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

SUPPLEMENTAL COMMENTS OF THE TRANSMISSION ACCESS POLICY STUDY GROUP

Pursuant to the Commission's November 15 Notice of Request for Supplemental Comments, the Transmission Access Policy Study Group ("TAPS") submits supplemental comments focusing on the Transparent Dispatch Advocates ("TDA") Proposal and conditional firm service. As transmission dependent utilities in more than 30 states, TAPS has long been an advocate of non-discriminatory transmission access. We have previously submitted extensive comments in this docket, including on the issues of redispatch (although not the TDA Proposal) and conditional firm service.[1]

In these Supplemental Comments, we express our serious concerns about the TDA Proposal. While the proposal is intended to be simple and modest, we fear that in practice it will prove to be anything but. The proposal to have non-independent transmission providers ("TP") operate bid-based redispatch markets would create new opportunities for discrimination and abuse by vertically integrated transmission providers, and represent a departure from fundamental objectives of the May 19, 2006

[1] *See* Initial Comments of the Transmission Access Policy Study Group, filed August 7, 2006 at 103-06 ("TAPS Initial NOPR Comments"). *See also* TAPS' November 22, 2005 Comments on the Notice of Inquiry ("TAPS NOI Comments") at 66-68, and 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. RM05-7-000 and AD04-13-000. TAPS participated as a panelist at the March 16-17, 2005 Workshop in Portland in Docket Nos. AD05-5-000 and PL03-1-000.

Notice of Proposed Rulemaking ("NOPR") at 3-4:

> [N]ote the major focus of this reform effort here. As a general matter, the purpose of this rulemaking is to strengthen the *pro forma* OATT to ensure that it achieves its original purpose – remedying undue discrimination – not to create new market structures.

In addition to responding to the Commission's questions regarding the TDA Proposal, TAPS addresses questions pertaining to conditional firm service and continues to urge that if the Commission requires such service, it should conform to the parameters discussed in TAPS' Initial NOPR Comments – an "almost always firm" service integrated with network service and available to network customers.

I. TAPS HAS SERIOUS CONCERNS WITH THE TRANSPARENT DISPATCH ADVOCATES PROPOSAL

TDA's September 20 Reply Comments ("TDA Proposal"), as further explained in TDA's "FAQs re Transparent Dispatch Advocates Coalition Proposal" ("TDA FAQS") and "Proposal Summary" ("TDA Summary"),[2] would require non-independent TPs to create and operate bid-based redispatch markets at designated constraints, but without providing for examination and mitigation of market power in the redispatch market at those constraints. Although TDA recognizes the need for certainty in pricing redispatch for a long-term transaction, its proposal offers quite the opposite; its real-time focus will not facilitate the availability of long-term transmission rights that Congress instructed the Commission to enable long-term entities to secure, both inside and outside "organized markets." FPA Section 217(b)(4). While TDA intends the proposal to foster grid expansion, experience shows that it is far more likely to be a disincentive, contrary to

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[2] The latter two documents are attached to the November 3, 2006 Comments of San Diego Gas & Electric Company Supplementing Technical Conference Reform in Docket Nos. RM05-25-000 and RM05-17-000.

EPAct's repeated directives. Auditing implementation of the TDA Proposal would be extremely difficult for customers, and ultimately the Commission. In short, although is well-intended, the TDA Proposal aggravates TAPS' concerns with expanded reliance on redispatch as a remedy for discrimination.[3] While TAPS would welcome the opportunity to work with TDA (and others) to address the grid inadequacies that we understand are motivating the TDA Proposal, we do not support the proposal.

1. TP Operation of Bid-Based Markets is Likely to Invite the Exercise of Market Power and Other Abuses

According to TDA's Summary, the "essential" features of the proposal include transmission provider posting of information "concerning the nature of congestion at designated flowgates, the characteristics of generation or demand side response needed to alleviate the constraint, and appropriate historical redispatch costs." "All generators,

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[3] As described in TAPS' Initial NOPR Comments at 96-103, TAPS does not object to the NOPR's modifications to OATT §§ 19.3 and 32.3 to provide preliminary estimates of redispatch hours and costs in the system impact study. However, TAPS expressed concern that lack of cost certainty would discourage customer reliance on redispatch, especially given difficult-to-audit opportunities for TP abuse. We urged:

