UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Preventing Undue Discrimination and Preference in Transmission Service	Docket No. RM05-25-000 and RM05-17-000

INITIAL COMMENTS OF THE TRANSMISSION ACCESS POLICY STUDY GROUP

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I. EXECUTIVE SUMMARY

The Transmission Access Policy Study Group ("TAPS"), an informal association of transmission dependent utilities in more than thirty states, applauds the Commission's May 19, 2006 Notice of Proposed Rulemaking ("NOPR"). The NOPR takes an enormous leap forward. Acknowledging and reaffirming previous findings that the Order 888 OATT did not fully remedy undue discrimination, the Commission identifies key areas where transmission providers retain the incentive and ability to discriminate and proposes concrete remedies for these deficiencies.

TAPS strongly supports the NOPR's findings that opportunities for undue discrimination continue to exist, requiring further reform. The Commission is targeting the right areas for major reforms—the lack of transparency and consistency in the ATC calculation and the failure to plan and invest in the grid that has produced an infrastructure that falls increasingly short of being able to reliably support competitive electricity markets. We agree that lack of transparency undermines confidence in open access and impedes enforcement of open-access requirements, and that a consistent method of measuring ATC has not been established. We have seen how chronic congestion and inadequate infrastructure impede customers' use of the grid and foreclose access to competitive alternatives. We have experienced first-hand how certain OATT pricing policies (*e.g.*, the provision that has been interpreted to unduly restrict credits for customer-owned transmission facilities) discourage customer investment in the grid, while others (*e.g.*, energy imbalance) impede the use of the grid or subjects such use to punitive, non-comparable terms.

We also agree that EPAct 2005, with its focus on ensuring reliability and promoting investment in our transmission infrastructure, adds impetus for reform. Section 217(b)(4) of the Federal Power Act, which applies both inside and outside RTOs, directs the Commission (1) to facilitate planning and expansion of the transmission system to meet the needs of load-serving entities ("LSEs") and (2) to enable LSEs to secure long-term rights for their long-term power-supply arrangements. The Commission is correct to interpret this provision as a Congressional wake-up call to reform the OATT to better achieve these directives. At the same time, EPAct 2005 reinforces the wisdom of the Commission's decision to retain core elements of the Order 888 OATT services that form the essential predicate to Section 217's mandate of comparable treatment of all LSEs, whether transmission provider ("TP") or transmission-dependent utility ("TDU"). Thus, we strongly support the Commission's decision to retain the comparability requirement and the basic nature of network service. We also support the Commission's reading of Section 217 as consistent with the Order 888 OATT's "native load" priority,[1] recognizing that Section 217 reinforces the OATT's commitment to comparable treatment of all LSEs—*e.g.*, transmission providers and network customers.

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[1] NOPR PP 70-71. *See also* TAPS November 22, 2005 Comments on the Notice of Inquiry ("TAPS NOI Comments") at 44-49 and TAPS January 23, 2006 NOI Reply Comments at 9-15.

TAPS strongly supports many of the NOPR's proposals to eliminate major sources of abuse, including:

- ATC reforms to achieve consistency, transparency and to improve the OASIS;
- Requiring coordinated, open and transparent joint and regional planning;
- Eliminating the joint planning requirement for credits for customer-owned facilities;
- Eliminating the $100/MWh penalty for energy imbalances;
- Increasing the transparency of the TP's use of its transmission system; and
- Strengthening enforcement.

TAPS believes a number of the proposals should be modified or expanded to achieve the Commission's intent. Key enhancements we recommend include:

- **CBM:** TAPS recommends a robust variation on the NOPR's first two proposals, crafted to take CBM out of the province of individual TP decision-making that can be driven by its competitive agenda. Part V.A.1(a).
  - CBM should be permitted only in the context of a multi-utility reserve-sharing group, open to all LSEs.
  - All LSEs must not only have access to CBM to meet their reserve-sharing needs, but must also have a real say in how much CBM is reserved and where, subject to dispute resolution at the Commission.
  - Reserved CBM capacity should be paid for (on a load-ratio basis) by all members of the multi-utility reserve-sharing group. Because the payments would be real (not just one TP shifting money between its pockets), all LSEs in the group would have a financial stake in minimizing the reservation.
- **TRM:** The reserve-sharing component of TRM should be subject to the same regimen as CBM. Each of the other uncertainties contributing to TRM should be justified and supported by plans to minimize the uncertainty and thus the required reservation, with periodic reports on the status of those efforts. Part V.A.1(b).
- **OASIS:**
  - Studies for TP transmission uses must be posted, as well as all impact and facilities studies for customers, with a 5-year retention for all. Part V.A.3(a).
  - If ATC is zero for more than two or three months, or certainly a season, the TP must report how long it has been zero; how long it foresees ATC remaining zero; when and at what level it predicts ATC becoming available; and, if no positive change is foreseen, what steps the TP is taking to relieve the constraint. Part V.A.3(b).

- TPs should be required to post projected longer-term ATC, for both constrained and unconstrained paths, through the TPs' planning horizon but no shorter than five years. Part V.A.3(b).
- Posting, availability, and retention requirements should encompass information supporting any action short of an unconditional grant of third-party service, as well as the grant of TP uses. Part V.A.3(c).

➢ **Planning:**

- Joint planning should be *collaborative* and *interactive*, inviting input from affected stakeholders at all stages, allowing stakeholders to participate in decisionmaking, and assuring that their views are considered on a non-discriminatory basis. To the extent RTO plans are developed by assembling plans submitted by individual transmission owners, the transmission owners' separate planning processes must also meet this requirement. Part V.B.1.
- All regional joint plans should be required to satisfy basic substantive goals crafted to assure that the plans anticipate and proactively correct transmission inadequacies. The facilities needed to provide access to competitive markets, enable use of probable generation sites, and accommodate load growth must be identified and constructed as part of the joint planning and expansion process. TAPS' *Balanced Principles for Transmission Planning and Expansion* is one model for incorporating such goals into the OATT's planning provisions. Part V.B.2.
- TPs must be required to construct facilities identified in the regional plan, and the Commission should adopt accountability provisions to give that obligation teeth. The planning process should encourage joint ownership or other inclusive transmission investment. Regional or joint rates and improved crediting provisions are also needed to address the regional scope of the NOPR's planning requirement. Parts V.B.3 and V.B.4.
- To capture synergies and help achieve a more balanced process, joint planning regions should include at least two TPs and be no smaller than a state. Part V.B.5.
- TAPS recommends the formation of a joint planning committee, not dominated by TPs, that would direct the study process and be responsible for the development of uniform planning criteria, assumptions for base and changed cases, and transmission plans. Load ratio share voting, which would give TPs the power to make decisions unilaterally, will not work. Part V.B.5.
- The planning horizon should be a minimum of 10 years; plans should be updated at least biennially, and more frequently if conditions warrant. LSEs that participate in the planning process must be able to rely on the plans in developing their power supply. An LSE should not be placed at the margin with respect to access, transmission funding requirements, or otherwise, if its uses are included in the joint plans, but other uses *not* included in the planning process unexpectedly appear and exhaust planned-for capacity before the LSE can submit its network resource designation. Part V.B.5.

- **Imbalances:**
  - Requiring TDUs to pay for imbalance energy is unduly discriminatory where their competitors, the TPs that are balancing authorities, swap energy for free through in-kind return of inadvertent energy. The Commission should address this discrimination by, *e.g.*, allowing all imbalances to be returned in-kind, or requiring balancing authorities to pay for inadvertent energy (beyond the return-in-kind bandwidth applicable to imbalances) at incremental cost and charging each customer only for its contribution to the control area's inadvertent obligations. Part V.C.1.
  - If the Commission does not completely align imbalance and inadvertent policies to eliminate this discrimination, TAPS favors a BPA-style imbalance regime, with its tiered deadbands and associated cost-based pricing, subject to certain key improvements, as reflected in Attachment A.
  - The new Schedule 4 should incorporate netting of the individual customer's generator and load imbalances. Netting is necessary to make imbalance more comparable to the treatment of the TP's own inadvertent, comports with principles of cost-causation, and provides customers incentives to adjust generation to match their load, thereby reducing the burden on the balancing authority and improving reliability. Part V.C.1(a).
  - Net imbalance resulting from operation of intermittent generation should be subject only to penalty levels associated with the second BPA deadband. In addition, generator imbalances resulting from TLRs or other TP instructions, and in connection with forced unit outages, should be treated as being within the first deadband. No penalties should be assessed for these events, since they cannot be avoided by customer actions. Part V.C.1(a).
  - To move closer to comparability and more accurately reflect cost-causation, Schedule 4 should impose penalties only if the individual customer's net imbalance contributes to (rather than mitigates) the aggregate system imbalance. Where the aggregate system imbalance falls within an aggregate deadband for an hour, or where the aggregate deadband is exceeded but the individual customer's imbalance is in the opposite direction from the aggregate imbalance, no penalties should apply. Part V.C.1(b).
  - No generic showing of a need for "intentional imbalance" penalties has been made, and they present great potential for abuse by TPs. If the Commission nonetheless concludes that it is appropriate to permit TPs to assess penalties for intentional imbalances, it must hold TP proposals to a very exacting standard, and ensure that the TPs are not able to exercise significant discretion in imposing such imbalance penalties. Part V.C.1(c).
  - The Commission should abandon the concept of including "commitment" costs in incremental-cost pricing of imbalances, as inconsistent with comparability and because TPs recover the capacity costs of generation used for imbalance service through Schedules 3, 5 and 6. No such costs should be permitted absent a compelling showing by the TP that they are incurred solely

in connection with providing imbalance to a particular wholesale customer and not otherwise recovered. Part V.C.1(c).

- The Commission should require TPs to allow customers to dynamically schedule their loads and resources into a single control area, so that they may minimize their imbalance exposure. Part V.C.1(d).

- **Credits for Customer-Owned Facilities:** TAPS supports what it understands to be the concept underlying the NOPR's proposed changes to Section 30.9—*i.e.*, changing the focus of the integration-plus-comparability test so that it proceeds from the integration standard utilized by the TP in determining which of its own facilities are to be included in its transmission cost of service, and applying this same standard to the facilities owned by the TP's customers. However, the NOPR's proposed Section 30.9 should be modified in three respects, as reflected in Attachment B.

  - References to "integration" should be deleted from Section 30.9 in order to avoid confusion. The requirement that customer-owned facilities would be eligible for inclusion in the TP's rates if it owned the facilities incorporates an integration requirement. Part V.C.2(a).

  - The same test, based on the TP's own standard for including facilities in its rate base, must apply to all customer-owned facilities, whether existing or constructed after the effective date of the final rule. The Commission has found that the current regime permits discrimination, which must be remedied as to existing facilities as well as newly constructed facilities. V.C.2(b).

  - The Commission should expressly provide that credits to be provided to customers for newly constructed facilities may include incentive ratemaking elements, if applicable. Incentive ratemaking is the only respect in which the Commission should distinguish between existing and new customer-owned facilities for purposes of determining credits under Section 30.9. V.C.2(c).

- **Capacity Reassignments:** TAPS opposes lifting the reassignment price cap for any entity. Elimination will allow market power exercise when ATC is tight, encourage hoarding, and undermine Section 217(b)(4)'s objectives. Part V.C.3.

- **Operational Penalties:**

  - Secondary network service should be available not only for economy energy but for substitute reliability resources (reserve sharing); TP/network customer use of point-to-point service for imports needs to be narrowly circumscribed to prevent import capacity from being tied up by the TP/network customer without designating a network resource. Part V.C.4(a)(1).

  - Penalties on unauthorized use of point-to-point service should be limited to 200% of the charge for the period of unauthorized use. Part V.C.4(a)(2).

  - Modifications of OATT § 30.4 (which appear in the proposed tariff, but are never described in the NOPR) authorize TPs to impose penalties on a network customer for scheduling and dispatch of the portion of remote resource not designated as network resource, foreclosing their import as an undesignated resource under secondary network service. This unnecessary, unreasonable and discriminatory restriction should be rejected. Part V.C.4(a)(3).

- **Redispatch Service:** In the hands of a vertically integrated TP, expanded reliance on directly assigned redispatch is more likely to increase opportunities for abuse than remedy discrimination, and it undermines the objectives of Section 217(b)(4). In any event, the TP should not be authorized to require network customers to redispatch their resources for new third-party transactions, thereby allowing TPs to severely interfere with network customers' use of their limited resources and unfairly exposing network customers to risks they cannot hedge. Part V.D.1(a).
- **Conditional Firm Service:** *If* narrowly defined and integrated with network service, conditional firm service could enable more efficient utilization of the grid in some circumstances. Part V.D.1(b). To that end:
  - Conditional firm should be limited to "almost always firm" service by restricting curtailments to no more than 100 hours per year to match its policy justification, provide customers sufficient certainty to sign long-term power-purchase contracts (*e.g.*, for renewable resources), and prod transmission construction.
  - When the maximum curtailment hours stated in the service agreement are exceeded, conditional firm service should be treated the same as other firm service, subject to curtailment on a pro rata basis.
  - To support development of generation, conditional firm service must work for LSEs—entities that typically take network service:
    - To allow LSEs to use this service to integrate on-system generation, the Commission should allow for network resource designation where transmission is available on a conditional firm basis (as described above).
    - To allow LSEs to use this service to integrate off-system generation, resources supported by conditional firm service on a third-party system must be eligible as a network resource on the host system where the LSE takes network service.
- **Hourly Firm Service:** Hourly firm service presents an issue of equity among customers (particularly network customers who bear the residual costs of the system), not "barriers to the market," and the Commission should not reverse the correct call made in Order 888 on those equities. If the Commission nevertheless adopts hourly firm service, it should modify Section 28.4 of the OATT to make clear that hourly firm service does not trump use of secondary network service. Part V.D.2.
- **Rollover:**
  - If rollover rights are restricted as proposed, the Commission must separately ensure the embedded TDU's fundamental right to continued transmission service. TP obligations to provide service to an embedded TDU, for whose needs it has long been obligated to plan, should not be contingent on the TDU's ability to secure a five-year power supply contract *and* match

competing customers. Nor can the Commission assume that upon the date of acceptance of Attachment K, the network customer will miraculously be assured reasonable access to the grid. The Commission must (Part V.D.3(a)):

- *Require the TP to accept a network customer's timely designated network resource, if necessary through redispatch with costs shared on a load-ratio basis.* This remedy would simply hold the TP accountable for its long-standing planning obligations, rather than shifting the risk to entities least able to bear that risk: TDUs.

- *Where a TP allows a weak grid to trap customers, the transmission provider should have an obligation to offer embedded-cost-based sales.* The Commission should not, by constricting rollover rights, allow a TP to have it both ways—deny customers a continued right to transmission to access alternative suppliers, without having any obligation to sell power within its control area at any rate, much less a reasonable (cost-based) one.

- *At minimum, exceptions to the five-year minimum and matching exposure must be made to ensure a continued right to service.* A "safety net" is needed to ensure that, at least, small customers (*e.g.*, 25 MW and under) and requirements purchasers will have continued transmission access.

o The NOPR's "five year/one year" rollover proposal must otherwise be clarified (Part V.D.1(b)):

  - Clarify § 2.2 rollover rights to clearly encompass reasonable access to sources other than those from which the customer is currently served, consistent with Order 888's intent to foster competition.

  - Limit matching to avoid undercutting TP planning/construction obligations and the customer's right to continued service:

    - The NOPR's reference to TP matching requirement should be clarified as a further restriction on when a TP can take back capacity already reserved for load growth, not an expanded opportunity for a TP to deny service by matching.

    - Matching should not force an existing customer off the system if it proposes to rollover for at least five more years, or transform an existing network customer into the marginal customer (for incremental pricing purposes).

    - Matching must be structured to recognize that a network customer must extend its power-supply to match a competing point-to-point customer that can simply extend its reservation.

o Minimum rollover term *in the absence* of a competing application should be clarified to be one year, with one year's notice of further rollovers.

  - Clarify the transition from old Section 2.2 to new Section 2.2 to effectuate the NOPR's intent and avoid confusion and customer harm.

- **Reservation Priority:** The newly proposed pre-confirmation priority may be a cure that is worse than the disease. If adopted at all, it should apply only to non-firm and short-term-firm (monthly or less) service. Pre-confirmation priority should not apply to long-term-firm or network service designations, where there should be adequate time to obtain confirmation. Alternatively, any pre-confirmation priority that applied to network or long-term-firm service would need to carve out exceptions at least for situations in which pre-confirmation is impractical and would unfairly foreclose legitimate customers' access to needed transmission service. In any event, the NOPR's tariff language is too broad, proposing no temporal constraint on pre-confirmation priority. Part V.D.5(c).

- **Qualification as a Network Resource:** The Commission should be careful of its terminology regarding liquidated damages, and make clear that it is the firmness of the contract, not the formulation of damages for violation of the firmness requirements, that is the determining factor in whether a power purchase qualifies as a network resource. Part V.D.6(a).

Finally, TAPS urges the Commission to address three other concerns raised in our NOI Comments:

- Treat retail and wholesale load served from behind-the-meter generation comparably and consistent with the obligation to plan. Part V.C.6(a).

- Eliminate from Schedule 2 rates non-comparable compensation for the TP's reactive capability within the range required by Order 2003, and provide for compensation, on a non-discriminatory basis, only for reactive production outside that bandwidth. Part V.C.6(b).

- Eliminate discrimination by granularity, and provide TPs an incentive to upgrade weak portions of their system where TDUs are located, by foreclosing TPs from denying a customer's network resource designation (or require upgrades or redispatch whose cost is not shared on a load-ratio basis) if the designation would have been accepted with the TP's load as sink. Part V.D.3.

II. [INTENTIONALLY BLANK TO RETAIN NOPR'S NUMBERING]

III. THE NEED FOR REFORM OF ORDER NO. 888

TAPS strongly supports the Commission's findings, pursuant to its Section 206 obligation to remedy undue discrimination,[2] that there is a need for reform. As described in detail in TAPS' comments in response to the NOI,[3] that need is compelling. As the NOPR recognizes (at P 21), that need is supported by previous Commission findings that Order 888 leaves opportunities for undue discrimination.[4] Given the Commission's continued reliance on the OATT to mitigate market power in the market-based-rate context, the OATT's ability to get that job done is key to whether the Commission is carrying out its Section 205 and 206 responsibilities with respect to jurisdictional power sales as well as transmission service.

TAPS to a great extent agrees with the NOPR's identification of areas that require reform and many of its proposals. TAPS would prefer a more regional approach to

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[2] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,539 (May 10, 1996), [1991–1996 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,036 at 31,682 ("it is our duty to eradicate unduly discriminatory practices"), *clarified*, 76 F.E.R.C. ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), [1996–2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 F.E.R.C. ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) ("Order 888").

[3] *See especially* TAPS NOI Comments at 1-43 and 75-86.

[4] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), [1996–2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,089 at 31,015, *order on reh'g*, Order No. 2000–A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,092, *appeal dismissed for want of standing sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) ("Order 2000"); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,846 (Aug. 19, 2003), [2001–2005 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,146 at PP 11-12, *modified*, 68 Fed. Reg. 69,599 (Dec. 15, 2003), *clarified*, 69 Fed. Reg. 2,135 (Jan. 14, 2004), 106 F.E.R.C. ¶ 61,009 (2004), *order on reh'g*, Order No. 2003–A, 69 Fed. Reg. 15,932 (Mar. 26, 2004), [2001-2005 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003–B, 70 Fed. Reg. 265 (Jan. 4, 2005), [2001-2005 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,171, *order on reh'g*, Order No. 2003–C, 70 Fed. Reg. 37,661 (June 30, 2005), [2001-2005 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,190 ("Order 2003").

transmission. For example, we continue to see the value of Day 1 RTOs,[5] and have long supported regional or joint rates as a means to minimize pancaked charges that create unnecessary barriers to competitive bulk power markets, and impose undue burdens on TDUs with loads and resources spread among multiple transmission systems.[6] While we continue to press for regional rates (at least for major new facilities) to support and make meaningful the regional planning the Commission proposes to mandate (*see* Part V.B.3 below), we recognize the NOPR's intent to improve the OATT as may be applied by a single transmission provider or an RTO.

We also agree with the NOPR's conclusion (P 46-49) that EPAct 2005 adds impetus to the proposed reforms and directs the Commission to advance particular Congressional objectives, particularly with regard to enhancing our often inadequate transmission infrastructure. Section 217(b)(4)[7] directs the Commission to facilitate the planning and expansion of the grid to meet the needs of load-serving entities and to enable load-serving entities to secure long-term rights for their long-term power-supply arrangements to meet their service obligations. Section 219 instructs the Commission to encourage investment in transmission expansion "regardless of the ownership of facilities."[8] Section 216(a) provides for backstop siting authority, recognizing the adverse effect on consumers of transmission constraints and congestion, including the impact on economic vitality resulting from lack of adequate or reasonably priced

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[5] While TAPS members are highly skeptical of the value of Day 2 RTOs with their hefty administrative costs and complexity, we continue to see the need for Day 1 RTOs or regional approaches that get us most of the way there.

[6] *See* TAPS NOI Comments at 18-21.

[7] EPAct 2005 Section 1233, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[8] EPAct 2005 Section 1241.

electricity, the jeopardy to economic growth, and impacts on diversification of supply and energy independence.[9] Through these and other provisions, Congress has told the Commission to change its approach to planning and expansion so consumers can obtain the benefits of the robust transmission infrastructure required to support competitive electricity markets. The new transparency authority granted by Section 220[10] further confirms and directs the Commission's findings of need for reform.

Thus, the Commission has the authority and the obligation to make the reforms proposed in the NOPR, as enhanced by TAPS' suggestions below.

IV. SCOPE AND APPLICABILITY OF THE PROPOSED RULE

TAPS strongly supports the NOPR's retention of the core elements of the OATT, particularly the comparability requirement and network service. TAPS has long supported the cleanest solution—requiring all load to be served under OATT rates, terms, and conditions. However, recognizing that the Commission is not yet prepared to take that step on a generic basis,[11] the only realistic way to satisfy *AEP*'s[12] requirement for comparability with the service the TP provides its bundled retail load is to preserve and strengthen network integration transmission service.

TAPS also agrees with the NOPR's assessment (at P 70) that Section 217 is fully consistent with the Order 888 OATT and the proposed reforms. The Commission correctly avoids the invitation of some TPs to misconstrue Section 217 as undermining

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[9] EPAct 2005 Section 1221.

[10] EPAct 2005 Section 1281.

[11] As discussed below, consistent with *N.Y. v. FERC*, 535 U.S. 1 (2002), the Commission's arsenal should include the potential assertion of jurisdiction over the transmission component of the bundled retail sales of a particular transmission provider where necessary to remedy undue discrimination in extreme cases.

[12] *Am. Elec. Power Serv. Corp.*, 67 F.E.R.C. ¶ 61,168, at 61,490 (1994).

Order 888 and comparability.[13] Section 217's identical treatment of all load-serving entities, whether they are TPs or TDUs, reinforces Order 888, the OATT, and the comparability principle, and supports the further reforms proposed in the NOPR as modified by TAPS. Section 217 makes clear that "native load protections" must cover and equally protect network customers, as the Order 888 OATT requires. For example, the transmission provider is supposed to be planning and reserving capacity not just for its reasonably forecasted native load (NOPR P 62), but also for its network customer load.[14] Thus, in retaining the "native load protections" embodied in Order 888, the Commission needs to maintain and reinforce comparable protection of network customers.

Further, we strongly support the Commission's retention of the structure of the standardized OATT, to which all jurisdictional TPs must adhere absent a demonstration that an alternative is "consistent with or superior to" the revised OATT.[15] TAPS supports requiring RTOs and ISOs to make compliance filings in response to the final rule that will be judged under the "consistent with or superior to" standard.[16] The Commission is correct that the OATT, as proposed to be reformed by the NOPR, is superior to current practice in RTOs in various respects.[17] For example, TDU needs are not well integrated into RTO planning, which all too often involves assembling individual transmission

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[13] *See* TAPS NOI Comments at 44-49, and TAPS NOI Reply Comments at 9-15.

[14] *See* OATT Section 28.2 and NOPR P 204. The requirement for comparable treatment of network customers for purposes of load growth reservation is recognized elsewhere in the NOPR. *See* PP 349, 358.

[15] NOPR P 99.

[16] NOPR P 100.

[17] NOPR P 101.

owners' plans in which TDUs have had no input.[18] While Order 681's requirement that RTOs implement a transmission planning process to accommodate long-term rights and ensure their feasibility over their entire term should be an important step forward,[19] it appropriately recognizes the role of this NOPR in implementing Section 217(b)(4)'s "broader mandate to exercise its FPA authority to facilitate planning and expansion."[20] In carrying out Congress' mandate, it will be essential to incorporate the NOPR's joint planning process into the RTO context, in development of both the individual transmission owners' plans and the RTO's regional plan.

The NOPR proposes a case-by-case approach to Section 211A compliance, with a presumption of compliance with Sections 211 and 211A applying only where an unregulated transmitting utility's "safe harbor" tariff meets the requirements of Order 888 and the final rule in this proceeding.[21] TAPS supports this approach, which places the burden of demonstrating compliance with Section 211 and 211A on an unregulated transmitting utility that does not already have an NJ tariff on file that meets such "safe harbor" requirements. Section 211A authorizes the Commission to require service on terms and conditions that are comparable to those under which the unregulated transmitting utility serves itself and that meet the "not unduly discriminatory or

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[18] As described by a MISO transmission owner, "in Midwest ISO each transmission owner plans its own system and Midwest ISO plans the overall Midwest ISO system." Initial Comments of Ameren Services Company, Inc. filed November 22, 2006 in Docket No. RM06-8-000 at 12; *see also* at 16-17.

[19] *Long-Term Rights in Organized Electricity Markets*, Order No. 681, 71 Fed. Reg. 43,564 (Aug. 1, 2006), 116 F.E.R.C. ¶ 61,077, P 453 (2006) (to be codified at 18 C.F.R. pt. 42) ("Long-Term Rights Final Rule").

[20] *Id.* P 457.

[21] *See* NOPR P 111 & n.106, and revised 18 C.F.R. § 35.28(e)(1)(ii).

preferential" standard.[22] As described in TAPS NOI Comments at 116-120, only terms and conditions for service that meet the "no undue discrimination" standard, as developed through the FPA's 70-year history, can pass muster under Section 211A. These days, such service is defined in reference to the OATT.[23]

V. PROPOSED MODIFICATIONS OF THE OATT

A. Consistency and Transparency of ATC Calculations

1. Consistency

TAPS strongly agrees that consistency and transparency of ATC calculations are key areas requiring reform. Order 2000 found that mistrust of ATC calculations will reduce competition.[24] As demonstrated in TAPS NOI Comments at 28-31 and TAPS' August 15, 2005 Comments in *Information Requirements for Available Transmission Capability,* Docket No. RM05-17, current arrangements for calculating ATC are simply not credible. We thus strongly concur in the NOPR's findings (PP 150-53) that lack of consistency and transparency of ATC calculations provides excessive discretion and opportunities for undue discrimination, and poses a potential threat to reliability.

The NOPR proposes (P 155) that within six months of the final rule, public utilities, working through NERC, "are to develop standards for (1) ATC/AFC, TTC/Total Flowgate Capacity (TFC), ETC, CBM, and TRM calculation methodologies, (2) data inputs, (3) modeling assumptions, (4) ATC calculation frequency, and (5) data exchange

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[22] Section 211A also authorizes the Commission to require that the rates charged be comparable to the rates the unregulated transmitting utility charges itself.

[23] Order 888 at 31,635. Consistent with Section 211A(j), the Commission should be flexible in allowing an unregulated transmitting utility to modify the OATT to accommodate maintenance of its tax-exempt status, as the Commission has previously done in the context of evaluating safe-harbor tariffs. *See* Order 2003-A at P 773 ("substantially conform to or are superior to the *pro forma*").

[24] Order 2000 at 31,017.

and coordination processes." It also "propose[s] to require public utilities, working through NAESB, to work with NERC to identify the appropriate business practices to complement the standards developed by NERC." *Id*. TAPS generally supports the NOPR's approach, as well as much of its more specific guidance as to how each these tasks should be accomplished. Given the difficulty reaching industry consensus on issues as competitively charged as the ATC calculation, the Commission needs to be very precise as to deadlines and the objectives that must be accomplished and make clear it will hold transmission providers (and NERC and NAESB) accountable for achieving those objectives within those deadlines. TAPS agrees that "without guidance, direction and a firm deadline, these industry developments [to address identified problems with ATC/TTC/TRM/CBM] may not succeed …." NOPR P 149.

NERC's track record is not impressive. In 1999, the Commission "direct[ed] transmission providers to take several short-term measures to make their Capacity Benefit Margin (CBM) set-asides more transparent, more accurate and more widely available."[25] It "recognize[d] the need for a standardized methodology for deriving CBM" and, given the NERC process then underway, set a December 1999 deadline for completion of this important, time-sensitive task. *Id.* at 61,238. A number of status reports (and years) later, NERC on May 17, 2002 filed a "Report on Actions of North American Electric Reliability Council Concerning Available Transmission Capacity" in Docket No. EL99-46. Instead of developing "*a* standardized methodology for deriving CBM" as the Commission ordered in 1999, 88 F.E.R.C. at 61,238 (emphasis added),

[25] *Capacity Benefit Margin in Computing Available Transmission Capacity*, 88 F.E.R.C. ¶ 61,099, at 61,236 (1999) (footnote omitted).

NERC left it to each region to develop its own methodology for calculating CBM pursuant to multiple-choice guidelines, and left reservation of CBM to individual transmission provider prerogative. The Commission did not notice NERC's status report for comments.

The Commission cannot let this crucial initiative lose steam this time around. To the extent reliability standards are involved, the enactment of Section 215 expands this Commission's authority to require timely development of standards,[26] and certainly does not detract from its authority to ensure just, reasonable and not unduly discriminatory transmission service. In any case, not all aspects of ATC are "reliability" issues required to be addressed through NERC. NERC's 2002 FERC submission and its 2005 Task Force Report (which documents treatment of CBM that is literally all over the map)[27] demonstrate that NERC does not mandate *any* reservation of CBM to ensure the "reliable operation of the bulk power system."[28] Rather, the appropriateness of calculating and reserving CBM and if so, how, by whom, under what conditions, and at what charge, is a competitively significant transmission policy and pricing issue that needs to be addressed

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[26] The Commission's new reliability rule expressly provides the Commission authority to set deadlines for developing standards. *See* 18 C.F.R. §§ 39.5(f) and (g); *Rules Concerning Certification of the Electric Reliability Organization, and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order 672 at PP 408-412, 416-17, 71 Fed. Reg. 8,662 (Feb. 17, 2006), III F.E.R.C. Stat. & Regs. ¶ 31,204 (to be codified at 18 C.F.R. pt. 39), *corrected*, 71 Fed. Reg. 11,505 (Mar. 8, 2006), *on reh'g*, Order No. 672-A, 71 Fed. Reg. 19,814 (Apr. 18, 2006), 114 F.E.R.C. ¶ 61,328 (2006).

