirable attributes of any market mechanisms that are used to manage congestion.<sup>472</sup> For example, PJM/NEPOOL Customers urges the Commission to employ three general criteria to evaluate any proposal: simplicity, visibility and predictability. They state that the proposed approach to relieve the congestion should be simple to administer, both for customers and for the RTO. They believe that market participants should be able to examine the operation of the congestion management mechanism on a real-time basis and verify that transmission access is being appropriately accorded to entities that most desire transmission service. They state that such visibility will engender confidence by market participants in the congestion management mechanism. In addition, they believe that the congestion management mechanism must be predictable to all transmission users to determine the anticipated price that will be necessary to ensure the continuation of transmission service if congestion occurs.

Cinergy states that an economically efficient congestion management system must begin with properly defining information posting requirements. Accordingly, Cinergy

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<sup>472</sup>See, e.g., NASUCA, CMUA, NSP, PG&E, Statoil, SMUD, UtiliCorp, PacifiCorp, PJM/NEPOOL Customers, Metropolitan, Cal DWR.

argues that the Final Rule should ensure that requisite information on congestion is posted on the OASIS. Similarly, Williams and Industrial Consumers believe that RTO access to region-wide information on network conditions and power transactions, coupled with efficient congestion management and well specified transmission rights, could help RTOs in taking preemptive actions against potential curtailment incidents. Statoil and EPSA believe that, ideally, economic rationing schemes should be uniform across RTOs and should be implemented as an ancillary service under a regional transmission tariff. Montana Commission asserts that congestion management must be efficient. CMUA believes that congestion management mechanisms must do their job, but not unreasonably interfere with choices by market participants.

Some commenters believe that efficient congestion management requires a transparent commodity market. Cinergy states that market mechanisms that include locational pricing and financial rights for firm transmission have been successfully implemented where they are supported by a power exchange or pool pricing mechanism that provides market-clearing prices and price transparency. CalPX emphasizes the value of a separate power exchange and argues that the bifurcation of the exchange and transmission operator functions does not add to the market cost of congestion management, as some have suggested. Also, Otter Tail believes that the development of an hour-ahead power exchange within the RTO would improve grid reliability.

Many commenters support the NOPR's requirement that market mechanisms be used to manage congestion and note the particular value of using price as a tool to manage congestion.<sup>473</sup> Some commenters specifically endorsed the proposed requirement that congestion pricing proposals must meet the two efficiency objectives set forth in the NOPR.<sup>474</sup> PJM/NEPOOL Customers state that these two objectives are fundamental to the operation of a market and to the ultimate goals of electricity supply competition.<sup>475</sup> SMUD believes that a well-designed congestion management policy, that provides proper locational price signals without creating opportunities for gaming or cost shifting, will attract market participation. SMUD agrees that market participants must be given efficient price signals concerning their use of the transmission system, but claims that this is difficult because the existing transmission grid was not designed with the capability to operate as a common carrier or to serve customers in an open access manner. Also, a few commenters expressed doubts about the overall value of using

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<sup>473</sup>See, e.g., PJM/NEPOOL Customers, United Illuminating, Allegheny, EPSA, SMUD, Los Angeles, NASUCA, Duke, NERC, Professor Hogan, EME, PJM, DOE, CSU.

<sup>474</sup>See, e.g., PJM/NEPOOL Customers.

<sup>475</sup>However, Montana Commission asks the Commission to specify more precisely the nature of the pricing and congestion management methods that will satisfy the NOPR's efficiency objectives.

pricing mechanisms to manage congestion,<sup>476</sup> and others cited reasons to move cautiously.<sup>477</sup> Tri-State is skeptical that market mechanisms for managing congestion will lead to a least-cost dispatch. Tri-State states that entities with firm transmission rights on the congested path may be reluctant to participate voluntarily in generation redispatch that will jeopardize the economics of long-term power supply contracts or firm resources, even if the result would lower costs.

Several commenters suggest principles to guide the design of congestion pricing mechanisms.<sup>478</sup> NASUCA states that any mechanism for using congestion prices for managing transmission system flows should be easy to implement; designed to minimize cost shifts; designed to support an economically efficient dispatch; and coordinated with the underlying transmission rate design. PacifiCorp states that key components of a good market-based congestion clearing methodology are: (1) tradable transmission capacity reservations; (2) a system in which all parties who can clear congestion can bid to do so; (3) the establishment of congestion costs far enough in advance to facilitate reasoned decision-making; and (4) the avoidance of any RTO rules that substantially reduce liquidity in power markets. UtiliCorp believes that a congestion management system

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<sup>476</sup>See, e.g., LIPA, Transmission ISO Participants.

<sup>477</sup>See, e.g., EPSA, Tri-State.

<sup>478</sup>See, e.g., NASUCA, NJBUS, PJM/NEPOOL Customers, EPSA, Enron/APX/Coral Power.

should establish tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary market for transmission rights, and give market participants the opportunity to hedge locational differences in energy prices. However, Enron/APX/Coral Power disagrees on the latter feature. It contends that the monopoly wires business should not be allowed to encroach on what they see as the highly competitive and innovative business of providing hedges against locational price differences of energy or capacity or against price volatility of these or any other competitive products.

