UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mandatory Reliability Standards for the Bulk-Power System	Docket No. RM06-16-000

COMMENTS OF TRANSMISSION ACCESS POLICY STUDY GROUP ON STAFF PRELIMINARY ASSESSMENT OF PROPOSED RELIABILITY STANDARDS

The Transmission Access Policy Study Group ("TAPS") appreciates the opportunity to comment on the Commission Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Reliability Standards, issued May 11, 2006 ("Staff Assessment"). NERC's Version 0 standards were adopted (mostly in April, 2005) to reflect without change, but in more enforceable form, then-existing NERC policies and practices, with the expectation that Version 1 standards would quickly follow. While the Version 0 standards were supportable at NERC on that basis and in many cases represent a good starting point, TAPS shares many of the Staff's concerns that the proposed standards are often "not ready for prime time"—*i.e.*, not quite ready to be implemented as reliability standards, enforceable through penalties under Section 215. Further refinement is required, particularly as to applicability, before they can be found just, reasonable and not unduly discriminatory or preferential and in the public interest. In addition, some standards require modification to avoid undue impact on competition.

I. INTEREST OF TAPS

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[1] TAPS members have long recognized the need for mandatory and enforceable reliability standards that ensure grid reliability. TAPS actively participated in the development of the NERC consensus reliability legislation in 1998 and as it was modified over time, and has long supported its enactment. As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members are particularly concerned that reliability standards not become a means to confer competitive advantages or disadvantages on particular types of market participants. For this reason, we view as crucial the oversight role to be performed by this Commission—the only entity in a position to assess reliability standards in the context of transmission tariffs, market rules, wholesale power rate schedules and related rules and business practices.

[1] TAPS is chaired by Roy Thilly, CEO of Wisconsin Public Power Inc. ("WPPI"). Current members of the TAPS Executive Committee include, in addition to WPPI, representatives of: American Municipal Power-Ohio; Blue Ridge Power Agency; Clarksdale, Mississippi; ElectriCities of North Carolina, Inc.; Florida Municipal Power Agency; Geneva, Illinois; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric Co.; Missouri River Energy Services; Municipal Energy Agency of Nebraska; Northern California Power Agency; Oklahoma Municipal Power Authority; Southern Minnesota Municipal Power Agency; and Vermont Public Power Supply Authority.

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II. COMMENTS

A. Common Issues: TAPS Shares Many of Staff's Concerns Regarding the Proposed Standards

The Staff Assessment, at 17-28, identifies common issues that cut across many of the proposed standards. These concerns include ambiguities, technical inadequacy, lack of measures and levels of compliance, fill-in-the-blank standards, and lack of precision as to the applicability of the standards.

TAPS agrees with many of Staff's concerns. More specificity will be needed before standards can be found reasonable for enforcement through penalties as contemplated by Section 215.

1. Fill-in-the-Blank and Ambiguous Standards

Order 672[2] made clear that "uniformity of Reliability Standards should be the goal and the practice, the rule rather than the exception," Order 672 at P 290, with regional differences limited to regional differences more stringent than the continent-

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[2] Order No. 672, *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, 114 F.E.R.C. ¶ 61,104

wide Reliability Standard (including covering matters not addressed in continent-wide standards), and regional standards "necessitated by a physical difference in the Bulk-Power System." *Id.* at P 291. The Commission stressed the particular importance of uniformity within an interconnection. *Id.* at P 292.

Fill-in-the-blank standards completely undermine Order 672's uniformity directives, and will result in many inconsistencies that cannot be justified based on physical differences in the Bulk-Power System or as regional standards more stringent than the continent-wide standard. By effectively delegating standard setting to the regional entity, they violate the fundamental structure of Section 215 of the Federal Power Act ("FPA"), in which the Electric Reliability Organization ("ERO") alone can set Reliability Standards, subject to Commission review. They therefore should be rejected. Regional differences that meet the Commission's requirements should be included explicitly in approved ERO standards as a variance or, where appropriate, proposed to the ERO by the regional entity and approved through the ERO for application in the region.[3]

Fill-in-the-blank standards are particularly troublesome where they leave flexibility for implementation based on market-driven needs of individual market participants (*e.g.*, CBM). Even where it is the region, and not individual market participants, that gets to fill in the blank, the region's choice may reflect the historical lack of a balanced process for developing standards at the regional level, allowing certain classes of market participants to determine the region's choice. While Order 672 requires

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(2006). ("Order 672")

[3] *See* Motion to Intervene and Limited Protest of the Transmission Access Policy Study Group, filed May 4, 2006 in *North American Electric Reliability Council and North American Electric Reliability Corporation*, Docket No. RR06-1, at 15-26.

balanced decision-making on a forward-looking basis,[4] the Commission needs to be concerned that at least in some regions, existing regional standards do not reflect anything close to balanced decision-making. Indeed, SERC still has no ANSI process for creating standards. Thus, there is significant potential for standards that have undue effects on competition. In any event, the reasonableness of "fill-in-the-blank" standards cannot be assessed until the blank is filled in.