[27] *Available at* ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf (last viewed Nov. 20, 2005).

[28] *See* FPA § 215(a)(3) as added by § 1211 of the Energy Policy Act of 2005. Section 215(a)(1) defines the "bulk power system" as "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network …; and (B) electric energy from generation facilities needed to maintain transmission system reliability." In contrast, NERC's definition of CBM, as described in the NOPR at n.111, is intended to lower reserve margins required to meet "generation reliability requirements," not transmission system reliability.

squarely by the Commission, particularly if NERC and NAESB fail to achieve the stated objectives in a timely fashion.

TAPS' response to the NOPR's question regarding priorities (P 155) is that CBM and TRM account for the most disputes and are probably the components most susceptible to improvement and greater consistency (because there's no consistency and huge opportunities for discrimination now), recognizing that the various elements of the ATC calculation interrelate so they would be best addressed as an interrelated package.

TAPS agrees with the NOPR (P 156) that it is not essential that all transmission providers use a single ATC calculation. While standardization of ATC calculations would be desirable, the Commission can get most of the way there through standardization of ATC inputs and components. However, to achieve its objectives, the Commission must not leave room for transmission provider discretion as to the ATC inputs or components.

In addition to generally supporting the NOPR's proposals regarding consistency of ATC calculations, TAPS offers some specific comments:

a) CBM

In 1998, after noting the disparate treatment of CBM among the utilities that shared the same interface and that reservation of CBM involved economic considerations (*e.g.*, the reduced amount of reserves for generation adequacy vs. the benefits of releasing transmission capacity for firm use) that differed among utilities,[29] the Commission

[29] One utility had reserved substantial CBM, foreclosing competitors from firm use of a constrained interface while allowing it to import non-firm economy energy; another utility that was short on capacity claimed no CBM on the same interface, thereby maximizing firm imports. *Wisconsin Pub. Power Inc. SYSTEM v. Wisconsin Pub. Serv. Corp.*, 83 F.E.R.C. ¶ 61,198, at 61,857-58, *order on reh'g denied*, 84 F.E.R.C. ¶ 61,120 (1998). CBM choices matched each utility's portfolio requirements.

recognized that "the exercise of this discretionary adjustment can turn on considerations (such as reduction of power supply costs and limiting the generation supply options of competitors) that involve the transmission provider's merchant arm rather than its transmission function."[30] The Commission explained (*id.*):

> [W]hile utilities make the CBM adjustment in their role of transmission provider, the decision as to whether to make such an adjustment and how large an adjustment to make can be driven by the needs of their merchant arms. And, their merchant arms will, in turn, be motivated to consider not only direct supply costs, but the impact of the CBM decision on competitors.

It's been eight years since this recognition that reservation of CBM involved economic considerations and (as described above) seven years since the Commission ordered NERC to develop a consistent standard for calculating CBM. However, we are still left with a range of methodologies that are subject to individual transmission providers' competitively motivated discretion and abuse.[31] NERC's April 14, 2005 Long-Term AFC/ATC Task Force Final Report findings (at 3) that "[s]ome [transmission providers] use CBM and some don't use CBM" and that "[t]he scope of CBM varies by footprint," show that NERC does not require *any* transmission provider to reserve CBM.

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[30] *Id.* at 61,858 (requiring compliance filing to explain computation of CBM, including comparison with practices of other utilities in the subregion, and to provide a forum for addressing the economic issues from the perspective of transmission customers). Protests were filed in 1998, but no action was taken until November 19, 2004, when the Commission by letter stated its belief that issues pertaining to the compliance filing had become moot because "[m]ore importantly, the CBM allocations at issue are now performed by the Midwest Independent Transmission System Operator, Inc. on an independent and regional basis," and noted that it would close the docket if no responses were received. After none were received, the Commission by letter order of December 15, 2004 accepted WPS' 1998 compliance filing.

[31] The Commission Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Reliability Standards, issued May 11, 2006 in Docket No. RM06-16, characterizes NERC's CBM standard as a "fill-in-the-blank" standard (*id.* at 23), which "delegate[s] the Transmission Service Providers to document their procedures" for CBM, *id*. at 80, but does not "implement a consistent and uniform calculation of CBM," *id*. at 81.

Even in regions that use CBM, it is often up to the transmission provider to determine whether it wants to reserve CBM and at which interfaces, with no effective review. As the NOPR recognizes (PP 119 and 159-60), transmission providers may withhold transfer capability to favor their own uses of the system, and block other firm uses.

The NOPR proposes three means to address CBM, although the first two are not necessarily mutually exclusive: (1) clear standards for determination and allocation of CBM across interfaces and use of CBM by LSEs (P 161); (2) specific charges for CBM set-asides (P 162); and (3) eliminating CBM altogether (P 163). The first approach, while helpful, would likely leave CBM in the hands of the individual TPs to a significant degree, thus preserving the opportunity for abuse. The Commission's second option—requiring payment for CBM—also doesn't go far enough. Many transmission providers would be more than happy to pay themselves for CBM if, by doing so, they could effectively reserve valuable interface capacity for themselves without designating a firm network resource on the other side of the interface. Indeed, some transmission providers have sought to do just that.[32] In the context of a vertically integrated transmission provider, we don't think a payment from one side of the house to the other will provide the financial discipline the Commission is hoping for.

The Commission should be skeptical in accepting CBM reservations in the absence of a confirmed firm path on both sides of the interface and a designated firm

[32] *See* Nevada Companies' November 22, 2005 NOI Comments at 21-22 (in favor of network contract demand service). As discussed in Part V.C.4 below, TAPS is concerned that an unintended consequence of requiring TPs to "pay themselves" for point-to-point service to make imports for off-system sales is to open up a pandora's box of allowing TPs to tie up the interface by making firm import reservations without having a firm network resource to support it. *Compare Wisconsin Power & Light Co.*, 84 F.E.R.C. ¶ 61,300 (1998).

resource for import. Absent such firm reservations and designations, it's not at all clear that the CBM reservation will have any value in an emergency. CBM is nothing more than a partial-path reservation where there is no assurance that transmission or energy will be available to complete the transaction when needed. The only purpose such reservations are assured of achieving would be to reduce firm ATC available for use by others. For this reason (among others), some TAPS members would prefer to eliminate CBM, because this is the only one of the Commission's three options that would eliminate the incentive and opportunity for abuse. However, because of CBM's value in supporting reserve sharing, TAPS recommends a more robust variation on the NOPR's first two proposals, crafted to take CBM out of the province of individual TP decision-making that can be driven by the TP's competitive agenda.

TAPS recommends beefing up the Commission's first option (requiring clear standards for determination and allocation of CBM across interfaces) to require consistency both within and between regions, and to prevent double-counting, whose likelihood is increased by the inclusion of automatic sharing of reserves as an uncertainty factored into TRM reservations as well. *See* NOPR P 164. But because, even with this improvement, the Commission's first option would not prevent TPs from using CBM reservations for competitive advantage (*i.e.*, blocking others from firm access to an interface, allowing the TP to enjoy priority non-firm access for economy imports), the Commission should also adopt the following more structural reforms in the way CBM set-asides are determined and paid for.

First, CBM should be permitted only in the context of a multi-utility reserve-sharing group, open to all LSEs. TDUs are often excluded from reserve-sharing groups (by definition, or by shaping requirements in ways TDUs can't satisfy, even if they pay the TP for operating reserves). A transmission provider should not be permitted to reserve CBM while excluding TDUs from the reserve-sharing arrangements CBM is intended to foster.[33] Absent such a condition, CBM reservations become another tool the transmission provider can utilize to competitively disadvantage TDUs.

Second, the Commission should ensure that all LSEs not only have access to CBM to meet their reserve-sharing needs, but have a real say in how much CBM is reserved and where, removing such decisions from the discretion of the vertically integrated transmission provider to use for the best advantage of its generation function. The final rule should require CBM reservations to be subject to an open process, with reservation decisions to be made, with cost consequences, by the multi-utility reserve-sharing group, subject to dispute resolution at the Commission. The inclusive reserve-sharing group would decide, as a group, if, where, and how much interface capacity needs to be reserved for CBM to achieve the reserve-sharing group's intended reliability purpose. The participation of all LSEs in the decisionmaking process must be real, not merely a rubber stamp on decisions made by the large transmission providers (or regions) that typically perform the studies. All LSEs must be invited to participate in the studies as well as review the results, assumptions, etc. Once a regional planning process is

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[33] Reserve regimens that penalize small systems for their size have long been recognized as anticompetitive and unreasonable, while equalized percentage reserves appropriately recognize the relative burdens and responsibilities for regional reliability. *See Gainesville Utils. Dep't v. Florida Power Corp.*, 402 U.S. 515 (1971) (affirming the FPC's rejection of standby charges proposed on basis of largest unit); *In re Consumers Power Co.* (*Midland Plant, Units 1 and 2*), 6 N.R.C. 892, 1090 (ASLAB 1977) (finding failure to coordinate with small utilities on terms that included sharing of reserves on an equalized percentage basis to be anticompetitive and unreasonable); *see also id*. at 1089 (reserve requirements based on small utility's largest unit found unreasonable).

established pursuant to the NOPR, the regional planning group should have to approve the CBM reservation as well.

Under this regimen, the reserved CBM capacity should be paid for (on a load-ratio basis) by all members of the multi-utility reserve-sharing group. Because the payment obligation would be real (not just one TP shifting money between its pockets), all LSEs in the group would have a financial stake in minimizing the reservation.

Finally, CBM reservations should have consequences for market-based-rate ("MBR") purposes. A TP should not be able to reserve capacity as CBM, while effectively treating that capacity as fully available for purposes of assessing its market power.[34]

b) TRM

TRM is necessary, but is also a source of potential abuse. For example, we understand that VACAR utilities reserve TRM for use in sharing operating reserves, but apply inconsistent practices as to whether TRM can be released for non-firm usage. As is apparent from data available on the MAPP OASIS, an upper Midwest utility whose system is a frequent source of constraints in the MAPP region reserves more TRM in remote years, and then reduces the TRM reservation for closer periods. This practice suppresses ATC for future periods,[35] foreclosing third parties from use of the capacity for

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[34] *See* Parts V and VIII.C of the comments of APPA and TAPS in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 71 Fed. Reg. 33,102 (proposed June 7, 2006), IV F.E.R.C. Stats. & Regs ¶ 32,602 (to be codified at 18 C.F.R. pt. 35), Docket No. RM04-7, filed today, proposing adjustments to the simultaneous import capability used for purposes of proposed screen to measure market power in bilateral markets.

[35] One provider modified its practice of increasing TRM in out-years only when faced with the threat of not being able to accredit an increase in capacity at one of its generating units because there was not adequate ATC on one of its constrained interfaces. *See* Minutes of May 23, 2006 Meeting of Mid-Continent Area Power Pool Design Review Subcommittee, at 3, item 6 (follow-up requiring adjustment of TRM), *available at* http://www.mapp.org/request/getfile?method=inline&gpfid=5267.

long-term transactions. The NERC Task Force Report's finding (at 3) that "[n]early all [transmission providers] use TRM" demonstrates that something is fundamentally wrong with this picture. If TRM is truly required for reliability, then *all* transmission providers should reserve it, not "nearly all."

The NOPR proposes to require development of clear standards that specify how TRM is determined, allocated across transmission paths, and used; that assure no double-counting; and that specify the uncertainties accounted for in TRM,[36] and the methods used to determine their impacts on TRM values. P 164. TAPS agrees with this approach, but urges the Commission to go further to ensure that TRM functions like a reliability requirement, not a discretionary, competitively driven set-aside.

Specifically, the Commission should subject the reserve-sharing component of TRM to the same reservation regimen as set forth above with regard to CBM. Consistent treatment of these two reserve-sharing-related set-asides is especially appropriate because some regions use TRM where others use CBM (although in theory, TRM is supposed to be limited to reserve-sharing for the initial one (VACAR) to six (MAPP) hours after an outage). Thus, as described above, TRM set-asides should also be conditioned on inclusive reserve-sharing arrangements, with the reservations determined by the reserve-sharing group, subject to dispute resolution before this Commission (and, eventually, approval by joint planning groups).

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[36] These uncertainties include "(1) load forecast and load distribution error, (2) variations in facility loadings, (3) uncertainty in transmission system topology, (4) loop flow impact, (5) variations in generation dispatch, including intermittent resources, (6) automatic sharing of reserves, and (7) other uncertainties identified through the NERC forums." P 164.

As to the other uncertainties identified by the Commission as contributing to TRM, each should be justified and supported by an action plan of efforts underway to minimize the uncertainty and thus the required reservation, with periodic reports on the status of those efforts. For example, the TRM reservation required to accommodate uncertainty in transmission system topology could be minimized by advance scheduling of maintenance, sharing those maintenance schedules within the interchange, and broadly sharing updated information on forced outages and changes to the maintenance schedule. If, by these measures, the uncertainty is limited to the operating horizon, the required set-aside should be reduced.

c) Modeling, Updating, and Data Exchange

TAPS agrees with the NOPR's proposal (PP 166-67) for accurate and consistent data and system modeling. The same methodology and grid topology (*e.g.*, the same line ratings and impedances) should be used for planning, granting transmission service requests, operating the system and issuing TLRs, although the inputs and assumptions may change with close to real-time data incorporated for operational decisions.[37] Because of use of more current inputs, the ATC values produced by operational and planning studies may differ,[38] but the underlying modeling should be consistent, with consistent dispatch assumptions.[39] As to the NOPR's question about impact on service to

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[37] For TLRs, the calculations are somewhat different (and use the NERC IDC calculator, which model is updated once a year).

[38] *See Oklahoma Gas & Elec. Co.*, 115 F.E.R.C. ¶ 61,350, P 30 (2006).

[39] For example, it appears that one of the reasons for problems experienced with AFC accuracy on the Entergy system is that the program used to calculate AFC assumes that resources are dispatched solely on the basis of economics, and not the security-constrained economic dispatch model that is actually used by Entergy in its operation of the system. Of course the use of one model to develop AFC (or ATC) calculations as to when transmission capacity is available to others and a different model to actually run the system inherently means that the AFC or ATC result will be wrong in almost all cases if there are

native load customers (P 167), more accurate and consistent modeling should minimize the opportunity for undue discrimination, improve access to the markets and enhance reliability, benefiting all consumers, including the transmission providers' customers.

TAPS also agrees with the NOPR's proposal (P 168) to require consistent standards on how often ATC/AFC and components are updated. Very frequent changing of posted information changes may not help the situation, however, if some but not all market participants have advance knowledge of changes. Even without such abuses, very frequent changing of posted information may play into the hands of those who use reservation computer programs the NOPR mentions (at P 395) as a source of abuse.

TAPS also agrees with the Commission that data exchange (P 169) is a crucial element in achieving consistent ATC determinations. In response to the Commission's question regarding access to the shared data (*id.*), TAPS urges the Commission not to restrict the data exchange to transmission providers. TDUs need an opportunity to access the data periodically as a check on the process. If necessary, to address confidentiality or standards-of-conduct concerns, TDU access to the data can be achieved through, *e.g.*, an employee barred from disclosing the information to marketing staff, or a third-party independent consultant selected and retained by the TDU. However, to maintain the integrity, credibility and auditability of the ATC calculation process, the data exchange cannot be restricted to transmission providers.

2. Transparency

TAPS supports the NOPR's proposals for transparency requirements for ATC/AFC, TTC, ETC, TRM and CBM. PP 172-78. As discussed above, and in our NOI

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significant transmission constraints on the system.

and ATC NOI Comments,[40] transparency has been lacking, heightening concerns about the accuracy of ATC calculations and the potential for abuse. Ending this secrecy is mandated not only by the Commission's obligations to ensure just, reasonable, and not unduly discriminatory or preferential transmission service, but also by the Commission's new transparency responsibilities under Section 220.

In particular, the NOPR's proposals for enhanced transparency for TRM and CBM appear helpful. TAPS urges the Commission to expand these requirements to accommodate implementation of TAPS' proposals regarding consistency of CBM and TRM determinations, as described above. Thus, the transparency requirements should be adapted to support TAPS' proposed open process among all LSEs in the inclusive reserve-sharing group for establishing CBM and the reserve-sharing component of TRM. Similarly, the transparency requirements should be expanded to track TAPS' proposal above requiring justification of all other factors contributing to TRM, a work plan for minimizing other components of TRM, and periodic status reports on those efforts.

3. OASIS

TAPS supports the NOPR's proposals (PP 180-95) to expand OASIS reporting requirements. These improvements are necessary steps toward achieving needed transparency and timely transmission of information, consistent with the Commission's obligations to ensure just and reasonable transmission and wholesale power rates under Sections 205 and 206, and its new transparency responsibilities under Section 220. To

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[40] TAPS NOI comments at 28-31 and TAPS comments in *Information Requirements for Available Transmission Capability*, Docket No. RM05-17-000 (filed Aug. 15, 2005) ("ATC NOI Comments").

better achieve the Commission's goals of eliminating the opportunity to discriminate, TAPS suggests the following enhancements to the NOPR's proposals.

a) Posting Requirements Must Include Facilities Studies and Studies for the TP's Own Uses, with Five-Year Retention

The NOPR (P 182) proposes to maintain existing requirements to make system impact studies for *customers* publicly available on request and to post a list. TAPS urges the Commission to close serious gaps in the current OASIS requirements by:

- including all studies for the TO's own transmission network resource designations and other uses of the system,
- encompassing facilities studies (as well as system impact studies),
- ensuring posted study lists are updated contemporaneously with the availability of new studies, and
- requiring retention of studies for a minimum of five years.

The ability of customers to scrutinize the studies performed not just for other customers, but for the TP's own uses of the system, is an ingredient essential to comparability and minimizing the opportunity for undue discrimination. Customers must have access to those studies to ensure that the TP is applying the same rules, and using the same modeling, for its own uses as it applies to others. While some TPs now post the availability of studies for their own transmission use, that is neither a standard nor required practice. The studies performed for the TP's own uses cannot be a secret, subject to disclosure only if the TP voluntarily agrees to do so.

Similarly, while some TPs (*e.g.*, SPP) already post facilities studies, such posting is not a standard or required practice. TAPS members have experienced facilities studies that have yielded dramatically different results than the impact study.[41] Both must be readily available to customers seeking to understand the TP's transmission system and to monitor for abuse.

As the Commission has recognized, the timeliness of access to information can be crucial. The Commission should clarify that the list of studies must be updated contemporaneously with the studies' completions and, if the studies themselves are not posted, the Commission expects prompt disclosure in response to a customer request.

Finally, TAPS asks that the period of required retention of studies (as clarified to include impact and facilities studies for all uses, including that of the TP) be expanded from two years, as now required (18 C.F.R. § 37.6(b)(2)(iii)), to five years. A five-year retention obligation would be consistent with the NOPR's proposed period for retaining data pertaining to denial of service requests (P 187) as well as the proposed five-year minimum for rollover rights. It is also consistent with the five-year retention obligations the Commission is now applying in other contexts.[42] A five-year retention requirement for studies also would provide a better check on the planning process and *vice versa*, and assist customers and the Commission's audit staff in detecting patterns that signal unequal treatment.

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[41] For example, Entergy's system impact studies for the participants in the Plum Point unit showed the need for many millions of dollars of backbone system upgrades. *See* TAPS NOI Reply Comments at 17-18. The facilities studies, however, ultimately concluded that no upgrades are required.

[42] *Revisions to Record Retention Requirements for Unbundled Sales Service, Persons Holding Blanket Marketing Certificates, and Public Utility Market-Based Rate Authorization Holders*, Order No. 677, 71 Fed. Reg. 30,284 (May 26, 2006), III F.E.R.C. Stat. & Regs. ¶ 31,218 (to be codified at 18 C.F.R. pts. 35 and 284).

b) ATC Posting Requirements Should Include Explanations of Persistent Zero ATC and Posting of Longer-Term ATC

The NOPR (P 186) proposes to require explanation of ATC changes and asks whether zero ATC for a specified time requires explanation. TAPS supports requiring explanations not only for ATC changes but for continuation of zero ATC. Specifically, if ATC is zero for more than two or three months, or certainly for a season, the TP needs to report how long the firm or non-firm ATC has been zero; how long it foresees ATC remaining at zero; when and at what level it predicts ATC becoming available; and, if no positive change is foreseen, what steps the TP is taking to relieve the constraint. Requiring the posting of such additional information for unchanged zero ATC will provide greater assurance that all customers have timely access to such crucial information, and can factor it into their power-supply plans. Spotlighting the issue of persistent zero ATC may help provide the accountability that may prod the TP to resolve the constraint. For example, an explanation that nothing is being done that would create ATC in the next three years needs to be assessed in the MBR context. Zero ATC data also needs to be collected and factored into the planning process.

In addition, TAPS asks the Commission to expand the data posted so that it includes the long-range ATC so crucial to customers' power-supply planning. The Commission's regulations now restrict posted ATC to 12 months (18 C.F.R. § 37.6(b)(3)(i)(A)(2) and (ii)(A)); data is only available for longer (through the planning horizon, but no longer than 10 years) *if* a planning or specifically requested system study has been performed (§37.6(b)(3)(i)(3) and (ii)(B)). The NOPR's planning requirements should eliminate any excuse for failing to post longer-term ATC information; as a result of the planning process, all TOs should be well aware of projected ATC through the planning horizon. Section 217(b)(4)'s emphasis on long-term rights and the NOPR's proposed five-year minimum term for rollover heighten the need for and appropriateness of requiring such data. Thus, the Commission's regulations should be modified to require the posting of projected longer-term ATC, for both constrained and unconstrained paths, through the TP's planning horizon, but no shorter than five years. Data for the period after the first twelve months now covered by the regulations should be posted for each year on, at minimum, a seasonal basis.

c) Information Supporting Anything Short of an Unconditional Grant of Service, As Well as Information Supporting the TP's Own Uses, Should Be Made Available to any Customer Retained for Five Years

The NOPR (P 187) proposes to retain the requirement in 18 CFR § 37.6(e)(2)(i) that a TP post the reason(s) for denying service, but to amend it to require the TP to maintain and make available information supporting its reason(s) for denying service, and to increase from three to five years the period for retention of transmission service information for audit. TAPS supports both of these proposals but suggests several modifications to ensure that such transparency similarly applies to anything short of an unconditional grant of service.

First, the Commission should clarify that the requirement to post reasons for denying service is triggered not only by a complete denial of the entirety of a transmission request, but to any disposition that falls short of a full unconditional grant of the service (with rollover rights if applicable). Given the gradations of grant or denial of service (especially if the NOPR's proposals to expand use of redispatch or grant conditional firm service are adopted), the information posting and retention net must be cast wider than a complete denial of service if it is to be effective.

Second, the regulatory text of proposed § 37.6(e)(2)(ii) should be modified to make the supporting data available, upon request, to any eligible customer. Limiting access to such data to “the potential transmission customer” (*i.e.*, the customer denied service) needlessly impairs the ability of customers to review and evaluate information that might reveal inconsistencies in TP analysis or patterns of abuse.

Third, the Commission should expand its OASIS regulations to require the TP also to maintain and make available on request the information supporting the disposition (positive, negative, or in between) of its own network resource designations and other usage needs. As discussed above with regard to access to studies performed regarding the TP’s own uses, assuring comparability and avoiding undue discrimination requires not only access to information regarding the failure to fully grant a transmission customer’s request, but also information supporting the TP’s treatment of its own service needs. While inclusion in the final rule of the requirement (NOPR P 189) that TPs use the OASIS to designate and undesignate network resources is necessary (as discussed below), it may not be sufficient to ensure the availability to customers of the information supporting the TP’s acceptance of its designations. Thus, this information should be made available to customers and preserved for five years under 18 C.F.R. § 37.6(e)(2)(ii) and 37.7(b) as proposed to be revised.

d) CBM

The NOPR (P 188) proposes that CBM be reevaluated at least quarterly, with practices posted. TAPS believes that this proposal may be inartfully phrased. TAPS agrees with the need for full transparency of CBM reservations and practices; as discussed above, we would remove them from the province of a TP’s unilateral discretion, and subject them to determination by an open and inclusive reserve-sharing group. Because CBM values may differ from season to season, CBM values should be separately calculated for at least each quarter.[43] However, that does not mean that it is necessary or appropriate for the quarterly CBM values to be *reevaluated* quarterly, especially given the effort involved in collecting the data and then performing the modeling analysis. CBM studies (that include determination of quarterly values) should be performed at least every other year, supplemented with "off-year studies" when appropriate (*e.g.*, in the event of significant generation or transmission additions and/or retirements).

e) Network Resource Designations Should Be Posted

TAPS strongly supports the NOPR's proposal (P 189) that TPs and network customers use the OASIS to request designation of new network resources and terminate designations, and that TPs post a list of their currently designated network resources and all network customers' currently designated resources (specifying amount of capacity designated). In most if not all cases, network customers already use the OASIS for this purpose, and comparability and transparency require application of the same requirements to the TP's own designations.

f) Load Forecasts Underlying ATC Should be Posted

The Commission (NOPR P 194) seeks comment on whether TPs should post the underlying load forecast for all ATC calculations and the actual peak load for the prior day, to allow comparison. TAPS supports this proposal. Because the TP's service to its

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[43] For example, to meet a specific LOLE value during the peak season, larger CBM values may be required than for other seasons; for some seasons, the CBM value could be zero.

native load accounts for the overwhelming majority of the use of its system, its load forecasts are a crucial component of ATC determinations that must be subject to disclosure to achieve needed transparency.

TAPS expects some TPs to argue against disclosure of load forecasts underlying ATC calculations based on claimed commercial sensitivity (because of what the forecasts might reveal as to their market position). Such a claim, however, poses no bar to disclosure of projected and actual load data on a one-day-lag basis, so it is always after-the-fact and could not compromise the TP's future market sales or purchases. Disclosure of such data is essential to enable customers to look for patterns of overestimation that result in unjustified restrictions on transmission access. Nor would such a claim affect current disclosure of the load forecast data most crucial to ATC—forecasted load on buses that affect constraints. Since such data would be a subset of the TP's load, it is unlikely to be as commercially sensitive, so should be disclosable along with actual load at the location affecting the constraint, at least on a one-day lag.

Finally, because of the importance of timely access to load forecast information, so that a customer can raise questions (with the TP, or if necessary the FERC hotline) before it loses a potential transaction, even disclosure on a one-day lag may be insufficient. Thus, the Commission should require disclosure of projected load forecast information, on request, to a customer's non-market employees or a consultant of the customer's selection that does not participate in market activities.

B. Transmission Planning—Coordinated, Open and Transparent Planning

The NOPR would require each TP to submit a proposal for a coordinated and regional planning process that meets eight requirements: (1) *Coordination* with transmission customers and interconnected neighbors; (2) *Openness* of planning meetings; (3) *Transparency* of basic criteria, assumptions, and data; (4) *Information Exchange* from transmission customers; (5) *Comparability*; (6) *Dispute Resolution*; (7) *Regional Participation* and coordination with interconnected systems to ensure system plans are developed on a consistent basis and to identify solutions to "significant and recurring" transmission congestion; and (8) annual *Congestion Studies* identifying significant and recurring congestion. NOPR P 214.

TAPS agrees with the Commission's conclusion that the existing *pro forma* OATT has not adequately foreclosed opportunities for undue discrimination (P 206-12), and strongly supports the NOPR's proposed joint regional planning requirement. TAPS members currently participate in successful, jointly planned and jointly owned transmission systems in Indiana, Minnesota, and North and South Dakota.[44] Some TAPS members have also been involved in voluntary joint planning efforts, including the North Carolina Transmission Planning Collaborative ("NCTPC") and the CapX 2020 transmission-planning process that encompasses seven utilities in the northern Midwest. Based on our experiences, we believe that joint planning is crucial to ending the current paralysis that has resulted in an inadequate grid in many parts of the country.

We are concerned, however, that the NOPR's proposed changes are insufficient to get the job done. To achieve the Commission's pro-competitive vision and satisfy Congress' mandate in Section 217(b)(4), the NOPR's eight process principles should be supplemented with: (1) the requirement that planning be collaborative and interactive;

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[44] *See* TAPS White Paper "Effective Solutions for Getting Needed Transmission Built at Reasonable Cost" at 12-13 and 19-20 (June 2004), *available at* http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf.

(2) substantive planning goals designed to assure that plans developed by individual regions anticipate and proactively correct transmission inadequacies; and (3) a clear obligation to construct needed transmission facilities, and provisions to hold transmission providers accountable for doing so.

1. The Joint Planning Process Must Be Collaborative and Interactive

TAPS agrees with the planning process principles identified in the NOPR (P 214). However, the Commission should clarify that its expanded planning obligation will not be satisfied by scheduling a few additional meetings at which the transmission provider's completed plan will be presented, along with coffee and snacks. To address the serious discrimination problems identified in the NOPR, the Commission should require TPs to implement *collaborative, interactive* joint planning processes that invite input from affected stakeholders at all stages of the process, allow stakeholders to participate in decisionmaking, and assure that the views of all stakeholders are considered on a non-discriminatory basis. Within an RTO, this requirement should be met in both the RTO's planning process and, to the extent RTO plans are developed by assembling the plans submitted by individual transmission owners, the separate planning processes of those transmission owners.

A true joint planning process will require fundamental changes in how planning and expansion decisions are made. As TAPS explained in its NOI Reply Comments (at 32, footnote omitted),

> The process must be fully open to participation by the network customers and existing and prospective long-term firm point-to-point customers, with all data disclosed and transparent, subject to appropriate confidentiality restrictions on use by market participants. All proposed

> base and changed cases, assumptions, and criteria must be made available, not simply the base case as proposed by EEI, with adequate time for review and comment.

Particularly in light of the NOPR's reliance on effective planning to provide customers continuing service and access to alternatives,[45] and its recent rule authorizing significant rate incentives to "transmission projects that result from a fair and open regional planning process,"[46] it is crucial that regional participation be meaningful and not just a cover for TP business-as-usual. We provide specific recommendations on how the planning process should be structured in Part V.B.5 below.

