2. Scope and Regional Configuration (Characteristic 2)

The NOPR proposed as the second minimum characteristic of an RTO that the RTO must serve an appropriate region—a region of sufficient scope and configuration to permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets.[335] The NOPR noted that there is likely no one "right" configuration of regions and proposed to establish a set of factors that encourage appropriate regional configuration without prescribing boundaries. The NOPR suggested that a region that is large in scope would facilitate the effective performance of many of the RTO's functions, but also recognized that there may be factors that might limit how large an RTO should be.[336] The NOPR also proposed a set of factors that may affect the location of regional boundaries These factors indicate that boundaries should facilitate essential RTO functions and goals, recognize trading patterns, mitigate the exercise of market power, do not unnecessarily split existing control areas or existing regional transmission entities, encompass contiguous geographic areas and highly interconnected portions of the grid, and take into account useful existing regional boundaries (such as NERC regions) and international boundaries. The NOPR put forth for discussion the appropriateness of existing configurations, such as the three electric interconnections

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[335]FERC Stats. & Regs. at 33,729.

[336]Id. at 33,730.

within the continental United States, the ten NERC reliability councils, and the 23 NERC security coordinator areas.

The NOPR also requested comments on what portion of the transmission facilities within an appropriate region the RTO must control in order to be approved as an RTO. The Commission recognized that it might be difficult to obtain 100 percent participation of all transmission owners within a region, but that, on the other hand, it would not be appropriate to approve an RTO proposal that included only a small portion of the facilities of the region. The Commission also requested comments on how much deference the Commission should give to regions proposed to us, and to what extent state commission approval or disapproval should be taken into account.

a. How Should Initial Boundaries be Established?

Comments

Most commenters agree with the Commission's proposal not to initially prescribe the boundaries for appropriate regions. [337] Among the rationales asserted by these commenters is that this is a matter best left in the first instance to the stakeholders in the

[337] See, e.g., South Carolina Authority, Cleco, SRP, LG&E, Detroit Edison, Wyoming Commission, Entergy, UtiliCorp, NECPUC, MidAmerican, Enron/APX/Coral Power, Duke, NASUCA, Industrial Consumers, Connectiv, Massachusetts Division, Iowa Board.

various regions, [338] there should be deference to proposals by transmission owners and market participants, [339] FERC should give deference to state commissions on scope and configuration, [340] boundaries should be determined naturally in a way that facilitates market transactions, [341] and size and configuration must be determined on a case-by-case basis. [342]

However, some commenters argue that the Commission should prescribe regional boundaries. APPA, East Texas Cooperatives, TDU Systems and the Michigan Commission urge that the Commission use section 202(a) authority to establish initial boundaries. APPA asserts that the Commission should establish a rebuttable presumption in favor of specific regional district boundaries based on the topology of the transmission network to enhance system security. East Texas Cooperatives argues that after the Commission established regional districts, the burden would be on those proposing different regions to show that they provide at least the benefits of the prescribed districts. Michigan Commission states that the electricity market is currently too immature to

[338] See, e.g., South Carolina Authority, NASUCA, Florida Power Corp.

[339] See, e.g., Entergy, MidAmerican.

[340] See, e.g., Southern Company, NECPUC, Nine Commissions, Florida Commission.

[341] See, e.g., Duke, FirstEnergy, Allegheny, Iowa Board.

[342] See, e.g., NYPP.

determine by itself the size of the markets, and that firm guidance is needed rather than allowing the RTO boundaries to be set by participants.

Several other commenters do not go as far in asserting that the Commission should initially set boundaries, but argue that the Commission should take a strong role in assuring proper boundaries. For example, Cinergy urges that the Commission be aggressive in establishing boundaries consistent with the proposed criteria, noting that the willingness of the Commission to exercise its authority over boundaries will determine the success of the Commission's restructuring efforts. Coalition of Alliance Users maintains that the Commission should take a direct and active role in formulating RTO boundaries. WEPCO believes that the role of the Commission should be to set criteria that encourage the establishment of sensible RTO boundaries. Project Groups assert that if the stakeholders in a region do not determine boundaries by the end of 2000, the Commission should make the determinations. LG&E states that while the Commission should show deference to voluntary RTOs, it should not hesitate to disapprove proposals with geographic shortcomings.

Commenters express a variety of views regarding whether particular regional configurations would be appropriate. Some commenters support interconnection-wide

RTOs as a desirable goal, [343] while others regard either an Eastern or Western interconnection RTO as unworkably large. [344]

Commenters offer specific ideas about the number and placement of RTOs. PG&E states that the long-term goal should be four or five RTOs nationwide. Williams argues for 3 to 10 RTO nationwide, while Project Groups advocates 3 to 12 RTO nationwide. WEPCO proposes the formation of five RTOs: (1) three in the Eastern interconnection (one covering MAPP, MAIN, ECAR and portions of SPP; one covering SERC, Florida and the rest of SPP; and one covering NPCC and MAAC); (2) one for WSCC; and (3) one for ERCOT. APPA, supported by East Texas Cooperatives, suggests: (1) no more than three RTOs in the West; (2) the combination of PJM, NY ISO and ISO-NE into one RTO with the possible participation of Ontario; (3) the combination of the Alliance RTO, Midwest ISO, and MAPP into one RTO; (4) Kansas to the Carolinas under one RTO; and (5) separate RTOs for Florida, ERCOT and Hydro-Quebec.

With respect to specific regions, ISO-NE contends that it already operates a region of appropriate size and configuration. Mass Companies agrees that ISO-NE is an

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[343]See, e.g., South Carolina Authority, Conlon, Industrial Consumers, First Rochdale, Los Angeles, PG&E, Sonat.

[344]See, e.g., South Carolina Authority, Desert STAR, MidAmerican, TDU Systems, CREDA, SNWA, CRC, Platte River, PSNM, SRP, Metropolitan.

appropriate region. NYC argues that the formation of a northeastern RTO with a broader geographic scope than the NY ISO would help remove existing institutional impediments to the construction of new transmission lines. American Forest argues that PJM is too small, while NASUCA and Mid-Atlantic Commissions believe that PJM satisfies the size criteria. Some commenters object to a split between the area represented by the proposed Alliance RTO and the Midwest ISO. [345] Most of the Florida commenters assert that peninsular Florida represents an appropriate region. [346] For example, Florida Commission claims that peninsular Florida is a large and efficient marketplace that does not share parallel flows with other electrical regions; however, it states that the Florida panhandle could be in a region with all of SERC or a subregion of SERC.

Although some commenters encourage a Western interconnection-wide RTO, the majority of commenters support three or four RTOs for the Western interconnection, noting that the interests in the WSCC are too diverse and the area too large for control by a single entity. [347] Cal ISO contends that California satisfies the minimum size criteria, but does not represent the maximum feasible area. Commenters from the Pacific

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[345] See, e.g., Michigan Commission, South Carolina Authority, Midwest ISO, Midwest ISO Participants, NASUCA..

[346] See, e.g., Florida Commission, JEA, FP&L, Florida Power Corp., Tallahassee, Gainesville.

[347] See, e.g., SRP, Metropolitan.

Northwest generally agree that a region including Washington, Oregon, and all or portions of Idaho and Montana is distinct enough to warrant an RTO limited to that area. [348] CREDA and Platte River envision one RTO for the Pacific Northwest, one for California and one for the Rocky Mountain/Desert Southwest area; CRC suggests a similar alignment, with the exception of the Rocky Mountain and Southwest areas as separate RTOs.

A number of commenters make the point that, regardless of where RTO boundaries are drawn, it is important that there be integration and coordination among RTOs. [349] NERC believes that there are two seams issues: reliability practices across seams and market practices across seams. TDU Systems suggests that there be a set of regions for reliability/operations purposes within a larger region for rates and scheduling. Industrial Consumers state that, if multiple RTOs are formed within an interconnection, RTOs should be required to coordinate their operations to collectively "simulate" an interconnection-wide RTO. Cinergy suggests that, if there were more than one RTO in a large interconnection, a "super" RTO could be established to operate and coordinate inter-RTO activities. Montana Commission states that RTO boundaries are less important than ensuring that seams do not interfere with the market, and proposes, as do

[348] See, e.g., Seattle, PGE, Industrial Customers, BC Hydro, Powerex, Tacoma Power, PNGC.

[349] See, e.g., South Carolina Authority, SPP.

others such as Ontario Power and CMUA, that the Commission require adjacent RTOs to embody consistent methods of access, pricing, and congestion management to encourage seamless trading. PacifiCorp asserts that reciprocity agreements among RTOs may be easier to achieve than having all parties in a large region agree to one RTO. Allegheny suggests that appropriate transmission pricing could provide some of the same benefits as a large RTO.

Several commenters express concern that multiple RTO proposals for the same region will be submitted. Indiana Commission contends that the NOPR leaves the door open for more than one RTO proposal for approximately the same wholesale power market region and this could limit the operational efficiency and increase the cost of transmission in the region. It suggests that the Commission consider requiring formal mediation or play an assertive role in such circumstances. Snohomish suggests favoring the RTO proposal that is negotiated pursuant to the most open process that included consumers, transmission dependent utilities and others with a vital interest in the effective and efficient operation of the transmission grid. Midwest ISO Participants submit that the proponents of multiple RTOs meet a heavy burden and demonstrate the need for more than one RTO. In particular, it would require demonstration that the proposals: do not balkanize the market; allow for effective congestion relief; maintain reliability; facilitate construction of new transmission facilities; and allow for effective tariff administration and unbiased ATC determination throughout the region.

Commission Conclusion

We adopt the NOPR proposal on this characteristic. All RTO proposals filed with us must identify a region of appropriate scope and configuration. The scope and configuration of the regions in which RTOs are to operate will significantly affect how well they will be able to achieve the necessary regulatory, reliability, operational, and competitive benefits.

As proposed in the NOPR, we will not at this time prescribe initial boundaries for RTOs. Section 202(a) of the FPA does give us the authority, after consultation with state commissions, to fix and modify boundaries for regional districts for the voluntary interconnection and coordination of facilities. We acknowledge those commenters who believe that it may be more efficient for the Commission to establish at least a rebuttable presumption that particular boundaries are appropriate starting points. However, we conclude, as a matter of policy, that we should not attempt to draw boundaries at this time. We are convinced that the transmission owners, market participants, and regulators in a particular region have a better understanding of the dynamics of the transmission system in that region, and that they should, at least in the first instance, propose the appropriate scope and regional configuration of an RTO. There are many technical considerations involved in discerning the appropriate scope and regional configuration of an RTO, and we believe that those most familiar with such considerations in a region are in a better position to propose a workable solution.

As noted above, some commenters advocate that the NERC regions be starting points; others advocate that the Interconnections be the goal; and still others propose specific configurations that would divide the Nation as many as three to 12 RTOs. Consistent with our decision to let the parties take the initiative to propose what is appropriate for their region, we will not specifically endorse any particular scheme for RTO configuration.

This is not to say, however, that we will deem appropriate any regional configuration proposed. As stated in the regulatory text for this characteristic, an appropriate region is one of sufficient scope and configuration to permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets. A proposed RTO could simply be too limited to satisfy several of the necessary functions. Further, we are aware that transmission owners could seek to gain strategic advantage by the way an RTO is formed. For example, an RTO could be placed to act as a toll collector on a critical corridor.[350] An RTO could propose a configuration that interferes with the formation of a larger, more appropriately configured RTO.

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[350]See Statement of Ohio Commission Chairman Craig Glazer, RTO Conference (St. Louis), transcript at 85-87.

As we review a proposal by a regional transmission entity for its scope and regional configuration, if we determine that the scope is inappropriate, that entity will not be deemed to be an RTO, and its participants will not be deemed to be RTO participants. [351] In response to the commenters questioning what the Commission would do if it received multiple RTO proposals for a region, we note that we hope the collaborative process we are encouraging in this Final Rule would foreclose that circumstance. However, if we are faced with multiple proposals, we would have to determine which RTO proposal best meets the objectives of this Rule.

As we stated in the NOPR, we are aware that there is likely no one "right" configuration of regions. One particular boundary may satisfy one desirable RTO objective and conflict with another. We recognize here, and elsewhere in this Final Rule, [352] that the industry will continue to evolve, and the appropriate regional configurations will likely change over time with technological and market developments. The Commission is also mindful of the interests of individual states regarding RTO boundaries. Given all these considerations, the Commission believes that the public interest will best be served if we provide guidance in this Final Rule, in the form of

[351]The proposal could be accepted, however, as something less than an RTO that represents an improvement over the status quo.

[352]See section F on Open Architecture.

factors that affect appropriate regional configuration, without actually prescribing boundaries.

b. Scope and Configuration Factors

Comments

A large number of commenters agree that the factors listed in the NOPR for determining a proper scope and configuration for an RTO are generally appropriate. [353] Industrial Consumers propose that the factors be codified as part of our regulations. Florida Commission, on the other hand, argues that the factors should not be mandated as part of the Commission's regulations.

Many commenters argue that the RTO region should be as large as possible, i.e., bigger is better. [354] Several commenters suggest the minimum size should be the NERC regions. [355] Conlon suggests a minimum area should be one containing a load of 50,000 MW. PJM states that its organization demonstrates that a very large RTOs is feasible, in

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[353] See, e.g., UtiliCorp, Desert STAR, Midwest ISO Participants, Metropolitan, NECPUC, LG&E, PJM/NEPOOL Customers, Midwest Municipals, Industrial Consumers, Dairyland, TDU Systems, ISO-NE, Midwest Energy, APX, APPA, Cal ISO.

[354] See, e.g., Cinergy, American Forest, EPSA, UtiliCorp, PG&E, NSP, Pennsylvania Commission, NJBUS, LG&E, Enron/APX/Coral Power, NASUCA, PJM/NEPOOL Customers, Cal ISO, Texas Commission, Conlon, Dynegy, Nine Commissions, Michigan Commission, Lincoln, WPSC, First Rochdale, East Texas Cooperatives, Los Angeles, Ohio Commission, EME, Ontario Power, H.Q. Energy Services, Ogelthorpe, UMPA, PG&E, Indiana Commission.

[355] See, e.g., Cinergy, WPSC, Lincoln, Ohio Commission, PG&E.

that it manages a grid serving more than 57,000 MW of generation and containing more than 8,000 miles of high voltage transmission lines. PJM states that even larger control areas are possible as technology advances. PJM/NEPOOL Customers, claiming that all potential factors that might limit size can be overcome, argue that the Commission should not conclude that there are factors that limit size. As discussed below with respect to the congestion management function, some commenters make a particular point of emphasizing the importance of large scope to effective congestion management. [356]

Other commenters argue that bigger is not necessarily better and that there are factors that limit size. [357] CMUA argues that the role of security coordinator and operational characteristics of a region may limit geographic scope. STDUG claims that size breeds inefficiency. Several commenters claim that requiring maximum scope upon creation may discourage RTO formation or make it more costly and take longer to achieve. [358] NYPP expresses concern that, if an RTO is too large, it may not be able to handle local reliability issues. Other commenters believe that the ability to plan new transmission facilities may limit scope. [359] AEPCO expresses concern that the voice of

[356] See, e.g., LG&E, ComEd, Midwest ISO Participants, Midwest ISO.

[357] See, e.g., AEPCO, Tallahassee.

[358] See, e.g., Enron/APX/Coral Power, FirstEnergy, Tri-State.

[359] See, e.g., Dairyland, Minnesota Power.

smaller participants could be lost in a larger RTO. Florida Power Corp. claims that there may be a security risk associated with concentrating control of too large an area into a single facility, and that large areas of non-pancaked rates may eliminate incentives for proper generator siting decisions. A number of commenters believe that either the Eastern interconnection or the Western interconnection is too large an area to be controlled by one RTO. [360] New York Commission argues that the Commission should recognize that experience must be gained in stages before an RTO encompassing an entire interconnection can be implemented. Several commenters in the Pacific Northwest cite the failed attempt to create IndeGo as evidence that trying to create too large an RTO is unworkable, and at some point "bigger" creates more problems than it solves. [361]

Some commenters offer subjective parameters for the scope of an RTO. For example, SNWA proposes that the RTO be large enough to accommodate as many market participants as possible, but not so large as to be overly burdensome to manage. SRP argues that a balance must be struck between an RTO that is too small to cover a meaningful wholesale power market and one that is too large to form and operate effectively. TDU Systems argue that RTOs should comprise the largest regions that

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[360] See, e.g., South Carolina Authority, Desert STAR, MidAmerican, TDU Systems, CREDA, SNWA, CRC, Platte River, PSNM, SRP, Metropolitan.

[361] See, e.g., Industrial Customers, Powerex, Tacoma Power.

could operate in a coordinated fashion within a short period of time with reasonable investments of funds.

A number of commenters emphasize particular factors that they consider important in determining scope and configuration. Some commenters assert that reliability and system security should be the primary determinant of scope and configuration.[362] Others place prime importance on trading patterns and facilitating market transactions.[363] EEI states that the most efficient size and configuration of an RTO should be left to the market to determine. Other commenters propose electrical configuration and physical power flows as important factors.[364] CREDA and Desert STAR argue that the preservation of a Federal Power Marketing Administration project marketing area is an important consideration. Chelan argues that cost shifts need to be considered in determining scope. Platte River contends that established security coordinators should be a factor. Southern Company argues that joint ownership agreements should be a factor. Tacoma Power claims that traditional business relationships and social and political commonality are factors that affect scope.

[362]See, e.g., CMUA, APPA, Florida Commission, Minnesota Commission.

[363]See, e.g., UtiliCorp, Reliant, Duke, South Carolina Commission, NU, Florida Power Corp., Detroit Edison.

[364]See, e.g., South Carolina Authority, Williams, NSP, Dynegy.

Commenters are divided on whether points where transmission facilities are constrained should be used as an RTO boundary or internalized within an RTO. Some commenters claim that constraints should be internalized to the extent possible and not constitute boundaries between regions. [365] NERC states that boundaries should not be placed at weak interconnections because a single entity is better able to strengthen them. On the other hand, other commenters believe that constrained facilities should constitute the boundaries, either because they may form a natural boundary between robust systems or because it makes more sense to internalize markets than to internalize constraints. [366] APPA states that, because it is not possible to internalize all constraints, the goal should be to alleviate or mitigate the effects of interregional constraints through additional construction and RTO operating rules and pricing policies. NECPUC argues that it does not matter where constraints are if compatible methods of locational pricing are adopted by contiguous RTOs. MidAmerican and Duke assert that constraints are not natural boundaries between regions because the location of points of constraint change over time as market conditions change. Several commenters, such as Dairyland and Desert STAR,

[365] See, e.g., Industrial Consumers, First Rochdale, Minnesota Power, STDUG, NARUC.

[366] See, e.g., Ohio Commission, EAL, Florida Power Corp..

take the position that the issue whether to design RTO boundaries at constrained interfaces cannot be stated generically, and must be decided on a case-by-case basis.

Commission Conclusion

The factors we believe should be used to develop appropriate regions are set out here and called regional configuration factors. These cover such considerations as how large a region should be and how boundaries should be evaluated. We do not see a benefit to placing them in regulatory text, as suggested by one commenter, and we will not do so. The factors are intended as guidance and, as such, must necessarily be applied flexibly.

Regional Configuration Factors

As stated above, the principal consideration in evaluating the appropriate scope of an RTO is that such scope must permit the RTO to perform its functions effectively. As we stated in the NOPR, many of the characteristics and functions for an RTO proposed in this section suggest that the regional configuration of a proposed RTO should be large in scope.[367] For example:

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[367]This reiterates the conclusion we reached in the eleven ISO principles in Order No. 888, where we stated that "[t]he portion of the transmission grid operated by a single ISO should be as large as possible." Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,731.

- Making accurate and reliable ATC determinations: An RTO of sufficient regional scope can make more accurate determinations of ATC across a larger portion of the grid using consistent assumptions and criteria.
- Resolving loop flow issues: An RTO of sufficient regional scope would internalize loop flow and address loop flow problems over a larger region.
- Managing transmission congestion: A single transmission operator over a large area can more effectively prevent and manage transmission congestion.
- Offering transmission service at non-pancaked rates: Competitive benefits result from eliminating pancaked transmission rates within the broadest possible energy trading area.
- Improving Operations: A single OASIS operator over an area of sufficient regional scope will better allocate scarcity as regional transmission demand is assessed; promote simplicity and "one-stop shopping" by reserving and scheduling transmission use over a larger area; and lower costs by reducing the number of OASIS sites.
- Planning and coordinating transmission expansion: Necessary transmission expansion would be more efficient if planned and coordinated over a larger region.

We note that the comments on this issue express a range of views. Many commenters assert that the bigger the RTO is the better, and that there really are no serious limitations to RTOs representing loads as large as several hundred thousand megawatts. Other commenters suggest a number of considerations that may militate against RTOs that are too large, including the role of security coordinator, operational characteristics, costs of formation, local reliability issues, and the effect on smaller participants. In the NOPR, we recognized that there may be a limitation on how many facilities or transactions can be overseen reliably by a single operator, imposed either by hardware design or costs, or imposed by human limitations to process the required amount of information. We further recognized that the difficulty and cost of transferring operational control over many transmission systems to one RTO may affect regional configuration. We also noted that, as regions get larger and involve more existing owners of transmission, reaching consensus on an appropriate transmission rate design for the region may prove challenging.

We note that a number of commenters make the point that, at least for some purposes and functions, the scope of an individual RTO is less important if it is part of a group of RTOs that have adequately eliminated the negative effects of "seams" between itself and the other RTOs. NERC identifies two seams issues: reliability practices across seams and market practices across seams. We further note that other commenters suggest that large RTOs could be "simulated" through coordinated operations and consistent methods of access, pricing, and congestion management, and that there may be different acceptable scopes for reliability and operations purposes on one hand, and rates and scheduling on the other. [368] We also detect a common theme that runs through a number of comments: large geographic size is most important for trading areas. Thus, the concept of large "seamless trading areas" for power emerges as a "scope" issue that is distinct from the scope of the region for organizing the transmission functions of an RTO.

We conclude that a large scope is important for an RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets. Adequate scope is not necessarily determined by geographic distance alone; other factors include the numbers of buyers and sellers covered by the RTO, the amount of load served, and the number of miles of transmission lines under operational control. The scope must be large enough to achieve the regulatory, reliability, operational and competitive objectives of this Rule.

We are receptive to flexible and innovative ways for an RTO to achieve sufficient scope. Where a proposed regional transmission entity may be of sufficient scope for

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[368] In a recent conference to address interregional ISO coordination in the northeast, the three northeast ISOs (ISO New England, New York ISO, and PJM ISO) and other market participants discussed current and future coordination efforts among the ISOs intended to simplify market transactions and enhance reliability in the northeast. See http://www.dps.state.ny.us/isoconf.htm.

some RTO purposes, but not others, an RTO may be able to achieve sufficient "effective scope" by coordination and agreements with neighboring entities, or by participating in a group of RTOs with either hierarchical control or a system of very close coordination. We do not foreclose the possibility that an RTO may satisfy some of the minimum characteristics and functions by itself, while satisfying others through a strong cooperative agreement with neighboring RTOs to create a "seamless trading area." The functions of a large RTO may be met by eliminating the effect of seams separating smaller RTOs through a contract or other coordination arrangement. One of our concerns about an RTO's scope is that the existing impediments to trade, reliability, and operational efficiency be eliminated to the greatest extent possible. However, an RTO application that proposes to rely on "effective scope" to satisfy Characteristic 2 must demonstrate that the arrangement it proposes to eliminate the effect of seams is the practical equivalent of eliminating the seams by forming a larger RTO.

Factors for Evaluating Boundaries

In addition to the factors affecting the size of a region, other factors may affect the delineation of regional boundaries. As stated in the NOPR, the Commission proposed that RTO boundaries be drawn so as to facilitate and optimize the competitive, reliability, efficiency and other benefits that RTOs are intended to achieve, as well as to avoid unnecessary disruption to existing institutions. The Commission proposed in the NOPR a list of factors it would consider in evaluating the configuration for a proposed RTO. Nearly all of the comments agree that these factors are generally appropriate.

We recognize that different factors may suggest different configurations and that assessing the appropriateness of a region's configuration will require balancing factors and a flexible approach. Given this qualification, the Commission, in evaluating an RTO's boundaries, will consider the extent to which the proposed boundaries:

<u>Facilitate performing essential RTO functions and achieving RTO goals</u>: The regions should be configured so that an RTO operating therein can ensure non-discrimination and enhance efficiency in the provision of transmission and ancillary services, maintain and enhance reliability, encourage competitive energy markets, promote overall operating efficiency, and facilitate efficient expansion of the transmission grid. For example, we understand that there have been instances where transmission system reliability was jeopardized due to the lack of adequate real-time communication between separate transmission operators in times of system emergencies. To the extent possible, RTO boundaries should encompass areas for which real-time communication is critical, and unified operation is preferred.

<u>Encompass one contiguous geographic area</u>: The competitive, efficiency, reliability, and other benefits of RTOs can be best achieved if there is one transmission operator in a region. To be most effective, that operator should have control over all

transmission facilities within a large geographic area, including the transmission facilities of non-public utility entities. This consideration could preclude a noncontiguous region, or a region with "holes." However, as we discuss below, we will not automatically deny RTO status where the RTO is not able to obtain full participation in its region.

Encompass a highly interconnected portion of the grid: To promote reliability and efficiency, portions of the transmission grid that are highly integrated and interdependent should not be divided into separate RTOs. One RTO operating the integrated facilities can better manage the grid. This is not to say, however, that every weak interconnection belongs on a regional boundary. Where a weak interface is frequently constrained and acts as a barrier to trade, it may be appropriate to place that interface within an RTO region. It may be more difficult to expand a weak interface on the boundary between two regions; this may act as a barrier to trade between the two regions. [369]

Deter the exercise of market power: While the industry should work toward a goal of virtually seamless trade between RTOs, it may be that initially a significant amount of trade may be contained within an RTO, especially if the RTO or the market establishes a power exchange that covers the same area as the RTO. Thus, to have a competitive

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[369]Commenters are also divided on whether weak interfaces should be encompassed within an RTO or act as a natural boundary. After consideration, we conclude that there is not a universal answer applicable to all situations. Consequently, we will address this issue as it arises in RTO proposals on a case-by-case basis.

market, it is important to create an RTO region that is not dominated by a few buyers or sellers of energy. Also, the RTO configuration should not be one where the RTO participants can exercise transmission market power by collecting congestion fees on a critical corridor.

Recognize trading patterns: Given that a goal of this initiative is to promote competition in electricity markets, regions should be configured so as to recognize trading patterns, and be capable of supporting trade over a large area, and not perpetuate unnecessary barriers between energy buyers and sellers. There may exist today some infrastructure or institutional barriers unnecessarily inhibiting trade between regions that could be economically reduced. RTO boundaries should not perpetuate these unnecessary and uneconomic barriers.

Take into account existing regional boundaries (e.g. , NERC regions) to the extent consistent with the Commission's goals for RTOs: An RTO's configuration should, to the extent possible, not disrupt existing useful institutions. The Commission recognizes that utilities have been working together regionally in different contexts for some time, and that there is value in preserving historical institutions and relationships; but we also recognize that in the evolving market, efficiencies may call for new configurations.

Encompass existing regional transmission entities: Because existing ISOs, and any other regional transmission entities we may hereafter approve, already integrate transmission systems, it may not be efficient to divide them into different regions. This is not to say, however, that RTO boundaries must coincide with existing regional transmission entities. An appropriate region may well be larger, and there may be circumstances that support combining or reconfiguring existing entities.

<u>Encompass existing control areas</u>: Many existing control areas are relatively small. It may be advisable not to divide them further. However, parties would not be precluded from proposing to divide a control area if they show this to be beneficial.

<u>Take into account international boundaries</u>: The Commission recognizes that natural transmission boundaries do not necessarily coincide with international boundaries. Indeed, a large part of Canada's transmission system, and a small part of Mexico's transmission grid, is interconnected on a synchronous basis with that of the U.S. Accordingly, an appropriate region need not stop at the international boundary. However, this Commission does not have, and is not intending by this rule to seek, jurisdiction over the facilities in a foreign country. We will ask our international neighbors to participate in discussion of these issues. Perhaps what may be thought of as a "dotted line" boundary at the international border could be used to indicate that a natural transmission region does not necessarily stop at the border, while this Commission's jurisdiction does.

Although most commenters generally support these factors, other considerations are proposed as factors. For example, some commenters claim that we should make reliability and system security the dominant factor, while other commenters propose that we make trading patterns and market transactions the dominant factor. After consideration, we do not think it appropriate to identify one factor as the most important. Although it is essential that reliability not be jeopardized by RTO formation, and it is important to promote competition, we do not believe that one goal needs to be sacrificed to achieve the other.

Other commenters suggest additional factors that they deemed important to RTO boundaries, including, for example, established security coordinators, joint ownership arrangements, and Federal power marketing administration project marketing areas. We do not intend the factors we have listed to be exclusive: other factors may have merit for a particular region. We encourage parties to identify additional factors they believe relevant as we consider specific RTO proposals.

c. Control of Facilities Within a Region

We proposed in the NOPR to accept as RTOs only those proposals for which a region of appropriate scope and configuration is identified and the proponents represent a large majority of the transmission facilities within the identified region.

We solicited comments on how best to balance our goal of having RTOs in place that operate all transmission facilities within an appropriately sized and configured region against the reality that there may be difficulties in obtaining 100-percent participation in all regions in the near term. We asked if we should deny RTO status for any proposal that does not include all transmission facilities within an appropriate region, or if we should require that the RTO at least negotiate certain agreements with any non-participants within its region to ensure maximum coordination.

Comments

Almost all commenters argue that RTO status should not be withheld if the RTO participants are unable to obtain participation by all transmission owners in the region. [370] Several commenters, such as Desert STAR and Minnesota Power, note that, if the Commission does not mandate 100 percent participation, it does not make sense to make it a condition of RTO approval. Other commenters propose standards to consider in determining when a proposed RTO represents sufficient facilities in the region. For example, Desert STAR suggests that the RTO have more than a majority of transmission owners and has not restricted membership. Southern Company proposes a standard that sufficient facilities include most of the major transmission facilities and the RTO can

[370] See, e.g., Desert STAR, Southern Company, Metropolitan, MidAmerican, Nevada Commission, Avista, Enron/APX/Coral Power, Duke, PJM/NEPOOL Customers, Cal ISO, Midwest Municipals, CRC, NPRB, Minnesota Power, Tri-State, TVA.

show benefits. MidAmerican proposes that the RTO be able to demonstrate that it would improve the wholesale market of any subregion of the country without hindering the wholesale market of any other region of the country. Enron/APX/Coral Power argues that an RTO should be approved if it provides an improvement even with "gaps." Midwest Municipals believe that an RTO should be accepted if the Commission can make the judgment that the proposal with "gaps" is likely to encourage others to join through the strength of its operations and the facilities support the development of a competitive generation market. CRC suggests a standard that the proponents make a showing that they have diligently tried to accommodate the concerns and needs of the nonparticipating transmission owners.

