UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities	Docket No. RM10-23-000

**COMMENTS OF THE
TRANSMISSION ACCESS POLICY STUDY GROUP**

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Pursuant to the Commission's June 17, 2010 Notice of Proposed Rulemaking[1] and its August 10, 2010 Notice Extending Comment Period,[2] the Transmission Access Policy Study Group ("TAPS") comments on this important NOPR.

EXECUTIVE SUMMARY

As transmission dependent utilities ("TDUs"), TAPS members have long recognized that regional transmission planning and cost allocation are necessary ingredients to achieving the "right sized" grid needed to reliably deliver existing and new resources, including renewable and low-carbon resources, to load-serving entities ("LSEs"). TAPS applauds the Commission's willingness to re-visit the Order 890[3] planning process in an effort to remove obstacles to needed expansion of the grid. TAPS supports the Commission's goals and the NOPR's findings that there is a need to reform the regional and interregional transmission planning process.

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[1] 75 Fed. Reg. 37,884 (proposed June 30, 2010), FERC Stats. & Regs. ¶ 32,660 (2010) ("NOPR").

[2] eLibrary No. 20100810-3030.

[3] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) ("Order 890"), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) ("Order 890-A"), *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 Fed. Reg. 61,511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009), *review docketed*, No. 08-1278 (D.C. Cir. filed Aug. 22, 2008).

TAPS approaches this NOPR from the perspective of seeking practical solutions to getting transmission built to satisfy the reasonable needs of LSEs, and to enable them to secure long-term rights for planned and existing power supply arrangements, which Federal Power Act ("FPA") Section 217(b)(4), 16 U.S.C. 824q(b)(4), directs the Commission to facilitate. The need for reform is confirmed by the continuing frustration of TAPS members' efforts to secure long-term rights for new resources, notwithstanding Section 217(b)(4)'s express directive that the Commission enable LSEs to secure such rights. A focus on the needs of LSEs would realistically incorporate satisfaction of applicable federal and state public policy requirements. To achieve a right-sized grid, TAPS supports a "no regrets" approach to transmission planning, which focuses first on the upgrades needed to meet a range of generation scenarios, recognizing that we can't accurately predict the future. Reform is needed to more effectively promote structural solutions that the Commission has long encouraged—inclusive joint ownership arrangements that have proven highly effective in getting needed transmission built, by (among other things) mobilizing area LSEs to support the often difficult-to-secure need and siting approvals. And TAPS agrees that cost allocation can be a significant barrier to getting needed transmission built.

TAPS therefore is generally supportive of the NOPR, but urges the Commission to include the following in its final rule.

Specifically, as to regional planning, TAPS supports the requirement for regional plans, and asks the Commission to:

- In non-Regional Transmission Organization ("RTO") areas, ensure that regions are defined to facilitate achievement of the NOPR's regional planning objectives by providing guidance that a region should include at least two transmission providers ("TPs") and be no smaller than a state or reliability region.

- Require jurisdictional TPs, preferably with stakeholder consultation, to: (1) demonstrate that their existing procedures provide stakeholders the timely and meaningful access to models, assumptions and other information directed by Order 890; and (2) propose modifications to make the intended meaningful and timely stakeholder participation in a transparent and open process a reality.

- Prevent the enhanced regional planning process from increasing the TPs' ability to discriminate in favor of their own interests, particularly in non-RTO regions, by making clear that balanced decisionmaking is expected to support the additional importance of the regional planning process, and apply heightened scrutiny to the resulting transmission cost allocations and rates if TPs dominate the planning process.

- Require regional plans to be regularly updated (at least every 24 months), with each update triggering a submission of a "planning report card" to enable assessment of the effectiveness of the process.

- Require decisions as to inclusion and exclusion of upgrades in the regional plan to be supported by reasonable, non-discriminatory criteria, which should be used to resolve disputes, and make clear the Commission's backstop role for timely resolution of complaints affecting jurisdictional rates.

- Enable the regional plan to achieve its intended purposes, by requiring a timely post-plan process for: (1) securing public commitments by the TPs (or others) to build the upgrades identified in the regional plan, whereupon the upgrade can be included in the "regional base model" on which those in the region can rely as they study specific generator interconnection and transmission service requests; and (2) holding TPs and others that commit to construction of facilities included in the "regional base model" accountable for making good faith efforts to do so.

- Require jurisdictional TPs to file an annual "construction report card" on the status of the additions included in previous regional plans.

- As it did in Order 890, establish clear procedures, process milestones, and guidance to assist TPs in developing their compliance filings and to assure that TDUs and other stakeholders have a meaningful role in shaping those filings.

Concerning consideration of public policy, the Commission should:

- Require consideration of federal and state public policy requirements, including state commission and local government requirements where applicable, but do so through the lens of Section 217(b)(4). Planning for the reasonable needs of LSEs as Congress directed will produce a robust, but "right-sized" grid, capable of reliably meeting realistic generation-to-load deliveries, reflecting applicable public policy requirements in a cost effective manner. To this end, and to fulfill the Commission's obligation to enable LSEs to secure long-term rights for planned and existing power supply arrangements, the final rule should expressly recognize Section 217(b)(4), the only section of the Federal Power Act that directly speaks to transmission planning, as a public policy requirement that must be considered in the planning process.

- Reject the NOPR's proposal to authorize TPs to consider public policy objectives *not* required by state or federal law. Instead, directing adherence to Section 217(b)(4)'s mandate to plan for the reasonable needs of LSEs will incorporate realistic plans to implement policy objectives without empowering TPs to plan the grid in accordance with their own idiosyncratic, and potentially discriminatory, policy views.

Regarding the rights of first refusal ("ROFR"), the Commission should:

- Maintain the incumbent transmission owner's ("TO") ROFR only as to (a) routine reliability upgrades that do not qualify for incentives under the Commission's incentive policy; and (b) other upgrades where it is structured to provide value in getting transmission built at a reasonable cost, *i.e.*, where the TO: (1) foregoes return on equity ("ROE") rate incentives; and (2) offers meaningful (*i.e.*, load ratio share) joint ownership, on reasonable terms, to TDUs within its pricing zone (or, where appropriate, TDUs located in or providing service to customers in the state(s) where the project is or will be located, or broader area where the RTO so permits). Restructuring the ROFR to deny ROE incentives to those seeking to exercise exclusive rights, and to increase the likelihood of success in the siting and permitting process by aligning, through joint ownership, the interests of all local LSEs, strikes a balance that should favor the Commission's goal of getting needed transmission promptly sited and built.

- Not adopt the NOPR's proposed new priority for "project sponsors," which is likely to bog down the planning process in disputes that create new barriers to getting needed transmission built. If the incumbent TO does not accept TAPS' proposed ROFR conditions, the Commission should require that the opportunity to construct and finance the projects identified in the regional plan be bid out to yield the lowest cost to consumers, and favor joint ownership arrangements that enhance the ability to get projects approved and constructed.

- Clarify the NOPR's directive for minimum qualification criteria for sponsoring projects so that it does not create barriers to TDU joint ownership and participation in regional planning. Such criteria should reasonably accommodate joint ownership, including by small entities that would not have the financial resources to fund the entire project, and apply only for purposes of sponsorship—any stakeholder should be able to propose projects for consideration as part of the regional planning process.

- Reject the NOPR's proposed exemption from the regional planning process for merchant transmission projects that do not seek recovery through the regional cost allocation. Otherwise, our nation will be saddled with transmission that is inefficient, both in terms of the delivered price of electricity and utilization of scarce resources and political capital in the often difficult transmission siting process.

As to interregional coordination, TAPS urges the Commission to:

- Make clear its expectation that interregional coordination should not be a TP-only club. TDUs should have a seat at the table in developing interregional planning agreements and in their implementation.

As to cost allocation, TAPS:

- Supports the NOPR's adoption of the *Illinois Commerce*[4] "roughly commensurate" standard, but stresses the need to adhere to the Court's prohibition against assigning costs to utilities if the benefits are trivial in relation to the costs allocated. In applying these principles, the Commission should adhere to a middle ground to secure acceptance by stakeholders and state commissions, *e.g.*, for siting and other purposes.

- Supports a finding that a participant funding approach would not be acceptable as a means of cost recovery for network upgrades.

- Supports the NOPR's principle that the cost allocation method and data requirements for determining benefits and identifying beneficiaries must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed facility.

As to participation by non-jurisdictional utilities, TAPS:

[4] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470 (7th Cir. 2009) ("*Illinois Commerce*").

- Agrees with the NOPR's proposed extension of the reciprocity approach adopted in Order 890.
- Agrees with the NOPR's decision not to invoke Section 211A authority.

Finally, TAPS urges the Commission to refine the application of its incentive rate rule. That rule leaves ample room to move away from ROE incentives that increase the cost of needed transmission expansion and aggravate cost allocation and siting issues, and instead to focus on incentives that reduce risks in the early stages of the process and support cash flow (*e.g.*, Construction Work in Progress ("CWIP"), precertification expense) without increasing life-cycle costs. The ROFR debate and the NOPR's proposed sponsorship priority highlight that transmission expansion with rate base recovery is a sought-after privilege, not a burden requiring returns above the level otherwise reasonable. If the Commission nevertheless retains ROE incentives and rejects TAPS' proposal to condition the ROFR on a commitment not to seek ROE incentives and to offer joint ownership to TDUs, it should tie ROE incentives to inclusive joint ownership arrangements that have a proven track record of helping to get transmission built.

INTEREST OF TAPS

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[5] As entities entirely or predominantly dependent on transmission facilities owned and controlled by

[5] TAPS is chaired by Roy Thilly, CEO of WPPI Energy ("WPPI"). Current members of the TAPS Executive Committee include, in addition to WPPI, representatives of: American Municipal Power, Inc.; Blue Ridge Power Agency; Clarksdale Public Utilities; Connecticut Municipal Electric Energy Cooperative; ElectriCities of North Carolina, Inc.; Florida Municipal Power Agency; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric; Missouri Public Utility Alliance; Missouri River Energy Services; NMPP Energy; Northern California Power Agency; and Oklahoma Municipal Power Authority.

others, TAPS members recognize the importance of a robust transmission grid, and have long advocated policies to get needed transmission built. *See* TAPS, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost (June 2004).[6] Recognizing the importance of regional planning, TAPS participated in the negotiation of the Regional Transmission Group ("RTG") provision that came close to being included in the 1992 Energy Policy Act, and was subsequently embodied to a significant extent in the Commission's RTG Policy Statement.[7] TAPS submitted initial and reply comments in Docket No. AD09-8-000, the proceeding leading up to the instant NOPR.[8]

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[6] *Available at* http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf.

[7] The Commission's Regional Transmission Group Policy Statement is set forth in 18 C.F.R. § 2.21 *et. seq.* *See* Policy Statement Regarding Regional Transmission Groups, 58 Fed. Reg. 41,626 (Aug. 5, 1993), FERC Stats. & Regs. ¶ 30,976 (1993) ("RTG Policy Statement"). *See also* Notice of Request for Public Comments on Regional Transmission Group Proposal, 61 FERC ¶ 61,232 (1992).

[8] *See* Comments of the Transmission Access Policy Study Group (Nov. 23, 2009), eLibrary No. 20091123-5154; Reply Comments of the Transmission Access Policy Study Group (Dec. 18, 2009), eLibrary No. 20091218-5145.

COMMENTS

I. REFORM IS NEEDED TO BETTER ACHIEVE A RIGHT-SIZED GRID THAT MEETS THE NEEDS OF LOAD SERVING-ENTITIES

TAPS agrees with the NOPR that the current planning process is not creating a sufficiently robust grid. Order 890 made a good start toward achieving a timely, inclusive and transparent transmission planning process, but it should be supplemented by an enhanced regional and interregional planning process, with Commission guidance on regional and interregional cost allocation.

A. Need to Focus on the Reasonable Needs of Load-Serving Entities

The NOPR identifies as a deficiency in the Order 890 planning process the failure to explicitly include state and federal public policy requirements, in addition to consideration of projects needed for reliability and economics. *See* NOPR, PP 36-37.[9] TAPS' perspective is informed by Section 217(b)(4),[10] the sole provision of the Federal Power Act that expressly addresses planning. Section 217(b)(4) provides:

> The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

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[9] As described in Parts II.A and II.B below, TAPS identifies other specific deficiencies in the Order 890 planning process (*i.e.*, denial of timely access to models; leaving responsibility for planning with the TP, without providing for accountability) and proposes solutions.

[10] 16 U.S.C. § 824q(b)(4), enacted as part of the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) ("EPAct 2005").

The Commission should fulfill Section 217(b)(4)'s mandate to facilitate planning for the reasonable needs of load-serving entities and for long-term rights for new and existing power supply arrangements. The objective of the planning process should be to determine what transmission facilities are required to meet these needs on a cost-effective, highly-reliable, and environmentally-responsible basis, taking account of alternative generation development scenarios, aggressive energy conservation and efficiency programs, and distributed generation potential. The criteria for adequacy should include transmission facilities needed to:

- develop new resources, including renewable and other low-carbon resources, that meet the reasonable needs of load serving entities;
- deliver new and existing generation to meet regional reserve requirements;
- grant new long-term transmission rights ("LTTRs") to LSEs for their new long-term resources and prevent the diminishment over time of existing long-term transmission rights;
- relieve congestion, minimize seams issues, and ensure that designated network resources are not trapped in generation pockets; and
- provide LSEs with optionality to meet their service obligations economically through access to diverse resources.