- 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. Doing so would appropriately hold the TP accountable for the accuracy of studies used to assess the availability of transmission service, rather than shifting that risk to the customer.
- Redispatch service should be limited so that it does not enable the TP to evade its OATT planning and expansion obligations. Redispatch would be most easily implemented and less likely to be counter-productive if applied to relatively short-term transactions (for which TPs have no construction obligation) and as an interim service while transmission upgrades are constructed (to avoid discouraging construction).
- A customer should have the ongoing option, by redispatching its own resources (including by voluntarily curtailing the requested service in the hours when redispatch would be required) to hedge the risks of paying for redispatch of the TP's resources.
- In any event, TPs should not be authorized to require redispatch of network customer resources to accommodate third party service requests. Such authorization would give TPs a new competitive weapon, enabling them to severely interfere with network customers' use of their limited resources and unfairly exposing network customers to risks they cannot hedge. While TPs should identify network customer resources that might efficiently provide redispatch, such redispatch should be left to voluntary agreement of the network customer.

including the utility's own generation, would then have the *right* to bid to be dispatched to clear the constraint." TDA Summary (emphasis added). In this "voluntary" bidding process in which the "transmission provider would choose the lowest bid that could most effectively clear the constraint consistent with all applicable reliability criteria," "[b]ids could be either market or cost based depending on whether the bidder has market based rate authority within the control area." *Id.* Monitoring would be provided through quarterly reports, with data "retained in order to allow for FERC monitoring and audit if necessary." *Id.*

The TDA Proposal goes beyond a mere request for greater transparency, to a demand that TPs operate a real-time bid-based market at designated constraints. Although the Proposal states (at 5) "In non-market environments, these [real time redispatch service] values can and will necessarily be cost-based," the TDA FAQs make clear that in many cases, redispatch bids, including those from the incumbent vertically integrated transmission provider, will not be restricted to cost:

> Bidders with market based rate authority in the control area could bid at market prices (including the incumbent provider if it has such authority within its own control area). Entities without market based rate authority would be subject to cost-based bids.

TDA FAQ (emphasis added). Because many vertically integrated transmission providers have market-rate authority within their control areas, the TDA Proposal evidently contemplates that many TPs will *not* be restricted to cost-based bids for redispatch.

TAPS finds extremely troubling the concept of vertically integrated TPs operating redispatch markets, in which they may participate, especially through market-based bids. While TAPS members have been skeptical about the benefits of Day 2 RTO markets with their high operating costs and high prices, at least such markets are operated by independent entities, with market-power monitoring and mitigation. The TDA Proposal includes neither protection, thus providing manifold opportunities for discrimination, the exercise of market power, and other abuses.[4] Such markets are certainly not assured to produce anything like the "actual cost" of redispatch, defeating what TDA identifies as a key prerequisite for effective redispatch service. TDA Proposal at 4. Particularly where the TDA Proposal envisions the grant of long-term service predicated on the customer bearing the real-time redispatch cost, there will likely no discipline on the price – such long-term customer may have no choice but to accept and pay the excessive redispatch charges associated with its long-term service (which it would have had no ability to predict with any certainty before deciding whether to take the service).

TDA's reliance on existing grants of MBR authority to support market-based redispatch offers no protection against market power exercise where transmission constraints exist, *i.e.*, the very market conditions under which the TDA Proposal would operate. Outside of RTOs, the Commission typically assesses eligibility for MBR authority for energy sales on a control-area-wide basis, except where transmission constraints internal to the control area suggest that the relevant geographic market is smaller than the control area. *See, e.g.*, *Entergy Servs., Inc.*, 111 F.E.R.C. ¶ 61,507 (2005). But control-area-wide evaluations do not address market power in providing redispatch service to relieve a particular constraint. In many cases, very few generators,

[4] The TDA Proposal (at 6 n.11) cites the August 7, 2006 Comments of TransAlta Energy Marketing (US) Inc. ("TransAlta"), as "rais[ing] concerns as to non-independent transmission providers' implementation of redispatch … based on actual, negative and discriminatory experiences with redispatch in the Pacific Northwest." The TransAlta Comments (at 7) specifically points to experiences where redispatch is used "to the benefit of some customers and the detriment of others." The TDA Proposal does nothing to address the opportunities for discrimination resulting from the lack of independence of the TPs that it intends to

or perhaps only one, will be in a position to efficiently relieve the constraint, rendering such generator pivotal. Even if multiple generators can have an influence, the high concentration of TP-owned generation within its control area means that in many cases the TP will be able to name its price for redispatch, even assuming it is generally subject to effective competition for energy sales within its control area.

Nor is it just vertically integrated TPs that enjoy market power with regard to a particular constraint. In some instances, it may be an independent generator that, because of its location relative to the flowgate, has market power with regard to redispatch.