Some commenters, such as NJBUS and Cal ISO, believe that an RTO should include the participation of all jurisdictional transmission owners in the region. Duke, however, opposes any attempt by the Commission to determine the appropriate level of participation, stating that the market should determine the participation level. Some commenters, such as Metropolitan, support having the RTO develop coordinated operations agreements with non-participants, while other commenters, such as Avista and Duke, caution that requiring such agreements would be contrary to market principles and would give the non-participating party too much bargaining power.

Seattle contends that the Commission should guard against utilities that would add to the RTO some facilities that are not necessary for RTO operations merely to obtain incentives. It argues that small municipal control areas should have some latitude to determine which of their facilities are regional for RTO purposes. Seattle also questions what "participation" entails for a utility that has limited transmission facilities.

Commission Conclusion

To satisfy the scope and configuration characteristic of this Final Rule, all or most of the transmission facilities in a region must be included in the RTO. Any RTO proposal filed with us should intend to operate all transmission facilities within its proposed region.

We recognize, however, that the proponents of an RTO may not be able to obtain agreement by all transmission owners in a region of appropriate scope and configuration to transfer operating control of their facilities to the RTO. This may occur, for example, because certain facilities may be owned by governmental entities that have restrictions on transfer of control that may require time to resolve. We do not believe that it would be desirable to deny RTO status or delay RTO start-up where the transmission owners representing a large majority of the facilities within a region are ready to move forward, while a few others are not. On the other hand, we do not believe it would be desirable to approve an RTO proposal for a region if the proponents represent only a small portion of the facilities in an otherwise satisfactory region.

Not knowing the full extent of difficulties that may be involved to achieve participation by all transmission facilities, we will not decide generically to automatically deny RTO status for lack of full participation. If an RTO proposal does not cover all the transmission facilities within its proposed region, it should identify the reasons for this, any continuing efforts to include all facilities, and any interim arrangements with the non-represented facility owners to coordinate transmission functions within the region. The Commission may at a future time determine whether the use of its authorities under FPA sections 202(a) and 206 is appropriate to rationalize proposed regions in order to accomplish the objectives of those sections, as discussed elsewhere in this Final Rule.

3. Operational Authority (Characteristic 3)

In the NOPR, the Commission proposed that the RTO have operational authority for all transmission facilities under its control. [371] We stated that this requirement raised two questions: Which functions must an RTO perform? How should an RTO perform the functions that it has reserved for itself? With respect to the question of which

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[371] FERC Stats. & Regs. ¶ 32,541 at 33,734 and proposed § 35.34(i)(3). In the NOPR, we used the terms "operational authority" and "operational responsibility" interchangeably. For purposes of clarity and consistency, we will use only the term "operational authority" to describe this function and have revised the proposed regulatory text accordingly.

functions an RTO should perform, the Commission proposed that, at a minimum, the RTO must have operational authority over all transmission facilities transferred to the RTO and must be the security coordinator for its region. [372] As security coordinator, the RTO would be responsible for real-time monitoring of system conditions (including voltage, frequency, transmission and generation availability, and power flows) in order to anticipate potential reliability problems, and for directing and coordinating relief procedures to respond to transmission loading problems (such as assisting the control area in alleviating the loading, halting additional interchange transactions, reallocating the use of the transmission system, selecting the transmission loading relief procedure, and implementing emergency procedures, including directing that the control area immediately redispatch generation, reconfigure transmission or reduce load). Those proposing an RTO may also decide to have their RTO perform other traditional control area functions (such as maintaining the energy balance, interchange schedules and system frequency). The Commission proposed, however, that an RTO would not be required to be a single control area because of concerns over potentially high costs and technical limitations. Instead those proposing an RTO would be given flexibility in determining the best division of functions between the RTO and any providers of other control area functions if there are no other grid operators in its region. However, the Commission

[372] FERC Stats. & Regs. ¶ 32,541 at 33,734 and proposed § 35.34(i)(3)(ii).

insisted that an RTO must be ultimately responsible for providing reliable and non-discriminatory transmission service.[373]

With respect to the second question of how an RTO will perform its functions, the Commission proposed that an RTO be given considerable flexibility in determining whether it will control facilities directly, delegate functions, or use a combination of these methods.[374] For example, we stated that an RTO proposal could have the RTO operate a single control area, or establish a master-satellite hierarchical control structure with one central and multiple distributed control centers (in either case it could propose to lease equipment and convert employees from existing control centers).[375] The Commission also proposed that the RTO must submit a public report assessing its operational arrangements no later than two years after it begins operations.[376]

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[373] Id.

[374] Id. and proposed § 35.34(i)(3)(i).

[375] Id.

[376] Id. at 33,735.

Comments

Comments on the Functions an RTO Must Perform?

Most commenters agree that the RTO must have operational authority [377] for the transmission facilities under its control. [378] Some commenters claim that this authority is necessary to prevent anticompetitive behavior by transmission owners. [379] Some commenters further contend that this authority must extend to all facilities involved in wholesale transactions so that the transmission owner does not retain control of "access ramps" that happen to be at low (34kV or 69kV) voltage levels. [380] In contrast, some utilities express concern that RTO authority over low voltage facilities will unnecessarily complicate operations. [381]

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[377] Operational authority refers to the authority to control transmission facilities, either directly or through contractual agreements with the entities that do have direct control. In contrast, security coordination refers to real-time monitoring of system conditions in order to anticipate potential reliability problems, and directing and coordinating relief procedures to respond to transmission loading problems.

[378] See, e.g., APPA, Cal ISO, Duke, East Texas Cooperatives, Entergy, EPSA, First Rochdale, Georgia Transmission, Illinois Commission, IMEA, ISO-NE, Michigan Commission, Minnesota Power, Montana-Dakota, NASUCA, NECPUC, Nevada Commission, Mid-Atlantic Commissions, PacifiCorp, PJM, PJM/NEPOOL Customers, SNWA, Southern Company, SRP, SPRA, Tri-State, UtiliCorp, WPSC.

[379] See, e.g., Illinois Commission, IMEA, NASUCA, PJM/NEPOOL Customers.

[380] See, e.g., First Rochdale, IMEA, UMPA.

[381] See, e.g., Montana-Dakota, Tacoma Power.

Several commenters oppose operational authority over the transmission system by the RTO. Some commenters claim that the Commission does not have the legal authority to require transmission owners to transfer control to any other entity.[382] Midwest Energy and SPP believe a transfer of authority would be too costly to implement. Other commenters maintain that the owner and operator of the transmission system must be the same entity in order to avoid liability disputes.[383] Mass Companies suggests that transmission owners retain authority to ensure the safe and prudent management of their facilities. ComEd suggests that transmission owners retain operational authority with the RTO having oversight responsibility.

Commenters are divided whether the RTO should be required to be a control area operator. The existing ISOs in California, New England and PJM, which are all control area operators, report that this structure is working in their regions. Some commenters express concern over potential harm to competitive markets if control area authority is not

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[382]See, e.g., Florida Commission, Puget. It appears that the Florida Commission interprets a transfer of operational control as a transfer of retail dispatch authority. Although other commenters such as WPSC support the RTO having operational authority, they believe that the Commission may need legislative action to obtain the authority to require such a transfer.

[383]See, e.g., Florida Power Corp., Georgia Transmission, JEA, MidAmerican, Southern Company, Enron/APX/Coral Power.

transferred to an independent entity.[384] ICUA recommends that the RTO be the sole control area operator. Many other commenters support a single control area as the ultimate goal, but suggest that the RTO be allowed to evolve to this structure and not be required to consolidate control areas immediately.[385] Other commenters express concern about potential costs associated with control area consolidation, but agree that such action would be acceptable if and when the RTO decides it is necessary for reliability or other reasons.[386]

Commenters that oppose requiring control area consolidation provide a variety of reasons.[387] Enron/APX/Coral Power state that only an RTO that is a transco should perform control area functions. The Florida Commission is concerned that control area consolidation may result in a security risk. Tri-State and WEPCO believe that there are higher priorities in RTO development (such as eliminating pancaking, and promoting

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[384] See, e.g., APPA, APS, Arkansas Consumers, NASUCA, NJBUS, TDU Systems.

[385] See ,e.g., Conlon, Illinois Commission, Los Angeles, FirstEnergy, Minnesota Power, SRP, TDU Systems.

[386] See, e.g., CP&L, ECAR, EEI, Entergy, EPSA, Southern Company.

[387] It appears that the Florida Commission and JEA believe that such a transfer would involve RTO control of retail dispatch. It also appears that Dynegy believes that the basic control area function of frequency control is identical to dynamic scheduling, which they believe should not be centralized or consolidated.

regional system planning) and that emphasizing control area consolidation may inhibit RTO formation.

With respect to specific control area functions, numerous commenters discuss the need for an RTO to have some control of generation in order to ensure system reliability, especially during emergency situations. [388] Minnesota Power suggests that the Commission include "control generation as required to ensure reliability" as an additional minimum function in the final rule. It also recommends that responsibility for area control error (ACE) and automatic generation control (AGC) be transferred to the RTO as control area functions because separating these functions from transmission operations can lead to reliability problems. Other commenters request that the balancing function be transferred to the RTO to prevent discriminatory behavior by transmission owners. [389]

There is widespread agreement among commenters that the RTO must be the security coordinator. Marketers, utilities, existing ISOs and customers all agree that coordination and reliability will be enhanced if a regional organization is responsible for maintaining grid security. [390] Some commenters state that the authority of a security

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[388] See, e.g., NASUCA, First Energy, Otter Tail, PJM, PJM/NEPOOL Customers, Professor Hogan, Project Groups, SPRA, UtiliCorp, Williams, WPPI. We also discuss below in more detail the issue of congestion management as an RTO minimum function.

[389] See, e.g., East Texas Cooperatives, WPPI, Project Groups.

[390] See, e.g., Allegheny, APPA, APX, Cal ISO, ComEd, Dynegy, East Texas (continued...)

coordinator to receive commercially sensitive information to order the curtailment of transactions and the shedding of firm load also grants it the ability to favor its own merchant functions. Confidence in comparable and non-discriminatory transmission service, therefore, will be improved if these functions are performed by an entity that is independent of all market participants.[391] Though essentially in support of our proposal, NERC and MidAmerican assert that is not necessary to link each RTO to a single security center, but rather it is possible to allow a single security coordinator to assume responsibility for more than one RTO. NERC points out that if an RTO performs all the characteristics and functions specified in the NOPR, it will necessarily be a security coordinator.

A number of parties state that the RTO must have access to real-time system information in order to perform its functions as security coordinator.[392] Montana-Dakota explains further that security centers, by definition, will be equipped with the hardware

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[390](...continued)
Cooperatives, Enron/APX/Coral Power, Entergy, EPSA, LG&E, Mass Companies, MidAmerican, Midwest Energy, Montana-Dakota, NASUCA, NECPUC, NERC, NJBUS, PJM/NEPOOL Customers, PPC, Professor Hogan, Seattle, South Carolina Authority, SPP, SRP, Tri-State, UtiliCorp, Williams.

[391]See, e.g., LG&E, PJM/NEPOOL Customers, SPP, UtiliCorp. See also supra section III.D.1 for a more detailed discussion of independence as an RTO minimum characteristic.

[392]See, e.g., Montana-Dakota, PJM/NEPOOL Customers, South Carolina Authority, Williams.

and software required to assume basic operational control of the system, which are beyond that required strictly for security functions.

Only two commenters express concern over the need for the RTO to be the security coordinator. ComEd, though supporting some security functions for the RTO, asserts that the RTO's role can be limited simply to one of oversight. ComEd does not believe that the RTO needs access to real-time data, and instead would allow the individual control areas to perform the bulk of the security functions. The only commenter that argues against making the RTO a security coordinator is Avista, which states that the security coordinator in the Pacific Northwest is already an independent body and has the authority necessary for ensuring reliability; therefore, no changes are required.

Comments on How an RTO Should Perform Its Functions

Overall, commenters strongly agree with the Commission's proposal to permit those proposing an RTO the authority to decide the type of control they require: direct, functional or a combination. Some commenters believe direct control is the best approach to prevent abuse of sensitive information and better ensure reliability. [393] However, Manitoba Board and Canada DNR express concern that continued coordination between U.S. and Canadian utilities might be undermined if highly centralized systems

[393] See, e.g., East Texas Cooperatives, First Rochdale, Illinois Commission, PJM/NEPOOL Customers.

are developed and controlled by U.S. entities. A few commenters contend that it is best for the RTO to delegate control authority.[394] The majority of commenters support some form of hierarchical control structure, where the RTO would establish a master control center and direct the operations in the existing geographically distributed control centers, which would become satellite centers.[395] PJM and ISO-NE indicate that they both currently operate with a hierarchical control structure, where the ISO control center is the master control room that directs the actions of the satellite control centers.

A number of supporters of the hierarchical structure specifically request that the Commission ensure that the RTO has the authority to direct all actions at the satellite control centers and that the satellite centers will be independent in order to prevent discriminatory transmission service and the transfer of commercially valuable information to market participants.[396] Montana-Dakota and Otter Tail believe a major benefit of the hierarchical structure is improved emergency response and system security in a large

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[394] See, e.g., MidAmerican, Seattle, South Carolina Authority.

[395] See, e.g., ECAR, Enron/APX/Coral Power, EPSA, East Texas Cooperatives, First Rochdale, Industrial Consumers, ISO-NE, LG&E, Los Angeles, Lincoln, MidAmerican, Montana-Dakota, NECPUC, NASUCA, Otter Tail, PJM, PJM/NEPOOL Customers, Project Groups, Seattle, South Carolina Authority, Tri-State. Many of these commenters support eventual consolidation when any cost and technical barriers are overcome and if the RTO decides it is necessary.

[396] See, e.g., EAL, East Texas Cooperatives, ISO-NE, Industrial Consumers, LG&E, NASUCA, PJM, PJM/NEPOOL Customers, Powerex, Project Groups, Tri-State.

region if the RTO is coordinating and directing the actions of all operators in the region. Finally, Enron/APX/Coral Power believe the standardization of balancing practices for a large region is an important benefit of a hierarchical system.

Commission Conclusion

Which Functions Must an RTO Perform?

We reaffirm the determination proposed in the NOPR that an RTO must have operational authority for all transmission facilities under its control and also must be the security coordinator for its region. We recognize that it is difficult to draw a precise line between transmission control and generation control, [397] and we also recognize that given the changing nature of the industry, terminology such as "control area operator" is undergoing definitional changes. [398] Accordingly, it is difficult to state precisely what functions an RTO must have in order to have full operational authority for transmission facilities. Moreover, our desire to allow RTOs flexibility dissuades us from trying to be

[397] See NERC Operating Manual Policy 2 which can be found at www.nerc.com. As we have stated before, the dividing line "between transmission control and generation control is not always clear because both sets of functions are ultimately required for reliable operation of the overall system." Midwest ISO, 84 FERC at 62,151. The idea that the entity that controls the transmission system must have some degree of control over some generation seems to be generally recognized. See Docket No. ER98-1438-000 Applicants' Response at 3.

[398] We note that the definition of a control area, and consequently the functions that must be performed by a control area, is currently being reexamined by the NERC Control Area Criteria Task Force in an open forum. See NERC web page at www.nerc.com.

too precise. However, certain concepts are basic and generally understood in the industry.

One necessary aspect of operational authority as used here refers to the authority to control transmission facilities. This includes, but is not limited to, switching transmission elements into and out of operation in the transmission system (e.g., transmission lines and transformers), monitoring and controlling real and reactive power flows, monitoring and controlling voltage levels, and scheduling and operating reactive resources. Functions such as these must be included within the operational authority of an RTO.

We conclude, as proposed in the NOPR, that the RTO is also required to be the NERC security coordinator for its region. The role of a security coordinator is to ensure reliability in real-time operations of the power system. As security coordinator, the RTO will assume responsibility for: (1) performing load-flow and stability studies to anticipate, identify and address security problems; (2) exchanging security information with local and regional entities; (3) monitoring real-time operating characteristics such as the availability of reserves, actual power flows, interchange schedules, system frequency and generation adequacy; and (4) directing actions to maintain reliability, including firm load shedding.

We believe that the RTO must be security coordinator for several reasons. The functions of the security coordinator are enhanced when they are performed over large regions. In addition, the independence of the security coordinator is important for ensuring non-discriminatory transmission service, and the RTO will have that independence. As we stated in Midwest ISO:

> This role [the role of a security coordinator] is central to maintaining grid reliability and non-discriminatory access. Under proposed NERC policies, security coordinators would be required to anticipate problems that could jeopardize the reliability of the interconnected grid. In the course of performing these reliability functions, the Security Coordinator would receive considerable information which is commercially sensitive. Therefore, it is important that the proposed Midwest ISO Security Coordinator be performed by an entity that is independent of market participants.[399]

However, we will allow flexibility in how the RTO performs its security coordinator functions. For example, an RTO may contract these responsibilities out to an independent security coordinator if this is justified. Also, this requirement does not prevent more than one RTO from sharing a single security coordinator as suggested by NERC.

As proposed in the NOPR, we will not at this time require the RTO to operate what traditionally has been thought of as a single control area for its region. However, the RTO must perform the control functions required to satisfy the minimum characteristics and functions in this Final Rule, including the transmission control and

[399] 84 FERC at 62,158.

security coordinator functions discussed above, [400] in a non-discriminatory manner for all market participants. [401] We will permit those developing an RTO proposal flexibility in deciding on the particular division of operational responsibilities with existing control areas.

We recognize that the feasibility of consolidating existing control areas into a single such area may be limited by cost and technical considerations. However, we note that physical consolidation may be unnecessary when a hierarchical control structure is used to define a single control area by making existing control areas subject to RTO direction (and so avoiding the high costs and technical uncertainty associated with centralization of physical control for a very large RTO region). Hierarchical control is a form of power system control that relies on a master-satellite control structure, which establishes a single controlling authority without requiring the construction of a single, consolidated control room. Existing control centers are not replaced, but continue to operate, independent from market participants, as satellite control centers reporting to the RTO master control center. The RTO security center assumes the dual role of the master

[400]For example, several commenters state that an RTO must have some authority over generation to ensure system reliability. The RTO is required to have some authority as a minimum characteristic, as discussed with respect to short-term reliability.

[401]In our order approving the Midwest ISO, we stated that our approval of the ISO was based on the applicants' commitment that the ISO would be able to "take all actions necessary to provide nondiscriminatory transmission service, promote and maintain reliability." Midwest ISO, 84 FERC at 62,159.

control center and security center, with clear authority to direct all actions at the satellite centers. [402]

We conclude that each region should be free to decide if and when the region will transition to a hierarchical control structure, consolidate the control areas in its region, or adopt a different control structure that best meets the region's needs.

How Should the RTO Perform Its Functions?

We conclude that those designing the RTO should have flexibility to decide how it would exercise its operational control authority. The RTO operate the transmission system through direct physical operation by RTO employees, contractual agreements with other entities (e.g., transmission owners and control area operators) or implement a hierarchical control structure involving a combination of direct and functional control. Under these arrangements, the personnel of existing control centers might become employees of the RTO or remain as employees of the control center owner, while being supervised by RTO personnel. We will leave it to the discretion of the region to decide on the combination of direct and functional control that works best for its circumstances. [403]

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[402] See, e.g., Marija Ilic and Shell Liu, Hierarchical Power System Control: Its Value in a Changing Industry, Springer-Verlag, 1996.

[403] This issue is also addressed in greater detail in our discussion of the RTO's role as a provider of ancillary services as an RTO minimum function.

However, regardless of the method of control chosen, the RTO must have clear authority to direct all actions that affect the facilities under its control, including the decisions and actions taken at any satellite control centers. The system of operational control chosen must ensure reliable operation of the grid and non-discriminatory access to the grid by all market participants. In addition, to ensure that the RTO does not become locked into an operational system that is unsatisfactory, the Commission will require the RTO to prepare a public report that assesses the efficacy of its operational arrangements no later than two years after it begins operations.

4. Short-Term Reliability (Characteristic 4)

The fourth proposed characteristic of an RTO is that it must have exclusive authority for maintaining the short-term reliability of the transmission grid under its control. In the NOPR we identified four basic short-term reliability responsibilities of an RTO: (1) the RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules; (2) the RTO must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of these facilities; (3) when the RTO operates transmission facilities owned by other entities, the RTO must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards; and (4) if the RTO operates under reliability standards established by another entity (e.g., a regional reliability council), the RTO must report to the Commission if these standards hinder its ability to provide reliable, non-discriminatory and efficiently priced transmission service. [404]

Comments

General Comments

Commenters address both general concerns about reliability as well as the four basic proposed short-term reliability responsibilities of an RTO. Most commenters generally agree that the RTO should have the responsibility for short term-reliability. [405] Several commenters raise questions regarding definition and scope of "short-term" reliability. TEP requests that the Commission further define the time period involved. It suggests that designating a specific time period (whether one month, six months or a year) would be beneficial to evaluating this characteristic. Enron/APX/Coral Power requests that the Commission make clear that "short-term" is intended to mean "real-time."

While agreeing that the RTO should be given ultimate control over facilities necessary to preserve reliability, SMUD expresses concern that the RTO should not be

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[404] FERC Stats. & Regs. ¶ 32,541 at 33,735.

[405] See, e.g., American Forest, Cal ISO, California Board, Cinergy, CMUA, CSU, EAL, Enron/APX/Coral Power, Entergy, EPSA, Industrial Customers, NASUCA, NECPUC, PJM, PNGC, SMUD, UtiliCorp, H.Q. Energy Services, Mass Companies, Mid-Atlantic Commissions, MidWest Energy, Minnesota Commission, NY ISO, PacifiCorp, PG&E, Williams, WPSC.

encumbered with responsibility for facilities that do not serve a regional transmission function. TANC requests that the RTO's responsibility over reliability not infringe on the management responsibilities of local regulatory authorities or interfere with the management and operation of the local system facilities of a utility distribution company.

PG&E requests that the Commission require that the RTO rely primarily on market mechanisms to maintain reliability. However, PJM/NEPOOL Customers urge the Commission to ensure that the RTO’s actions in maintaining the short-term reliability of the grid do not unreasonably impinge on the freedom of business decisions inherent in a competitive supply market. Several commenters, such San Francisco and Minnesota Commission, state that because the primary function of a RTO is ensuring short-term reliability, it should be more clearly defined and should not be compromised by any other RTO market functions.

PJM suggests that the Commission grant additional authorities to the RTO to ensure reliability, including the authority to (1) collect information, (2) direct operations in the control area, (3) assure that those it directs will respond in a predictable manner (which the RTO can achieve through training and drills) and (4) declare an emergency, direct emergency operations, and determine when emergency conditions have ended.

Southern Company notes that the industry has little, if any, experience in granting a new entity control over the operations of a transmission system that encompasses a broad, multi-state region. [406] It claims that transmission owners and State commissions must be assured that the RTO is capable of operating a regional transmission system reliably before an RTO is formed. New York Commission indicates that the authority of States to require the maintenance of electric system reliability should be recognized in establishing responsibilities. Iowa Board believes that there is a need for greater regional development of reliability standards to reflect regional needs and conditions. It requests that State commissions be involved in the decisionmaking process of an RTO to ensure that electric facilities are properly sized and located and that additions are not detrimental to the reliability of the grid.

Comments on Interchange Scheduling

The Commission proposed that, in the context of the RTO's role as the recipient and evaluator of all requests for transmission service under its own FERC-approved tariff, an RTO that is a control area operator must also receive, confirm, and implement all interchange schedules between adjacent control areas. [407] The Commission expressed concern that non-RTO control area operators would receive commercially sensitive

[406]Southern Company notes that the California and ERCOT ISOs operate within the boundaries of a single state. In PJM, New York and New England, the control of the grid remains remarkably unchanged because the ISOs in those regions were already operating the system on behalf of the transmission owners and adopted the institutions and infrastructures of an ISO.

[407]FERC Stats. & Regs. ¶ 32,541 at 33,735-36.

information involving its competitors in implementing interchange schedules and questioned whether there is any Commission action, other than its current code of conduct standards, and short of requiring consolidation of all control areas within a region, which could address this concern.

Several commenters agree that the RTO should have authority over receiving, confirming and implementing all interchange schedules. [408] PJM believes that an independent ISO is in the best position to exercise the scheduling authority of an RTO. It suggests that an RTO that is independent of commercial interests in the market does not face the commercial information problem because it does not compete with market participants and consequently would make scheduling decisions in an unbiased and fair manner.

PJM/NEPOOL Customers claims that interchange scheduling oversight must be performed by an independent entity because it would be neither possible nor desirable for a non-RTO control area operator to perform this function without access to commercially sensitive information. It suggests that the RTO maintain direct control over interchange scheduling either by using RTO employees or a master satellite arrangement where ultimate responsibility remains in the RTO master control area operating room. APX

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[408] See, e.g., Cal ISO, CMUA, Entergy, Mass Companies, NECPUC, Nevada Commission, PJM/NEPOOL Customers, PJM, SMUD, Southern Company, WPSC, PG&E.

suggests that requiring a contractor (acceptable to the RTO and the control area operator) to operate the control area operator facility could help address this concern.

Enron/APX/Coral Power believes that the risk is eliminated if transmission operations, including control-area operations, are operationally separated from the load and generation of vertically-integrated utilities. Barring such complete separation, this risk could nevertheless be substantially obviated if the RTO provided control area operators with information only about scheduled net interchanges between control areas without disclosing the individual transactions making up the new schedules. [409]

However, other commenters contend that control area operators will continue to need information on individual transactions in order to implement interchange schedules and to ensure real-time reliability. [410] Desert STAR believes that work should be done in this area to determine what information is required by control area operators and when they must receive it in order to carry out their reliability responsibilities

Florida Commission states that this issue has already been resolved within the Florida Reliability Coordinating Council (FRCC) by requiring all entities who operate control areas within the region that require access to commercially sensitive information

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[409] See also Southern Company.

[410] See, e.g., Duke, Florida Power Corp.

to sign agreements that separate reliability personnel and the relevant information from their wholesale merchant personnel.

Several commenters, such as Duke and Florida Power Corp., state that no additional Commission action is necessary. These commenters believe that the existing code of conduct standards are working and the reciprocity provisions of Order No. 888 provide for compliance with the code of conduct standards by all non-public utility control area operators. Florida Power Corp. also notes that within the FRCC, all entities operating control areas are required to sign agreements verifying functional separation.

Comments on Generation Redispatch

In the NOPR, the Commission proposed that the RTO's reliability authority include the ability to order redispatch of any generator connected to the transmission grid when necessary for the reliability of the grid. However, the RTO would have no authority over initial unit commitment and normal dispatch decisions. [411]

Several commenters agree that the RTO have some authority to order redispatch when necessary to maintain the the reliability of the grid. [412] Sithe, however, believes that, in the evolving competitive marketplace, redispatch authority alone is insufficient. It

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[411]FERC Stats. & Regs. ¶ 32,541 at 33,736.

[412]See, e.g., Cal ISO, Cinergy, CMUA, NECPUC, PJM, UtiliCorp, Entergy, Allegheny, LG&E, Lincoln, Metropolitan, Minnesota Power, Nevada Commission, Otter Tail, Southern Company, TDU Systems, NASUCA, Reliant, Mass Companies, TAPS.

argues that the RTO should also provide appropriate incentives to the owners of assets that are needed for reliability to maintain those assets and make them available for operation in constrained areas. Sithe urges the Commission to consider adopting a final rule that provides RTOs with sufficient commercial authority, "including the necessary financial resources" to enter into market-rate business arrangements, that assure availability of assets needed for reliability. Sithe states that without this authority, the RTO may not have sufficient tools to fully ensure reliability, because must-run generators would have little incentive to continue to operate in constrained areas.

CMUA maintains that it is insufficient to vest authority in the RTO to maintain short-term reliability without also vesting enforcement powers to ensure compliance with RTO dispatch instructions. Allegheny and other commenters agree that RTOs should be able to direct redispatch, particularly if the redispatch is accomplished under a market-based compensation scheme as a part of transmission service pricing methodology that uses the redispatch costs to set marginal system use costs. However, they argue that in no case should the RTO be able to direct generation redispatch unless the generator is compensated at market value (unless market power issues are involved). [413]

Avista expresses serious concern with the breadth of a redispatch requirement. It believes that the right to order redispatch of generation should be negotiated among the

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[413] See, e.g., Cinergy, Chelan, Southern Company, LG&E, Reliant.

parties in the region without a presumption that the RTO must have broad redispatch authority, except in emergency circumstances. Avista and others note that a negotiated approach is particularly important to operators of hydroelectric resources which are subject to numerous environmental and operating restrictions that limit their ability to redispatch. [414] Avista and SMUD request that the Commission clarify that the RTO's authority to redispatch is limited to emergency circumstances affecting reliability.

Chelan believes that RTOs should be required to enter into arm's-length agreements with those generators that are willing to service redispatch requests, and compensate those generators for supplying this service. RTOs should not be allowed to unilaterally redispatch a generating unit without the generator's consent, and without compensation.

Commenters, such as Cal ISO and Nevada Commission, suggest that the Commission require reliability-related services (i.e. redispatch) be provided to RTOs under a set of uniform rates, terms and conditions. Such a requirement would reduce the Commission's administrative burden of contracts governed by different sets of terms and conditions.

EME believes that the RTO's control over dispatch of generation should be carefully circumscribed. It recommends that reliability functions be internalized into

[414] See, e.g., CMUA.

explicit procedures for congestion pricing. It states that in most cases proper pricing signals can provide sufficient incentives for generators to schedule operation of their facilities to ensure system reliability.

Industrial Consumers states that the RTO's redispatch decisions regarding "any generator" must be qualified to excuse on-site generators that serve an industrial load, especially those that serve a critical steam host. For environmental, safety and economic reasons, these units should not be forced to redispatch except as a last resort option.

Metropolitan supports an RTO having authority to order redispatch of any generating unit when necessary for the reliability of the grid. However, "reliability" must be carefully defined to avoid RTO interference with normal market operations by redispatching generation for its own convenience, or to alleviate adverse market conditions. [415]

Several commenters oppose the proposal to allow the RTO to redispatch generation. [416] PG&E believes that the proposal would give too much latitude to RTOs and create an incentive to impose centrally determined fixes on market operations, rather

[415]Metropolitan believes the Cal ISO's definition of system emergency appropriately describes the circumstances in which redispatch may be appropriate. A "system emergency" is described as "any abnormal system condition which requires immediate manual or automatic action to prevent loss of load, equipment damage or tripping of system elements which might result in cascading outages or to restore system operation to meet the minimum operating reliability criteria."