2. Baseline Substantive Planning Goals Should be Added to the OATT's Planning Provisions

TAPS urges the Commission to put teeth into the NOPR's planning requirement by setting out several baseline *substantive goals* that all joint planning efforts must meet. Of the eight planning principles identified in the NOPR, seven are primarily procedural. Only one—comparability—is a substantive planning goal. In theory, the NOPR's principles, properly implemented, might eventually result in each region developing non-discriminatory substantive planning standards consistent with the Commission's vision and Congress' mandate, and coordinated with the goals of adjacent regions. Achieving that baseline consensus, however, will be time-consuming and contentious—especially in areas without joint planning experience. Just as the OATT's Golden Rule of comparability has been insufficient to produce a robust grid in all parts of the country

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[45] *See, e.g.,* NOPR P 359 & n.337.

[46] *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), 116 F.E.R.C. ¶ 61,057, P 58 (2006) (to be codified at 18 C.F.R.§§ 35.34-35.35) ("Pricing Reform Final Rule").

today, regions may be slow to develop proper planning goals under the NOPR's new requirements.[47]

Indeed, the NOPR (at P 25) attributes the failure of the OATT's existing comparable planning obligation to the absence of clear guidelines on (among other things), "what standards and criteria should be used in system planning, and whether the planning process should identify potential economic upgrades that could benefit a wide range of customers, as opposed to responding only to customer-specific requests." Instead of repeating this error of omission, the final rule should specify clear substantive standards and criteria that ensure broadly beneficial transmission upgrades will get built. Each region will still need to develop specific planning standards for both regional and local area planning.[48] However, clarifying basic goals at the outset would provide crucial guidance and assure that those detailed standards and the OATT's new joint planning process result in proactive plans consistent with Congress' mandate.

EPAct 2005, prior Commission orders, and the NOPR itself identify key substantive planning goals that should be incorporated into the OATT's planning

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[47] Experience has shown that just putting something in the tariff doesn't assure its effectiveness. For example, Section 35.3 of the Order 888 OATT expressly provides for formation of a Network Operating Committee, with meetings no less than once a year. TAPS believes that this provision has not been widely implemented. Indeed, we are aware of only a few network customers that have ever had the opportunity to participate in such meetings, which could be a useful forum to address issues that affect the reliability of service (*e.g.*, development of business practices that affect all network users, work-arounds during scheduled maintenance of major facilities).

[48] GridFlorida, for example, proposed a local area planning standard that would measure the service reliability at all Points of Delivery ("POD") on the GridFlorida system, and require improvements to the PODs that ranked in the worst 3%. Compliance Filing of GridFlorida LLC, *et al.* in Docket No. RT01-67-001, Vol. III, Open Access Transmission Tariff, Attachment O, Section I.F.4, O.S. 247 (filed May 29, 2001) (eLibrary accession no. 20010531-0172). As described in n.54, the GridFlorida applicants subsequently withdrew their RTO application. Similar standards that require improvements to an even higher percentage of PODs may be appropriate to remedy discrimination where TPs have failed to maintain an evenly robust grid.

provisions. Section 217(b)(4), for example, includes two directives for the Commission: (1) to exercise its authority to facilitate planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy their service obligations; and (2) to enable load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power-supply arrangements made, or planned, to meet such needs.[49] The latter directive makes clear that both the existing and *planned* network resources that LSEs use to serve their loads are included within the "reasonable needs" that planning and expansion must support. To meet those needs, joint planning and expansion must be *proactive*. The grid enhancements needed for *potential* resources must be studied, as discussed in the NOPR (at P 218(c)). The lead time for building major transmission infrastructure can be longer than for major baseload generation; so the backbone facilities needed to create a robust grid and enable use of probable generation sites must be identified and constructed as part of the general joint planning process. As TAPS explained in its NOI Reply Comments (at 28 (footnotes omitted)), "IOUs do not wait to plan until after they have formally designated network resources for their own loads; nor do successful joint planning processes that currently exist…."

Transmission planning and expansion must also promote access to competitive markets for both consumers and suppliers. As the NOPR (at P 18) explains, EPAct 2005 "recognized the importance of adequate transmission infrastructure development and its role in facilitating the development of competitive wholesale markets." In Sections 216

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[49] EPAct 2005, § 1233, 119 Stat. at 958; *see also* Long-Term Rights Final Rule, 116 F.E.R.C. ¶ 61,077 at P 79.

and 219, Congress made clear its strong support for transmission expansions that address the "lack of adequate or reasonably priced electricity,"[50] or "reduce[e] the cost of delivered power by reducing transmission congestion."[51] Order 888 also sought to "facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa." NOPR P 303 (*quoting* Order No. 888 at 31,646). In *GridFlorida, LLC*, 94 F.E.R.C. ¶ 61,363, at 62,367 (2001), the Commission honed in on the importance of planning as a way to increase competition, requiring a demonstration that the long-range planning process will "ensure that efficient investments are made to make generation markets more competitive, increase import capability, and improve reliability."

The NOPR recognizes the failure of the grid to support competitive markets as a deficiency that must be corrected.[52] The Commission stresses that regional joint planning will be part of the solution, by "improving the ability [of consumers] to access competitive supplies" (*id.* at n.337), and by producing "a more rationally planned transmission system that will result in fewer transmission constraints and more ATC available to accommodate requests" for service to different locations (*id.* at P 371).

The Commission should integrate these basic substantive goals and standards into the OATT's new planning provisions. TAPS' *Balanced Principles for Transmission Planning and Expansion* is a compact, coherent proposal that provides a potential model

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[50] FPA, Section 216.

[51] FPA, Section 219.

[52] In discussing the need for reform, the NOPR documents how transmission providers have used existing planning and expansion processes to restrict competition (P 208), and how transmission infrastructure has failed to keep pace with load growth and the demands of a developing bulk power market (PP 31, 206). *See also id.* at P 25.

for doing so.[53] Although originally developed for the RTO context, the *Balanced Principles* fit well with the Commission's new regional planning requirement for both RTO and non-RTO transmission providers. They identify and explain seven specific planning and construction goals:

- Reliability/adequacy;
- Accommodating load growth;
- Preserving existing transmission rights;
- Providing loads with reasonable access (that is, without significant congestion charges) to regional competitive generation markets;
- In RTO regions, maintaining the simultaneous feasibility of FTRs (in the non-RTO context, this corresponds to maintaining the specific deliverability of network resources and firm point-to-point service);
- Facilitating regional and inter-regional power transfers through major transmission facilities that integrate markets within an interconnection; and
- Integrating new generation into the regional grid.

These forward-looking, proactive planning goals are similar to the best practices of existing voluntary joint planning efforts. The NCTPC, for example, establishes both a Reliability Planning Process that is "based upon reliability requirements for firm load and resource projections," and an Enhanced Transmission Access Planning Process that:

> will involve the analysis of potential transmission expansion projects that would provide *enhanced access to generation resources and markets inside and outside of the Duke and Progress control areas in North Carolina*, and the development of corresponding transmission expansion options including the costs and schedules associated with such options.[54]

[53] This document is Attachment 3 to TAPS NOI Comments.

[54] North Carolina Load Serving Entities' Transmission Planning Participation Agreement, Section 6

The NOPR's new regional joint planning process should likewise anticipate needs (*e.g.*, by projecting the likely sources of generation to meet load growth or to replace generation when a unit is retired or a contract ends), ensure access to competitive markets, and propose solutions before serious transmission problems emerge.

3. The OATT's Obligation to Build Should be Strengthened

The NOPR does not significantly change transmission providers' obligation to build. It would amend Section 28.2 of the OATT to provide:

> The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System.

For point-to-point customers, Section 15.4 provides that when a transmission provider cannot accommodate a point-to-point transaction because of insufficient capability on its system, it will "use due diligence to … expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K."

The OATT's construction obligation rests on the NOPR's enhancements to the transmission planning process. While this approach is economical from a drafting perspective, it places too heavy a burden on the as-yet-unproven foundation of the new joint regional planning process.

(emphasis added) available at http://www.nctpc.org/nctpc/document/REF/2005-05-20/pagreement.pdf (last accessed August 5, 2006). *See also* GridFlorida Planning Protocol, Section I.A.3., May 29, 2001 Compliance Filing in *GridFlorida LLC,* Docket No. RT01-67-001, which set out similar goals, including the identification and evaluation of "longer range needs" and facilitation of "transmission projects to expand competitive markets, including increased intertie capacity at the interfaces." The GridFlorida applicants subsequently withdrew their RTO application, and proceedings on the GridFlorida RTO Proposal have been terminated. *GridFlorida LLC*, 115 F.E.R.C. ¶ 61,341 (2006).

TAPS' recommended additions to the NOPR's planning provisions—particularly the adoption of substantive planning goals, such as TAPS' *Balanced Principles* and the best practices of existing and proposed voluntary joint planning efforts—would help address those concerns by ensuring that all regional plans encompass the important expansion needs identified in the NOPR (*e.g.*, to support competitive markets; to address "significant and recurring" congestion; and to support regional needs, including the needs of customers outside the TP's footprint). However, additional changes are needed to satisfy Section 217(b)(4)'s mandate to "facilitate[] the planning *and expansion* of transmission facilities to meet the reasonable needs of load-serving entities …." (emphasis added).

Specifically, the NOPR should strengthen the connection between planning and construction by clarifying that TPs will be obligated to build facilities identified in the regional plan. Even the best plans will fail if transmission providers can refuse to build in accordance with the plan. For regional plans to be meaningful, TPs must be required to implement them, or credibly explain why they cannot do so. Further, in order to give such provisions teeth, the Commission should adopt accountability provisions such as those discussed in Part V.B.4 below.

The planning process should also provide opportunities for joint ownership or other inclusive transmission investment models (*e.g.*, the "consortium approach" being explored by PJM, which would allow TDUs to share in the ownership of certain transmission projects).[55] TAPS supports the NOPR's suggestion (at P 218(b)) that an

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[55] *See* TAPS NOI Comments at 51-52, 101-05. *See also* TAPS Comments filed in *Promoting Transmission Investment through Pricing Reform*, Docket No. RM06-4-000 (filed Jan. 11, 2006) at 9-15, 31-37.

open season be required to allow market participants to participate in joint ownership of new transmission projects. A revised Section 30.9, particularly if modified as TAPS suggests in Part V.C.2, is another important vehicle to accommodate and provide recognition for such investment.

The NOPR (at P 218(d)) also asks "whether we should require public utilities to develop cost allocation principles to address the sharing of the costs of new transmission projects." Particularly if the Commission is serious about the regional participation requirement for joint planning, it must require transmission providers to address cost allocation among the TPs that participate in the process.[56] The Commission already knows how to use regional cost allocation mechanisms to encourage the construction of transmission upgrades. As recognized in *NEPOOL and ISO-NE*, 101 F.E.R.C. ¶ 61,344 (2002),[57] regional cost spreading will promote construction of the backbone high-voltage facilities needed to foster robust competitive markets. Speakers at technical conferences have stressed again and again that the best way to promote transmission expansion is to move toward a regional cost allocation approach.[58]

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[56] In light of the Commission's statement that it does not intend to overhaul transmission pricing policies in this proceeding (NOPR P 220), TAPS is not providing detailed comments on pricing issues for individual TPs. It submits these limited comments on the allocation of costs among multiple TPs in response to the Commission's specific question in Paragraph 218(d).

[57] In *NEPOOL and ISO-NE*, 101 F.E.R.C. ¶ 61,344 at P 36, the Commission sought to create incentives for the construction of transmission upgrades into Southwest Connecticut, by committing to allow the costs of those upgrades to be spread among customers throughout New England.

[58] *See, e.g.*, testimony of Joe Welch, CEO of International Transmission Company's, at the April 22, 2005 Technical Conference *Transmission Independence and Investment*, Docket No. AD05-5-000 and PL03-1-000 ("Transmission Investment Technical Conference") ("What is needed is the regional pricing mechanism whereby the revenue requirements associated with new transmission investment is properly allocated to the region, including across seams.") (Tr. at 82); testimony of Mike Morris, President and CEO of American Electric Power at the May 13, 2005 Technical Conference *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources*, Docket No. AD05-3-000 ("Coal Transmission Technical Conference") (Tr. at 188); and Roy Thilly, President of Wisconsin Public Power, Inc. on behalf of TAPS, at the Transmission Investment Technical

TAPS has long supported regional or joint rates as a means to minimize pancaked charges that create unnecessary barriers to competitive bulk power markets, and that impose undue burdens on TDUs with loads and resources spread among multiple transmission systems.[59] Regional or joint rates have the added benefit of encouraging the construction of transmission upgrades by: (a) assuring appropriate cost recovery for new network transmission facilities that provide widespread benefits; and (b) allowing transmission providers to proactively plan and construct new network upgrades, without waiting for a specific customer service request over known constrained interfaces. Regional or joint rates would also ease the problem that the NOPR requires regional planning, but has no provision requiring TPs to build facilities to support regional needs.

Even outside of an RTO, rate mechanisms can be developed to spread the costs of new facilities over multiple TPs. The Commission, for example, can exercise its long-recognized authority to require joint rates where systems are integrated. *Ft. Pierce Utils. Auth. v. FERC*, 730 F.2d 778, 783-85 (D.C. Cir. 1984).[60] It could also invite filings for partial joint rates covering new regionally planned, high-voltage facilities of transmission providers (and TDUs that invest in those facilities) to operate in conjunction with single-system rates covering existing facilities and new lower-voltage facilities. Variations of this approach have a proven track record. Prior to Order 888 and the creation of ISO-NE,

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Conference (Tr. at 283). *See also* TAPS White Paper "Effective Solutions for Getting Needed Transmission Built at Reasonable Cost" at 19-20 (June 2004), *available at* http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf; Post-Technical Conference Comments of the Transmission Access Policy Study Group, filed in *Transmission Independence and Investment,* Docket Nos. AD05-5-000, PL03-1-000 (May 2, 2005).

[59] *See, e.g.,* TAPS NOI Comments at 18-21.

[60] *See generally Permian Basin Area Rate Cases*, 390 U.S. 747, 776-77 (1968) (Supreme Court approving Commission's use of area rates, noting that "the width of administrative authority must be measured in part by the purposes for which it was conferred"); TAPS NOI Comments at 18-21.

NEPOOL members had rates that were designed to spread the costs of regionally significant Pool Transmission Facilities ("PTF") among all NEPOOL members. Basin Electric Power Cooperative, Black Hills Power, Inc., and Powder River Energy Corporation also operate an integrated transmission system under a Commission-approved Joint OATT.[61]

Failure to spread the costs of regionally significant facilities is likely to cause needed transmission to be delayed, or not built at all. On a dynamic AC grid, network upgrades will provide benefits to many market participants, specific beneficiaries are difficult to identify and change over time, and benefits can be enjoyed by "free riders."[62] Assigning the costs to a particular market participant (*e.g.*, under a participant-funding system) invites a game of chicken where would-be beneficiaries sit back in the hope that others will step forward to bear the cost of an upgrade; meanwhile, transmission construction is delayed.[63] Regional planning processes will be crippled if plans can only be implemented reactively—with the construction of plan-recommended network facilities only *after* a specific transmission service request has been received—or if they depend on prior resolution of a complex and contentious process to determine how each facility's benefits and costs will be allocated over the life of the facility.[64]

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[61] *See, e.g.*, *Basin Elec. Power Coop.*, 113 F.E.R.C. ¶ 61,079 (2005).

[62] *See, e.g.*, NOPR at P 218(d); Pricing Reform Final Rule, 116 F.E.R.C. ¶ 61,057 at P 42 (finding that there will be few transmission projects that do not provide both reliability and congestion benefits).

[63] *See* TAPS NOI Reply Comments at 15-25.

[64] *See, e.g.*, Comments of TAPS in *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Docket No. RM06-8-000, at 17-22 (filed March 13, 2006) (describing the drawbacks of participant funding).

4. Transmission Providers Must be Held Accountable if They Fail to Construct

Enhancements to the planning and construction obligations of the OATT will be meaningless if transmission providers cannot be held accountable for building needed upgrades. TAPS urges the Commission to adopt measures that would require transmission providers—the entities in the best position to control and manage the risks of the planning and construction process—to share the burden of failing to build necessary transmission upgrades. As explained in Part V.D.3, such measures include requiring the TP to accept a network customer's timely designated network resource, if necessary through redispatch with costs shared on a load-ratio basis. At minimum, to address discrimination through granularity differences, TPs should also be required to accept *any* request for transmission to a network customer load (if necessary, by redispatch shared on a load-ratio basis) if the request would have been accepted if the TP's own load had been the designated sink. *See* Part V.D.1.c.

In addition, if the TP's failure to plan has left embedded TDUs trapped without reasonable access to alternatives, the TP should be required to offer embedded-cost sales to such TDUs. *See* Part V.D.3.

The Commission should also make clear that its toolbox to address egregious failures to plan and construct a robust grid that meets the needs of network customers includes the exercise of jurisdiction over the transmission component of bundled retail sales of a particular utility to remedy undue discrimination. *New York v. FERC*, 535 U.S. 1 (2002). While we would not expect the Commission to take this step lightly, the Commission should recognize its availability in extreme cases.

5. Additional Planning Process Guidance Is Needed

TAPS supports the Commission's commitment to remedy discriminatory practices through an enhanced regional joint planning process. However, only a few regions currently have the experience and institutions needed to make coordinated, open, and transparent planning a reality. We are concerned that in the absence of more specific guidance, the rights of transmission customers will be compromised during a lengthy transition period while regions struggle to develop joint planning protocols and institutions that work. Specific guidance, based on the best practices of existing regional planning processes, would expedite the process and help avoid potential pitfalls.

- **Joint planning regions should include at least two TPs and be no smaller than a state.** The NOPR requires regional participation in transmission planning and "strongly encourages that such coordination encompass as broad a region as possible, given the interconnected nature of the transmission grid and the efficiency of addressing these issues in a single forum." P 214. TAPS supports this goal and urges the Commission to supplement it with the more specific requirements that joint planning regions include at least two TPs and be no smaller than a state.

  Based on the experience of TAPS members, balkanized single-TP planning can result in inefficient, costly solutions, because each TP has limited knowledge of and control over interconnected transmission systems and therefore fewer available options to solve problems. A broader footprint enhances the ability to develop least-cost solutions by expanding those options, allowing properly sized, cost-effective upgrades to address regional needs, and combining the problem-solving personnel and resources of multiple TPs within the region. According to TAPS member ElectriCities, which is a participant in the NCTPC:

> We have already seen significant benefits from using a cooperative regional approach, such as: better modeling of the transmission system, improved information about loads and resources, standardized assumptions and planning criteria, coordinated efforts for investment in new transmission facilities, and improved solutions due to the new ideas generated by diverse stakeholders.[65]

ElectriCities is hopeful that the combined efforts of the NCTPC participants will result in new ideas and cost-effective solutions for significantly increasing transfer capability across constrained interfaces, at reasonable cost and for the benefit of all participants.

Each joint planning region should include at least two TPs, in addition to TDUs. Involving multiple TPs should capture at least some of the synergies discussed above. Based on the experience of TAPS members, joint planning processes that involve multiple TPs are more balanced and less likely to be dominated by a single entity.

Joint planning regions also should be no smaller than one state. While the benefits of joint planning do not necessarily stop at the state line, TAPS recognizes that siting and retail rate treatment of new facilities may sometimes be expedited by limiting the number of states within the joint plan footprint. However, the minimum size allowed should be one state. Where a multi-state region is needed to satisfy the two-TP minimum, that should be the minimum size permitted.

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[65] Letter from Clay Norris (ElectriCities Division Director, Planning) to Commissioner Nora Brownell (April 11, 2006), filed in *Preventing Undue Discrimination and Preference in Transmission Services*, RM05-25-000, eLibrary accession no. 20060411-4004.

Successful implementation of the NOPR's regional participation obligation will require Commission oversight. Each TP's compliance filing should identify the other TPs that it proposes to include in its regular regional planning process, recognizing that particular projects may require a different regional grouping, and recognizing that these grouping may change over time. The Commission should encourage coordinated filings, preferably with some commitment or process to grapple with the regional cost sharing/allocation issues needed to make the regional planning process productive in getting transmission built.

- **Joint planning processes must provide LSEs with a meaningful voice.** The NOPR requires each transmission provider to coordinate "with all of its transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis;" and the Commission "seeks comment on specific requirements for this coordination." P 214. TAPS strongly supports the NOPR's Coordination and Comparability requirements. To achieve them, transmission-dependent LSEs must have a meaningful voice in planning decisions.

  TAPS recommends the formation of a regional joint planning committee, not dominated by TPs, that would direct the study process and be responsible for the development of uniform planning criteria, assumptions for base and changed cases, and transmission plans.[66] As described in Part V.B.1, all proposed base and changed cases, assumptions, and criteria must be made available with adequate time for review and comment. By working closely with technical staff, the joint planning committee

[66] TAPS NOI Comments at 15-18, 88-90, TAPS NOI Reply Comments at 31-33.

will develop a general familiarity with the modeling process and local conditions, building expertise that should facilitate and expedite subsequent transmission planning cycles and allow the TPs to share some of the modeling work.

The joint planning committee approach has already been implemented in a variety of shared systems and voluntary planning efforts. The NCTPC, for example, has established an Oversight/Steering Committee ("OSC") comprising eight voting members, equally divided between Duke Power, Progress Energy Carolinas, ElectriCities of North Carolina, and the North Carolina electric cooperatives. The OSC seeks to reach decisions on reliability and enhanced transmission access planning by consensus. If it is unable to reach a decision by consensus, decisions are reached by majority vote; and in the event of a tied vote, an independent third-party consultant/facilitator is entitled to cast the tie-breaking vote. OSC decisions are not necessarily binding on the TPs. However, a TP that disputes an OSC decision must provide an explanation for its disagreement, and dispute resolution procedures are available to challenge a TP that does not abide by a decision of the OSC.

The NCTPC's combination of an OSC in which TDUs and TOs have equal voting rights, an independent third-party tie-breaker, and dispute resolution is only one potential model for participation; and it may not be suitable for all regions. The NCTPC is relatively new—although initial signs are promising, only time will tell if it can deliver effective and nondiscriminatory joint transmission plans over the long-run.

Although there may not be a one-size-fits-all solution, the crucial task for all regions is to provide representation and safeguards that will prevent transmission providers from continuing to dominate the transmission planning process and failing to achieve Section 217(b)(4)'s objective. Consensus-based approaches, or voting rights schemes that give each participant one vote regardless of size,[67] for example, could also accomplish this goal if combined with the right other elements.[68]

Load-ratio-share voting will not work. Most transmission providers have large retail loads, so their load-ratio-share votes would swamp the votes of transmission customers, giving TPs the power to make planning decisions unilaterally. If anything, this approach would *increase* the likelihood of discriminatory transmission planning, as TPs would have every incentive to cast purely self-interested votes, defeating the coordination and comparability goals of the NOPR.

Use of a joint planning committee will not eliminate the need for broader customer participation in the process. For example, stakeholders who do not directly participate in the joint planning committee should have opportunities to provide data for the base plan and to review and comment on data, models, and draft plans. A strong and effective joint planning committee, however, should increase customer confidence in the transmission planning process, facilitate review of transmission plans, and reduce the time needed for comment periods.

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[67] *Cf. Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission*, 111 F.E.R.C. ¶ 61,473, P 9 & n.6 (2005), in which the Commission noted that the governance structure of American Transmission Company ("ATC"), which provided each ATC owner with one vote regardless of size, "allows some degree of participation by market participants, but ensures the operational and managerial independence of the stand-alone transmission company."

[68] For example, the Commission has expressly recognized the importance of dispute resolution to joint planning, including it as one of the eight planning principles in the NOPR (at P 214) and OATT Attachment K. Clear planning standards and goals are essential to giving dispute resolution processes teeth and protecting minorities with legitimate concerns who might otherwise be overruled in the decisionmaking process.

- **Planning horizon should be a minimum of 10 years; and plans should be updated regularly.** The NOPR seeks comment on whether joint planning "should be required to look out at least as far as the longest time it would take to build [multi-state regional backbone facilities] in the region in question." P 218(d). TAPS' answer is "yes." A 10-year planning horizon is also consistent with the 10-year minimum term for long-term FTRs that the Commission recently adopted in the Long-Term Rights Final Rule, 116 F.E.R.C. ¶ 61,077 at P 255. TAPS also recommends that transmission plans be updated regularly, at least biennially, to assure that they remain relevant to transmission service and construction decisions. In some areas—*e.g.*, fast-growing regions where loads and resources are changing rapidly—plan updates may be needed annually or even more frequently.

  LSEs that participate in the planning process must be able to rely on the ten-year regional joint transmission plans in developing their power supply. Notwithstanding the strong first-come-first-served principle of the OATT, such LSEs should be assured that the transmission service needs they identify, and which are included in the joint planning process, will be met by the transmission provider in a manner consistent with the ten-year regional plan—even if other uses not included in the planning process unexpectedly appear and exhaust planned-for capacity before the LSE can submit its network resource designation. The LSE should not be placed at the margin under these circumstances with respect to access, transmission funding requirements, or otherwise.

  Assuring such LSEs that their needs will be met would more appropriately allocate the risks of unexpected (and unplanned-for) service requests, reduce the likelihood that market participants will try to game the system by submitting unnecessary or premature transmission service requests, and encourage the orderly development of new resources by discouraging a "Gold Rush" mentality in which every market participant seeks to lay claim to transmission capacity created by relatively low-cost facility expansions as soon as possible. It would also help reduce the "chicken and egg" problem created by the interaction of OATT § 30.7 (which prevents a network customer from designating a resource until it can "demonstrate that it owns or has committed to purchase generation pursuant to an executed contract," or "establish that execution of a contract is contingent upon the availability of transmission service") and the realities of power supply planning (where early assurance that transmission service will be available may be needed to determine whether a potential new resource is viable, and planning horizons for transmission may be longer than those for generating resources).[69]

As an alternative, or in addition, to including this type of assurance in the OATT's planning provisions, it might be possible to achieve the same effect by expanding Order 888's load-growth reservation provisions (*e.g.*, to expressly encompass network customer replacement resources included in the planning process).

- **Confidentiality concerns can be addressed without compromising the Openness principle.** The NOPR would require open, inclusive joint planning processes, but requests "comment on whether there are any circumstances under which participation should be limited, *e.g.*, to address confidentiality concerns." P 214(2). It is crucial that the integrity of the joint planning process be maintained, and that confidential

[69] *See* TAPS NOI Reply Comments at 28-29.

information obtained through the planning process not be used to gain an unfair advantage in wholesale generation markets. However, proper safeguards can assure the confidentiality of sensitive information without undermining the open, inclusive planning process that the NOPR envisions. Many TDUs are not required to functionally separate their operations (*e.g.*, because they do not own transmission, or because they qualify for an Order 889 small-system waiver). While some information necessary to effective regional planning may be competitively sensitive, excluding such entities from joint planning would defeat the NOPR's nondiscrimination purpose. The experience of TAPS members is that confidentiality issues can be addressed by limiting data access to TDU employees not involved in marketing, or to an outside consultant.

- **Form 715 is inadequate to meet the NOPR's proposed transparency requirement.** P 214(3); *see also* n.196. Although Form 715 includes information on the physical layout and characteristics of the transmission grid, it does not include detailed data on how the system is being used—*e.g.*, information on economic dispatch and interchange. As a result, Form 715 includes insufficient data to perform an adequate load-flow study—part of the baseline information needed for effective transmission planning—or even to replicate and verify the analyses provided as part of Form 715. Nor does Form 715 provide the data necessary to perform basic reliability analyses. Such information must be provided to those involved in planning to allow the process to be interactive. However, so long as this information is readily available to those in the planning process, it may not be necessary to revise and expand Form 715 to include it.

C. Transmission Pricing

1. Imbalances

To bring greater standardization to imbalance provisions and to ensure that they are just and reasonable, the Commission proposes to modify Schedule 4, governing the treatment of energy (load) imbalances, and to create a new OATT schedule for generator imbalances. The NOPR sets forth three principles that will govern these imbalance provisions: (1) charges must be based on "incremental cost" or some multiple thereof (*i.e.*, eliminating the all-too-common $100/MWh penalty charge, a change TAPS wholeheartedly supports[70]); (2) charges must provide an incentive for accurate scheduling; and (3) the provisions must account for the special circumstances of intermittent generators. P 239.

More specifically, the Commission suggests (P 240) that BPA's three-tier energy imbalance system could work well for both energy imbalance and generator imbalance. Under the BPA system, imbalances less than or equal to the *pro forma* 1.5%/2 MW deadband are returned in kind throughout the month, with any remainder cashed out at 100% of the monthly average incremental or decremental cost. Imbalances in excess of this 1.5%/2 MW deadband are cashed out at multiples of incremental or decremental cost: between 1.5% (or 2 MW) and 7.5% (or 10 MW), at 90% of decremental cost or 110% of incremental cost; and above 7.5% or 10 MW, at 75% of decremental cost or 125% of incremental cost. Unpredictable generating resources are exempt from the third tier and pay second-tier charges for all deviations greater than 1.5% or 2 MW. The

[70] *See* TAPS NOI Comments at 31-38 and TAPS NOI Reply Comments at 8-9.

NOPR asks whether the BPA approach should be adopted as the *pro forma* model for pricing imbalances (P 241).

The Commission's imbalance proposal is premised on the finding that it does not violate the principle of comparability to treat inadvertent energy differently than energy and generator imbalances (P 245). TAPS disagrees with this premise, and continues to believe that requiring TDUs to pay for imbalance energy is unduly discriminatory where their competitors, the TPs that are balancing authorities, enjoy the benefits of swapping energy for free through in-kind return of inadvertent energy.[71] TAPS responds to the NOPR's inquiry regarding the need for reform of the current approach to inadvertent energy by urging the Commission address this discrimination through the final rule in this proceeding and/or in Docket No. RM06-16, rather than leaving the industry to sort this out. The Commission could resolve the issue in this proceeding by adopting a genuinely comparable and cost-based treatment of imbalance, such as allowing all imbalances to be returned in-kind, or requiring balancing authorities to pay for inadvertent energy (beyond the return-in-kind bandwidth applicable to imbalances) at incremental cost and charging each customer only for its contribution to the control

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[71] Although the Commission asserts that inadvertent energy "is caused by the combined effects of all the generation and loads in the control area and not simply the loads and generation of the transmission provider," P 245, the lion's share of inadvertent energy is typically under the control of the TP that controls the vast majority of the load and generation in the control area. Neither this difference without meaningful distinction nor "historical practices" – the Commission's other stated reason – justifies radically different regimes for inadvertent and energy imbalance, especially where the difference has significant impacts on competition. Nor can the competitive impact of dramatically different treatment of what are plainly very similar services be justified by the Commission's statement that it does "not believe that the two [services] should have *precisely* the same treatment." *Id.* (emphasis added). *See* correspondence between TAPS and NERC and NAESB on this subject, attached to TAPS NOI Comments at Attachment 2. If anything, the evidence would support a more stringent regimen for inadvertent than imbalance, and not *vice versa*. The most notorious abusers have been balancing authorities/transmission owners, and the Commission Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Reliability Standards, issued May 11, 2006 in Docket No. RM06-16 (at 32), observes that inadvertent is increasing.

area's inadvertent obligations (*e.g*., there would be no charge if the customer's imbalance served to reduce the control area's inadvertent).