A focus on the needs of LSEs, as directed by Section 217(b)(4), will automatically incorporate satisfaction of the public policy mandates imposed on LSEs.

As required by EPAct 2005, the Commission has issued a rule implementing Section 217(b)(4) in organized markets.[11] However, the adequacy of the grid to support

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[11] Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 71 Fed. Reg. 43,564 (Aug. 1, 2006), FERC Stats. & Regs. ¶ 31,226 (2006) ("Order 681"), *corrected*, 71 Fed. Reg.

the needs of LSEs remains a significant problem, especially when it comes to long-term transmission rights for new resources. Despite the clear statutory directive and several years of implementation experience, LSEs in various RTOs are increasingly concerned about their inability to secure long-term transmission rights for new resources. Although the Commission has recognized that planning for long-term rights was an important part of the Section 217(b)(4) directive[12] and expressly required planning to maintain long-term rights to be integrated into the RTO planning process,[13] the problems that Congress sought to address have persisted, especially as to the long-term rights for "planned" long-term power supply arrangements specifically addressed by Section 217(b)(4).

For example, under the Midwest ISO's ("MISO") current long-term transmission rights system, it is almost impossible for a new baseload generation resource to obtain new long-term rights, even when all transmission upgrades required to support Network Resource designation are completed. During the two annual allocation processes that have been conducted since the current long-term transmission rights system was established by MISO, virtually no such long-term rights were allocated.[14] TAPS member

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46,078 (Aug. 11, 2006), *clarified*, Order No. 681-A, 71 Fed. Reg. 68,440 (Nov. 27, 2006), 117 FERC ¶ 61,201 (2006), *clarified*, Order No. 681-B, 74 Fed. Reg. 13,103 (Mar. 26, 2009), 126 FERC ¶ 61,254 (2009).

[12] *See, e.g.*, Order 681, P 453 ("FPA Section 217(b)(4) requires the Commission to exercise its authority under the FPA in a manner that facilitates the planning and expansion of transmission facilities, and to enable load serving entities to obtain long-term firm transmission rights. To implement that section in a transmission organization with an organized electricity market, as required by section 1233(b) of EPAct 2005, we believe that the transmission organization must plan its system to ensure that allocated or awarded long-term firm transmission rights are feasible.").

[13] *Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,062, P 48 (2007), *order on reh'g*, 123 FERC ¶ 61,178 (2008).

[14] In the past two years, no LSE has been able to add a new resource to its Baseload Reserved Source Set—which is a prerequisite to asking for the associated LTTRs—except for approximately 50 MW in the fall season, and then only for the off-peak hours. *See* Midwest ISO, RSP/PTP Addition/Replacement Results for 2010-2011 at 2 (Jan. 6, 2010), *available at* http://www.midwestmarket.org/publish/Document/538398_1259d29a2bd_-7eae0a48324a?rev=4 (Item 08).

WPPI Energy ("WPPI") sought long-term rights for its share of the new Elm Road Generating Station. Neither WPPI nor any of the other joint owners of those units—two 600 MW supercritical coal units located in Wisconsin, about forty miles from WPPI's load center, and currently the cleanest and most efficient coal plant in the Midwest—has been able to obtain long-term transmission rights for more than a small fraction of the deliveries from the plant.[15] Notwithstanding the fact that the American Transmission Company has constructed $2.2 billion of transmission upgrades to improve the grid in Wisconsin and the Upper Peninsula of Michigan, MISO has rejected almost all requests for new long-term rights.

MISO's long-term transmission rights system likewise provides no mechanism for LSEs to plan for and assure the availability of long-term rights for their planned new long-term power supply arrangements—even when MISO has ample advance notice. For example, the Prairie State Project—two supercritical, mine-mouth coal units with a nominal net output capacity of 800 MW each—are scheduled to commence commercial operation in 2011 and 2012. Their development is no surprise; the units have been under full construction since October 2007, and planned long before that date. Under MISO's long-term rights system, however, none of Prairie State's municipal and cooperative owners can even apply for an allocation of long-term transmission rights until just before the units begin running, and there is no assurance that *any* long-term rights will be available for allocation at that time.

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[15] WPPI's share of the Elm Road Project is 102.459 MW. It received only a long-term transmission rights allocation of 47.4 MW for the fall season, off-peak hours. WPPI's request for long-term rights for all other seasons, and for the peak hours of the fall season, was rejected. Another joint owner of the Elm Road Project received only a fall season, off-peak LTTR allocation; the third joint owner received no LTTRs for its share of the Elm Road Project in any season or period.

The expected growing reliance on low-carbon resources makes this problem worse. Wind resources will not be located near load, nor will nuclear. And carbon capture is limited to where the geology supports it. LSEs will find it hard to support commitment to the purchase power agreements needed to finance these resources if they cannot obtain the long-term rights to obtain delivered cost certainty. Given the often-remote location of new generation resources, the unavailability of long-term transmission rights required to assure delivery at reasonable, predictable cost is a serious issue for LSEs that must commit to new long-term resources to serve their customers, and therefore for developers that need LSE purchase power agreements for financing.

B. Need to Focus on Achieving a Right-Sized Grid

In recognizing that we need a robust, adequate, reliable transmission system that satisfies Section 217(b)(4), TAPS emphasizes the need to plan for a "right-sized" grid. "Right-sized" means a reliable system that is neither under- nor over-built, with adequate facilities to relieve congestion, minimize seams issues, and enable the delivery to load of generation (both existing and new resources, including but not limited to renewable and low-carbon resources). Generation and transmission should be considered together, in order to ensure that an economical, integrated electric system is built and maintained for the benefit of consumers. While such processes are underway in some regions or subregions (*e.g.*, the Upper Midwest Transmission Development Initiative[16] and the New England 2030 Power System Study[17]) such a process is not in place in all regions.

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[16] The Upper Midwest Transmission Development Initiative ("UMTDI") was launched in 2008 by Minnesota, Iowa, Wisconsin, North Dakota and South Dakota to promote regional electric transmission investment and cost sharing among the states. The initiative is led by utility commissioners and representatives from those states' governors' offices and coordinates efforts among entities involved in transmission matters, including state regulatory agencies, transmission companies, utilities, independent generation owners and other key stakeholders. In June of 2009, UMTDI released cost sharing principles

We support the NOPR's recognition of DOE-funded interconnection-wide efforts now underway, without mandating interconnection-wide planning (*see* PP 112, 114) or prejudging the outcome and assuming (as some have urged) that the nation needs 765 kV overlay lines to deliver renewable resources to load. The 765 kV vision, with its associated hefty price tag (which will be further inflated by the incentive return on equity the Commission has already awarded to lines that have been announced in advance of their inclusion in a regional planning process[18]), is not only impeding the ability to reach consensus solutions on cost allocation, but may be misguided. The assumption that we need 765 kV lines to deliver wind from the Midwest to the East Coast may be wrong for any number of reasons—including the desire of states and regions to develop their own renewable resources (*i.e.*, as governors and state legislatures seek to spur local economic development);[19] the astronomical all-in costs of wind power transported over long

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which outline the policy parameters for developing a multi-state agreement on developing and sharing costs for an upgraded transmission network. Included among the eight principles is the requirement that transmission planning include regional impacts. Upper Midwest Transmission Development Initiative, Regional Electric Transmission Planning in the Upper Midwest to Support Wind Energy 3 (2009), *available at* http://www.misostates.org/UMTDI%20To%20Support%20Wind%20Energy.pdf. For more information, *see* http://www.misostates.org/UMTDIList.htm.

[17] The New England 2030 Power System Study was undertaken by the ISO-New England at the request of the governors of Connecticut, Maine, Massachusetts, New Hampshire, Vermont, and Rhode Island. The report "identifies potential transmission to integrate a range of renewable resource expansion scenarios and preliminary cost estimates for this transmission." New England-ISO, New England 2030 Power System Study 7 (2010), *available at* http://www.nescoe.com/uploads/2009_Economic_Study_Final_Report.pdf. *Also see* New England Governors' Conference, Inc., New England Governors' Renewable Energy Blueprint (2009), *available at* http://www.negc.org/documents/2009/Renewable_Energy.pdf.

[18] *See, e.g., Green Power Express LP*, 127 FERC ¶ 61,031, P 80 (2009); *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281, P 56 (2009); *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, P 58 (2008).

[19] Some state renewable portfolio standard ("RPS") statutes even include local generation and/or deliverability requirements. For example, the Ohio utilities subject to that state's RPS must meet half of their renewable generation obligation with power generated from renewable generating facilities within the state. The other 50% must be met with power that is deliverable into the state. *See* Ohio Rev. Code § 4928.64(B)(3). Michigan utilities are also required to meet the state's renewable portfolio requirements largely from Michigan resources. *See* State of Michigan Clean, Renewable, and Efficient Energy Act, 2008 Pub. Acts 295, Mich. Comp. Laws §§ 460.1001-460.1195.

distances (inclusive of transmission, energy, marginal losses, and back-up capacity); development of wind resources offshore of the East Coast and in the Great Lakes; increased installation of distributed generation, including solar; and growing reliance on demand response.

Properly taking the cost of the associated transmission upgrades into account could result in a very different and more efficient geographic distribution of renewable resources that relies more heavily on local resources with lower total delivered costs. A recent study performed by Burns & McDonnell for WPPI, for example, developed an economic model to assess the viability of transporting wind energy from wind-rich areas in the northern Midwest to Eastern load centers.[20] As part of this evaluation, Burns & McDonnell estimated the financial trade-off between: (1) developing wind projects in wind-rich areas and constructing the necessary electric transmission infrastructure to transfer energy from those projects to load centers; or (2) developing wind projects near the load centers, despite a less attractive wind resource in those locations. Even based on the simple, two-dimensional economic criterion used by the study—*i.e.*, setting aside siting issues, public policy favoring local renewable generation, the reliability and power supply benefits of geographic diversity, and other factors—the report demonstrates that reliance on remote, Upper Midwest wind resources may not be the most cost-effective way of meeting national renewable energy goals. Closer, but lower-capacity-factor, wind

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[20] Burns & McDonnell, Wind Energy Transmission Economics Assessment, Prepared for WPPI Energy (March 2010), *available at* http://www.wppienergy.org/media/WPPI_Wind_EnergyTransmission_Economics_Assessment.pdf.

resources may well provide comparable renewable energy benefits while imposing a smaller economic burden on consumers.[21]

We suggest that regional and interregional processes focus initially on immediate steps that can be taken to significantly reinforce the grid to meet the needs of LSEs and the customers they serve, while providing flexibility for the future. Wise investment of transmission dollars would first concentrate on the major grid reinforcements that will be needed under a range of different scenarios, while building in optionality for future development. For example, planners could initially consider the significant upgrades required to deliver Midwest wind to Midwest load centers and rely on displacement to reach further eastward. To achieve this end, 345 kV lines to Midwest load centers can be reinforced using oversize towers and rights-of-way that will permit the cost-effective addition of a second circuit if needed at a later date. Similarly, DC collector points could be included in the design to facilitate implementation of DC options if that proves to be needed given the expected distribution of new resources, including renewables. By moving quickly to implement incremental, but substantial, "no regrets" steps, recognizing where we want to get to, we can achieve a robust, "right-sized" grid at a much lower cost, thereby minimizing difficult cost allocation issues and effectively accommodating the varying renewable generation criteria and policies of different states. Although the option of building 765 kV "overlay" lines should not be ruled in or out at this time, development of such facilities requires careful, disciplined study. Thus, it makes sense to first move forward with the reinforcement of the underlying system that will be required in any event.

[21] *Id.*, Cover Memo at 1.

The California ISO has proposed a similar approach to the planning needed to meet that state's 33% renewable portfolio standard. CAISO's June 4, 2010 filing of its *Revised Energy Transmission Planning Process* would establish a process for identifying Category 1 policy-driven transmission elements based on a "least regrets" evaluation of alternative generation scenarios.[22] In a proceeding where many issues are disputed, the "least regrets" concept appears to appeal to most parties.

The approach TAPS is suggesting is consistent with that successfully undertaken by CapX 2020, a joint transmission-planning process in the northern Midwest. CapX consists of eleven investor-owned, municipal, and rural cooperative utilities in Minnesota, North and South Dakota, and Wisconsin that have jointly planned needed transmission upgrades and now all have opportunities to jointly own those facilities.[23] CapX planners evaluated various generation scenarios, and started by focusing on the substantial transmission facilities that were always required, regardless of the generation scenario studied. In its first phase, CapX is seeking to build four backbone transmission lines—three 345 kV lines and one 230 kV line—to significantly strengthen the Minnesota transmission system.[24] These facilities are designed to meet the load-serving and reliability needs of all 11 participating utilities, and provide the common infrastructure to reach new sources of supply. The first phase is estimated to cost about $2 billion,[25] and additional "partner project" related upgrades are required on individual systems.

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[22] CAISO Filing Letter at 5, *Cal. Indep. Sys. Operator Corp.*, Docket No. ER10-1401-000 (June 4, 2010), eLibrary No. 20100607-0203.

[23] *See* CapX2020 frequently asked questions, http://www.capx2020.com/faq.html (last visited Sept. 10, 2010).

[24] *Id*.