[416]See, e.g., PG&E, Southern Company, Reliant, SMUD.

than allowing market mechanisms to self-correct. Therefore, PG&E argues that RTOs should be allowed to redispatch generation facilities only when there is a true reliability emergency as specified in the RTO tariff. Moreover, RTOs should be able to redispatch only those units that have actually participated in the market.

PJM/NEPOOL Customers believes that the authority as proposed in the NOPR is too broad and must be further defined. It requests that the Commission ensure that this authority is exercised only during only the most serious circumstances when grid reliability is truly in danger. It suggests that the Commission promulgate or pre-approve reliability standards for determining when the RTO can order redispatch of generators, the amount of generation assets that the RTO will have authority over and standards for the redispatch order. Southern Company recommends that the Commission provide only general guidance concerning redispatch and allow the regions to develop more specific procedures.

When considering allowing an RTO to redispatch a Federal hydroelectric generator, SPRA emphasizes that the Commission must recognize that individual Federal hydroelectric generators are under the control of either the Corps, the Bureau of Reclamation or the International Boundary Waters Commission, not the PMA. While a PMA may belong to an RTO, it is unlikely that other Federal agencies will. The

Commission must give careful consideration to determine that RTO redispatch authority does not prohibit or limit a PMA's ability to fulfill its statutory obligations.

Comments on Transmission Maintenance Scheduling

In the NOPR, the Commission proposed that an RTO which operates transmission facilities owned by other entities be authorized to approve or disapprove all requests for scheduled outages of transmission facilities in order to ensure that maintenance outage schedules meet applicable reliability standards. [417]

The Commission requested comments on a number of issues related to this proposed requirement: Does it cede too much or too little authority to the RTO? If the RTO requires a transmission owner to reschedule its planned maintenance, should the transmission owner be compensated for any costs created by the required rescheduling? Would it be feasible to create a market mechanism to induce transmission owners to plan their maintenance so as to minimize reliability effects? Should an RTO that is an ISO have any authority to require rescheduling of maintenance if it anticipates that the planned maintenance schedule will adversely affect power markets? If the RTO is a transco, can it manipulate its transmission maintenance schedules in a manner that harms competition?

[417] FERC Stats. & Regs. ¶ 32,541 at 33,736-37.

The Commission stated that the RTO's regional perspective will allow it to coordinate individual maintenance schedules with each other as well as with expected seasonal system demand variations. Because the RTO will have access to extensive information, it will see the "big picture" and be able to make more accurate assessments of the reliability effect of proposed maintenance schedules than individual, sub-regional transmission owners.

Commenters address essentially three issue related to transmission maintenance scheduling: the RTO's authority; appropriate compensation; and use of market mechanisms.

RTO Authority to Schedule Transmission Maintenance

Many commenters support giving an RTO authority over transmission maintenance scheduling. [418] Duke, however, believes that an enforcement mechanism may also be needed. First Rochdale recommends that transmission owners be given the right to protest an RTO's actions to the Commission. Reliant, however, opposes RTO authority over maintenance scheduling, arguing that transmission maintenance decisions must reside with transmission facility owners.

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[418] See, e.g., Cal ISO, NECPUC, PJM, Desert STAR, Entergy, PGE, Allegheny, Avista, LG&E, Lincoln, Tri-State, WPSC, CRC, Duke, EAL, First Rochdale, Industrial Consumers, ISO-NE, Metropolitan, Montana-Dakota, NASUCA, New Smyrna Beach, NYPP, Oneok, PG&E, Southern Company, SRP, Turlock, WPPI, Florida Power Corp., Nevada Commission.

Seattle and NYPP suggest that the Commission define an RTO role only for scheduling facility outages that are clearly associated with the regional transmission network because internal subtransmission and radial transmission facilities do not have regional significance. Turlock supports restricting the RTO's authority to the grid it manages to prevent its outage scheduling authority extending beyond the grid for which it is responsible. On the other hand, TDU Systems claims that an RTO should also coordinate maintenance of interconnected distribution facilities that are not under its control, if maintenance on those facilities would adversely affect RTO operations.

Duke suggests that with the creation of an RTO that is not a transco, a set of governing principles for outage coordination should be established. The parties should agree on the timing of requests for planned maintenance and the timing of responses to those requests. If for any reason, other than the gross negligence of the transmission owner, a scheduled maintenance outage were determined to be a problem after an agreement is reached, rescheduling the outage would require the mutual consent of the transmission owner and the RTO.

EAL recommends that appropriate contracts with existing transmission facility owners that ensure the continued reliable operation of the grid are required. Principal elements of such contracts would include standards of service, provisions for information sharing and reporting, maintenance scheduling, transmission facility ratings, testing and performance expectations. Maintenance scheduling should include provisions for maintenance deferral under instructions from the RTO if required for system security reasons only.

NYPP states that arrangements for outages should be made well in advance of the outage start date because RTO approval of proposed schedules could become the critical path. If approval is delayed, or subsequently revoked, the transmission owner will incur significant expenses that should be reimbursed.

Montana-Dakota suggests that the effects of rescheduling can be decreased by having the RTO review and approve all transmission maintenance schedules on a weekly, monthly and quarterly basis. After reviewing the transfer capability and market effects of the proposed outage, the RTO should communicate the need to reschedule to the transmission owner far enough in advance of the planned outage to allow the owner to reschedule, possibly to avoid any cost impact. Montana-Dakota notes, however, that the closer the date of the outage, the higher the probability of an economic impact.

Southern Company requests that the Commission clarify that once an RTO approves a scheduled outage, it should be allowed to change that schedule only if implementing the plan would compromise system integrity or reliability.

Seattle believes that the NOPR fails to provide adequate assurances to transmission owners that a timely maintenance schedule will be adopted by the RTO.

The RTO must establish timely dates certain for maintenance outage requests from operating entities. To do this the RTO must adequately balance safety considerations, and the cost of deferring maintenance with commercial impact. For these reasons, an RTO should not be permitted to arbitrarily postpone required maintenance.

Compensation

Nearly all of the commenters believe that transmission owners should be compensated in some form if they are required by an RTO to reschedule maintenance. [419] Avista argues that the transmission owners' shareholders should not bear the burden of decisions made by an independent body that result in reduced revenues or increased costs for the transmission owner.

Metropolitan states that if an RTO requests a transmission owner to reschedule planned maintenance for reliability concerns, a transmission owner should be compensated only for its direct costs necessarily and reasonably incurred in complying with the RTO's request. Direct costs may include, for example, increased labor or equipment expenses arising from the rescheduled maintenance. However, Metropolitan does not believe a transmission owner should recover lost opportunity costs arising from the rescheduled maintenance because opportunity costs are uncertain and speculative.

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[419] See, e.g., PJM, TANC, WPSC, Avista, Lincoln, CRC, Duke, Metropolitan, Minnesota Power, Montana-Dakota, NASUCA, NPRB, NYPP, PJM/NEPOOL Customers, Reliant, TDU Systems, Turlock, Florida Power Corp., Reliant, Desert STAR, Southern Company.

Southern Company argues that, if an RTO requires a transmission owner to reschedule a previously approved outage, the RTO should compensate the transmission owner for any additional costs caused by the rescheduling.

NASUCA believes that the RTO should compensate transmission or generation owners only to the extent that incremental costs are incurred due to the rescheduling of outages. NASUCA argues that it is unlikely that owners would incur significant incremental costs, especially for transmission outages.

Some commenters such as PGE and Minnesota Power state that if an RTO requires a transmission owner to reschedule its planned maintenance for reliability reasons in an emergency situation, the RTO should not be required to compensate the transmission owner. However, if an RTO requires a transmission owner to reschedule its planned maintenance for economic reasons, the RTO should be required to compensate the transmission owner for liquidated damages.

Other commenters such as Tri-State and Cal ISO oppose transmission owners being compensated for the rescheduling of maintenance work. Cal ISO states that, where an RTO properly exercises such authority by requiring a transmission owner to reschedule a maintenance outage, that transmission owner is not entitled to compensation for the costs associated with rescheduling. Tri-State recommends factoring any additional expense into the revenue requirement that the transmission owner receives from the RTO.

Market Mechanisms

PJM/NEPOOL Customers suggests that the RTO enact a compensation mechanism in transmission outage rescheduling situations or propose to use a market mechanism to encourage transmission owners to plan maintenance so as to minimize reliability effects. Minnesota Power, however, argues that maintenance rescheduling to benefit power markets is analogous to generation redispatch and should be paid for by the benefitting market participants.

Montana-Dakota believes that an RTO should have the authority to reschedule maintenance for market effects if there is an incremental cost reimbursement mechanism in place that would provide an incentive to the transmission owner to change maintenance schedules to benefit the market.

Metropolitan argues that an RTO with authority to unilaterally reschedule transmission maintenance for market considerations could have a destabilizing effect on the power market. Emerging markets require predictability to thrive, and therefore RTOs should interfere in market operations only when necessary to address reliability concerns.

Florida Power Corp. suggests that, while it may be feasible to develop a market mechanism to induce transmission owners to plan their maintenance to minimize reliability effects, it would be far simpler to retain the existing structure in which a single entity both owns and operates the transmission system. When ownership and operation are combined, a single entity is responsible for both reliability and maintenance, and thus has a natural incentive to seek an optimal balance between these activities. Thus, Florida Power Corp. opposes RTOs having authority to reschedule maintenance to manage the performance of the market.

Turlock also does not believe an RTO should have authority to make transmission outage decisions based on market considerations. Turlock, as well as Desert STAR and CRC, believe instead that consideration should be given to motivating transmission owners to appropriately schedule their maintenance outages, to minimize impacts on competitive markets.

Comments Generation Maintenance Scheduling

The short-term reliability characteristic, as proposed in the NOPR, would not give an RTO authority over proposed generation maintenance outage schedules. However, the Commission noted that some generation control is necessary for reliable operation of a transmission system. The Commission asked whether an RTO should have some authority over generation maintenance schedules and, if so, how much. [420]

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[420] FERC Stats. & Regs. ¶ 32,541 at 33,737.

The majority of commenters support an RTO having at least some authority over generation maintenance schedules. [421] However, most commenters suggest limiting the RTO's authority. Some commenters suggest that an RTO have authority only for generating units that are "must-run" or that the RTO has under contract due to the requirement to maintain system reliability. [422] Desert STAR believes that an RTO should not attempt to manipulate the commercial power market when reliability is not affected.

Cinergy supports an RTO having the ability to request changes to a schedule to serve reliability needs, coordinate transmission outages, and maximize grid efficiency to increase ATC for transmission customers' use, so long as generators receive compensation at market-based prices for missed market opportunities. Other commenters agree that an RTO should compensate the generation owner if a schedule change is necessary. [423]

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[421] See, e.g., Cinergy, NECPUC, PJM, Desert STAR, WPSC, Cal ISO, EAL, Industrial Consumers, ISO-NE, Turlock, Florida Power Corp., Metropolitan, Minnesota Power, Montana-Dakota, NASUCA, Nevada Commission, NYPP, PSNM, TDU Systems.

[422] See, e.g., Desert STAR, Metropolitan, Turlock, Florida Power Corp., PSNM, NYPP.

[423] See, e.g., WPSC, LG&E, Montana-Dakota.

A few commenters claim that the RTO should not have any authority over generation maintenance schedules.[424] SPRA states that requiring such authority would discourage or prevent participation by PMAs because other Federal agencies own the hydroelectric plants that generate the power marketed by the PMAs.

Tri-State does not believe that an RTO should have approval authority over generation maintenance outages because these outages are driven by the cost considerations associated with generation plant equipment replacement or rehabilitation. However, Tri-State agrees that an RTO must have advance knowledge of the scheduled generation outages in order to assure transmission system reliability and adequacy of reserves. Other commenters concur with a notification requirement.[425] Cinergy notes, however, that while it believes a generator may be required to submit its maintenance schedule to an RTO, the RTO should be prohibited from sharing that information with any other market participants, or affiliates of market participants.

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[424] See, e.g., Duke, PJM/NEPOOL Customers, SPRA, Tri-State, Empire District.

[425] See, e.g., Enron/APX/Coral Power, FirstEnergy, Mass Companies, Metropolitan.

Comments on Performance Standards

In the NOPR, the Commission discussed the establishment of performance standards by an RTO for transmission facilities under its direct or contractual control.[426] For example, an RTO could establish a standard that identifies specific performance targets for planned and unplanned outages of facilities. The Commission requested comments on whether a non-profit ISO could establish incentive schemes for the transmission owners whose facilities it operates.

PJM believes that an RTO will be capable of developing performance standards and incentives to encourage transmission owners and generators to operate and maintain reliable facilities. It states that market participants cooperatively can create market-oriented incentives to maintain their transmission and generation facilities effectively.[427]

Duke also believes that incentive schemes can be developed. It suggests that the revenues collected from users by the RTO could be returned to transmission owners according to a prearranged formula that incorporates quality standards for reliability. Thus, the revenue allocation would reflect transmission owner performance in providing a reliable system.

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[426] FERC Stats. & Regs. ¶ 32,541 at 33,737.

[427] See also LG&E.

PSE&G believes that RTOs will, and should, be able to offer incentives to participants to ensure that reliability standards are not only met but exceeded. It states that a mechanism of linking payment with performance, measured against accepted benchmarks, has worked well for many years in PJM.

EAL states that appropriate contracts with existing transmission facility owners that ensure the continued reliable operation of the grid are required. It suggests that these contracts include standards of service, provisions for information sharing and reporting, maintenance scheduling, transmission facility ratings, testing and performance expectations.

Industrial Consumers believes that an RTO could establish performance standards for transmission facilities that takes into account the “reliability” of each facility. It argues that a facility that has frequent unplanned outages should not receive the same compensation as a facility whose availability is more reliable. It suggests that a transmission owner be precluded from recovering fixed costs during periods of unplanned outages that exceed some minimum threshold based on superior performance.

Cal ISO indicates that its tariff provides for the implementation of maintenance standards, and penalties under those standards, to ensure both adequate maintenance and system reliability. These provisions act in concert with the California ISO's authority to coordinate and approve maintenance outages.

Southern Company believes that the establishment of performance standards for transmission facilities controlled by an RTO is misplaced. Transmission owners plan and operate their transmission systems according to NERC and regional reliability standards, as well as State legal and regulatory requirements. Thus, while Southern Company doesn't claim that performance-based incentives are inappropriate, it points out that there already are existing standards to ensure reliable system operations.

Comments on Facility Ratings and Operating Ranges

Reliable operation of the transmission system in the short-term requires both continuous monitoring of equipment availability and loading, and actions to maintain loading levels within the established operating ranges and equipment ratings. The NOPR suggested that RTOs are best situated to establish ratings and operating ranges for two reasons. First, they will have the most complete information about expected and real-time operating conditions. Second, RTOs will be trusted because they will not have any economic interests in electricity market outcomes and they will not be owned or controlled by any market participants. The Commission proposed to let RTO established equipment ratings prevail in a dispute with a transmission owner pending the outcome of a dispute resolution process. [428]

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[428] FERC Stats. & Regs. ¶ 32,541 at 33,737-38.

Nearly all commenters that address this issue oppose the NOPR proposal. South Carolina Authority urges the Commission to proceed with caution to prevent avoidable damage to persons or property. SRP argues that ratings and operating ranges influence the useful life and maintenance cost of equipment, as well as the level of service to the end-use customer, and notes that each transmission owner has a legitimate interest in the ratings. SRP believes that the ideal situation would be to establish ratings by mutual consent of the transmission owner and RTO. If they cannot agree, the issue should go to dispute resolution.

NYPP and Mass Companies oppose this proposal because transmission owners have the fiduciary responsibility to protect their assets. Furthermore, they state that the rating of equipment necessarily requires a particularized knowledge of the equipment and related facilities that is unlikely to be possessed by the RTO.

Metropolitan believes that a well-established reliability organization is best suited for establishing maximum transmission line ratings that can be sustained over most of the hours in a year because it will include the cooperation of technical groups representing all systems, not just those under RTO control. It sees no benefit from moving this responsibility to RTOs when the reliability councils have historically performed this function with a minimum of controversy. EAL suggests that since the owner of the transmission facility assumes the equipment, personnel and public risks for the operation of its equipment, the RTO could fulfill an audit role to ensure that facility ratings by the owners follow industry norms.

Seattle suggests that the Commission instruct RTOs to work cooperatively with facility owners, since ratings on most power transmission equipment are a function of age and past usage, and a new entity will not have such historical information.

Southern Company states that transmission owners have responsibilities to their shareholders and State commissions to operate their equipment safely and reliably.

SPRA believes that this proposal has the potential to create significant liability risks for the United States.

Entergy believes that a transco has an advantage at performing this function because it will have the natural incentive to maintain the highest and safest ratings for the transmission facilities since it will be solely and directly responsible for the risks and rewards of equipment ratings.

Comments on Liability for Actions

Given that an RTO has responsibility for system reliability, the NOPR requested comments on the appropriate extent of an RTO's liability for its actions, and whether RTO facility ownership changes this determination. [429]

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[429] FERC Stats. & Regs. ¶ 32,541 at 33,738.

Most commenters believe that liability must be linked to the entity operating and controlling the transmission assets. Several commenters recommend that all RTO governing documents and operating agreements clearly establish the RTO's liability for any facilities that it operates but does not own. [430] SRP recommends that the Commission not set a hard and fast rule, but rather give deference to assignments of liability worked out between the RTO and the transmission owner in the course of negotiating an operating agreement.

Salomon Smith Barney believes that an RTO should be paid to run the network, and should suffer the consequences if it is not run well. Given this reasoning, it believes that an RTO requires sufficient capital to bear the risk, and that it operates under a regulatory scheme that acknowledges that higher risk taking requires a higher return.

Other commenters focus on how to apportion liability. Several commenters suggest that the governing standard for liability for a particular activity should be the same standard that the Commission has approved for comparable ISO conduct. Thus, for example, the RTO would be subject to liability only on account of its reliability activities when damage caused by its actions is found to be the result of gross negligence or intentional misconduct. [431]

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[430] See, e.g., Seattle, PGE, Desert STAR, PSNM, South Carolina Authority.

[431] See, e.g., NY ISO, Cal ISO, Nevada Commission, New York Commission.

Other commenters believe that, if the RTO assumes authority to ensure proper maintenance and reliability of the system, it should assume that role fully (i.e., assume liability for its decisions) and it should hold transmission owners harmless for any increased cost responsibility. [432]

Tri-State believes that an RTO should not be held liable for the inevitable errors and omissions that will occur during transmission system operations except in the instance of gross negligence. It believes that without some form of indemnification, the RTO could be the target of numerous lawsuits alleging financial harm as a result of RTO actions.

TANC believes that the RTO should be held liable for the consequential damages resulting from the RTO's instructions, if damage is caused to the transmission owners facilities as a result of the RTO requiring a transmission owner to operate its facilities in a manner that is inconsistent with prudent utility practice.

Comments on Reliability Standards

In the NOPR, the Commission expressed a potential concern regarding an RTO's implementation of reliability standards that are established by another entity. The Commission identified two specific concerns: (1) regional or sub-regional reliability groups may not be as independent from market participants as RTOs; and (2) almost

[432] See, e.g., Avista, Minnesota Power, SPRA, MidAmerican, Florida Power Corp.

every reliability standard will have a commercial consequence. The NOPR proposed to require an RTO to notify the Commission immediately if implementation of externally established reliability standards will prevent it from meeting its obligation to provide reliable, non-discriminatory transmission service. [433]

Most commenters generally support the proposal in the NOPR, although a few commenters believe that the NOPR proposal does not go far enough. On the other hand, some commenters seek clarification or oppose the NOPR proposal; most commenters that oppose the NOPR proposal believe that RTOs must be subordinate to national or regional reliability groups.

PJM/NEPOOL Customers and other commenters agree that the RTO is an appropriate institution to evaluate whether other rules and requirements are impacting its ability to perform its function and to inform the Commission of this fact. [434]

PSE&G requests that the Commission clarify in its Final Rule that RTOs, not reliability trade associations, will have primary responsibility for resolving reliability issues in the future. It suggests that reliability trade associations can continue to play a role in developing reliability standards to be incorporated into RTO tariffs; these standards would then be implemented by the RTOs and ultimately enforced by the FERC.

[433] FERC Stats. & Regs. ¶ 32,541 at 33,738-39.

[434] See, e.g., Entergy, NECPUC, NASUCA.

The standards, however, must be developed through a fair and open consensus process, such as the American National Standards Institute (ANSI) process.

EPSA believes that reliability standards should be uniform throughout the United States. Reliability standards should be established at the national level through an industrywide representative organization, subject to review and approval by the Commission. Reliability rules should deviate regionally only if necessary to reflect specific operating conditions that are unique to a particular region. EPSA requests that existing reliability rules be considered carefully by the RTO, and reviewed by the Commission, as to their function and importance. EPSA and other commenters suggest that RTOs replace existing regional reliability councils as the entity responsible for maintaining compliance with nationally established reliability standards. [435]

Conlon claims that the RTO must have the ability to establish various reliability standards that every participant. He suggests that the RTO, or the Commission with delegated authority to the RTO, set mandatory standards and impose sanctions or fines for violations.

Cal ISO believes that RTOs are the appropriate entities to establish reliability standards. Regional organizations (not a single national standard-setter) should have the flexibility to develop standards that reflect regional priorities as well as individual issues

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[435] See, e.g., Cal ISO, Duquesne, Nevada Commission, Statoil.

related to particular areas or configurations in the transmission grid. It recommends that RTOs have the authority and responsibility to develop regional reliability standards, subject to general oversight by an appropriate independent national reliability organization such as NAERO.

Similarly, Entergy believes that the RTO should have the primary role, authority and responsibility to adopt, implement and enforce regional reliability standards. Entergy further argues that this authority must be subject to regional oversight, especially as to reliability issues between and among interconnected RTOs.

Some commenters argue that the Commission should provide additional authority to RTOs. For example, PJM believes that an RTO should have exclusive authority for administering the regional reliability of the bulk power system. It argues that no entity external to an RTO's region should have authority to dictate reliability rules that adversely affect the reliability in a region served by an RTO. Thus, PJM believes the Commission should extend this proposal beyond the proposed reporting requirement. In its opinion, RTOs that are responsible for a particular area of the bulk power market system best can develop tools that are designed to meet the needs of their individual areas. PJM requests that the Commission insist in its rule that RTOs play a significant role in setting any national reliability standards. Sithe suggests that RTOs should also have independent authority to modify existing rules, and/or to place new rules before the

Commission for its review and approval in order to promote rules that intrude less into the markets and that promote efficiency goals, as well as system reliability.

Illinois Commission argues that the proposal is not adequate and that the Commission must more directly address the concern over lack of independence between reliability standards development, enforcement organizations and commercial market interests. Illinois Commission suggests some possibilities: (1) require NERC/regional reliability council reform so that the process of establishing and enforcing reliability guidelines, standards, and policies is independent of discriminatory generation/transmission owner influence; (2) require that all NERC/regional reliability council guidelines, standards, and policies be approved by FERC prior to their adoption; or (3) reform NERC so that it is independent of generation/transmission owners, then eliminate MAIN and ECAR and require the Midwest ISO to act as the regional standards setting entity and as the reliability enforcement entity for the Midwest Region.

A few commenters seek clarification. [436] British Columbia Ministry requests that the Commission clarify how the RTO roles and responsibilities overlap with duties outlined for the Self Regulating Reliability Organization in the North American Electric Reliability Council's draft legislation. New York Commission and Iowa Board request

[436]See, e.g., Canada DNR, Manitoba Board, Cal DWR, Entergy, Minnesota Commission, PSE&G.

that the Commission recognize the authority of the states to require the maintenance of electric system reliability.

NERC and several other commenters generally oppose the proposal. NERC urges the Commission to include an obligation that the RTO adhere to the reliability rules adopted by NERC and the relevant regional reliability council as a condition of becoming an RTO. NERC states that RTOs must be designed, implemented and operated consistent with NERC operating and planning policies. NERC notes it will revise its operating and planning policies to recognize and accommodate these emerging institutions, as necessary.

Several commenters such as Duke and SERC supports the work of NERC to establish consistently applied reliability standards and supports NERC’s authority to enforce these standards. Duke also supports NERC and the regional reliability councils continuing to play a vital role in setting reliability standards. NERC oversight of reliability should prevent different RTOs from applying different standards and will ensure that inter-RTO reliability matters will be dealt with effectively. CEA suggests that the reliability responsibilities authorized for RTO's be respectful of the carefully balanced design of the evolving NERC/NAERO.

SRP requests that each RTO be required to join NERC, or NAERO when formed. In addition, other commenters such as SRP and Los Angeles propose that RTOs be required to use planning and design criteria that comply with the criteria established by the appropriate NERC (or NAERO when established) regional reliability council.

NYPP believes that properly constituted local and regional reliability councils authorized by FERC should have the authority to establish criteria necessary to maintain the reliability of the transmission system including the reliability of discrete locations (e.g., the supply of reactive power to support voltage in load pockets). [437]

FirstEnergy requests that the role of the regional reliability councils be clarified with respect to regional RTOs. Also it would have us identify the need boundaries so that each RTO reports only to one regional reliability council. In addition, the regional reliability councils may need to undergo a transformation similar to NERC/NAERO to expand the role of the various industry segments.

Commission Conclusion

The Commission adopts the proposal in the NOPR that the RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates. Although many commenters support this requirement, some pose additional questions regarding how this function will be performed by the RTO. Some commenters request that the Commission define better the time period associated with "short-term" reliability. We clarify that the term "short-term" is intended to cover transmission reliability

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[437] The Commission has authorized the establishment of the New York State Reliability Council and has accepted the relationship between it and the NY ISO.

responsibilities short of grid capacity enhancement. It includes all time periods, including but not limited to "real-time," necessary for the RTO to satisfy its reliability responsibilities, up to the planning horizon. There is no time gap between what is included within short-term reliability and the RTO's planning responsibilities.

Commenters also request more specificity in describing the RTO's functions. The facilities that will be under RTO control, the specific functions that the RTO must perform, and how the RTO will execute its responsibilities and direct operations, are all defined above in the section on operational authority. PJM's additional request that the RTO have authority to collect information is discussed in both the operational authority and the market monitoring sections.

PG&E requests that the RTO rely on market mechanisms to maintain short-term reliability. PJM/NEPOOL Customers requests that reliability and commercial activities be kept separate. We will not require the RTO to rely on market mechanisms in every instance to maintain short-term reliability. The Commission believes that some reliability functions may not be conducive to supply through competitive market mechanisms since a reliable power system provided to one customer cannot be withheld from other customers, viz., many reliability functions are, in economic terms, "public goods." In Order No. 888, we identified some functions necessary to maintain grid reliability as ancillary services and required them to be provided as separate products. These services and their potential inclusion in emerging markets is discussed in the section on ancillary services below. We cannot conclude at this time that it is appropriate to rely solely on market mechanisms to supply the reliability functions that the transmission system operator must perform, but we expect that over time most of the generation services that perform these functions will be competitively procured.

Interchange Scheduling

We conclude that the RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules, which are often coincident with schedules for unbundled transmission service. This function will automatically be assumed by RTOs that operate a single control area. If the RTO structure includes control area operators who are market participants or affiliated with market participants, the RTO will have the authority to direct the implementation of all interchange schedules. As stated in the NOPR, a remaining concern is that non-RTO control area operators, who are also competitors in energy markets, have unequal access to commercially sensitive information and could use this knowledge of their competitors' schedules and transactions to gain an unfair competitive advantage in the energy markets. In the event that the RTO filing includes a structure in which non-RTO control area operators receive sensitive information, we will require the RTO to monitor for any unfair competitive advantage, and report to the Commission immediately if problems are detected. In addition, to address concerns about protecting commercially sensitive information, we will require the RTO or any entities who operate control areas within the RTO's region that require access to commercially sensitive information to sign agreements that separate reliability personnel and the relevant information they receive from their wholesale merchant personnel.

Redispatch Authority

We conclude that the RTO must have the right to order the redispatch of any generator connected to the transmission facilities it operates, if necessary for the reliable operation of the transmission system. [438] We also require each RTO to develop procedures for generators to offer their services and to compensate generators that are redispatched for reliability. In order to maintain the reliability of the transmission system, the entity that controls transmission must also have some control over some generation. In general, we believe this control should be through a market where the generators offer their services and the RTO chooses the least cost options. This authority does not extend to initial unit commitment and dispatch decisions for generators. However, for reliability purposes, the RTO should have full authority to order the redispatch of any generator, subject to existing environmental and operating restrictions that may limit a generator's ability to change its dispatch.

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[438] Redispatch for congestion management is addressed under different rules, as discussed in the section on congestion management.

Some commenters request that we define what is meant by redispatch for reliability. We clarify that we intend the authority for generator redispatch to be used by the RTO to prevent or manage emergency situations, such as abnormal system conditions that require automatic or immediate manual action to prevent or limit equipment damage or the loss of facilities or supply that could adversely affect the reliability of the electric system, or to restore the system to a normal operating state. [439]

Transmission Maintenance Approval

We conclude that, when the RTO operates transmission facilities owned by other entities, the RTO must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards. Control over transmission maintenance is a necessary RTO function because outages of transmission facilities affect the overall transfer capability of the grid. If a facility is removed from service for any reason, the power flows on all regional facilities are affected. These shifting power flows may cause other facilities to become overloaded and, consequently, adversely affect system reliability.

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[439] In general, a power system can be in one of three states: normal, emergency and restorative. When all constraints and loads are satisfied, the system is in its normal state; when one or more physical limits are violated, the system is in an emergency state; and when part of the system is operating in a normal state yet one or more of the loads is not met (partial or total blackout), the system is in a restorative state.

The RTO is expected to base its approval on a determination of whether the proposed maintenance of transmission facilities can be accommodated within established state, regional and national reliability standards. The RTO's regional perspective will allow it to coordinate individual maintenance schedules with other RTOs as well as with expected seasonal system demand variations. Since the RTO will have access to extensive information, it will be able to make more accurate assessments of the reliability effect of proposed maintenance schedules than individual, sub-regional transmission owners.

If the RTO is a transmission company that owns and operates transmission facilities, these assessments will be an internal company matter. However, if there are several transmission owners in the RTO region, the RTO will need to review transmission requests made by the various transmission owners.[440] In this latter case, we expect the RTO to: receive requests for authorization of preferred maintenance outage schedules; review and test these schedules against reliability criteria; approve specific requests for scheduled outages; require changes to maintenance schedules when they fail to meet reliability standards; and update and publish maintenance schedules as needed.