The limited scope of bid-based redispatch markets, and the resulting elevated potential for the exercise of market power, has been recognized by the Commission. *See GridSouth Transco, LLC*, 96 F.E.R.C. 61,067, at 61,299 (2001) ("[N]ew market conditions and the potential for market power may arise when (as here) bid-based congestion markets are created"). For example, in addressing a bid-based redispatch scheme MISO proposed to apply *prior* to implementation of LMP, the Commission identified market-power concerns requiring study.[5] The study conducted by MISO's independent market monitor as a result of that order confirmed that market power was a significant concern and proposed mitigation.[6] After MISO's further revisions were suspended and set for technical conference,[7] MISO withdrew the proposal.[8]

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operate and participate in redispatch markets.

[5] *Midwest Independent Transmission System Operator, Inc.,* 98 F.E.R.C. ¶ 61,075, at 61,220 (2002).

[6] *See* April 2 Report of Dr. David B. Patton of Potomac Economics, Ltd., submitted on April 4, 2002 in Docket No. ER01-3142-007 (finding pivotal suppliers in connection with 23 of the 41 flowgates studied).

[7] *Midwest Independent Transmission System Operator, Inc.,* 99 F.E.R.C. ¶ 61,346 PP 25-26 (2002).

[8] *See Midwest Independent Transmission System Operator, Inc.*, 101 F.E.R.C. ¶ 61,174 (2002).

More generally, the Commission has recognized the increased potential for market-power exercise when constraints bind, *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,157, P 232 (2004), including when such constraints cause suppliers to become pivotal. *See*, *e.g.*, *ISO New England*, 104 F.E.R.C. ¶ 61,039, P 19 (2003). The need for mitigation arises areas "where well-defined structural barriers to competitive performance exist." *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163, P 271 (2004). A "structural problem exists when suppliers become pivotal; pivotal suppliers have market power because at least a portion of their offers must be accepted, no matter how high the offer price, in order to maintain reliability." *ISO New England*, 104 F.E.R.C. ¶ 61,039 at P 19.

TDA's suggestion that market-based authority, granted based on control-area-wide tests, apply to the provision of redispatch is a significant flaw in its proposal. The Proposal contains no mechanism for examining or mitigating market power risks associated with transmission constraints in a dynamic AC grid. The FPA forbids the acceptance of market-based rates without evidence that the market will be effective in disciplining bids.[9] Any consideration of TDA's approach will require a constraint-by-constraint examination of market power, with ongoing independent monitoring and mitigation, all complicated by the proposed implementation by a non-independent TP.

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[9] *AEP Power Mktg., Inc.*, 107 F.E.R.C. ¶ 61,018, PP 40, 144 (2004); *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870 (D.C. Cir. 1993); *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1510 (D.C. Cir. 1984); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1009, 1013 (9th Cir. 2004).

2. Implementation of the TDA Proposal Would Require Active Supervision by the Commission, Audit by Customers, and Review by Independent Market Monitors

As described above, the TDA Proposal brings with it significant opportunities for abuse. Contrary to the suggestion of the TDA Summary, quarterly reports to the Commission will not be sufficient to identify and guard against the exercise of market power and other abuses. Nor is it enough that "[d]ata would be retained in order to allow for FERC monitoring and audit if necessary." TDA Summary. While active Commission supervision of TP-operated redispatch markets will be necessary, given the number of TPs and constraints it is hard to see how the Commission could effectively police implementation. Thus, it is likely that independent market monitors, if not independent operators, will be required. And experience has taught that neither of these come cheaply. Nor do the mechanisms required to operate markets. TDA has not shown that the benefits of its proposal outweigh the high costs it can be expected to engender.

In addition, customers will need access to information required to audit redispatch costs. Audit of such costs has long been recognized to be a customer's right. As the Commission concluded` in *GridSouth*, 96 F.E.R.C. at 61,300: "[I]t is reasonable for customers to have sufficient information ... to verify their bills." *See also Midwest Independent Transmission System Operator*, *Inc.*, 98 F.E.R.C. ¶ 61,075 at 61,217 (2002) (requiring customer access to models and input data to verify congestion management costs). Customers are entitled to no less where redispatch costs are imposed by a non-independent TP. Such audits, while necessary, will impose burdens on customers. Abuses in the implementation of redispatch will not be easy to ferret out, as described in TAPS' Initial NOPR Comments at 97.

3. The TDA Proposal Will Not Provide the Certainty Needed to Facilitate Long-Term Service

TDA asserts that for redispatch to be effective, it must be "predictable and reasonably certain." TDA Proposal at 4. *See also id*. at 7 ("We agree with customers that in order for redispatch to provide real value, the cost of redispatch should be certain."). TAPS agrees, and for that reason urged the Commission *not* to increase reliance on directly assigned redispatch. *See* TAPS' NOPR Comments at 96-103.