Ambiguous standards suffer from many of the same defects. As discussed below with regard to transmission planning standards, ambiguous standards invite discriminatory application. Before they can be found just and reasonable, such standards must be clarified to eliminate the potential for undue competitive impacts.

2. Greater Precision is Required on Applicability, Which Must be Limited to Entities That Materially Impact the Bulk Electric System

The standards filed by NERC are the "Version 0 standards," which were intended quickly to translate existing policies and procedures into more enforceable form, without changing them.[5] Because of these origins, many standards that previously only applied to NERC and Regional Reliability Organization ("RRO") members are expressed broadly, or lack clarity as to their applicability. The Staff Assessment (at 24) notes that "the Applicability sections of the standards are not always sufficiently specific to be clear and unambiguous about the applicability of the standard."

As a result of the failure to adequately specify applicability or to fully assess the impact of broadly applying Version 0 standards, standards that previously applied to the

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[4] Order No. 672, 114 F.E.R.C. ¶ 61,104 at P 728.

[5] Although it was recognized that many required significant work and/or refinement, such efforts were

larger entities that were NERC and RRO members may apply on a mandatory basis to some small entities whose actions do not have a material impact on the Bulk Electric System. For example, some standards may be applicable to Generator Operators without reference to size or location of the generator.[6] Small Distribution Providers may be made subject to the standards in a manner that provides no meaningful reliability benefit.[7] Applicability of standards needs to be refined to make sure application is justified from a reliability perspective, and would not have an undue impact on competition or impose undue costs.

Further, care must be taken to avoid imposing compliance obligations in a manner that imposes non-comparable burdens on small systems. For example, large utilities are not required to include under-frequency load shedding equipment at each substation serving 5 MW (or less); rather, they provide sufficient under-frequency response for their load viewed as a whole. Comparable treatment is required for small loads served at wholesale. Particularly where the small distribution provider is part of a joint action agency ("JAA") or G&T coop (or other supplier) that has the contractual ability to provide the necessary response, under-frequency load shedding requirements should be assessed at the level of the JAA, G&T or other supplier from the perspective of their total load, rather than imposing greater granularity where service is to wholesale load, rather than retail load. However, current PRC standards are now drafted to apply on a

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intended to be reflected promptly in Version 1 standards (which has not occurred in most cases yet).

[6] *E.g.*, VAR-001 may subject operators of a 2 MW behind-the-meter generator to reporting and operational requirements. *See* VAR-001.R9 and R9.1.

[7] *See*, *e.g.*, PRC-009-0, which requires Distribution Providers with a transmission protection program to analyze (including by simulation) an under-frequency event and document the post-mortem. It may be difficult and unduly burdensome for a small entity to perform given limited access to event data and the

mandatory basis to *each* Distribution Provider that has the equipment, without flexibility to have compliance assessed at a higher level—for example, to ensure sufficiency of load shedding response by the JAA viewed as a whole.

More generally, as the Staff Assessment notes, many standards fail to specify with clarity the entities to whom they apply. Nor is the applicability section of the standards consistent with NERC's Compliance Registry Criteria, which include minimum size requirements for distribution providers, LSEs, and generators (subject to specified exceptions).[8]

The potential for confusion is heightened by the fact that the NERC Functional Model, which defines the entities referenced by the standards, but which is not itself proposed to be a standard, is itself in flux, with comments currently being solicited by NERC on the most recent set of proposed modifications. More generally, the NERC matrix is confusing as applied to a joint action agency and its members, and information from TAPS members suggests that the regions are applying registration labels in a manner that adds to the confusion.[9]

Finally, NERC's all or nothing approach to joint action agencies furthers the potential for confusion and unfairness. NERC permits a distribution entity or LSE to be exempt from registration if a JAA, G&T coop, or other balancing authority/transmission operator registers in its place.[10] Because of the contractual nature of joint action

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need the perform a stability analysis.

[8] *See* Statement of Compliance Registry Criteria, Appendix B to *Motion for Leave to File Reply Comments and Reply Comments of North American Electric Reliability Council and North American Electric Reliability Corporation*, filed June 12, 2006, as corrected June 13, 2006, in Docket No. RR06-1.