[25] *See id*. CapX is beginning to plan its later phase projects. They will be focused primarily on enabling

CapX participants worked hard to inform the public of the need for the projects and collaborated with local government officials, regulators, and landowners to work out the most acceptable configuration and routes for the projects. All four projects have received a Minnesota Certificate of Need,[26] and are at various stages of the process for obtaining a Minnesota Route Permit.[27] One of the projects, the 230 kV line, had no interventions at all filed in the Minnesota Certification of Need proceeding.[28] For the others, the primary issues raised are that the use of the lines should be restricted to transmission of renewable energy (which represents an engineering impossibility) and that the proposed single-circuit 345 kV lines may not be large enough.[29] Minnesota regulators ultimately required that those proposed facilities be "upsized" (*i.e.*, built to accommodate double-circuit 345 kV lines).[30] This experience shows the benefits of

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area utilities to meet their renewable energy needs under state law. The cost estimates range between $4 and $7 billion.

[26] *In re Great River Energy*, Docket No. CN-06-1115 (Minn. Pub. Utils. Comm'n May 22, 2009), *modified*, Docket No. CN-06-1115 (Minn. Pub. Utils. Comm'n Aug. 10, 2009), Document ID No. 20098-40627-01 ("*Great River Energy*"), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={BE377BE8-DEF9-4763-910A-70523BD56C8F}&documentTitle=20098-40627-01; *In re Otter Tail Power Co.*, Docket No. CN-07-1222 (Minn. Pub. Utils. Comm'n July 14, 2009), Document ID No. 20097-39617-01, *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={EA1BC6A6-C854-48F1-9CEB-51568E6A6178}&documentTitle=20097-39617-01.

[27] *N. States Power Co.*, Docket No. TL-09-246, (Minn. Pub Utils. Comm'n July 12, 2010), Document ID No. 20107-52483-01, *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=viewDocument&documentId={C13A6C8C-5AB3-420C-90D1-160125E7F21C}&documentTitle=20107-52483-01&userType=public; *In re Great River Energy*, Docket No. TL-08-1474 (Minn. Pub. Utils. Comm'n Sept. 14, 2010) Document ID No. 20109-54429-01, *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={22E8FC0B-0F17-4E60-96D0-C02861982101}&documentTitle=20109-54429-01; *see Otter Tail Power Co.*, Docket No. TL-07-1327 (Minn. Pub. Utils Comm'n); *N. States Power Co.*, Docket No. TL-09-1056 (Minn. Pub. Utils. Comm'n), *N. States Power Co.*, Docket No. TL-09-1448 (Minn. Pub. Utils. Comm'n).

[28] *See In re Otter Tail Power Co.*, Docket No. CN-07-1222 (Minn. Pub. Utils. Comm'n).

[29] *Great River Energy* at 43.

[30] Order Granting Certificates of Need with Conditions, *In the Matter of the Application of Great River*

inclusive ownership arrangements that galvanize broad support for projects and is certainly very different from the usual.

C. Need for Inclusive Ownership Structures to Get Transmission Built

The CapX success in getting transmission expansion approved is similar to successes achieved elsewhere where an inclusive ownership model has been adopted. Another example of the success of inclusiveness is the American Transmission Company, LLC ("ATC"), the load-serving-entity-owned transmission company located primarily in Wisconsin and the Upper Peninsula of Michigan. ATC is owned by 5 investor-owned utilities, 17 municipal utilities, and 6 rural cooperatives. This single purpose transmission company has a legal obligation to meet the needs of all of the load-serving entities in its footprint and to provide a robust grid to support wholesale competition. To date, ATC has brought approximately $2.2 billion of new transmission into rate base and has plans for an additional investment of $3.4 billion over the next 10 years.[31] ATC has experienced no rejections of its applications to construct, most have proceeded expeditiously, and there have been no complaints filed against ATC at this Commission.

Experience has shown that joint ownership structures, whether they be pooled systems as in Georgia, Indiana, and Minnesota or a load-serving entity transco as in Wisconsin and Vermont, lead to a collaborative and inclusive process for planning and

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Energy, Northern States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for the CapX 345-kV Transmission Projects, Docket Nos. ET-2, E002, CN-06-1115 (May 22, 2009), *available at* http://energyfacilities.puc.state.mn.us/documents/19120/CapX%20Con%20Order.pdf.

[31] American Transmission Company 2010 Ten-Year Assessment, *available at* http://www.atc10yearplan.com/R1.shtml (last modified Sept. 2010) ("ATC Ten-Year Assessment"). While ATC's transmission plan does account for proposed new generation in the ATC footprint, including renewable energy, it does not yet take into consideration the transmission needed to integrate potential offshore Great Lakes wind or planned changes in the energy portfolio of interconnected regions. *See id.*, Planning Factors & Regional Planning.

development, which TAPS believes has been proven to be highly effective in getting transmission sited and built that accommodates all needs.[32] As confirmed by others,[33] the benefits of joint ownership include:

1. It makes joint planning real. While Order 890 and this NOPR include provisions that promote joint planning, there is a big practical difference when all LSEs are at the table as owners. When diverse parties are owners, openness and transparency flow automatically.

2. Joint ownership results in a better and more efficient transmission system planned to meet multiple needs. This has been the experience of TAPS members in Wisconsin where combining five systems into one has certainly led to a more rationally developed system than balkanized planning and construction. We also see it in CapX, where the utilities have taken a proactive approach, looking at all of their load-serving and reliability needs, and different potential generation development scenarios, to develop a common backbone that will best meet their needs, regardless of where generation is developed in the future. This is a far better approach than a reactive approach, planning for discrete transmission or interconnection requests after the requests are made.

3. The diverse support that joint ownership provides is very important in siting. All siting is local. By meeting the needs of multiple utilities, a joint project is able to demonstrate multiple local benefits. Although participation by municipals and cooperatives may be relatively small percentage-wise, these utilities bring a wealth of political support to the state approval process. This support can make all the difference in speeding up the permitting process and addressing local concerns.

4. Joint ownership arrangements such as CapX and the ATC provide the critical allignment of interests that make the job of state regulators much easier. Transmission siting decisions are not easy for state commissions. When they can deal with projects that are least-cost because they meet multiple needs, they see unity among the utilities on need, and are faced with a broad base of support from diverse stakeholders, it is far easier for them to grant the needed authorizations.

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[32] *See* TAPS, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost (June 2004), http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf.

[33] *See, e.g.*, Transcript of the October 14, 2008 Technical Conference on Transmission Barriers to Entry at 58, Docket No. AD08-13-000, eLibrary No. 20081014-4031 ("Oct. 14 Tr.") (Paul McCoy from Trans-Elect describing as positive Trans-Elect's experience with public power involvement both in the Western Interconnect and Michigan, and concluding: "[T]o the extent that we would have a willing public power partner in a locale that we could take a walk with and resolve the process, we would view that as very positive."); *id.* at 59 (Tom Wray, Sunzia Transmission Project: "our experience with Sunzia has been truly positive partnership [with] public power"). *See also id.* at 12-14, 59-60 (Richard Hayslip from the Salt River Project describing joint ownership arrangements and the positive experience of working together to address challenges).

5. Joint ownership makes the cost allocation issue easier to resolve, although it still remains a thorny issue. For instance, the transmission rates paid by TAPS member WPPI have gone from $1.30 per kW up to $4.26 per kW since ATC was formed because of ATC's major construction program. That is a very large increase, but WPPI and the other municipal and cooperative owners have been able to offset about 30% of that increase through their ownership. This has made it much easier for them to support the build-out that is necessary. Similarly, investor-owned utilities that are able to participate in projects have an earnings opportunity, rather than simply an opportunity to pay.

6. Joint ownership spreads the risk of major projects broadly and provides a variety of sources of capital for projects. In a post-financial-crisis world of tightened credit and tougher credit-worthiness standards, the financial diversity and strength achieved through joint ownership arrangements should be increasingly valuable. Rating agencies have recognized that ATC's inclusiveness is a significant benefit.[34]

7. The broad base of support achieved through joint ownership arrangements can also be essential to securing state legislative action required to better align retail rate recovery with the need for supporting major transmission investment, as has occurred in Minnesota with the full support of the CapX group.

8. Where there is joint ownership (pooled systems, LSE transcos, or large joint facilities), there are typically far fewer disputes before the Commission.

Despite the Commission-recognized success of joint ownership models in getting transmission planned and sited,[35] it remains the exception despite efforts of TAPS members to seek joint ownership opportunities.[36] Order 890 (PP 593-594; Order 890-A,

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[34] Fitch Report, Attachment 2 to the Comments of Wisconsin Public Power Inc., Electricity Market Design and Structure, Docket No. RM01-12-000 (Mar. 12, 2002), eLibrary No. 20020314-0339.

[35] *See* Oct. 14 Tr. 55-56 (Commissioner Spitzer: "I can tell you from a very personal experience, having public power and some large, some small participating power lines have a great deal of cachet and a great deal of ability to move the ball forward in that regard in expediting the process.")

[36] *See id.* at 129, (Commissioner Spitzer); *see also* Comments of Connecticut Municipal Electric Energy Cooperative to Technical Conference on Transmission Barriers to Entry, Docket No. AD08-13-000 (Nov. 13, 2009), eLibrary No. 20081113-5064 (describing the difficulty public power organizations and individual transmission systems encountered in New England when attempting to pursue joint investment in new transmission with Regional Transmission Owners); Comments of Transmission Access Policy Study Group at 3 & n.6, Promoting Transmission Investment Through Pricing Reform, Docket No. RM06-4-000 (Jan. 11, 2006), eLibrary No. 20060111-5132 (noting the unsuccessful efforts of efforts of certain TAPS members to invest in the rebuilding of the Katrina-damaged Entergy system); Comments of Lafayette Utilities System, Mississippi Delta Energy Agency, the Clarksdale Public Utilities Commission, *et al.* at 22-23, Preventing Undue Discrimination and Preference in Transmission Service, Docket No. RM05-25 (Nov. 22, 2005), eLibrary No. 20051123-0080 (describing those entities' thwarted efforts to invest in the Entergy system).

P 264) encouraged joint ownership,[37] but the right of first refusal, combined with the potential for hefty return on equity incentives that TOs can pocket themselves, operate to discourage joint ownership.

There should be opportunities for joint ownership in projects that emerge from the planning process for TDUs that are located in or provide service to customers in the pricing zone or the state(s) where the project is or will be located (or a broader region where an RTO or ISO so provides)—particularly if the TDU will be required to bear the cost of the facility. Any right of first refusal should be conditioned on the TO offering TDUs meaningful (*e.g.*, load ratio share) joint ownership on reasonable terms and committing not to seek ROE incentives. At minimum, where joint ownership has not been offered to public power, cooperative, and other smaller load-serving entities on a reasonable basis (or where TDU offers have been rebuffed), no incentives should be granted.

D. Need for Commission Guidance on Cost Allocation, Particularly on a Regional and Interregional Basis

TAPS agrees that cost allocation can be a significant barrier to getting needed transmission built and concurs in the NOPR's summary of the serious challenges associated with addressing cost allocation. As described in the NOPR (P 40), cost allocation is a very difficult problem, even within RTOs. For example, in conditionally accepting amendments to the Midwest ISO's cost allocation for generator interconnection-related network upgrades on an interim basis, the Commission "recognize[d] that cost allocation is one of the most difficult and contentious issues

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[37] This NOPR mentions joint ownership only in passing, as a cost sharing mechanism it has permitted. NOPR, P 141.

facing the Midwest ISO region at this time."[38] The issue was so contentious that two TOs had stated an intent to withdraw from MISO because of the then-current generator interconnection cost allocation methodology.[39]

The many proposals for crisscrossing the nation with 765 kV overlay lines have greatly complicated the already very difficult cost allocation debate. The staggering costs of those proposals, bloated by unnecessary rate of return incentives, enormously raise the stakes and make compromise much harder.

It is very challenging to figure out what is a "just and reasonable" allocation of long-lived transmission facilities, whose use and beneficiaries change over their lives, with changes in grid topology and usage over time. General allocation rules have the potential for unintended consequences,[40] but case-by-case allocation is impractical to support timely construction. While some Order 890 compliance filings made progress on inter-TP cost allocation issues, others did not, but were still found compliant.[41]

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[38] *Midwest Indep. Transmission Sys. Operator, Inc*., 129 FERC ¶ 61,060, P 2 (2009).

[39] *Id.* P 10.

[40] *See, e.g.,* Informational Compliance Filing of the Midwest Independent Transmission System Operator, Inc. at 5, 10-12, *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER06-18-000 (Aug. 29, 2009), eLibrary No. 20080903-0303 (describing the inability to get any projects to qualify as Regionally Beneficial).

[41] *See, e.g., Southwest Power Admin.*, 127 FERC ¶ 61,173, P 53 (2009) (emphasis added) (accepting as Order 890-compliant a filing that left cost allocation to SWPA's discretion:

> We find that Southwestern has addressed the concerns of the Southwestern Planning Order regarding the cost allocation principle of Order No. 890. Southwestern has revised Attachment O to state clearly that its participation in the SPP cost allocation methodology, and in particular the allocation of costs associated with economic projects, will be governed by the SPP/Southwestern Agreement. *That agreement provides that SPP will propose the allocation of costs associated with upgrades within the SPP footprint, including on the Southwestern system, and that Southwestern will respond to SPP as to the allocation it accepts.*

See also Midwest Indep. Transmission Sys. Operator, Inc., 123 FERC ¶ 61,164, P 77 (accepting MISO's Order 890 transmission planning cost allocation provisions despite the fact that they did not address allocating costs of inter-RTO projects, but instead accepting MISO's statement "that it is working with PJM to address cross-border cost allocation for network upgrades.").