The TDA Proposal, with its focus on real-time redispatch markets, appears to diminish, rather than enhance, the certainty customers need to commit to long-term transmission service. The TDA Proposal (at 15) concedes that "the level and frequency of redispatch required to support a particular long-term service request, and the cost of providing such redispatch, cannot be predicted with any precision."

As the Commission recognized in its rule implementing Section 217(b)(4) in organized markets, Congress concluded that load-serving entities ("LSEs") need long-term rights that protect them from volatile congestion charges. According to Order 681-A, Section 217(b)(4) requires that long term rights be "firm"; in the financial context, that means the rights, once allocated, should remain constant, and the rights should not "experience volatility in the actual financial coverage that they provide relative to congestion charges associated with the same points of injection and withdrawal (although there might be some volatility experienced in the uplift charges that support full funding)."[10] In *PJM Interconnection, LLC*, 117 F.E.R.C. ¶ 61,220 (2006), the Commission found PJM's proposal lacking because it failed to adequately assure full

[10] *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681-A, 71 Fed. Reg. 98,440 (Nov. 27, 2006), 117 F.E.R.C. ¶ 61,201 at P 46 (2006) (footnote omitted).

funding of the rights and their availability, especially given recent experience with extreme pro-rationing of FTRs due to loop flow. There is no reason to assume that bid-based redispatch charges produced by the TDA Proposal (or even cost-based redispatch) will be more certain over the long term than highly volatile RTO congestion charges.

The TDA Proposal will not provide the certainty required for LSEs to commit to long-term service needed to support long-term power supply arrangements that are key to serving load at a predictable and affordable cost. Rather, it would subject LSEs outside of organized markets to the volatility that Congress' long-term rights directive sought to address. For the Commission to adopt the TDA Proposal would run contrary to Section 217(b)(4), which applies outside of organized markets, as well as within.

4. The TDA Proposal Will Discourage Creation of a Robust Grid

Allowing TPs to collect market-based prices for redispatch will enhance the TPs' ability to profit from constraints, and as a result will discourage the grid expansion OATT reform is rightly intending to promote. TDA statements that the Proposal will reveal the value of upgrades and thus encourage construction (Proposal at 15-16) echo claims that LMP would encourage expansion. But PJM itself has conceded that LMP signals have proven insufficient to create the robust grid Congress has directed the Commission to achieve, producing "disappointing results:"[11]

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[11] Written Remarks of Audrey Zibelman, Executive Vice President, PJM Interconnection, L.L.C., at 5, for the April 22, 2005 Transmission Investment Technical Conference, Docket Nos. AD05-5-000 & PL03-1-000 (comments dated Apr. 21, 2005). *See also, e.g.*, Hogan, Electricity Transmission Investment: Theory and Practice, Infocast Conference Transmission Summit, January 28, 2004, at 7-8 (market may not be able to support transmission investments because of economies of scope and scope may imply market failure), available at http://ksghome.harvard.edu/~whogan/Hogan_Trans_Sum_012804.pdf; Joskow, Patterns of Transmission Investment, March 15, 2005 (describing failure of the economic vs. reliability upgrade dichotomy (at 43-44, 46) and how PJM's "dream that the invisible hand would lead merchant investors to come forward to make … investments in response to congestion rents has not been matched by reality" at 40), available at http://econ-www.mit.edu/faculty/download_pdf.php?id=1133; Joskow, Merchant

> Do we want a "minimalist" transmission grid that essentially serves as an "add-on" facilitating the reliable movement of power from generation sited close to load? In other words, should the transmission system merely be a facilitator for a model based on local generation? Or are we looking for a strong transmission system that, by its design, links distant generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose? The "rules of the road" and the costs to build one system versus another are vastly different….
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> In many ways, the Energy Policy Act of 1992 answered this question in favor of the strong superhighway to support a competitive generation industry. … Assuming that we wish a strong transmission system to provide load with many options, we believe a new set of "building blocks" is needed.[12]

EPAct 2005, with its provision for backstop federal siting of national interest transmission corridors (where constraints and congestion adversely affect consumers),[13] its directive that the Commission exercise its authority to facilitate the expansion of the grid to meet the reasonable needs of LSEs,[14] and its provision for incentive/performance-based rates to benefit consumers by ensuring reliability and reducing delivered power cost by reducing transmission congestion[15] all point the Commission toward affirmative steps to create the robust grid that supports competitive markets, rather than creating new profit motives to keep the grid constrained. Congress has witnessed the high and growing congestion costs borne by consumers, even in RTO markets, and has made clear

Transmission Investment, Journal of Industrial Economics, June 2005, at 233, 240-62 (describing limitations on relying on merchant transmission due to imperfections in energy market and lumpiness of transmission investment), available at http://econ-www.mit.edu/faculty/download_pdf.php?id=910.