Nonetheless, if separate imbalance charges are to continue notwithstanding the lack of comparability with inadvertent interchange, TAPS believes that the NOPR's proposal to eliminate the $100/MWh penalty is absolutely necessary, and the proposal to include something akin to the BPA imbalance provisions as part of the *pro forma* tariff is definitely a step in the right direction. Greater uniformity in the treatment of imbalance is desirable, and a BPA-style imbalance approach, with its tiered deadbands and associated cost-based pricing, would represent a significant improvement over the *status quo.* However, in fashioning its *pro forma* imbalance provisions, the Commission should incorporate netting of the individual customer's generator and load imbalances. Further, to move closer to comparability and more accurately reflect cost-causation, the *pro forma* provisions should impose imbalance penalties only if the individual customer's net imbalance contributes to (rather than mitigates) the aggregate system imbalance, or at least the aggregate wholesale customer imbalance, similar to the approach of the imbalance provisions in the OATT of Sierra Pacific Power Company and Nevada Power Company.

a) The Commission Should Incorporate Netting of Load and Generator Imbalances into the BPA-Style Regime

The NOPR (P 247) solicits comments on whether it is appropriate to net imbalances, at least on an individual-customer basis and within a single control area. In particular, the Commission asks whether netting of generator and load imbalances can and should be permitted within a reasonable percentage without triggering reliability concerns or redispatch costs. TAPS' answer is "yes." Netting is necessary to make imbalance more comparable to the treatment of the TP's own inadvertent, and comports with principles of cost-causation—it is only the net imbalance of a customer that can have any impact on the control area's imbalance (and even that effect will depend on the prevailing direction of imbalances in the control area). Furthermore, from the perspective of the TP operating as balancing authority, it is desirable to have a customer try to match its load when that load deviates from projections, even though technically that produces both load and generator imbalances for the customer (as they are currently defined). If a customer has erred in scheduling its load and resources, or when the inevitable weather and other unpredictable factors cause deviations from schedule, the customer should have an incentive to try to minimize the difference between actual load and actual generation, irrespective of what its schedules were. Netting would provide an incentive to promote reliable operation.

TPs can be expected to argue that it is important to retain an incentive to schedule accurately. While there might be some surface appeal to this argument,[72] the TP's own deviations between forecasted load and actual use will have significant impacts on ATC (as the NOPR recognizes at P 194), yet no limit applies to the TP's own ability to adjust its generation to match its load. If the Commission were to find that it is both necessary and consistent with comparability to place limits on the degree to which a customer can net its generator and load imbalances, we suggest that the second deadband in the BPA-style imbalance regime (*i.e.*, 7.5%/10 MW of scheduled load/generation) should be used

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[72] TPs may assert that to the extent customers under-schedule, ATC could be overestimated and transmission might be oversold, leading to constraints and possible curtailments; over-scheduling might result in false reductions of ATC, possibly causing the TP to turn away transactions that otherwise would be accommodated. But wholesale customers typically reflect only a small fraction of transmission uses in a control area, with the bulk remaining the TP's use for its native load.

for this purpose, subject to a maximum (of, say, 25 MW) to address the impact of applying the allowed percentage to large customers.

This netting process would be the first step in determining imbalances. To the extent a customer has both load and generator imbalances in an hour in the same control area, with one causing an over-supply and the other causing an under-supply, these imbalances should offset each other (up to any applicable netting limit[73]). The resulting net imbalance would be considered a generator imbalance, so that any applicable exceptions (discussed below) may be factored in.[74] This netting process would effectuate the Commission's determination (P 246) that only load or generation imbalance charges, not both, may be assessed. Customers who have only load or generation imbalance would obviously not be subject to this netting. Nor would a customer who has both load and generation imbalance that deviate from schedule in a non-offsetting direction (over-supply or under-supply). For example, if the customer scheduled 100 MW of both load and generation, but its actual load was 110 MW and its actual generation was 90 MW (thus, both imbalances constituting an under-supply), the customer would be subject to both the load imbalance and the generation imbalance provisions, as contemplated in the Imbalance Provision NOPR.[75]

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[73] If a netting limit such as TAPS (reluctantly) suggests above were imposed, it would work as follows. If a customer scheduled 100 MW of load and generation in an hour, but its actual load was 105 MW and its actual generation was 104 MW, the customer's net imbalance would be just one MW after the five MW of load imbalance is offset by the four MW of generation imbalance (both of which are within the netting limit). If another customer scheduled 150 MW of load and resources in an hour, and ended up with 170 MW of actual load and 165 MW of generation, its generation and load imbalances should cancel each other out up to 11.25 MW (7.5% of 150 MW), leaving this customer with a net imbalance of 8.75 MW (as opposed to just the five MW discrepancy between its actual load and resources).

[74] *See Imbalance Provisions for Intermittent Resources*, 70 Fed. Reg. 21,349 (Apr. 26, 2005), IV F.E.R.C. Stat. & Regs. ¶ 32,581, P 9 (to be codified at 18 C.F.R. pt. 35) ("Imbalance Provisions NOPR").

[75] *Id.* P 9 & n.19.

To the extent each customer's imbalance determined in this manner[76] is less than the first deadband (*i.e.*, 1.5%/2 MW), the customer may schedule return-in-kind of the imbalance within 30 days, consistent with the existing *pro forma* Schedule 4 provisions. Any such imbalances remaining at the end of the 30-day period would be cashed out at 100% of incremental or decremental cost, whichever is applicable. Net imbalances that exceed the first deadband but are less than the second deadband (7.5%/10 MW) would be cashed out at 110% of incremental cost or 90% of decremental cost. Any portion of the customer's net imbalance that exceeds the second deadband would be cashed out at 125% of incremental cost or 75% of decremental cost.

Under TAPS' proposal, there would be certain exceptions to the foregoing rules. Consistent with the NOPR's third criterion for imbalance pricing, a net imbalance resulting from operation of an intermittent generating facility,[77] even if it exceeded the second deadband, would not be subject to the higher penalty level and would be priced as though it was within the second deadband. In addition, there should be an exception for generator imbalances resulting from TLRs or other TP instructions, and for both the unexpected loss of a generating unit and the response of other generators to replace that unit pursuant to inclusive reserve-sharing arrangements, with resulting imbalances treated as being within the first deadband.[78] As recognized in the Imbalance Provisions NOPR

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[76] In determining all imbalances, generation located behind the meter and the load served by that generation should both be excluded. In other words, only the metered load and generation served by the transmission system should be used in determining imbalances.

[77] TAPS would propose to utilize at least the same two intermittent-generation exceptions as BPA has adopted in its OATT, *i.e.*, test energy from new generating facilities (for up to 90 days) and wind generation. TAPS suggests that the test-energy exception should be broadened to encompass testing that must be done from time to time on existing units, within reasonable limits.

[78] As discussed in Part V.A.1.a above, reserve-sharing should be an open club that admits all LSEs. Allowing an exception for reserve-sharing without opening up the clubs to smaller participants would result

at P 57, "penalties must be avoidable by customer actions." It is plainly inappropriate to punish the transmission customer for TLRs or for otherwise following TP instructions, actions that, from the customer point of view, are unavoidable.[79] Penalizing imbalances in the case of forced generation outages similarly would not give plant operators any better incentive to schedule accurately, since unplanned unit outages by their very nature cannot be predicted and scheduled for, and the purpose of the reserve-sharing response to these unexpected outages is to reduce overall imbalance/inadvertent. Avoiding imbalance penalties for forced outages is particularly appropriate in the control area where a customer's load is located, because the customer already compensates the TP for operating reserves—the capacity required to cover such events.

b) In Order to Satisfy Comparability and Cost-Causation Requirements, the New *Pro Forma* Imbalance Schedule Should also Include Aggregate Imbalance Provisions

TAPS believes that the final rule should include *pro forma* imbalance provisions that meet at least the foregoing criteria, which are very close to those described in the NOPR. In addition, the Commission should take a further major step toward comparability and cost-causation by taking into account whether the customer's individual imbalance aggravates or mitigates the system's aggregate customer imbalance.

Under such a regime, the aggregate imbalance would be the sum of the net imbalances of all wholesale transmission customers of a given TP (or within a given zone, if the TP has multiple control-area zones operating under a single OATT).

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in undue discrimination, leaving the excluded LSEs exposed to imbalance penalties while others are insulated from such impacts. The period of allowed deviation should be consistent with regional reserve-sharing group practices.

[79] *See also* Part V.D.8 below.

Negative net imbalances and positive net imbalances of individual customers would offset each other in this calculation. An aggregate imbalance deadband would also be calculated, equal to a percentage of the total load of the wholesale transmission customers (*i.e.*, the sum of network loads plus the reservations of point-to-point customers). An appropriate percentage for this purpose would be the same percentage used by the TP to allocate generation costs to its Schedule 3 charges, since this is the generation deemed to be used for load-following. This aggregate imbalance deadband would be calculated each hour, to take account of varying hourly total loads.

The aggregate imbalance and the aggregate imbalance deadband would be considered in determining the rate treatment for any portion of an individual customer's net imbalance that exceeds the first deadband (1.5%/2 MW). During hours in which the aggregate imbalance was within the aggregate imbalance deadband, no penalties would be applied to any individual customer's net imbalance (*i.e.*, the imbalances should be cashed out as if they were within the first bandwidth). During hours in which the aggregate imbalance exceeded the aggregate imbalance deadband, the penalties associated with the second and third tiers would apply to an individual customer's net imbalance only if its net imbalance is in the same direction (over-supply or under-supply) as the aggregate customer imbalance for that hour.

This approach, while it adds some complexity, has been used successfully by at least one TP for several years under a Commission-approved OATT. We believe that the added complexity is justified by its much greater fairness, in that it exempts from penalties those customers whose imbalances offset other customers' imbalances, and thereby contribute to the balancing of the total system. In short, this approach is much better "tailored to deter the unwanted action, without providing an unnecessary windfall,"[80] such as the windfall that would result from imposing penalties on those who offset or reduce others' imbalances. TAPS therefore urges the Commission to incorporate the concept of aggregate imbalance into the *pro forma* imbalance provisions promulgated in the final rule, as reflected in TAPS' proposed tariff language set forth in Attachment A hereto.[81]

c) The Commission Must Exercise Great Caution in Considering Any Proposed Provisions Regarding Intentional Imbalance Penalties or Inclusion of "Commitment" Costs in Incremental Pricing

The NOPR (P 242) "seek[s] comment on whether the *pro forma* OATT imbalance provision should provide for penalties for behavior that represents deliberate reliance on the transmission provider's generation resources, as opposed to scheduling errors, with such penalties being subject to prior notice and approval by the Commission and based on the facts and circumstances of the individual transmission provider." TAPS questions the wisdom of going down the path of "intentional imbalance" penalties, given that no generic showing of a need for such penalties has been made and they present great potential for abuse by TPs. Nor do TPs incur penalties for intentionally relying on inadvertent energy (even though such incidents have occurred[82]).

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[80] *Entergy Servs., Inc.*, 109 F.E.R.C. ¶ 61,095, P 44 (2004).

[81] In compliance with P 494 of the NOPR, Attachment A includes a redline/strikeout comparison to the Schedule 4 attached to the NOPR. However, because we have primarily added to the existing *pro forma* language, we also attach a clean version of TAPS' proposed Schedule 4 that is much easier to read.

[82] *E.g.*, in what has been termed Cinergy's "grand theft electric" (*see Cinergy's Brazen Taking from Grid Stuns Market* …, Power Markets Week, November 22, 1999), as found by ECAR, in six to eight different hours during a heat wave in July 1999, Cinergy drew from the interconnection 1500-1700 MW of power without incurring any penalty.

If, notwithstanding these concerns, the Commission concludes that it is appropriate to permit TPs to assess penalties for intentional imbalances, the Commission must ensure that the TPs are not able to exercise significant discretion in declaring imbalances to be intentional and/or imposing penalties therefor. This would be done most effectively by specifying in the final rule that intentional imbalance penalties are limited to instances in which the customer exceeds the second deadband *and* the TP has provided notice to the customer and advised the customer to reduce its imbalance because of its adverse impact. Further, the final rule must make clear that any TP proposals for penalties must be supported by a demonstration of customer abuse that warrants imposition of penalties and that the level of the penalty is the minimum required to discourage inappropriate behavior.[83]

In any event, the Commission should clarify that it is ***not*** an intentional imbalance, subject to penalties, for the customer to aim to slightly over-schedule in all hours in order to avoid onerous imbalance charges for under-deliveries.[84] This clarification is particularly important if the final rule implements the NOPR's proposal "that incremental cost be defined to include both energy and commitment costs (to the extent additional commitments are needed)" (P 244, footnote omitted). However, TAPS

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[83] *Entergy*, 109 F.E.R.C. ¶ 61,095 at P 44.

[84] For example, a customer that almost always over-delivers within the first deadband, and only rarely exceeds the first deadband, is clearly trying just to avoid under-deliveries and should not be penalized for intentional imbalance, especially since the NOPR's stated concern (P 242) relates to under-deliveries ("deliberate reliance upon the transmission provider's generation resources"). Viewed in this light, BPA's criteria for intentional imbalance (summarized in n.233 of the NOPR) would not be a good model. Although we suspect BPA does not abuse the discretion it has under its definition of intentional imbalance, TAPS is certain that many investor-owned TPs would not hesitate to exercise such discretion to selectively harm the wholesale customers with which they compete.

urges the Commission to reverse course on this point, and clarify that incremental cost will be based solely on energy costs.

Specifically, customers already pay capacity-related costs of generation that supplies imbalance energy in the form of regulation and/or operating-reserve charges under Schedules 3, 5 and 6. Furthermore, including capacity-related costs in imbalance pricing would exacerbate the non-comparability of the imbalance charges as compared with the treatment of inadvertent energy. Thus, the final rule should foreclose TPs from including any "commitment" component in incremental costs for imbalance pricing purposes.

If the Commission nonetheless provides latitude for such a component, it should make clear that TPs will have to meet a very heavy burden of proof that they will incur generation commitment costs, attributable solely to wholesale customer imbalances, that will not be recovered through other charges (*e.g.*, Schedules 3, 5 and 6). The Commission should expressly recognize that this showing should be very difficult to make in the typical situation where the customer's imbalance represents a small fraction of the aggregate control area deviations followed by the TP's generation devoted to regulation and operating reserves. Further, commitment costs should only be permitted to be included in imbalance pricing if and to the extent that a transmission customer has a net under-supply (excluding any limits that might otherwise apply to netting of its load and generator imbalances) at the same time that the control area as a whole (not just the aggregate imbalance of wholesale transmission customers) is under-supplied. Otherwise, no causal connection between the transmission customer and the incurrence of unit-commitment costs would even be plausible. And finally, the attribution of the commitment costs to solely a particular customer's imbalance, as well as the charges themselves, must be subject to audit by the customer.

d) The New Imbalance Provisions Should Incorporate Additional Customer Protections

TAPS believes that re-writing the *pro forma* imbalance provisions to reflect the concepts discussed above (as suggested in Attachment A) would be a significant move in the direction of greater comparability, and greater protection of wholesale customers against unjust, unreasonable, and unduly discriminatory imbalance charges. However, certain additional protections should be included in the final rule. First, the Commission should make clear that the new *pro forma* imbalance provisions will not cause customers who have entered into contracts for load-following service to have the value of their agreements undermined by the new imbalance provisions, particularly any limit on the ability to net one's generation and load imbalances. Those agreements, which are aimed at matching the customers' load and generation and avoiding net imbalances, should be grandfathered and customers served thereunder should be exempt from imbalance charges.

In addition, the Commission should provide TDUs a clear right to dynamically schedule their loads and resources into a single control area in order to avoid being charged for both generator and energy imbalance on a single transaction where the customer has load and resources spread across multiple control areas. In Order 888, the Commission declined to require transmission providers to provide, at cost, dynamic scheduling and the ancillary services required for the load dynamically imported into the control area. Order No. 888 at 31,709-10. Given developments since Order 888, it can no longer be said that dynamic scheduling is a "special service" that is "used only infrequently" and requires "advanced technology and … a great level of coordination." *Id.* Where control-area utilities have remote generation and/or load, they regularly use a pseudo-tie to import it into their control area.[85] TDUs should have comparable options. Leaving TDUs in the position of having to negotiate with the TPs for this option will expose them to unjust and unreasonable and unduly discriminatory imbalance pricing.

2. Credits for Network Customers

The NOPR proposes to eliminate the joint-planning requirement for credits for new facilities constructed by network customers. PP 254-57. TAPS strongly supports this improvement to OATT Section 30.9, which we urged the Commission to adopt in our NOI comments. We believe there is more than ample support for the NOPR's conclusion that the current joint-planning requirement allows TOs to veto a customer's receipt of credits for new facilities, discourages joint planning, and operates in a discriminatory fashion.[86]

The NOPR goes on to state:

> The Commission continues to believe that, for existing facilities, the integration standard is the appropriate standard for determining whether a network customer's facilities should be eligible for credits. We clarify, however, that for new facilities, *the integration standard must be applied comparably, because application of the integration test in a manner that exclusively benefits the transmission provider is unduly discriminatory, and a violation of the FPA.* Specifically, we propose that the network customer shall receive credit for transmission

[85] For example, a proposal by AmerenUE to incorporate a large remote retail load into its existing control area via pseudo-tie was approved by this Commission in Docket No. ER05-485.

[86] For these same reasons, as discussed below, we urge the Commission to allow a customer to utilize, in calculating credits under Section 30.9, incentive-rate principles for which its newly constructed facilities may be eligible, irrespective of whether the TP has been willing to make a joint proposal with the customer as contemplated in the Commission's recently issued final transmission pricing rule. *See* Pricing Reform Final Rule, 116 F.E.R.C. ¶ 61,057 at P 354.

> facilities added subsequent to the effective date of the Final Rule in this proceeding provided that: (1) such facilities are integrated into the operations of the transmission provider's facilities, and (2) if the transmission facilities were owned by the transmission provider, would be eligible for inclusion in the transmission provider's annual transmission revenue requirement as specified in Attachment H of the pro forma OATT.

NOPR P 256 (footnotes omitted, emphasis added).

As TAPS understands it, the Commission proposes to adopt a more even-handed version of the integration-plus-comparability test that has always been embodied in Section 30.9. To date, Section 30.9 has been applied by focusing in the first instance on the facilities owned by the customer, which practice has allowed TPs to fashion a one-sided version of the integration standard that would disqualify most or all of the customer-owned facilities from credit eligibility. Only afterwards would the TPs' own facilities potentially be subject to examination to see if they met the same narrow standard.[87]

The poster child for what was wrong with this application of the integration-plus-comparability requirement is the proceedings involving the efforts of TAPS member Florida Municipal Power Agency ("FMPA") to get credits from Florida Power & Light Company ("FPL"). FMPA's request to receive credits for certain transmission facilities had been denied under a very stringent application of the integration test urged by FPL, which required that the customer-owned facilities be used by the TP to serve its other

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[87] More often than not, a TP could avoid such inquiry in a § 205 context by simply not filing a new transmission rate case. In the last decade, with very little new transmission being built and existing rates producing over-recovery of a rate base declining as a result of depreciation, this was a profitable strategy for many TPs.

customers.[88] Then, in a companion transmission rate case, the Commission ruled that in order to ensure comparability, consistent with Order 888, FPL's transmission rates had to be revised to exclude all facilities that would not pass the integration test under which FMPA was denied credits, *i.e.*, facilities that serve only a single FPL retail load center and are not used to provide service to other customers.[89] The Commission noted that this application of the integration test differed from the integration standard typically used in evaluating transmission facilities for inclusion in rates, and that comparable application of this one-sided integration test artificially narrowed the facilities to be included in FPL's rolled-in transmission rates.[90]

Now, the Commission apparently proposes (but only for newly constructed facilities) to flip the focus of the integration-plus-comparability test so that it proceeds from the integration standard utilized by the TP in determining which of its own facilities are to be included in its transmission cost of service, and applying this same standard to the facilities owned by the TP's customers. The long and tortured history of the *FMPA* and *FPL* cases points toward the wisdom of the Commission's proposal to look first to whatever standard the TP has used in setting rates, and determine eligibility for credits

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[88] *Florida Mun. Power Agency v. Florida Power & Light Co.*, 65 F.E.R.C. ¶ 61,125, *reh'g dismissed*, 65 F.E.R.C. ¶ 61,372 (1993), *final order*, 67 F.E.R.C. ¶ 61,167 (1994), *clarified*, 74 F.E.R.C. ¶ 61,006 (1996), *reh'g denied*, 96 F.E.R.C. ¶ 61,130 (2001), *aff'd sub nom., Florida Mun. Power Agency v. FERC*, 315 F.3d 362 (D.C. Cir.), *cert. denied*, 540 U.S. 946 (2003).

[89] *Florida Power & Light Co.*, 105 F.E.R.C. ¶ 61,287 (2003), *reh'g denied*, 106 F.E.R.C. ¶ 61,204 (2004); *order on compliance filing*, 110 F.E.R.C. ¶ 61,058, PP 10-11, 13 (2005); *order on revised compliance filing*, 113 F.E.R.C. ¶ 61,263 (2005), *reh'g denied*, 116 F.E.R.C. ¶ 61,013 (2006). Under this application of the comparability leg of the test, the Commission ruled that FPL had to exclude from its rate base all radial facilities as well as facilities that provided only "unneeded redundancy."

[90] *Florida Power & Light Co.*, 116 F.E.R.C. ¶ 61,013 at P 22 n.31 ("We again note that our determination of which facilities are not eligible for transmission rate base inclusion is a very narrow determination aimed at achieving comparability to the test FP&L devised to test FMPA's facilities in the TX Case. In other circumstances, we would typically find these looped facilities to be integrated transmission facilities.").

that way, rather than having to revisit the TP's transmission rates years after the fact to apply a one-sided integration test advocated by the TP in a credits case. It is perhaps because of lessons learned the hard way in the *FMPA* and *FPL* cases that the Commission's proposed revisions to Section 30.9 appear intended to base credit eligibility on the integration standard employed in the development of the TP's own transmission rate base.

TAPS believes that the NOPR's proposal as to new facilities, assuming we understand it correctly, represents a significant improvement over the existing Section 30.9. However, the Commission should make three modifications in order to ensure that its goal of true comparability is met. TAPS' proposed revisions to the Commission's proposed language of Section 30.9 to address all three of the concerns discussed herein are set forth in Attachment B hereto.

a) The Commission Should Omit Vestigial "Integration" References from Section 30.9

TAPS continues to believe that the best course would be for the Commission to expressly eliminate integration as an independent requirement of Section 30.9, or replace it with a more straightforward "interconnection" standard. Such an approach would avoid confusion that is likely to ensue from continuing to use the "integration" terminology that carries substantial adverse baggage and has been unfairly applied to deprive customers of compensation for facilities they contribute to the network. By simply providing that customer-owned facilities would be eligible for credits to the extent they would be included in the TP's rate base if they were owned by the TP, the Commission would avoid much litigation that is likely to ensue over what (if anything) the separate "integration" requirement adds in the proposed formulation.

To be read consistently with the comparability requirement, the integration requirement must mean only that the customer and TP facilities are interconnected. If additional concepts that have been read into the credits-related integration test over the years since Order 888—such as the exclusion of radial facilities—were to be retained, they would erode the comparability part of the test.[91] The Commission's historically prevalent, broadly inclusive integration test is itself an essential component of the requirement that customer-owned facilities would be eligible for inclusion in the TP's rolled-in rates if they were owned by the TP. That is the only integration test that can and should apply if the comparability requirement is truly to be observed.[92]

In addition to being easy to apply and fully compatible with comparability, this more inclusive crediting approach would encourage investment in transmission expansion "regardless of the ownership of facilities," as required under Section 1241 of EPAct 2005.[93] As directed by Section 217(b)(4), this approach would provide an effective vehicle to facilitate construction of facilities identified in the joint planning

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[91] For example, if the TP includes radial facilities in its transmission rate base, its customers' radial lines should be equally eligible for compensation, irrespective of whether any such radial lines would meet an "integration" test such as has been applied under the Commission's current version of Section 30.9.

[92] This approach would also be consistent with the more even-handed credits test the Commission has employed in the context of RTOs. *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 106 F.E.R.C. ¶ 61,219, PP 53-56 (2004) (the seven-factor test would apply without a further showing of integration); *Southwest Power Pool, Inc.*, 112 F.E.R.C. ¶ 61,355 (2005) (approving, with modifications, a consistent definition of transmission facilities that would apply to transmission owner and transmission customer facilities, and make customer facilities eligible for revenue sharing). Such a shift in focus to better achieve comparability is appropriate given that no further RTO development seems to be on the horizon, and most TPs that are currently stand-alone transmission owners are likely to remain so for the foreseeable future. Thus, the optimistic prediction that RTO development would make credits issues easier to resolve (*see, e.g., Florida Power & Light Co.*, 105 F.E.R.C. ¶ 61,287 (2003) (Wood, concurring)) has not borne out and the Commission must find ways to ensure that credits are dealt with as fairly in the stand-alone TP context as they are in RTOs.

[93] EPAct 2005, 119 Stat. at 961.

process, even where the transmission provider itself is reluctant to make the needed investment.

At the very least, if the integration terminology is retained in Section 30.9, the Commission should clarify that the new integration test is truly different from the old integration test and cannot properly be read as limiting the comparability requirement. In order to avoid pointless debate and delay in customers' getting credits, the Commission should leave no doubt that by applying the comparability requirement (as formulated in revised Section 30.9 to focus on the standards employed by the TO with respect to its own rates) together with the integration requirement, the Commission will not follow precedents developed in credits cases decided under the original Section 30.9.

b) The New Section 30.9 Standard Must Apply to Existing As Well As New Facilities

The standard that the Commission proposes to apply only to new facilities should apply prospectively to ***all*** customer-owned transmission facilities, no matter when they were built. The NOPR is certainly correct in recognizing (at P 256) that "application of the integration test in a manner that exclusively benefits the transmission provider is unduly discriminatory, and a violation of the FPA," and thereby proposing to re-focus the test for credits in a way better aimed at achieving comparability. The NOPR loses its compass, however, in proposing that the new Section 30.9 standard should apply only to transmission facilities a customer constructs ***after*** issuance of a final rule in this docket.

The Commission has correctly found that the current formulation and application of Section 30.9 have resulted in undue discrimination and a lack of comparability. The NOPR's proposal, however, would leave customers who have already constructed transmission facilities subject to the very discrimination the Commission recognizes as a statutory violation in formulating its new standard, contrary to the Commission's obligation under FPA Sections 205 and 206 to remedy undue discrimination that it finds.[94] The Commission offers no explanation of why the new Section 30.9 standard should apply only to facilities constructed after issuance of a final rule in this docket. TAPS cannot conceive of any possible justification for limiting application of the new rule in this manner,[95] particularly given that the "new" standard seems to essentially re-focus the inquiry to start with the comparability component (*i.e.*, by looking at what the TP includes in its rate base and thus considers to be "integrated"), rather than deferring the comparability component of the test until after application of an unduly narrow "integration" test to the customer's facilities.

It cannot be claimed that the revised standard should apply only to new facilities because the comparability requirement is new. To the contrary, comparability has been the theme and bedrock foundation of the Commission's transmission open-access requirement since its inception.[96] More specifically, Order 888 placed TPs on notice that the comparability standard would require the Commission to utilize the same standard in determining eligibility for inclusion in a TP's rate base as was applied to customers

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[94] In this context, the discrimination takes the form of TDUs essentially bearing pancaked charges even within a single transmission system. They must pay for their own transmission facilities as well as a load-ratio share of the surrounding transmission provider's system, leaving them bearing disproportionate transmission charges as compared to the transmission provider's native load customers. Unless the Commission applies its new credits standard to existing as well as new facilities, these transmission customers will be permanently burdened by the lack of comparable treatment of their existing transmission facilities.

[95] TAPS is not suggesting that the standard articulated in the NOPR would apply retroactively in the sense of providing for credits to be paid for *past use* of customers' existing facilities. The standard can, and should, be applied prospectively to existing facilities. The important consideration is when the claim for credits is brought, not when the facilities were constructed.

[96] Some form of the word "comparable" appears more than 130 times in each of Orders 888 and 888-A.

seeking credits for their own transmission facilities under Section 30.9. Indeed, the Commission quotes this very language in the current NOPR:

> In Order No. 888, the Commission addressed the comparability requirement:
>
> > We caution all transmission providers that while our discussion here addresses the requirements necessary for a customer's transmission facilities to become eligible for a credit, the principles of comparability compel us to apply the same standard to the transmission provider's facilities for rate determination purposes.

NOPR P 256 n.248 (quoting Order No. 888 at 31,743 n.452). This very language formed the basis of the Commission's requirement, discussed above, that FPL exclude the costs of certain of its own transmission facilities from its cost of service.[97]

In any event, the language of the NOPR and the Commission's proposed revisions to Section 30.9 attached to the NOPR leave the treatment of facilities built in this interim period unclear. The application of the integration-plus-comparability standard to all customer-owned facilities, no matter when constructed, will have the added benefit of eliminating the confusion that would result if the final rule were to adopt the Commission's currently proposed revisions to Section 30.9. Accordingly, the Commission's final rule should make clear that the new integration-plus-comparability standard articulated in the NOPR will apply in determining credit eligibility for ***all*** customer-owned transmission facilities, whether they were constructed prior to Order 888, after Order 888 but before the issuance of a final rule in this docket, or after issuance of the final rule in this docket.

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[97] *See* n.89, *supra.*

c) The Final Rule Should Enable Customers to Enjoy Rate Incentives

The Commission should expressly provide that credits to be provided to customers for newly constructed facilities may include (or be calculated using) incentive ratemaking elements. Incentive ratemaking is the only respect in which the Commission should distinguish between existing and new customer-owned facilities for purposes of determining credits under Section 30.9.