At the same time, the Commission has allowed participant funding, which is a recipe for a weak grid where virtually nothing gets built. This fundamental deficiency is perhaps most evident in the transmission system of Entergy, a prominent proponent of participant funding. When TDUs seek to add new network resources (or to become network customers and add resources), they are faced with claims for hundreds of millions of dollars in upgrades to fix problems on the Entergy grid that have existed for years due to Entergy's grid starvation policy.[42]

It's time for the Commission to directly address and provide for rates that cross TP and regional boundaries. TAPS agrees with the NOPR's adoption (P 173) of the *Illinois Commerce Commission* "roughly commensurate" standard, but stresses the need for the Commission, in implementing such rates, to abide by and give effect to the Court's prohibition against assigning costs to utilities if the benefits they would receive are trivial in relation to the costs allocated. *Illinois Commerce*, 576 F.3d at 476.

II. REGIONAL PLANNING

The NOPR proposes to build on the Order 890 planning process by requiring the regional process to produce a regional transmission plan, by explicitly expanding the objectives of the regional planning process, and by tying cost allocation to inclusion of upgrades in the regional plan. The purpose of these and other interrelated reforms is to improve the results of the regional and interregional planning process to overcome the incentives to delay needed transmission construction (NOPR, P 40), identify "the

[42] *See, e.g.*, Transcript of the Joint FERC and State Regulator Conference on the State of Transmission in the Entergy Region Before the Federal Energy Regulatory Commission, Arkansas Public Service Commission, Louisiana Public Service Commission, Mississippi Public Service Commission, Public Utility Commission of Texas and Council of the City of New Orleans, Entergy Services, Inc. at 166, Docket Nos. ER05-1065-000, ER09-555-000 (June 24, 2009), eLibrary No. 20090624-4012 ("Entergy Transcript").

facilities best suited to meet the needs of a particular region" (NOPR, P 35), and enable more facilities included in the plan to move forward to construction (NOPR, P 42).

TAPS generally supports the NOPR's proposal to enhance the value and importance of the regional planning process. And we generally agree with the NOPR's proposal to bring difficult cost allocation issues into that process and tie cost allocation to the regional plan. However, to carry the weight of the heightened significance of the regional planning process, the Order 890 principles need to be reinforced.

A. Need for Commission Guidance that in Non-RTO areas, a Region Should Include at Least Two TPs and Be No Smaller Than a State or Reliability Region

The NOPR proposes to "require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan." NOPR, P 50. TAPS supports this directive and urges the Commission to supplement it with more specific requirements that planning regions in areas outside of RTOs: (1) include at least two TPs; and (2) be at least as large as the smaller of a state or one of NERC's Regional Entities.

The Commission has long recognized that regional planning "should encompass an area of sufficient size and contiguity to enable members to provide transmission services in a reliable, efficient, and competitive manner." RTG Policy Statement at 30,873. Order 2000 likewise requires RTOs to have an "appropriate region" of sufficient scope and configuration to permit the RTO to maintain reliability, efficiently perform its functions, and support non-discriminatory power markets.[43] Although these

[43] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809, 859 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089, at 31,076 (1999) ("Order 2000"), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *appeal dismissed for want of standing sub*

geographic scope requirements have sometimes been honored in the breach, the final rule should require that the new planning regions have a scope and configuration that accommodates the planning purposes identified by the Commission (*e.g.*, to address congestion and plan for renewables), precluding regional scope definitions that fail to encompass natural trading partners and highly integrated systems.

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

According to TAPS member ElectriCities, which is a participant in the North Carolina Transmission Planning Collaborative ("NCTPC"):

> We have already seen significant benefits from using a cooperative regional approach, such as: better modeling of the transmission system, improved information about loads and resources, standardized assumptions and planning criteria, coordinated efforts for investment in new transmission facilities, and improved solutions due to the new ideas generated by diverse stakeholders.[44]

The experience of the NCTPC illustrates the very substantial benefits that can be realized through joint, collaborative planning. During the early 2000s, ElectriCities was

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nom. Pub. Util. Dist. No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[44] Letter from Clay Norris (then ElectriCities Division Director, Planning) to Commissioner Nora Brownell at 1, Preventing Undue Discrimination and Preference in Transmission Services, Docket No. RM05-25-000 (Apr. 11, 2006), eLibrary No. 20060411-4004.

investigating power supply options for one of its member municipal power agencies. At that time, ElectriCities was told that there was no transfer capability from the western part of the state to load centers in eastern North Carolina due to phase angle problems. In studying the issue on its own, the TP had examined a number of traditional transmission solutions that involved building new lines to relieve the flows causing the problem. Based on these studies, the estimated cost of relieving the constraint was in excess of $300 million. By implementing a collaborative planning process in North Carolina, the process participants shared technical and planning expertise that resulted in improved modeling of the combined North Carolina transmission systems and consideration of more extensive sets of transmission solutions. This often involved brainstorming sessions that considered technologies used elsewhere but in different applications, specifically, in this case, the use of 500 kV thyristor controlled series reactors. Within a year after the North Carolina stakeholders began working together through the NCTPC, they had jointly developed a transmission solution that produced around 600 MW of transfer capability across the previously constrained interface—for a cost of less than $20 million.

Each planning region outside an RTO should therefore include at least two TPs, in addition to TDUs. Involving multiple TPs should capture some of the synergies discussed above.

In addition, planning regions outside an RTO should be no smaller than the smaller of one state, or of the footprint of one of NERC's Regional Entities within the state.[45] While the benefits of joint planning do not necessarily stop at the state line, siting

[45] The Florida Reliability Coordinating Council ("FRCC"), for example, is one of NERC's Regional Entities. Although smaller than the state of Florida, its footprint and existing regional transmission planning process cover all the TPs in Peninsular Florida east of the Apalachicola River. Areas west of the

and retail rate treatment of new facilities may sometimes be expedited by limiting the number of states within the regional plan footprint.[46] Where a multi-state region is needed to satisfy the two-TP minimum, that should be the minimum size permitted.

Although the Commission declined to adopt specific scope requirements for the regional coordination required by Order 890,[47] the NOPR's expanded planning requirements, and linkage between regional plans and cost allocation, heighten the importance of getting the geographic scope of regional planning right. TAPS strongly supports these proposals and the Commission's effort to make effective regional plans—that lead to constructed upgrades—a reality. However, ordering TPs to produce regional plans will not achieve a robust, right-sized grid, unless planning structures are up to the task. Prompt Commission guidance on the minimum geographic scope could save enormous industry effort and expenditures that might otherwise be wasted, while enhancing the likelihood that the regional planning process will achieve the Commission's goals.

B. Need for Enhanced Requirements – Transparency and Openness

The NOPR assumes that the Order 890 planning principles are largely working as contemplated and proposes to apply seven of the nine principles without change or enhancement. *See* NOPR, P 50. Order 890 provided for a coordinated, transparent, and open planning process, and made clear that stakeholders are supposed to have access to

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Apalachicola River are within the SERC Region, which also includes neighboring states. A regional planning process that covered all of FRCC would therefore satisfy TAPS' proposed geographic scope criteria.

[46] *See, e.g.*, RTG Policy Statement at 30,874 ("We agree that consultation and coordination with the states are critical to the successful implementation of [Regional Transmission Groups], especially in view of the fact that states have authority over retail rates which recover transmission costs, integrated resource planning, and siting of transmission facilities.").

the TP models, assumptions, and criteria, subject to appropriate measures to safeguard confidentiality and Critical Energy Infrastructure Information ("CEII"). *See, e.g.*, Order 890, PP 460, 471. The NOPR (P 52) expresses confidence that these same principles will ensure stakeholders timely and meaningful access to the regional planning process.

Unfortunately, the Order 890 planning principles have not consistently provided the intended access to planning information. Some TAPS members' participation in the planning process has been effectively thwarted by roadblocks erected by TPs. This experience shows that the implementation of the Order 890 principles needs to be examined to ensure that the principles achieve the Commission's objectives.

For example, as reported by TAPS member Alabama Municipal Energy Authority, the Southern Company has waited until the scheduled transmission planning meeting before releasing meaningful planning data to TDU stakeholders. This practice prevents stakeholders from effectively participating in the planning process. Small TDUs that would turn to consultants to provide expert input to the planning process are denied any chance to review the data with the benefit of consultant help in advance of the planning meeting.

TAPS members dependent on the jointly-operated Kentucky Utilities Company/Louisville Gas & Electric Company ("KU/LG&E" or "E.ON") transmission system have been unable to fully participate in the KU/LG&E Attachment K planning process because of E.ON's insistence on intrusive and unreasonable access to personal information from stakeholders seeking access to confidential materials or CEII. These "background check" provisions—which E.ON has proposed but the Commission has not

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[47] Order 890, PP 506 n.295, 527.

accepted—include a requirement that anyone wishing to gain access to CEII portions of the planning process consent to a background check of unspecified scope by the unspecified members or agents of the KU/LG&E Stakeholder Planning Committee by completing a "Background Authorization" form. The Background Authorization form requires that a stakeholder disclose sensitive personal information (including his or her Social Security number, driver's license number, a seven-year history of personal residences, and date and place of birth), and consent to a background investigation and to the release of all related information to the KU/LG&E Stakeholder Planning Committee and/or to governmental authorities.[48] The Background Authorization form also requires individuals to grant a sweeping release of liability relating to the use of that sensitive personal information, even though E.ON's proposed changes to Attachment K place no limits on how the information obtained through the background check will be used or with whom it may be shared.[49] Stakeholders have been understandably reluctant to complete the Background Authorization form and, although the Commission has not accepted those E.ON tariff provisions, E.ON has not to date—two years after the commencement of the Attachment K planning process—released to the Stakeholder Planning Committee its planning model or other confidential information, such as the details of the results of its planning studies, pending resolution of the background check issue.

TAPS members in the Southwest Power Pool ("SPP") region report that SPP is reluctant to release planning models due to stated concerns (on commercial and

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[48] *See* Limited Protest of Kentucky Municipals, *E.ON. U.S. LLC*, Docket No. OA08-27-003 (Sept. 8, 2009), eLibrary No. 20090908-5140.

[49] *See id.*

proprietary grounds) about disclosure of merchant generation information within the model. As a result, stakeholders have received only a partial model that is not useable to verify results. While information may ultimately be made available to a consultant, obtaining access to the data requires a significant investment of time and expense. And the resulting access is unlikely to be timely.[50] Consequently, the Order 890 planning principles are not being implemented in a way that provides TDUs what the NOPR (P 52) expects: "an opportunity to participate meaningfully in that [planning] process."

These examples illustrate that notwithstanding Order 890's directives and other Commission efforts to support the planning process,[51] the Commission cannot simply assume that the Order 890 planning principles operate as intended. In the compliance filings required in the instant rulemaking proceeding, the final rule should require jurisdictional TPs to: (1) demonstrate that their existing processes in fact provide stakeholders the timely and meaningful access to models, assumptions, and other

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[50] Although not in the Attachment K process, another illustration of this problem can be seen in the efforts of TAPS member Oklahoma Municipal Power Authority to obtain timely access to the power flow models used by SPP to support assignment of costs to a network service customer. As shown in *SPP, Inc.*, 127 FERC ¶ 61,230 (2009), SPP determined that it needed an express Commission waiver of its tariff before it could disclose to the affected customer, even under protective order, the power flow studies it submitted to the Commission in response to a deficiency letter. *See also SPP, Inc.*, 127 FERC ¶ 61,076, PP 38-41 (2009) (description of the data disclosure issue in the initial hearing order).

[51] The Commission has revamped its Standards of Conduct requirements to avoid impeding open planning processes. *See* Standards of Conduct for Transmission Providers, Order No. 717, 73 Fed. Reg. 63,796, 63,811 (Oct. 27, 2008), FERC Stats. & Regs. ¶ 31,280, P 135 (2008), *on reh'g*, Order No. 717-A, 74 Fed. Reg. 54,463 (Oct. 22, 2009), FERC Stats. & Regs. ¶ 31,297 (2009), *clarified*, Order No. 717-B, 74 Fed. Reg. 60,153 (Nov. 20, 2009), 129 FERC ¶ 61,123 (2009), *on reh'g*, Order No. 717-C, 75 Fed. Reg. 20,909 (Apr. 22, 2010), 131 FERC ¶ 61,045 (2010), *corrected*, Docket No. RM07-1-002 (Apr. 21, 2010), eLibrary No. 20100421-3039, *corrected*, Docket No. RM07-1-002 (Apr. 23, 2010), eLibrary No. 20100423-3025, *reh'g granted*, Docket No. RM07-1-003 (June 15, 2010), eLibrary No. 20100615-3062 (explaining that the prior Standards of Conduct approach "created difficulties for public utilities engaged in long-range planning, and this difficulty was one of the impetuses that led to the reforms instituted in this Final Rule"). In doing so, the Commission reiterated the importance of ensuring that such processes are open and non-discriminatory. *Id.* P 152.

information as directed by Order 890; and (2) propose specific modifications to make the intended meaningful and timely participation in a transparent and open process a reality.

Better yet, the Commission should ask the TPs to consult with stakeholders in submitting this assessment and proposal for further reform. In any case, requiring TPs to make public their assessment of whether the process is living up to the Commission's expectations will provide a forum for stakeholders to provide their view, if that differs, and to require modifications to fine-tune the planning process to better assure the "timely and meaningful input and participation of customers into the development of transmission plans" that the Commission expects. NOPR, P 51 n.59, quoting Order 890, P 454.