[12] Zibelman Written Comments at 5.

[13] EPAct 2005 § 1221; FPA § 216.

[14] EPAct 2005 § 1233; FPA § 217(b)(4).

[15] EPAct 2005, § 1241; FPA§ 219.

that this is not what it wants. The Commission is on the right track with its focus on regional joint planning, and should not dilute the impact of such efforts by providing new reasons for the TP to resist construction—the opportunity to reap profits from redispatch.

5. "And" Pricing for Redispatch Service Should be Rejected

TDA appears to adopt Southern's position that the Commission allow "and" pricing of redispatch service. *See* TDA Proposal at 4 n.5. Such treatment (*e.g.*, by attempting to cast redispatch as a "new service") ignores the contrary teachings of the cases cited in the NOPR (at P 284 n. 269) supporting "or" pricing. *See Pennsylvania Elec. Co*., 58 F.E.R.C. ¶ 61,278 at 61,873 (charging "out-of-rate" charges *and* embedded cost rate amounts to "double dipping"), *reh'g denied*, 60 F.E.R.C. ¶ 61,034 at 61,124-28, *reh'g denied*, 60 F.E.R.C. ¶ 61,313 (1992), *aff'd sub nom. Pennsylvania Electric Co. v. FERC*, 11 F.3d 207, 210-11 (D.C. Cir. 1993) ("and" pricing would result in charging twice for the same transaction).

"And" pricing for redispatch would also be counter-productive. As explained in the TransAlta NOPR Comments (at 7) on which the TDA Proposal relies (at 6 n.11):

> Allowing a transmission provider to collect redispatch costs higher than its maximum rate for transmission service stated in its tariff will create a compelling disincentive to building more capacity. The fact that redispatch is required should [be] a clear signal to all that additional capacity probably needs to be constructed. TransAlta suggests that redispatch prices capped at the Point-to-Point transmission rate does not impact construction decisions, and stimulates market activity by creating cost certainty.

Adopting "and" pricing for redispatch would discourage the transmission construction that the NOPR's joint planning provisions, and Congress, through EPAct2005, are seeking to encourage. The Commission should adhere to "or" pricing.

6. Responses to the Commission's Questions

- *Is the TDA proposal required to remedy undue discrimination*?

No. In its Initial NOPR Comments at 95-103, TAPS agreed with the NOPR's finding (PP 300-304) that TPs approach customer transmission requests differently than their own, and that the result is unduly discriminatory (while noting that this finding applies to network resource designations, not just point-to-point requests, and overlooks an important source of discrimination: granularity). However, TAPS advised *against* increased reliance on directly assigned redispatch costs. As described above, TAPS is concerned that the TDA Proposal would create more opportunities for discrimination than it is claimed to cure. It is also not undue discrimination for non-RTO markets to provide redispatch service in a different way than PJM and other RTOs.

- *What are the implementation impediments to requiring greater transparency of redispatch cost information? For example, if long-term point-to-point service is granted based on redispatch of the transmission provider's generation, would it be reasonable to require the transmission provider to post its daily or hourly redispatch cost for the constraint implicated by that request?*

- *Are there confidentiality or anticompetitive issues associated with requiring posting of this type of information? Are any concerns alleviated or exacerbated if the transmission provider were required to post the differential in costs between redispatched generators?*

In new Section 220(b), Congress directed the Commission to facilitate enhanced price transparency in a way that does not adversely affect competitive markets. The Commission has insisted on a 6-month delay for release of bid information, and even then has required the participants' names to be masked, to protect the market from collusion.[16] While TAPS has questioned the need for such a long delay in the release of

[16] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 at P 559 (2004).

market information, the proposed real-time disclosure of bid and cost information runs contrary to the Commission's policy and may have adverse effects on competition and facilitate gaming by larger market participants.

As noted above, the TDA Proposal will require customer access to information required to audit redispatch charges.

- *Would the TDA proposal for the transmission provider to provide real-time redispatch using third party resources require the establishment of limited markets and, if so, what are the costs or benefits of doing so?*

Yes. As discussed above, TAPS sees the Proposal as fraught with high costs, and little benefits.

B. Conditional Firm Service Should Adhere to the Parameters Previously Urged by TAPS

TAPS has previously submitted detailed comments on conditional firm service,[17] and after issuance of the NOPR, worked with AWEA to develop parameters to make conditional firm service a viable option by limiting it to "almost always firm" service.[18] In these comments, TAPS responds to the Commission's additional questions.