[9] *E.g.*, some regions have sought to register both the JAA and its members as LSEs.

[10] *Id*. at Note 3. *See also* NERC's proposed Rules of Procedure § 501.1.2.7: "A generation or transmission

agencies, requiring a JAA to register in lieu of its members for all compliance purposes is unlikely to work, for example, where the JAA has contractual rights to require member compliance with certain standards but not others.

To address these problems, TAPS suggests:

- The Commission should require NERC to be more precise on applicability of standards, with the reasonableness of standards reassessed once applicability is specified and *before* standards are made mandatory.[11] The Commission should not make mandatory standards that apply to entities that have no material impact on the Bulk Electric System.[12]
- NERC's Functional Model should be filed as a standard. The model is intrinsic to determining the applicability of standards and authority of the identified entities to perform the functions assigned by the various standards. Allowing the Functional Model to remain fluid without the need to file changes with FERC, while standards that reference the Functional Model become enforceable by penalty after filing with and approval by the Commission, could result in violation of section 215's criteria for standards. An unfiled change in the Functional Model could change the standard in a way that makes it unjust, unreasonable and unduly discriminatory or preferential. Filing of the Functional Model as a standard would avoid the potential for this serious disconnect.
- The Commission should provide for flexibility as to how standards are met within a JAA (and similar entities) to ensure comparability. Rather than restricting JAAs to an all or nothing approach to registration in lieu of their members, NERC should allow JAAs to accept compliance responsibility on a standard-specific basis—to take responsibility to the extent permitted by the individual JAA's contracts with its members. Further, to ensure comparability, JAAs should be allowed (where authorized by their contracts with their members) to cost-effectively achieve compliance with a standard at the JAA level (*i.e.*, on the same total-system basis on which the compliance of larger utilities is assessed), rather than to simply stand in the shoes of their individual members.

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cooperative, or similar joint-action agency may be registered, in lieu of each of its members being registering individually [sic], by accepting the reliability functions identified in Section 1.1 above, of that entity's members."

[11] An Applicability SAR is currently out for comments. *See* http://www.nerc.com/~filez/standards/SAR-Applicability.html

[12] NERC's Bulk Electric System definition provides for a pragmatic approach for limiting applicability of standards in a manner that is consistent with Section 215 and its reliability purpose. Thus, TAPS does not share Staff's concern (Staff Assessment at 25-26).

B. Inadvertent Interchange

1. The Existing Treatment of Inadvertent, as Compared with Energy Imbalance, Creates Undue Competitive Impacts

The OATT, as currently implemented with Commission approval by numerous transmission providers, requires non-control-area utilities to pay the higher of $100/MWh or 110% of incremental cost for under-deliveries in excess of the narrow 1.5% or 2 MW bandwidth (with over-deliveries compensated at 90% of decremental cost).[13] A small utility experiencing inevitable and unavoidable imbalances must pay charges far in excess of its transmission provider/host control area's cost of supplying energy to correct the imbalance. Ironically, a customer may be subject to penalty charges for energy imbalances that help the transmission provider remain in balance by offsetting its own imbalances.[14]

The treatment afforded a Balancing Authority's inadvertent energy under NERC and NAESB rules is non-comparable to the imbalance penalties imposed on non-control-area utilities. As noted by the Staff Assessment (at 32), NERC's inadvertent standard includes no requirement to prevent excessive leaning or measures to address the reliability impact of large inadvertent energy, but instead includes only a reporting requirement for inadvertent energy, which under NAESB standards is paid back in-kind.

This non-comparable treatment of imbalances and inadvertent energy promotes proliferation of small control areas and creates undue competitive impacts. It makes it

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[13] *See, e.g., Detroit Edison Co.*, 88 F.E.R.C. ¶ 61,070, at 61,165, *reh'g denied*, 88 F.E.R.C. ¶ 61,224 (1999).

[14] Where a transmission provider charges separately for generator imbalances, a customer may pay both energy imbalance penalties and generator imbalance charges when the two imbalances would partially or completely offset each other if they were netted. For example, the North Carolina Municipal Power Agency #1 is subject to paying Duke for generator imbalances associated with deliveries from its share of the Catawba Nuclear Plant, without being permitted to net those imbalances against its energy imbalances.

particularly hard for non-control-area utilities to cost-effectively utilize intermittent resources, like wind power,[15] and disadvantages them in competing to serve wholesale loads – even if their cost of power is identical, non-control-area utilities must factor in significant energy imbalance charges that the TO never has to face.[16] Imposition of this penalty when TLRs are imposed for the benefit of the whole system adds insult to injury without encouraging good scheduling practices – not only does the curtailment result in the customer losing the benefit of its intended source of supply, but (because it cannot change its schedule until the hour after it learns of the TLR) the customer is also likely to be forced to pay the transmission provider $100/MWh for the resulting imbalance.