C. Need for Enhanced Stakeholder Role and TP Accountability

The NOPR expressly recognizes that its proposed reforms will make the planning process more important. For example, at Paragraph 52 the NOPR acknowledges:

> [B]ecause of the increased importance of regional transmission planning that is designed to produce a regional transmission plan, transmission customers and other stakeholders must be provided with an opportunity to participate meaningfully in that process. … Greater access to information and transparency would also help transmission customers and other stakeholders to recognize and understand the benefits that they will receive from a transmission facility that is included in a regional transmission plan. This consideration is particularly important in light of our proposal below to require that each public utility transmission provider have a cost allocation method for transmission facilities included in its regional transmission plan that reflects the benefits that those facilities provide.

Despite the increased importance of the regional planning process and its close nexus to cost allocations affecting Commission-jurisdictional rates, the NOPR proposes to apply most of the Order 890 planning principles without modification to the regional planning process (*id.* P 52), noting further that "existing regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes to fully comply with these requirements." *Id.* P 53. In particular, the NOPR proposes to continue to leave the decisionmaking to the TP (*id.* P 51 n. 59):

> As noted in Order No. 890, the planning obligations proposed here do not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438. As also noted in Order No. 890, the ultimate responsibility for transmission planning remains with transmission providers.

TPs are required to provide stakeholders only the opportunity for "timely and meaningful input and participation … into the development of transmission plans." *Id*., quoting Order 890, P 454.

The enhanced regional transmission planning and cost allocation authority given to TPs under the NOPR require enhanced requirements for balanced decisionmaking and accountability.

1. Particularly in Non-RTO Regions, Balanced Decisionmaking is Required to Support the Important Role of the Planning Process

The Commission has long recognized that TPs have the opportunity and incentive to exercise their authority as TP in a manner that will enhance their self-interest.[52]

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[52] *See* Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,539, 21,567-21,568 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,862 (1996) ("Order 888"), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997) ("Order 888-A"), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 FERC ¶ 61,248 (1997) ("Order 888-B"), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 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*

Indeed, Order 2003[53] expressly recognized the potential for non-independent TPs to exploit the "inherent subjectivity" in the planning process to its own advantage, by attributing to others a disproportionate share of the costs of network upgrades needed to serve the TP's own power customers, and found "any policy that creates opportunities for such discriminatory behavior to be unacceptable." *Id.*; *see also* Order 890, P 39.

The NOPR proposes to enhance the capability of TPs to benefit their own generation function and the returns they earn by virtue of their ownership and control of transmission by giving them the right to make decisions as to which upgrades go into the regional plan, and thereby qualify for regional cost allocation. Thus, the proposed reforms will reinforce, rather than restrict, the TPs' opportunity and incentive to discriminate.

For example, the NOPR would give TPs the ultimate say on whether an upgrade that serves embedded TDUs is included in the regional plan. The TPs will also determine whether the plan includes the 765 kV overlay facility on which it proposes to earn an incentive return, or whether to start by proactively enhancing the 345 kV grid under a "no regrets" plan to achieve a right-sized grid that minimizes the risk of stranded transmission investment. As envisioned by the NOPR, TDUs that undoubtedly will be included in the load required to bear the cost of the facilities are entitled only to the opportunity to offer

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York v. FERC, 535 U.S. 1 (2002).

[53] *See* Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 Fed. Reg. 49,846, 49,904 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146, P 696 (2003), *modified*, 68 Fed. Reg. 69,599 (Dec. 15, 2003), *clarified*, 69 Fed. Reg. 2135 (Jan. 14, 2004), 106 FERC ¶ 61,009 (2004) ("Order 2003"), *order on reh'g*, Order No. 2003–A, 69 Fed. Reg. 15,932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004) ("Order 2003-A"), *order on reh'g*, Order No. 2003–B, 70 Fed. Reg. 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003–C, 70 Fed. Reg. 37,661 (June 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. NARUC v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

input. TPs are free to ignore that input and proceed to make decisions that augment their own self-interest and disadvantage others.

While individual TAPS members in RTO regions may have quarrels with the outcome of RTO planning process, they can take some comfort from the involvement of the RTO's independent management and board in approving the plan.[54] No such comfort is available in non-RTO regions under the NOPR's proposal—enhanced authority over planning and cost allocation is to be handed to the TP to wield, with other LSEs given no role in the decisionmaking.

To avoid creating new opportunities for discrimination, the Commission needs to enhance the Order 890 principles to mandate a collaborative, interactive regional planning process. At least as applied in non-RTO regions, the enhanced regional planning and cost allocation authority provided to TPs should have an important string attached: all those required to pay for the upgrades included in the plan, *i.e.*, all LSEs in the region (not just the TPs), should have a meaningful role in determining the upgrades included in the plan. Only where the Commission is satisfied that TDUs have a meaningful decisionmaking role can the Commission give any credence to determinations as to which facilities are included in the plan for purposes of allocating costs to be included in jurisdictional rates.

Further, when multiple TPs are involved in the NOPR's regional planning process—which should always be the case in non-RTO regions—reliance on the Order 890 principles, coupled with leaving all decisionmaking to the individual TP, does

[54] Even in the RTO context, the TOs' ever-present right to withdraw from the RTO may cause the RTO to weigh their views more heavily to maintain its footprint. Indeed, in reviewing cost allocation proposals the Commission has recognized the need to deter TO withdrawal. *Midwest Indep. Transmission Sys. Operator,*

not work. A mechanism is required to determine what happens when the multiple TPs involved in the regional process do not agree. Given the NOPR's expectation that non-jurisdictional TPs will participate in the regional planning and cost allocation process, the Commission has an obligation to ensure that such TPs, especially relatively small non-jurisdictional TPs, have an effective voice in the regional planning process and are not subjected to discriminatory or unjust allocation of transmission costs as a result of the domination of the regional transmission planning process by large jurisdictional TPs.

The Commission already has a policy on the governance to be used in agreements to perform the regional planning function envisioned by the NOPR. Specifically, the Commission's RTG Policy Statement provides:

> An RTG agreement should include fair and non-discriminatory governance and decision-making procedures, including voting procedures.

18 C.F.R. § 2.21(b)(3). In issuing the RTG Policy Statement, the Commission explained:[55]

> Component No. 5 provides for fair and non-discriminatory governance and decisionmaking procedures. No commenter opposed such a standard, and transmission-dependent entities expressed particular concern that they not be powerless within an RTG. The Commission will not specify in this Policy Statement what specific governance rules or features would be acceptable. In general, we think an RTG should have rules or procedures to protect the rights of entities that are more susceptible to the exercise of market power, such as transmission dependent utilities (TDUs). If the voting rules permit transmission owners to dominate the RTG, for example, this would disadvantage weaker users and would be unfair. An RTG may wish to strive for consensus when dealing with regional grid issues

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Inc., 129 FERC ¶ 61,060, P 7 (2009).

[55] RTG Policy Statement at 30,875.

> that affect most members. Accordingly, super-majority voting rules may be appropriate in some circumstances. Different regions and organizations may wish to address these issues in their own manner. The Commission believes that RTGs must have substantial flexibility in designing governance procedures to deal with the difficulties that will be encountered. The procedures must be fair and non-discriminatory if an RTG is to meet the objectives discussed above.

The Commission followed and reinforced this policy in acting on specific RTG proposals.[56] Any final rule issued in this proceeding should build on this crucial element of the RTG Policy Statement.

Thus, the Commission should make clear that it expects TPs to propose, as part of their compliance filing, a fair and non-discriminatory decisionmaking process to be used in developing the regional plan and approving the facilities to be included. Only a proposal that provides for balanced decisionmaking should be accepted as a foundation for regional cost allocation, thereby avoiding the need for stringent Commission scrutiny of the choices made.[57]

The Commission has well-established rules on what balanced decisionmaking

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[56] *See, e.g., Southwest Reg'l Transmission Ass'n*, 69 FERC ¶ 61,100, at 61,400-61,402 (1994) (proposed proportional class voting procedure for general membership and the board is acceptable to avoid domination by any particular class because it ensures that no action can be taken without assent of the majority of each class, but majority voting proposal for committees would permit a measure to pass because of high attendance of one class, even with no support from other classes; therefore requiring revision of bylaws to clarify that all committee actions are subject to board's proportional class voting review); *PacifiCorp*, 69 FERC ¶ 61,099, at 61,382 n.70 (1994) (proportional class voting procedures are acceptable because they ensure that no action can be taken without assent of a majority of the members or directors from each class).

[57] The Commission's authority to include governance expectations in its final rule, and identify consequences with regard to jurisdictional rates if they are not satisfied, is not restricted by *California Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 404 (D.C. Cir. 2004). In finding that the Commission lacked authority to reform and directly regulate the governing body structure of a jurisdictional utility, the D.C. Circuit made clear that the Commission has authority to place conditions on Independent System Operator ("ISO") status and does not have to accept as an ISO an entity whose governance does not meet Commission requirements.

means. In the reliability context, FPA Section 215(c)(2)(A) and (D) call for "balanced decisionmaking in any ERO committee or subordinate organizational structure" and "due process, openness, and balance of interests in developing reliability standards and otherwise exercising [the ERO's] duties." In implementing this requirement, the Commission has generally adhered to the standard:[58]

> no two stakeholder sectors should be able to control the vote on any matter, no single sector should be able to defeat a matter, and no entity should be eligible to be a member of more than one sector in the board selection process….

The governance of NERC regional entities has already been determined to satisfy FPA Section 215(e)(4)(A)'s balanced stakeholder governance requirements; similar structures could be adopted for the NOPR's new regional planning processes.

This fair and non-discriminatory governance requirement could also be satisfied by formation of a regional joint planning committee, not dominated by large TPs, that would direct the study process and be responsible for the development of uniform planning criteria, assumptions for base and changed cases, and transmission plans. As otherwise required by the Order 890 planning principles, all proposed base and changed cases, assumptions, and criteria must be made available with adequate time for review and comment. By working closely with technical staff, the joint planning committee will develop a general familiarity with the modeling process and local conditions, building expertise that should facilitate and expedite subsequent transmission planning cycles and allow the TPs to share some of the modeling work. While a joint planning committee

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[58] Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, Order No. 672, 71 Fed. Reg. 8662, 8675 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204, P 153 (2006), *corrected*, 71 Fed. Reg. 11,505 (Mar. 8, 2006), *on reh'g*, Order No. 672-A, 71 Fed. Reg. 19,814 (Apr. 18, 2006), FERC Stats. & Regs.

will not eliminate the need for broader customer participation in the process, a strong and effective joint planning committee should increase customer confidence in the transmission planning process, facilitate review of transmission plans, and reduce the time needed for comment periods.

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

The NCTPC's combination of an OSC in which TDUs and TOs have equal voting rights, an independent third-party tie-breaker, and dispute resolution procedure is only one potential model for participation; and it may not be suitable for all regions. Although there may not be a one-size-fits-all solution, the crucial task for all regions is to provide representation and safeguards that will prevent transmission providers from continuing to dominate the transmission planning process and failing to achieve Section 217(b)(4)'s

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¶ 31,212 (2006), *modified*, 73 Fed. Reg. 21,814 (Apr. 23, 2008), 123 FERC ¶ 61,046 (2008).

objective. Consensus-based approaches, or voting rights schemes that give each participant one vote regardless of size,[59] for example, could also accomplish this goal if combined with the right other elements.

Particularly given the heightened importance of decisions on which facilities are included in the regional plan, balance-of-interests-type decisionmaking is required, so that all those required to pay for the facilities have a fair opportunity to participate in the decisionmaking, not merely state a view that the TPs are free to disregard. Where a non-RTO region does not provide for balanced decisionmaking, there should be consequences when it comes to jurisdictional ratesetting. The Commission should apply a much tougher level of scrutiny to transmission rates and regional cost allocation proposals from non-RTO regions where the planning is determined solely by TPs. In those regions, even where jurisdictional TPs now use a formula rate, enhanced filing and review requirements should be imposed to facilitate close Commission scrutiny. Also, incentive rate requests should be even more closely evaluated in those regions, or altogether rejected, to make sure that the TPs are not abusing the regional planning process to extract incentive rates for themselves.

More generally, the failure to allow for balanced decisionmaking in the regional planning process—and particularly as to which facilities are included in the regional plan—may and should be considered in determining what equity return within the range of reasonableness a jurisdictional TP should be allowed. A TP that seeks to dominate the regional planning process should be exposed to having its equity return reduced below

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[59] *Cf.* Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission, 111 FERC ¶ 61,473, P 9 & n.6 (2005), noting that the governance structure providing each ATC owner with one vote regardless of size "allows some degree of participation by market participants, but ensures

the median of comparable companies. The Commission has found that it has authority to adjust equity returns within the range of reasonableness in order to promote governance policy objectives,[60] and there is no principled reason why such adjustments should run in only one direction.

2. Compliance Filings Should Provide for Regular Updating of the Regional Plans and Planning Report Cards

To ensure that they are relevant and timely, regional plans should be regularly updated. While annual updates may not be required in all regions, the period for updating should be no longer than every 24 months and set forth in the compliance filings, so that expectations are clear.[61]

In addition, whenever the regional plan is adopted or updated, the Commission should require jurisdictional TPs to file a "planning report card." The report card should identify the projects proposed during the planning process, the projects approved and

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the operational and managerial independence of the stand-alone transmission company."