Cal DWR and Metropolitan urge the Commission to adopt RTO ratemaking principles that include off-peak rates. Cal DWR believes that customers should face accurate transmission price signals and, therefore, transmission prices should be lower in periods of off-peak demand for transmission. Cal DWR believes that off-peak pricing provides an accurate price signal over the longer term, promoting investment necessary to shift transmission usage to off-peak periods. In addition, Metropolitan believes that off-peak pricing can help to resolve problems of cost-shifting.

A number of commenters emphasize certain benefits of a well designed congestion pricing policy, claiming that price signals can assist RTOs and market participants in determining the efficient size and location of both new generation and new grid

expansions.<sup>479</sup> Los Angeles argues that ensuring accurate market signals through the creation of a congestion pricing mechanism will be the keystone to future system planning. Los Angeles states that these signals should alert generators to the advantages of siting in congested areas, motivate marketers and distribution companies to develop demand-side management options, and generally foster marketplace innovation. Los Angeles also believes that congestion price signals should help in determining the proper size of transmission upgrades that the RTO might build to relieve congestion. Otter Tail believes there exists a great need for new transmission capacity and, indeed, argues that the overall focus of the NOPR and FERC transmission policy should be on providing the appropriate financial incentives to assure investment in and expansion of the system.<sup>480</sup> To ensure that price signals translate into appropriate expansion of the grid, SMUD believes that the RTO must be sufficiently independent and strong to require the expansion of the grid. NASUCA notes that, while congestion cost pricing may help to signal where new generation and transmission lines are needed, it may not be necessary for the efficient daily operation of the transmission grid.

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<sup>479</sup> See, e.g., Allegheny, EME, United Illuminating, EPSA, SMUD, Los Angeles, NASUCA, CSU.

<sup>480</sup> Other commenters emphasize the need for significant investments to expand transmission capacity. See, e.g., EPRI, Salomon Smith Barney.

Other commenters believe that it may be difficult to design market mechanisms to provide incentives for the efficient expansion of the grid.<sup>481</sup> H.Q. Energy Services states that currently, the rules for congestion management do not act as a sufficient incentive to transmission owners to upgrade facilities. NWCC states that it is unclear whether congestion charges can act as a means of driving transmission expansion, since adding transmission is, by nature, capacity-based. NWCC also states that it is unclear whether congestion costs will be an adequate incentive for market participants to finance transmission expansion on their own, given the extensive permitting and regulatory requirements that are involved. LIPA states that, while new location-based pricing mechanisms have not been in place long enough to determine if they will provide empirical evidence that is helpful in identifying efficient transmission expansions, it believes that the mechanisms do not provide sufficient incentives for development of transmission. Also, LIPA claims that they do not provide a useful signal when reliability, as opposed to economic efficiency, drives the need for transmission enhancements.

SoCal Edison criticizes the congestion management policies implemented by the Cal ISO, stating that procedures intended to encourage the voluntary mitigation of congestion through investment in new transmission may not provide a sufficient incentive. SoCal Edison contends that, while correct congestion price signals will assist

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<sup>481</sup>See, e.g., Transmission ISO Participants, SoCal Edison, H.Q. Energy Services, LIPA, NWCC.

in the identification of transmission investment needs, they will not eliminate fundamental disputes among affected market participants over the responsibility for the costs of new transmission or eliminate the risks associated with attempting to construct new transmission projects. It asserts that the Commission cannot simply assume that the market will respond to congestion signals if, at the same time, it is creating a regulatory climate that discourages investment in new transmission. SoCal Edison believes that impediments to grid expansion can be overcome only if the Commission adopts transmission pricing policies that more accurately reflect the value that new transmission investments bring to electric consumers. Similarly, FirstEnergy argues that if the Commission desires an efficient generation market that optimizes the public good, then a mechanism that allows transmission owners to capitalize on increases in the transmission capacity at fair market value must be found. FirstEnergy contends that the interaction of these free market forces will drive the proper allocation of resources between transmission and generation over the long term.

### **Locational Marginal Pricing**

A number of commenters advocate the use of locational marginal pricing (LMP) for congestion management.<sup>482</sup> Professor Hogan states that, with LMP, the security-constrained economic dispatch process would produce prices for energy at each location,

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<sup>482</sup>See, e.g., Professor Hogan, PJM, NERA, Sithe, Allegheny, Mid-Atlantic Commissions, DOE, Duke, United Illuminating, EME.

incorporating the combined effect of generation, losses and congestion. He states that the corresponding transmission price between the location where power is supplied and where it is used would be determined as the difference between the energy prices at the two locations. Professor Hogan therefore contends that this same framework is easily extended to include bilateral transactions. Professor Hogan states that, with LMP, the system operator coordinates the dispatch and provides the information for settlement payments, with regulatory oversight to guarantee comparable service through open access to the pool run by the system operator through a bid-based economic dispatch. He claims that PJM implemented LMP after experimenting with an alternative market model and pricing approach that proved to be fundamentally inconsistent with a competitive market and user flexibility. He states that the earlier pricing system allowed market participants the flexibility to choose between bilateral transactions and spot purchases, but did not simultaneously present market participants with the costs of their choices. He states that this created perverse incentives. Professor Hogan argues that LMP is the only workable system that can support a non-discriminatory competitive market that allows for participant choice and flexibility.