In its recently issued final rule on incentive ratemaking for new transmission facilities, the Commission stated that, "to the extent allowed under our jurisdiction, a public power entity should have the same opportunity afforded to jurisdictional entities to recover costs related to new transmission investment."[98] TAPS submits that not only must a customer have a comparable opportunity to recover its *costs* of new transmission investment, it should also have the same opportunity to include incentive-return adders and other benefits that can be justified by the customer under the final transmission pricing rule.

Further, a transmission customer's ability to enjoy these incentive-rate provisions must not be subject to the TP's pocket veto through refusal to engage in joint development of transmission projects with its customers. The final rule states (at P 354):

> [T]he ratemaking incentives we discuss in the Final Rule are generally not directly available to non-jurisdictional entities such as most public power entities, because they do not file their rates with the Commission. However, to the extent our jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power

[98] Pricing Reform Final Rule, 116 F.E.R.C. ¶ 61,057 at P 356.

> participates with jurisdictional entities as part of a proposal for incentives for a particular joint project.

This passage could be read to limit customers' enjoyment of incentives in the credits context (which is certainly subject to the Commission's jurisdiction) to only those situations in which the TP has agreed to joint development of a transmission project and a joint incentive-rate plan. Such a reading would impose the same unduly discriminatory joint-planning requirement (as to any incentive-rate components) that the Commission proposes in the NOPR to eliminate from Section 30.9. To avoid such perverse results, the Commission should include language in Section 30.9 that affirmatively states customers' eligibility for rate incentives for new facilities under applicable Commission policy.

d) TAPS Supports Other Credits Findings in the NOPR

As to other matters discussed in this section of the NOPR, TAPS generally agrees with the Commission. We support the Commission's conclusion (P 258) that it would not be appropriate in this rulemaking to allow TPs to automatically add costs of credits to their cost of service, and that such costs should continue to be evaluated as part of a regular transmission rate case (or recovered through an approved formula rate).

TAPS also supports the Commission's determination (P 259) that, in lieu of attempting to fashion a generic rule for credit eligibility for point-to-point customers, "consistent with the Commission's statement in Order No. 888, the Commission will address such situations on a fact-specific, case-by-case basis." As noted in TAPS' NOI Comments (at 91), we believe that there are circumstances in which a point-to-point customer should be eligible for credits. One clear example would be where a customer has invested in network facilities that were constructed in connection with a jointly owned generating unit in which the customer is participating, but the generator and associated network facilities are located on a transmission system other than where the customer's network load is located (such that the customer uses point-to-point service on the system where it owns transmission facilities).

3. Capacity Reassignment

The NOPR (PP 270-76) proposes to lift Order 888's cap on reassignment prices except in the case of transmission providers and their affiliates. While TAPS strongly supports the Commission's decision not to eliminate the reassignment cap as applied to TPs and their affiliates, TAPS urges the Commission to rethink the NOPR's proposal to otherwise lift Order 888's reassignment cap.[99]

As the NOPR recognizes (at P 272), lifting of the reassignment price cap will only have impact in cases where there is a transmission constraint. In such a situation there is no basis for the NOPR's statement that "we expect that competition among releasing customers will restrict the potential exercise of market power." *Id.* As the courts have made clear, the Commission is without authority to authorize market-based rates absent "empirical proof" that "existing competition would ensure that the actual price is just and reasonable," *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1510 (D.C. Cir. 1984). "[U]ndocumented reliance on market forces" is insufficient to satisfy the Commission's regulatory responsibilities. *Id*. at 1508. It must find that a seller "lacks market power (or has taken sufficient steps to mitigate market power), coupled with strict

[99] Order 888 capped the rate at the highest of: (1) the original transmission rate charged to the purchaser (assignor), (2) the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment or (3) the assignor's own opportunity costs capped at the cost of expansion. Order No. 888 at 31,697.

reporting requirements to ensure that the rate is 'just and reasonable' and that markets are not subject to manipulation." *California ex. rel. Lockyer v. FERC,* 383 F.3d 1006, 1013 (9th Cir. 2004). While the NOPR proposes a quarterly reporting requirement, it makes no empirical examination of whether in particular constraint situations the would-be assignor is likely to be in a position to exercise market power. Nor can it—lifting the cap will have value to the seller when it is exercising market power, *i.e.*, where, because it is effectively the "only game in town," the reassign or can name its price.[100] Thus, while the Commission is right to retain the cap for TPs and their affiliates on market-power grounds, it is wrong to assume an unaffiliated customer would need to "amass market power similar to that of the transmission provider" (NOPR P 274) before elimination of the reassignment cap becomes unlawful. To exercise market power, an unaffiliated customer would simply need rights to the only available path on a constrained interface.

Even assuming elimination of the cap were not inconsistent with the FPA's just and reasonable rate requirement, it would still be a bad idea. The NOPR's assumption that elimination of the cap will provide greater access and efficiency is contradicted by comments submitted by marketers that it is source-to-sink restrictions, not price caps, that limit reassignment. *See* NOPR P 269. If removal of the cap were effective in making reassignment profitable—ensuring capacity goes to "customers that value the capacity more highly" (NOPR P 273)—it would encourage hoarding of capacity on key paths that

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[100] The NOPR's states (P 272) that "if congestion exists, the 'incremental rate,' which reflects the transmission provider's cost of expansion, should act as a price ceiling for long-term transactions." This conclusion fails to take into account the delay and uncertainty associated with such expansion, even if the cost were known. There is no basis to assume that the TP's expansion cost would limit the amounts that could be charged for reassignment of existing capacity during the often lengthy period before an upgrade would be available. Indeed, the NOPR (at P 273) concedes that the price of reassigned capacity may "temporarily" exceed the cost of expansion.

would run afoul of Section 217(b)(4)'s directive to ensure the ability of LSEs to secure long-term rights for their long-term power-supply arrangements.[101] Nor would hoarding be limited by the TP's cost of expansion (NOPR P 274). As the planning section of the NOPR reflects, TPs are hardly chomping at the bit to plan and construct new transmission, especially where the excessive price of reassigned capacity is borne by competitors. Except in the unlikely case where it is the TP that pays exorbitant prices for reassigned capacity, the "price signal" is heard only by customers not in a position to avoid the *de facto* penalty by constructing additional transmission.[102]

In any event, TAPS strongly urges the Commission to retain the Order 888 price cap for TPs and their affiliates. The Commission (NOPR P 275) is right to be concerned that lifting the cap for the TPs and affiliates would invite the exercise of market power and act as a powerful disincentive to the transmission planning and expansion Congress has instructed this Commission to foster.

4. "Operational" Penalties

a) Unauthorized Use Penalties

(1) Unauthorized Use of Secondary Network Service

The NOPR explains that unauthorized use penalties do not apply "when a transmission customer inappropriately uses a network service reservation to support an off-system sale …. However, a transmission *customer* that inappropriately uses network

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[101] Removal of the cap could aggravate concerns (discussed in Part V.B.5**)** about the potential for frustration of the intended purpose of the joint regional planning process (*e.g.*, using a ten-year horizon required for many transmission projects), by encouraging point-to-point customers to snap up capacity planned for the anticipated needs of LSEs before the LSE has the opportunity to designate a network resource, leaving the LSEs vulnerable to extortion.

[102] As recognized in the Imbalance Provisions NOPR at P 57, "penalties must be avoidable by customer actions."

service would be required to pay for the point-to-point service it should have reserved and could be subject to a civil penalty depending on the circumstances." P 280 (emphasis added).

TAPS assumes the NOPR's reference to transmission customers was not intended to exempt a TP that does the same from the requirement to pay for point-to-point service to support off-system sales, and potentially face civil penalties. Further, as discussed in Part V.D.7 below, TAPS asks the Commission to clarify that secondary network service may be used not only to import economy purchases, but also to import substitute resources (*i.e.*, reserve sharing—emergency or maintenance service) during forced or planned unit outages, as required to reliably serve network load. Such reliability imports from non-network resources have always been a core part of network service.[103] Indeed, it is for that very purpose that TPs are permitted to reserve CBM.

TAPS also asks that the Commission clarify that the TP's (and network customer's) use of point-to-point service for imports must be narrowly restricted to non-firm point-to-point service except where it is demonstrated that the point-to-point usage is dedicated exclusively to serving an off-system sale (not included in Network Load or Native Load). We are concerned about unintended consequences of broadly allowing TPs to use firm point-to-point service to tie up firm import capability without having to

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[103] *See, e.g.*, *Florida Mun. Power Agency v. Florida Power & Light Co.*, 67 F.E.R.C. ¶ 61,167 at 61,483-84 (1994) ("[b]oth parties agree that FMPA should be allowed to designate substitute resources (that is, to displace an existing resource on a temporary basis because of an outage or a chance to buy cheaper energy)"), *reh'g denied*, 74 F.E.R.C. ¶ 61,006 (1996), *reh'g granted*, Order Granting Rehearing for Further Consideration, Docket Nos. TX93-4-004 and EL93-51-003 (Feb. 27, 1996), Order to Determine Mootness, 95 F.E.R.C. ¶ 61,001, *reh'g denied*, 96 F.E.R.C. ¶ 61,130 (2001), *aff'd sub nom. Florida Mun. Power Agency v. FERC*, 315 F.3d 362 (D.C. Cir.), *cert. denied*, 540 U.S. 946 (2003).

designate a firm network resource, a practice currently prohibited.[104] For example, the initial NOI comments of Nevada Power Co. and Sierra Pacific Power Co. ("the Nevada Companies") in this proceeding advocated a form of network contract demand service expressly to avoid the pesky problem of designating network resources to meet their native load as they are required to do under the *pro forma* OATT's network service provisions. *Id.* at 21-22. As the Nevada Companies' variation on NCD service suggests, TPs may be all too happy to pay themselves to reserve point-to-point service as a means to bottle up transmission capacity.[105] The Commission needs to be careful that in avoiding one abuse—inappropriate use of secondary network service for imports used for off-system sales—it does not create a loophole that allows TPs to tie up import capacity, while evading network resource designation requirements. Thus, a TP's (and network customer's) use of *firm* point-to-point service for imports needs to be narrowly circumscribed (*i.e.*, restricted to circumstances where it is demonstrated to be dedicated exclusively to making off-system sales not included in Network Load or Native Load), if permitted at all.

(2) Unauthorized Use of Point-to-Point Service

The NOPR asks whether existing penalties (limited to twice the standard rate for the service) have "resulted in penalties that are not just and reasonable; and, if so, we seek comment regarding provisions that would yield unauthorized use penalties that are just and reasonable." P 280. The answer is "yes"—the Commission's current policy

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[104] *See Wisconsin Power & Light Co.*, 84 F.E.R.C. ¶ 61,300 (1998) (improper reservation of import capability to benefit affiliated merchant function).

[105] As described in Part V.A.1.a above, it is for that reason that requiring a TP to pay itself for CBM reservations is unlikely to discipline CBM reservations.

permits unjust and unduly discriminatory penalties that disproportionately punish the long-term customer that exceeds its transmission reservations. For example, a long-term point-to-point customer that exceeds its reservation by 10 MW for one hour is charged 200% of the monthly charge for those 10 MW, while an hourly customer would be charged 200% of the hourly rate for the same unauthorized use. The disproportionality of the penalty imposed on the long-term customer, as compared to the short-term customer, for the same offense renders the charge unjust. To be more even-handed, penalties should be limited to 200% of the charge for the period of unauthorized use.

(3) Other Issues: Unexplained OATT Revision Providing for Penalties for Use of Remote Network Resources

Although never mentioned in the NOPR, the proposed tariff attached to the NOPR revises OATT § 30.4 by including unexplained new language restricting a network customer's use of its remote network resources beyond their designation, and inviting imposition of penalties. The additional language reads as follows:

> The Network Customer may not schedule delivery of a Network Resource not physically interconnected with the Transmission Provider's Transmission System in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the Point of Delivery for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity.

The absence of any mention of this added language in the NOPR[106] suggests that it may have been included by error, a surmise confirmed by considering the language itself. This unnecessary and discriminatory language should be removed.

The language targets TDUs—the network customers most likely to have network resources located on a transmission system other than its "host" transmission system from which it takes network service.[107] The TDU in such circumstance would be supporting use of the designated portion of the resource to serve its network load by network service on the host system (the import system), plus point-to-point service on the transmission system on which the resource is located (the export system). To the extent a network customer wished to schedule more of that resource into its host control area than was designated as a network resource on the import system, it should be able to do so (the same way it would any other non-designated resource) by requesting secondary network service on the import system and by increasing the point-to-point reservation on the export system.

There is no justification for new language that could be read to restrict such legitimate usage of the customer's own resource and entitle the import system to impose penalties for conduct that cause it no harm. Indeed, the language is so ambiguous as to restrict the network customer's scheduled delivery of the undesignated portion of that resource to serve its own load located other than on the import system. The unexplained addition is all the more suspect because it is one-sided—imposing restrictions on a

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[106] The only mention in the NOPR of Section 30.4 appears in P 462; the discussion there relates to language in the existing OATT rather than the quoted new language.

[107] Indeed, a TDU's reliance on off-system generation may well be the product of discrimination, *e.g.*, the unwillingness of its competitor/host TP to allow the TDU to participate in baseload generating units.

network customer's use of its resources that are not comparable to the treatment of the TP's own network resources.

TAPS asks that this mysterious, unexplained addition to OATT § 30.4 be deleted in the final rule. If nevertheless retained (and supported by meaningful explanation), it must be clarified to expressly permit use of the undesignated portion of a remote network resource under secondary non-firm service (as a non-network resource), and to preserve the customer's right to use the undesignated portion of the resource for other purposes (*e.g.*, to serve its load on systems other than the host TP, or to make off-system sales). Further, the additional language would need to be modified to eliminate the inappropriate reference to a remote Network Resource's "Point of Delivery," a point-to-point service concept alien to network service.[108] In addition, the language would need to be rid of its internally inconsistent reference to a Network Resource beyond the capacity designated as a Network Resource in the customer's application—*i.e.*, the portion of the resource that is, by definition, not a Network Resource. *See* OATT § 30.1. Because the added language is unjustified by any finding (or even discussion) in the NOPR, serves no legitimate purpose, and is hopelessly garbled and confused, it should be deleted.

b) How Transmission Providers Should Pay Operational Penalties

TAPS supports the NOPR's proposal (P 283) to subject TPs to operational penalties, which would be credited back to non-offending customers through an annual

[108] *Compare* Preamble to Part II of the OATT (describing point-to-point service in terms of deliveries from designated Point(s) of Receipt to Point(s) of Delivery) *with* Preamble to OATT Part III and OATT § 28.1 and § 28.3 (which define a TP's obligations in reference to designated Network Resources to Network Load without reference to specific Points of Delivery or Receipt). *See also* OATT § 29.2(v) (describing Network Resource without reference to a specific Point of Delivery or Receipt).

compliance filing or automatic flow-through mechanism. Comparability demands such treatment. TAPS suggests one exception to this general rule, however. As noted in Part V.D.5.a below, penalties for study delays should go to the victims—those customers harmed by the delays in processing of system impact and facilities studies.

5. "Higher of" Pricing Policy

While, as discussed in Part V.B.3 above, TAPS urges the Commission to promote multi-TP rates to support the regional planning process the NOPR mandates, TAPS generally supports the Commission's determination (P 285) not to "undertak[e] generic transmission pricing reform in this proceeding" and instead to continue to apply its long-standing "higher of" transmission pricing policy, subject to considerations of comparability. Further, in response to the Commission's specific inquiry (P 286), TAPS believes that the Commission should modify the OATT to ensure that the "higher of" policy is properly implemented.

The Commission correctly observes that the practice of quoting incremental expansion costs as a lump-sum amount, "rather than in the form of a monthly transmission rate that can be compared, on an 'apples-to-apples' basis, to the embedded cost rate … has the potential to discourage customers from proceeding with service requests." P 285. Indeed, through such purported application of the "higher of" pricing policy, TPs may have in practice converted "or" pricing to a form of participant funding of transmission upgrade costs, and possibly prohibited "and" pricing.

To keep TPs from making an end-run around the strictures of "or" pricing, the Commission should include language in Sections 19.3 and 19.4 of the OATT specifying the manner in which the costs of Network Upgrades are to be presented in the results of the System Impact Study and Facilities Study. In Attachment C hereto, TAPS suggests modifications to Sections 19.3 and 19.4 that would accomplish the desired result.

As shown on Attachment C, similar changes should also be made to Sections 32.3 and 32.4 of the OATT, to ensure that network customers are not unduly scared off by inappropriate presentations of Network Upgrade costs. Although incremental pricing is somewhat more complex in the context of network service than it is in point-to-point service,[109] "higher of" pricing can work in the context of network service. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,085, P 57 (2004) (applying Order 2003 crediting mechanism to network customers).

Of course, the specifics of a TP's proposal to charge a network customer on an incremental basis—for that portion of the customer's load served by the resource giving rise to the network upgrade—will need to be specified in the study results as well as the service agreement. Moreover, the incremental rate will have to be submitted to the Commission as a proposed rate change. In this context, the Commission must not only consider whether the proposed incremental charge correctly implements the "higher of" pricing rule, but also must evaluate whether any such proposal to apply incremental pricing to a network customer violates the comparability principle. In other words, in each such case the Commission must examine whether the TP rolls in the costs of similar projects needed for its own native load service, and if so the Commission must decide

[109] Entergy claimed in its NOI comments in this proceeding that "higher of" pricing was not a practical alternative in the context of network service, so "and" pricing should be permitted as a means to protect other customers from bearing costs caused only by a particular network customer. This argument does not hold water, as shown in TAPS' NOI Reply Comments (at 15-25).

whether incremental pricing can be applied to the network customer without resulting in undue discrimination.[110]

Further, although the Commission did not address financial security provisions in this section of the NOPR, in considering the potential for abuse of "higher of" pricing the Commission should be cognizant of the language in Sections 19.4 and 32.4 requiring customers to provide a letter of credit or other security equal to the full cost of the network upgrade in order to maintain their reservations. TAPS accepts the need for a TP to demand such security from point-to-point customers (under Section 19.4), since certain point-to-point customers such as merchant generators may be more likely to abandon a service request and go out of business, leaving the TP (and its native load and network customers) to pick up the costs of the network upgrades occasioned by their requests. Nonetheless, the fact that the TPs can demand *security* equal to the entire cost of the upgrade makes it all the more necessary to ensure that the *pricing* of the upgrade is clearly and correctly conveyed to the customer. Otherwise, the customer may mistake a demand for security for a request for upfront *payment* of the entire cost of the upgrade.

Network customers should be treated differently. Since they are captive, load-serving entities, they will always pay their fair share of the costs of the system. Simply put, there is less financial risk to the TP in connection with building upgrades in response to network service requests. Further, the planning process should be taking network

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[110] TAPS submits that, in such event, it would be nearly impossible to reconcile the different pricing approaches without running afoul of the comparability requirement. If a TP rolls in the costs of upgrades related to its own generation resources, TDUs on the system pay their share of those facilities. Conversely, where TDUs are burdened, in addition, with incremental costs of upgrades required for their network resource designations, the TP and its other customers are protected from any impact of the upgrades occasioned by the network customers' resource selections. Indeed, the TP and its other customers will get to use the increased capability of the system but will not pay the associated costs. Such asymmetry is antithetical to the notion of comparability that animates the OATT.

customers' plans and needs into account anyway, and (as noted above) comparability would appear to require rolling in costs of network upgrades needed to accommodate network customers' service requests where the TP's own similar upgrades are accorded rolled-in treatment. It would be inappropriate to demand security from a network customer for the costs of facilities that will be rolled into the TP's rate base.

To the extent a network customer's service will be incrementally priced, the TP should be able to demand security under Section 32.4 only upon a proper showing of need. In no event should a network customer's reservation request be forfeited if the customer objects to posting security; rather, absent agreement between the TP and customer, the question of whether any security is required (and if so, how much) should be resolved by the Commission upon filing of an unexecuted service agreement. Modifications to the language of Section 32.4 to address these concerns are also presented in Attachment C.

6. Other Issues: The Final Rule Should Address Two Issues Not Sought to Be Remedied by the NOPR

a) Retail and Wholesale Load Served From Behind-the-Meter Generation Must Be Treated Comparably and Consistent With the Obligation to Plan

As described in our NOI Comments (at 26-28), TAPS generally agrees that load-ratio pricing for network service is necessary to achieve comparability with the treatment of bundled retail load. However, that approach must give way where the planning and cost-causation assumptions underlying load-ratio pricing do not apply in practice, and application of load-ratio pricing must scrupulously adhere to comparability in the treatment of wholesale and retail load served from behind-the-meter generation.

On remand from *Florida Municipal Power Agency v. FERC*, 411 F.3d 287 (D.C. Cir. 2005), the Commission recently required full load-ratio-share pricing where transmission limitations on an intermediate system prevented the customer from receiving service from the transmission provider for its full load,[111] relegating it to reliance on its on-system resources to serve the remainder of its load. Although (as the Commission noted),[112] the transmission provider's system had sufficient capacity to serve the customer's full load, the customer's full load would not reasonably drive the transmission provider's planning given the physical restrictions on the customer's ability to take service. In such cases, the Commission should align cost responsibility with realistic planning obligations and cost-causation by carving out a narrow, physical impossibility exception to load-ratio pricing.

The potential for inequity is heightened to the extent load served from behind-the-retail-meter generation is treated differently than wholesale load served from behind-the-meter generation. Commission precedent supports comparable treatment of load served by generation behind the retail and wholesale meters.[113] Although the Commission initially permitted preferential treatment of behind-the-retail-meter load in an RTO context,[114] it subsequently set the issue for hearing,[115] which resulted in a settlement that

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[111] *Florida Power & Light Co.*, 113 F.E.R.C. ¶ 61,290 (2005), *reh'g denied*, 116 F.E.R.C. ¶ 61,012 (July 6, 2006).

[112] *Florida Power & Light Co.*, 116 F.E.R.C. ¶ 61,012 at P 15.

[113] *Consumers Energy Co.*, 98 F.E.R.C. ¶ 61,333, at 62,410 (2002), *aff'g in relevant part*, 86 F.E.R.C. ¶ 63,004, at 65,032 (1999) (transmission provider's retail behind-the-meter loads should be included in the transmission provider's load-ratio share for allocating costs to network customers).

[114] *PJM Interconnection, L.L.C.*, 107 F.E.R.C. ¶ 61,113 (2004) (permitting netting of retail load served at a single electrical location by behind-the-meter generation).

[115] *PJM Interconnection, L.L.C.*, 112 F.E.R.C. ¶ 61,034, PP 15-20 (2005).

treats retail and wholesale load more comparably, while providing PJM rights to call on the behind-the-meter generation in certain circumstances.[116] In short, retail and wholesale load (including interruptible load) must be treated comparably for purposes of the load-ratio-share calculation.

Further, the comparability essential to support load-ratio pricing of network service also requires comparable treatment of the transmission facilities that serve the total grid load counted toward the load-ratio calculation. To deny credits for the customer-owned transmission facilities that are used to serve wholesale load from behind-the-meter generation, while also counting the load as network load served by the transmission provider's system, is plainly inconsistent. As discussed in Part V.C.2 above, while the NOPR makes significant strides to eliminate this discrimination with regard to credits for new transmission facilities, it fails to cure the discrimination in treatment of existing customer-owned facilities.

b) The Final Rule Should End Non-Comparable and Excessive Compensation for Reactive Capability Within the Order 2003 Deadband

Another key pricing issue omitted from the NOPR is reactive compensation, which is currently non-comparable and inconsistent with Order 2003. As discussed in TAPS NOI Comments (at 38-41), most transmission providers recover from transmission customers under OATT Schedule 2 the allocated cost of the reactive power capability of all of the TPs' generation. Transmission customers have a hard time obtaining credits for the reactive contribution made by their own generation, even when the generation is jointly owned with the TP. Although comparability can be achieved within RTOs where

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[116] The settlement was accepted in *PJM Interconnection*, 113 F.E.R.C. ¶ 61,279 (2005).

any LSE may file for recovery of the reactive power it sells to the RTO, outside an RTO some generators will be paid under OATT Schedule 2, while others similarly situated will not. This means that the generation sales of transmission providers (and IPPs) will be subsidized in comparison with sales from units owned by most municipal or cooperative utilities.

A more inclusive approach to compensating those with reactive power capability would satisfy comparability, but would produce other problems. In RTOs that compensate all generators for their reactive capability, without any restriction as to what capability is used and useful, reactive power compensation can grow to excessive levels.[117] Therefore, the OATT's preferential compensation of TPs for the reactive power supplied from their generation should be replaced with a regimen that is even-handed, while holding total reactive compensation to just and reasonable levels.

More specifically, the OATT's treatment of reactive power compensation should be made consistent with Order 2003-A, which requires transmission providers to treat all sources of reactive power in an equitable and non-discriminatory manner. LGIA Article 9.6.3, as amended by Order 2003-A,[118] provides:

> Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility

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[117] For example, even as reduced by settlement (in Docket Nos. ER04-1055 and -1059), the annual reactive revenue requirement associated with two new gas plants in Wisconsin's Alliant East zone, totaling 1075 MW, is $1.945 million. That annual price almost equals the combined total price for all other reactive generators in that zone (as collected by MISO through its currently effective Schedule 2 unit rate) of approximately $2.6 million, for the other 2570 MW of in-zone generation.

[118] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, 69 Fed. Reg. 15,932 (Mar. 26, 2004), [2001-2005 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,160 ("Order 2003-A"), at 31,020, *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (Jan. 4, 2005), F.E.R.C. Stat. & Regs. ¶ 31,171, *order on reh'g*, Order No. 2003-C, 70 Fed. Reg. 37,661 (June 30, 2005), F.E.R.C. Stat. & Regs. ¶ 31,190.

> when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer.

Consistent with this policy, the Commission should eliminate from Schedule 2 all charges for reactive capability within the Order 2003 bandwidth, leaving compensation only for required outside-the-deadband production. This approach was recently proposed by Entergy. In accepting Entergy's Schedule 2 revisions, the Commission found them to be "consistent with Order 2003-A and Commission policy on reactive power," as well as comparability.[119]

Similarly, in *Calpine Oneta Power, LP*, 113 F.E.R.C. ¶ 63,015, P 127(12) (2005), a well-reasoned initial decision found, on the basis of an evidentiary record, that taking into account cost-causation, engineering, regulatory and economic principles, it is unjust and unreasonable and "against the public interest to permit any utility to recover fixed costs attributable to reactive power capability from transmission customers." It further concluded that allowing all generators to receive Schedule 2 payments "only for costs incurred in supplying reactive power when required to operate outside their specified power factor range" to be "the only method that is just and reasonable to the rate-paying public and maintains comparability between traditional utilities and independent power producers so that they can compete on equal terms." *Id.* P 125. The initial decision

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[119] *See Entergy Servs., Inc.*, 113 F.E.R.C. ¶ 61,040, PP 22-24, 39 (2005), *reh'g denied*, 114 F.E.R.C. ¶ 61,303, *reh'g denied*, 115 F.E.R.C. ¶ 61,378 (2006) (granting Entergy's petition for declaratory order that if Entergy does not compensate its own or affiliated generators for reactive power service provided to transmission customers within the generator's specified power factor range (deadband), then Entergy need not compensate a non-affiliated generator for maintaining reactive power within the deadband, and setting for hearing Entergy's proposal to pass through costs third-party generators charge Entergy).

found that, at least in some areas, American Electric Power Company's reactive charges "leave the public with paying for from three to ten times the amount of reactive power capability than is used or useful." *Id.* P 108.

Transmission customers, particularly LSEs that have had to arrange for enough generation to meet their own load and reserve obligations, and therefore already paid their share of the regional reactive power control needs provided by generators,[120] should not be burdened with non-comparable and excessive charges for reactive capability far in excess of what is used and useful to the grid.[121] If the costs of reactive power within the deadband are treated as a generation cost (rather than a transmission or ancillary service cost),[122] then none of the generating units is subsidized vis-à-vis the others, and all of their customers are treated comparably.

Thus, TAPS asks that the Commission apply its comparability principle to eliminate from Schedule 2 compensation for reactive capability within the Order 2003 deadband, and provide for compensation, on a non-discriminatory basis, only for reactive production outside that bandwidth. If the Commission chooses the alternative path of compensating all generators' reactive capability (including that within the Order 2003

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[120] There are limitations to the use of reactive power over distances, but the fact that the system works demonstrates that there are adequate sources in each smaller region that is relevant, and if LSE "A" in region "Y" controls generation (and reactive power) in region "Z" while LSE "B" in region "Z" controls generation (and reactive power) in region "Y," the obligations are in many senses fungible.

[121] The February 4, 2005 Staff Report, *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, Docket No. AD05-1, at 14, recommended review of the *AEP* methodology. However, Staff proposed to compensate all generators, rather than eliminate compensation within the specified power factor range. *Id.* at 9-10. We agree that comparability is key, but suggest (in addition to the over-collection issue discussed above) that reactive needs, and any defensible level of reactive payments, are too small relative to the cost of a real power generator to materially affect decisions to invest in and site a generator.

[122] Any mechanism to compensate generators for reactive output outside the deadband must be designed to be available to all suppliers of this service, including non-jurisdictional utilities.

deadband) on a non-discriminatory basis, as is the practice in some RTOs, the Commission must develop a mechanism to avoid charging transmission customers for far more reactive capability than the grid requires, *e.g.*, by pro rating among all generators on a system (or region) compensation for the reactive capability reasonably required.

D. Non-Rate Terms and Conditions

1. Potential Modifications to Long-Term Firm Point-to-Point Service

The NOPR (PP 300-304) finds that TPs approach customer transmission requests differently than their own, and that the result is unduly discriminatory. TAPS agrees and notes that this finding applies to network resource designations, not just point-to-point reservation requests, and overlooks another important source of discrimination in assessment of transmission customer requests: granularity.

We agree with the NOPR's proposal to clarify the transmission evaluation sequence so that redispatch options are identified in system impact studies. However, even with this change, TAPS cautions that particularly in the absence of an independent operator, directly assigning redispatch costs is unlikely to be an effective remedy to undue discrimination. A potentially more attractive means of obtaining more efficient utilization of the grid and minimizing undue discrimination would be conditional firm service, if limited to 100 hours/year, subjected to curtailment on the same basis as firm service beyond those hours, and made available and useful to network customers.

Further, the Commission should address discrimination resulting from differences in granularity by foreclosing a TP from rejecting transmission requests to load within its system where the request would be accepted if the TP's own load were the designated sink.

a) Redispatch Service

The Commission proposes to modify OATT §§ 19.3 and 32.3 to provide for preliminary estimates of redispatch hours and costs in the system impact study for point-to-point requests and network resource designations, to provide the customer "the option of having the transmission provider perform the necessary studies to determine the projected redispatch costs or perform the facilities study, or both." NOPR P 308.[123] Clarification of the transmission request processing sequence is helpful, but this change is unlikely to make redispatch an attractive means for customers to obtain access to the grid. Thus, the Commission should not rely on expanded use of directly assigned redispatch as an effective remedy for the discrimination it has found.