[60] *See, e.g.*, Promoting Transmission Investment through Pricing Reform, Order No. 679, 71 Fed. Reg. 43,294, 43,298 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222, P 27 (2006) ("Order 679"), *on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006) ("Order 679-A"), *clarified*, 119 FERC ¶ 61,062 (2007) (Commission may adjust equity returns within the range of reasonableness "where necessary to encourage creation of a Transco or participation in a Transmission Organization").

[61] NERC requires Transmission Planners and Planning Authorities to assess transmission system plans annually:

> The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall … [b]e made annually.

NERC Standard TPL-001-0.1, Requirement R1, http://www.nerc.com/files/TPL-001-0_1.pdf.

included in the regional plan, and the projects that were proposed but excluded from the plan and the reasons those proposed projects were rejected.

The planning report card should also include information on the performance of the prior regional plans that are being supplemented or supplanted by the new plan. For example, the planning report card should identify and explain: the projects included in prior regional plans that have been changed and the reasons for the change; the status of construction for projects identified in prior regional plans; and the projects completed from prior regional plans, and whether they were completed on schedule and the reasons for schedule changes, if any. This basic information is needed to assure ongoing accountability, and to determine whether or not the regional plans being produced are useful, making a difference, and actually being executed.

The report card should be noticed for public comment. Although TAPS does not suggest that the plans themselves be filed, submission of the report card, with an opportunity for public comment, would enable the Commission to assess how the regional planning process is working, and whether adjustments are needed to ensure that it functions as intended. (As discussed below, the TP should also be required to file an annual construction report card that includes the status of projects included in the currently-applicable regional plans.)

3. Dispute Resolution

a) Inclusion and Exclusion Decisions Should be Supported by Reasonable, Non-Discriminatory Criteria, and Disputes Should be Resolved Using the Same Criteria

The Order 890 principles that the NOPR proposes to apply to the regional planning process include dispute resolution. *See* NOPR, P 50. Order 890 left TPs flexibility in proposing dispute resolution mechanisms, with mediation and arbitration included in the available options.[62] Order 890 did not specify the standards to apply in such dispute resolution, although *pro forma* open access transmission tariff ("OATT") provisions (such as the TP's Section 28.2 obligation to plan for the needs of network customers in a manner comparable to its own load), were in the background, along with the potential for complaint to the Commission. *See* Order 890-A, P 180.[63]

In non-RTO regions, provisions for balanced governance and/or involvement of independent third parties as a tie breaker (as used in the North Carolina Transmission Planning Collaborative) should be of significant help in adding credibility to the planning process and limiting disputes. However, to address whatever disputes remain, and especially in the absence of measures to achieve balanced decisionmaking, more Commission guidance is needed to make dispute resolution useful in the context of regional or interregional planning. Meaningful dispute resolution is also needed to address issues that arise in the RTO planning process.

Clear planning standards and goals are essential to give dispute resolution processes teeth and protect minorities with legitimate concerns that might otherwise be overruled in the planning process. For example, if the dispute resolution process adopted is arbitration, what standard would an arbitrator apply in resolving a dispute (which will have significant cost allocation implications) as to whether particular upgrades were improperly included in, or excluded from, a regional plan? If the final rule adheres to the NOPR's proposal (P 51 n.59) to leave unchanged Order 890's determination to leave the

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[62] *See, e.g., Bonneville Power*, 124 FERC ¶ 61,054 (2008) (mediation not required); *Maine Pub. Serv. Comm'n*, 123 FERC ¶ 61,162 (2008) (binding arbitration not mandatory).

[63] *See Idaho Power Co.*, 124 FERC ¶ 61,053, P 19 (2008) (directing TPs to revise dispute resolution procedures to preserve the exercise of a party's rights under Section 206).

ultimate responsibility for planning to the TPs, is there any meaningful check on the exercise of that responsibility? If the upgrade is for public policy purposes, or to address regional congestion or loop flow issues not directly related to service over an individual TP system, reference to the OATT provisions governing planning and expansion responsibilities (Sections 13.5, 15.4, or 28.2) is likely to be of limited use. Nor are those tariff provisions likely to provide guidance in resolving a dispute among TPs in a regional planning effort or within an RTO.

Commission guidance is needed so that any dispute resolution process can be systematic and effective, and so that the results will be consistent with the statutory requirement for just and reasonable transmission rates. As the NOPR correctly recognizes in the cost allocation context, the key is for decisions to be "transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility." NOPR, P 164, principle 5. That same standard should apply with respect to decisions on whether to include particular facilities in the regional plan, and any dispute should be resolved by application of the same objective and non-discriminatory criteria. Use of reasonable, non-discriminatory criteria is required to minimize the potential for discriminatory results. In a highly integrated grid, rules of thumb can operate unreasonably. For example, the NOPR (P 169) states that facilities located entirely within one transmission owner's territory may not be subject to the regional cost allocation unless "the regional transmission planning process determines that a new facility located solely within a transmission owner's service territory would provide benefits to others in the region." If an upgrade within a service area is made to serve local load, it should not be included; if such upgrade is made to mitigate the adverse impacts of loop flow from transactions on other systems, then it should be included in the regional plan.

b) Given the Cost Allocation Implications of Planning Decisions, Commission Processes Must Be Available to Resolve Disputes

In addition to other dispute resolution provisions (*e.g.*, arbitration or mediation, or dispute resolution assistance from the state public utility commission (like the NCTPC, which provides that any participant may request that the Public Staff of the North Carolina Utilities Commission render a non-binding opinion with regard to certain disputed decisions)), the Commission needs to provide at least a backstop forum to resolve disputes over the facilities included (or not) in the regional plan, to fulfill its obligations under Section 205 with regard to the justness and reasonableness of jurisdictional transmission rates, as well as to satisfy its obligations under Section 217(b)(4) to facilitate the planning and expansion of the grid to meet the reasonable needs of LSEs and enable them to secure long-term rights for their long-term power supply arrangements. TAPS is not proposing that regional plans be filed with and reviewed by the Commission as a matter of course. However, given the proposed tie between cost allocation and the regional plan, the Commission should provide stakeholders a timely means to challenge a determination to include or exclude a particular upgrade in/from the approved regional plan. Such a determination can cause the resulting rates to be unjust, unreasonable, and unduly discriminatory. In particular, the Commission should invite complaints as to undue discrimination in planning decisions, as well as with regard to the planning process. To make such invitation effective and timely, some form of expedited complaint process may be needed.

4. For Regional Planning to Achieve its Objectives, Clarity and Accountability for Construction Commitments is Needed

The NOPR expresses high expectations that the more robust regional planning process that includes consideration of state and federal public policy mandates will reduce the need for upgrades triggered by specific generator interconnection or transmission service requests. For example, at Paragraph 68, the NOPR states:

> [A]dherence with this proposed requirement may eventually increase the proportion of transmission network investment that is constructed pursuant to proactive transmission planning processes, thereby reducing the proportion of network upgrades that would otherwise be triggered by individual generator interconnection requests, which can be time consuming and inefficient. If more of the transmission network were expanded under the type of regional transmission planning process described above, then the network upgrades triggered by interconnection requests should be less significant in size and cost than they have been in the past and the associated differences in cost allocation provisions may become less significant as well.

To achieve the Commission's objectives, regional TPs need to know whether upgrades included in the regional plan are real—*i.e.*, whether they can include them in the base model used for considering generator interconnection and transmission service requests. Simply leaving the construction determination to individual TP discretion, as the NOPR proposes (P 51 n.59), with no apparent limitations or transparency as to how and when that discretion will be exercised, will result in inefficiencies as others in the region make transmission upgrade decisions—either to build or not to build—that would be affected by whether a particular upgrade included in the plan is built.

Uncertainty and confusion as to whether planned upgrades will be built could be worse than having no regional plan at all. The absence of a process in which construction commitments are timely made, with accountability for failing to proceed with due diligence, will severely undermine the efficacy of the regional plan. Other, less cost-effective facilities may be needlessly constructed because of a lack of certainty as to the status of the facilities in the regional plan, undermining the anticipated benefits of the regional planning process. Or, where a TP has failed to build facilities to which it committed in the regional plan and which were assumed in studies used to grant transmission and/or interconnection service, a region could wind up being transmission-short several years later when that transmission service is to commence. In such case, the TP's change of heart may threaten regional reliability or require redispatch solutions to maintain reliability.

The Commission can make the regional planning process effective and avoid this fatal pitfall, and can do so without expanding the TPs' obligation to build upgrades identified in the plan. The key is to require a timely and transparent process for construction commitments, with accountability for any commitments made. Specifically, the final rule should include a timely post-plan process for: (a) securing commitments by the TPs (or others) to build the upgrades identified in the regional plan, whereupon the upgrade can be included in the "regional base model" on which those in the region can rely as they study specific generator interconnection and transmission service requests; and (b) holding TPs and others that commit to construct facilities included in the "regional base model" accountable for doing so.

In its essence, TAPS' suggestion is that the regional planning process in non-RTO regions adopt procedures commonly used in RTOs. Each RTO has a stakeholder process for developing the regional plan, a process for securing commitments for facilities in the plan, and authority to require that the upgrades get built.[64] Once the facility is in the plan with needed commitments, the RTO can include that upgrade in its models used to assess specific interconnection and service requests.

Without requiring TPs to include a mechanism to require construction of all regionally-planned upgrades (consistent with Order 890 and the NOPR (P 51 n.59)), the Commission can make regional plans effective by requiring TPs to propose a transparent "post-plan" process by which construction commitments are made that others in the region can count on, so that facilities included in the regional plan can be included in the regional base models used to evaluate service requests. The dynamic nature of the AC grid, the interrelationship of the various components of the plan (which may involve actions by multiple incumbent TPs and/or independent developers), and the long lead-time for siting and constructing major upgrades all make it essential that the commitments be known and firm, subject to the transmission developer's inability to secure necessary approvals and property rights under Federal, State, and local laws, despite good faith efforts.

Further, such a process should be integrated with the implementation of the right of first refusal, project sponsor priority, or other mechanism used to determine which

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[64] For example, under the ISO-New England Transmission Operating Agreement, "each [Participating Transmission Owner] shall have the obligation to own and construct (or cause to be constructed) any New Transmission Facility or Transmission Upgrade that is designated in the ISO System Plan as necessary and appropriate for system reliability or economic efficiency." ISO-NE Transmission Operating Agreement Schedule 3.09(a), Sec. 1.1(a), *available at* http://www.iso-ne.com/regulatory/toa/v1_er07-1289-000_toa_composite.pdf; *see also* Midwest ISO Transmission Owner Agreement, Article Four, Section I.C., *available at* http://www.midwestmarket.org/publish/Document/469a41_10a26fa6c1e_-6d790a48324a ("Each [Transmission] Owner shall use due diligence to construct transmission facilities as directed by the Midwest ISO …."). The Commission recently recognized the right of the SPP RTO to direct construction. *SPP, Inc.*, 127 FERC ¶ 61,171, P 50 (2009) ("[T]ransmission owners who are signatories to the SPP Membership Agreement … are required under the SPP OATT and the Membership Agreement to use due diligence to construct facilities as directed by SPP" (citing SPP Membership Agreement Sec. 3.3(a), *available at* http://www.spp.org/publications/Current%20Membership%20Agreement.pdf)).

entities have the right to construct upgrades identified in the regional plan. Absent a timely and transparent construction commitment process, how would potential transmission developers know whether priority development rights (of the TP or others) have been exercised? Where transmission developers hold or seek to exercise these types of priorities, they should commit to deliver real upgrades. And once those commitments are made, the upgrades may be included in the regional base models.

Once the construction commitment is publicly made and the upgrade is included in the regional base models that others in the region rely upon, TPs (and others that make such commitments) must be held accountable for following through with good faith efforts to secure necessary approvals and property rights, and for proceeding to expeditiously build the facilities in accordance with the timeline set forth in the regional plan. If a TP (or other constructor) changes its mind, it should have a clear responsibility to hold harmless those that relied on completion of the upgrade. While a TP may not be obliged to construct an upgrade included in the regional plan in the first instance, once it makes that commitment the TP should not have the option to say, "Never Mind," and walk away, leaving other TPs, as well as transmission and generation interconnection customers whose timely service was predicated on the TP's construction of the upgrade, potentially holding the bag.[65] Nor should others in the region that moved forward with their parts of the regional plan bear the redispatch costs associated with maintaining regional reliability in light of one TP's failure to make good faith efforts to fulfill its construction commitments.

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[65] *See SPP, Inc.*, 118 FERC ¶ 61,148, P 41 (2007) (network service may be made dependent on completion of specified network upgrades).

Imposing accountability on TPs for fulfilling their construction commitments is consistent with Commission precedent. For example, in Order 2003-A, P 643, the Commission limited an interconnection customer's finance obligation to facilities that were not already included in the TP's transmission expansion plans, even recognizing that a TP may adjust its plans.

> The Transmission Provider may from time to time adjust its expansion plan. However, for purposes of this rule, we assume that any project included in the expansion plan at the time the Interconnection Facilities Study is undertaken is a project that the Transmission Provider intends to construct. Otherwise, the Transmission Provider could always claim that it did not intend to construct a project in its expansion plan. If such a project is required to meet the In-Service Date for the Interconnection Customer's Generating Facility, the Transmission Provider may require the Interconnection Customer to finance the expediting of the construction schedule for the project, but it may not require the Interconnection Customer to finance Network Upgrades that the Transmission Provider was planning to build.