PJM states that the Commission correctly concludes that LMP will "encourage efficient use of the transmission system, and facilitate the development of competitive electricity markets." PJM notes that, under LMP, transmission customers are assessed congestion charges consistent with their actual use of the system and the actual redispatch

that their transactions cause. It claims that this provides an economic choice to non-firm transmission customers to self-curtail their use of the transmission system or pay congestion charges determined by the market. PJM believes that by basing congestion charges on the true redispatch cost, parties behave in a rational and efficient manner. It states that the market determines the clearing price for transmission congestion and which customers ultimately utilize the transmission system. PJM states that the use of fixed transmission rights (FTRs) enables market participants to pay known, fixed transmission rates and to hedge against congestion charges.

The FTC believes that accurate LMP signals for investment to reduce congestion may become even more important as distributed generation presents opportunities for small-scale, fine-tuned (with respect to both size and location) generation investments to relieve transmission congestion, in place of large-scale transmission or generation investments. EME endorses the LMP pricing approach adopted by PJM and the New York ISO, and states that the Midwest ISO and the Alliance RTO should be encouraged to adopt similar approaches. The CalPX notes that the separation of the CalPX and the ISO in California does not prevent the use of a locational pricing model that incorporates the individual buses and transmission lines in the network.

Allegheny believes that "[c]onsistent locational marginal price dislocations readily identify system expansion, or other congestion relief, requirements as well as serve as an indicator of the most economic fix to congestion patterns over time." It claims that there

would be no incentives for the RTO or transmission owners to maintain congestion, since there is no financial impact on them from LMP because any excess payments received by the RTO during congestion are returned to holders of FTRs. Allegheny recommends that the Commission remain flexible in considering other pricing innovations for congestion management, but believes that a simplified locational marginal pricing methodology should be established as a default market mechanism against which other pricing innovations are evaluated.

Some commenters, however, criticize the locational marginal pricing approach to congestion management.<sup>483</sup> APX argues that, because LMP requires the RTO to implement a centrally optimized dispatch, it will discourage, if not eliminate, the commitment of forward contracts in the energy market and replace the price discovery of forward markets with ex post pricing. APX contends that because LMP price calculations occur only periodically and in a single iteration, price visibility is restricted compared to a continuous forward market. APX claims that this diminished visibility can make the result less efficient and more vulnerable to an exercise of market power. APX contends that, for most industries, a process of continuous trading creates efficiency in a competitive market, while the LMP optimization process has no role for trading. APX asserts that no competitive industry uses optimization to simulate and substitute for

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<sup>483</sup>See, e.g., APX, LIPA, TDU Systems, CP&L, Virginia Commission, Tri-State, Dynegy.

market outcomes. APX contends that under LMP, the system operator, not the market, will specify the structure of the optimization problem. APX claims that markets process information much more flexibly and comprehensively through the self-interested trading behavior of buyers and sellers. APX asserts that this is the strength of markets and the critical shortcoming of LMP.

Dynegy claims that markets for FTRs have yet to fulfill their promise to provide market participants with critically important price certainty for their transmission transactions. For example, Dynegy states that allocation problems still exist, in that only a small portion of available FTRs is being auctioned off in certain markets while a large number are being withheld for incumbents' use. Dynegy argues that in order for FTRs to provide a truly effective hedge against transmission price increases resulting from LMP in the hourly market, hourly FTRs would have to be available in a liquid market at a moment's notice, but nothing close to such a market exists. Dynegy suggests that, because the LMP model has yet to be implemented successfully due to the lack of a liquid FTR market, the time is ripe to look at other models, such as a physical rights model.

LIPA claims that neither the opportunity to obtain fixed transmission rights nor the prospect of locational price reductions are sufficient to encourage efficient generation and transmission expansions. For example, LIPA notes that awarding a transmission expander transmission rights that entitle it to collect congestion rents on the expanded capacity creates an incentive that runs counter to the purpose of the expansion; *i.e.*, the

more successful the expansion is in eliminating congestion, the less value the incentive has for the expander. Also, LIPA believes that locational pricing systems are biased toward using generation to solve congestion problems on the transmission grid and, as a result, could lead to market power abuse by an operator that sites a new generator in a load pocket and then takes advantage of transmission limitations to manipulate the operation of other generators that it owns.

The Virginia Commission claims that pricing mechanisms incorporating locational marginal prices tend to produce intense signals over short time frames, particularly when constraints are seasonal and driven by extraordinary events such as extreme weather. The Virginia Commission therefore believes that, at least initially, locational marginal prices may provide incentives for short-term actions for congestion relief, rather than longer term solutions such as the construction of additional transmission or generating facilities in a particular location.<sup>484</sup> The Virginia Commission also states that the use of locational marginal pricing is heavily dependent on the existence of transparent short-term competitive power markets. It urges the Commission to evaluate carefully proposals that place greater reliance on market mechanisms through the use of price signals, and to condition the use of such mechanisms on the existence of such things as fully functioning

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<sup>484</sup>The Brattle Group believes that, in addition to locational congestion pricing, some form of regulatory incentives may be needed to bring about efficient investment in the transmission grid.

power exchanges, the establishment of fixed transmission rights and the existence of secondary markets for such rights.

CP&L argues that while the proposed congestion management rule appears to permit only PJM-redispach types of arrangements, CP&L does not believe that the PJM model is the only workable congestion management process. Rather, CP&L believes that congestion is best managed through the coordinated reservation and scheduling of transactions on the grid rather than post-congestion fixes. Also, TDU Systems states that it may be difficult to transplant the PJM model to regions that do not have a centrally dispatched, tight power pool to use as an RTO platform.