2. The Order 888 Reform NOPR Proposes to Continue the Disparate Treatment of Imbalance and Inadvertent

In the Order 888 Reform NOPR,[17] the Commission proposes to eliminate the $100/MWh penalty for under-deliveries beyond the 1.5%/2 MW band, and instead to require that charges be based on incremental cost (or some multiple thereof), provide an incentive for accurate scheduling, and address the special circumstances of intermittent

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[15] *See* TAPS Pre-Technical Conference Comments in *Assessing the State of Wind Energy in Wholesale Electricity Markets*, Docket No. AD04-13-000 (as filed Dec. 23, 2004) (providing concrete illustration of the severe and discriminatory impact of imbalance penalty).

[16] *See Okla. Gas & Elec. Co.*, 80 F.E.R.C. ¶ 61,012 (1997), *reh'g denied*, 85 F.E.R.C. ¶ 61,035 (1998) (rejecting arguments that transmission provider was serving itself and favored wholesale customers on a preferential basis and finding no energy imbalances will be experienced by partial requirements customer served by transmission provider).

[17] *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, *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), *subject to proposed rulemaking*, *Preventing Undue Discrimination and Preference in Transmission Service*, 71 Fed. Reg. 32,636 (proposed June 6, 2006), 115 F.E.R.C. ¶ 61,211 (2006) (to be codified at 18 C.F.R. pts. 35 and

generators. Order 888 Reform NOPR at P 239. While this would seem to be a step in the right direction, the NOPR proposes to include in the OATT both energy and generation imbalance schedules, and raises questions as to whether and the extent to which netting should be permitted even within the same balancing authority. *Id.* at P 247. The NOPR also proposes that incremental costs may include "commitment charges (to the extent additional commitments are needed)," and raises questions as to the inclusion of demand, redispatch and additional regulation reserve costs. *See Id.* at P 247 & n. 234. TAPS is hopeful that the final rule will improve upon the NOPR (*e.g.*, "commitment charges," which are unlikely to be fairly attributed to imbalances, should not be includable in incremental cost). However, the NOPR's treatment of imbalance energy fails to ensure comparability with the return-in-kind treatment of Balancing Authority inadvertent energy, with much of the same adverse effect on competition as discussed above with regard to the existing imbalance regimen.

The Order 888 Reform NOPR attempts to justify continued discrimination on the ground that imbalance and inadvertent energy "are not comparable." Order 888 NOPR at P 245. 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," *id.*, the lion's share of inadvertent energy is typically under the control of the transmission provider (or balancing authority) 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

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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 the two services should have *precisely* the same treatment." *Id.* at P 245 (emphasis added). 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,[18] and the Staff Assessment (at 32) observes that inadvertent is increasing.

3. The Commission Should Make the Treatment of Inadvertent and Imbalance Comparable

This competitively charged issue is not going to be solved by the industry. TAPS has asked both NERC and NAESB to eliminate the preferential treatment of control area inadvertent energy, to no avail. As shown in the attached correspondence,[19] NERC ducked the issue (as is typical with issues having competitive implications), asserting that "NERC cannot ensure that standards that apply to balancing authorities will be economically comparable to tariff rules … that NERC has no influence over" and pointing to practical hurdles identified by NAESB's Inadvertent Interchange Payback Task Force ("IIPTF"). On November 29, 2005, NAESB's Wholesale Electric Quadrant modified the report by the IIPTF, which had been deliberating for more than two years, to make clear that it recommended retaining the return-in-kind regimen for control areas

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[18] *E.g.*, in what has been termed Cinergy's "grand theft electric" (*see Cinergy's Brazen Taking from Grid Stuns Market*, *Prompts Drive for Penalties*, 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.

[19] *See* July 22, 2005 letter from Roy Thilly to NERC and NAESB; NERC's August 9, 2005 response; and Mr. Thilly's August 29, 2005 reply, appended hereto as Attachment 1.

simply because of lack of consensus on this competitively charged issue.[20] The IIPTF Report's recommendation now reads:[21]

> The IIPTF reviewed numerous possible solutions to the settlement of Inadvertent Interchange and determined that, at this time, no consensus can be reached regarding alternatives to the NAESB Version 0 standard.