[440]Since some of these transmission owners may also own generation, they may have an incentive to schedule transmission maintenance at times that would increase the prices received from their power sales. A transmission company, not affiliated with any generators, would not have these same incentives.

We conclude that, if the RTO requires a transmission owner to reschedule planned maintenance, the transmission owners should be compensated for any costs created by the required rescheduling only if the previously scheduled outage had already been approved by the RTO.

We encourage the RTO to establish performance standards for transmission facilities under its direct or contractual control. Such standards could take the form of targets for planned and unplanned outages. The rationale for this requirement is that two transmission owners should not receive equal compensation if one owner operates a reliable transmission facility while the other operates an unreliable facility. For RTOs that are transcos, we will require that such quality standards be made explicit in any rate proposal.

Generation Maintenance Approval

We conclude that the RTO is not required to have authority over proposed generation maintenance schedules. However, we acknowledge that there are reliability advantages to the RTO having this authority, and we would accept RTO proposals where the participants choose to grant the RTO such authority. In our order approving the Midwest ISO, we observed that "the dividing line between transmission control and generation control is not always clear because both sets of functions are ultimately required for reliable operation of the overall system." [441] Because of this close connection between generation and maintenance of system reliability, it is essential for generator owners and operators to provide the RTO with advance knowledge of planned generation outage schedules so that the RTO can incorporate this information into its reliability studies and operations plan. However, although a generator may be required to submit its maintenance schedule to an RTO, the RTO should be prohibited from sharing that information with any other market participants, or affiliates of market participants.

Facility Ratings

After consideration of the comments, we conclude that is inappropriate here to require RTOs to establish transmission facility ratings. We encourage, however, such ratings to be determined, to the extent practical, by mutual consent of the transmission owner and the RTO, taking into account local codes, age and past usage of the facilities.

The Commission acknowledges the concern that changes in existing equipment ratings may lead to problems of equipment safety and possible damage. We further recognize that the RTO may initially need to rely upon existing values for equipment ratings and operating ranges so as not to disrupt reliable system operation. However, as an RTO gains experience operating or directing the operation of the transmission facilities in its region, we expect this responsibility to migrate to the RTO, as facility

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[441] Midwest ISO, 84 FERC at 62,180.

ratings have at least an indirect effect on the ability of the RTO to perform other RTO minimum functions (e.g., planning and expansion, ATC and TTC). If there is a dispute over equipment ratings, the parties should pursue resolution through an ADR process approved by the Commission.

Liability

After consideration, we will determine the extent of RTO liability relating to its reliability activities on a case-by-case basis.

Reliability Standards

We conclude that the RTO must perform its functions consistent with established NERC (or its successor) reliability standards, and notify the Commission immediately if implementation of these or any other externally established reliability standards will prevent it from meeting its obligation to provide reliable, non-discriminatory transmission service.

E. Minimum Functions of an RTO

In the NOPR, we proposed seven minimum functions that an RTO must perform. In general, we proposed that an RTO must:

(1) administer its own tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;

(2) create market mechanisms to manage transmission congestion;

(3) develop and implement procedures to address parallel path flow issues;

(4) serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders;

(5) operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC;

(6) monitor markets to identify design flaws and market power; and

(7) plan and coordinate necessary transmission additions and upgrades.

We basically affirm these seven functions with the clarifications and revisions as noted below. In addition, we have added interregional coordination as an eighth minimum function, as discussed below.

1. Tariff Administration and Design (Function 1)

Sole Administrator of Tariff

In order to ensure non-discriminatory service within the region, the NOPR proposed that the RTO be the sole administrator of its own transmission tariff. [442] The RTO would thus be the sole authority making decisions on the provision of transmission service including decisions relating to new interconnections. The NOPR requested comments on several aspects of this standard, including how the authority over

[442] FERC Stats. & Regs. ¶ 32,541 at 33,739-740. The authority to file changes in the RTO tariff is discussed above under the Independence Characteristic.

interconnections would work for ISOs that do not own transmission and would not be performing the construction. The NOPR also sought comment on whether authority over interconnection should apply to all new interconnections, including those for reliability and connections to other regions.

Comments

The vast majority of commenters addressing these issues agree with the proposal that the RTO be the sole administrator of its own tariff. [443] Commenters noted many of the benefits of an RTO being the sole tariff administrator: it will eliminate confusion; reduce transactions costs; assure that access decisions are independent; [444] reduce reliability concerns; [445] and ensure consistent ratemaking across the RTO. [446] Some commenters suggest that their respective organizations already meet this requirement, including ISO-NE and NY ISO, which ask whether sharing authority with transmission owners for non-discriminatory access meets the standard.

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[443] See, e.g., Allegheny, APX, SMUD, NASUCA, NY ISO, East Kentucky, Utilicorp, JEA, LG&E, Enron/APX/Coral Power, EPSA, South Carolina Authority, First Energy, Cal DWR, California Board, PacifiCorp and NSP.

[444] PJM.

[445] PJM/NEPOOL Customers.

[446] UAMPS.

But some of the commenters that support the proposal had specific concerns and suggestions: the Commission should adopt specific pricing regulations and expressly permit expedited declaratory orders on pricing; [447] the Commission should take a more active approach in developing innovative rates; [448] there may be a problem for an RTO located in both the United States and Canada if there is disagreement over the tariff by the respective authorities; [449] and quicker decisions are likely if a stakeholder board is not involved. [450]

A number of commenters also supported the proposal with respect to the RTO's authority over interconnections. [451] Some of these commenters expressed concerns and recommendations about the Commission's proposal, e.g., transmission owners should be a part of the decision process; [452] transcos will be better able to integrate interconnection decisions into a unified strategy covering investment, operations, maintenance and facility

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[447]Entergy.

[448]Illinois Commission.

[449]Canada DNR.

[450]New Smyrna Beach.

[451]See, e.g., Entergy, PJM, South Carolina Authority, Southern Company, Tri-State, Desert STAR, East Texas Cooperatives, Enron/APX/Coral Power, Sithe and PG&E.

[452]Cal ISO.

design; [453] RTOs should not have the authority to deny a generator that is not optimally located on the grid; [454] interconnection policy should rely more heavily on market mechanisms; [455] the transmission owner should develop the actual interconnection agreement to insure adequate protections for its equipment; [456] national fees and technical standards should be established for interconnections; [457] authority over interconnections should involve coordinated planning and construction, not "autonomous, unilateral authority"; [458] RTOs need to develop procedures and guidelines so that there are no adverse impacts of interconnection on existing facilities; [459] RTOs should have authority to assess the impact of a new interconnection on regional facilities but should only have

[453] Duke.

[454] Minnesota Power.

[455] PG&E.

[456] Southern Company.

[457] Distributed Power and EAL.

[458] SPRA.

[459] TANC.

authority over interconnections involving RTO facilities, not all regional facilities; [460] and an RTO must be required to show harm to deny an interconnection request. [461]

A few commenters opposed the Commission's proposal or suggested making significant modifications. With respect to tariff administration, Seattle opposes the Commission giving RTOs with small control areas blanket authority to approve new interconnections and also argues that the RTO should not be given authority over the interconnection of customer based backup and load shaving generators, QFs, or subtransmission and radial transmission facilities (used to reinforce municipal grids). TXU Electric argues that the Commission should be more flexible and allow RTOs to choose whether to administer the tariff of other entities. TXU Electric notes that in ERCOT, each owner has its own tariff with its own revenue requirement but with uniform terms and conditions of access and that this approach can protect the owner better than an RTO tariff. Florida Commission recommends that the question of tariff administration be determined on a regional basis with endorsement by state regulators.

With respect to RTO authority over interconnections, Mass Companies argues that the RTO should not have the authority over interconnections because such authority is unlawful, impairs reliability, and because the transmission owner is in a better position to

[460] Metropolitan.

[461] Williams.

perform this function. SRP suggests that an RTO’s exclusive right to administer its own tariff and the right to control interconnections may establish a property right that would jeopardize a public power’s tax free status by being declared a private business use. This would be a potential problem if the RTO were not a governmental entity or a 501(c)(3) non-profit organization. To prevent this, SRP says that the RTO would have to be structured carefully with these concerns in mind. DOE indicates that the authority over interconnection is a concern for PMAs because of the NEPA requirements which must be accommodated. Industrial Consumers would amend the proposed Regulatory Text on tariff administration to add "throughout the interconnection within which the Regional Transmission Organization resides" to the requirement to promote efficient use and expansion. Industrial Consumers also propose that the Regulatory Text on interconnection be amended to add the responsibility to coordinate transmission needs across the interconnection. Finally, Industrial Consumers would amend the provision that RTOs review and approve requests for new interconnections to add "by new loads that take service at transmission voltages and by any new generation resource regardless of the nominal voltage at the generator's point of interconnection. Any proposal to increase the nameplate-rated capacity at an existing generating site shall be treated as a new request for interconnection" to clarify that the RTO is to authorize such interconnections and minimize entry barriers to new sources of generation.

Commission Conclusion

We note the strong support for this standard in the comments and we adopt the NOPR's requirement that the RTO be the sole provider of transmission service and sole administrator of its own open access tariff. Included in this is the requirement that the RTO have the sole authority for the evaluation and approval of all requests for transmission service including requests for new interconnections. [462]

With the RTO the sole provider of transmission service, transmission customers have a nondiscriminatory and uniform access to regional transmission facilities. This type of access cannot be assured if customers are required to deal with several transmission owners with differing tariff terms and conditions. As noted in the NOPR, the RTO must be the provider of transmission service in the strong sense of the term. Mere monitoring and dispute resolution are insufficient to meet the requirements of this standard.

The requirement that the RTO administer its own tariff and not the tariff or tariffs of other entities received little objection in the comments, even from ISOs where this requirement is not currently being met. [463] One commenter, SCE&G proposes that the RTO's tariff only cover its own costs and wheeling. The transmission owners would

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[462] Of course, eligible applicants always have the right to seek interconnections from the Commission pursuant to sections 202(b) and 210 of the FPA.

[463] See, e.g., ISO-NE at 9.

maintain standard open access tariffs which would be administered by the RTO. We reject this proposal. To provide truly independent and nondiscriminatory transmission service, the RTO must administer its own tariff and have the independent authority to file tariff changes.

Mass Companies argues that the RTO is not in as good a position as transmission owners to judge requests for new interconnections. SPRA and Metropolitan suggest that an RTO's authority over new interconnections should be limited. Because the ability for customers to obtain nondiscriminatory access to the regional transmission system, whether over existing facilities or over new facilities, is integral to a competitive market for generation, we reject these proposals to modify our original position on new interconnections.

Other commenters, as noted above, support this standard but have specific concerns they would like to see the Commission address. The concerns listed do not cause us to change our original proposal. These concerns, to the extent they apply, should be voiced at the time RTO proposals are filed and they will be considered on a case-by-case basis.

Multiple Access Charges

The NOPR proposed that the RTO's tariff must not result in transmission customers paying multiple access charges. We affirm that proposal in this Final Rule.

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.[464] 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

[464] 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. [465]

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

[465] 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. [466] CSU believes that congestion management is uniquely

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[466] 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.[467] 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

[467] 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. [468] 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. [469] 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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[468] See, e.g., PJM, Professor Hogan, CSU, Sithe, NERA, Duke, PJM/NEPOOL Customers, H.Q. Energy Services, Minnesota Power, FTC.

[469] 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.[470] For example, Otter Tail contends that the RTO should have direct authority to order redispatch of generation for purposes

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[470] 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.[471] 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

[471] 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. [472] 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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[472] 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.[473] Some commenters specifically endorsed the proposed requirement that congestion pricing proposals must meet the two efficiency objectives set forth in the NOPR.[474] 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.[475] 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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[473]See, e.g., PJM/NEPOOL Customers, United Illuminating, Allegheny, EPSA, SMUD, Los Angeles, NASUCA, Duke, NERC, Professor Hogan, EME, PJM, DOE, CSU.

[474]See, e.g., PJM/NEPOOL Customers.

[475]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, [476] and others cited reasons to move cautiously. [477] 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. [478] 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

[476] See, e.g., LIPA, Transmission ISO Participants.

[477] See, e.g., EPSA, Tri-State.

[478] 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. [479] 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. [480] 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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[479] See, e.g., Allegheny, EME, United Illuminating, EPSA, SMUD, Los Angeles, NASUCA, CSU.

[480] 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. [481] 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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[481] 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. [482] Professor Hogan states that, with LMP, the security-constrained economic dispatch process would produce prices for energy at each location,

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[482]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. [483] 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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[483] 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. [484] 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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[484] 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-redispatch 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, [485] 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

[485] 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. [486] 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. [487] 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. [488] Seattle notes that with an

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

[487] See, e.g., DOE, NSP, Enron/APX/Coral Power, Seattle, Nevada Commission.

[488] 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.[489] 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.[490]

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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[489] See, e.g., NERA, Professor Joskow, Allegheny.

[490] 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.[491] 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.

[491] 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. [492] 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. [493] 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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[492] See, e.g., TDU Systems, NCPA, Los Angeles, Wyoming Commission, SMUD, South Carolina Authority.

[493] 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. [494] 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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[494] 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. [495]

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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[495] 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.[496] 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

[496]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. [497] 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

[497] 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. [498] 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

[498] See, e.g., Trans-Elect, FirstEnergy, Entergy.

managing congestion.[499] 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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[499] 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.[500] 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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[500] 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. [501] Others, however, believe that it is essential that the RTO have some form of congestion management system in place when it begins operation. [502] SMUD and CMUA state that a significant deterrent to participating in the Cal ISO has been the fact that, in California,

[501] See, e.g., Industrial Consumers, Allegheny, PGE, Entergy.

[502] 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 an 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 market in forward contracts for energy will not develop. As a result, these commenters claim, society will never obtain the efficiency benefits that would otherwise flow from a marketplace in which buyers and sellers are able to trade actively among themselves. These commenters also argue that the price certainty provided by forward markets will be replaced with the uncertainty of prices that are determined after the fact.

We disagree with these commenters and see no reason why the RTO's operation of a market for congestion management should inhibit the ability of others to offer forward contracts for energy, or other market instruments that provide price certainty. We recognize that some of the market redispatch programs undertaken to date are experimenting with various ways to manage congestion efficiently-including relying upon decentralized markets to effect the necessary redispatch. [503] It is too early to tell if these decentralized markets will work efficiently. But given the short time frame in which system operators often must react to congestion situations, experience may ultimately show that markets for congestion management can achieve more efficient and effective results if they are centrally operated. Therefore, we will not deny here the RTO, or other independent entity, the opportunity to operate a market-either centralized or de-centralized-for congestion management.

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[503] See, e.g., the market redispatch experiment of NERC (Docket No. ER99-2012-000).

As we proposed in the NOPR, we will require the RTO to implement a market mechanism that provides all transmission customers with efficient price signals regarding the consequences of their transmission use decisions. We are convinced that efficient congestion management requires that transmission customers be made aware of the cost consequences of their actions in an accurate and timely manner, and we believe that this is best accomplished through such a market mechanism. Also, as we proposed in the NOPR, we believe that congestion pricing proposals should seek to ensure that (1) the generators that are 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. Although we agree with some commenters that price signals can also assist in determining the efficient size and location of new generation and grid expansions, we share the view of LIPA and others that price signals alone cannot be relied upon to identify all needed enhancements.

While we will not prescribe a specific congestion pricing mechanism, we note that some approaches appear to offer more promise than others. As we stated in our order approving the PJM ISO and reiterated in the NOPR, markets that are based on locational marginal pricing and financial rights for firm transmission service appear to provide a sound framework for efficient congestion management.[504] A number of commenters express strong support for the LMP approach. As PJM notes in its comments, LMP

[504]See PJM, 81 FERC at 62,252-53.

assesses congestion charges directly to transmission customers in a manner consistent with each customer's actual use of the system and the actual dispatch that its transactions cause. In addition, LMP facilitates the creation of financial transmission rights, which enable customers to pay known transmission rates and to hedge against congestion charges. We further note that, where financial rights holders are entitled to receive a share of congestion revenues, the availability of such rights helps to address the concerns of commenters who fear that congestion pricing can lead to the over-recovery of transmission costs. The Commission recognizes, however, that LMP can be costly and difficult to implement, particularly by entities that have not previously operated as tight power pools.

The principal alternative to LMP advocated by commenters is an approach that manages congestion by means of physical transmission rights that are tradable in a secondary market. Under this approach, the RTO may be required to issue the transmission rights initially through an auction or allocation process. Market participants would then generally have to demonstrate ownership of sufficient rights in a constrained interface before they would be allowed to schedule firm service over the interface. Such an approach greatly reduces the role of the RTO in congestion management. While the approach of trading physical transmission rights in a secondary market may prove to be workable in regions where congestion is minor or infrequent, in other regions where congestion is more of a chronic problem, it may not be workable. Also, commenters such as NERA and Professor Hogan claim that the network interactions on complex electricity grids make it difficult to define physical transmission rights that will use the system fully and yet can be traded in decentralized markets. We expect RTOs and any affected stakeholders to consider carefully such issues as they formulate specific pricing proposals.

While our experience has shown that, in specific situations, some approaches to congestion pricing appear to have advantages over others, we have not yet identified one approach as being clearly superior to all others. Furthermore, the Commission recognizes that an RTO's choice of a congestion pricing method will depend on a variety of factors, many of which may be unique to that RTO. Therefore, we will allow RTOs considerable flexibility to propose a congestion pricing method that is best suited to each RTO's individual circumstances.

Some commenters appear to confuse the need to redispatch generators to maintain reliability with the need to take specific actions to relieve congestion. Commenters generally agree that the RTO should have clear authority to order redispatch for reliability purposes. However, for congestion management, we conclude here that the RTO should attempt to rely on market mechanisms to the maximum extent practicable. We recognize, of course, that there may be times when even well-functioning markets will fail to provide the RTO with the options it needs to alleviate a specific instance of congestion. In those cases, the RTO must have the authority to curtail one or more transmission service transactions that are contributing to the congestion. Although the act of curtailing a transaction may sometimes require the redispatch of generation, we clarify that we are not requiring the RTO to redispatch any generators exclusively for the purpose of managing congestion.

In the NOPR, we stated that a workable market approach to congestion management 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. Most commenters agree that these are reasonable features of any congestion management proposal. However, Enron/APX/Coral Power believes that the RTO should not be allowed to provide a hedging instrument. It contends that the "monopoly wires business" should not be allowed to encroach on what it views 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. In response, we note that, while decentralized markets may ultimately prove to be capable of providing such products, as these commenters claim, we do not yet have evidence to that effect. Therefore, in the interest of allowing RTOs flexibility to experiment with different market approaches, we will not prohibit the RTO from offering such products through markets that it may operate.

Finally, with regard to the timing of implementation of the congestion management function, we will adopt our proposal to allow the RTO to take up to one year after start-up to implement market mechanisms for managing congestion. Most commenters agree that some period of time is needed for implementation. However, a number of them indicate that the RTO must have some form of congestion management system in place when it begins operation. We agree, and clarify that, upon start-up, the RTO must have in place effective protocols for managing congestion while preserving reliability. Because the NOPR did not make this point explicitly, we do so here.

3. Parallel Path Flow (Function 3)

In the NOPR, the Commission proposed to require that an RTO develop and implement procedures to address parallel path flow issues within its region and with other regions. [505] The Commission noted that measures to address parallel path flow between regions may not necessarily be in place on the first day of RTO operation, and proposed to allow up to three years after start-up for this function to be implemented. [506] The Commission sought comments on whether such an additional implementation time period is warranted, and whether three years is an appropriate additional time period.

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[505] The terms "parallel path flow" and "loop flow" are sometimes used interchangeably to refer to the unscheduled transmission flows that occur on adjoining transmission systems when power is transferred in an interconnected electrical system.

[506] FERC Stats. & Regs. ¶ 32,541 at 33,743-44.

Comments

Virtually all commenters support the NOPR's proposal to require that an RTO develop and implement procedures to address parallel path flow issues as a separate function. [507] Industrial Consumers states that parallel path flow-related disputes will diminish as a result of RTOs addressing this issue. [508] But PGE notes that grandfathering existing transmission contracts may impede the RTO's ability to address loop flow.

Many commenters assert that parallel path flow and congestion management issues are closely related to one another since both the issues involve identification of power flows resulting from a specific transaction. [509] Therefore, they argue that any solution to parallel path flow should recognize this close relationship. For example, Industrial Consumers believes that an RTO can take preemptive actions against potential curtailment situations to manage congestion resulting from loading of chronically

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[507] See, e.g., ComEd, East Texas Cooperatives, EPSA, Industrial Consumers, LG&E, NASUCA, NSP, PJM, Southern Company and Williams. However, Cinergy argues that parallel path flows should not be considered as a separate function but should be considered as a characteristic under the scope and regional configuration because that will allow an RTO to address congestion management issues along with parallel path issues.

[508] Industrial Consumers also notes that the first sentence in the proposed regulation should be modified to read as: "RTO must develop and implement procedures to address parallel path flow issues within its region and with other regions in the interconnection within which it resides." (Suggested change underlined)

[509] See, e.g., EPSA, Florida Power Corp., FTC, Georgia Transmission, LG&E, Mass Companies, NSP and PJM.

constrained transmission interfaces due to loop flow. PJM suggests that the use of redispatch solutions like LMP not only is more efficient and beneficial to a competitive market, but is preferable to curtailing transactions under TLR to address congestion due to loop flow. South Carolina Authority is convinced that over the long run the problem of parallel path flow needs to be addressed as a planning issue, focusing on appropriate reinforcements to constrained transmission lines.

Many commenters recommend that an RTO should encompass as large a region as possible so that it can "internalize" most of the loop flow within its region. [510] However, others argue that the loop flow issue can be solved satisfactorily only if it is addressed at the interconnection level. [511] They believe that while a large RTO will "internalize" most of the parallel path flows within its region, parallel path flows between RTOs will remain. Some other commenters are convinced that cooperative efforts among regional entities works best when it comes to resolving issues such as parallel path flow issue. [512] NERC notes that it is in the process of developing the needed information system to address the parallel path flow issue on an interconnection basis and urges the

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[510] See, e.g., LG&E, Michigan Commission, NASUCA, New Smyrna Beach, NSP, PJM and South Carolina Authority.

[511] See, e.g., Cleveland, East Texas Cooperatives, Georgia Transmission, Industrial Consumers, NY ISO, Southern Company, TEP. Industrial Consumers note that several other issues need to be addressed at the interconnection level and not at the regional level. They are: ATC calculation, inadvertent flows and congestion management.

[512] Central Maine Reply at 9; NYPP Reply at 10.

Commission to direct the RTOs to work closely with it to coordinate efforts to resolve this issue. Southern Company and Industrial Consumers support NERC's initiative in solving the loop flow issue. Cleveland states that the national grid should be viewed as a single electrical system which calls for a universal approach rather than a regional approach to resolve the loop flow issue. The universal approach, Cleveland argues, will not only improve the integrity and reliability of the national grid but also eliminate the need for any policy shift in the future.

Commenters from Western System Coordinating Council (WSCC) assert that the loop flow issue in their region was solved by the adoption of WSCC Flow Mitigation Plan (Plan) that provides for controlling unscheduled flows through the use of phase shifting transformers.[513] SRP suggests loop flow in WSCC should continue to be addressed at the WSCC level and not at the RTO level because WSCC may end up with four or more RTOs. PG&E recommends that the establishment of property rights such as FTRs be explored as a means to solve loop flow issues, on the basis that developing property rights will ensure the most efficient use of the transmission lines. Enron/APX/Coral Power urges RTOs in the Eastern Interconnection to move toward the Western model. NASUCA believes that RTOs should perform a cost-benefit analysis of controlling loop flows with phase shifting transformers.

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[513] See, e.g., PG&E, Seattle, SRP and TEP.

Most commenters support the NOPR's proposal for an additional implementation time period of three years for coordination among RTOs.[514] They argue that the proper resolution of loop flow presents a number of complex issues that may require negotiations and agreements among neighboring RTOs and that the additional time period will give them an opportunity to coordinate their efforts. Allegheny supports an additional time period for implementation of this function but urges the contract path methodology be replaced at a faster pace than three years. Industrial Consumers notes that an additional time period of three years is necessary for NERC to solve the loop flow issue at the interconnection level. However, Florida Power Corp. and Florida Commission observe that the severity of parallel path flow varies from region to region and therefore opposes setting an arbitrary time limit for the implementation of this function. Duke likewise believes that the deadline for the implementation of this function should be determined by the Commission on a case-by-case basis.

Commission Conclusion

We reaffirm our preliminary determination that an RTO should develop and implement procedures to address parallel path flow issues within its region and with other regions. Most commenters agree that the formation of RTOs, with their widened

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[514]See, e.g., Cal ISO, Desert STAR, Entergy, Industrial Consumers, NECPUC, NERC, NY ISO, PGE, SRP, Tri-State, TVA, UtiliCorp and WPSC. Cleveland also argues that a similar grace period should be given for the implementation of function # 5. (TTC and ATC Calculation). Cleveland at 14.

geographic scope of transmission scheduling and expanded coverage of uniform transmission pricing structures, provide an opportunity to "internalize" most, if not all, of the effect of parallel path flow in their scheduling and pricing process within a region. NERC notes that it is in the process of developing the needed information system to address parallel path issues on an interconnection basis, and we will direct RTOs to work closely with NERC, or its successor organization, to resolve this issue. As noted by Industrial Consumers, parallel path flow-related disputes will diminish as a result of RTOs addressing this issue.

Commenters from Western System Coordinating Council (WSCC) state that they adopted the WSCC Flow Mitigation Plan (Plan) to address parallel path flow issue in their region. SRP suggests that parallel path flow in WSCC continue to be addressed at the WSCC level and not at the RTO level because WSCC may end up with more than one RTO. We will not here make any judgments on the merits of WSCC's Plan as a solution for parallel path flow issues. However, we clarify that this rule does not prevent addressing parallel path flow issues on a larger-than-single-RTO basis. In fact, we require RTOs to develop and implement procedures for addressing parallel flow issues with other regions.

In the NOPR we proposed that the RTO have measures in place on the date of initial operation to address parallel path flow issues within its own region. We also noted that measures to address parallel path flow issues between RTO regions may not necessarily be in place on the first day of RTO operation. We proposed to allow up to three years after start-up for this function to be implemented. Most commenters support the NOPR's proposal for an additional time period of three years. A few commenters [515] prefer a case-by-case approach. Since severity of the parallel path flow varies from region to region, some parts of the Nation may choose to resolve inter-regional parallel path flow issues sooner than the required three years. Consequently, we will adopt our proposal in the NOPR that the RTO have measures in place to address parallel path flow issues in its region on the date of initial operation. We also adopt three years as an adequate time period for implementation of measures to address parallel path flow issues between regions.

We recognize that these measures to address parallel path flows combined with the requirement that the RTO be the sole provider of transmission services over facilities that it owns or controls will eliminate or diminish the ability of transmission users to choose among different contract paths owned by different service providers within the RTO region. However, these users will have the ability to move power anywhere within the RTO at a single rate and under a single set of terms and conditions. We believe this is pro-competitive and represents one of the fundamental benefits that is envisioned by the Rule. As we noted in the NOPR, the creation of large RTOs that can internalize most, if not all, of the effect of parallel path problems through their scheduling and pricing actions

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[515] Florida Power Corp., Florida Commission and Duke.

provides a unique opportunity to resolve a major operating concern that has caused problems on both the Eastern and Western Interconnections and which is a significant impediment to promoting efficient competition in generation markets. [516] Therefore, in reviewing the competitive implications of a proposed RTO application under section 203, we believe that any inability of transmission customers to choose among different contract path suppliers within an RTO will be outweighed by their enhanced ability to reach numerous buyers and sellers of electricity throughout the region.

4. Ancillary Services (Function 4)

The fourth proposed minimum function is that the RTO must serve as the supplier of last resort for all ancillary services required by Order No. 888. [517] This supply obligation for the RTO is necessary because only the single grid operator will be able to provide certain ancillary services, not all transmission customers may be able to self-supply (some own generation, others do not), and because it typically is more efficient for the RTO to provide some ancillary services for all transmission users on an aggregated basis.

In carrying out this function, the Commission proposed that all market participants would have the option of self-supplying or acquiring ancillary services from third parties. In addition, the RTO must have the authority to decide the minimum required amounts of

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[516] See FERC Stats. & Regs. ¶ 32,541 at 33,744.

[517] FERC Stats. & Regs. ¶ 32,541 at 33,744.

each ancillary service and, if necessary, the locations at which these services must be provided; must be able to exercise direct or indirect operational control over all ancillary service providers; must promote the development of competitive markets for ancillary services whenever feasible; and must ensure that its transmission customers have access to a real-time balancing market.

Comments

Supplier of Last Resort

Comments on whether an RTO should serve as a supplier of last resort are mixed. A large number of commenters support the Commission's proposal, as written. [518] Detroit Edison believes that the RTO should serve as the sole supplier of ancillary services to transmission customers and that the RTO should be permitted either to purchase services directly from generation suppliers or to purchase generation resources for this purpose. First Energy believes that the RTO's obligation as the supplier of last resort for ancillary services cannot be eliminated, since it is the basis of reliability. [519]

On the other hand, a few commenters suggest that the Commission allow flexibility. Duke believes that an RTO should always have the responsibility for ensuring that transmission customers have arranged adequate ancillary service and that those

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[518] See, e.g., Entergy, Industrial Consumers, NECPUC, Cal ISO, EPSA, FirstEnergy, LG&E, PacifiCorp, Empire District, EME, Southern Company, UtiliCorp, PGE, PNGC, PSNM, TDU Systems, Nevada Commission.

[519] See also Florida Power Corp.

services are delivered. They suggest that where a competitive market for ancillary services exists, the RTO should not be required to provide such ancillary services as a supplier of last resort. [520] And a number of commenters take issue with one or more aspects of the proposed requirements, although many of these commenters generally support the proposal.

For example, some commenters suggest that more information is needed. Southern Company suggests that the Commission allow NERC to finalize an ancillary services policy before mandating changes to ancillary service requirements. [521] Professor Hogan suggests further investigation into developments in ancillary services. [522]

Other commenters believe that the focus of the proposal should be narrowed. Los Angeles suggests that an RTO should be the "safety net" of last resort for providing generation-based ancillary services. As such, the RTO would not play a significant role in the energy market and can remain essentially indifferent to energy market issues. PG&E believes that an RTO could set appropriate rules for ancillary services but would not itself procure such services from the marketplace absent clearly defined emergency

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[520] See, e.g., NASUCA, Seattle, CalPX, Mass Companies.

[521] Southern Company notes that NERC's Interconnected Operations Services Working Group is currently addressing the ancillary services that should be required in a competitive environment and has issued a proposed policy for public comment and review.