Some commenters claim that LMP is more complex than necessary,<sup>485</sup> although Allegheny believes that today's technology mitigates these concerns. The FTC states that, despite the apparent virtues of LMP, it may be reasonable to back away from a full application of an LMP approach if doing so provides benefits to consumers from increased competition in generation markets. For example, the FTC states that, in light of its alleged complexity and the difficulty that financial markets may have in anticipating congestion charges, LMP may inhibit the formation of efficiency-enhancing futures markets in electricity generation and trading because congestion prices are more uncertain under LMP than under other pricing approaches (such as zonal transmission congestion pricing). The FTC thus suggests that the Commission may want to continue to entertain

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<sup>485</sup> See, e.g., PG&E, PJM/NEPOOL Customers, FTC, Tri-State, Dynegy.

alternatives to LMP if a reasonable case is made that benefits to consumers are greater under the alternatives than under LMP.

### **Managing Congestion with Tradable Transmission Rights**

Several commenters emphasize the importance of including explicit transmission rights in any congestion management plan that relies on market mechanisms.<sup>486</sup> EPSA believes that when transmission rights are clearly defined and allocated, ATC calculations can be made more accurately and congestion management simplified. DOE notes that financial transmission rights will provide a hedge against long-term fluctuations in spot prices, will encourage the development of competitive markets and will likely contribute to efficient generation and transmission resource planning. SMUD emphasizes that, without the pricing hedge provided by such rights, it cannot guarantee its customer-owners low cost or reliable transmission service.

A number of commenters emphasize that transmission rights must be tradeable in a secondary market.<sup>487</sup> Indeed, some commenters believe that the use of firm (physical) transmission rights along with a robust secondary market in these rights is the most workable solution for efficient congestion management.<sup>488</sup> Seattle notes that with an

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<sup>486</sup>See, e.g., PJM, SMUD, DOE, Enron/APX/Coral Power, EPSA, NSP, Seattle, Professor Hogan, EME.

<sup>487</sup>See, e.g., DOE, NSP, Enron/APX/Coral Power, Seattle, Nevada Commission.

<sup>488</sup>See, e.g., APX, Enron/APX/Coral Power, Tri-State, Desert STAR.

effective market for transmission rights, market participants may be afforded transmission-based options for resolving congestion. It states that market participants that invest in transmission facilities that increase capacity can receive the right to use or sell that capacity. Enron/APX/Coral Power believes that the RTO should be charged with developing a workable market approach to congestion and parallel-path management based on clear and tradeable rights for transmission usage that promote efficient regional dispatch, and support the emergence of secondary markets for transmission rights.

Enron/APX/Coral Power contends that this will require that RTO systems be operated as they are in the Western Interconnection based on physical rights. It suggests that, in order to ensure a firm right to schedule service over an interface when it is constrained, a customer would have to demonstrate ownership of sufficient property rights in the interface. Enron/APX/Coral Power suggests three options for obtaining rights: (1) from the RTO in the primary auction or other primary form of allocation; (2) from holders of rights in the secondary market; and (3) from the RTO in the form of short-term released rights not scheduled by their holders. Enron/APX/Coral Power states that by defining and enhancing physical property rights, the market for those rights will provide ex ante transmission prices that include the cost of purchasing rights in constrained interfaces. It claims that this will permit dispatch decisions to be made on the basis of delivered energy prices. Enron/APX/Coral Power states that to ensure that no market participant can

exercise market power by hoarding property rights, the rights should be designed as use-or-lose so that if a right is not scheduled it can be used by others on a non-firm basis.

Similarly, Dynegy proposes a physical rights model in which a limited amount of firm physical rights would be sold and only those holding physical rights would be allowed to schedule when capacity is constrained. Under Dynegy's proposal, only those with preassigned FTRs would be allowed to schedule on a firm basis at a set price.

Dynegy states that others could submit non-firm schedules, subject to curtailment, or, if the party is willing, redispatch. Dynegy adds that the proponents of rights that are financial only argue that it is impossible to define physical rights as "100 percent firm" from a given source to a given sink. Dynegy states that, while such arguments are convincing, the capacity between a source and sink may actually be available for a significant percentage of the time to a reasonable degree of certainty and, accordingly, could be sold as firm.

APX states that the definition of transmission property rights requires the calculation of stable power distribution factors that show the proportion of a power transaction that flows over each path on the grid connecting the source-sink pair. It states that after defining the property rights, the RTO can conduct an auction to allocate them. APX states that, following the auction, holders of transmission rights can retain them or trade them in a secondary forward market. APX believes that FTR trading will provide a more direct and comprehensive valuation of rights than LMP. Desert STAR states that it

plans to rely on firm transmission rights markets as the primary vehicle for managing commercially significant congestion, and the use of incremental/decremental generation bids to manage other congestion.

Other commenters, however, doubt that a system of physical transmission rights can be used effectively to manage congestion.<sup>489</sup> NERA states that most commodity markets operate according to a process based on physical contracts or rights traded in decentralized markets separated from physical operations. NERA adds, however, that most commodities do not flow on an integrated grid where network externalities are so strong and complex that a monopoly system operator is needed. NERA argues that network externalities on any complex electricity grid make it virtually impossible to define physical transmission rights that will use the system fully and yet can be traded in decentralized markets. Also, Professor Joskow believes that on complex electric power networks with loop flow, a financial rights system can be designed more easily and can work more smoothly and efficiently than can a physical rights system.<sup>490</sup>

Some commenters offer additional notes of caution regarding the use of transmission rights. For example, APPA states that one must guard against market

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<sup>489</sup>See, e.g., NERA, Professor Joskow, Allegheny.