The partition of the inadvertent/imbalance issue among NERC, NAESB and OATT reform does not eliminate the Commission's duty to identify and eliminate the discrimination. However, the solution always seems to be in some other docket. For example, in its recent order approving NAESB's initial business practices, the Commission punted the issue of treatment of imbalance to the Order 888 Reform docket, while urging NERC and NAESB to work to cooperatively revise inadvertent standards, which it noted "are susceptible to abuse for financial gain, particularly if such abuse can lead Balancing Authorities to create imbalances that may jeopardize reliability."[22] The Order 888 Reform NOPR (at P 245) proposes to maintain the disparate treatment of inadvertent energy and imbalance energy (albeit without the current $100/MWh under-scheduling penalty), but asks whether the current approach to inadvertent energy encourages leaning on the system in times of shortage; whether reform is appropriate; whether pricing at incremental cost would be an appropriate disincentive; and whether reforms in this area should be pursued under FPA section 215 as part of the review of the reliability standards, *i.e.*, in this docket.

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[20] *See* December 3, 2005 revised draft minutes of the November 29, 2005 WEQ meeting, along with the redlined IIPTF recommendation and attachment (the IIPTF Report), *available at* http://www.naesb.org/weq/weq_ec.asp (last viewed on Jan. 22, 2006).

[21] *Id.*

[22] *Standards for Business Practices and Communication Protocols for Public Utilities*, 115 F.E.R.C.

In short, the differences between treatment of inadvertent and imbalance energy are discriminatory and have an adverse effect on competition. The Commission has an obligation to provide comparable treatment of two forms of essentially the same service—whether by expanding the payback-in-kind opportunities for imbalance or by requiring Balancing Authorities to pay for inadvertent energy (beyond the return-in-kind bandwidth applicable to imbalances) at incremental cost (calculated in a manner comparable to the incremental cost calculation that would apply to imbalances beyond the bandwidth under the Order 888 reform final rule). The Commission must address this issue in this docket and/or the OATT Reform docket, and must not allow discriminatory practices to be enshrined as reliability standards. Without Commission intervention, the non-comparability of the inadvertent standard will continue to have undue competitive impacts, and TDUs will be driven to inefficient actions, such as the creation of small control areas, to avoid imbalance charges.

C. ATC/TTC/TRM CBM Standards

The Staff Assessment (at 74-83) recognizes numerous problems with the ATC/TTC/TRM/CBM standards, which have "resulted in different interpretations and applications of calculation methodologies resulting in different values for ATC when using the same data and assumptions." *Id.* at 76. Staff's concerns include:

- the "fill-in-the-blank" nature of these standards, with the development of methodologies and procedures delegated to the RRO; *id*. at 80
- Absence of any requirement for consistent and uniform calculation of CBM; *id*. at 80.

¶ 61,102, PP 31-32 (2006).

- "delegat[ion] to the Transmission Service Providers to document their procedures" for CBM, *id*. at 80, but "not to implement a consistent and uniform calculation of CBM; *id*. at 81.
- Absence of specificity as to how TRM or CBM is determined and allocated across transmission paths; *id*. at 80, 82.

The Staff Assessment concludes that the standards "may result in unnecessary regional variations not justified by technical differences and inconsistent application." *Id.* at 80. It also finds (*id*. at 76):

> [T]he different approaches could have undue negative impact on competition. The Commission is considering this issue in Docket Nos. RM05-17-000 and RM05-25-000 and anticipates addressing it in any Notice of Proposed Rulemaking that may be issued in those dockets.

Since issuance of the Staff Assessment, the Commission has issued its Order 888 Reform NOPR, confirming the Staff Assessment as well as additional concerns and proposing significant reforms.

TAPS strongly agrees with the Staff Assessment's concerns about ATC/TTC/CBM/TRM standards. As explained in the August 15, 2005 TAPS comments in RM05-17-000 and our November 22, 2005 comments in Docket No. RM05-25 at 28-31, TAPS sees significant flaws and undue competitive impacts in the way these standards now operate, and urges the Commission to make these calculations transparent, consistent, and better yet, regional. In particular, we have noted the significant potential for abuses from the current flexibility afforded transmission providers in the calculation of CBM and TRM, as documented by NERC's April 14, 2005 Long-Term AFC/ATC

Task Force Final Report, and questioned how TRM or, especially, CBM can be viewed as reliability standards if they are optional to the transmission provider.

Given the strong direction on these issues in the Order 888 Reform NOPR, TAPS assumes that the Commission will not be approving the Version 0 standards on these competitively crucial issues, but will continue to address them forcefully in Docket No. RM05-17-000 and RM05-25-000.