Customers are unlikely to accept significant redispatch cost risks that they cannot manage, especially given their susceptibility to abuse. Unless capped at or close to the embedded transmission rate, directly assigned redispatch costs burden customers, and reward TPs operating constrained systems with forced generation sales (potentially on an "and" pricing basis), while allowing the TP to avoid making needed transmission upgrades, contrary to Congress' mandate and this Commission's intent. The inherent conflict of interests within a vertically integrated TP makes redispatch susceptible to difficult-to-audit abuse, especially if network customer resources can be caught in a vise between TPs and third-party customers. While, in the hands of an independent

[123] Although the Commission added language to OATT Sections 19.3 and 32.3 requiring that *estimated* redispatch requirements and costs be included in the results of the system impact study, the NOPR's revised OATT does not include similar language changes to Sections 19.4 and 32.4 regarding facilities studies. If the Commission pursues the redispatch approach, some such modification to those sections must be made in order to effectuate its intent (NOPR P 308) that the customer have the option to have the "projected" redispatch costs "determined."

transmission provider, redispatch can be useful in particular circumstances (*e.g.*, where, because of distribution factors and infrequent constraints, a little bit of redispatch goes a long way toward allowing transactions to flow), TAPS members would be reluctant to accept long-term transmission service based on an "estimate" of redispatch hours and costs because it would require them to effectively hand their checkbook to the TO. Such open-ended cost exposure makes it hard for customers to assess the economics of a proposed transaction, and creates significant risks down the road.[124] It fails to provide the certainty that (as Congress and the Commission have recognized) load-serving entities require to support long-term power-supply commitments.[125]

TAPS agrees with the NOPR's concerns (at P 316) about complexity and discretion in charging for redispatch. Redispatch charges would necessarily depend on the TP's dispatch. Audits would entail second-guessing of decisions that are both complex and subject to manipulation—*e.g.*, precisely how has the TP's dispatch been changed to accommodate the customer's transaction? What other operating decisions has the TP made to effect these charges?

A formula based on the decremental/incremental fuel costs (NOPR P 311) might limit some potential for abuse, but complexity and discretion is added back in by "harder

[124] For example, while MidAmerican will offer "mitigation" options after an impact study shows flowgate problems standing in the way of granting a transmission request, TDUs generally have not pursued that option beyond obtaining preliminary estimates, which showed mitigation to be an expensive proposition. In addition to being uneconomic, TDUs found mitigation a risky proposition because the actual costs will depend on actual conditions that are likely to diverge from what was forecast due to many factors, such as weather or system contingencies. Further, securing a mitigation agreement in the MAPP region is itself time consuming and not assured, often requiring agreement of 4 or 5 parties. If MAPP flowgates are affected**,** it must be approved by MAPP**,** which approval is only good for six months. So TDUs are understandably reluctant to predicate a ten-year power supply, for example, on redispatch.

[125] *See* Section 217(b)(4) and the Long-Term Rights Final Rule.

to quantify costs such as those listed by EEI: startup costs, higher capital costs due to shorter life and accelerated replacement, higher maintenance costs, and potential emergency power purchases" (*id.*), if permitted.[126] Complexity and concerns about discouraging needed transmission investment are increased where redispatch is long-term, requiring projections years into the future.

Unlike in the case of load-ratio-shared redispatch, which is self-disciplining because the TP has substantial "skin in the game," we see no easy way out of the complexity of and potential for gaming directly assigned redispatch costs, especially where projections are involved.[127] PacifiCorp's "higher of" redispatch or embedded OATT charge proposal (NOPR P 316) avoids "and" pricing, but hardly "address[es] the complexity and risk associated with determining redispatch costs over a long period …." *Id.* Deseret's tariff (NOPR n.291 and P 312) provides for some netting and crediting, which might avoid "and" pricing (although it's not entirely clear), but again shifts substantial risk to the customer, including the potential for opportunity costs where redispatch causes lost sales. We also understand that it has never been used.

SPP's redispatch schedule—which bases charges on the higher of incremental cost (including opportunity costs for lost sales) or replacement fuel—caps the customer's cost exposure at the sum of the pancaked individual-system transmission charges that would have applied before SPP adopted a regional tariff. While the protectiveness of this cap depends on how many systems the transaction crosses, the SPP cap has no parallel

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[126] These charges would not seem justified in the typical case where redispatch involves backing down one unit and ramping up another similar unit.

[127] *See* NOPR P 317. We also agree with the Commission that challenging standard-of-conduct questions come into play. NOPR P 318.

where individual-system charges continue to apply under a single-system OATT. Further, although this schedule preceded SPP's RTO approval, it requires the involvement of SPP—an entity other than the vertically integrated TP. SPP, rather than the individual transmission owners, determines by study when redispatch is likely to be needed to resolve a constraint, identifies the unit to be redispatched and the required amount, calls for redispatch in the operating horizon, and determines the redispatch charges.

Authorizing TPs to require redispatch of a network customer's resources to support new third-party transmission service (NOPR P 309) is more likely to increase undue discrimination than remedy it. Even with "appropriate compensation" (*id*.), such redispatch obligations put the network customer at far greater risk than the TP, which can manage the risks through its control over transmission which the network customer lacks. For example, the TP can perform a cost/benefit analysis of the impact of providing redispatch vs. expanding the system and rolling in the cost, and take action to protect itself; it can consider the impact of granting new transmission requests on the amount or frequency of redispatch. It can also influence the need for redispatch of the customer's resource by its own dispatch decisions. Because a network customer has no similar means to manage redispatch risk, requiring it to redispatch for new third-party transactions creates an open-ended obligation that may unduly interfere with its economic dispatch—subjecting its generation to its competitor's dispatch instructions potentially on a regular basis.[128] The fact that a network customer is likely to have far fewer resources

[128] TAPS has no objection to the OATT's existing provision for redispatch of network customer resources for reliability purposes, with load-ratio sharing of redispatch costs.

than the TP makes this more problematic. If the network customer is called upon to run a peaker with a limited air permit, redispatch may entirely exhaust the customer's physical hedge against the potential for paying super-peak prices (potentially to the transmission provider), a result the TP would have no interest in minimizing. Even opportunity costs, if included, will not necessarily hold the customer harmless. If redispatch costs were capped (which is what the third-party customer would need for certainty), the network customer required to redispatch to make room for third-party transmission service could be bled dry by the TP, which would bear no financial responsibility for the accuracy of the transmission studies it used to grant the third-party customer's transmission request (whose transmission revenues it pockets until the next rate case).[129]

Thus, while in the hands of an ISO or RTO, redispatch can be an efficient way to go in some cases (*e.g.*, redispatching 5 MW for 10 hours a year to permit firm network resource designation of a 45 MW resource), it is open to abuse by non-independent TPs, and provides them more latitude not to construct a robust system that allows customers to purchase from other suppliers without "strings attached." If the obligation to redispatch to make room for new third-party transactions is extended to network customer resources, it could become a means for TPs to severely interfere with a network customer's use of its limited resources. TAPS therefore urges the Commission not to rely on redispatch as an effective means to remedy undue discrimination. Instead, it should be recognized as a limited tool that may be useful in selected situations if subject to a number of safeguards:

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[129] Nor would the TP be accountable for its actions (*e.g.*, in granting other transmission requests, dispatching its own generation, or failing to construct needed upgrades) that increase the need for the customer to redispatch for the third-party transaction.

- Redispatch must remain optional to the customer.
- Not only should the Commission insist on "or pricing" of redispatch, but redispatch charges must be capped up front at fixed dollars (and hours) at or close to the embedded cost rate.[130] Doing so would appropriately hold the TP accountable for the accuracy of the studies used to assess the availability of transmission service, rather than shifting that risk to the customer.
- Redispatch would be most easily implemented and less likely to be counter-productive if applied to short-term transactions (for which the TP would not have a construction obligation) and service for the interim period while planned transmission upgrades are being constructed (to avoid discouraging construction).[131]
- Redispatch requirements should be limited so that redispatch service does not enable the TP to evade its obligation to plan for and provide reliable service from the network customer's network resources to its network load, as well as its other planning and expansion requirements.[132]
- A customer should have the option, by redispatching its own resources (including by voluntarily curtailing the requested service in the hours

[130] Of course, TO redispatch costs must be subject to customer audit and refund.

[131] *Cf. Midwest Indep. Transmission Sys. Operator, Inc.*, 116 F.E.R.C. ¶ 61,009 (2006) (conditionally accepting proposed modifications to LGIA to permit generator to enjoy Network Resource status on an interim basis).

[132] Entergy, for example, has been known to grant service subject to the customer redispatching its own units (totally at the expense of the customer) in ways that make the transmission "rights" granted totally unusable, and make the economics of the customer worse than they were before service was granted.

when redispatch would be required), to hedge the risks of paying for redispatch of the TP's resources. While (because of distribution factors) such redispatch may or may not be as efficient as redispatch of the TP resources, this option should be identified and exercisable at the outset (effectively converting redispatch into a form of conditional firm service) and on an ongoing basis if the customer finds it less expensive to redispatch its own resources than pay for redispatch of the TP's resources.

- However, redispatch of network customer resources should not be mandatory, whether to accommodate their own service requests or those of third parties. While TPs should identify network customer resources and resources on adjacent systems that might efficiently provide the needed redispatch, such redispatch should be left to voluntary agreement of the network customer or adjacent generation owner.

If, nevertheless, the Commission requires network customers to redispatch their resources to make room for new third-party transactions, it would be doing so to enable the TP to provide additional service (and, if point-to-point, receive additional revenues), without expanding the transmission system on the assumption that it is not cost-effective to construct and roll in the costs of those facilities—effectively imposing an "all-for-one, one-for-all" treatment of network customers and the TP. Particularly if the Commission imposes this treatment for redispatch service, it should make clear that network customers should be able to count on this same "all-for-one, one-for-all" approach to planning and expanding the grid to meet the needs of network customers and the TP, with required upgrade costs rolled in for both; the network customer should be assured that it will not be treated (for cost allocation purposes or otherwise) as the marginal customer.

b) Conditional Firm Service (Redefined)

The NOPR identifies conditional firm service as an alternative means to increase the availability of transmission service to support competitive generation (*e.g.*, wind) where denial would be inefficient and unduly discriminatory because firm service would be available except for a small number of hours per year. The NOPR (P 321) defines conditional firm service as a point-to-point-only service where the TP commits, in the service agreement, to a maximum number of hours of curtailment per year. Although TAPS supports development of fuel-diverse resources, including wind, in the past TAPS has opposed conditional firm service, because it may unduly harm other customers,[133] could discourage expansion of the grid, and (as proposed to date) would be incapable of achieving its stated purpose of fostering development of wind generation.[134] Because point-to-point conditional firm service, as defined previously and in the NOPR, is not integrated with network service, it cannot support the long-term power-purchase contracts with LSEs required by generators to secure their financing. The service would not be available to LSEs (*i.e.*, network customers) on the same transmission system as the generator and, because it would not be firm, could not support designation of a network resource by an LSE on a remote system.

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[133] It also serves no purpose for a customer requiring a fully firm supply of power.

[134] *See* TAPS NOI Comments at 66-68. *See also* TAPS' April 13, 2005 Post-Workshop Comments filed in *Potential New Wholesale Transmission Services; Assessing the State of Wind Energy in Wholesale Electric Markets*, Docket Nos. RM05-7 and AD04-13. TAPS participated as a panelist at the March 16-17, 2005 Workshop in Portland.

In response to the NOPR, TAPS has worked with AWEA to refine conditional firm service to minimize the pitfalls TAPS identified. Because it would avoid many of the problems identified above with regard to redispatch, a narrowly defined conditional firm service, made available to and integrated with network service, could enable more efficient utilization of the grid in some circumstances. The parameters TAPS proposes to make conditional firm service a viable option are as follows:

- **Limit to "almost always firm" service: restrict curtailments to no more than 100 hours per year:** Conditional firm service must be restricted in order to match its policy justification, provide customers sufficient certainty to sign long-term power-purchase contracts (*e.g*., for renewable resources); and prod (rather than deter) transmission construction. By restricting interruptions of conditional firm service to no more than 100 hours a year (and within that limit, only as justified by constraints identified in the studies), the service would be limited to instances where firm service is available in all but a few hours a year, and where there is a policy justification for treating it differently than non-firm service.
- **Treat conditional firm the same as firm once interruptible hours are exceeded:** While curtailments of firm service are rare, no customer is immune. To shield other customers from undue burden, if and when the maximum curtailment hours stated in the service agreement are exceeded the conditional firm service should be treated the same as other firm service for purposes of curtailment (as set forth in the NOPR

P 322)—subject to curtailment on a pro rata basis with other firm uses to preserve reliability.[135]

- **Conditional firm service must be integrated with network service:** Generators don't get built on spec anymore; they must be supported by long-term power purchases from LSEs. To be useful in supporting development and financing of generation, conditional firm service must work for LSEs—entities that typically take network service. LSEs come in two basic flavors—LSEs on the same system as the resource (the customer for whom the resource would be most attractive since there is no pancake) and LSEs on another system (that would need to have the conditional firm point-to-point service integrate with network service on the system where the load is located). Conditional firm service must be adapted to work for both types of LSEs if it is to serve its intended purpose.[136]

  1. For the on-system LSE, the Commission should allow for network resource designation where transmission is available on a fully firm basis in all but a very limited number—no more than 100—of hours per year. Permitting designation of narrowly defined transmission-limited resources is not different in kind than other energy-limited resources that are eligible for such designation (*e.g.*, a wind resource, water-limited hydro, air-permit-limited units), which are considered

[135] *See* OATT §§ 13.6 and 33.

[136] TAPS disagrees with the NOPR's assumption (P 325) that secondary network service makes conditional firm service unnecessary for network customers. Secondary network service, unlike conditional firm service, provides no assurance of firmness in any hour; can always be trumped by a short-term (even hourly firm service, if the NOPR's proposal were accepted without modification) or long-term firm service request; and has no rollover rights. Except during the limited interruption hours for conditional firm service, which the NOPR proposes to accord the same priority as secondary firm service, the secondary firm service is an inferior service, one unlikely to support investment in generation or a long-term purchase contract.

"non-interruptible" for purposes of the designation of network resources. *See* OATT §§ 1.27 and 30.1. Absent this extension, the LSE would be relegated to secondary service, a service far less firm than conditional point-to-point service.

2. For the off-system LSE, the key would be enabling a resource supported by conditional firm service on a third-party system to be treated as a network resource on the host system where the LSE takes network service. As noted in the NOPR (P 403), the OATT has been interpreted to require a network resource to be supported by firm transmission throughout the contract path. That would have to be changed, by altering the network resource definition or the Commission's interpretation of that definition to permit such designation, an accommodation that would only make sense if conditional firm service were narrowly limited to "almost always firm" service as discussed above.

c) Other Issues: Granularity Discrimination

The NOPR's finding of undue discrimination in the evaluation of transmission service requests as compared with the TP's evaluation of its own uses of the network fails to focus on and address a significant source of that discrimination—differential granularity. The TP's flexibility to treat its control area as a whole for sink purposes (including load on both sides of a constraint), while selectively disaggregating its resources for sourcing purposes, gives the vertically integrated transmission provider the ability to shape transactions to avoid constraints, at least on paper. In contrast, TDU loads and resources are treated with more granularity. As a result, the TDU may be denied a transmission request because of the location of its load in relation to the source for a transaction that would be approved if submitted by the transmission provider's merchant function on a less granular basis, even though the TP actually has more load in the area where the TDU is located. Absent appropriate protections, the TDU could be denied transmission to serve its load from economical generation, and forced to watch from the sidelines while the TP captures the same resource for its own loads.

As requested by TAPS in its NOI Comments (at 17),[137] to address discrimination through granularity differences and to provide an incentive for a TP to upgrade weak portions of its system where TDUs are located,[138] the Commission should not permit the TP to deny any request for transmission to a network customer (or require upgrades or mitigation whose cost is not shared on a load-ratio basis) if the request would have been accepted if the TP's own load had been the designated sink. To allow such denial would reward the TP for creating a weak and uneven grid, encouraging neglect of the parts of the grid that affect service to TDUs. The greater granularity used to evaluate a TDU's request for transmission service, as compared with the modeling of the TP's request, should not create an opportunity to discriminate.

2. Hourly Firm Service

The NOPR proposes to add hourly firm service on the grounds that "it will eliminate a barrier to the development of markets and thereby decrease opportunities for undue discrimination." P 343. TAPS disagrees. Not only does the NOPR's proposal invite cream-skimming, but it also would unduly interfere with the ability of network customers (and the TP on behalf of its native load customers) to use secondary network

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[137] *See also* TAPS NOI Comments at 75, 109.

[138] *See* Part V.D.3.a below, supporting a broader requirement that the TP accept any timely designated network resource through load-ratio-shared redispatch.

service. A customer who reserves one hour of firm service should not be able to trump the needs of those entities, who bear the residual costs of the system, to utilize resources (not designated as network resources) for either economy or reliability purposes. The equity problem *vis-à-vis* secondary network service is thus not ameliorated by the potential for preemption of the hourly firm request by longer-term firm requests, as the NOPR suggests (*id.*). Hourly firm service presents an issue of equity among customers, not "barriers to the market," and the Commission should not reverse the correct call made in Order 888 on those equities.

If, notwithstanding the foregoing, the Commission adopts hourly firm service in the final rule, it should modify Section 28.4 of the OATT to make clear that hourly firm service does not trump use of secondary network service. Specifically, the words "and Hourly Firm Point-to-Point Transmission Service" should be inserted at the end of Section 28.4 just before "under Part II of the Tariff."

3. Rollover Rights

a) If the Commission Restricts Rollover Rights, It Must Separately Ensure the Embedded Customer's Fundamental Right to Continued Transmission Service

In our NOI comments (at 75-86; *see also* 11-15), TAPS argued that rollover rights as they now stand have been construed to deny customers reasonable continued access to the grid to reach alternative suppliers. Too often, network customers find themselves faced with no ATC into (or even within) their host transmission system, and in such cases a TP's narrow interpretation of rollover rights may effectively permit only continued use of the existing sources (*i.e.*, the incumbent supplier), rather than providing the access to alternative sources intended by the Commission. If the incumbent supplier chooses not to respond to the customer's RFP for a replacement contract, the customer may be left with no cost-effective source of power to reliably serve its load.[139] While rollover rights may not play a prominent role in the transmission provider's power supply (which is based on its fleet of on-system generation), for a TDU they can be a lifeline—the only assured rights to continue to use the transmission system to meet its service obligations at the end of a power-supply contract. We asked that rollover rights (at least in the network customer context) be clarified to encompass reasonable access to sources other than those from which the customer is currently served, and suggested measures to ensure the ability of TDUs to secure, without exposure to incremental-cost assessment, the transmission they need for power purchases used to supply load. As explained in TAPS NOI Comments at 84-85:

> Until such time as the grid is made consistently robust to assure TDUs reasonable access to competitive supplies without reliance on rollover rights, the Commission cannot restrict the availability and flexibility of rollover rights without assuring embedded TDUs rights to continue to rely on the transmission provider for the transmission required to deliver their power supply to their load on a cost-effective basis. …
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> If the Commission provides embedded TDUs with real assurance of reasonable and cost effective access to the market without necessarily relying on rollover rights, the Commission could then redesign rollover rights to be tied to the planning process …."

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[139] In its order revoking Duke Power's market-based-rate authority in its control area, the Commission noted this very behavior: "Duke Power has indicated that it has not responded to RFPs where it was the supplier potentially being replaced. NCEMC has raised concern that this policy deprives it of a qualified bidder in its RFPs." *Duke Power*, 111 F.E.R.C. ¶ 61,506, P 47 (2005) (footnote omitted). The Commission stated that Duke's action "suggests untenable market behavior." *Id.* P 48.

The NOPR (n.337) says it has done just what TAPS asked by tying its new, more restrictive rollover restrictions to Commission acceptance of a TP's Attachment K that initiates a joint planning process. We strongly support the NOPR's planning requirements and (especially with the enhancements TAPS suggests) share the Commission's hope that it will produce a more robust grid that supports customer access to alternatives. However, that certainly won't happen on the Attachment K acceptance date. Nor should all risks of the planning process failing to achieve its goals fall on the transmission customer. But by pointing to the mere inception of the planning process as ensuring customer needs, without expanding the obligation to construct or holding the TP accountable for failing to plan and construct facilities needed to meet network customer needs, the Commission shifts risks (and potentially incremental-cost exposure) to those least able to address those risks—transmission customers.

Under the Order 888 OATT, the rollover provision does triple duty. It is the mechanism for point-to-point customers to extend their path-specific reservations. It is the vehicle for network customers/transmission providers with resource portfolios (albeit small portfolios in the case of some TDUs) to rollover particular network resource designations, as an adjunct to their ongoing right to receive transmission service for their network load.[140] In the case of a full-requirements customer, rollover rights are the whole ball of wax—the only provision in the tariff that provides for continuation of transmission service at the end of its power-supply and/or transmission contract.

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[140] Although the language of Section 2.2 refers to contracts, it has properly been interpreted to apply to rollover of network resource designations during the term of a network service agreement or by the transmission provider for its native load. *Wisconsin Pub. Power Inc. SYSTEM v. Wisconsin Pub. Serv. Corp.*, 84 F.E.R.C. ¶ 61,120 (1998) (analyzing assertions of rollover of network resource designations).

The NOPR's proposal to restrict rollover to power-supply arrangements of at least five years, subject to matching, could leave embedded customers, especially those dependent on a full- or near-full-requirements supply contract,[141] with no right to continued transmission service. For example, for a small TDU dependent on power purchases in an increasingly short-term-focused and volatile market, it may not be practical, prudent or even possible, a year in advance of the time the contract is turning over, to lock in a five-year supply contract. Perhaps even more frightening, a TDU that is able to secure a five-year extension of an existing supply contract may still find itself "matched out" of its path. While a point-to-point customer faced with the need to match a longer request can simply extend its transmission service agreement, to match a competitive reservation the network customer must quickly extend its power-supply contract (an act its supplier is unlikely to take without a steep premium, particularly when it knows its customer is over a barrel). For a TDU to be stripped in such circumstances of its rights to continue to use the transmission it needs to serve its loads would be disastrous and very anticompetitive. It is certainly not what Order 888 contemplated when it concluded that "*all* firm transmission customers (requirements and transmission-only), upon the expiration of their contracts or at the time their contracts become subject to renewal or rollover, should have the right to continue to take transmission service from their existing transmission provider." Order 888 at 31,665 (emphasis added).

Forfeiture of essential transmission access rights would be particularly unfair for a network customer that has supported the TP's transmission system for decades and for

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[141] By "near-full-requirements customer" we mean a customer that receives most of its requirements (beyond its own behind-the-meter generation or a federal power allocation) from a single supplier, rather than having a portfolio of resources.

whom the TP has long been required to plan on a basis comparable to its planning for service to its native load customers.[142] It is plainly unreasonable and unduly discriminatory for the transmission provider to be allowed to deny service, or treat incrementally, an embedded TDU for whom it has failed to plan, whatever the term of the TDU's power contract. The TP would not cut off service to a subset of its own retail native load customers because it failed to plan for its continued needs. Nor can it, consistent with comparability, be permitted to deny service to the embedded TDU.

New FPA § 217(b)(4) certainly does not authorize the Commission to leave TDU LSEs at risk of denial of continued use of transmission to meet their service obligations. Restructuring the OATT to enable TPs to leave embedded LSEs without any access to the grid also fails to recognize and preserve the LSEs' continuing rights under Section 217(b)(1) to (3) to use their existing firm transmission rights, including rollover rights.[143]

Thus, if the Commission adopts the NOPR's proposed rollover modifications, it must separately ensure customers reasonable access to alternative suppliers, at least through the period before the new planning process can be expected, and is demonstrated, to bear fruit. Particularly in the case of network customers for whom the TP bears long-standing obligations to plan, the right to continued transmission service on the host TP's

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[142] OATT § 28.2. *See also* Preamble to OATT Part III ("Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers").

[143] As discussed in TAPS NOI Comments at 44-49, Section 217(b)(1) to (3) permits a load-serving entity to continue to use its existing resource-to-load firm rights to deliver energy to its load from its resource, or other resources that can be delivered using those rights, to meet its wholesale or retail service obligation. The attributes of the firm rights preserved in Section 217 are defined (for transmission providers and OATT customers) by Order 888 and the OATT. Thus, they are consistent with the firm rights that should continue to be respected in the normal course of operation under the OATT, including applicable rollover rights.

system, without treatment as the incremental customer, should be a fundamental element of the OATT.

The Commission therefore should directly address the rights of customers to continued service and reasonable access to alternative suppliers, without necessarily cabining those rights as a question of rollover or redirect. Particularly for the embedded TDU that is the TP's "transmission native load," the risk of denial of service should be shifted from the customer to the TP—the entity in a position to manage that risk and who has long been obligated to plan for the TDU's needs.

In addition to adopting the rollover right clarifications proposed in Part V.D.3.b below, the Commission should:

- **Require the TP to accept a network customer's timely designated network resource, if necessary through redispatch with costs shared on a load-ratio basis.** This remedy would simply hold the TP accountable for its long-standing planning obligations. TP accountability for results should be required permanently as a check on the efficacy of the planning process, or at least for the period before the planning process can be expected to bear fruit (*e.g.*, 10 years) or better yet, has been demonstrated to do so. The only "out" should be through Commission action on a TP petition demonstrating that the customer's supply choice was not reasonably foreseeable. The Commission should not accept excuses such as those offered in response to Ann Kimber's technical conference testimony that graphically described the inability of TDUs of only a few MWs to obtain access to an alternative supplier.[144] MidAmerican answered that it does not plan "for each of its network customers to import 100% of its load under contingency conditions, just as MidAmerican does not plan for 100% import levels for its own bundled retail load."[145] While a vertically integrated transmission provider would not plan for 100% import levels for its own retail load (because most, if not all, of its resources are on-system), it cannot use that same assumption in planning for network customers that must often look beyond the host system to find alternative suppliers.[146] The Commission should ensure that the customer has reasonable access to the market before it will excuse denial of a network service designation, particularly at the end of a full- or near-full-requirements contract.[147]

- **Require cost-based sales to the trapped embedded TDU.** On the assumption that the Order 888 OATT, through § 2.2 or more generally, would assure customers continued use of the grid to access alternative suppliers, Order 888 modified § 35.15 of the Commission's regulations to eliminate the obligation of public utilities to file notices of termination of power contracts entered after the final rule and eliminated

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[144] *See* Written Statement of Anne Kimber on behalf of MMTG and TAPS for the December 7 Technical Conference, Docket No. RM04-7, at 3 (Dec. 7, 2004) ("Written Statement of Anne Kimber"), quoted and described in TAPS NOI Comments at 12-13, 77-80.

[145] January 21, 2005 Written Statement of MidAmerican Energy Company, filed in Docket No. RM04-7, at 5. *See* February 15, 2005 Supplemental Comments of TAPS, filed in Docket No. RM04-7 (responding to MEC comments).

[146] By effectively assuming, for planning purposes, that after the termination of its contract the TDU will continue to purchase from the incumbent, the transmission provider walls such customers out of the competitive market, or potentially any supply at all. In most cases, any new contract with the incumbent will be at "market prices" even though there is little or no competition.

[147] As described in Part V.D.1.c, the TP also should not be able to deny a customer's transmission request that would be accepted with the TP's native load, instead of the TDU, used as the designated sink. While such a remedy would address granularity discrimination, it would not hold the TP accountable for planning for network customer needs.

any obligation to continue to sell wholesale power at cost-based rates except under unusual circumstances.[148] The Commission should not, by constricting rollover rights, allow a TP to have it both ways—deny customers a continued right to transmission to access alternative suppliers,[149] without having any obligation to sell power within its control area at any rate, much less a reasonable (cost-based) one.[150] Where a transmission provider allows a weak grid to trap customers, the transmission provider should not only lose its market-based rates within the transmission system, but it should have an obligation to offer embedded-cost-based sales.[151]

- **At minimum, exceptions to the five-year minimum and matching exposure must be made to ensure a continued right to service**. Some mechanism is needed, although not necessarily through "rollover," to ensure a TDU's continued right to transmission service and to make the TP accountable for planning for the needs of network customers, especially full- or near-full-requirements customers. A reasonable "safety net" would include at least the following:

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[148] *See* Order 888 at 31,805-06; Order 888-B at 62,110 (refusing to provide a generic mechanism for a customer to obtain continued power service, but allowing customer to file a complaint to demonstrate that it had a reasonable expectation of continued service beyond the contract term). Indeed, Order 888's provision for stranded cost was predicated on the intended ability of the embedded customer to use its incumbent supplier's transmission system to reach alternative suppliers.

[149] Indeed, Order 888 expressly preserved application of § 35.15 to termination of transmission contracts, recognizing that such terminations may reflect exertion of market power. *See* Order 888 at 31,806.

[150] A TAPS member reported that at NARUC's November 15, 2005 annual convention, a representative from the Southern Company indicated publicly that if Southern was not permitted to use market-based rates within its control area, it would not sell at cost-based rates, but would sell its MWs outside the control area at market-based rates.

[151] *See* Part IV.A. of comments of American Public Power Association and TAPS filed today in Docket No. RM04-7-000.

- Exempt small embedded TDUs (*e.g.*, 25 MW or under) from the new restrictions on rollover rights. Something is fundamentally wrong with the way the system is planned if it can't continue to accommodate the needs of these small customers.
- Exempt full- or near-full-requirements customers from the new restrictions on rollover rights. Absent such protections, the Commission will have converted the most traditional, conservative power-supply choice for a small TDU into an extremely risky proposition, in which it must gamble on market prices for no less than five-year intervals, and risk loss of any access to the grid if it cannot find an acceptable five-year supply or, on short notice, match a competing customer's request.

b) The Commission Should Otherwise Clarify its Rollover Proposal

Assuming the Commission provides embedded TDUs with real assurance of reasonable and cost-effective access to the market without necessarily relying on rollover rights (as discussed above), the Commission could then redesign rollover rights to be tied to the planning process. In our NOI Comments at 82-86, TAPS recognized that the current policy of permitting rollover on 60 days' notice is not conducive to coherent planning and expansion of the grid, and may permit significant capacity on constrained interfaces to be tied up in relatively short-term deals (*e.g.*, inexpensive, one-year "paper capacity" deals) designed to hold the firm reservation as a path for non-firm economy purchases[152] and to block competitors' firm access. The NOPR's five-year minimum

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[152] Or in Day 2 RTOs, as a basis for allocation of FTRs.

term for rollover on one year's notice would better align rollover rights with the planning process *if* clarified and fine-tuned (as follows) to achieve that goal.