[522] NWCC recommends that additional research regarding the application of ancillary services to wind and other intermittent generation technologies be conducted.

situations or in its role as provider of last resort. Avista states that while a transitional "supplier of last resort" role may be appropriate, an RTO should generally not become deeply involved in any of the markets for generation services.

A number of commenters suggest that the obligation to provide ancillary services should be expanded to include more or different sellers. MidAmerican believes that each control area should retain responsibility for the provision of ancillary services and should be allowed to self-provide or acquire necessary ancillary services in the most economical means it sees fit to meet performance compliance standards. East Texas Cooperatives suggests that the Commission require both transmission owners and the RTO to offer ancillary services at cost-based rates unless a seller can demonstrate a competitive market in a particular ancillary service. PPC and Desert STAR also believe that the role of provider of last resort of ancillary services would better rest with local control areas or independent generators that can supply ancillary services. Steel Dynamics requests that the final rule require generation-owning members of RTOs to maintain Commission approved cost-based tariff schedules for ancillary services. Georgia Transmission believes that any RTO members that are capable of providing ancillary services should be the providers of "first resort," and the ability to acquire such services from different providers would enhance competition in these markets.

While not specifically objecting to the RTO being the supplier of last resort for ancillary services, some parties suggest that the Commission should allow other mechanisms to work.[523] California Board urges the Commission to allow consideration of other means for ensuring that the need for ancillary services is addressed. It recommends that the final rule reflect a requirement that the RTO filings must indicate how default provision of ancillary services will be accomplished without necessarily requiring the RTO to be the provider of last resort. Enron/APX/Coral Power advocates a form of performance-based ratemaking in which the RTO would have an incentive to perform its ancillary service function as efficiently and economically as possible. Florida Commission recommends that an RTO only be responsible for providing non-competitive ancillary services and should require users to purchase or self-provide the other competitive services.

Similarly, FTC suggests that the Commission consider arrangements in which the RTO's primary role is to provide a market mechanism for transmission customers to acquire ancillary services for themselves. It argues that this method may reduce costs by allowing customers to customize their purchases of ancillary services to better fit their specific needs.[524] Some commenters suggest that final RTO regulations expressly recognize the administration of an ancillary service exchange as an alternative to the provider-of-last-resort obligation that is imposed on a RTO under the proposed

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[523] See, e.g., CMUA, LPPC, California Board, San Francisco, Oneok, SMUD, Avista, Sithe, Seattle.

[524] See also Empire District.

regulations.[525] For example, ISO-NE believes that a competitive market for ancillary services is a superior supply mechanism, and ISO-NE suggests that the text of proposed § 35.34(j)(4) be amended to read:

> An RTO must develop and maintain a market or other contractual arrangements for the supply of all ancillary services required by Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders.

Comments were also sought on the circumstances under which an RTO's obligation as supplier of last resort could be eliminated.[526] Several commenters believe that the supplier of last resort obligation can be eliminated once a viable competitive market develops within the RTO region.[527] For example, WPSC suggests that an RTO must continue to fulfill the role of supplier of last resort for these services or a power exchange must be available to supply these services. WPSC believes that it would be difficult to predict the circumstances under which the market for ancillary services is sufficiently robust that the RTO's role as supplier of last resort may be eliminated. WPSC believes that it would be a mistake to eliminate that role in any market where the generation market concentration levels as measured by the Herfindahl-Hirschman Index exceed 1,800. TDU Systems states that it is not aware of a market in any of the ancillary

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[525] See, e.g., Cinergy, APX, EAL, NY ISO, JEA.

[526] FERC Stats. & Regs. ¶ 32,541 at 33,745.

[527] See, e.g., WPSC, APS, Florida Commission, Duke.

services that is now sufficiently competitive to warrant elimination of an ancillary service from this obligation. However, TDU Systems acknowledges that there may never be a competitive market for certain ancillary services and that an alternative mechanism must be created.

The NOPR also asked for comments on whether a different set of ancillary services requirement for RTOs is needed because RTOs will not own generating resources. Comments on this issue were mixed.

Sithe and several other commenters [528] generally believe the Commission's initial set of guidelines on ancillary services is reasonable, and that a new set of ancillary services requirements for RTOs is unnecessary. LG&E adds that, as already is the case under the open access tariff, an RTO should be allowed to choose to add to the list of ancillary services in recognition of local or regional conditions. MidAmerican believes that while no additional or revised ancillary services are required, an RTO must ensure that sufficient transmission capacity is available to allow delivery of backup supply, planning reserves and the existing six ancillary services.

On the other hand, Los Angeles believes that a different set of ancillary services requirements than those required currently from a vertically integrated utility should apply to an RTO which does not own generation resources. They envision an ultimate industry structure of complete desegregation of generation and transmission assets so that

[528] See, e.g., PGE, TDU Systems, Cal ISO, Duke, Tri-State.

any incentive (either real or perceived) for the transmission provider to act in a discriminatory manner is eliminated.

NSP requests that the Commission refer to the draft NERC policy that discusses the role of an operating authority as an unbundled procurement agent for community ancillary services. They describe this document as a good "guidepost" for the Commission to follow in the RTO NOPR, and for the establishment of additional ancillary services such as system blackstart and frequency responsive reserve. [529] Desert STAR and Cal ISO agree that additional blackstart ancillary service may be required. TDU Systems believes that RTOs should be required to offer backup service and an additional load following service. It describes backup service as required to meet contingencies during periods following those covered by the OATT's reserve services, and load following service as required to complement the OATT's minute-to-minute regulation service with a service matching hour-to-hour variations in load. Industrial Consumers recommends that the Commission remove Schedule 4 (energy imbalance service) from any tariff administered by an RTO. They suggest that this service be provided by the real-time balancing market as proposed in the NOPR.

Self-Supply Option

Nearly all who commented on the self supply option generally agree that, where feasible, all market participants should have the option of self-supplying or acquiring

[529] See also Eric Hirst.

ancillary services from third parties.[530] Some commenters strongly endorse the self-supply model. For example, APS believes that it should be the aim of the RTO to have each transmission customer self-supply its generation-related ancillary service requirements to the fullest extend practical. Los Angeles suggests that the role of the RTO should be limited to ensuring that the transmission customer has adequately provided for the necessary ancillary services for each transaction, and the RTO provide such services only in the event of non-compliance. It believes that the RTO should develop specific rules and protocols that would support the self-provision of ancillary services. Some commenters, including PJM/NEPOOL Customers and LG&E, suggest that it is important for the development of a competitive market in ancillary services that RTO customers not be required to purchase them from the RTO, and that an RTO must not prohibit or interfere with the ability of all market participants to have the option of acquiring competitive ancillary services or providing such services through buy/sell transactions from customer-owned generation.

On the other hand, FirstEnergy states that the Commission should be very cautious that policies that encourage self-supply of ancillary services do not compromise the very ability of the RTO to ensure reliable and secure network operation. It maintains that the provision of "self-supplying" ancillary services is untested, the infrastructure needed is as

[530] See, e.g., CMUA, Cal ISO, LG&E, PG&E, PJM/NEPOOL Customers, PPC, APX, Metropolitan, MidAmerican, NSP, Seattle, SMUD, Desert STAR, TDU Systems, Tri-State.

yet undeveloped, and the process of providing them could potentially lead to abuses. FirstEnergy identifies this issue as one of the reasons that NERC is pushing for mandatory compliance requirements. [531] It believes that an RTO must have the ability to evaluate and accept/approve those NERC-certified sources that reliably contribute to support the grid.

Authority to Determine Amounts and Location of Ancillary Services

Most commenters generally support the proposal that the RTO have the authority to determine the quantities and, where appropriate, the location at which ancillary services must be provided. [532] In addition, CMUA suggests that the RTO be responsible for enforcing compliance with established standards.

PJM/NEPOOL Customers requests that RTO decisions regarding the amounts and locations of ancillary services consider both stakeholder input and NERC standards. It believes that this requirement would ensure that the RTO does not impose unnecessarily high ancillary service obligations that will inhibit the operation of the competitive market. In addition, PJM/NEPOOL Customers asks that the Commission ensure that the RTO exercises this authority only to the extent necessary for reliability purposes, since

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[531] FirstEnergy notes that NERC is developing certification and verification criteria for ancillary service providers.

[532] See, e.g., Industrial Consumers, PJM, Turlock, Cal ISO, Florida Power Corp., PJM/NEPOOL Customers, LPPC, PGE, SMUD, TDU Systems, NYPP, Tri-State, Nevada Commission.

decisions regarding ancillary services could impact the competitive electricity supply market.

NYPP requests that the RTO's authority not be exclusive. It suggests that properly constituted local and regional reliability councils authorized by FERC should have the authority to establish criteria necessary to maintain the reliability of the transmission system including the reliability of discrete locations.

Duke notes that the Commission has previously recognized NERC's leadership role in developing concepts in the area of ancillary services. [533] It encourages the Commission to recognize and adopt NERC's development of ancillary service definitions and reliability standards. [534]

Industrial Consumers and Steel Dynamics request that the Commission first approve the standards by which the RTO determines the requirements. They requests that these standards include the development of "metrics," i.e., standardized units of measurement such that the performance of each service can be verified. In addition, Industrial Consumers recommends modifying the requirement to ensure seamless application between multiple RTOs and for transactions that only go through an RTO. It suggests adding an additional requirement to § 35.34(j)(4)(ii):

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[533] Citing FERC Stats. & Regs. ¶ 31,036 at 31,705 (1996).

[534] See also Eric Hirst.

> The Regional Transmission Organization must support the minimum required amounts of each ancillary service for transactions between itself and other Regional Transmission Organizations in the interconnection and through itself.

Control Over Ancillary Services Providers

All commenters that commented on this subject believe that the RTO should be able to exercise some operational control, either directly or indirectly, over any supplier of ancillary services.[535] SMUD supports the RTO establishing well documented and specific operating criteria and the ability to require compliance with such operating criteria, including monetary penalties and commission-approved sanctions. JEA believes that this control should be exerted only where pre-existing contractual rights are established.[536]

Some commenters would broaden the requirement. For example, FirstEnergy is concerned that limiting the RTO's control to ancillary services providers rather than all generation located within the RTO may compromise the RTO's ability to operate the transmission system reliably. It suggests that the Commission allow a greater flexibility for the RTO and all generation owners located within the RTO to develop an agreement for provision of ancillary services through the RTO that provides for the necessary requirements for voluntary generation participation in the ancillary services market

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[535] See, e.g., PJM, Cal ISO, Florida Power Corp., Cinergy, Los Angeles, PSNM, SMUD, Duke.

[536] See also Cinergy.

including operational control if appropriate, and the necessary requirements for calling on ancillary services from connected generation necessary for the reliable operation of the transmission system.

On the other hand, PJM/NEPOOL Customers suggest that the RTO control be limited to those providers that the RTO will rely on to fulfill its obligation as supplier of last resort for ancillary services. It claims that control over additional generators is unnecessary and may affect the operation of the competitive market.

Metropolitan recommends that the Commission allow RTO indirect control of existing large hydroelectric plants to protect and facilitate use of existing systems that have been operational for a substantial period of time and to preserve the integrity of the FERC hydro license. It states that allowing indirect control would eliminate the need for costly installation of software and infrastructure. [537]

Promote Competitive Markets for Ancillary Services

Most commenters support the proposal in the NOPR that RTOs promote competitive markets for ancillary services. [538] Seattle suggests that the RTO provide incentives to ensure a robust, transparent market with many buyers and sellers of ancillary services. PJM/NEPOOL Customers states that it is important that the RTO not impede the development of competitive markets for ancillary services and that the RTO

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[537] See also NYPP, PSNM.

[538] See, e.g., FTC, LPPC, Avista, APX, PJM/NEPOOL Customers, Seattle.

actually facilitate the development of these markets. However, it stresses that the RTO and incumbent transmission owners should not be permitted to have market-based rates for ancillary services until a viable competitive market for such services develops.[539]

Sithe advocates that the final rule grant RTOs the authority to administer spot markets for ancillary services and establish rules obligating all participants to meet uniform requirements. PG&E believes that the RTO should not be the sole purchaser of ancillary services. Instead, it should facilitate the development of bilateral markets for as many of the ancillary services as possible, thereby allowing market participants to self-provide those ancillary services.

Access to Real-Time Balancing Markets

In the NOPR, the Commission proposed that an RTO must ensure that its transmission customers have access to a real-time balancing market. We proposed that the RTO must either develop and operate such markets itself or ensure that this task is performed by another entity that is not affiliated with any market participant. The Commission noted that although system-wide balancing is a critical element of reliable short-term grid operation, this does not necessarily require that there be a moment-to-moment balance between the individual loads and resources of bilateral traders and load-serving entities and the schedules and actual production of individual generators. We also noted that unequal access to balancing options for individual customers can lead to

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[539] See also TDU Systems.

unequal access in the quality of transmission service available to different customers, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. The Commission proposed to give RTOs considerable discretion in how a real-time balancing market would be operated.

We invited comments on the use of market mechanisms to support overall system balancing and imbalances of individual transmission users. In addition, we invited responses to the following questions. Is it feasible to rely on markets to support a function that is so time-sensitive? Can such markets be made to function efficiently if the RTO is not a control area operator? For the imbalances of individual transmission customers, should a distinction be made between loads and generators? Should customers have the option of paying for all imbalances in such a market or only imbalances within a specified band?

Several commenters hold the view that it is indeed feasible to rely on markets to support a balancing function that is time-sensitive, [540] and many agree that access to a real-time balancing market would be of considerable benefit to market participants. [541] NERA claims that technical logic dictates that an electricity system have a central process to co-ordinate real-time physical operations. NERA argues that to the extent that this

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[540] See, e.g., Duke, PJM, Illinois Commission, Cal ISO, NERA.

[541] See, e.g., Enron/APX/Coral Power, Eric Hirst, NYPP, Powerex, East Texas Cooperatives, Industrial Consumers, Professor Hogan.

process is not based on markets, it must be based on less efficient command-and-control methods. NERA also claims that economic and commercial logic requires that a commodity market have short-term trading arrangements to bring market positions into agreement with physical reality, and argues that to the extent that market trading does not reflect physical reality, some non-market process must close the gap between the market and reality. NERA asserts that these two propositions imply that the best way to maximize the role of the market and minimize the role of non-market processes is to base real-time physical operations on a spot market and to allow market participants to use this market for commercial purposes to the extent they find this useful.

Enron/APX/Coral Power states that access to a real-time energy balancing market is central to assuring comparability in open access, and Industrial Consumers believes that this proposal is the beginning of a much needed "paradigm shift" in the manner in which ancillary services are defined and provided in the marketplace. Eric Hirst states that implementation of a real-time balancing market would permit FERC to eliminate the Order No. 888 requirement that transmission providers offer an energy imbalance service to transmission customers. He argues that elimination of energy imbalance service, with its awkward and arbitrary deadband and penalty payments, would be a pro-competitive change. Professor Hogan claims that without an efficient spot market and the associated transparent spot prices, it will be much more expensive and difficult to arrange balancing and settlement for the increasing number of retail access programs in the states. East

Texas Cooperatives agrees that real-time balancing markets are desirable but believe that simply commanding RTOs to promote the development of competitive markets for ancillary services provides no incentive for the RTO and its members to do so.

Also, two commenters argue that access to real-time balancing markets would eliminate some significant barriers to entry for non-traditional resources such as renewable and distributed energy. [542] In particular, EPA notes that providing such access would eliminate arbitrary energy imbalance penalties that are a major barrier to intermittent resources such as wind and solar energy.

Some commenters believe that the RTO itself should develop and operate a real-time balancing market. [543] PJM/NEPOOL Customers believe that the development of such a market is an essential function of the RTO that will facilitate the further development of retail competitive supply markets. PJM states that a real-time balancing market can best be provided through a power exchange operated by an RTO. Commenters are divided as to whether the development of a real-time balancing market requires that the RTO be a control area operator. Several believe that such markets are possible whether or not the RTO operates a control area. [544] Indeed, MidAmerican believes that, to function efficiently, these markets normally must operate in a region that

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[542] See EPA and Project Groups.

[543] See, e.g., PJM, PJM/NEPOOL Customers, Professor Hogan, NERA.

[544] See, e.g., Tri-State, Illinois Commission, MidAmerican, Duke.

is larger than a typical control area. However, others take an opposite view. [545] FirstEnergy, for example, argues that the timing, dispatch and telecommunications infrastructure needed to operate a real-time balancing market today can only be done by a control area operator and then only for a combined load within a control area with ample generation resources under automatic generation control.

Some commenters provide detailed recommendations regarding the rules that should govern the RTO's operation of real-time balancing markets. [546] Professor Hogan notes that the complex network interactions in an electric grid require that there be an entity that can provide certain critical coordinating services, and that the most obvious example of such services is energy balancing. He states that the operator should offer an energy balancing redispatch service where market participants can make offers to buy and sell energy.

He believes that the best approach would be to run the balancing market as a "bid-based, security-constrained economic dispatch" with voluntary participation by generators and loads. Professor Hogan emphasizes that the RTO must not reject voluntary bids, stating that the natural extension of open access and the principles of choice would suggest that participation in the coordinated balancing market offered by the operator should be voluntary. He states that market participants can evaluate their

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[545] See, e.g., PJM/NEPOOL Customers, Southern Company, FirstEnergy.

[546] See, e.g., Professor Hogan, Allegheny.

own economic situation and make their own choice about participating in the operator's economic dispatch or finding similar services elsewhere. He believes that any other rule would require some form of discrimination, and adds that there should be a strong burden of proof for those who argue that it is necessary to restrict voluntary bids, or discard consideration of some bids. Professor Hogan claims that experience in PJM and elsewhere shows that his suggested approach can work.

However, several commenters take a very different view, claiming that the development of a real-time balancing market is not a viable option. [547] For example, FirstEnergy is concerned that a real-time balancing market is not practical to implement. It claims that transmission customers do not yet have the real-time metering and associated communication needed to dispatch and match fluctuating loads to generation. FirstEnergy argues that it would be much better to tie this service to the NERC effort of certifying ancillary service providers for control of generation, and activate the service when the technology and installation can be accommodated. Seattle states that it performs its own real-time energy balancing and expects to continue to do so. Seattle opposes adding this function to an RTO because Seattle believes it will increase the overhead costs of the organization. Seattle believes that market participants that require this service should contract with third parties that stand ready to provide it. Florida Power Corp. states that, given the complexity of implementing short term transmission

[547] See, e.g., Seattle, FirstEnergy, Florida Power Corp..

service in general, it is difficult to imagine that a market for energy imbalance service could be developed. It argues that if the market is limited to the generators needed for control, the development of market mechanisms will depend on resolving issues such as the mitigation of potential market power. Florida Power Corp. suggests that an RTO could contract with generators to perform this balancing function using a mechanism that is market-like in that generators would be selected based on their bids to perform the function over some designated period of time, albeit not on an hourly basis.

Several commenters believe that control areas or RTOs should not be the sole provider of energy imbalance services, [548] while others argue that the role of RTOs should be limited to that of a supplier of last resort. [549] UtiliCorp states that, in addition to serving as a supplier of last resort, the RTO must ensure public access to real-time balancing information. SMUD argues that any burden on the RTO that falls outside of the core function of ensuring regional transmission reliability will add cost and complexity to an already costly and complex endeavor. SMUD recommends that the Commission should limit its focus on generation to the role that generation-related service plays in promoting reliable transmission. Desert STAR and FirstEnergy believe that the Commission should give deference to RTOs regarding the development of markets for real-time balancing.

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[548] See, e.g., Southern Company, Tri-State.

[549] See, e.g., UtiliCorp, Avista, APX..

FirstEnergy believes that, ultimately, ancillary service provision must be based on a free-market pricing mechanism, and Southern Company believes that if a real-time balancing market is desired in a region, it will develop without a mandate. FirstEnergy asserts that the detrimental effects of regulated and capped ancillary service markets have been observed in the California and PJM markets. Also, APX believes that the Commission should let the market, not the RTO, provide the trading arrangements in the power industry. APX asserts that efficiency in the competitive market comes from the de-centralized trading activity of self-interested buyers and sellers, and that competition will develop further when market participants self-provide their ancillary services which they acquire in forward contract markets. In APX's view, the RTO should not provide a centrally optimized dispatch because a central dispatch 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. To the extent that the RTO must acquire ancillary services, including balancing services, APX believes that the RTO should acquire them from a market created by market participants, and not create its own markets. NERA, however, states that this argument ignores the fact that preventing the ISO from operating balancing markets does not eliminate the network interactions and real-time events that are inherent in any electricity network. Rather, according to NERA, it merely forces the ISO to manage these interactions and events by less efficient and more intrusive non-market means. NERA contends that if the objective really is to maximize the role of competitive market forces and minimize the extent to which the monopoly ISO determines the outcome, the ISO should operate market-clearing mechanisms that reflect network interactions and real-time events as accurately as possible. Similarly, ISO-NE claims that it does not understand how operating a market in which (as in New England, currently) an RTO does not buy and sell the pertinent commodities can constitute "taking a position" in those markets such that its operation is perceived as biased. ISO-NE believes that because it does not own market assets or commodities, an ISO-type RTO is exceptionally well situated to run a fair and non-discriminatory market. ISO-NE states that the linkages among transmission operation/dispatch, generation commitment/dispatch, and economic and market forces strongly support the integration of a physical market with an RTO's operations. Nevertheless, ISO-NE states that other financial power markets are welcome and can co-exist in the same region with an RTO market.

Several commenters offered their views as to whether unequal access to balancing options leads to unequal access in the quality of transmission service available to different customers, and whether this is a significant problem when RTOs serve some customers that operate control areas and other customers that do not. [550] A number of

[550] See, e.g., Enron/APX/Coral Power, LG&E, PJM/NEPOOL Customers, FirstEnergy, TDU Systems, Florida Power Corp..

commenters believe that the present system does lead to undue discrimination. [551] Enron/APX/Coral Power states that both the NERC and pro forma tariff rules are inequitable and discriminatory in that large customers rarely will be significantly out of balance due to the law of large numbers. Enron/APX/Coral Power states that such customers are given great flexibility to balance their scheduled deliveries and load, while smaller customers are much more likely to exceed the 1.5 percent deviation band, making them immediately subject to penalties. Enron/APX/Coral Power believes that by offering real-time balancing to all transmission customers, the NOPR promises to redress this inequity. TDU Systems recommends that, pending the development of competitive balancing markets, the existing inequity between control area operators and other users be partially redressed by enlarging the deadband for imbalances to be repaid or received in kind to no less than five percent of scheduled amounts. It also recommends that the penal character of these charges should be reduced to a ten percent premium, except in cases of abuse.

PJM/NEPOOL Customers argue that, to the extent current control area operators wish to maintain access to inadvertent energy accounts to pay back imbalances and avoid penalties, other transmission customers must have the same opportunity. In the alternative, it recommends that all users be required to cash-out through the RTO balancing process. Utility Engineers recommends implementing a pricing plan for

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[551] See, e.g., Enron/APX/Coral Power, PJM/NEPOOL Customers, TDU Systems.

inadvertent interchange by participants of the RTO, where the price for inadvertent interchange is geographically differentiated to reflect losses and constrained transmission paths. They claim that such a pricing plan would need a continuous auction, which could be achieved through establishing a pricing formula.

With regard to providing access to inadvertent energy accounts, other commenters argue that there are valid reasons for distinguishing between customers that are control areas and those that are not. FirstEnergy argues that no other entity, other than control areas, can or should have that access to inadvertent accounts. It claims that, if market participants are provided with the authority to "go inadvertent" as control area operators currently have, the strain on the grid would drastically degrade system reliability, requiring much higher reserve capacity requirements. FirstEnergy believes that marketers would "borrow" from the grid during high price time periods and make whole on their borrowing during low price time periods, thus distorting the true price signal. Florida Power Corp. notes that in addition to balancing generation against load, control area balancing also includes a requirement for contributing to the maintenance of system frequency. In contrast, it notes that the non-control area transmission customer's balancing requirement is limited to the directly measured load it serves. Florida Power Corp. also claims that, if a system of payments was substituted for the inadvertent payback system presently used, control area operators would simply be circulating large sums of dollars between themselves to accomplish the same result at a higher administrative cost. LG&E suggests that the Commission treat such technical issues separate from the RTO NOPR and work in conjunction with NERC’s parallel efforts in this area. Also, Florida Commission believes that inadvertent energy accounting between control areas should continue to be allowed within the operating standards of NERC.

With regard to any requirement that loads and resources must be in balance from moment-to-moment, Professor Hogan and Eric Hirst believe there is no need for individual loads and generation to balance their schedules separately, and PJM/NEPOOL Customers states that balancing should be required only to ensure that generators deliver the amount scheduled and committed. Professor Hogan argues that individual balancing requirements both complicate the task for the RTO and provide a device to reinforce market power. Eric Hirst states that the RTO's costs of providing or absorbing imbalance energy should be charged equitably to those that under-generate and over-consume, with compensation to those that over-generate and under-consume. He states that this will result in charges and payments netting roughly to zero in each hour. However, Enron/APX/Coral Power believes that any RTO proposal should include development of an ex post energy balancing market in which buyers and sellers are given a finite amount of time after the market has closed to find others with offsetting positions.

Regarding the imbalances of individual transmission customers, commenters disagree as to whether a distinction should be made between loads and generators. MidAmerican and Florida Power Corp. believe that loads and generators should be treated differently. MidAmerican contends that it is much easier to control generators than it is to control load, and in the future managing imbalances will become more complex in that control from the load-side will involve the response of potentially thousands of entities that may or may not respond as quickly as central generation. MidAmerican states that a distinction exists between loads and generators both in magnitude and response time. Florida Power Corp. claims that load and generators are not always similarly situated. It states that the nature of energy imbalance service depends on whether a generator and the load that it serves are in the same control area or are in different control areas. Eric Hirst, TDU Systems, and Duke believe that, in general, the market rules and principles should be the same or comparable for generators and loads, although TDU Systems believes that loads may be less likely than generators to abuse the system by leaning on it. Eric Hirst states that the use of imbalance markets would eliminate the asymmetry between generation and load in FERC's definition of energy imbalance.

Finally, the NOPR also asked whether customers should be able to pay for all imbalances in a market or only imbalances within a specified band. Duke believes that it is appropriate to let the market participants determine how imbalances will be determined and paid. PJM/NEPOOL Customers believes that the RTO should provide transmission users with as many service offerings as possible, including the ability to opt for different balancing pricing proposals. Florida Power Corp., however, believes that there should only be one method of settling the imbalance market. It claims that complexity and opportunities for gaming increase with options for settlement.

MidAmerican believes that transmission customers should pay for all energy imbalances caused by the mismatch of scheduled energy and actual load. It recommends that imbalance charges be based on market prices at the time the imbalance occurred, and should include a penalty, in appropriate circumstances, to deter future imbalances. MidAmerican contends that if transmission customers are allowed to avoid payment within a specified bandwidth, gaming of the transmission system will occur.

PJM/NEPOOL Customers and Professor Hogan, however, argue that the RTO should not be allowed to impose balancing penalties on transmission users. Eric Hirst states that RTOs should maximize the use of price signals rather than penalties to encourage appropriate behavior on the part of generators and loads, and Professor Hogan states that such prices should reflect the marginal cost for power. Eric Hirst believes that penalties should be imposed only to counter the perverse incentives that are created when metering or billing procedures require prices to be calculated over time intervals that do not correspond to those used to measure generation and consumption quantities. Using the example of the California ISO, he states that mismatches between ten minute prices and hourly quantities provide unintended incentives to generators to ignore ISO dispatch instructions or to ignore their schedules. He claims that aligning the time periods for price determination and billing would eliminate these perverse incentives. He adds that, where penalties are needed, they should be closely tied to the costs incurred by the ISO.

TDU Systems argues that if markets for balancing services are fully competitive, transmission users should be able to use them to deal with any amount of imbalance. TDU Systems recommends that until such markets are fully competitive, it may be necessary to restrict such purchases to a deadband to prevent abuse. It believes that any such deadband should be less restrictive than that of the pro forma tariff. In that regard, it recommends that the minimum within-band allowance should be no less than the greater of two megawatts or five percent for loads or capacities up to 200 MW, with declining percentage tolerances as loads and capacities increase in size.

Commission Conclusion

We conclude that an RTO must serve as the provider of last resort of all ancillary services required by Order No. 888 and subsequent orders.

Since some commenters interpreted the "supplier" of last resort obligation as proposed in the NOPR to require that the RTO be the direct supplier of ancillary services, [552] we have made a minor change to the requirement by substituting the term "provider" for "supplier." We clarify that this obligation requires that the RTO have adequate arrangements in place for the provision of ancillary services.

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[552] See, e.g., LPPC, Los Angeles, Georgia Transmission, JEA, PPC. A direct supplier of ancillary services either owns or operates generation.

The ancillary services adopted in Order No. 888 were defined using the control area and its operator as the basis because a majority of transmission service was provided by control area operators and they controlled the generation facilities that supplied ancillary services. We note that since we are not requiring that the RTO to be a single control area operator, we can not require an RTO that owns no generation to be the direct supplier of ancillary services. Therefore we will give the RTO and its participants flexibility in developing adequate arrangements for the provision of ancillary services to all transmission customers that request service over the facilities under RTO control.

The RTO could fulfill its ancillary services obligations through a variety of mechanisms, including contractual arrangements, indirect or direct control of specified generation facilities, or market mechanisms. However, regardless of the method of provision, the ancillary services must be included in the RTO administered tariff so that transmission customers will have access to one-stop shopping for transmission service.

We conclude that all market participants must continue to have the option of self-supplying or acquiring ancillary services from third parties subject to any general restrictions imposed by the Commissions's ancillary services regulations in Order No. 888 and subsequent orders. In such instances, the RTO must determine if the transmission customer has adequately obtained these services. The Commission believes that allowing self-supply provides a possible competitive check on the RTO to ensure that to the extent it does provide the services, it acquires them at lowest cost.

In the NOPR we asked whether additional or revised ancillary services are needed. While a completely unbundled and competitive environment may require a modification to the ancillary services required by Order No. 888, comments suggest that an immediate change is unnecessary. We will not, at this time, make changes to the ancillary services described in Order No. 888. However, we will allow an RTO to propose other services in recognition of local or regional conditions.

We conclude that the RTO must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. All generators or other facilities that provide ancillary services must be subject to direct or indirect operational control by the RTO. The RTO must promote the development of competitive markets for ancillary services whenever feasible. To ensure the reliable operation of the system, an RTO must have authority to determine quantities and locations for ancillary services. The RTO should consider stakeholder input as well as established industry standards in determining these requirements. The Commission anticipates that some of the generation-based ancillary services could be acquired in short-term markets. This has been the approach taken by most of the ISOs that we have approved, and we see no reason that this would be different for transcos or other types of RTO entities. Apart from establishing the general requirement to use competitive markets, the Commission will allow the RTO considerable flexibility in determining many of the detailed market design questions, with case-by-case review by us.