D. Transmission Planning Standards Performance Requirements

As explained in the Staff Assessment (at 111), Table 1 of the Planning Standards lays out performance requirements for a range of contingencies, including the N-1 requirement of no load loss or curtailment of firm transfers from contingencies resulting in the loss of the a single element. However, the Table also includes footnotes intended to aid in interpretation, including footnote b: "Planned or controlled interruption of electrical supply to radial customers or some local Network customers, connected to or supplied by the faulted element or affected area, may occur in certain areas without impacting the overall reliability of the interconnected system."[23] As Staff observes, "this footnote is sufficiently ambiguous to allow for differing interpretations." Staff Assessment at 111. Staff explained (*id.*):

> One interpretation of this statement is that load interruption for a single contingency is permitted, while another interpretation is that the practice is the exception rather than the rule, and for this reason load interruptions are not permitted for a single contingency except in very special circumstances where such interruption is limited to the firm load directly associated with the failure. In the case of the former interpretation, applicable entities may argue that they can deliberately interrupt firm load customers as a

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[23] Standard TPL-002, Table 1 Category B Footnote (b).

> result of the loss of a single contingency without violating any reliability standard.

TAPS strongly concurs in Staff's assessment of footnote (b). Indeed, TAPS members have experienced first hand the consequences of this ambiguity. For example, as reflected in pleadings filed with the Commission in now-terminated Docket No. EL05-38, American Electric Power ("AEP") claimed, in connection with a service agreement associated with a transmission service request, that TAPS member Oklahoma Municipal Power Authority ("OMPA") should reimburse it for advancing an additional 138 kV circuit to feed OMPA member Altus, Oklahoma, a 51 MW city served via a single 138 kV and two 69 kV delivery points. The AEP affidavit submitted in that case admits that 14% of the time the AEP plan for a first contingency is to dump the Altus load.[24] OMPA knows of no AEP retail customer afflicted by a similar "plan" for contingencies, and noted that the line to fix this problem has been in planning studies for nearly two decades. While this particular situation appears headed toward resolution, footnotes to the planning standard Table should not permit such a situation to persist for twenty years.[25]

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[24] "The longstanding 69 kV contract demand limit at Altus is 30 MW. There is no stated 138 kV contract demand limit. For 7,536 hours of 2004, the total OMPA Altus load was less than or equal to the 69 kV contract demand limit. Thus, 86% of the time, AEP has capacity in its 69 kV system sufficient to serve the entire OMPA Altus load even during a single contingency outage of the circuit that serves OMPA's 138 kV Altus delivery point. Firm transmission service does not guarantee continue service to a delivery point connected to an outaged line." January 27, 2005 Affidavit of Robert L. Pennybaker, ¶ 22, attached to the January 27, 2005 *Answer of American Electric Power Service Company to Complaint of Oklahoma Municipal Power Authority*, Docket No. EL05-38.

[25] The Altus situation, unfortunately, is not an isolated instance. Other TAPS members have similarly suffered for many years from grid inadequacies claimed to be consistent with N-1 standards, but which require curtailment of service to TDU loads in a contingency situation, causing the TDU high blackout rates and/or excessive internal redispatch costs. For example, issues regarding cost responsibility for 230 kV facilities finally constructed to deal with a decades-old problem of this nature remain pending in *Mississippi Delta Energy Agency v. Entergy Services, Inc.*, Docket No. EL04-99.

Thus, TAPS concurs in the Staff Assessment that footnote (b) and the other ambiguous footnotes "should be clarified so that they are applied appropriately and consistently by all the entities to whom they apply." Staff Assessment at 111.

Respectfully submitted,

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Attachment 1

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116-390 Village Boulevard
Princeton, NJ 08540

Re: Inadvertent Interchange Payback

Dear Mr. Gent and WEQ Executive Committee Members:

I am writing to NERC and NAESB on behalf of the Transmission Access Policy Study Group (TAPS) to request that in future consideration of the treatment of inadvertent energy, an important comparability issue does not get overlooked —*i.e.*, allowing return-in-kind treatment of inadvertent energy among control areas, while non-control area utilities are burdened with punitive imbalance charges.

The TAPS group is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access. TAPS members have been following the progress of NAESB's Inadvertent Interchange Payback Task Force (IIPTF). We were pleased to see the establishment of the IIPTF in March of 2003 with the goal of developing standards to define the alternatives that may be used to settle inadvertent interchange, particularly the mitigation of the potential financial gain that misuse of the payback-in-kind methodology does not prevent. However, we are disappointed that, after 27 months and the consideration of numerous proposals to replace the current payment-in-kind methodology of settling inadvertent energy accounts between control areas/balancing authorities, the IIPTF was unable to reach agreement on an improved system and so concluded in its June 1 memo discussing Task Force results, that "…none of the proposed solutions… better than the payback-in-kind methodology (as embodied in the NAESB Version 0 Inadvertent Interchange Payback Standard)." The result would leave a clearly discriminatory practice in place. We understand that the final IIPTF report will be considered by WEQ at its November meeting.