<sup>490</sup>Professor Joskow notes that Enron/APX/Coral Power claims that two unpublished papers he has co-authored with Jean Tirole conclude that physical rights designed on a use-it-or-lose-it basis (so that they cannot be hoarded) more effectively prevent the exercise of market power than financial rights, which can always be hoarded. He states that this is not what the papers conclude.

participants using transmission rights to act strategically. APPA argues that if a generator can adversely affect transfer capability, it may seek to purchase and resell transmission rights in the secondary market after manipulating its internal operations to create congestion on the grid. RECA considers proposals that allow customers to purchase long-term rights to mitigate the risk of congestion pricing to be unacceptable because such proposals result in long-term firm customers having to pay a premium for price stability. Also, CSU contends that no party should hold any entitlement over a constrained path due to transmission ownership which predates the formation of the RTO. CSU argues that, because all parties dedicating bulk transmission assets to the RTO will be fully compensated for their embedded costs, there should exist no reserved rights of use other than those purchased from the RTO. In addition, Great River is concerned that the NOPR's proposal regarding the establishment of clear and tradable transmission rights is not consistent with the flexibility that transmission customers currently have under network service. Great River urges the Commission to carefully consider congestion management proposals that preserve network-like service, even if such proposals do not result in the identification of asset-based transmission rights.

### **Other Mechanisms for Managing Congestion**

Some commenters support yet other market mechanisms for managing congestion.<sup>491</sup> EPSA notes that other pricing approaches that deserve consideration include the RTO's use of supply-side bids to relieve congestion in load pockets, as well as the use of bilateral arrangements to solve congestion problems. Also, NSP recommends that the RTO offer a "firming" service, at posted rates, that would provide customers with the assurance that their transaction will occur under most curtailment conditions. In addition, NSP proposes that the RTO offer a real-time redispatch service that will allow transmission customers to buy through congestion at real-time prices. Cal ISO notes that the Commission has accepted its zonal approach to congestion management, which relies on market mechanisms to manage inter-zonal congestion. PG&E claims, however, that while providing a more understandable picture of congestion, such a system must still solve the problem of intra-zonal congestion. Also, the Montana Commission recommends that the congestion management regime that was developed as a part of the IndeGO proposal serve as a model for how to manage congestion on the transmission system. However, Avista claims that the IndeGo proposal proved to be too complicated to solve a problem that exists only on a few select transmission paths in the Pacific Northwest.

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<sup>491</sup>See, e.g., Cal ISO, Montana Commission.

### **Costs and Revenues in Congestion Management**

A number of commenters urge the Commission to pay close attention to issues related to the distribution of the costs and revenues of congestion management among market participants.<sup>492</sup> In particular, several commenters caution that congestion pricing mechanisms should ensure that congestion costs are fairly allocated and should not result in excessive revenues or monopoly profits for transmission owners.<sup>493</sup> APPA states that only after we have a nationwide framework of truly independent RTOs should the Commission consider a new approach to transmission pricing that would allow the RTO to price transmission capacity rights and usage on congested paths above embedded costs while discounting uncongested paths below embedded costs, subject to a balancing account to ensure that the total transmission revenue requirement is not over-recovered.

Similarly, TDU Systems believe that while the formation of RTOs is a unique opportunity to experiment with new forms of transmission pricing, the Commission should be mindful that an RTO will be a large regional transmission monopoly. TDU Systems question the wisdom of designing congestion pricing mechanisms to ensure that limited transmission capacity is used by market participants who value that use most highly. It states that such an auction-to-the-highest-bidder approach could reap monopoly

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<sup>492</sup> See, e.g., TDU Systems, NCPA, Los Angeles, Wyoming Commission, SMUD, South Carolina Authority.

<sup>493</sup> See, e.g., APPA, RECA, TDU Systems, Los Angeles, EPSA.

rents for transmission providers, at the expense of consumers. TDU Systems thus argues that over-reliance on economic self-interest and market mechanisms in transmission pricing may become a recipe for new forms of undue discrimination. It suggests that an incentive to avoid expanding the system in order to collect monopoly rents can be removed by placing any excess revenues from congestion pricing in a fund earmarked for transmission system expansion.

TDU Systems also recommends that the Commission encourage congestion management plans that distinguish between congestion caused by the RTO's obligation to provide service to firm transmission customers, and congestion caused for economic reasons. It argues that, in the case of the former, the costs of relieving the congestion should be averaged over the firm RTO transmission customers that are using its system. However, it claims that economic congestion occurs because market participants wish to take advantage of short-term production cost economies to minimize their power costs. In this case, TDU Systems argues that the specific loads purchasing the generation should pay the associated congestion costs. Also, RECA states that long-term firm transmission customers are the ones that use and pay to support the system throughout the year, but the auction approach allows a short term trader to outbid these customers at the very times they need it most. Enron/APX/Coral Power notes that, if the RTO's regulated rates for transmission service, including congestion management, are properly designed to reward the RTO for cutting operating costs and maximizing throughput, then it would not have to

assign the grid expansion costs to new generators that interconnect. Instead, the RTO would charge the new generator only the cost of local interconnection with the grid.