(1) **Clarify OATT § 2.2 rollover rights, so that they clearly encompass reasonable access to sources other than those from which the customer is currently served**, consistent with Order 888's intent that such rights be available whether the customer buys from the incumbent or a new supplier. While the language of OATT § 2.2 makes that intention express, this section has often been applied more narrowly, as described above and in TAPS NOI Comments (at 75-81). The final rule should emphasize that the Commission will require TPs to broadly apply rollover rights to make them a viable source of reasonable access to alternate power sources.

(2) **Matching opportunities should be limited to avoid undercutting TP planning/construction obligations and the customer's right to continued service.**

(a) *TPs should not be permitted to use matching to avoid planning obligations*. At P 358, the NOPR states:

> [W]hile we expect a transmission provider to be continually updating its forecast for native load growth and applying this updated projection to new requests for service, applying this to contracts at rollover may require an additional change to the right of first refusal process. Specifically, the transmission provider would have to compete for the capacity rather than reclaim it through its rights to reserve capacity for native load growth.

The final rule should clarify that this TP matching requirement is intended as a further restriction on when a TP can take back capacity that it has already reserved for load growth, and does not provide an expanded opportunity for a TP to deny service by matching the rollover requests of customers whose plans the TP will know in advance through the OATT's requirement for submission of ten-year load and resource projections and for whom the TP is obligated to plan. The TP's ability to reclaim capacity should continue to be limited to those instances where in the initial service agreement the customer was been put on notice that it would not be permitted to exercise rollover rights, based on an adequate showing of need by the TP, in accordance with current Commission policy. Enabling the TP to deny customers continued rollover rights in other instances by matching the customer's rollover request would severely undermine the TP's obligation to plan for customer rollover rights and the intended planning-facilitation purpose of the NOPR's rollover reform. *See* NOPR P 360.

(b) *Matching should not force an existing customer off the system if it proposes to rollover to another transaction for at least five more years*. If a second customer submits a competing request for service of equal or greater length and the existing customer gives one year's notice to extend its service at least five years, the TP should be expanding the system to accommodate both requests. It should not, through the matching process, transform an existing customer, and particularly a network customer—its transmission native transmission load customer for whom it is obligated to plan—into the marginal customer (for incremental pricing purposes) for merely continuing its use of the system.

(c) *The matching process must be structured to recognize the challenges posed for network customers.* A point-to-point customer, faced with a competing longer-term reservation, could simply extend the term of its point-to-point commitment to match the competing request. Assuming the matching process is intended to apply to network resource designations under a network service agreement, the network customer would need to extend its power-supply commitment in order to extend its transmission reservation to match the competing request.[153] This task is much more difficult (requiring a commitment of a power supplier), with much more at stake, than a point-to-point customer's unilateral decision to extend a transmission reservation that can be reassigned; we would expect many power suppliers to take advantage of the network customer seeking a quick extension in order to preserve its transmission service. Putting the network customer into such an impossible power-supply position to avoid losing transmission rights is contrary to the NOPR's intent to promote planning and enhance customers' access to reasonably priced power. If matching is to apply in the network service context, the Commission should require the following adaptations to ensure that it does not operate to disadvantage the customers who have supported, and are committed to supporting, the TP's system:

- restrict reservations qualified to compete against a network customer's reservation to customers with long-term *power* contracts, so they are on more equal footing with network customers. Such requirement would be consistent with Section 217(b)(4)'s directive to enable LSEs to secure long-term transmission rights for their long-term power-supply arrangements.

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[153] Indeed, the NOPR proposes to toughen up the requirements for network resource designations. *See* NOPR PP 407, 412, 422.

- provide a cut-off for requests with which the network customer will need to compete. For example, the network customer would only need to compete with those requests that had been submitted at least three months prior to when the network customer exercises its rollover right. Such a cut-off on qualified competing applications will enable the network customer to structure its power-supply commitments with some degree of advance knowledge of the competing requests. In addition, such a rolling cut-off (*i.e.*, one tied to the network customer's rollover notice) would encourage early exercise of rollover rights, thereby benefiting the planning process.

(3) **Minimum rollover term in the absence of a competing application should be clarified to be one year.** The NOPR's description of rollover reform fails to address one important situation—the minimum rollover term required to continue to maintain a customer's rollover right if the path is not constrained at the time of rollover. While the NOPR (at P 355) provides for a five-year minimum term to be initially eligible for rollover and states that where there is a constraint and a competing application, the rollover customer will need to commit for a rollover term of the longer of five years or the length of the competing reservation, it does not say what rollover term is required to preserve continuing rollover rights in the absence of such competition. Since the customer will have already made at least one five-year commitment entitling it to rollover, TAPS would suggest that a minimum term of one year should be sufficient to maintain future rollover rights in the absence of

competition, with notice of further rollovers still required on one year's notice. In such situation, restricting the customer to five-year terms serves no purpose.

In addition, the NOPR's stated intent regarding the timing for effectiveness of the new rollover regimen, and the treatment of rollovers in the interim, requires clarification. The NOPR (P 357) proposes to tie effectiveness of its new rollover regimen to Commission acceptance of the TP's coordinated and regional planning process set forth in Attachment K: "all new transmission service agreements executed after the effective date of Attachment K will be subject to the five year/one year right of first refusal rule." It also provides a transition mechanism, whereby service agreements entered prior to the Attachment K effective date become subject to the new rule "on the first rollover date after the effective date of revised section 2.2." *Id.*

Subject to our discussion in Part (a) above regarding the need to ensure a continued right to service, TAPS supports the intent to delay effectiveness of this provision and to provide for a transition. However, we are concerned that the means of implementing this plan are not clearly set forth. As we understand it, the Commission's intention is not to have its proposed new Section 2.2 language replace the old Section 2.2 in each TP's OATT until the effective date of its Attachment K planning proposal (*id.*). This would mean that a TP's compliance filing made in response to the final rule would *not* include the revised Section 2.2 language; rather, the Section 2.2 revisions would be proposed later in conjunction with the filing of its proposed Attachment K. If this is indeed the Commission's plan, it invites confusion by including the revised Section 2.2 language as part of the *pro forma* OATT attached to the NOPR.

In the final rule, the Commission should clarify this implementation scheme, in order to avoid premature replacement of the Section 2.2 language, which could leave customers in a very uncertain and unprotected position during the interim before Attachment K is placed into effect. Instead of including revised Section 2.2 language in the body of the new *pro forma* OATT, the Commission should include that language in the body of the final rule, with directions to the TPs to file it as a part of their Attachment K filings. Further, some clarification of that language is needed to ensure that customers with existing contracts currently subject to rollover rights do not get caught in a trap due to changing the deadline and eligibility for exercising rollover rights. This is particularly essential since the timing of the effective date of the new Section 2.2 rules for each TP will be controlled by actions of the TP and the Commission, and the customer will need significant lead time to be able to factor the new rules into its power-supply and transmission arrangements. To prevent unintended adverse consequences to customers who have rollover rights under existing contracts, TAPS proposes replacing the last sentence of revised Section 2.2 as proposed in the NOPR with the following language:

> This provision shall apply to all contracts entered into after [insert date of acceptance by the Commission of this revised Section 2.2 and the Transmission Provider's Attachment K ("DATE")]. Firm service customers who had rollover rights under existing contracts pursuant to Section 2.2 as it was in effect prior to [DATE] shall be subject to the following grandfathering provisions:
>
> (a) A customer shall be permitted to exercise its rollover rights pursuant to the previously effective eligibility (one-year duration) and 60-day notice rules, upon the first rollover occasion after [DATE], provided that it takes such action within one year of [DATE].
>
> (b) Such customer shall also be entitled to exercise, within one year of exercising its rollover right under (a)

> above, one more rollover subject to the previous 60-day notice requirement, but the service it obtains through such rollover must have a duration of at least five years (subject to any applicable matching requirement).
>
> (c) All subsequent rollovers shall be subject to both the five-year duration requirement and the one-year notice requirement.

Finally, in response to the Commission's questions regarding load-growth reservations (NOPR P 358), TAPS suggests that they be posted on the OASIS, submitted in relevant state planning documents, and identified in the Attachment K planning process, in the same manner as the load-growth needs of other network customers, for which the TP is also supposed to be reserving capacity.[154] Indeed, with the enhanced focus on planning and expanding the grid, load-growth reservations should be viewed not as a means to withdraw capacity from third-party use, but rather as a need that must be factored into the expansion plan.

4. Modification of Receipt or Delivery Points

It appears that the NOPR has categorized under the "redirect" label fundamental concerns raised by TAPS in response to the NOI regarding the customer's ability, through rollover or otherwise, to use the transmission provider's system to access new sources of supply. *See* NOPR P 370. The Commission responds to these concerns by stating that "our reforms in the area of transmission planning and ATC calculation should go a long way toward addressing transmission customer concerns in this area," and seeking comments if further action is required. P 371.

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[154] *See* NOPR PP 349, 359.

As discussed above, while TAPS supports the Commission's ATC and planning reforms, TAPS believes that more must be done to ensure the OATT operates as intended—to provide customers access to alternative suppliers. TAPS proposes enhancements to the transmission planning process (*see* Part V.B. above), as well as specific measures to shift the risk of transmission inadequacy from the customer to the TP—to hold the TP accountable if ATC required to enable the customer reasonable access to the market is not available due to the TP's failure to plan for the customer's needs (*see* Part V.D.3.a above).

5. Acquisition of Transmission Service

a) Processing of Service Requests

TAPS supports the NOPR's proposal to require posting of specified metrics for TP processing of transmission service requests (P 385) and to impose operational penalties when TPs routinely fail to meet the 60-day due diligence deadlines for completing studies (P 384). Given the high threshold for the penalties (more than 20% of non-affiliated studies completed outside the deadlines for two consecutive quarters) and the high cost to customers of delayed access, TAPS questions whether the proposed penalty level ($500/day) is sufficient to ensure compliance. In any event, not only should the penalties be non-recoverable for ratemaking purposes, but penalty revenues should go to victims of study delay.

However, TAPS opposes the NOPR's proposal (P 384) to exempt RTOs/ISOs from such operational penalties. While, as the NOPR notes (*id.*), independence may not give RTOs/ISOs an incentive to neglect their obligations to process applications, RTOs/ISOs may still fail to complete studies on a timely basis due to competing internal priorities or bureaucratic indifference, as TAPS members have learned the hard way. Although some adaptation of the penalties may be necessary to make them appropriate and effective in the non-profit RTO/ISO context (*e.g.*, to hold management accountable by requiring a reduction in management compensation), RTOs/ISOs should not be above the Commission's study deadline requirements.

The NOPR (P 387) seeks comments on structuring fees to provide a disincentive for transmission customers to submit duplicative requests, without penalizing transmission customers with legitimate requests for services. Because the concern is the ability of certain market participants to jam the queue with zombie requests, it would be appropriate to allow a TP, upon a showing of persistent queue abuses, to propose a reasonable fee narrowly designed to address such abuse. The fee should be low enough to cause no significant burden except upon those who flood the OASIS with requests, and should be refunded to the customer unless service accepted by the TP is not confirmed by the customer. Fee revenues should be shared with network customers on a load-ratio basis, so they do not become a new profit center for the TP, [155] and should apply in a meaningful way to the TP's merchant arm (so it isn't out of one pocket and into the other for the TP). However, in structuring a reasonable fee it will be important to provide for exceptions where the failure to confirm reflects a legitimate purpose, not jamming. For example, exceptions should be made for transmission requests associated with RFPs, consistent with other provisions in the OATT to accommodate multiple submissions in relation to the same competitive solicitation. *See, e.g.*, OATT § 19.2(ii) and 32.2(ii).

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[155] Such distribution would be consistent with the Commission's policy regarding distribution of imbalance penalties to customers not in violation. *Carolina Power & Light Co.*, 97 F.E.R.C. ¶ 61,048 (2001), *reh'g denied*, 103 F.E.R.C. ¶ 61,209 (2003).

Other legitimate purposes for failing to confirm that should exempt the requestor from the fee would include consideration of alternative sites for planned generation and the inability to secure timely confirmation of all legs of a multi-system path.

The NOPR (P 388) seeks comments on clustering of transmission studies (a practice encouraged in Order 2003). A robust, pro-active planning process should reduce the need for clustering of the transmission service request studies. While the NOPR raises questions about transmission customers "cherry picking" clusters, TAPS is concerned about vertically integrated TPs abusing clustering to burden customers with costs and delay. If clustering is permitted, safeguards are required to prevent such abuses from occurring, and it may be best to limit their use to projects that naturally lend themselves to a clustered study (*e.g.*, joint participation in a large new generating unit).

b) Queue Processing Business Practices [No Comments]

c) Reservation Priority

The NOPR (399-400) proposes several reforms to address problems that can arise from customers using software to bombard the OASIS with requests. TAPS does not object to the "5-minute window" equivalence, with duration as the tie-breaker within priority classes.

However, TAPS is concerned that the newly proposed pre-confirmation priority may be a cure that is worse than the disease. Although it would be helpful to avoid a multiplicity of unconfirmed requests tying up the queue and foreclosing service, as proposed in the NOPR pre-confirmation priority threatens to undermine a customer's ability to obtain transmission access where, for very legitimate reasons, pre-confirmation is not feasible, *e.g.*, for transmission requests in connection with an RFP, exploration of possible alternative generation sites, or the inability to commit to one segment of a multi-system transmission path until the customer has obtained confirmation that the entire path is available. The Commission should not set up priority rules that punish transmission customers that find themselves in situations where pre-confirmation is impractical.

Thus, TAPS cautions against the drastic shift in reservation priority for the full spectrum of transactions as proposed in the NOPR. If the Commission wants to move in this direction, it should limit the pre-confirmation priority to non-firm and short-term-firm (monthly or less) service, where there is little time to work through the queue once service is accepted. Pre-confirmation priority should not apply to long-term-firm or network service designations, where there should be adequate time to obtain confirmation. Alternatively, any pre-confirmation priority that applied to network or long-term-firm service would need to carve out exceptions at least for the situations identified above where pre-confirmation is impractical and imposition of a pre-confirmation priority would operate to unfairly foreclose legitimate customers' access to needed transmission service.

In any event, the NOPR's tariff language is too broad, proposing no temporal constraint on the pre-confirmation priority. As proposed, a pre-confirmed request could trump an un-pre-confirmed request that was submitted six months earlier but is still stuck in "study mode" (an all-too-common experience). Thus, at minimum, the pre-confirmation priority should apply only to very limited periods appropriate for each type of service to which the priority applies.

6. Designation of Network Resources

a) Qualification as a Network Resource

The NOPR (PP 407-409) comments on several aspects of network resource qualifications as they relate to purchased-power resources. Among other things, the Commission attempts to clarify whether contracts containing liquidated damages ("LD") provisions qualify as network resources (NOPR P 409):

> In response to suggestions that liquidated damages products should not be designated network resources because they are interruptible for economic reasons, we clarify that network customers may not designate as network resources those power purchase agreements that give the seller a contractual right to compensate the buyer instead of delivering power even if the seller is able to deliver power. For instance, a network customer may not designate as a network resource a purchase agreement that allows the seller to interrupt service for reasons other than reliability, but allows the buyer to force delivery at a higher price. In addition, a network customer may not designate as a network resource a purchase agreement that requires a seller to pay the buyer's cost of replacement power when the seller chooses not to deliver energy for economic reasons.

TAPS questions whether any such clarification is necessary given the Commission's governing precedent. However, if there is to be a clarification, TAPS is concerned that, by focusing on "liquidated damages" (or LD) terminology as much as on express contract provisions governing the firmness of a transaction, this passage (if not read carefully) could be misinterpreted as disqualifying any contract that provides for liquidated damages equal to the customer's replacement power costs when the supplier does not deliver. In that the Commission proposes to maintain its current policy (NOPR P 407), we do not believe this is the Commission's intent, and therefore TAPS urges the Commission to make clearer in the final rule that it is the firmness of the contract, not the formulation of damages for violation of the firmness requirements, that is the determining factor in whether a power purchase qualifies as a network resource.

The confusion may stem from the fact that some in the industry have attempted to cast the issue as whether a "firm LD" product (as the term is defined in the commonly used EEI Master Agreement) should qualify as a network resource. While such shorthand may be convenient, it is not at all precise. As the Commission has recognized, the inclusion of LD provisions in a contract does not inherently make the power supply less than firm.[156] In order to determine the firmness of a purchase, one must look at the entirety of the agreement, and in particular the criteria for whether a failure to supply is excused. Even in contracts that expressly require the supplier to provide a firm power supply, where failure to deliver is excused only for *force majeure* or reliability reasons,[157] the parties can anticipate that through inadvertence or perhaps intentional breach, the selling party may fail to deliver during certain periods. In such event, the buyer would obviously want to be compensated for its costs of replacement power it may need to purchase as a result of the seller's unexcused failure, in order to be kept whole. Parties often use LD provisions (keyed off of the buyer's replacement power costs) to specify the damages to which the buyer will be entitled in such circumstances.

The NOPR (quoted above) seems to suggest that the mere presence of an LD provision entitling the buyer to recoup its replacement power costs would make a power contract ineligible to qualify as a network resource. In the final rule, the Commission

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[156] *Dynegy Midwest Generation, Inc. v. Commonwealth Edison Co.*, 101 F.E.R.C. ¶ 61,295, P 1 (2002) (finding that firm liquidated damages power service contracts, when not interruptible for economic reasons, can be designated as network resources), *reh'g dismissed as moot*, 108 F.E.R.C. ¶ 61,175 (2004).

[157] As the Commission expressly recognizes elsewhere in the NOPR (P 462), sales that are interruptible only to maintain system reliability are firm sales.

should make clear that the important criterion is the degree of firmness of the product, including the scope of what constitutes an excused failure to deliver, rather than the existence of an LD provision.[158]

In addition, the Commission's clarifications in PP 407-409 of the NOPR should apply only to new network resource designations (including extensions or rollovers of existing resources). In other words, to the extent that the Commission's clarifications are inconsistent with any existing power-purchase agreements that have already been accepted as network resources, those clarifications should not retroactively disqualify the resources that network customers are currently relying on and that have been accepted by transmission providers based on their prior understanding of the rules.

Finally, the Commission notes (P 407) that "third party transmission arrangements to deliver the purchase to the network have to be noninterruptible as well." As discussed in Part V.D.1.b above, the Commission should clarify or modify this requirement in order to accommodate use by a network customer of a network resource located on another transmission system that is delivered to the load zone using conditional firm service. Similarly, as also discussed in Part V.D1.b, the Commission

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[158] One conceivable interpretation of the Commission's discussion is a finding that LD provisions that allow a seller to pay only the buyer's replacement power costs, without any adder or other penalty, for an unexcused failure to deliver even when the contract includes other clear indicia of firmness, would disqualify a power-purchase contract from being a network resource. TAPS does not believe that such a conclusion would be justified, or that the Commission should be dictating the details of matters that are generally negotiated between consenting parties, particularly where mandating such details will undoubtedly raise the prices of products to customers under market-based rates. Such a finding would also be unjustified in that it would fail to take account of other contract provisions that the parties may reasonably conclude give the seller adequate incentive to abide by its obligations, such as the ability of the customer to terminate the agreement in response to repeated unexcused delivery failures. In short, the Commission should not be dictating isolated terms of unregulated contracts; instead, it should make clear that whether a contract may qualify as a network resource depends on the nature of the contract as a whole.

should provide for designation of network resources within the control area on a conditional-firm basis.

b) Documentation for Network Resources

The NOPR proposes to require each NITS customer and TP merchant function (taking service for native load) to attest that (1) it owns or has committed to purchase its designated network resources ("DNRs") and (2) the DNRs comport with the requirements for DNRs. This attestation is to be provided with each application for network service, and each time an existing network customer submits an application to designate a new network resource. P 413. The NOPR also proposes (PP 414-15) consequences for failure to provide this attestation (*i.e.*, the DNR request will be deemed retracted and the customer's queue position will be lost), and for "designat[ing] a network resource that it does not own or has not committed to purchase or that does not comport with the requirements for designated network resources" (*i.e.*, this is an OATT violation, subject to penalties).

Although the language of the NOPR in P 413 makes the attestation requirement applicable to the TP itself, the discussion of consequences in PP 414-15 does not so clearly apply to the TP. In the final rule, the Commission should clarify that the TP's own use is subject to the same ramifications for failure to provide the required attestation and for improper designation of network resources. The TP cannot be more lenient in enforcing its own merchant function's observance of these rules than it is in requiring network customers' compliance.

c) Undesignation of Network Resources

TAPS supports the NOPR's clarification (P 422) that the rules requiring network customers to undesignate DNRs in order to make firm sales (and get back in the queue for any re-designations) apply to the TP as well as network customers.

7. Clarifications Related to Network Service

TAPS agrees with the NOPR's clarification (P 427) that secondary network service should not be used to import power for purposes of making off-system sales. However, the Commission's proposed tariff language to effectuate this purpose would unduly (and, we assume, inadvertently) constrain the use of secondary network service by network customers. The Commission proposes to specify in Section 28.4 of the OATT that secondary network service may be used only for delivery of "Economy Energy."

TAPS requests that the Commission clarify in the final rule that secondary network service may be used not only for delivery of economy purchases, but also of substitute resources during periods when one or more DNRs are unavailable, as required for the network customer to reliably serve network load. Such reliability-based usage of non-network resources has always been a core part of network service.[159] Indeed, it is for that very purpose that TPs reserve interface capacity for CBM.

The Commission also observes (P 428) that it does not wish to discourage opportunities to make purchases for resale, it just requires that market participants "use

[159] *See, e.g.*, *Florida Mun. Power Agency v. Florida Power & Light Co.*, 67 F.E.R.C. ¶ 61,167, at 61,483-84 (1994) ("[b]oth parties agree that FMPA should be allowed to designate substitute resources (that is, to displace an existing resource on a temporary basis because of an outage or a chance to buy cheaper energy)"), *reh'g denied*, 74 F.E.R.C. ¶ 61,006 (1996), *reh'g granted*, Order Granting Rehearing for Further Consideration, Docket Nos. TX93-4-004 and EL93-51-003 (Feb. 27, 1996), Order to Determine Mootness, 95 F.E.R.C. ¶ 61,001, *reh'g denied*, 96 F.E.R.C. ¶ 61,130 (2001), *aff'd sub nom, . Florida Mun. Power Agency v. FERC*, 315 F.3d 362 (D.C. Cir.), *cert. denied*, 540 U.S. 946 (2003).

point-to-point service to complete all segments of a purchase for resale off-system." As noted in Part V.C.4.a.(i) above, TAPS urges the Commission to ensure that this development cannot be used by TPs as a means to tie up scarce import capacity through point-to-point reservations. The Commission must clarify (and be vigilant in enforcing) a requirement that any such point-to-point reservations be actually tied to off-system sales, and not a means to serve native load while evading the requirement to designate associated network resources.

One other clarification regarding network service that is not mentioned in the NOPR, but which the Commission should include in the final rule, relates to the Network Operating Committee. As discussed in n.47 above, TAPS is concerned that the existing requirement in Section 35.3 of the Order 888 OATT for formation of a Network Operating Committee, with meetings no less than once a year, is honored more in the breach than in the observance. Indeed, TAPS is aware of at least one TP that interpreted the Network Operating Committee requirement as obligating it to meet bilaterally with each of its network customers, and despite arguments to the contrary from network customers this TP refused to assemble a committee encompassing all network customers and the TP. Where TPs misinterpret the tariff in this fashion, or ignore it altogether, the Commission's expectations for the Network Operating Committee—*e.g.*, providing a vehicle to "coordinate operating criteria,"[160] and development of protocols that are mutually acceptable to the TP and its network customers to fill in the interstices of the tariff[161]—will remain unfulfilled. The Commission should therefore take this opportunity

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[160] OATT Section 35.3.

[161] *Florida Power & Light Co.*, 95 F.E.R.C. ¶ 61,046, at 61,116 & n.5 (2001).

to ensure that Network Operating Committees are actually assembled and used to resolve operational issues and develop policy.

8. Transmission Curtailments

The NOPR (P 441-42) reiterates existing OASIS requirements to post notices of curtailments and the reasons for such curtailments, and to maintain and provide on request information to support such curtailment. The NOPR asks whether concerns expressed about the sufficiency of curtailment information stem from inadequate standards, inadequate compliance, difficulty dealing with the information in the form provided, or some other source. TAPS' answer is "all of the above." NERC's TLR rules (Standard IRO-0006-1) are complex, and leave room for discretion and discrimination, especially as between treatment of tagged interchange transactions and a TP's use of generation within (or pseudo-tied into) its control area to serve native load customers.

At least one TAPS member has experienced curtailment of transmission for its portion of a shared generator, because its small tagged interchange transaction was determined to exceed the 5% threshold on the IDC calculator, while the unit continued to generate at full tilt and the TP's deliveries to its own load were not curtailed. Further, the lack of a tagging requirement for within-the-control-area generation-to-load transactions leads to discriminatory treatment of a TDU and the TP in the event both are curtailed, resulting in the TDU being subjected to imbalance charges, while the TP is free to alter its internal generation schedule.[162] Thus, it would be appropriate to reexamine TLR

[162] For example, a network customer and the TP/control area operator may each be buying non-firm energy from off-system resources. If non-firm transmission service is cut, the TDU and the control area operator each will need to fall back to firm network resources and dispatch those resources to replace the non-firm energy that no longer is flowing due to the transmission curtailment. However, the TDU and the control area operator are in vastly different positions. Because the control area operator does not tag its intra-

procedures to eliminate continuing sources of discrimination and make it easier to identify abuse.

As to the NOPR's question (P 442) regarding the need for additional information, TAPS urges the Commission to move toward maximum transparency, particularly where a decision of great competitive consequence—TLRs—remains in the hands of a customer's competitor. Because examination of actions taken under NERC's TLR standards requires a wide range of information as to what actions were taken and not taken with respect to the many tagged transactions and untagged dispatch actions then occurring, the Commission should make clear that the information to be maintained and provided upon request must sweep very broadly. It is only by looking at the complete picture that a customer can evaluate whether it has been treated fairly as compared with other users of the system (including the TP), and in accordance with NERC's TLR standard.

Finally, recognizing that implementation of TLRs should be a reliability decision, the NOPR (at 443) does not propose generic penalties for improper TLRs, although emphasizing that it will "remain vigilant in monitoring for intentionally discriminatory provision of transmission service, and stand ready to use our enforcement powers and penalty authority when needed." By the same token, the Commission needs to make sure that TPs do not profit from calling TLRs. Specifically, as discussed in Part V.C.1.a,

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control-area generation-to-load transactions, it has the flexibility to dispatch its intra-control-area generation resources without tagging and without permission from any party. In comparison, the TDU will be required to obtain a NERC tag from the control area operator and receive transmission clearance before it is allowed to "dispatch" one of its network resources. In the meantime, the TDU may be subject to imbalance payments.

imbalances resulting from TLRs should be treated as within the first deadband in all cases.

9. Standardization of Rules and Practices

The NOPR leaves largely unchanged the Commission's current policy as to what is required to be included in the OATT itself (P 452), and proposes to establish a requirement that each TP post on its OASIS other rules, standards and practices related to the OATT (P 451). TAPS supports such a requirement, and urges the Commission to cast a broad net with respect to the materials that should be available on the OASIS. Also, as noted in Part V.D.7 above, the Commission should ensure that the Network Operating Committee is actually used as a vehicle for development of policies that are mutually agreeable to the TP and network customers, as contemplated under Section 35.3 of the OATT.

In addition, the NOPR (PP 453-56) proposes to require each TP to include as part of its OATT a new Attachment L that sets forth the TP's creditworthiness and security requirements. TAPS supports the inclusion of such provisions in the OATT, and believes that the improved transparency and consistency of the TP's application of such requirements would more than outweigh the minimal burden on the TP resulting from these provisions being reflected in the OATT.[163] However, in addition, the Commission should include provisions in the final rule to ensure that the standards to be included in each TP's Attachment L are just and reasonable, consistent with the Commission's

[163] TAPS does not believe that creditworthiness standards should need to be changed with any great frequency, so their inclusion in the tariff would not appear to place more than a minimal burden on TPs.

creditworthiness policies, and do not provide an opportunity for the TP to impose added costs on long-term, highly creditworthy customers.

More specifically, to facilitate non-burdensome and fair assessments of creditworthiness, the Commission should require TPs to adopt a two-part creditworthiness assessment. The first step would be to apply a standard similar to that in the Florida Power Corp. OATT, which provides that customers would not have to post any credit security if they have a "satisfactory long-term payment history" and a minimum credit rating of Baa2 (Moody's) or BBB (S&P).[164] As explained by Florida Power Corp. (now Progress Energy Florida) at the July 13, 2004 technical conference concerning electric creditworthiness standards in Docket No. AD04-8-000, the creditworthiness standards adopted by Florida Power Corp. "ensure financial security for the Company, while providing transparent and flexible creditworthiness standards for its customers."[165]

If a customer does not meet this threshold test, the TP should perform a transparent credit assessment that, consistent with the Commission's Creditworthiness Policy Statement[166] and the credit policies that have been developed for use in RTOs such as MISO and SPP, considers quantitative and qualitative factors and recognizes the different financial characteristics of for-profit and not-for-profit electric industry participants. The creditworthiness standards applied to not-for-profit entities such as

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[164] *See* the February 14, 2003 filing of OATT creditworthiness provisions by Carolina Power & Light Company and Florida Power Corporation in Docket No. ER03-540-000, eLibrary Accession no. 20030220-0058, at First Revised Sheets nos. 32-33.

[165] *See* the transcript of the July 13, 2004 Technical Conference in Docket No. AD04-8-000 at 58:3-6.