We also understand that NERC has asked that NAESB's Inadvertent Interchange Payback standard (WEQBPS) be transferred to NERC's and included as a reliability standard, and is drafting a Standards Authorization Requests (SAR) for this standard. (For that reason, NERC on June 24 asked FERC to defer action on NAESB's proposed Version 0 standard in FERC Docket No. RM05-5-000.) This proposed transfer will also bring aspects of this issue shortly before both WEQ (for action on the SAR) and NERC.

Thus, the inadvertent energy payback issue may soon be before NERC and/or WEQ. We ask that such consideration resolve, and not avoid, the fundamental comparability issue, rather than simply perpetuate a flawed and discriminatory system. Specifically, the payback-in-kind methodology for inadvertent energy between control areas is clearly not comparable to the treatment of imbalances experienced by non-control area utilities under FERC's open access tariffs. For non-control area utilities, return-in-kind provisions are typically limited to imbalances within a narrow 1.5% deadband, with under-deliveries beyond the deadband charged $100/MWh or 110% of incremental cost for under-deliveries (whichever is higher), with payments of 90% of decremental cost for over-deliveries. Payback in kind of inadvertent energy avoids these penalty aspects of the tariff completely. Neither the NERC nor NAESB standard should be designed to create or perpetuate competitive advantages for control area operators. This is important not only to achieve fundamental fairness, but also to avoid creating an obvious additional impediment to reasonable control area consolidation.

Whether through NAESB or NERC, the current discriminatory system of payback-in-kind should be replaced with a methodology that treats all utilities equally. As FERC, in Order 2000, concluded:[1]

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

Because much of the nation will not have RTO balancing markets any time soon, it is critical that any policies promote a non-discriminatory system to manage inadvertent energy flows. Therefore, we ask the WEQ Executive Committee to reject the recommendation of the IIPTF and direct the IIPTF to develop a methodology that does not perpetuate what FERC has recognized to be a discriminatory treatment of imbalances. To the extent the issue is transferred to NERC, NERC should do the same. If NERC and/or NAESB cannot deal with this fundamental comparability issue (*e.g.*, because sufficient consensus is not possible), they should clearly inform FERC of this problem, identifying the comparability concern as a tariff issue that should be addressed by FERC.

Very truly yours,

Roy Thilly

Roy Thilly

cc: TAPS Members
Allen Mosher, APPA

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[1] *Regional Transmission Organizations*, Order 2000, FERC Stat. & Regs. ¶ 31,089, at 31,142 (1999).

MICHEHL R. GENT
President and CEO

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

August 9, 2005

Mr. Roy Thilly
Chairman
Transmission Access Policy Study Group
Wisconsin Public Power Inc.
1425 Corporate Center Drive
Sun Prairie, Wisconsin 53590

Dear Roy:

Inadvertent Interchange Payback

This is in response to your July 22, 2005 letter to me and the NAESB Wholesale Electric Quadrant regarding the comparability between inadvertent interchange payback and energy imbalance. I understand that you and Don Benjamin talked about this in San Diego last week.

The inadvertent-energy imbalance comparability issue arose frequently within NERC committees soon after the Commission promulgated its *pro forma* tariff. In fact, this is one of the issues that resulted in NERC developing our reliability functional model.

We have debated the characteristics of inadvertent interchange over many years. Specifically:

1. Inadvertent interchange is between a balancing authority and the Interconnection, not between two individual balancing authorities. In other words, inadvertent interchange is not a bilateral arrangement.

2. Inadvertent interchange has two forms: 1.) Inadvertent caused by imperfect generation control that we call "primary inadvertent," and 2.) Inadvertent caused by Interconnection frequency error that we call "secondary inadvertent" (the result of other balancing authorities' primary inadvertent). How should the values of these different forms of inadvertent interchange be determined?

Therefore, while inadvertent interchange appears to have many of the attributes of energy imbalance, they are not the same, and I question whether they can be dealt with on the comparable basis that you are suggesting.

It appears to me that NERC and NAESB have both worked hard on inadvertent settlement methods, with NAESB's Inadvertent Interchange Payback Task Force delving into these concepts further than any group we're aware of. Despite the considerable discussions by industry experts, including economists, the IIPTF realized the practical hurdles of calculating Interconnection market prices and values for frequency response couldn't be crossed. Don explained this at the Stakeholders Committee meeting.