Dynegy claims that, with respect to each transmission provider's system, there is a predictable level of constraints and, similarly, some representative level of costs associated with relieving those constraints. Dynegy believes that such costs should be rolled into firm transmission rates that can be quoted up front and with certainty. Dynegy argues that transmission providers would have an economic incentive to operate their transmission systems efficiently if they are given an uplift cost target, and are rewarded for beating the target and penalized for exceeding the target. EPSA states that some congestion pricing mechanisms can impose potentially huge costs on individual transactions, which can be detrimental to the goal of fostering wholesale competition. EPSA thus urges the Commission to consider whether these pricing mechanisms provide greater benefits than a system that internalizes more of the congestion costs. Indeed, EPSA argues that it is still appropriate to spread many of those costs to all system users because redispatch generally benefits all users of the transmission system.

NCPA asserts that, in order to prevent large increases in the cost of generation for customers in congested areas, some non-discriminatory way must be found to return the extra revenues collected to those customers. NCPA believes that this will require restructuring of tariffs, but failure to address the problem is likely to keep utilities with customers in congested areas out of the California ISO. Similarly, the South Carolina

Authority is concerned that certain centralized market mechanisms would cause cost shifts for those participating in an RTO, and if so, potential participants opt out. Also, the Wyoming Commission is concerned that, by offering rewards for transmission investment such as a higher return on equity, the Commission would effectively be discouraging a more market-oriented review of alternatives to building transmission to solve congestion problems.

Some commenters emphasize the importance of ensuring full cost recovery for generators that are redispatched by an RTO to alleviate transmission constraints or to provide other support services.<sup>494</sup> NERC contends there must not be disincentives, in the form of unrecovered costs, to having generators perform these vital functions. MidAmerican asserts that optimal dispatch will occur during congestion management as long as all power suppliers are fully compensated at market prices. Cinergy claims that, unless generators have the ability to recover lost revenues for reducing generation in response to congestion management needs, generators have no incentive to follow dispatch orders. SMUD contends that the Commission needs to develop congestion management principles that ensure that market participants will receive fair market value for facilities that they have owned and operated for many years.

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<sup>494</sup> See, e.g., Allegheny, Platte River, NERC.

### **Importance of Scale in Congestion Management**

A number of commenters argue that the achievement of an appropriate scale by an RTO will be important to the effective management of congestion.<sup>495</sup>

LG&E states that the Commission should require RTOs to be of sufficient size to be capable of meaningfully addressing congestion. It believes that if a proposed RTO's ability to address congestion would be impaired by its size or configuration, then the Commission should either refuse the RTO's application or should condition approval on attaining the necessary size and configuration to manage regional congestion issues.

Industrial Consumers state that, although congestion management can be addressed with non-market solutions such as transmission loading relief procedures, it is far better to internalize the problem within an RTO with an appropriate scope and configuration.

Minnesota Power notes that, currently, it can have transactions curtailed by two different procedures, NERC Transmission Loading Relief and MAPP Line Loading Relief. It claims that an RTO will provide transmission users with region-wide, standard, congestion management.

The Midwest ISO states that an appropriately sized RTO will be able to relieve congestion on a broad scale. However, it claims that its own redispatch options will be limited by the failure of border companies, such as FirstEnergy and AEP, to join it. Also, it notes that longer term congestion relief involves the construction of transmission

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<sup>495</sup> See, e.g., LG&E, ComEd, Midwest ISO Participants, Midwest ISO.

facilities. It claims that, if border companies are not members, the Midwest ISO will not have the ability to coordinate required transmission construction by those entities. Also, the Midwest ISO Participants state that new transmission facilities required to relieve constraints may involve both the companies of the Alliance RTO and the Midwest ISO Participants. The Midwest ISO Participants believe that, with planning and authority split between these two regional entities, these facilities may not be optimally constructed or located.

Ontario Power, however, takes a different view. It claims that many of the advantages that would flow from expanding U.S. markets to include Ontario can be realized without requiring the Independent Electricity Market Operator (IMO) in Ontario to join a larger RTO at this time. Ontario Power believes that these advantages could be achieved by negotiating agreements between the IMO and other RTOs. Also, Central Maine states that if transmission line loading relief is performed on a market basis, many of the benefits that might result from merging existing ISOs could be realized without actually requiring those ISOs to merge.

Tri-State argues that the Commission should provide an incentive for non-participating transmission owners to join an RTO by allowing the RTO to use a pricing and congestion management structure that withholds the benefits of the RTO from entities that refuse to turn control of their transmission assets over to the RTO. Also, Vernon claims that non-participants can take unfair advantage of ISO-controlled facilities

by scheduling their own loads over ISO grid facilities that parallel the non-participant paths, instead of scheduling them over their own wires. Vernon contends that having thus freed up their own wires, the non-participants can then put their facilities to various uses, such as to avoid the increased ISO grid congestion.

### **Congestion Management Between RTOs**

Many commenters believe that effective congestion management must take into account effects that extend beyond the RTO's boundaries.<sup>496</sup> NERC states that congestion management approaches that work within a particular region may not adequately deal with transactions that originate or terminate outside the region. NERC believes that as RTOs develop congestion management approaches, the Commission must require that they be compatible with what is happening elsewhere.

Industrial Consumers believe that congestion management, especially during emergency conditions, is an interconnection-wide responsibility. It asserts that, if multiple RTOs are allowed within an interconnection, congestion management must be coordinated across RTO boundaries. Industrial Consumers argues that an RTO can accomplish this only by sharing data on system conditions (e.g., ATC calculations) with neighboring RTOs, agreeing to protocols for cross-boundary actions to mitigate

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<sup>496</sup>See, e.g., NERC, Mass Companies, Industrial Consumers, Montana Commission, Indiana Commission, AEP.

congestion, and cooperating in a process to ensure fair compensation to generators that are redispatched.