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[17] *See* footnote 1 above.

[18] As described in TAPS' Initial NOPR Comments at 103-106:

- 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 pro rata curtailment.
- 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.
    - 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.

- *Should conditional firm be offered as an alternative to redispatch or are they complementary services? For example, if redispatch is not available, should the transmission provider nevertheless be required to offer conditional firm service if available?*

As discussed in TAPS' Initial NOPR Comments at 95-106, particularly in the absence of an independent operator, directly assigning redispatch costs is unlikely to be an effective remedy to undue discrimination. TAPS suggested that conditional firm service—if limited to 100 hours/year, subjected to curtailment on the same basis as firm service beyond those hours, and integrated with network service and made available to network customers—could provide a better means to more efficiently use the grid.

However, TAPS notes that conditional firm service has limited application. It will not meet the needs of a small TDU that requires firm transmission for its full requirement purchases. Nor does it meet the needs of TDUs that require full-availability of a resource to meet resource adequacy and other requirements[19] to reliably serve load.

- *Should conditional firm service be available for all long-term requests (including those of 20-30 years) or should it be offered only as a "bridge" service where the customer agrees to pay for transmission system upgrades and conditional firm service is provided until those relevant upgrades are constructed? For example, for a 20-year request for service, should the transmission provider be required to offer conditional firm service only during the first few years until relevant upgrades are constructed?*

- *Do limitations on system modeling present problems in offering conditional firm service over long periods (e.g., 10-30 years)? For example, do standard modeling techniques make it easier to analyze system conditions in the near term (e.g., 1-5 years) than over the long term (e.g., 10-30 years)?*

Conditional firm service works best as a bridge service, greasing the wheels of construction. It is especially useful where, *e.g.*, a wind generator can be installed before the upgrades can be completed. Defining conditional firm service as a bridge service

[19] *E.g.*, network resource designation requirements, if not changed to accommodate conditional firm service.

would prevent it from contributing to an increasingly constrained grid and unfairly impairing the availability of secondary network service needed by those who have committed on a long term basis to bear the residual grid costs.[20] It also addresses concerns raised by TPs about the difficulty in estimating curtailment hours many years in advance, *e.g.*, for a 30-year service contract, as would be needed if conditional firm service were to be used as a long-term solution.

Restricting conditional firm service to a bridge service also avoids difficult issues as to equity in the queue, *e.g.*, if the conditional firm customer is unwilling to share in the upgrade costs (to the extent required under "or" pricing), but absorbs ATC and exposes the next customer to upgrade obligations or increases the size of the required upgrade. Because the conditional nature of the service will be cured by the later upgrade, the conditional customer will have unfairly taken a free ride on the next customer, and subjected it to additional costs.

Accordingly, conditional service should be limited to bridging the gap before upgrades can be completed.

- *If conditional firm service is considered as a "bridge" product, should special rules apply when the necessary upgrades are extremely expensive (e.g., 10 times the embedded cost rate)?*

- *If any necessary upgrades produce "lumpy" capacity (e.g., a request for 100 MW of point-to-point service results in upgrades that create 1,000 MW of additional*

[20] *See AES Power, Inc.*, 69 F.E.R.C. ¶ 61,345, at 62,300 (1994) (proposed order), 74 F.E.R.C. ¶ 61,220 (1996) (final order)), cited in *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, 21,607 & n.464 (May 10, 1996), [1991–1996 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,036, at 31,750 & n.464, *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).

> *flowgate capacity), how should the lumpy capacity be handled? Should the costs be assigned exclusively to the requesting customer or, alternatively, be shared with other customers? If costs are assigned to the requesting customers, should it obtain rights to the lumpy capacity that can be resold in the marketplace? Alternatively, could a "bridging" application of conditional firm service even out the "lumpiness" of the upgrade requirement by permitting deferral of the upgrade until load growth or new customers are prepared to absorb and help pay for the excess capacity from the upgrade and, if so, how could the transmission provider implement such a mechanism?*

These questions highlight the consequences of the inconsistency between the economics of grid upgrades, which often are characterized by significant economies of scale that make them "lumpy," and the Commission's transmission pricing policy, which permit the TP to assign to the requesting customer, subject to "or" pricing, the costs of upgrades that typically provide broader benefits. As described in TAPS' NOI Comments at 13-15 and TAPS' January 23, 2006 Reply NOI Comments at 16-22, often a customer seeking service is asked to pay for the same upgrades that continually show up when others inquire about delivery of alternative power supplies. In many places, the grid has become so fundamentally inadequate that a spider web of massive deficiencies shows up whenever any change is studied, no matter how small.[21] As a result, transmission customers take turns presenting individual needs and then walking away from proposed purchases or generation projects when transmission costs are disproportionate to the scale of individual uses and benefits.[22] All the while, network upgrades that are cost-effective from a system viewpoint do not get made, leading to a cycle of increasing grid