See also PJM Interconnection, LLC, 124 FERC ¶ 61,059 (2008) (facilities for which interconnection customer is responsible for funding are "locked in" in the interconnection agreement).

Enhanced accountability requirements are particularly necessary in the regional context in non-RTO regions. In an individual TP's planning process, the OATT's construction obligations provide a backstop. *See* Order 890-A, P 180 (relying on case-by-case determination in the event of violation of OATT Sections 13.5, 15.4 or 28.2). In contrast, a TP's failure to build regionally-planned facilities is likely to have impacts far beyond that TP's footprint, harming other TPs and their customers, none of whom may take OATT service from the TP that failed to fulfill its construction commitment. And those sections of the OATT provide little protection against a TP's decision to renege on a commitment to an upgrade to the regional backbone to enable fulfillment of public policy mandates, or to address regional congestion or loop flow issues. Also less effective in this context is enforcement of a TP's obligations to construct the facilities needed to commence service. *See SPP, Inc.*, 118 FERC ¶ 61,148, P 41 ("SPP may be held accountable if it fails to satisfy its obligations under Section 29.3 of its tariff, which require that the equipment associated with the upgrades be installed 'consistent with Good Utility Practice' and with the 'exercise [of] reasonable efforts ... as soon as practicable taking into consideration the Service Commencement Date'").

Similarly, the tariff's self-accountability mechanisms are less effective to ensure that a TP follows through on commitments to complete upgrades identified in the regional plan. Section 33 of the OATT provides for redispatch, with costs shared on a load ratio basis, in the event of constraints on the TP's system. With this provision, the TP has "skin in the game" should it fail to make necessary upgrades to support the service it grants. But if the TP's failure to follow through on its regional planning commitments causes constraints on adjacent systems, this provision will not necessarily come into play.

Some mechanism needs to be put in place to ensure that TPs committing to upgrades have an incentive to make good on their expansion commitments, which were then reflected in the regional base models reasonably relied upon in deciding whether to grant long-term firm transmission or interconnection service. Specifically, customers and neighboring LSEs should be held harmless from redispatch and other costs resulting from a TP's failure to make good faith efforts to build regionally-planned facilities to which the TP committed. This type of hold harmless mechanism is particularly needed with respect to planned facilities that were identified for construction during the five-year planning horizon, when reliance is of heightened importance and alternatives to accommodate planned resources may be limited. Absent such a mechanism, the regional planning process may cause more harm than good.

A post-plan construction commitment process and associated accountability provisions are essential to countering the incentives for TPs to discriminate in transmission expansion, which the NOPR acknowledges.[66] TAPS agrees that "the complexity of the transmission grid and changing conditions of supply and demand for power" may require changes to the regional plan over time, and that financial penalties based on the failure to build a particular facility may be inappropriate in some circumstances.[67] That possibility does not justify abdicating responsibility to remedy discrimination, especially where it is possible to devise accountability provisions that flexibly address the problem by placing burdens and risks where they belong. It's one thing if system changes obviate the need for the committed upgrades even taking into account service commitments made in reliance on such upgrades. But if a TP fails to make good faith efforts to construct the planned upgrades to which it committed, and other system changes do not produce the transmission capacity necessary to accommodate planned uses in the region, some form of hold harmless obligation is required.[68] Thus, while a TP's priorities and business strategy may change over time, a TP that has made a commitment to build transmission facilities in a regional plan, which commitment is then relied upon in granting interconnection or transmission sources,

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[66] *See, e.g.,* NOPR, P 8**.**

[67] Order 890, P 594.

should be obligated to provide an alternative that holds others harmless. Only by altering the risks and burdens of discrimination—and forcing a TP to bear a fair share of the costs of failing to fulfill commitments it made to upgrade the grid consistent with regional plans—can the Commission create the framework needed to assure non-discriminatory open access and a robust grid.

Accountability is also needed to ensure the TP's exercise of a right of first refusal, or whatever substitute mechanism is adopted as to the right to build facilities included in the plan, is a real commitment to build the line. There need to be meaningful obligations attending the exercise of such rights.

Thus, the final rule should require TPs to propose a "post-plan" process to: (a) secure timely commitments by the TPs (or others) to build upgrades included in the regional plan, whereupon the upgrade can be included in the "regional base model" on which those in the region can rely; and (b) hold those committing to construct upgrades included in the "regional base model," at least within the five-year horizon, accountable for failing to follow through on those commitments, subject to an inability, despite good faith efforts, to secure necessary approvals and property rights.

5. The Commission Should Require Construction Status Reports

The Commission should require that TPs file an annual "construction report card" on the status of the additions included in the currently applicable regional plans, identifying for each upgrade: (1) the TP or other transmission developer, if any, that has committed to build the facility; (2) the facility's development and construction status,

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[68] Hold harmless provisions can take different forms, depending on the circumstances.

including the status of efforts to obtain regulatory approvals and property rights; and (3) a milestone schedule with a report on adherence to the schedule. This reporting is needed so that the Commission and stakeholders have the basic information and tools to monitor whether plan implementation is evenhanded and non-discriminatory.

Annual reporting on commitment and construction status will also help the Commission determine whether the final rule's regional plans are relevant to real world expansion decisions. It is not the NOPR's goal to produce elegant plans that sit on shelves and gather dust. If a high percentage of regionally-planned facilities are "orphaned," with no one willing to commit to build them, that may be a signal that the plan is insufficiently grounded in real-world needs and unlikely to obtain state siting approval, or that other challenges of completing the property acquisition and siting process for planned facilities are simply too daunting. Data on the development and construction status of regionally-planned facilities will likewise enable the Commission to pinpoint problems and bottlenecks and develop solutions.[69]

D. Need to Establish Compliance Filing Procedures

Commission oversight will also be needed to successfully implement the NOPR's proposed regional planning requirements. As required by Order 890, each TP's

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[69] These reporting requirements could build off of the Form FERC-730 reporting requirements applicable to Transmission Owners that have been granted incentive rates. Form FERC-730 requires TOs to provide limited information on the completion status of projects, and note the reason(s) for delay if the project is not on schedule. *See* Form FERC-730, Report of Transaction Investment Activity, *available at* http://www.ferc.gov/docs-filing/forms/FERC-730/FERC-730.doc; Order 679, PP 367-371. However, reporting on regionally-planned projects should include more information than is currently required of Form FERC-730 responses (where, generally, one-word explanations for delays—such as "Construction"—are deemed sufficient). At minimum, the required reporting should state whether the project has met objective milestones, such as: identification of the entity(ies) that has committed to construct the project, if any; first application(s) for required permits filed; all applications for required permits filed; first required permit issued; all required permits issued; land acquisition begun; land acquisition completed; site-specific engineering begun; site-specific engineering completed; construction begun; construction complete; testing begun; testing complete; and in commercial operation.

compliance filing in response to the final rule established under this rulemaking should identify the other TPs that it proposes to include in its regional planning process.[70] The Commission should encourage coordinated filings, with detailed procedures and protocols for the multiple TPs and TDUs within the region to engage in effective joint planning; procedures for integrating local, regional, and interregional planning efforts; and clear commitments and processes to grapple with the regional cost allocation issues needed to make the regional planning process productive in getting transmission built.

As it did in Order 890, the Commission should establish clear procedures, process milestones, and guidance to assist TPs in developing their regional planning compliance filings and to assure that TDUs and other stakeholders have a meaningful role in shaping those filings.[71] It is especially important that the process for developing and implementing regional planning procedures be inclusive, open, and collaborative in non-RTO areas, where existing OATT Attachment K protocols are often inadequate to support the creation of a regional plan.

Once they are filed, the Commission must scrutinize the specifics of each TP's regional planning proposal to assure that it includes the details, procedures, milestones, and explanations needed to make the intended regional planning a reality.[72] Because the

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[70] *See* Order 890, P 523; Transmission Planning Process Staff White Paper at 13, Preventing Undue Discrimination and Preference in Transmission Service, Docket No. RM05-17-000 (Aug. 2, 2007), eLibrary No. 20070802-3033 ("Staff White Paper").

[71] *See, e.g.*, Order 890, P 443; Staff White Paper.

[72] *See, e.g.*, *Entergy Services, Inc.*, 124 FERC ¶ 61,268, P 102 (2008):

> Although Entergy's Attachment K generally describes processes that can be used to coordinate regional reliability planning, Entergy has not provided sufficient detail to allow customers and other interested stakeholders to understand how its local planning activities will be integrated into those regional processes. For example, Entergy does not identify the timelines and milestones for the coordination of models and system plans by SERC and SPP, including opportunities for stakeholders to provide input and comment in each process. It is also unclear how each of the

NOPR's proposed regional planning requirements are more substantial than the regional coordination requirements of Order 890, Commission scrutiny should be even higher than it was for the original Attachment K compliance filings.

III. PUBLIC POLICY

A. Consideration of Requirements Imposed by State and Federal Laws and Regulations Is Appropriate

TAPS supports the NOPR's proposal to modify the Order 890 principles to expressly provide for consideration of state and federal laws and regulations in the local and regional planning process, as the NOPR proposes in the first two sentences of Paragraph 64. Frankly, we do not see how state and federal laws and regulations, which necessarily affect LSE resource commitments, can be ignored. By the same token, the planning process needs to consider requirements imposed on LSEs by state regulatory commission orders. Such requirements can have the same binding effect on an LSE as one written in the U.S. Code. For the same reason, local governmental requirements should also be permitted to come into the mix. For example, if a city ordinance requires its LSE to achieve a 30% renewable portfolio, that requirement should also be factored in. Thus, the final rule should expand or clarify the reference to state and federal policy

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regional and interregional processes will interact with each other when coordinated with Entergy's own planning activities, including development of the Construction Plan and Base Plan. Entergy has acknowledged its proposal's inadequacies and has agreed to make a compliance filing once the details of its regional reliability planning procedures have been developed. Accordingly, the Commission directs Entergy to file … a further compliance filing describing in detail its process for coordinating with interconnected systems to share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and identify system enhancements that could relieve congestion or integrate new resources. While we recognize that Entergy will discuss its regional participation procedures in more detail in this compliance filing, as an initial matter we agree with East Texas that Entergy must identify all neighboring transmission owners with which it will coordinate in its revised Attachment K.

requirements, so that it includes state regulatory commission orders and regulations and local governmental mandates on LSEs.

But the best way to consider these requirements is through the planning focus directed by Congress in enacting Section 217(b)(4)—planning to meet the reasonable needs of LSEs and for long-term rights for their planned long-term resources. Transmission planning aimed at meeting the projected needs of LSEs, if done right, will incorporate the public policy requirements with which LSEs must comply, and it is the method most likely to yield the "right-sized" grid that enables the nation to meet renewable energy targets and goals in a cost-effective way.

Public policy requirements will be reflected in the projections and resource designations of LSEs obliged to comply with the legal mandates. Transmission should be planned to connect generation to load. LSEs are the essential ingredient in resource location decisions, and their needs should guide transmission planning for public policy requirements—it is the LSE's commitment to enter into a purchase power contract with a wind developer, for example, that enables the resource to be financed and constructed. LSE designation of more local renewable resources, based on "all in" costs of generation and transmission (or locally-focused renewable portfolio requirements), should guide transmission planners to decisions that will likely produce a very different build out—one much less costly in terms of dollars and environmental impacts than a plan that ignores this crucial factor. As discussed in Part I.B above, "right-sizing" means planning and expanding the grid to meet projected LSE needs as Section 217(b)(4) directs, rather than viewing public policy objectives in the abstract and adopting a "Field of Dreams" approach to planning based on hoped-for development.

A focus on LSE needs would also help to address the difficulties inherent in attempting to plan the transmission grid (and appropriately allocate costs so they are roughly proportionate to benefits) based on public policy requirements that can vary widely from state to state within a multi-state region. Planning to meet the reasonable needs of LSEs, as Section 217(b)(4) mandates, should facilitate identification of regional and subregional benefits, and thus strengthen the connection between transmission planning and cost allocation.

To integrate public policy requirements in the sensible way that Congress directed, the final rule should expressly identify Section 217(b)(4) as a federal public policy requirement that the regional planning process must consider. While perhaps the inclusion of Section 217(b)(4) was intended to be implicit in the NOPR, it merits express recognition, because it is the only provision of the Federal Power Act that directly addresses the Commission's planning responsibilities; the NOPR's failure to even mention Section 217(b)(4) was conspicuous.

Much remains to be done to satisfy Section 217(b)(4)'s directive that the Commission enable LSEs to secure long-term rights for planned, as well as existing, long-term power supply arrangements. As described in detail in Part I.A above, LSEs are currently unable to secure new long-term rights for any new long term power supply arrangements. This failure to follow through on Congress' directive will become an increasing problem as LSEs seek to meet their needs through renewable and other low carbon resources that must be located remote from load. The Commission's obligations under Section 217(b)(4) did not end with issuance of Order 681. Rather, as Congress instructed, the Commission, in exercising its authority in this rulemaking, should fulfill its mandate to facilitate such planning, and enable LSEs to secure long-term rights for their existing and planned long-term power supply resources, by making explicit the role of this provision in the planning process.