UAMPS believes that if a state is involved in the consideration of various potential solutions to regional congestion, it will likely be more willing to accept that a particular proposal to construct new transmission within its borders is indeed the most efficient solution to a genuine problem, and to provide the necessary approvals for that construction.

### **Transcos and Congestion Management**

Some commenters are concerned that, if a for-profit company owns transmission (e.g., a transco), it may not have the correct incentives to manage congestion efficiently.<sup>497</sup> ISO-NE argues that if such a company seeks to operate transmission and markets as an RTO, it will have competing responsibilities and economic interests. ISO-NE believes that, given the company's economic motivations, market participants may have insufficient confidence in such a company's determinations of whether a transmission-expansion solution to congestion is preferable to a generation-based solution. EAL believes that compensating a wire-owning RTO on the basis of invested capital could lead to over-building of transmission. New Smyrna Beach is concerned that a for-profit transmission company will exhibit a bias toward transmission construction when other, more economical alternatives might exist. New Smyrna Beach states that the

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<sup>497</sup> See, e.g., ISO-NE, EAL, New Smyrna Beach, Industrial Consumers.

Commission should consider requiring the RTO to conduct a competitive bidding process when it determines that transmission construction, or an alternative, is needed to relieve transmission constraints.

Industrial Consumers asserts that transcos would compete head-on with generation companies wherever there is congestion. It thus believes that transcos-as-RTOs would have a serious conflict of interest if they have the authority over congestion management and over the decision whether to eliminate congestion with new generation or transmission facilities. Industrial Consumers believes that where new generation is a more cost-effective option than construction of new transmission facilities, the cheaper option should be built, and markets should be given the opportunity to make the choice. Industrial Consumers believes, however, that this will require that the markets have access to redispatch costs, congestion valuations (from a secondary market for capacity reservations), and other data on grid conditions. This is information that is better disclosed by a disinterested independent RTO than a self-interested transco or generation company.

Cal DWR questions whether either ISOs or transcos have an incentive to use transmission alternatives (such as demand-side management, load shedding, distributed generation, or generation) to reduce the overall cost of transmission. However, it believes that this problem may be more acute for a transco, for which revenues and return are directly tied to the use of their transmission assets.

However, other commenters claim that there is no basis for concerns that a transco will favor a transmission solution to constraints.<sup>498</sup> Entergy contends that, if a generation solution is the most efficient way to resolve congestion, a new generator will likely realize that and try to locate in the appropriate area. Entergy states that an RTO's obligations as an open access transmission provider leave it with no choice but to interconnect with the new generator. Also, Entergy argues that an RTO will not have the unfettered ability to propose and build inefficient transmission solutions. It believes that review by state regulators with siting authority, and prudence review by the Commission, will make it difficult for an RTO to build inefficient and unnecessary transmission additions. Enron/APX/Coral Power and JEA believe that a transco may, in fact, be well suited for congestion management. Enron/APX/Coral Power states that placing responsibility for managing congestion in the RTO's hands complements their view that an RTO-Transco must be obligated to assume delivery risk (i.e., deliver physically firm power) in exchange for being rewarded for cutting costs and increasing system throughput.

### **The Need for Flexibility in the Design of Market Mechanisms**

Commenters in general showed considerable support for the NOPR's proposal to give RTOs considerable flexibility in experimenting with different market approaches to

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<sup>498</sup> See, e.g., Trans-Elect, FirstEnergy, Entergy.

managing congestion.<sup>499</sup> Mass Companies state that the NOPR's willingness to allow RTOs latitude to develop local approaches to congestion management is particularly appropriate, given the difference in conditions in different parts of the country. CP&L believes that congestion management is an area where a one-size-fits-all solution would miss the mark and unnecessarily increase the cost of forming and operating an RTO. SRP believes that a flexible approach is needed because the use of market mechanisms for congestion management is in its infancy, and poorly designed market mechanisms can exacerbate problems and adversely impact reliability.

The Florida Commission states that the details of proposals for managing congestion using a market mechanism should be determined on a regional basis with endorsement by the state regulatory body. The Florida Commission recommends that the Commission continue to monitor discussions of these issues within NERC and not duplicate or foreclose their development and resolution at NERC.

Montana-Dakota recommends that the Commission not limit the experimentation with market mechanisms to the provision of firm transmission service. Montana-Dakota believes that there is potential to further improve transmission services by allowing RTOs the ability to implement congestion management methods for non-firm services rather than relying only on the use of TLR to curtail such services.

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<sup>499</sup> See, e.g., Mass Companies, SRP, CP&L, Southern Company, PJM/NEPOOL Customers, United Illuminating, Georgia Commission, JEA, Florida Commission, NYPP, Cinergy.

Many commenters express support for the proposal to allow RTOs flexibility in developing approaches to congestion pricing.<sup>500</sup> Some, such as Florida Power Corp. and Desert STAR, believe that allowing flexibility in pricing may provide incentives for transmission owners to join or form an RTO. Florida Power Corp. argues that such flexibility allows transmission owners to deal with issues such as cost shifting, and believes that providing more specific guidance will only limit possible options.