As we proposed in the NOPR, we conclude that an RTO must ensure that its transmission customers have access to a real-time balancing market that is developed and operated by either the RTO itself or another entity that is not affiliated with any market participant. We have determined that real-time balancing markets are necessary to ensure non-discriminatory access to the grid and to support emerging competitive energy markets. Furthermore, we believe that such markets will become extremely important as states move to broad-based retail access, and as generation markets move toward non-traditional resources, such as wind and solar energy, that may operate only intermittently.

Some commenters believe that implementation of real-time balancing markets presents technical problems that may prevent RTOs in some areas of the country from making such markets available to market participants. For example, some argue that it is difficult if not impossible for an RTO that is not a control area operator to operate an efficient real-time balancing market. These commenters suggest that to the extent such markets are feasible and desirable in a particular region, the RTO, its stakeholders and market participants should be given the flexibility to develop markets in accordance with their needs and capabilities.

We are not convinced that, at this time, technical considerations preclude the development of a real-time balancing market for any potential RTO. As discussed elsewhere in this Final Rule, we are requiring each RTO to be the security coordinator for its region and to have, at a minimum, the authority to exercise a combination of direct and functional control over facilities within its region. Thus, even if an RTO is not a control area operator, it should have sufficient operational authority to ensure that a real-time balancing market can be implemented. With regard to the issue of flexibility, we believe that real-time balancing markets are essential for development of competitive power markets. Therefore, although we will give RTOs considerable discretion in how they operate real-time balancing markets, we will not allow implementation of such markets to be discretionary.

Our conclusions regarding provision of real-time balancing markets are similar to our conclusions regarding markets for congestion management; that is, we will not prevent an entity other than an RTO that is unaffiliated with market participants, from seeking to offer transmission customers a real-time balancing market. However, because this function is so time-sensitive and requires such close coordination with the actual dispatch, experience may ultimately show that it cannot be performed to a high degree of efficiency unless it is made a part of the RTO's central or hierarchical dispatch activities. Also, we do not agree that an RTO's operation of a real-time balancing market will interfere unduly with the efforts of others to establish markets in forward contracts for energy.

We asked in the NOPR whether customers should have the option of paying for all imbalances in a real-time balancing market or only imbalances within a specified band. Based on the comments received, we decline to give a generic solution for all RTOs in this rule. An RTO may propose one approach or the other but should explain how it proposes to overcome any disadvantages of the approach selected.

In the NOPR, we noted that unequal access to balancing options can lead to unequal access in the quality of transmission service, and that this could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. We conclude that control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market. We believe that providing options for clearing imbalances that differ among customers would be unduly discriminatory.

Finally, we asked in the NOPR whether, for the imbalances of individual transmission customers, a distinction should be made between loads and generators. We conclude that, for the purpose of determining cost responsibility for imbalances, no distinction needs to be made. The system-wide balance between load and generation is affected comparably by changes in load and changes in generation. Therefore, the cost of an imbalance is unaffected whether the imbalance is determined ultimately to be the responsibility of load or of generation. However, commenters point out certain differences between loads and generators (such as in the time needed to respond to an operator's instructions) that are important from the standpoint of system operation. These differences can be relevant to the determination of the appropriate penalties to assess to loads and generators that fail to submit accurate schedules. Thus, for purposes of assessing penalties for inaccurate schedules, we conclude that a penalty mechanism that treats loads and generators differently may be appropriate.

5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)

In the NOPR, the Commission proposed that an RTO must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC. The Commission stated that the most controversial aspect of OASIS operation is the calculation and posting of ATC [553] and noted that there is widespread dissatisfaction with the reliability of posted ATC numbers. To alleviate this problem, the Commission proposed that the RTO become the administrator of a single OASIS site for all transmission facilities over which it is the transmission provider. [554] The NOPR outlined three levels at which an RTO could be involved in ATC calculations. At Level 1, the RTO would post ATC values received from transmission owners. At Level 2, the RTO would receive raw data from transmission owners and itself calculate

[553] FERC Stats. & Regs. ¶ 32,541 at 33,747.

[554] Id. at 33,748.

ATC values. At Level 3, the RTO would itself calculate ATC values based on data developed partially or totally by the RTO.

In the NOPR, the Commission envisioned that RTOs would operate at Level 3 to ensure that ATC values are based on accurate information and to minimize the opportunities for manipulation. [555] The Commission also proposed that: (1) an RTO must formulate a validation system to check any ATC data supplied by others; (2) in the event of a dispute over ATC values, the RTO's data should be used pending the outcome of the dispute resolution process; and (3) the RTO must formulate the operating standards (subject to regional and national reliability requirements) underlying ATC calculations. [556]

Comments

Most commenters who address the subject agree with the Commission's observations regarding dissatisfaction with ATC/TTC data. Moreover, most commenters on the subject endorse the proposal that an RTO must be the single OASIS site administrator for all transmission facilities under its control. [557] Some commenters,

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[555] See id.

[556] Id.

[557] See, e.g., NASUCA, WPSC, EAL, NERC, Industrial Consumers, Entergy, Mass Companies, JEA, LG&E, NY ISO, NJBUS, Sithe, TAPS, How Group, Southern Company, PG&E, PJM, UtiliCorp, Williams, Cinergy, Oneok, East Texas Cooperatives, Cal DWR, Tri-State, Seattle, New Smyrna Beach, RUS, Cinergy, Nevada Commission, (continued...)

however, are opposed to mandating the RTO as the OASIS site administrator. For example, Central Maine argues that it should not be precluded from operating its own site because as a "wires-only company" it has an incentive to operate an efficient site in order to maximize use of transmission capacity. EEI asserts that OASIS operation can occur independently of formation of an RTO and that the tasks and problems of OASIS operation will not become naturally easier to solve with the creation of an RTO.

Most commenters also support the Commission's proposal to have the RTO independently calculate ATC and TTC. [558] In addition, a number of commenters emphasize that independent and disinterested RTOs could be trusted and empowered to maintain reliable ATC data and calculate accurate values. [559] Moreover, several commenters are concerned with consistency across RTOs and contend that RTOs must

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[557](...continued)
and Enron/APX/Coral Power.

[558]See, e.g., Sithe, RUS, TAPS, PG&E, SMUD, Cal DWR, New Smyrna Beach, East Texas Cooperatives, WPSC, EAL, NERC, NASUCA, Seattle, Georgia Transmission, First Rochdale, Tri-State, Industrial Consumers, Enron/APX/Coral Power, Cinergy, Oneok, PJM, Williams, Empire District, PJM/NEPOOL Industrial Customers, Entergy, Mass Companies, Nevada Commission, NJBUS, and LG&E.

[559]E.g., FMPA, East Texas Cooperatives, NJBUS, Empire District, Entergy, Oneok, First Rochdale, Seattle, EAL, Sithe, WPSC, Sithe, PG&E, SMUD, New Smyrna Beach, and PJM/NEPOOL Customers.

also coordinate ATC values with adjacent regions and with the NERC regional reliability councils. [560]

Many commenters concur with the Commission's conclusions about the different levels of RTO involvement in ATC calculations. These commenters believe that Level 1 is insufficient for reliable and trustworthy data and that an RTO should independently calculate ATC values. Several commenters, however, disagree about the appropriate timing for Level 3 compliance. Some commenters, such as Cinergy, argue that upon commencement of operation, an RTO should be required to perform all studies and analysis needed for accurate ATC values consistent with Level 3. APX supports each RTO reaching Level 3 as quickly as possible. Enron/APX/Coral Power asserts that upon commencement of operation, an RTO should operate at Level 2 and, as it gains operational experience, migrate to Level 3. SMUD supports RTO operation at Level 3 but is concerned about the significant costs associated with developing data.

JEA is opposed to any RTO structure that gives an RTO complete authority over ATC calculations for transmission that JEA will continue to own. JEA asserts that transmission owners are in the best position to assess the capabilities of their own transmission system. Therefore, absent formation of a transco, JEA does not support relying on an RTO for ATC and TTC calculations because JEA argues that ownership

[560] See, e.g., Industrial Consumers, Seattle and WPSC.

and control of the assets would be split between two or more entities whose interests are not always the same.

Both Cal ISO and NY ISO argue that the final rule should provide flexibility in the OASIS requirements to accommodate network systems like the Cal ISO and the NY ISO in which transmission service is not explicitly reserved. In addition, numerous commenters argue that the Commission should expand the minimum requirements to have every RTO employ a single set of OASIS practices and terminology.[561] They note that consistency in OASIS procedures will allow seamless trades across RTOs.

How Group also focuses its comments on the standardization of transmission transactions. It notes that without some level of standardization only a limited number of market participants who learn all of the differences between RTOs can perform transactions that span multiple RTOs. How Group proposes that each RTO establish a coordinating committee with neighboring RTOs and transmission customers in order to: (1) coordinate the naming of interconnected facilities, sources, sinks, paths, points of receipt and/or delivery between the RTO and its neighbors; (2) coordinate the sharing of necessary data for the calculation of transmission capability on interconnected paths; and (3) foster coordination with neighbors in adopting standardized business practices. It also suggests that continued industry-wide coordination is necessary to formulate common

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[561] See, e.g., Williams, EPSA, Cinergy, Empire District and PJM/NEPOOL Customers.

definitions for types of transmission and ancillary services, curtailment priorities, and timing requirements for arrangement of transmission services.

Only one commenter expressed concern about the proposal to use the RTO's ATC values in the event of a dispute. Southern Company contends that the existing transmission owner's data are preferable to the RTO's data. Southern Company argues that existing transmission owners have experience in operating the regional transmission facilities and, therefore, are best qualified to determine ATC values.

Some commenters raise other OASIS-related issues that were not addressed in the NOPR. For example, commenters argue that: (1) all reservations and scheduling, including that for network service, should occur on the OASIS; (2) sanctions should be levied against transmission providers that skew their ATC values; and (3) the power flow methodology rather than the contract path model should be used for scheduling. [562] A few commenters address issues relating to Capacity Benefit Margin (CBM). NASUCA argues that administration of CBM should be a required function of RTOs and that a uniform methodology for calculating CBM is needed. Similarly, Idaho Commission asserts that requiring the posting of CBM on OASIS with a narrative explanation of its derivation would be beneficial. Empire District states that the Commission should provide better guidance about how to calculate CBM.

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[562] See, e.g., Ontario Power, Williams, NERC and EPSA.

Commission Conclusion

After considering the comments, we continue to believe that an RTO must be the single OASIS site administrator for all transmission facilities under its control. As numerous commenters note, independent RTOs can be trusted to maintain an OASIS site with reliable and current data that is easy to use. In addition, a single OASIS site for each region instead of multiple sites will enable transactions to be carried out more efficiently.

However, in response to those who argue for flexibility in OASIS requirements, we clarify that this requirement does not mean that each RTO must itself operate the OASIS for its region. Our concern is that there be no more than one OASIS site for the facilities under the RTO's control, and that the RTO ensure that the OASIS site operator have the same attributes of independence we require for an RTO. Thus, we will allow an RTO the flexibility to contract out OASIS responsibilities to another independent entity, if justified. More specifically, we do not intend to keep an RTO from participating in a "super-OASIS" jointly with other RTOs.

We reaffirm that an RTO should operate at what the NOPR characterizes as Level 3 for ATC/TTC calculations, which requires the RTO itself to calculate ATC values based on data developed partially or totally by the RTO. Most commenters believe that Levels 1 and 2, where the RTO would accept the transmission owners' ATC calculations or data, are insufficient for reliable and trustworthy ATC values. Level 3 ensures that

ATC values are based on accurate information and consistent assumptions. When data are supplied by others, the RTO must create a system for tests and checks that ensure customers of coordinated and unbiased data. We also agree with commenters who recommend that RTOs coordinate ATC values with adjacent regions.

We recognize that the NOPR was silent on the appropriate timing for Level 3 compliance. Commenters suggested that: (1) an RTO should reach Level 3 compliance upon commencement of operation; (2) an RTO should reach Level 3 as quickly as possible; or (3) an RTO should operate at either Level 1 or 2 upon commencement of operation and as it gains operational experience, migrate to Level 3. We conclude that an RTO OASIS site, including ATC calculations, must be fully operational at Level 3 upon commencement of service. All parties to a transmission transaction need precise ATC values to make scheduling decisions.

We affirm that in the event of a dispute over ATC values, the RTO's values should be used pending the outcome of a dispute resolution process. Only one commenter, Southern Company, disagreed with this proposal and we are not persuaded by its arguments. Each RTO must develop procedures to validate its ATC values.

How Group and other commenters address issues relating to the standardization of transmission transactions. Standardization of transactions involves two separate concerns: (1) many transactions will cross RTO boundaries; and (2) numerous customers will do business with multiple RTOs. Without standardized communications protocols and business practices, the costs of doing business will be increased as market participants will be required to install additional software and add personnel to transact with different RTOs and regions. Therefore, to promote interregional trade, standardized methods of moving power into, out of, and across RTO territories will be needed.

We believe that standards for communications between customers and RTOs must be developed to permit customers to acquire expeditiously common services among RTOs. For example, we envision the creation of standardized communications protocols to schedule power movements and to acquire auction rights. These protocols would not standardize what the rights are, or the nature of the auctions. Instead, the focus of the communications protocols would be on how customers communicate their intentions to an RTO and how customers receive an RTO's responses.

We agree with How Group and others that certain business and communication standards [563] are necessary, and we believe that these standards will facilitate the development of efficient markets. We believe, however, that these issues need further examination based on a complete record.

[563]We believe that the communications standards and protocols would, like the current OASIS, make use of: (1) the Internet for communications; (2) interactive displays using World Wide Web browsers; (3) file uploads and downloads for computer-to-computer communication; and (4) templates defining the file uploads and downloads.

A few other commenters discussed issues that were not addressed in the NOPR. For example, commenters argue that: (1) all transmission transactions (reservations and scheduling) should occur on the OASIS; (2) sanctions should be levied against transmission providers that skew their ATC values; and (3) the power flow methodology for scheduling, rather than the contract path model, should be utilized. In addition, NASUCA, Empire District and the Idaho Commission raise issues relating to CBM. These issues are too detailed for this proceeding and we will not address them at this time. Commenters will have the opportunity to bring up these issues in response to specific RTO filings, as well as during OASIS Phase II proceedings and in the CBM docket (Docket No. EL99-46-000).

6. Market Monitoring (Function 6)

In the NOPR, the Commission proposed that RTOs perform a market monitoring function. Specifically, RTOs would be required to: (1) monitor markets for transmission service and the behavior of transmission owners and propose appropriate action; (2) monitor ancillary services and bulk power markets that the RTO operates; (3) periodically assess how behavior in markets operated by others affects RTO operations and how RTO operations affect those markets; and (4) provide reports on market power abuses and market design flaws to the Commission and affected regulatory authorities, including specific recommendations. In addition, the Commission asked a number of questions regarding the role of RTOs in market monitoring, the tools RTOs should use, and similar issues.

Comments

Commenters address a number of issues regarding the market monitoring function. The issues can be grouped into three general areas: (1) the need for and scope of a market monitoring function; (2) who should perform the market monitoring function and how it should be performed; and (3) what are the specific components or procedures of a market monitoring plan.

Need For and Scope of Market Monitoring

As a general proposition, a variety of commenters favor having RTOs serve as market monitors.[564] Commenters, such as Blue Ridge, argue that RTOs should conduct market monitoring because they will be in the best position to deal with the growing volume of multiparty transactions and discern any manipulation or preferential treatment. Several commenters, such as the Florida Commission, note that the appropriate role for RTOs in market monitoring and the various aspects of the function will depend upon the nature of the RTO that is ultimately established. TEP claims that RTO market monitoring needs to be flexible given the costs involved in such a function. PP&L Companies believes that RTO market monitoring should focus on properly structuring business rules

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[564] See, e.g., New York Commission, South Carolina Authority, Mass Companies, LG&E, ISO-NE, TAPS, SMUD, NECPUC, WPSC, Project Groups and Tri-State.

to foster efficient transactions and gathering statistical information to make available to the Commission or other enforcement agencies. EEI and Allegheny recommend that RTO market monitoring identify market design flaws and propose solutions that lead to greater efficiency, competitiveness and reliability.

A number of commenters support having the RTO should serve as the "first line of defense" for detecting design flaws and market power abuses. [565] Cal ISO suggests that the RTO serve as a first line of defense in conjunction with state commissions and local regulatory authorities in the region, particularly in the operation of hourly and real-time markets where potential buyers may not have the ability to decline electric service, and where transmission and ancillary services markets tend to have high concentrations. PJM believes that market monitoring by RTOs provides a continual check on market activities and accordingly, RTOs should have clear authority to investigate potential market power abuses or flaws and to compel market participants to produce relevant information. SMUD contends that although RTO monitoring should be the first line of defense, an independent RTO monitoring unit must not be a substitute for review by the Commission and other regulatory agencies.

In contrast, some commenters, such as Cinergy, argue that, if transmission markets realize the efficiencies envisioned in the NOPR, the commodity market should be able to regulate itself, with the Commission and the courts serving as backstops. SNWA

[565] See, e.g., Metropolitan, DOE, CMUA, NASUCA and Project Groups.

cautions that RTOs may be too focused on safe and reliable operations to be a first line of defense. Some commenters, such as Metropolitan and Southern Company, claim that there is no benefit in having RTO monitoring replicate the costly regulatory responsibility that already exists in state and Federal agencies.

Several commenters propose an expansive RTO market monitoring role. NECPUC proposes that monitoring include mitigation of both market flaws and market power. East Texas Cooperatives and SMUD believe that RTO market monitoring should include remedying market abuse. Project Groups believes that an RTO should monitor energy and ancillary services markets and their interplay, and develop indices and criteria to evaluate activities and behaviors that may reflect market power abuse. Advisory Committee ISO-NE suggests that the RTO monitor transmission and ancillary services markets to identify design flaws and market power, and to administer or propose remedial actions. Dynergy claims that monitoring should include oversight of transmission owners' behavior. EPSA proposes that the RTO also document any significant market impacts attributable to application of reliability rules.

Some commenters support limits on market monitoring by the RTO. Commenters, such as Southern Company and Entergy, argue that RTO monitoring should not reach to any market the RTO does not operate, nor should it encompass market power abuse and the effect of existing structural conditions on the competitiveness of electricity markets. Entergy adds that the RTO will not be in a good position to monitor markets it does not operate. Several commenters claim that the purpose of monitoring should be to look for market flaws, not act as policeman looking for bad behavior. [566] Desert STAR recommends that any proposed remedy be restricted to market flaws within the RTO's area of operation. Enron/APX/Coral Power argues that evaluation of the structure of power markets and policing market power lies outside of an RTO's core competencies as the operator of the transmission system. Tri-State opposes RTO monitoring of power markets because it would add to the complexity and cost of RTOs and impermissibly involve the RTO in issues about generation market power. NY ISO opposes monitoring to the extent that it encompasses the RTO playing an investigative and enforcement role. Nonetheless, in its view, the RTO could mitigate evident market power problems on a prospective basis by applying pre-approved remedies.

Sithe recommends that RTOs not have the authority to compel the provision of commercially sensitive data and should instead rely on nonproprietary information to monitor markets. PG&E contends that commercially sensitive information should not be released to anyone except in accordance with Commission-approved rules. PP&L raises concerns regarding the ability of the RTO market monitoring organization to guarantee confidentiality of commercially sensitive information supplied to it. Seattle argues that any claims of commercial sensitivity must be tempered by the need to create an efficient, self-policing, transparent market for nondiscriminatory transmission services.

[566] See, e.g., Desert STAR, CRC and Tri-State.

Various commenters would limit the RTO market monitoring function to information gathering. [567] They argue that the NOPR proposal is overly broad, too extensive and open-ended, and a potentially burdensome requirement. Sithe argues that the application of mitigation measures by the RTO could have real commercial impacts on market participants that often cannot easily be measured or repaid after the fact; therefore, market participants should have an opportunity to review and comment on monitoring procedures prior to their implementation. Seattle claims that the Commission should take a minimalist approach by facilitating market monitoring through greater public information disclosure. PG&E believes that the RTO should not regulate the functioning of the energy market. Duke supports RTO identification and description of alleged market abuses to appropriate authorities through the regulatory framework that exists today.

Other commenters question the need for or otherwise oppose an RTO market monitoring function, in general, as a form of back door regulation. [568] They contend that RTO monitoring will be unduly burdensome, overtaxing and costly to the ratepayers. Los Angeles and Salomon Smith Barney argue that RTO monitoring may interfere with the proper relationship between the RTO and its customers, which they claim should be

[567] See, e.g., CP&L, TDU Systems, PP&L and PG&E.

[568] See, e.g., Industrial Consumers, Williams, Southern Company, PSE&G, Arizona Commission, Georgia Transmission and East Kentucky.

focused solely on providing nondiscriminatory open access transmission services. UtiliCorp argues that the assignment of market monitoring functions to a commercial entity such as a transco (other than those functions concerned strictly with transmission pricing) may raise antitrust concerns both for the transco and its customers.

Commenters differ on whether market monitoring should continue indefinitely. East Texas Cooperatives believes that continuous RTO market monitoring is necessary because, in its view, antitrust laws and complaints to the Commission provide only a slow, after-the-fact remedy. Entergy recommends that any RTO self-monitoring be allowed to terminate after a fixed period, subject to Commission approval. Industrial Consumers suggests that market monitoring be limited to the period when the risk of discriminatory conduct is greatest. Los Angeles claims that, once the Commission determines that generation markets are workably competitive, market forces should be allowed to discipline the markets. If an RTO market monitoring function is required, PSE&G suggests a five-year sunset provision.

Who Should Perform Market Monitoring and How Should it Be Performed

Many commenters address the issue of whether the RTO should perform market monitoring depending on the form of the RTO (i.e., whether the RTO is a for-profit or a not-for-profit organization). Most commenters raise concerns about and generally oppose a for-profit RTO monitoring markets. [569] The commenters generally argue that, due to its economic and business interests, a for-profit RTO cannot objectively monitor itself. CP&L submits that a for-profit RTO may be a competitor of other market participants in the provision of congestion relief and ancillary services, which would make unbiased monitoring of those markets difficult. TDU Systems would limit a for-profit RTO's role to data collection. Other commenters recommend that for-profit RTOs employ a fully independent organization to monitor market conditions. [570] A few commenters, however, support for-profit RTOs serving as market monitors. [571] Entergy claims that market monitoring conducted by a transco could be as effective as for any other type of RTO as long as procedures are in place that ensure its independence.

Commenters also address whether an RTO that is an ISO needs to insulate its market monitoring function from other RTO functions to ensure independence and objectivity. A number of commenters generally believe it is appropriate for ISOs to internally monitor market activities either through staff devoted to the function or through a committee of ISO members assigned to the function. [572] They argue that an ISO, which would be free of commercial interests, can be trusted by market participants, and

[569] See, e.g., Dynegy, South Carolina Authority, Industrial Consumers and East Texas Cooperatives.

[570] See, e.g., PJM/NEPOOL Customers, Cal ISO, Tri-State and Metropolitan.

[571] See, e.g., Entergy and Duke.

[572] See, e.g., PJM, ISO-NE, NY ISO, WPSC and East Texas Cooperatives.

therefore should not have to undertake costly establishment of autonomous monitoring units. Mid-Atlantic Commissions note that PJM ISO's monitoring unit is a neutral body that has access to and maintains confidentiality of market sensitive data in accordance with sharing arrangements with each of the states in the region. California Board contends that, if the internal unit is independent and has the ability to report and/or consult with state and Federal authorities without needing additional approval, those regulators are likely to respect the opinions and recommendations of the market monitoring unit. CalPX suggests that RTOs and separate power exchanges coordinate their market monitoring functions and jointly conduct research to lower costs. EPSA suggests that the information and market data, if collected by an independent and unbiased RTO, could be relied upon by market participants in formulating business strategies, and by regulators for purposes of reviewing and approving modifications to regulated aspects of RTO structures and operations.

Most commenters, however, would require an ISO (i.e., a not-for-profit RTO) to make its market monitoring function more independent. Pennsylvania Commission contends that an independent ISO is absolutely necessary to perform market monitoring functions. EEI points out that while an RTO's independence may ensure that its recommendations do not favor particular market participants, this does not ensure that it will monitor its own performance objectively. In its view, an ISO should use outside experts within the monitoring committee or on an ad hoc basis to address concerns about objectivity. Similarly, PG&E contends that experience has shown that an ISO's rules and actions may interfere with the proper functioning of the market. Industrial Consumers contend that an RTO's operations must be sufficiently transparent that it is the market participants that do the real monitoring. FTC suggests that internal RTO monitoring could be problematic if the internal monitoring unit is given enforcement powers, because this could both devolve into re-regulation and raise conflict of interest issues. FTC recommends that the Commission's RTO rules explicitly make clear that self-monitoring controlled by an RTO does not create an antitrust exemption for the RTO and its participants.

Los Angeles believes that market monitoring should be conducted by an independent body. CP&L, however, believes that delegation to a private party is questionable, where its objectivity may also be challenged on grounds of conflict of interest, particularly, if the delegated authority includes the ability to impose sanctions and penalties. Oregon Commission believes that RTOs should appoint a local committee to use RTO data to monitor the market for ancillary services because RTOs, as major buyers and sellers of such services, will want to protect their market shares. The Commission should consider establishing its own regulatory advisory bodies to monitor markets. DOE also claims that the Commission should avoid reliance upon RTO monitoring to the exclusion of the Commission's own monitoring efforts. Alliant believes that moving responsibility for monitoring market power to another organization would allow the RTO to focus on the many technical demands that will be placed on it. Metropolitan believes market monitoring should occur on two levels: an internal group responsible for data gathering and publication and frequent preliminary analysis of anomalous conduct; and formal analyses performed by a group or committee independent of RTO management whose results and recommendations would not require RTO approval.

LG&E proposes that the RTO make its monitoring findings public and refer them to an appropriate regulatory body. Industrial Consumers opposes giving deference to the RTO's recommendations for correcting such market power abuses and flaws. Instead, it believes that stakeholders and market participants should use the RTO reports to make their own recommendations.

NYPP believes that structural solutions are matters for legislators, courts or regulatory agencies. In contrast, PJM believes that, if the market issue is a structural one, the RTO should be able to propose structural remedies to the Commission.

In the case of localized market power, MidAmerican submits that it would be inappropriate for the RTO to take corrective competitive actions in the case of localized must run generating unit market power. Similarly, PG&E contends that RTOs should allow temporary supply and price issues to be resolved by the competitive forces of the market, unless there is a threat to the physical supply of power or a Commission determination that markets are not workably competitive.

CalPX believes that monitoring and reporting should be simplified in order to reduce costs and to rationalize staff and committee work loads. Also, the RTO and power exchange compliance related staffs should jointly conduct research that is beneficial both to increase coordination and reduce costs. NY ISO submits that RTOs that are ISOs should not be required to establish costly and otherwise burdensome autonomous market monitoring units.

Many commenters address the issue of the appropriate role for the Commission and the state commissions in market monitoring. Commenters overwhelmingly believe that the Commission and state commissions have an important role to play, whether it is a primary role as market monitors, or a secondary role providing oversight of market monitoring activities by RTOs.

Some commenters believe that market monitoring is better handled by the existing statutory and regulatory agency frameworks than by RTOs.[573] They suggest a continuing, if not mandatory, role for the Commission and other Federal and state authorities in conjunction with any market monitoring undertaken by RTOs.[574] PP&L

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[573]See, e.g., Salomon Smith Barney, South Carolina Commission, PG&E, Enron/APX/Coral Power and Duke.

[574]See, e.g., SMUD, Tri-State, Cinergy, TDU Systems, EPSA, Industrial Consumers, CMUA, PJM/NEPOOL Customers, NY ISO, ISO-NE and DOE.

Companies argues that, in Gulf States Utilities Co. v. FPC, [575] the Supreme Court made it clear that the Commission is charged with serving as the first line of defense to protect and preserve competition in wholesale power markets.

TDU Systems and Sithe contend that regulatory commissions cannot abdicate to RTOs the responsibility to ensure that wholesale electric markets are free of market power. Many commenters see RTOs serving to forward any claims of market abuse and market power to the various federal and local regulatory agencies consistent with their respective jurisdictions. PJM and LG&E see the Commission reviewing remedies and approving penalties and sanctions. Desert STAR and CRC see the Commission acting as a backstop to an RTO's ADR process or mitigation plan. EEI suggests that RTOs regularly inform the Commission about monitoring results, which will enable it to respond quickly to problems not resolved by the RTO. SoCal Cities suggest that RTOs share responsibility to remedy structural defects in the market or impose general sanctions for market power abuse with appropriate state and federal agencies, but not duplicate their responsibilities such as implementation of the FPA. CalPX believes that there is a decreasing role for regulatory oversight as a result of a progression toward greater RTO self-regulation.

Florida Power Corp. and Nevada Commission suggest close coordination of RTO market monitoring with state regulators. Nevada Commission also suggests that RTOs

[575] 411 U.S. 747 (1973).

collaborate their monitoring efforts with neighboring RTOs, as well as audit the records of those parties who violate the RTO's rules. Project Groups recommends adding an eighth minimum function under which RTOs provide data support for states' policies, monitoring the competitive impacts of emissions regulations, verifying compliance with state generation portfolio standards.

NARUC claims that the states need to be heavily involved in RTO market monitoring and that the Commission should work with the states to make utility codes of conduct more effective. In its view, such collaboration is the most effective means of monitoring market power in generation, since the RTO would have information for the region on transmission planning, generation expansion and transmission constraints, and state commissions would have utility specific data and information on local operations. NARUC argues that such collaboration is critical because state commissions are responsible for both evaluating local markets to assure competitiveness and for licensing electric supplies, and abusers of market power can inhibit competition and distort the prices of locally regulated services. NASUCA similarly claims that market participants, state and federal regulatory agencies, and state consumer advocates periodically review the indices and screens to be used for RTO market monitoring. The RTO should periodically issue confidential reports to federal and state regulatory authorities and state consumer advocate offices, that describe the state of the markets and the results of matters under investigation.

A number of state commissions suggest a continuing oversight role over RTO monitoring by the Commission and the states.[576] Oregon Commission recommends that the Commission establish its own regulatory advisory bodies to monitor ancillary services markets. For a for-profit RTO, it recommends that a regional oversight committee perform this function with the Commission reviewing any oversight committee reports.