NERC is committed to ensure that our standards do not unduly discriminate among the responsible entities to which those standards apply. Standards that apply to balancing authorities must apply comparably to all balancing authorities. However, NERC cannot ensure that standards that apply to balancing authorities will be economically comparable to tariff rules or other protocols that apply to other transmission customers such as generators or load-serving entities, and that NERC has no influence over.

Roy, I believe NERC and NAESB have thoroughly debated inadvertent payback possibilities over many years. We believe NAESB should continue to set the on- and off-peak periods and develop whatever financial payback provisions that industry may agree upon in the future. Both NERC and NAESB have very open standards development processes that will welcome your thoughtful insight.

Sincerely,

Michael R Gent

cc: Allen Mosher, APPA
Rae McQuade, NAESB

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August 29, 2005

Michehl R. Gent
President & CEO
North American Electric Reliability Council
116-390 Village Boulevard
Princeton, NJ 08540

Re: Inadvertent Interchange Payback

Dear Mike:

Thank you for your August 8 response to my July 22 letter, which raised what TAPS members consider to be a fundamental comparability issue.

In our view, inadvertent and imbalance must be treated comparably. In contrast, based on the observation that inadvertent energy is not a bilateral arrangement and takes two forms—primary and secondary—your letter concludes that inadvertent energy is not the same as imbalance and questions whether they can be dealt with on a comparable basis.

In fact, all inadvertent interchange and imbalance energy stem from primary inadvertent. Primary inadvertent is caused by imperfect generation control within a balancing authority. Where a balancing authority is the only entity within its area, its own energy imbalance is its primary inadvertent. Where there is also a TDU within the balancing authority's area, the primary inadvertent is the net of the combined imbalances of the TDU and the balancing authority. While balancing authorities include a calculation for secondary inadvertent based on interconnection frequency, secondary inadvertent simply reflects the impact of primary inadvertent from other balancing authorities.

Providing for in-kind payback for balancing authorities at the same time monetary penalties are imposed for TDU imbalances results in financially non-comparable treatment of the same conduct: imperfect generation control within a control area. Balancing authorities' imbalances are exempt from penalties, while the same imbalances for the TDUs in its area are not, even though the TDUs' imbalances may actually offset the balancing authority's imbalance and so reduce the balancing area's primary inadvertent. The TDU should pay the cost of balancing service, but it should not be penalized when the balancing authority is not penalized for the same conduct. Similarly, the fact that inadvertent energy is not a bilateral arrangement does not justify use of a simple, non-punitive return-in-kind treatment for inadvertent energy while, for tariff customers within a balancing authority, similar imbalances are subject to significant penalties.

Michehl R. Gent
August 2, 2005
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Your letter narrowly defines NERC's job as ensuring that NERC standards do not unduly discriminate among the entities to which they apply (i.e., as among all balancing authorities), and concludes that NERC cannot ensure that the standards for balancing authorities are comparable to the treatment of others under tariffs. In contrast, we believe that NERC should not turn a blind eye to fundamental comparability issues when formulating its standards and allow its standards to perpetuate or create obvious discrimination that is not required for technical reliability-based reasons.

We also do not believe NAESB is performing its role if it adopts business standards that discriminate against a minority by reinforcing a clearly non-comparable flow of dollars – market participants subjected to substantially different financial outcomes for substantially identical behavior depending on whether they are balancing authorities. Also, based on discussions with TAPS members who participated in the process, we do not believe it was "practical hurdles … [that] couldn't be crossed" that caused NAESB's IIPTF to recommend no change, but rather a lack of consensus; the IIPTF's July 19 final report concludes (at 5): "With the lack of industry direction for a new 'inadvertent interchange payback' standard the IIPTF has inferred that the industry is satisfied with the requirements within the current NAESB Version 0 Inadvertent Interchange Business Practice Standard." From our perspective, IIPTF's inference that the "industry is satisfied" with the status quo is wrong.

Thus, we reiterate our request that NERC and NAESB address this comparability issue. However, as requested in my July 22 letter, if NERC and NAESB cannot deal with this fundamental comparability issue (because sufficient consensus is not possible), each organization should clearly inform FERC of this problem, identifying the comparability concern that has been raised as a tariff issue that should be addressed by FERC.

Sincerely,

Roy Thilly

Roy Thilly
TAPS Chair

cc: NAESB WEQ Executive Committee
TAPS Members
Allen Mosher, APPA