[166] *Policy Statement on Electric Creditworthiness*, 109 F.E.R.C. ¶ 61,186, PP 13-14 & nn.13-14 (2004).

municipalities and cooperatives should reflect public power's sterling record of payment for power sales and transmission service, and the special characteristics that make municipal and cooperative entities particularly creditworthy. Such entities tend to follow very conservative business models, and many municipal entities and joint action agencies provide significant security for their obligations through bond resolutions that give power suppliers and transmission providers priority over bondholders.[167] Because traditional quantitative measures of creditworthiness tend to understate public power creditworthiness, the Commission should require TPs to weight qualitative factors more heavily than quantitative factors in assessing public power creditworthiness.[168]

In particular, credit standards that rely heavily on tangible net worth as a measure of creditworthiness discriminate against public power entities, who, in order to keep rates low, tend to keep low amounts of equity. In order to avoid this discriminatory result, for public power entities who do not pass the threshold test described above, the Commission should require TPs to use outstanding bond indebtedness as a proxy for tangible net worth for those entities whose energy and transmission service payments receive priority over bond payments. The Commission found in MISO that this approach "ensure[s] that public power entities with outstanding revenue bonds receive appropriate unsecured

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[167] *See* Written Comments of Raj Rao for the July 13, 2004 Technical Conference in *Electric Creditworthiness Standards*, Docket No. AD04-8-000, at 4 (describing that, as typical for joint action agencies, under Indiana Municipal Power Agency's Bond Resolution, payments before transmission service come before debt service, even in a default situation).

[168] *Southwest Power Pool, Inc.*, 114 F.E.R.C. ¶ 61,222, P 37 (2006) (requiring SPP to adopt the 60% qualitative, 40% quantitative split in use by MISO).

credit, but the Midwest ISO does not diminish its credit position," and required its adoption by SPP.[169]

Any effort by a TP to impose more burdensome standards on long-term creditworthy customers than have been applied by Florida Power Corp. or have recently been adopted by MISO and SPP should have a heavy burden to demonstrate problems or abuses that make such burden appropriate.

10. OATT Definitions

TAPS supports the NOPR's proposal to modify the definition of Good Utility Practice "to reference the reliable operation definition adopted in section 215 of the FPA." P 461.

The NOPR does not mention in this section, but includes in the revised OATT (and discusses elsewhere in the NOPR) a new definition of "Economy Energy," which is proposed in connection with the Commission's clarification that secondary network service may be used to support delivery of economic energy. As discussed in Part V.D.7 above, the Commission must recognize that secondary network service may also be used for delivery of substitute resources needed by a network customer to replace designated resources that are temporarily unavailable. This could be done through expansion of the definition of Economy Energy, or addition of a new definition, or modification of the language of Section 28.4 of the OATT. Further, we note that the revised Section 28.4 uses the capitalized term "Secondary Service" but there is no definition of this term.

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[169] *Midwest Indep. Transmission Sys. Operator, Inc.*, 112 F.E.R.C. ¶ 61,163, P 2 (2005); *Southwest Power Pool, Inc.*, 114 F.E.R.C. ¶ 61,222, P 44 (2006).

Either a defined term should be added to the OATT, or the term should be used in lower case.

E. Enforcement

TAPS generally supports the Commission's stated intent to make use of its enhanced penalty authority, as well as its other remedies, in cases of violations of the OATT. NOPR PP 464-85. The Commission properly recognizes the need for a strong, Commission-led audit program, given the difficulties that customers can have bringing complaints on their own, including fear of retaliation, difficulties of detection, and the fact that a customer-filed complaint for an OATT violation may do little to remedy the lost opportunities for economic transactions caused by the transmission provider's OATT violation. TAPS agrees.[170]

With respect to the use of revocation of MBR authority as a remedy for an OATT violation, TAPS opposes requiring "a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority." NOPR P 480. As discussed in Part IX.B of the comments filed today by APPA and TAPS in Docket No. RM04-7, restricting MBR revocation to cases where specific OATT violations have a nexus to MBR authority will leave that authority in place where it is plainly inappropriate. A filed OATT is a prerequisite to MBR authority. A serious violation of the OATT diminishes or even nullifies the transmission market power mitigating effect of the filing requirement. If the violation is material, that is, if the violation effectively denies, delays, or diminishes the availability of transmission service or raises its costs,

[170] *See* TAPS NOI Comments at 41-44.

that alone should suffice for consideration of revocation of MBR authority.[171] Whether the violation had a "nexus" to the seller's MBR sales may well be irrelevant.

The "nexus" standard adds an unnecessary and counter-productive test. Take the case of a transmission provider that fails to engage in proper planning and construction of the transmission system. Such failure may have no express link with the provider or an affiliates' MBR sales, but rather may have the effect of weakening the competitive position of wholesale customers that are captive to the transmission provider's system, leaving them more vulnerable to buyout. A nexus requirement could divert the Commission and injured parties through needless disputes about whether the alleged violator used the OATT violation to enable a specific sale under its MBR tariff authority, ignoring the larger picture painted by the transmission provider's anticompetitive conduct and exercise of transmission market power.

Thus, instead of the "nexus" standard, the Commission should require that the OATT violation be "material," *i.e.*, that the violation denies customers the just, reasonable and non-discriminatory and comparable transmission service that is essential to mitigating transmission market power.

[171] While an OATT violation, such as failure to return a deposit, could be serious, it would not merit revocation of MBR authority if it did not result in the denial of non-discriminatory service.

CONCLUSION

TAPS urges the Commission to take account of TAPS' comments as its moves forward on this crucial effort to modify the OATT so that it better provides non-discriminatory open access transmission service that satisfies the Commission's statutory responsibilities as amplified by EPAct 2005.

Respectfully submitted,

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ATTACHMENT A (CLEAN)

SCHEDULE 4

Imbalance Service

Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of output from one or more generators and/or between the scheduled and actual Transmission Customer load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load and/or deliver output from generators located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider's provision of Imbalance Service shall be subject to the following terms and conditions.

1. Definitions

1.1. "Aggregate Imbalance,"[1] for each hour, is the sum of the Net Imbalances in that hour of all wholesale transmission customers served under the Tariff. Under-supply Net Imbalances and over-supply Net Imbalances of different wholesale customers will offset each other in this calculation.

1.2. "Aggregate Imbalance Deadband," for each hour, is X% of the total load and reservations of wholesale transmission customers served under the Tariff in that

[1] If, notwithstanding the compelling comparability and cost-causation justification set forth in TAPS' comments, the Commission were to elect not to include the aggregate imbalance concept in the *pro forma* provisions in the final rule, the following Sections 1.1, 1.2, 3.2.1-3.2.3, and 4.2.1-4.2.3 would be excluded, and Sections 3.2.3.1-3.2.3.4 and 4.2.3.1-4.2.3.4 would be re-numbered.

hour (*i.e.*, the sum of network loads plus MW reserved by point-to-point customers), where X is the same percentage used by the Transmission Provider to allocate generation costs to Schedule 3 charges.

1.3. "First Deadband" is a deviation band of +/- 1.5 percent of scheduled load or generation, subject to a minimum of 2 MW, to be applied hourly to any Net Imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

1.4. "Net Imbalance," for each hour, is the Transmission Customer's imbalance calculated in accordance with Section 2 of this Schedule 4. As determined under Section 2, each Net Imbalance shall be treated as a Net Generation Imbalance or Net Load Imbalance in accordance with Sections 2.3 – 2.5 below.

1.5. ["Netting Limit" is equal to 7.5 percent of the Transmission Customer's scheduled load or generation, subject to a minimum of 10 MW and a maximum of 25 MW.][2]

1.6. "Second Deadband" is a deviation band of +/- 7.5 percent of scheduled load or generation, subject to a minimum of 10 MW, to be applied hourly to any Net Imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

2. Determination of Net Imbalance

2.1. The Transmission Customer's load imbalance for each hour shall be the difference between its actual metered transmission load (*i.e.*, not including load

[2] As indicated in the text of TAPS' comments, we do not believe it is necessary or appropriate to set a limit on the netting process; however, if the Commission were nonetheless to find it both necessary and consistent with comparability to impose such a limit, TAPS suggests the bracketed language here and in Section 2.5.2 to accomplish that result.

served from behind-the-meter generation) in the hour and its scheduled transmission load in the hour, measured in MW and expressed as an under-supply (where actual load exceeds scheduled load) or an over-supply (where actual load is less than scheduled load). If the Transmission Customer has multiple loads being served under the Tariff, the load imbalance shall be a single value equal to the difference between total actual load and total scheduled load.

2.2. The Transmission Customer's generation imbalance for each hour shall be the difference between its actual metered generation delivered over the transmission system (*i.e.*, not including behind-the-meter generation) in the hour and its scheduled generation in the hour, measured in MW and expressed as an under-supply (where actual generation is less than scheduled generation) or an over-supply (where actual generation exceeds scheduled generation). If the Transmission Customer has multiple generating resources being served under the Tariff, the generation imbalance shall be a single value equal to the difference between total actual generation and total scheduled generation.

2.3. If the Transmission Customer has only a load imbalance or a generation imbalance, the applicable deviation calculated under Section 2.1 or 2.2 above shall be the Net Imbalance, which shall be treated as a Net Generation Imbalance under Section 3 or a Net Load Imbalance under Section 4 below, as applicable.

2.4. If the Transmission Customer has both a load imbalance and a generation imbalance, and its deviations calculated under Sections 2.1 and 2.2 both caused either an under-supply (*i.e.*, load exceeded scheduled load, and generation was less than scheduled generation) or an over-supply (*i.e.*, load was less than scheduled load, and generation exceeded scheduled generation), then the Transmission Customer will have both a Net Load Imbalance and a Net Generation Imbalance, equal to the amounts calculated under Sections 2.1 and 2.2 respectively, which will be treated separately pursuant to Sections 3 and 4 without any offsetting.

2.5. If the Transmission Customer has both a load imbalance and a generation imbalance, and Section 2.4 is not applicable, its Net Imbalance shall be deemed to be a Net Generation Imbalance equal to:

2.5.1. the larger of the deviations calculated under Sections 2.1 and 2.2, minus

2.5.2. [the lesser of (i)] the deviation in the opposite direction (*e.g.*, a generation under-supply will offset a load over-supply)[, or (ii) the Netting Limit for the hour].

3. Net Generation Imbalance

3.1. Imbalances Within First Deadband. Any Net Generation Imbalance that is equal to or less than the First Deadband, and the portion within the First Deadband of any larger Net Generation Imbalance, shall be subject to the following terms:

3.1.1. Parties shall attempt to eliminate imbalances within the limits of the First Deadband within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider.

3.1.2. If an imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer shall pay or be paid for such remaining Net Generation Imbalance in accordance with Section 3.1.3 or 3.1.4, as applicable.

3.1.3. The Transmission Customer shall pay for under-supply Net Generation Imbalance at a rate equal to 100% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

3.1.4. The Transmission Provider shall pay the Transmission Customer for over-supply Net Generation Imbalance at a rate equal to 100% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

3.2. Imbalances Exceeding First Deadband. The pricing of the portion of any Net Generation Imbalance that exceeds the First Deadband shall be as follows, subject to Section 3.3:

3.2.1. If the Aggregate Imbalance is equal to or less than the Aggregate Imbalance Deadband, the Transmission Customer shall pay or be paid for the quantity of its Net Generation Imbalance that exceeds the First Deadband in accordance with Section 3.1.3 or 3.1.4, as applicable.

3.2.2. If the Aggregate Imbalance is greater than the Aggregate Imbalance Deadband, and the Transmission Customer's Net Generation Imbalance is in the opposite direction of the Aggregate Imbalance (*e.g.*, if the Aggregate Imbalance is an under-supply, and the Transmission Customer's Net Generation Imbalance is an over-supply), the Transmission Customer shall pay or be paid for the quantity of its Net

Generation Imbalance that exceeds the First Deadband in accordance with Section 3.1.3 or 3.1.4, as applicable.

3.2.3. If the Aggregate Imbalance is greater than the Aggregate Imbalance Deadband, and the Transmission Customer's Net Generation Imbalance is in the same direction of the Aggregate Imbalance (*e.g.*, if the Aggregate Imbalance is an under-supply, and the Transmission Customer's Net Generation Imbalance is an under-supply), the following pricing shall apply.

3.2.3.1. The Transmission Customer shall pay for under-supply Net Generation Imbalance that exceeds the First Deadband but is less than or equal to the Second Deadband at a rate equal to 110% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

3.2.3.2. The Transmission Customer shall pay for under-supply Net Generation Imbalance that exceeds the Second Deadband at a rate equal to 125% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

3.2.3.3. The Transmission Provider shall pay the Transmission Customer for over-supply Net Generation Imbalance that exceeds the First Deadband but is less than or equal to the Second Deadband at a rate equal to 90% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

3.2.3.4. The Transmission Provider shall pay the Transmission Customer for over-supply Net Generation Imbalance that exceeds the Second Deadband at a rate equal to 75% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

3.3. Exceptions.

3.3.1. Notwithstanding Section 3.2, any portion of the Transmission Customer's Net Generation Imbalance that results from any of the following shall be treated as though it were within the First Deadband:

3.3.1.1. Unscheduled full or partial outage of a generating resource, for a period consistent with applicable reserve-sharing arrangements.

3.3.1.2. Increased output in response to any such unscheduled outage pursuant to reserve-sharing arrangements.

3.3.1.3. Variance from scheduled operation in response to TLR or otherwise in response to direction by the Transmission Provider or Control Area operator.

3.3.2. Notwithstanding Section 3.2, any portion of the Transmission Customer's Net Generation Imbalance (to the extent it exceeds the First Deadband) that results from any of the following shall be treated as though it were within the Second Deadband:

3.3.2.1. Operation of wind generation or other non-dispatchable generating resources.

3.3.2.2. Testing of new generating facilities being placed into commercial operation (up to 90 days) or of existing generation upon its return to service after outage or as required periodically in accordance with Good Utility Practice (*e.g.*, to demonstrate rated capacity).

4. Net Load Imbalance

4.1. Imbalances Within First Deadband. Any Net Load Imbalance that is equal to or less than the First Deadband, and the portion within the First Deadband of any larger Net Load Imbalance, shall be subject to the following terms:

4.1.1. Parties shall attempt to eliminate imbalances within the limits of the First Deadband within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider.

4.1.2. If an imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer shall pay or be paid for such remaining Net Load Imbalance in accordance with Section 4.1.3 or 4.1.4, as applicable.

4.1.3. The Transmission Customer shall pay for under-supply Net Load Imbalance at a rate equal to 100% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

4.1.4. The Transmission Provider shall pay the Transmission Customer for over-supply Net Load Imbalance at a rate equal to 100% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

4.2. Imbalances Exceeding First Deadband. The pricing of the portion of any Net Load Imbalance that exceeds the First Deadband shall be as follows:

4.2.1. If the Aggregate Imbalance is equal to or less than the Aggregate Imbalance Deadband, the Transmission Customer shall pay or be paid for the quantity of its Net Load Imbalance that exceeds the First Deadband in accordance with Section 4.1.3 or 4.1.4, as applicable.

4.2.2. If the Aggregate Imbalance is greater than the Aggregate Imbalance Deadband, and the Transmission Customer's Net Load Imbalance is in the opposite direction of the Aggregate Imbalance (*e.g.*, if the Aggregate Imbalance is an under-supply, and the Transmission Customer's Net Load Imbalance is an over-supply), the Transmission Customer shall pay or be paid for the quantity of its Net Load Imbalance that exceeds the First Deadband in accordance with Section 4.1.3 or 4.1.4, as applicable.

4.2.3. If the Aggregate Imbalance is greater than the Aggregate Imbalance Deadband, and the Transmission Customer's Net Load Imbalance is in the same direction of the Aggregate Imbalance (*e.g.*, if the Aggregate Imbalance is an under-supply, and the Transmission Customer's Net Load Imbalance is an under-supply), the following pricing shall apply.

4.2.3.1. The Transmission Customer shall pay for under-supply Net Load Imbalance that exceeds the First Deadband but is less than or equal to the Second Deadband at a rate equal to 110% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

4.2.3.2. The Transmission Customer shall pay for under-supply Net Load Imbalance that exceeds the Second Deadband at a rate equal to 125% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

4.2.3.3. The Transmission Provider shall pay the Transmission Customer for over-supply Net Load Imbalance that exceeds the First Deadband but is less than or equal to the Second Deadband at a rate equal to 90% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

4.2.3.4. The Transmission Provider shall pay the Transmission Customer for over-supply Net Load Imbalance that exceeds the Second Deadband at a rate equal to 75% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

5. Penalty Revenues. All penalty revenues collected under Sections 3.2.3 and 4.2.3 shall be flowed back to customers whose Net Imbalances did not exceed the First Deadband and/or were in the opposite direction of the Aggregate Imbalance.

ATTACHMENT A (REDLINED)

SCHEDULE 4

~~Energy~~ Imbalance Service

~~Energy~~ Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of ~~energy to a~~output from one or more generators and/or between the scheduled and actual Transmission Customer load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load and/or deliver output from generators located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its ~~Energy~~ Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider ~~may only charge a Transmission Customer for either hourly generator imbalances under Schedule 9 or hourly energy imbalances under this Schedule for the same imbalance, but not both~~'s provision of Imbalance Service shall be subject to the following terms and conditions.

1. Definitions

1.1. "Aggregate Imbalance,"[1] for each hour, is the sum of the Net Imbalances in that hour of all wholesale transmission customers served under the Tariff. Under-

[1] If, notwithstanding the compelling comparability and cost-causation justification set forth in TAPS' comments, the Commission were to elect not to include the aggregate imbalance concept in the *pro forma* provisions in the final rule, the following Sections 1.1, 1.2, 3.2.1-3.2.3, and 4.2.1-4.2.3 would be excluded, and Sections 3.2.3.1-3.2.3.4 and 4.2.3.1-4.2.3.4 would be re-numbered.

supply Net Imbalances and over-supply Net Imbalances of different wholesale customers will offset each other in this calculation.

1.2. "Aggregate Imbalance Deadband," for each hour, is X% of the total load and reservations of wholesale transmission customers served under the Tariff in that hour (*i.e.*, the sum of network loads plus MW reserved by point-to-point customers), where X is the same percentage used by the Transmission Provider to allocate generation costs to Schedule 3 charges.

1.3. "First Deadband" is a deviation band of +/- 1.5 percent of scheduled load or generation, subject to a minimum of 2 MW, to be applied hourly to any Net Imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

1.4. "Net Imbalance," for each hour, is the Transmission Customer's imbalance calculated in accordance with Section 2 of this Schedule 4. As determined under Section 2, each Net Imbalance shall be treated as a Net Generation Imbalance or Net Load Imbalance in accordance with Sections 2.3 – 2.5 below.

1.5. ["Netting Limit" is equal to 7.5 percent of the Transmission Customer's scheduled load or generation, subject to a minimum of 10 MW and a maximum of 25 MW.][2]

1.6. "Second Deadband" is a deviation band of +/- 7.5 percent of scheduled load or generation, subject to a minimum of 10 MW, to be applied hourly to any Net

[2] As indicated in the text of TAPS' comments, we do not believe it is necessary or appropriate to set a limit on the netting process; however, if the Commission were nonetheless to find it both necessary and consistent with comparability to impose such a limit, TAPS suggests the bracketed language here and in Section 2.5.2 to accomplish that result.

Imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

2. Determination of Net Imbalance

2.1. The Transmission Customer's load imbalance for each hour shall be the difference between its actual metered transmission load (*i.e.*, not including load served from behind-the-meter generation) in the hour and its scheduled transmission load in the hour, measured in MW and expressed as an under-supply (where actual load exceeds scheduled load) or an over-supply (where actual load is less than scheduled load). If the Transmission Customer has multiple loads being served under the Tariff, the load imbalance shall be a single value equal to the difference between total actual load and total scheduled load.

2.2. The Transmission Customer's generation imbalance for each hour shall be the difference between its actual metered generation delivered over the transmission system (*i.e.*, not including behind-the-meter generation) in the hour and its scheduled generation in the hour, measured in MW and expressed as an under-supply (where actual generation is less than scheduled generation) or an over-supply (where actual generation exceeds scheduled generation). If the Transmission Customer has multiple generating resources being served under the Tariff, the generation imbalance shall be a single value equal to the difference between total actual generation and total scheduled generation.

2.3. If the Transmission Customer has only a load imbalance or a generation imbalance, the applicable deviation calculated under Section 2.1 or 2.2 above shall be the Net Imbalance, which shall be treated as a Net Generation Imbalance under Section 3 or a Net Load Imbalance under Section 4 below, as applicable.

2.4. If the Transmission Customer has both a load imbalance and a generation imbalance, and its deviations calculated under Sections 2.1 and 2.2 both caused either an under-supply (*i.e.*, load exceeded scheduled load, and generation was less than scheduled generation) or an over-supply (*i.e.*, load was less than scheduled load, and generation exceeded scheduled generation), then the Transmission Customer will have both a Net Load Imbalance and a Net Generation Imbalance, equal to the amounts calculated under Sections 2.1 and 2.2 respectively, which will be treated separately pursuant to Sections 3 and 4 without any offsetting.

2.5. If the Transmission Customer has both a load imbalance and a generation imbalance, and Section 2.4 is not applicable, its Net Imbalance shall be deemed to be a Net Generation Imbalance equal to:

2.5.1. the larger of the deviations calculated under Sections 2.1 and 2.2, minus

2.5.2. [the lesser of (i)] the deviation in the opposite direction (*e.g.*, a generation under-supply will offset a load over-supply)[, or (ii) the Netting Limit for the hour].

3. Net Generation Imbalance

3.1. Imbalances Within First Deadband. Any Net Generation Imbalance that is equal to or less than the First Deadband, and the portion within the First Deadband of any larger Net Generation Imbalance, shall be subject to the following terms:

3.1.1. Parties shall attempt to eliminate imbalances within the limits of the First Deadband within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider.

3.1.2. ~~The Transmission Provider shall establish a deviation band of +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider. If an energy~~If an imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer ~~will compensate the Transmission Provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider. The charges for Energy Imbalance Service are set forth below.~~ shall pay or be paid for such remaining Net Generation Imbalance in accordance with Section 3.1.3 or 3.1.4, as applicable.

3.1.3. The Transmission Customer shall pay for under-supply Net Generation Imbalance at a rate equal to 100% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

3.1.4. The Transmission Provider shall pay the Transmission Customer for over-supply Net Generation Imbalance at a rate equal to 100% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

3.2. Imbalances Exceeding First Deadband. The pricing of the portion of any Net Generation Imbalance that exceeds the First Deadband shall be as follows, subject to Section 3.3:

3.2.1. If the Aggregate Imbalance is equal to or less than the Aggregate Imbalance Deadband, the Transmission Customer shall pay or be paid for the quantity of its Net Generation Imbalance that exceeds the First Deadband in accordance with Section 3.1.3 or 3.1.4, as applicable.

3.2.2. If the Aggregate Imbalance is greater than the Aggregate Imbalance Deadband, and the Transmission Customer's Net Generation Imbalance is in the opposite direction of the Aggregate Imbalance (*e.g.*, if the Aggregate Imbalance is an under-supply, and the Transmission Customer's Net Generation Imbalance is an over-supply), the Transmission Customer shall pay or be paid for the quantity of its Net Generation Imbalance that exceeds the First Deadband in accordance with Section 3.1.3 or 3.1.4, as applicable.

3.2.3. If the Aggregate Imbalance is greater than the Aggregate Imbalance Deadband, and the Transmission Customer's Net Generation Imbalance is in the same direction of the Aggregate Imbalance (*e.g.*, if the Aggregate Imbalance is an under-supply, and the Transmission Customer's Net

Generation Imbalance is an under-supply), the following pricing shall apply.

3.2.3.1. The Transmission Customer shall pay for under-supply Net Generation Imbalance that exceeds the First Deadband but is less than or equal to the Second Deadband at a rate equal to 110% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

3.2.3.2. The Transmission Customer shall pay for under-supply Net Generation Imbalance that exceeds the Second Deadband at a rate equal to 125% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

3.2.3.3. The Transmission Provider shall pay the Transmission Customer for over-supply Net Generation Imbalance that exceeds the First Deadband but is less than or equal to the Second Deadband at a rate equal to 90% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

3.2.3.4. The Transmission Provider shall pay the Transmission Customer for over-supply Net Generation Imbalance that exceeds the Second Deadband at a rate equal to 75% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

3.3. Exceptions.

3.3.1. Notwithstanding Section 3.2, any portion of the Transmission Customer's Net Generation Imbalance that results from any of the following shall be treated as though it were within the First Deadband:

3.3.1.1. Unscheduled full or partial outage of a generating resource, for a period consistent with applicable reserve-sharing arrangements.

3.3.1.2. Increased output in response to any such unscheduled outage pursuant to reserve-sharing arrangements.

3.3.1.3. Variance from scheduled operation in response to TLR or otherwise in response to direction by the Transmission Provider or Control Area operator.

3.3.2. Notwithstanding Section 3.2, any portion of the Transmission Customer's Net Generation Imbalance (to the extent it exceeds the First Deadband) that results from any of the following shall be treated as though it were within the Second Deadband:

3.3.2.1. Operation of wind generation or other non-dispatchable generating resources.

3.3.2.2. Testing of new generating facilities being placed into commercial operation (up to 90 days) or of existing generation upon its return to service after outage or as required periodically in accordance with Good Utility Practice (*e.g.*, to demonstrate rated capacity).

4. Net Load Imbalance

4.1. Imbalances Within First Deadband. Any Net Load Imbalance that is equal to or less than the First Deadband, and the portion within the First Deadband of any larger Net Load Imbalance, shall be subject to the following terms:

4.1.1. Parties shall attempt to eliminate imbalances within the limits of the First Deadband within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider.

4.1.2. If an imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer shall pay or be paid for such remaining Net Load Imbalance in accordance with Section 4.1.3 or 4.1.4, as applicable.

4.1.3. The Transmission Customer shall pay for under-supply Net Load Imbalance at a rate equal to 100% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

4.1.4. The Transmission Provider shall pay the Transmission Customer for over-supply Net Load Imbalance at a rate equal to 100% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

4.2. Imbalances Exceeding First Deadband. The pricing of the portion of any Net Load Imbalance that exceeds the First Deadband shall be as follows:

4.2.1. If the Aggregate Imbalance is equal to or less than the Aggregate Imbalance Deadband, the Transmission Customer shall pay or be paid for the quantity of its Net Load Imbalance that exceeds the First Deadband in accordance with Section 4.1.3 or 4.1.4, as applicable.

4.2.2. If the Aggregate Imbalance is greater than the Aggregate Imbalance Deadband, and the Transmission Customer's Net Load Imbalance is in the opposite direction of the Aggregate Imbalance (*e.g.*, if the Aggregate Imbalance is an under-supply, and the Transmission Customer's Net Load Imbalance is an over-supply), the Transmission Customer shall pay or be paid for the quantity of its Net Load Imbalance that exceeds the First Deadband in accordance with Section 4.1.3 or 4.1.4, as applicable.

4.2.3. If the Aggregate Imbalance is greater than the Aggregate Imbalance Deadband, and the Transmission Customer's Net Load Imbalance is in the same direction of the Aggregate Imbalance (*e.g.*, if the Aggregate Imbalance is an under-supply, and the Transmission Customer's Net Load Imbalance is an under-supply), the following pricing shall apply.

4.2.3.1. The Transmission Customer shall pay for under-supply Net Load Imbalance that exceeds the First Deadband but is less than or equal to the Second Deadband at a rate equal to 110% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

4.2.3.2. The Transmission Customer shall pay for under-supply Net Load Imbalance that exceeds the Second Deadband at a rate equal to 125% of the Transmission Provider's incremental energy cost for the hour in which the deviation occurred.

4.2.3.3. The Transmission Provider shall pay the Transmission Customer for over-supply Net Load Imbalance that exceeds the First Deadband but is less than or equal to the Second Deadband at a rate equal to 90% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

4.2.3.4. The Transmission Provider shall pay the Transmission Customer for over-supply Net Load Imbalance that exceeds the Second Deadband at a rate equal to 75% of the Transmission Provider's decremental energy cost for the hour in which the deviation occurred.

5. Penalty Revenues. All penalty revenues collected under Sections 3.2.3 and 4.2.3 shall be flowed back to customers whose Net Imbalances did not exceed the First Deadband and/or were in the opposite direction of the Aggregate Imbalance.

ATTACHMENT B

30.9 Network Customer Owned Transmission Facilities:

The Network Customer that owns ~~existing~~ transmission facilities that are interconnected ~~integrated~~ with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. ~~In order to receive such consideration the Network Customer existing must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the [the effective date of a Final Rule in RM05-25-000], the~~The Network Customer shall receive credit provided that such facilities ~~are integrated into the operations of the Transmission Provider's facilities and, if the transmission facilities~~, if they were owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's Annual Transmission Revenue Requirement. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties. With respect to customer-owned facilities constructed after [the effective date of the Commission's final rule in Docket No. RM06-4-000], the calculation of the Network Customer's credits for facilities that meet the foregoing standard shall include rate incentives if applicable.

ATTACHMENT C

[Section 19.3] The System Impact Study shall identify any system constraints and redispatch options, including an estimate of the number of hours of redispatch that may be required to accommodate the request for Transmission Service and a preliminary estimate of the cost of redispatch, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. <u>The preliminary estimate of the costs of Network Upgrades for which the Transmission Customer may be responsible under Section 27 shall be stated in the form of a monthly incremental-cost transmission rate, determined by amortizing the cost of the upgrades (or the Transmission Customer's share thereof) over the life of the transmission service contract.</u>

[Section 19.4] When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. <u>The good faith estimate of the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff shall be stated in the form of a monthly incremental-cost transmission rate, determined by amortizing the Transmission Customer's share of the cost of the Network Upgrades over the life of the transmission service contract.</u>

[Section 32.3] The System Impact Study shall identify any system constraints and redispatch options, including an estimate of the number of hours of redispatch that may be required to accommodate the request for Transmission Service and a preliminary estimate of the cost of redispatch, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. The preliminary estimate of the costs of Network Upgrades for which the Transmission Customer may be responsible under Section 27 shall be stated in the form of a monthly incremental-cost transmission rate to be applied in lieu of the portion of the Network Customers’ monthly Demand Charge related to the portion of the Transmission Customer’s load to be served by the Network Resource, determined by amortizing the cost of the Network Upgrades (or the Transmission Customer’s share thereof) over the life of the Network Resource.

[Section 32.4] When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer~~'~~’s appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The ~~Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code~~good faith estimate of the Transmission Customer’s appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff shall be stated in the form of a monthly incremental-cost transmission rate to be applied in lieu of the portion of the Network Customers’ monthly Demand Charge related to the portion of the Transmission Customer’s load to be served by the Network Resource, determined by amortizing the cost of the Network Upgrades (or the Transmission Customer's share thereof) over the life of the Network Resource. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement ~~and provide the required letter of credit or other form of security~~ or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn. If the parties cannot agree upon terms in the Service Agreement relating to the provision of security by the Transmission Customer, the Transmission Provider may include proposed security requirements in an unexecuted Service Agreement, which must be supported by a showing of need under the particular circumstances.