Commenters also address a number of issues related to the ability of RTOs to perform self-assessments. A number of commenters believe that RTOs are capable of objective analysis. NY ISO contends that an ISO will have no incentive to distort the results of its analysis. Cinergy recommends that RTOs be limited to monitoring the behavior of the markets they administer because of the ready access to relevant information. Los Angeles comments that, if the RTO is not primarily responsible for providing ancillary services, it should not be burdened with surveying that market.

Other commenters oppose RTOs monitoring the markets that they operate because of conflict of interest concerns.[577] EEI argues that independence from market participants does not ensure that the RTO will be able to monitor its own performance objectively, e.g., a non-profit RTO may not have sufficient incentives to minimize the costs under its control. Oregon Commission comments that RTOs cannot be entrusted to

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[576] See, e.g., Florida Commission, New York Commission and Michigan Commission.

[577] See, e.g., Florida Power Corp., CMUA and DOE.

monitor ancillary services markets, where they will be providing services and have incentives to protect market share. Industrial Consumers contends that market participants must perform monitoring and, accordingly, an RTO's operations should be fully transparent. SNWA and PG&E claim that the RTO should establish an independent body to monitor and evaluate its performance.

Some commenters, such as Salomon Smith Barney and Michigan Commission, oppose the RTO monitoring markets where the RTO takes a market position because the RTO plays the dual role of seller of services and policeman. Alliant contends that an RTO will be competing with generation providers in congestion management and have an incentive to build transmission facilities. Similarly, CP&L contends that a for-profit RTO may compete with others in providing ancillary services, and therefore any proposal by the RTO monitor for remedial action raises serious conflict of interest concerns. Industrial Consumers suggests that, even in markets where the RTO is the supplier of last resort, the RTO should not have quasi-regulatory powers.

Commenters also address the issue of whether RTOs should be required to provide periodic assessments of markets they do not participate in or operate, thereby assessing the effect of existing structural conditions on the competitiveness of their region's electricity markets. Some commenters oppose this proposal. Tri-State opposes an RTO monitoring of power markets because it would not only violate the Commission's goal of separation between transmission and power sales, it would also add a level of complexity and cost to the operation of the RTO. Justice Department believes that the RTO cannot reasonably be expected to monitor activities with which it has no involvement. Justice Department therefore recommends that the Commission consider requiring each separate electric power trading institution to monitor any market that it operates.

On the other hand, a number of commenters favor extending RTO monitoring responsibility to markets they do not operate. PJM/NEPOOL Customers argues that the independence of the RTO would enable market participants and the Commission to have confidence in the RTO's assessments. ISO-NE favors RTOs monitoring power markets. NASUCA recommends that RTOs monitor bulk power markets, capacity markets, transmission rights markets, ancillary services markets and any other potentially competitive markets. FTC suggests that, where an RTO is smaller than one of the major interconnects, the Commission may wish to encourage all the RTOs within each of the interconnects to coordinate their efforts to examine the effects of market rules or variations between RTOs in market rules on the volume and price of inter-RTO transactions. Cal ISO also sees collaborative market monitoring and assessment by neighboring RTOs and at the national level.

Florida Power Corp. recommends that an RTO that is an ISO be required to make regular assessments as to whether it has sufficient operational authority to ensure its ongoing ability to provide reliable, open access transmission service on a comparable basis to all customers—nonetheless, the RTO should not be self-regulating.

For those regions where the real-time balancing function is performed by an ISO, Advisory Committee believes that the ISO should monitor market power in generation markets. SoCal Edison claims that, where markets are not yet workably competitive, the RTO, with Commission approval, should ensure that prices are just and reasonable through appropriate temporary mechanisms such as price caps. PG&E counters that, in no case, should RTOs be permitted to use control of a power exchange for unilaterally capping prices set by the market.

Many commenters address the issue of how the RTO should report, if at all, its monitoring activities. The Commission did not propose to establish detailed standards on the format and content of monitoring reports, noting that such matters are best left to the RTO. We asked commenters to address whether reporting should be limited to when a specific problem is encountered, or whether periodic reporting on the state of competition and transmission access would be more appropriate.

Commenters express mixed views on reporting requirements. CRC supports the concept of RTOs reporting to the Commission regarding RTO design flaws, and New York Commission suggests that RTOs report on market power abuse as well. Florida Power Corp. submits that, if market monitoring is necessary, it should be performed by the RTO reporting and filing appropriate information with state and Federal regulators. Project Groups wants the provision of data to support state programs pertaining to the monitoring of the competitive impacts of emissions regulations. Project Groups argue that RTOs would be uniquely positioned to support data collection for verification of green marketing claims and compliance with information disclosure requirements and portfolio standards. EEI opposes a Commission mandate for RTOs to track generation source and emissions data. EEI recommends the RTO voluntarily undertake this task to meet specific state compliance requirements provided appropriate safeguards protect competitively sensitive information. EEI expresses concern regarding the possibility that the RTO would have authority to collect and disclose information from a generation source where the state has not imposed such a requirement.

Several commenters favor issuance of monitoring reports at regular intervals. Project Groups believes that RTO monitoring units should issue public reports on their activities and findings, including annual reports on the general state of the market. Metropolitan supports reporting at regular intervals from an external monitoring source; however, during initial startup, more frequent reporting is advisable to assist participants' understanding of the market operation. East Texas Cooperatives believes that RTOs should prepare periodic reports to the Commission with the precise form left to the discretion of the RTO.

California Board contends that regular reports on market performance should issue at least on a yearly basis, and include all relevant data that can be made publicly available. NASUCA contends that, to further create trust in the RTOs' ability to effectively and objectively monitor the market, RTOs should periodically issue reports describing the state of the markets that it is monitoring, items under investigation by the RTO, and any results from completed investigations. In its view, market participants, state and federal regulatory agencies and state consumer advocates should participate in the development and periodic review of the indices and screens the RTO will use to monitor the operation of the markets. Reports should be provided to state and federal regulatory authorities as well as state consumer advocate offices, on a confidential basis, to enable them to independently assess whether additional investigation is merited. Cal ISO submits that the Commission should specify regular reporting requirements for the RTO's monitoring unit. PJM believes that RTOs should periodically report results of monitoring activities to the Commission and state agencies.

Components of a Market Monitoring Plan

Commenters address various issues regarding particular elements of a market monitoring plan. Many commenters address the issue of whether RTOs should be allowed to impose penalties and sanctions. Most commenters would limit the RTO's ability to impose penalties or sanctions. Many of them argue that such authority should remain the province of the regulatory and antitrust agencies. [578] Justice Department claims that RTOs lack experience either in detecting exercises of market power or in making recommendations on correcting market power problems. SPRA questions

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[578] See, e.g., Entergy, Duke, PG&E, PSE&G, PJM/NEPOOL Customers and Williams.

whether the imposition of sanctions by the RTO may conflict with the Supremacy Clause of the Constitution and whether affected public power bodies could only consent to such sanctions if they do not create indefinite or uncertain liabilities. PP&L argues that, because it will be judge and jury, the RTO must demonstrate competitive harm before taking any market action. Some commenters, such as CP&L, note that a for-profit RTO may not be objective in imposing sanctions because it competes with other market participants. Other commenters, such as Salomon Smith Barney, claim that RTOs should be limited to extracting ordinary commercial penalties when market participants fail to follow the market's rules. EPSA claims that RTOs should be empowered to intervene in a market within the strict confines of the Commission's oversight only when a situation has the potential to become catastrophic. Mass Companies opposes allowing a private RTO or one that is operated by a non-stakeholder board to enforce violations of market standards and impose sanctions and penalties.

Canada DNR claims that it will be problematic for Canadian entities subject to the jurisdiction of Canadian provincial and Federal energy regulators also to be subject to an RTO that has its disciplinary authority backstopped by the Commission. In its view, the issue will not be resolved by simply having the appropriate Canadian regulator serve as the regulatory backstop to the RTO for each Canadian entity because the Canadian regulator may take a different position than the Commission.

A few commenters support authority for RTOs to impose penalties and sanctions. Among them, CalPX believes that RTO governing boards and power exchange market monitoring committees must be able to take appropriate action either by referral to regulatory agencies or directly through applicable sanctioning authority. It views this as critical for self-policing and providing prompt remedies before problems detrimentally affect market results. ISO-NE believes that an RTO should have the ability to impose penalties and sanctions, but suggests that the RTO not act as an antitrust agency, in order to increase the acceptability of sanctions among participants.

The Commission specifically sought comment on whether penalties should be limited to violations of RTO rules and procedures, or whether the RTO should be allowed to impose penalties for the exercise of market power. More commenters oppose than support RTOs imposing sanctions and penalties for market power abuse. Among them, Allegheny and Metropolitan claim that this is a proper function of regulatory or antitrust authorities. Central Maine argues that the Commission cannot grant RTOs the authority to impose corrective actions without affording the affected public utilities with procedural due process. EEI believes that the RTO tariff may include RTO authority to impose fines or sanctions to ensure compliance with RTO rules in accordance with the costs imposed by their actions. Pointing to similar positions taken by Justice Department and FTC, EEI contends, however, that the RTO should not attempt to define or prosecute alleged exercise of market power because it is not a regulatory body or an antitrust agency authorized to take such actions. It also suggests that limited additional authority might be granted during the transition to restructured markets to permit the RTO to deal effectively and timely with identified market design flaws, software errors, or other unanticipated situations that could be costly if no action is taken.

Cinergy also argues that the RTO should not be allowed to take corrective action against individual market participants. It believe that claims of market abuse and the exercise of market power should be forwarded to the Commission to address consistent with its jurisdiction. Similarly, MidAmerican recommends that RTO penalties be limited to (1) willful violations of material RTO directives related to the operation of regional transmission facilities, Commission approved RTO standards for transmission facility operations, and material provisions of RTO agreements that conflict with the RTO transmission tariff, and (2) violations of RTO transmission tariff provisions relating to operating reserves and energy imbalances. NASUCA recommends that compliance with RTO rules be enforced with penalties and sanctions imposed through a collaborative process involving all market participants, regulatory agencies and consumer advocates. However, the Final Rule should specify that any actions taken by the RTO cannot substitute for penalties or other remedies which may stem from independent investigations by governmental authorities. Similarly, ISO-NE and SNWA generally would impose sanctions based on a participant's engaging in patterns of conduct defined in the RTO's rules or its tariff.

NYPP, DOE, and LG&E generally concur that RTO sanctions and penalties should only be levied for violations of RTO rules and procedures, whereas penalties and sanctions for market power abuses are matters for the regulatory and antitrust agencies, legislators, or the courts. Florida Power Corp. argues that, since an RTO does not have authority to grant or terminate market-based rate authorizations premised respectively on the absence or presence of market power, the RTO should therefore have no role in passing judgement or imposing penalties for the exercise of market power.

On the other hand, some commenters, such as East Texas Cooperatives, are more comfortable with RTO imposition of penalties and sanctions for market power abuse. PJM recommends that RTOs be able to take corrective action to ameliorate market abuses or flaws and to seek Commission approval to add penalties and sanctions to its market monitoring plan. NECPUC recommends that market monitoring be expanded to include formalized mitigation and sanction rules in connection with market design, implementation flaws and market power. NY ISO claims that RTOs should mitigate evident market power problems, on a prospective basis, by applying pre-approved remedies. CRC submits that RTOs investigate whether market power abuse results from a design flaw and report the results to the Commission for approval of its mitigation plan. WPSC sees RTOs being effective because they will have access to real-time data on system conditions and should be given authority to take appropriate corrective action immediately to respond to market abuses.

Some commenters also want sanctions against market participants for reliability rule violations. PSNM claims that RTOs should defer to existing mechanisms where they exist (such as the WSSC's Reliability Management System RMS, and NERC Reliability Standards and Measures) for sanctions against market participants for poor performance, rather than create new monitoring and sanction systems for RTOs. Similarly, Desert STAR submits that any RTO should be allowed to pass the reliability performance standards sanctions on to participants who do not comply. SMUD concurs that an important aspect of enforcing reliability standards is ensuring that the RTO has sufficient authority to police and investigate the markets they administer, and assess fines and other appropriate penalties, or resolve disputes amongst market participants as to any alleged market abuse.

A few commenters also address the Commission's questions about how much discretion the RTO should have in setting penalties (e.g., should the RTO's penalty authority be limited to collecting liquidated damages). Nevada Commission submits that RTOs should be allowed to impose specific penalties and sanctions for non-compliance with RTO rules based on liquidated damages and not punitive damages. Cal ISO and Metropolitan believe that penalties should be limited to liquidated damages. Cal ISO argues that for cases of repeated or intentional violations or serious abuses of market power, the RTO should seek relief, including imposition of punitive damages, from the Commission or other appropriate agencies such as the Justice Department. Metropolitan argues that liquidated damages sought by an RTO should be approved by the Commission. And Duke opposes the RTO assuming the role of market monitor and enforcer; therefore, it recommends that terms and conditions for any penalties the RTO might impose should be agreed upon by contract during the RTO development process.

On the other hand, WPSC claims that the RTO should have the discretion to determine the amounts of adequate sanctions and penalties to discourage anti-competitive conduct. Whether the RTO has acted properly can always be reviewed after the fact through a dispute resolution procedure either through the Commission or the Justice Department. NASUCA contends that sanctions and other penalties should be large enough to be an effective deterrent. It suggests that a for-profit RTO may have incentives to impose unjustified penalties and should be required to allocate all revenue derived from sanctions and penalties in a way that benefits customers. SMUD offers that, since liquidated damages are a mere proxy designed to make a victim whole for a transgression, they do not really serve as a deterrent to market abusive conduct.

Several commenters address whether the SEC model of regulating stock exchanges, i.e., requiring extensive and sophisticated market monitoring of stock exchanges, should applicable to RTO market monitoring. Some commenters, such as EEI and PP&L, do not believe the model is applicable. EEI claims that monitoring scheme in the securities industry is an exception because in most industries the market participants bring competitive problems to the attention of antitrust authorities. Sithe also opposes any emulation of the NASD or NYMEX model of self-regulation at this time because of the limited amount of market experience to date.

PJM/NEPOOL Customers and Cal ISO, however, contend that the RTO monitoring function should be similar to that of a stock exchange because the RTO is designed to ensure that the exchange of electricity can occur readily and easily in a competitive marketplace.

Commission Conclusion

In the NOPR, the Commission proposed that RTOs perform a market monitoring function. Many commenters raise a number of issues regarding market monitoring. The issues largely encompass the following concerns: the need for and scope of a market monitoring function; who should perform this function and how it should be performed; and what are the specific components or procedures of a market monitoring plan.

The Commission recognizes that the market monitoring concept is new and not yet well-refined, either at the Commission or within existing ISOs. We also acknowledge the apprehensions of some parties that market monitoring by an RTO could intrude into markets and affect their behaviors. The Commission, however, is engaged in finding ways to understand market operations in real-time, so that it can identify and react to any problems that are preventing the most efficient operations. It also has a responsibility to protect against anticompetitive effects in electricity markets.[579] If we are to satisfy this goal, we must systematically assess whether our policies and decisions are consistent with this responsibility. Market monitoring is an important tool for ensuring that markets within the region covered by an RTO do not result in wholesale transactions or operations that are unduly discriminatory or preferential or provide opportunity for the exercise of market power. In addition, market monitoring will provide information regarding opportunities for efficiency improvements.

However, in light of the different forms of RTOs that could be developed by market participants and the varying types of markets an RTO may be operating within its region, different market monitoring plans are likely to be appropriate for different RTOs. Consequently, after careful consideration of the comments, the Commission will require that RTO proposals contain a market monitoring plan that identifies what the RTO participants believe are the appropriate monitoring activities the RTO, or an independent monitor, if appropriate, will perform. We believe that such approach will provide those proposing an RTO sufficient flexibility to design a monitoring plan that fits the corporate form of the RTO as well as the types of markets the RTO will operate or administer. We have revised the regulatory text for the RTO market monitoring function to reflect our decision to allow this flexible approach.

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[579] See Gulf States Utilities v. FPC, 411 U.S. 747, 758-59 (1973).

Although we decline at this time to prescribe a particular market monitoring plan or the specific elements of such a plan, the RTO must propose a monitoring plan that contains certain standards. The monitoring plan must be designed to ensure that there is objective information about the markets that the RTO operates or administers and a vehicle to propose appropriate action regarding any opportunities for efficiency improvement, market design flaws, or market power identified by that information. The monitoring plan also must evaluate the behavior of market participants, including transmission owners, if any, in the region to determine whether their behavior adversely affects the ability of the RTO to provide reliable, efficient and nondiscriminatory transmission service. Because not all market operations in a region may be operated or administered by the RTO (e.g., there may be markets operated by unaffiliated power exchanges), the monitoring plan must periodically assess whether behavior in other markets in the RTO's region affect RTO operations and, conversely, how RTO operations affect the efficiency of markets operated by others. Reports on opportunities for efficiency improvement, market design flaws and market power abuses in the markets the RTO operates and administers also must be filed with the Commission and affected regulatory authorities.

In developing its market monitoring plan, the RTO should identify the markets that will be monitored, i.e., transmission, ancillary services or any other market it may develop (e.g., congestion management). With regard to those markets, the monitoring plan should examine the structure of the market, compliance with market rules, behavior of individual market participants and the market as a whole, and market power and market power abuses. The monitoring plan should also address how information will be used and reported. The monitoring plan should indicate whether the RTO will only identify problems and/or abuses or whether it also will propose solutions to such problems. We note that sanctions and penalties may be appropriate for certain actions such as noncompliance with RTO rules. However, the monitoring plan should clearly identify any proposed sanctions or penalties and the specific conduct to which they would be applied, provide the rationale to support any sanctions, penalties or remedies (financial or otherwise) and explain how they would be implemented. With regard to the reporting of market monitoring information, the monitoring plan should indicate the types and frequency of reports that will be made and to whom the reports will be sent. Under the FPA, the Commission has the primary responsibility to ensure that regional wholesale electricity markets served by RTOs operate without market power. An appropriate market monitoring plan must provide an objective basis to observe markets and, if appropriate, provide reports and/or market analyses. Market monitoring also will be a useful tool to provide information that can be used to assess market performance. This information will be beneficial to many parties in government as well as to power market participants. This includes state commissions that protect the interests of retail consumers, especially where they are overseeing the development of a competitive electric retail market. We note, however, that the market monitoring function for the RTO does not limit the ability of each state within the RTO's region or other authorities to decide the nature and extent of its own market monitoring activities.

We are not requiring a plan that necessarily involves the collection of data the RTO would not collect in its ordinary course of business. We believe that the information collected through the RTO market monitoring plan will reflect data that the RTO will collect or have access to in the normal course of business (e.g., bid data, operational information). In light of our requirements that the RTO have operational control over the transmission facilities transferred to it and the RTO be the security coordinator for its region, the RTO will be in the best position to perform (or provide information to another entity, if appropriate, for it to perform) objective monitoring functions for the markets that the RTO operates or administers in the region.

In response to commenters' arguments that RTO market monitoring results in an impermissible shift of Commission authority to other entities, we emphasize that performance of market monitoring by RTOs is not intended to supplant Commission authority. Rather it will provide the Commission with an additional means of detecting market power abuses, market design flaws and opportunities for improvements in market efficiency. Further, because market monitoring plans will be required to be filed with and approved by the Commission as part of an RTO proposal, we will retain the ability to determine what, how and by whom activities will be performed in the first instance.

Because we believe market monitoring is essential, we decline to set any sunset date for monitoring at this time. However, as bulk power markets evolve and become more competitive, we may revisit the need for the type of monitoring the Rule requires.

7. Planning and Expansion (Function 7)

In the NOPR, the Commission proposed that the RTO planning and expansion process must satisfy certain standards. Specifically, RTOs would be required to: (1) encourage market-motivated operating and investment actions for preventing and relieving congestion; and (2) accommodate efforts by state regulatory commission to create multi-state agreements to review and approve new transmission facilities, coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary. We suggested that RTOs be designed to promote efficient use, which requires efficient price signals such as congestion pricing, and efficient expansion of their regional grid, which requires control over planning and expansion. We specifically proposed that the RTO have ultimate responsibility for both transmission planning and expansion within its region. If the RTO is unable to satisfy the planning and expansion requirement when it commences operation, we proposed that the RTO must file a plan with specified milestones that will ensure that it meets this requirement no later than three years after initial operation. In addition, the Commission sought comment on whether three years is an appropriate amount of time for implementation of this function. [580]

Comments

Encourage Market-Motivated Operating and Investment Actions for Preventing and Relieving Congestion

Many commenters support the Commission's proposal to require that an RTO must ensure the development and operation of market mechanisms to plan and refinance transmission system expansion. As part of this an RTO should provide all transmission customers with efficient price signals that show the consequences for their transmission use decisions. [581]

Some commenters, such as JEA and Williams believe that this role is best performed by for-profit entities because system expansion decisions must be driven by economic considerations. Entergy also contends that a transco will not create any bias in the method of grid expansion.

Los Angeles agrees that an RTO should rely upon market signals and market solutions in assessing all feasible options (e.g., construction of new generation, redispatch of existing generation, grid expansion) to assure the least-cost option is pursued. NASUCA also argues that the Commission should mandate that RTOs use least-cost

[580] FERC Stats. & Regs. ¶ 32,541 at 33,751-53.

[581] See, e.g., United Illuminating, Wyoming Commission, Industrial Consumers, Champion, NSP, PG&E, Williams, LG&E, FTC and APX.

planning on a region-wide basis for transmission system expansions and upgrades. It notes that the larger the region over which least-cost planning is conducted, the more economically efficient the outcome is likely to be. If market solutions do not develop or are not timely, Los Angeles believes that the RTO must have the power to resolve the transmission problem. LG&E proposes that RTOs be permitted to use competitive bidding as a means to meet new transmission investment needs.

EPA believes that RTOs should adopt a resource planning process with sufficient flexibility to consider non-traditional resources and to assign appropriate values to their unique benefits. EPA further believes that RTOs should be encouraged to take into account environmental costs and benefits that are not reflected in resource prices.

Puget suggest that the Commission should recognize that the concept of RTOs may contain some elements that do not enhance the reliable operation of the transmission grid. Puget requests that the Commission should address more fully how it will mitigate the effects of the severance of generation and transmission planning and operation and how it plans to ensure maximum reliability at the lowest integrated costs.

NASUCA recommends that the Commission require RTOs to develop a baseline regional transmission expansion plan that would identify the regional system's ability to meet essential NERC reliability criteria and isolate potential constraint areas of the existing system where upgrades may be necessary or additional generation desirable. Such a baseline plan could provide a valuable tool to market participants in signaling the best locations for new generation projects. Entergy proposes the use of a regional transmission plan that includes a regional transmission planning summit process involving all stakeholders.

TAPS, however, questions whether market-based mechanisms to expand the transmission grid will emerge readily from an efficient short-term transmission pricing regime that accounts properly for the costs of congestion. TAPS asserts that, while efficient congestion pricing is an important component of a well-designed transmission regime, it is not the answer to the concerns that have been raised regarding the lack of economic and regulatory incentives to expand the transmission grid.

Many commenters agree that RTOs should be responsible for conducting the studies necessary to assess the need for new transmission system enhancement. [582] However, some commenters argue that the role of the RTO should be to facilitate market investment by others in new transmission and generation, not to lead the market by making its own plans for new facilities. For example, Seattle suggests that the RTO should generate information on the locations, frequencies and costs of congested paths to guide capital investment. It believes that the RTO need not make capital investments directly; rather it should seek market mechanisms, such as requesting bids for needed capacity, to encourage investments. EME states that performance of this role requires

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[582] See, e.g., EME and Seattle.

accurate accounting for the impact of congestion and new generation, and proper allocation of costs to those that require such costs to be incurred.

To ensure that transmission expansion decisions are not biased, ComEd proposes that RTO functions be performed by two linked organizations that together make up a "Binary RTO." ComEd envisions that the Binary RTO would consist of for-profit independent transmission companies (ITCs), each operating a large aggregation of existing transmission systems, under the oversight of an independent, not-for-profit Regional Transmission Board (RTB). The ITCs will identify transmission additions, upgrade opportunities, and prepare long-range plans which would be reviewed by the RTB and subsequently integrated in an RTB-wide planning system.

Powerex believes that it is better to eliminate congestion at its source through facilities upgrades, if economically and environmentally feasible, than to attempt to manage congestion on a long-term basis through congestion pricing schemes.

Many commenters support the concept that RTOs must be responsible for transmission planning and that single-system planning should be the objective of the RTO planning process.[583] Commenters differ, however, on the extent of the RTO's role in the planning process. Some commenters, such as Powerex, argue that the RTO must have control over transmission service, planning, system impact studies and facilities studies,

[583] See, e.g., PNGC, Wisconsin Commission, EAL, Entergy, PJM, Minnesota Power and Montana-Dakota.

and the authority to determine the need for, and require the implementation of, transmission upgrades by member utilities. Other commenters, such as LIPA and H.Q. Energy Services, propose that, in the absence of transmission expansion proposals from current or proposed market participants, the RTO should have the responsibility for assessing whether transmission improvements are needed and, if a need is found, the RTO should have the authority to order such expansion.

Some commenters such as NY ISO, on the other hand, express concern that exclusive authority by the RTO over transmission planning is overly restrictive. NY ISO claims that entities which are responsible for coordinating transmission expansion, but which lack authority to make enforceable planning decisions, can nevertheless achieve the Commission's primary transmission expansion-related goal, i.e., ensuring that investments in new transmission facilities are coordinated to ensure a least-cost outcome that maintains or improves existing reliability levels.

H.Q. Energy Services objects to NY ISO's arguments as being merely concerned with preserving its so-called "two-tier" governance system which provides NY ISO transmission owners with significant authority, or veto power, over interconnections with generating facilities and over decisions related to transmission system planning and expansion. H.Q. Energy Services does not believe that the two-tier approach is appropriate unless the RTO has ultimate decision-making authority.

Many commenters agree with the proposal that an RTO must be ultimately responsible for all transmission expansions and upgrades. [584] These commenters claim that transmission operations must be conducted on an independent and fair basis and must be undertaken by an impartial entity if transmission services are to be offered on a truly non-discriminatory basis. They argue that vesting the RTO with the ultimate responsibility for expanding transmission systems eliminates the conflict that is inherent in vesting these responsibilities with an entity that also has commercial interests that are competing with users of the system.

Although SMUD supports having the RTO be responsible for transmission planning and expansion, it cautions that, in such a paradigm, people that have no responsibility to the ratepayers will be deciding planning and expansion issues. Therefore, SMUD argues that the Commission needs to scrutinize the recovery of the costs of such expansion to ensure that such expansion decisions and costs are prudent, just and reasonable.

Several commenters agree that the RTOs can and should play a significant role in the transmission planning and expansion process. [585] Some of these commenters, such as NYPP and Mass Companies, however, do not believe that the Commission should require

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[584] See, e.g., San Francisco, SoCal Cities and CMUA.

[585] See, e.g., NYPP, Industrial Customers, Mass Companies and Nevada Commission.

that RTOs have authority to order a transmission owner to modify or expand its transmission system. Nevada Commission believes that transmission owners should be allowed to assist an RTO in the development of grid planning criteria and could take the lead in such grid planning with RTOs performing more of an overview role. Professor Joskow states that the transmission owners, operating through a sound RTO/ISO transmission planning process should be expected to be the primary, but not necessarily the exclusive, source of network enhancement initiatives. WEPCO argues that transmission owners should be integrated into the RTO regional transmission plans where they can be improved and expanded to meet regional needs most efficiently. Turlock contends that the RTO's authority over the transmission system it operates must be limited to that system. Turlock argues that the RTO should not have the ability to force expansion of lower voltage or tangentially related facilities which are beyond the area of its responsibility, even if those other facilities might have a small but theoretically possible impact on the RTO's facilities.

CP&L supports a coordinated planning approach which would be similar to the planning approaches identified in the Midwest ISO and the Alliance RTO filings, where the RTO would have responsibility for review of the transmission plan, but the individual transmission-owning entities would provide the necessary input to facilitate the development of the comprehensive RTO transmission plan. East Kentucky argues, however, that an individual transmission owner should be able either to require or to veto the building of a particular RTO facility.

MidAmerican disagrees with the proposal that the RTO have the ultimate responsibility for both transmission planning and expansion in the region. MidAmerican claims that existing regional transmission groups (RTGs) have clear and prominent roles in transmission expansion decisions in which planning for transmission improvements are coordinated through collaborative processes that already involve many interested stakeholders in the widest fashion possible. MidAmerican states that throughout the MAPP region there is broad support for continuing transmission planning and expansion decisionmaking as a collaborative function and that the existing collaborative processes adequately accommodate RTO participation.

Central Maine believes that RTOs/ISOs can and should play a significant role in the transmission planning and expansion process, but disagrees with the Commission's proposal to give ISOs ultimate responsibility for transmission planning and expansion. Central Maine does not object to ISOs having oversight responsibility in these area, but Central Maine believes that the planning and engineering functions should be a shared responsibility between utilities and RTO, i.e., the Commission should consider utility planners as a satellite to the ISO/RTO similar to satellite function served by utility control centers in monitoring, switching and dispatching. Central Maine states that the

Commission should grant individual transmission owning utilities an equal voice in determining the technical aspects of transmission planning and expansion.

Although Big Rivers believes that, as proposed in the NOPR, the RTO should be the default provider of transmission planning and expansion, it agrees with NRECA that incumbent transmission owners should have the first opportunity to build required transmission system expansion with RTO ability to facilitate needed construction by others.

Some commenters suggest specific tasks and functions that the RTO should perform or have the ability to require as part of the transmission planning and expansion function. [586] For example, SRP proposes that at a minimum, each RTO should have the authority to: (1) direct transmission owners to study and evaluate system performance and to develop plans to solve known reliability or adequacy problems; (2) revise or combine elements of transmission owners' plans to achieve the most efficient and reliable transmission expansion plan; (3) approve or reject any component of the RTO transmission plan developed by a transmission owner; and (4) approve facility additions by third parties.

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[586] See, e.g., Project Groups, LIPA and SRP.

Accommodate Efforts by State Regulatory Commission to Create Multi-State Agreements to Review and Approve New Transmission Facilities

Many comments concur that multi-state agreements are to be encouraged and that the RTO should be designed to work within that structure. [587] Commenters, including NSP and Nevada Commission, encourage the Commission to provide an active role for RTOs to participate with state and local government in the siting and licensing of new facilities. PJM states that a cooperative relationship between RTOs and the states is essential to effective transmission expansion planning. In PJM's view, states are more likely to trust the planning decisions of RTOs that have no commercial interest in transmission and generation expansion than decisions made by transmission-owning entities, which have commercial interests.

Cinergy recommends that the final rule include a Commission commitment to proceed aggressively to establish a forum to encourage coordination of RTO planning and expansion among states through multi-state certification agreements and multi-state regional planning boards. Cinergy notes, however, that the creation of a forum or agency to review grid planning and expansion that would consider the public interest beyond the constraints of state boundaries may require federal legislation. If so, the Commission should be aggressive in its dialogue with Congress to obtain the requisite legislative relief.