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[21] *See* December 7, 2006 Written Statement of Anne Kimber in Docket No. RM04-7 at 6, describing efforts of one small city on the MidAmerican system to take service from the Municipal Energy Agency of Nebraska ("MEAN") at the end of its power contract: "According to the MAPP-MISO 'scenario analyzer'—the tool available to market participants to test the availability of transmission service, transmission from MEAN to Callender, Iowa (0.6 MW) impacted both MAPP and MISO (Alliant) flowgates. Frankly, it is hard to believe that a transmission request this small could cause such big problems" (footnote omitted).

[22] Numerous detailed examples are set forth in TAPS' NOI Comments at n.24.

degradation and constrained supply options. At the same time, although TAPS members are ready and willing to invest in the TP's grid, and receive revenues (or credits) comparable to the TP, these offers repeatedly get rebuffed.[23]

The inefficiencies caused by the current request-driven approach to upgrades are documented in *Oklahoma Mun. Power Auth. v. American Elec. Power Serv. Corp.*, 110 F.E.R.C. ¶ 61,228, *reh'g denied*, 112 F.E.R.C. ¶ 61,107 (2005), which deals with OMPA's request to designate an additional 29 to 54 MW from the Oklaunion plant (associated with exercise of a right of first refusal) that it jointly owns with AEP. AEP had determined that this service would require an additional DC tie between SPP and ERCOT. According to AEP, the cost of building a 29 MW tie is $23.7 million and the cost of building of a 200 MW tie is $57 million. A 200 MW tie would be far more efficient and save more money for consumers by relieving this constrained path. As described in TAPS' NOI Comments at 97-99, the SPP Independent Market Monitor confirmed the substantial differences between the electricity prices in ERCOT and in SPP,[24] and documented frequent denials of service.[25] Even though OMPA was willing to

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[23] *See* Written Statement of Anne Kimber at 11. *See also* letters from TAPS members Lafayette Utilities System, Clarksdale, Mississippi, and the Missouri Joint Municipal Electric Utility Commission to Entergy, offering to invest in rebuilding of the Katrina-destroyed Entergy system. Entergy did not exactly jump on the offers. The letters are appended to TAPS' NOI Comments as Attachment 1.

[24] *See* May 31, 2005, "2004 State of the Market Report Southwest Power Pool, Inc." *available at* http://www.spp.org/publications/SPP_State-of-the-Market-Report_05312005.pdf ("SPP IMM Report"). The SPP IMM Report shows that the average annual on-peak energy price in SPP in 2004 was $45.29/MWh, while the annual on-peak energy price in ERCOT in 2004 was $47.32/MWh, for an annual average difference of $2.03/MWh. *See Id.* at 45, 52. More significantly, off-peak, the average SPP price was $20.58/MWh, while the ERCOT price was $31.49/MWh, for an average difference of $10.91/MWh. *Id.* It observes that "the significant differences in power prices between SPP … and ERCOT should provide incentives for exports from SPP even after costs to move power are taken into account." *Id.* at 53.

[25] SPP IMM reported that in 2004 SPP denied 62,276 requests to export power out of SPP over the ERCOT East tie and 6,951 requests for exporting power out of SPP over the ERCOT North tie, and observed: "the large number of requests experienced by SPP for exports over the DC ties to ERCOT is a potential indicator of the demand for such service." IMM Report at 34 and 35. According to the report, "much of the overall increase in requests during the second half of 2004 may have been due to requests submitted for

own, build and fund the 200 MW upgrade that would relieve these constraints[26] (if it could obtain credits under Section 30.9), AEP argued strongly for restricting the additional tie to the amount requested by OMPA—29 or 54 MW, allowing for no additional capacity to relieve the current constraints between ERCOT and SPP.[27]

OMPA illustrates the lumpiness of upgrades and failure of the OATT, as interpreted by transmission providers, to promote the efficient upgrades that would create the robust grid Congress is seeking to foster, *e.g.*, through new Sections 216, 217(b)(4), and 219, and that benefit consumers by reducing constraints and congestion. Economies of scale associated with transmission upgrades should be viewed as a positive attribute that facilitates achievement of EPAct's goals, rather than a problem that needs to be addressed.