However, the FTC cautions that the Commission should not allow its policy of flexibility to continue indefinitely. The FTC states that although experimentation with transmission congestion pricing alternatives to LMP may be appropriate at present, it does not believe that great uncertainty about the most effective approach to transmission congestion management need exist indefinitely. It suggests that the Commission may wish to establish a date in the not-too-distant future when it will undertake a comparative analysis of the consumer costs and benefits of alternative transmission pricing regimes. The FTC states that if one or more approaches provide substantially superior results for consumers, the Commission may wish to initiate a rulemaking on policies to encourage RTOs to adopt these approaches. The Oregon Commission recommends that the Commission evaluate the effectiveness and efficiency of various congestion pricing experiments, and based on its evaluation, require RTOs to use the better methods.

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<sup>500</sup> See, e.g., PJM/NEPOOL Customers, United Illuminating, Florida Power Corp., Desert STAR, Oregon Commission, NERC.

However, the Oregon Commission estimates that the process of refining congestion pricing methods may take a decade or more.

NERC states that there are strongly held, differing opinions throughout the industry on how congestion prices should be designed. NERC states that, while flexibility is one important consideration, the various regional solutions must be able to work together. It believes that the Commission can provide the leadership needed to bring the industry to closure on these issues. NERC notes that this may require the Commission to be more proscriptive, and it should not hesitate to do so. In this regard, Minnesota Power suggests that the Commission encourage neighboring RTOs with constrained interfaces to jointly develop constraint relief procedures including common constraint pricing where appropriate.

### **Timing of Implementation**

With regard to the NOPR's proposal to allow RTO's up to one year after start-up to implement the congestion management function, commenters express a variety of opinions. Some indicate that one year is an appropriate additional time period.<sup>501</sup> Others, however, believe that it is essential that the RTO have some form of congestion management system in place when it begins operation.<sup>502</sup> SMUD and CMUA state that a significant deterrent to participating in the Cal ISO has been the fact that, in California,

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<sup>501</sup>See, e.g., Industrial Consumers, Allegheny, PGE, Entergy.

<sup>502</sup>See, e.g., SMUD, Tri-State, CMUA, TANC, Desert STAR, Cinergy.

Cal ISO transmission is strictly a short-term transaction given that Cal ISO has not yet fully implemented FTRs. SMUD emphasizes that, without the hedge provided by FTRs, it cannot guarantee its customer-owners low cost or reliable transmission service. TANC believes that allowing an RTO to begin operations without a congestion management procedure in place greatly increases the opportunity for market power abuses as well as market inefficiency.

Duke states that, ideally, the permanent congestion management function should be in place on the first day of RTO operation. Then, Duke notes, it would not be necessary to incur the cost of implementing, and developing strategies and behavior appropriate to an initial system, only to have to incur additional costs and changes in behavior to adapt to a permanent system. However, Duke states that congestion management issues are complex and substantial information management systems must be put in place. Consequently, Duke believes one year from the time the RTO becomes operational may not be a sufficient length of time to implement the congestion management function.

Desert STAR states that the new approaches to congestion management called for by newly competitive markets will take additional time to work out and, therefore, the Commission should be willing to consider additional time on a case-by-case basis. However, in order to ensure reliable operation, Desert STAR believes some congestion management system must be in place when the RTO begins operation.

Some commenters believe that more than one year of additional time may be needed for the RTO to implement the congestion management function. NSP states that if the RTO has a state-estimator model with the necessary properties, it is possible that a congestion management system, of the type preferred by NSP, could be implemented within about 18 months from the time of project initiation. However, for regions without the necessary models, NSP expects the time-line would likely be three years from time of project initiation.

Montana Power believes that there will be many "growing pains" associated with implementation of RTOs that will take time to work out, especially in areas like the Pacific Northwest, which have no history of tight pool operation. Montana Power believes that allowing one-year for implementing a market mechanism for congestion management is a very aggressive schedule. Montana Power thus encourages the Commission to allow up to three years. Similarly, Avista states that, with the IndeGo experience in mind, it encourages the Commission to allow two to three years for implementation of this function, especially where it is demonstrated that the RTO will comply immediately with other characteristics and functions identified in the Commission's Final Rule.

The Florida Commission believes that the Commission should not impose any arbitrary time period for implementation of congestion management. It states that NERC is working with the regions on this issue and FERC should monitor those activities before

setting any deadlines, if at all. Also, JEA believes that requiring the congestion management function to be in place within one year from the start-up of RTO operation may be feasible only for those RTOs structured as transcos from the beginning.

### **Commission Conclusion**

As we proposed in the NOPR, we conclude that an RTO must ensure the development and operation of market mechanisms to manage congestion. Furthermore, as we proposed, we will require that responsibility for operating these market mechanisms reside either with the RTO itself or with another entity that is not affiliated with any market participant.

We agree with the large number of commenters that believe that the use of market mechanisms to manage congestion is superior to the use of administrative curtailment procedures or other approaches that do not take into account the relative value of transactions that are curtailed and those that are allowed to go forward. In addition, we conclude that the RTO or an independent entity must assume an active role in developing and implementing any congestion market mechanisms, because the use of such mechanisms must necessarily be closely coordinated with the operational activities that the RTO performs on a day-to-day and, in many cases, moment-to-moment basis.

Some commenters argue that an RTO should not be allowed to operate a centralized market for congestion management. The commenters contend that, if such a market is operated by an RTO or other entity that is independent of the market, a robust