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[587] See, e.g., Illinois Commission, DOE and New Smyrna Beach.

The Kentucky Commission suggests creating a voluntary "Joint Board on Regional Transmission Siting" to develop and review standards for transmission expansion. The Joint Board would include participation from the Commission, state commissions, RTOs, and other interested parties. The Joint Board would also convene ad hoc committees to review specific transmission expansion proposals. Pennsylvania Commission also prefers a joint Federal-state approach towards regulating RTO site approvals, expansion, innovation and customer service. It notes that a joint Federal-state approach has been used with success in other areas, such as the Susquehanna River Basin Commission, the Delaware River Basin Commission and the Joint Pipeline Office which regulates the Trans-Alaska Pipeline System.

Illinois Commission recommends that accommodation of multi-state efforts be expanded to include the possibility of multi-state regional regulatory oversight organizations. Such organizations could be instrumental in coordinating regional solutions to regulatory and policy issues.

Otter Tail expresses concern that multi-state agreements may not actually add to the efficient use and expansion of the interstate transmission system due to a danger that these types of agreements could be mired in state-versus-state political conflict and become unworkable, to the detriment of transmission owners, generators, and ultimately customers. Industrial Consumers also does not believe that requiring an accommodation with "multi-state agreements" is necessarily productive. It states that nothing now prevents such coordination among states, yet there is no obvious evidence that this will work. Industrial Customers believes that states will always reserve the right to veto a project that may be partially situated within their jurisdiction, regardless of the benefits elsewhere.

East Texas Cooperatives believes that retention of state public utility commission authority over siting (and other necessary approvals) is necessary to control the risk of overbuilding because RTOs will have no real incentive to limit facility construction.

Commenters generally express support for the proposal that the RTO build on existing RTG processes. [588] For example, Industrial Consumers urges that the Commission require existing RTGs to merge their functions with the RTOs because RTGs should not be allowed to develop an institutional culture that diverges from the goals and objectives of RTOs.

New Smyrna Beach and Oneok claim that market participants will undoubtedly benefit from a multi-state siting process for transmission because it may make siting of new generation easier if there is more certainty that related transmission siting decisions will be made on a timely basis with one-stop shopping.

Several commenters address the role of the Commission in the RTO planning and expansion process. Detroit Edison and Wolverine Cooperative support the establishment of the Commission as the primary channel of certification for transmission siting,

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[588] See, e.g., Wisconsin Commission, Industrial Customers and SRP.

construction, and expansion. Detroit Edison states that regional reliability organizations and the RTOs in each reliability region should be permitted to determine necessary changes and additions in transmission with input from transmission owners, control area operators, and other interested parties. It is vital, it states, that a single administrative agency resolve issues related to the siting of transmission facilities on a regional basis and have the authority to approve transmission expansion plans on a timely basis. Detroit Edison believes that the Commission should fill the important role of sole regulator over transmission siting and construction, just as it currently does in approving the siting and construction of natural gas pipelines, and it urges the Commission to work to gain such authority.

Pennsylvania Commission recommends that, if an RTO determines that transmission expansion is necessary, it should file with the Commission to demonstrate that need. Once the Commission determines a need exists within the RTO, the RTO should then file with the appropriate states for a determination of the siting issues. Pennsylvania Commission believes that vesting authority for determining the need for transmission expansion with the Commission solves several problems that are certain to arise in state forums. Federal determination of the need for transmission expansion obviates the burden of filing with multiple jurisdictions and possibly receiving conflicting determinations.

Otter Tail states that Commission should seriously consider whether the public interest would be better served through adoption of a transmission siting policy that is similar to review of interstate natural gas pipelines.

NY ISO claims that in many cases transmission expansion is delayed or blocked entirely by environmental and other transmission siting regulations. Nevertheless, NY ISO supports the NOPR's proposal that RTOs participate in efforts to create multi-state transmission expansion agreements.

East Kentucky believes that there needs to be some regulatory oversight authority for facilities that are deemed necessary by an RTO planning staff. East Kentucky proposes that this regulatory authority be the Commission or a regional regulatory authority.

Conlon recommends that the Commission have the necessary authority to enforce reasonable siting request, or critically needed future transmission lines could be delayed causing a reliability risk. Granting the right of eminent domain to transcos or ISOs in Federal legislation would be another approach. This could be accomplished by the Commission recommending to Congress that it have the right of eminent domain.

LG&E believes that it is important that state authority over system expansion not impede necessary improvements that enhance the efficiency of the regional grid that is, or will be, subject to RTO control. Ultimately there may be a need for a congressional solution to the current balkanized system for authorizing grid expansion. In its comments, the East Central Area Reliability Council explicitly calls for such legislative action based on its concern that transmission facility expansion requests will fail as they become bogged down in multiple state reviews. LG&E shares this concern. Still, until such time as the statutory framework for transmission expansion is amended, LG&E believes that RTOs represent an opportunity for coordinating regional transmission expansion needs among transmission owners and state authorities.

Project Groups maintains that RTOs should be required to coordinate and lead in the development of comprehensive least cost regional plans for assuring short- and long-term system reliability, and they must coordinate the actions necessary for implementing timely system upgrades and additions pursuant to those plans. For example, RTOs must be given the authority to petition state and local regulators for necessary siting authorizations, including certificates of need or public necessity and environmental permits, as well as the authority to order construction of facilities sited and permitted under state regulatory authorities. The Commission should encourage state reliance on RTO-approved plans as the primary basis for the exercise of eminent domain powers under state law.

Puget notes that state condemnation powers granted to utilities are usually limited for the benefit of the citizens of the state in which the utility operates. It is not clear that a state utility can delegate its state condemnation power to a regional RTO. Therefore, the final rule should expressly address how state condemnation authority can be legally exercised by a regional RTO.

NASUCA maintains that the RTO regional planning efforts must not displace state government siting authority. NASUCA states that the final rule should specifically recognize state statutory authority to regulate siting of transmission facilities. For other planning and expansion matters, the Commission should require RTOs to establish a process to ensure that the RTO obtains input from state government agencies with respect to the regional transmission plan. Nevada Commission states that it is imperative that the RTO coordinate transmission siting and planning with state agencies. Tri State believes that states should continue to fulfill their traditional roles in siting transmission facilities. However, it notes that it may be necessary for the states to consult with the RTO on transmission facility certification since the RTO will be charged with overall responsibility for transmission planning and will be required to work cooperatively with states and other regional groups.

CP&L supports state and local governments retaining the authority for certification and siting of new transmission facilities. These government agencies are closer to the local residents who will be affected and can best evaluate the great number of factors that must be considered in approving transmission routes.

Several commenters address the issue of eminent domain authority as a component of the transmission planning and expansion function. East Kentucky believes that the issue of eminent domain needs to be addressed for not only RTOs, but also for the entire open access transmission network. East Kentucky questions whether an entity, if required by an RTO or the Commission to construct a transmission facility, has eminent domain authority that is sufficient to allow the entity to acquire all property rights necessary to construct the required facility. Consequently, East Kentucky argues that, as a general proposition, Congress needs to grant federal eminent domain authority to any entity that is required by the Commission or any form of RTO to build a facility so that such entity can acquire private property rights under Federal law. Because it believes that siting of transmission has become the principal impediment to transmission expansion, EPSA also advocates that the RTO should be delegated sufficient authority to direct transmission owners or others to excise their eminent domain authority, as necessary, to implement transmission system expansion plans independent of the source of funds or the beneficiary of the project. Under current law, this authority must come from the states. Thus, EPSA also advocates the passage of Federal legislation that vests the Commission with primary jurisdiction over major transmission planning and siting decisions, perhaps subject to a requirement that the Commission consult with a regional siting authority or a consortium of affected state siting boards.

Central Maine disagrees and recommends that the Commission should reject EPSA's comments. Central Maine notes that, if a state government intends that an RTO have the power of eminent domain, the state legislature will grant it. Central Maine argues that RTOs should not be granted the power to do something indirectly that they may not do directly. Consequently, it believes that EPSA must pursue its proposal through the enactment of state legislation.

Whether Three Years Is an Appropriate Amount of Time for Implementation of This Function

Several commenters support the Commission's proposal to allow up to three years to implement the planning and expansion function. [589] Some commenters, however, believe that three years is too short. [590] South Carolina Authority suggests a five-year period. Florida Commission believes that it is premature to set any time limit for implementation of the planning and expansion function.

On the other hand, several commenters believe that three years is too long a period. [591] Most of these commenters believe that the planning and expansion is such an important function that its implementation should not be delayed at all. NYC suggests that implementation should not delayed more than a year. SRP argues that the uncertainty the currently exists about who ultimately will be responsible for building and paying for new transmission facilities is causing delays in upgrades. According to SRP, requiring the RTO to perform this function upon commercial operation will eliminate this

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[589] See, e.g., Tri State, SoCal Edison and PNM.

[590] See, e.g., NECPUC, Duke and South Carolina Authority.

[591] See, e.g., Champion, NYC, Turlock, SRP, TDU Systems and Industrial Customers.

uncertainty. Industrial Customers also argues that any delay should not be used as an excuse to stall the construction of any facility for which the need has been established. SRP suggests that, if a delay in implementation is permitted, the RTO should be required to identify the entity responsible for financing and building transmission expansion prior to the RTO assuming such responsibility.

Commission Conclusion

We reaffirm the NOPR proposal that the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities. In carrying out this overall responsibility, the Commission has concluded that the NOPR's three separate requirements for RTO planning and expansion must also be satisfied or, in the alternative, the RTO must demonstrate that an alternative proposal is consistent with or superior to these three requirements. Specifically, an RTO must satisfy the requirement to: (1) encourage market-motivated operating and investment actions for preventing and relieving congestion; (2) accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities, coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary; and (3) file a plan with the Commission with specified milestones that will ensure that it meets the overall planning and expansion requirement no later than three years after initial operation, if the RTO is unable to satisfy this requirement when it commences operation.

As noted above, the RTO should have ultimate responsibility for both transmission planning and expansion within its region. The rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability. We also recognize that the RTO's implementation of this general standard requires addressing many specific design questions, including who decides which projects should be built and how the costs and benefits of the project should be allocated. [592] As with other requirements of the Final Rule, we propose to give RTOs considerable flexibility in designing a planning and expansion process that works best for its region. It is both inevitable and desirable that the specific features of this process "should take account of and accommodate existing institutions and physical characteristics of the region." [593] We emphasize that, as the transmission provider in the region, the RTO is required to provide service under a tariff that is consistent with or superior to the Commission's pro forma tariff, and that tariff obligates the transmission provider to expand and modify its system to provide the

[592] FERC Stats. & Regs. ¶ 32,541 at 33,751-52.

[593] Id. at 33,752.

services requested under the pro forma tariff.[594] Because an RTO may not own all of the facilities it operates, we clarify that nothing in this Rule relieves any public utility of its existing obligation under the pro forma transmission tariff to expand or upgrade its transmission system upon request. Accordingly, we shall evaluate each RTO proposal to ensure that the RTO can direct or arrange for the construction of expansion projects that are needed to ensure reliable transmission services.[595] However, the Commission reiterates, as discussed below, its strong preference for market-motivated operating and investment actions.

We further note that the pricing mechanisms and actions used by the RTO as part of its transmission planning and expansion program should be compatible with the pricing signals for shorter-term solutions to transmission constraints (i.e., congestion management) so that market participants can choose the least-cost response. Otherwise, their choices may reflect less efficient outcomes for the marketplace. For example, if the

[594]See, e.g., Section 15.4 of the pro forma tariff which requires the transmission provider to use due diligence to expand or modify its transmission system to provide requested services. Also, Section 28.2 of the pro forma tariff requires the transmission provider to plan, construct, operate and maintain its transmission system in order to provide network service, and to endeavor to construct and place into service sufficient transmission capacity to deliver network resources to network customers on a basis comparable to its own use of the transmission system.

[595]We note that existing ISOs have addressed similar issues successfully. For example, the PJM ISO is responsible for expansion planning, but the transmission owners remain obligated to undertake upgrades necessitated by the plan, 81 FERC ¶ 61,257 at 62,275 (1997).

price of expansion overstates its cost (or the price of congestion management understates actual congestion cost), market participants likely will continue congestion management solutions to a transmission constraint when expanding the system to relieve congestion is more efficient.

Market-Motivated Actions

Planning new generation or new transmission requires a coordinated approach to ensure reliability and efficient congestion management. However, this does not necessarily imply that all transmission expansions must be centrally planned by the RTO. Where feasible, an RTO should encourage market approaches to relieving congestion. A market approach will require providing all transmission customers with access to well-defined transmission rights and efficient price signals that show the consequences of their transmission usage decision. If the RTO's market approach is successful, the decisions of where, when and how to relieve congestion will be driven by economic considerations.

Most commenters agree with the NOPR proposal that RTOs should rely upon market signals and market solutions in assessing all feasible options (e.g., construction of new generation, redispatch of existing generation, as well as expansion of the transmission grid) to assure that the least costly option is pursued. If an RTO can facilitate market-motivated decisions, several commenters point out that its planning role may largely be limited to extreme circumstances where continuing congestion in an area threatens reliability. However, we also recognize that different market approaches to relieving congestion are still in the early stages of development. Similarly, while market approaches to expansion are the subject of much discussion, they are also in the early stages of development. [596] It is not the intent of the Commission either to mandate a market approach to the exclusion of an executive decision by the RTO or to mandate any particular market approach.

Nevertheless, if any market-driven approach is to be successful, there must be accurate price signals that reflect the costs of congestion and expansion costs. As we stated in the NOPR, accurate price signals are the link between current usage and future expansion. Therefore, as discussed in more detail in Section III.E.2 Congestion Management, every RTO must establish a system of congestion management that establishes clear rights to transmission facilities and provides market participants with price signals that reflect congestion and expansion costs. In implementing its planning and expansion responsibility, an RTO must ensure that its decisions are not unduly discriminatory and produce efficient outcomes.

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[596] For example, TDU Systems and other commenters suggest that, by promoting competition for new construction, the RTO can minimize construction cost and also reduce its own risk profile. For example, an ISO in Victoria, Australia (VPX), which operates, but does not own transmission assets, uses competitive bidding for new transmission facilities. At the Regional ISO Conference in Richmond, Virginia on June 8, 1998, Raymond Coxe described how VPX's strategy resulted in a number of bidders competing for the right to build, own and operate new facilities. He concluded that the "result of this competition was a lower price to the consumers of Victoria than would have resulted from regulated transmission service by the largest incumbent provider." Transcript at 86, Docket PL98-5-006.

The Commission reaffirms its statement in the NOPR that independent governance of the RTO is a necessary condition for nondiscriminatory and efficient planning and expansion. While accurate price signals can signal the need for expansion, such expansion may not be achieved if an RTO operates under a faulty governance system (e.g., a governance system that allows market participants to block expansions that will harm their commercial interests).

Multi-State Agreements and RTGs.

The final rule fully recognizes the statutory authority of the states to regulate siting of transmission facilities. Currently, state and local governments and regulatory agencies have exclusive authority over the siting process. Therefore, an RTO's planning and expansion process must be designed to be consistent with these state and local responsibilities.

RTOs must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The Commission encourages the development of multi-state agreements or compacts to review and approve new transmission facilities. This would expedite transmission construction and eliminate duplicative (and possibly conflicting) reviews by multiple states. To facilitate any voluntary actions taken by our state colleagues, we will require that the RTO planning and coordination system must able to accommodate the possible emergence of new regional regulatory systems.

Existing RTGs have clear and prominent roles in transmission expansion decisions in which planning for transmission improvements are coordinated through collaborative processes. To avoid duplicative efforts, the RTO process must build on existing RTG planning processes. Over time, since the RTO will have ultimate responsibility for planning the entire transmission system within its region, we expect that the functions of an RTG will be assumed by an RTO to avoid unnecessary duplication of effort.

Three-Year Implementation.

If the RTO is unable to satisfy the planning and expansion function when it commences operation, it must file a plan with the Commission with specified milestones that will ensure that it meets this requirement no later than three years after initial operation. Recognizing that the planning and expansion function may require coordination among multiple parties and regulatory jurisdictions, we do not require this function to be in place at the initial operation of the RTO. We continue to believe that three years is a reasonable deadline for creating an operational planning and expansion system. Therefore, we will not extend this deadline or the requirement to file a plan with the Commission with an implementation timetable. This time period could be affected by the RTO's scope, the number of states and market participants, and implementation costs; however, the urgent needs of the electricity markets make us disinclined to extend these deadlines.

However, the delay should not stall the construction of new or enhanced facilities for which needs have been established, unless the RTO makes a positive decision that the facility is not in the best interests of the region. Delaying transmission expansion could result in significant market inefficiencies as well as unacceptable risks to reliability given the long regulatory and construction lead times required to build new facilities.

8. Interregional Coordination (Function 8)

In Order No. 888, the Commission identified eleven principles it would use to assess Independent System Operator (ISO) proposals submitted to the Commission. [597] One of these principles required that the ISO develop mechanisms to coordinate with neighboring control areas to ensure reliability and the provision of transmission services that cross system boundaries. The RTO NOPR encouraged transmission entities to consider ways to reduce impediments to transactions among themselves, [598] but a coordination requirement was not included explicitly in the RTO NOPR. Several commenters pointed out that there was no explicit coordination requirement proposed in the RTO NOPR and recommended including a function for RTOs similar to the coordination principle in Order No. 888.

Comments

[597] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,730-32.

[598] FERC Stats. & Regs. ¶ 32,541 at 33,758.

Several commenters identify coordination with other regions as a necessary element that should be added more explicitly to the RTO functions.[599] These commenters express this need as either required to ensure reliability or necessary for bulk power markets to operate over sufficiently large areas. For example, NERC states that the need for such coordination effort has increased as the management of short-term reliability of the interconnected bulk power system and the operation of increasingly competitive bulk power markets have become inseparable. Accordingly, NERC recommends that an additional function be added to the final rule that requires RTOs to integrate their market interface practices and reliability practices. It identifies OASIS standards, information sharing with neighboring RTOs, ancillary services requirements, parallel path flows, transmission loading relief, and interregional congestion management, as practices and standards that need to be integrated.

Duquesne states that efficiencies can be realized from coordinating and developing a seamless marketplace. It recommends that the Commission require RTOs to coordinate and plan for seamless and uniform transmission rules, scheduling systems and procedures, and reliability standards. In addition, Oneok suggests that the Commission encourage neighboring RTOs to form reliability compacts under which loop flow and

[599]Many parties supported this requirement including NERC, Justice Department, NARUC, NASUCA, Oneok, PJM, Duquesne and Industrial Consumers.

other issues involving interregional reliability impacts can be resolved.[600] Also, Wyoming Commission believes that the Commission should be flexible with respect to inter-RTO interaction and that it may be appropriate to address these issues later rather than in initial RTO filings.

Commission Conclusion

Coordination of activities among regions is a significant element in maintaining a reliable bulk transmission system and for the development of competitive markets. In the NOPR, we discussed several region-to-region coordination activities in connection with the parallel path, congestion management, and expansion planning functions. However, the comments persuade us to add a more general inter-regional coordination requirement as one of the minimum RTO functions.

We will require an RTO to develop mechanisms to coordinate its activities with other regions whether or not an RTO yet exists in these other regions.[601] If it is not possible to set forth the coordination mechanisms at the time an RTO application is filed, the RTO applicant must propose reporting requirements, including a schedule, for itself to provide follow-up details as to how it is meeting the coordination requirements of this

[600] ISO-NE, NY ISO and PJM recently signed a memorandum of understanding concerning interregional coordination activities.

[601] This is similar to the existing ISO Principle #10 in Order No. 888 for single control area ISOs: "An ISO should develop mechanisms to coordinate with neighboring control areas."

function. We expect the RTO to work closely with other regions to address inter-regional problems and problems at the "seams" between the RTOs. Therefore, as recommended by NERC and others, we will add the following regulatory text to our RTO Final Rule functions:

> (8) Interregional Coordination: The Regional Transmission Organization must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

An RTO proposal must explain how the RTO will ensure the integration of reliability and market interface practices. An RTO may ensure the integration of these practices either by developing integration practices itself or by cooperating in the development of integrated practices with an independent entity that covers all regions or, for reliability practices, covers an entire interconnection. The term, interconnection, [602] refers here to any one of three large U.S. transmission systems. The Eastern Interconnection covers most of the area east of the Rocky Mountains in the United States and Canada. The Western Interconnection covers an area that is mostly west of the Rocky Mountains in the United States and Canada, as well as a small portion of Mexico. The Electric Reliability Council of Texas (ERCOT) Interconnection covers much of Texas.

[602] "Interconnection" is a term used by the North American Electric Reliability Council and others to refer to an interconnected alternating current transmission system. Engineering considerations require all generators connected to any one interconnection to operate in a coordinated manner, that is, synchronously.

This provision does not mean that all RTOs necessarily must have a uniform practice, but that RTO reliability and market interface practices must be compatible with each other, especially at the "seams." RTOs must coordinate their practices with neighboring regions to ensure that market activity is not limited because of different regional practices.

We understand, as NERC pointed out in its comments, that the reliability and market interface practices are becoming highly interrelated. The reliability practices affect how markets interface with each other, and the market interface practices affect reliability. For example, TLR and congestion management are both used to unload an overloaded transmission interface, and these two practices must work together. We consider congestion management and TLR are best used as sequential steps to unload a line, with congestion management used first to unload a line in a market-oriented manner, and TLR used to unload a line in a fair manner when either congestion management is unavailable or an emergency condition requires immediate action. We therefore list below TLR as a reliability practice and congestion management as a market interface practice, understanding that these and other practices listed affect both reliability and markets.

The integration of reliability practices involves procedures for coordination of reliability practices and sharing of reliability data among regions in an interconnection, including procedures that address parallel path flows, ancillary service standards, transmission loading relief procedures, among other reliability-related coordination requirements in this Final Rule.

The integration of market interface practices involves developing some level of standardization of inter-regional market standards and practices, including the coordination and sharing of data necessary for calculation of TTC and ATC, transmission reservation practices, scheduling practices, and congestion management procedures, as well as other market coordination requirements covered elsewhere in this Final Rule.

F. Open Architecture

In the NOPR, the Commission stated its commitment to a policy of "open architecture" and proposed to require that RTOs be designed so that they can evolve over time. The Commission noted that there should be no provision in any RTO proposal that precludes the RTO and its members from improving their organization to meet market needs.[603] The Commission sought comments regarding the open architecture policy in general and the flexibility needs of RTOs in particular.

Comments

Virtually all commenters support the NOPR's open architecture concept and recommend that an RTO have the ability to evolve over time as it gains operating

[603]FERC Stats. & Regs. ¶ 32,541 at 33,753.

experience. [604] They endorse the principle of flexibility to accommodate the changing needs of the market. [605] WEPCO notes that open architecture should permit flexibility and urges the Commission not to require an RTO to be the only control area operator in the region. [606] Ontario Power states that the open architecture policy should enable RTOs to accommodate Canadian entities in the future. Oglethorpe observes that open architecture policy would allow RTOs to utilize existing infrastructure and avoid high transition costs.

However, Central Maine and Southern Company argue that the flexibility implied by open architecture should not be used carte blanche. For example, there should be limits to an RTO's evolution process because transmission owners have some fundamental rights, such as: (1) the right to terminate their participation in the RTO; (2) the right to switch to another RTO; (3) the right to merge RTOs; (4) the right to recover

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[604] See, e.g., APX, Arizona Commission, Cal ISO, Central Maine, Consumers Energy, CP&L, Conectiv, Desert STAR, DOE, Duke, Entergy, EPSA, FirstEnergy, Florida Commission, Georgia Transmission, Illinois Commission, Industrial Consumers, LG&E, NERC, NPCC, NSP, NU, NY ISO, Oglethorpe, PJM, Seattle, Southern Company, SMUD, SRP, TDU Systems, TEP, Tri-State and WEPCO.

[605] NSP states that the configuration of electric markets will be much different five or ten years from now.

[606] WEPCO notes that costs savings associated with creating large, efficient electricity markets will dwarf the savings attained by reducing the number of operators through control area consolidation.

their costs and a return on investment; and (5) the right to protect their assets and employees from damages and injuries.

LG&E states that the flexibility inherent in the open architecture concept should be applied fairly to all market participants, including those transmission owners that have already committed to existing or proposed ISOs. For example, a member of an existing ISO should be allowed to move to another RTO.

Industrial Consumers perceives a potential downside to the open architecture policy in that it may give existing IOUs a license to continue their opportunistic behavior rather than facilitating true market transformation. Therefore, Industrial Consumers argues that it supports the notion of flexibility inherent in the open architecture policy only in the absence of market power. Illinois Commission argues that the pace of evolutionary improvement of RTOs should not remain in the hands of vertically integrated utilities because their interest in structural change may not be consistent with the public interest.

Cinergy, EPSA and Georgia Transmission state that the flexibility implied by open architecture should not be used to support deviations from minimum characteristics and functions. However, CP&L believes that the proposed minimum characteristics and functions are too stringent and do not allow for much flexibility that a changing market needs.[607] Georgia Transmission supports the Commission's commitment to providing regulatory flexibility to allow RTOs to evolve.

Many commenters state that the open architecture concept is so broad that it will prevent stakeholders from developing meaningful RTO proposals. To bring some certainty to the negotiating parties to an RTO proposal, CP&L recommends that the Commission find that some necessary and reasonable limitations on modifications to RTOs are permissible, and these can be overridden only by unanimous consent or a supermajority vote.[608] MidAmerican states that the Commission should accept RTO proposals that contain stated limitations, such as a transmission owner's right to withdraw from an RTO. MidAmerican argues that such limitations are consistent with the Commission's open architecture policy and would prevent transmission owners from being discouraged to join RTOs. To promote certainty, Entergy notes that the Commission should establish a general policy of grandfathering previously approved RTOs and not altering their requirements except in extraordinary circumstances.[609]

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[607]CP&L and Southern Company state that the Commission should establish basic RTO guidelines through a policy statement rather than by a rule. They contend that the rules under the NOPR are too prescriptive, and will stifle the development of new RTOs.

[608]CP&L notes that participants in Midwest ISO identified certain conditions that could be altered only by the transmission owners, including revenue distribution, pricing methodology and withdrawal rights.

[609]Entergy at 42.

Southern Company is concerned that RTOs could evolve in ways that are undesirable to the participants that initiated its formation. Therefore, it argues that the parties should have some assurance that certain key provisions of an RTO would not change in the name of RTO evolution. For example, functions, boundaries, transmission rate design, and allocation of transmission revenues should not be amended by the RTO except by vote of the transmission owners, at least for the duration of a specified transition period. Southern Company contends that the transmission owners will then know what they are "getting into" when they join an RTO.

Many commenters recommend that the Commission should not mandate the ultimate organizational form of the RTO given the electric industry's current state of structural flux and the uncertainty of the future. These commenters argue that the Commission's open architecture policy should encourage market participants to develop transmission institutions that are effective in meeting the needs of the marketplace. FirstEnergy and NU state that there is a range of organizational and functional forms—power pool (tight and loose): gridco, transco, marketco—which can accomplish the Commission's goal of improving the efficiency of the transmission grid, and only time and market forces should determine which form is best suited for a specific region of the country. Southern Company believes that there should be no requirement that would prohibit an RTO with no transmission ownership to transform into one that owns transmission (i.e., change from an ISO to a transco).

PJM urges the Commission to clarify that RTOs can propose improvements to the RTO independently of its members to meet changing market needs. PSE&G is opposed to giving such authority to RTOs because it believes that the market participants rather than RTOs should drive changes in the structure and operation of electric markets. [610] Cal ISO recommends that the Commission's open architecture policy should support the creation of a structure that facilitates the addition of new participants, both within and outside of the existing RTO boundaries. Illinois Commission urges the Commission to modify the proposed paragraph 35.34(k) of proposed regulations to include an affirmative expectation that RTOs will change to meet new competitive market needs and to improve over time.

Commission Conclusion

As proposed in the NOPR, we adopt the principle of open architecture in order that the RTO and its members have the flexibility to improve their organizations in the future in terms of structure, geographic scope, market support and operations to meet market needs. We will require that the RTO design have the ability to evolve over time. In addition, we will provide flexibility to allow RTOs to propose changes to their enabling agreements to meet changing market, organization and policy needs.

Open architecture will permit RTOs to evolve in several ways, as long as proposed changes continue to satisfy RTO minimum characteristics and functions. As a first

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[610] PSE&G Reply Comments at 6-7.

example, open architecture will allow basic changes in the organizational form of the RTO to reflect changes in facility ownership and revised corporate strategies. As noted by Southern Company, an RTO that initially does not own any transmission facilities might acquire ownership of some or all of those facilities. With an open architecture design, the RTO's enabling agreements should anticipate and facilitate changes of this nature.

Second, open architecture design accommodates change in the geographical scope of RTOs. Electric markets are evolving quickly and future market trading patterns cannot be foreseen at the time of RTO organization. An open architecture design will enable an RTO to grow geographically and possibly merge with another RTO as changes in markets suggest a realignment of organizations to meet evolving market needs.

Third, market support is another area that benefits from open architecture design. For example, an RTO may not initially operate a PX to support a regional spot market, but later determine that the establishment of a PX would provide additional benefit in its region. With open architecture, the RTO can propose to add a PX function (or a PX monitoring function) to its design. Open architecture design ensures that such future developments that are beneficial to the marketplace are not foreclosed.

Fourth, open architecture design accommodates changing operational needs. Most commenters agree that, as RTOs gain operating experience, some changes will become necessary. Cal ISO acknowledges that it had to make significant changes to its tariff and operational practices as it gained operating experience, and it believes further modifications are likely to be identified as additional experience is gained regarding evolving competitive markets.

Finally, as noted in the NOPR, technological change make changes in RTO design inevitable and desirable. Accommodating that change will require flexibility and adaptability in the RTO organization; open architecture will permit design modification to keep pace with technology.

Some commenters argue that the flexibility implied by open architecture design should not be interpreted to mean unfettered ability on the part of the RTO to modify its structure or processes. We agree. Although under our open architecture policy the RTO will have the ability to propose whatever changes it believes are appropriate to meet the evolving needs of the RTO and the region, any such proposals or changes to existing agreements, which will be changes to the RTO's jurisdictional rate schedule(s) and contracts, will be subject to Commission review and approval under the FPA. The Commission will consider the merits of any changes to an approved RTO on a case-by-case basis. Interested parties will have the opportunity to comment on any such proposal. This process will enable all parties and the Commission to guard against proposed changes that are likely to stifle competition.