TAPS believes that the way to take advantage of economies of scale and achieve Congress' grid expansion directives is to broadly assign the costs of broadly beneficial upgrades, rather than crafting convoluted pricing adjuncts to conditional firm service. *See* TAPS' Initial NOPR Comments at 44-46 and TAPS' NOI Comments at 18-21.[28] Providing opportunities for joint ownership, with crediting, similarly hold more promise

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use of SPP's DC ties with ERCOT." *Id.* at 34-35.

[26] Although the denied transmission requests involved transmission primarily from North to South (from SPP to ERCOT), a DC tie is bi-directional. Additional DC capacity will alleviate existing constraints and allow SPP to grant more transmission requests in both directions.

[27] The proceeding was terminated without prejudice based on a joint motion stating that a Texas trial court decision had created a situation in which it might be years before there was a definitive decision as to whether OMPA was entitled to the additional ownership interest in the Oklaunion plant and that it would be a waste of resources of the parties and the Commission to further pursue OMPA's complaint at this time. *Oklahoma Mun. Power Auth. v. Am. Elec. Power Serv. Corp.,* 114 F.E.R.C. ¶ 61,124 (2006).

[28] *See, e.g.*, November 22, 2005 AEP NOI Comments at 4, 8 ("Regional markets demand a regional rate design;" "urg[ing] the Commission to adopt regionalization of 'highway' facilities as a national policy that can aid in the development of a more extensive network of critical interstate facilities that can unlock major efficiencies for the benefit of consumers").

for getting needed grid expansions built. *See* TAPS' Initial NOPR Comments at 43-44 and TAPS' Reply NOPR Comments at 15-18.

At minimum, the Commission should increase the emphasis placed on recognition of benefits to other customers in the application of "or" pricing of upgrades. In *Northeast Utilities Serv. Co.*, 62 F.E.R.C. ¶ 61,294, at 62,932 (1993), *remanded in part, on other grounds, Northeast Utils. Serv. Co. v. FERC,* 993 F.2d 937 (1st Cir. 1993), the Commission required that in applying incremental-cost pricing under the "but for" concept, the transmission provider must adjust the expansion cost assignable to third parties over time to account for the benefits received by native load (*e.g.*, where a portion of the capacity is subsequently used to meet load growth). The benefits requiring re-adjustment of the expansion cost assignment should also include use by other customers, which enables the TP to obtain more revenues (in the case of point-to-point customers) or to fulfill its obligations to network customers. Similarly, if by relieving constraints on the TP's system, the expansion enables the TP to lower costs of energy to its native load or gain access to renewable resources required to meet state mandates, it would be inequitable to permit the entire costs of the expansion to be assigned to the requesting transmission customer. The Commission should make clear that where the TP institutes incremental-cost pricing, it should have to evaluate the benefits and adjust the assignable expansion costs (1) upfront; and (2) whenever a new usage is permitted by the upgrade and periodically (*e.g.*, no less than every five years) to ensure that this important facet of "or" pricing is made meaningful.

Viewed against this re-adjustment obligation, a bridging use of conditional firm service could permit deferral of upgrades until additional native load or third-party usage arises, or at least gets closer in time, so that the period when the customer would be required to bear expansion costs on an incremental basis would be reduced, if not eliminated altogether.

- *In responding to a request for conditional firm service, should the transmission provider be required to provide customers with a choice between conditional curtailment based on specified system conditions and the maximum number of hours per year?*

To be effective, conditional service must be limited to "almost always firm" service – service where curtailments are restricted to no more than 100 hours per year. Conditional firm service should be restricted 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.

If the specified system conditions would be expected to produce curtailments in the narrow (less than 100 hours/year) range that would allow the service to be deemed "almost always firm," the customer should have option of expressing the curtailment restriction on the basis of such specified system conditions. However, such expression of the curtailment conditions should not be allowed to evade TAPS' proposed "almost always firm" restriction on the availability of conditional firm service.

- *Should conditional firm service qualify as a network resource when the associated resource is imported by a network customer on an adjacent system?*

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 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 point-to-point service to integrate with network service on the system where the load is located). If firm service is not available, conditional firm service must work for both types of LSEs if it is to serve its purpose:

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 from 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 "non-interruptible" for purposes of network resource designation. *See* OATT §§ 1.27 and 30.1. Absent this extension, the LSE would be relegated to secondary network service, a service far less firm than conditional point-to-point service. [29]
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

[29] 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 service, secondary service is an inferior service, one unlikely to support investment in generation or a long-term purchase contract.

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 consistent with limiting conditional firm service to "almost always firm" service.

Respectfully submitted,

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