B. Policy Objectives Not Legally Required Should Not Be Considered Unless Reflected in Service Requests and LSE Resource Plans

TAPS opposes the NOPR's proposal (last two sentences of Paragraph 64) to allow public utility TPs to consider public policy objectives that are not required by state or federal law, and to use TP-created public policy objectives as the basis for inclusion of upgrades in the plan.

As proposed in the NOPR (P 64):

> After consulting with stakeholders, a public utility transmission provider may include in the transmission planning process additional public policy objectives not specifically required by state or federal laws or regulations. This proposed requirement would be a supplement to, and would not replace, any existing requirements with respect to consideration of reliability needs and application of the economic studies principle in the transmission planning process.

This proposal would leave it up to a TP, after merely consulting with other stakeholders, to include upgrades in the regional plan that reflect its own views on "public policy."

TAPS urges the Commission *not* to incorporate this elective public policy approach into the final rule. Unconstrained by the dictates of officially-adopted laws and regulations, it is too easy for transmission planners to go off course; and construction of planned facilities to meet the TP's own vision of "public policy" will likely result in large stranded costs.

TAPS has particular concerns about the operation of this aspect of the NOPR in non-RTO regions, where determinations may be made by the TPs that benefit from that determination.[73] For example, the TP's definition of "public policy" may well be influenced by the incentive rate recovery for transmission expansion. The TP may also define public policy in a manner that advances its own generation interests. Even in a regional planning context, we have concerns about TPs agreeing to define public policy to provide themselves with an undue preference. The Commission should avoid establishing rules that would enhance the TP's ability and incentive to use its control over transmission to discriminate.[74]

An open-ended invitation to TPs to become policymakers—to define public policy in a way that goes beyond what lawmakers and regulators have done—is also unnecessary. If LSEs are planning for resources in a proactive way that goes beyond the minimum standards set forth in federal and state requirements, those actions will be reflected in their network resource designations and the ten-year projections of planned resource and anticipated loads required by Section 31.6 of the OATT, as well as generator interconnection requests and point-to-point service requests. These resource plans can and should be appropriately reflected in regional transmission planning, consistent with Section 217(b)(4).

A sounder approach than empowering TPs to plan in accordance with their own idiosyncratic policy views, is to urge them to adopt a "no regrets" strategy that takes account of LSE needs (consistent with Section 217(b)(4)), by focusing on constructing the upgrades needed under multiple potential power supply and public policy scenarios,

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[73] This is not to suggest that the concern is moot in RTO regions. *See, e.g.*, *supra* footnote.

[74] *See supra* Part II.C.1.

which lead to a "right-sized" grid with greater flexibility to respond to changing technology, resource options, and customer needs.

IV. RIGHTS OF FIRST REFUSAL FOR INCUMBENT TRANSMISSION OWNERS AND FOR "PROJECT SPONSORS"

A. ROFR for Incumbent TOs Should be Limited

TAPS supports limiting the TO's ROFR in Commission-jurisdictional tariffs. Specifically, TAPS would maintain the right of first refusal as to routine reliability upgrades that do not qualify for incentives under the Commission's incentive policy, and for other upgrades where it is structured to provide value in getting transmission built at a reasonable cost, *i.e.*, where the TO: (1) foregoes any ROE rate incentives for the transmission upgrade; and (2) offers meaningful (*i.e.*, load ratio share) joint ownership, on reasonable terms, to TDUs within its pricing zone (or, where appropriate, TDUs located in or providing service to customers in the state(s) where the project is or will be located, or broader area where the RTO so permits). Limiting the ROFR in a way that denies ROE incentives to those seeking to exercise exclusive rights and increases the likelihood of success in the siting and permitting process by aligning, through joint ownership, the interests of all local LSEs strikes a balance that should favor the Commission's goal of getting needed transmission promptly sited and built.

TAPS supports retention of the ROFR for routine reliability upgrades. Such retention is necessary to facilitate prompt construction of upgrades needed by a TO to maintain compliance with reliability standards. Such upgrades are not entitled to incentives under the Commission's policy.[75] Nor should TOs that could face NERC

[75] Order 679-A, PP 23-24 (citing Order 679, P 27).

penalties have to go through an elongated process to construct what is needed for reliability standards compliance. The incumbent TO should also be in a good position to get these clearly-needed upgrades promptly sited, and to accomplish any required condemnation consistent with state law. Thus, retention of the ROFR in these circumstances is in the public interest.

Beyond the routine reliability upgrades discussed above, however, the ROFR should be limited so that it is structured to provide value. The TO right of first refusal, particularly when coupled with a TO's ability to include upgrades in its transmission rate base, gives incumbent TOs a big advantage, allows them to shape projects to meet their needs, and discourages third-party developers from proposing transmission that may be more cost-effective. *See* NOPR, PP 87-88. As currently structured, the ROFR allows the incumbent TO to monopolize the ROE incentives and other transmission rate benefits, and denies consumers the benefits of allowing competition for the right to construct and obtain the associated steady, secure return through rate base—a risk reduction that makes rate-based transmission an attractive investment that should reduce the capital cost of the substantial transmission infrastructure that may be required.[76]

On the other hand, the ROFR, when supported by broad joint ownership and when ROE incentives that needlessly raise the cost have been avoided, can be very effective in getting needed transmission built. Siting large transmission lines is rarely easy, but state siting processes tend to run more smoothly where the applicant is an established local utility with whom the state siting agency is already familiar, and who has established relationships with the state's policymakers. As the NOPR recognizes (P

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[76] *See infra* Part VII.

89), state and local laws and regulations may limit the entities authorized to obtain necessary approvals to site and construct transmission facilities, and authority to condemn private property for this purpose. These limitations may make it critical that the incumbent TO or other local utilities with necessary statutory rights be involved. An incumbent TO is also likely to be in a better position to shepherd a major upgrade through the state siting process than an "outsider," as well as be more sensitive to the need not to "burn bridges" with state regulators given the need to secure approvals for future upgrades. This advantage is heightened where it's not just the incumbent TO seeking state approval of the upgrades, but the TO is instead working with many of the area LSEs that jointly own the project.

As described in Part I.C above, recent experience with the state siting processes associated with the transmission upgrades proposed by the CapX2020 process confirm the value of this approach in securing state approvals. As also discussed in Part I.C, the success of ATC in siting and constructing $2.2 billion of upgrades over the last 9 years, further attests to the value of inclusive ownership.[77] Broad joint ownership of proposed upgrades by multiple local utilities, both public and private, demonstrates an industry consensus that the proposed facility is necessary and desirable, and positions local utilities and local government to support the upgrades as they proceed through the state and local processes.

To strike a balance in favor of getting needed transmission built at a cost that will not burden consumers, the right of first refusal for the incumbent TO should not be available as a matter of course. Conditioning retention of the ROFR on incumbent TOs'

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[77] *See* ATC Ten-Year Assessment.

offering TDUs in the pricing zone (or other appropriate area) a meaningful opportunity to participate in joint ownership of a fair share of the project on reasonable terms provides TDUs that otherwise are too small to sponsor a major upgrade with a mechanism to manage the financial risk of transmission rate increases associated with major expansions. And it does so while expanding the political base to support facility siting and providing access to capital for large projects, increasing the likelihood that they will be completed.

In addition, a TO exercising the ROFR should be required to forego ROE rate incentives, a condition that mitigates the potential financial benefits of monopolizing transmission expansion, reducing the likelihood of abuse by incumbent TOs. Limiting capital costs to a reasonable return without incentives should go a significant distance in securing for consumers the benefits that would have been available by bidding out the right to construct, allowing construction of needed transmission infrastructure in a manner that will result in the lowest reasonable rates, as the FPA requires.[78] Requiring transmission customers to pay ROE incentives to an entity that *also* claims a priority right to construct the transmission facilities is simply absurd. Incumbent TOs should not be allowed to claim that they need both the right to keep out competitive developers *and* incentive rates to encourage them to construct needed transmission upgrades.

Where the incumbent TO meets these joint ownership and non-ROE incentive conditions, the ROFR serves the Commission's objectives of fostering cost-effective transmission expansion, and justifying its retention. However, where the upgrade goes beyond routine reliability upgrades, if the TO does *not* meet both of these conditions, or

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[78] *See Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959).

does not exercise the ROFR within a reasonable time limit that should be set forth in compliance tariffs, the Commission-jurisdictional tariff should clearly allow third parties: (1) to construct facilities in the regional plan, subject to state law limitations on the entities authorized to site transmission or exercise eminent domain; and (2) to obtain cost recovery comparable to that available to the TO and in accordance with the regional cost allocation methodology.

B. The NOPR's Proposed Right of First Refusal for Project Sponsors Should Be Eliminated; Instead, the Commission Should Require Competitive Bidding of Facilities in the Regional Plan and Encourage Collaboration of Local Stakeholders

The NOPR would replace the ROFR with a new regimen where a developer (or the incumbent TP) can claim "dibs" on a transmission project by sponsoring it in the planning process. The NOPR (P 93) provides that "the sponsor … of a facility that is selected through the regional transmission planning process for inclusion in the regional transmission plan to have a right, consistent with state or local laws or regulations, to construct and own that facility." With respect to proposed facilities that are *not* selected for inclusion in the regional plan, the sponsor would have the right of priority for a number of subsequent planning cycles (*e.g.*, 5 years), even if one or more "substantially similar" projects are proposed by others in future cycles. *Id.* P 95.

TAPS opposes the NOPR's proposed new right of first refusal for "project sponsors." The proposed new regimen is likely to lead to a "gold rush," with developers staking myriad claims by sponsoring proposals. It will likely embroil the planning process and related dispute resolution mechanisms, this Commission, and potentially the courts, in sorting out which of the holders of the newly-created priority rights to construct sponsored projects will be granted the right to build the inevitably somewhat different project approved in the planning process. A sponsor-priority regime also is likely to distort the regional planning process, so that it is less likely to produce the most cost-effective way to achieve plan objectives. None of this will help get needed transmission built.

The proposed "project sponsor priority" seems likely to create problems analogous to those that plague generator interconnection queues. Particularly where full cost-of-service recovery *plus* ROE rate incentives are available, the sponsor's priority right to construct a new transmission upgrade is potentially very lucrative. Based on the Commission's experience with generator interconnection queues, regional planning processes will likely be flooded with sponsored project proposals that seek to secure those valuable rights. Although the suggested need for detailed information to support the proposed project (NOPR, P 90 n.97) would hopefully limit the "planning by PowerPoint" that is all too common, given the potential for high rewards we expect a flurry of proposals, with the sufficiency of the detail submitted providing yet another dimension for potential disputes.

A substantial share of regional transmission planning resources and effort would therefore have to be spent evaluating the alternatives proposed by project sponsors, and on determining which of the sponsored project alternatives—both current and historical—if any, most resembles the facilities ultimately included in each regional transmission plan. Disputes and endless, time-consuming litigation on these judgments are likely, as significant financial benefits will turn on the decisions.

The regional planning process itself will also suffer. Project sponsors, including the incumbent TO, will also be participants in the regional planning process; and each will have a significant financial interest in the regional plan adopting its own sponsored projects, rather than those sponsored by other entities. Such stakeholder/sponsor financial interests—which are independent from the merits of the projects—will needlessly complicate and distort the already challenging regional planning process. And the fact that it is easier—and potentially much more lucrative—to propose grand plans rather than smartly-tailored solutions, raises serious concerns as to whether the facilities promoted by project sponsors, and selected by the TPs that control regional plans, will be "right-sized," as they need to be if we are to deal with climate change and other challenges without undue economic burden.

Finally, the NOPR's proposed sponsorship priority could well produce the very outcomes the NOPR was seeking to avoid by eliminating the ROFR for incumbent TOs. The NOPR gives TPs significant discretion to decide which facilities are included in the regional plan (*see* Part II, above); and TPs control the underlying models used to develop those plans. Particularly in non-RTO regions, it seems very likely that the NOPR's "project sponsor priority" will produce the same outcome as the incumbent TO ROFR, albeit through a process that is far more administratively complicated and expensive to implement. Even in RTOs, incumbent TOs would have a significant advantage. The RTO "ground up" planning process builds on the TO data and plans. Incumbent TOs' knowledge of the system well-positions them to sponsor projects that stand good chances of emerging from the planning process intact, as part of an approved regional plan. And RTOs are all too aware of the need to keep their TOs happy, or face the very real threat of withdrawals.[79]

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[79] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060, P 10 (2009) (noting

Instead, if the incumbent TO does not accept the ROFR conditions proposed in Part IV.A above, the Commission should encourage competition by requiring that the opportunity to construct and finance the projects identified in the regional plan be bid out to yield the lowest cost to consumers. The NOPR notes the possibility of bidding out projects in the case of projects for which an RTO is considering invoking a TO obligation to build. NOPR, P 97 n.101. The procedure should be broadly applied, except for routine reliability upgrades and where TAPS' conditions for invoking the ROFR (discussed above) have been satisfied. Any bidding process should include clear mechanisms to limit cost overruns, and to restrict the ability of winning bidders to transfer their construction right.[80]

This approach to disciplining capital costs is similar to competitive solicitation requirements imposed by the Commission in evaluating some RTO proposals. *See, e.g., Carolina Power & Light Co.*, 94 FERC ¶ 61,273, at 62,010 (2001) (rejecting GridSouth companies' right of first refusal on grid expansion, and instead requiring a "competitive solicitation for transmission expansion and upgrades[,]… consider[ing] the cost, quality and timing aspects of proposals submitted"). The Competitive Renewable Energy Zone process—a large-scale competitive process conducted by the Public Utility Commission

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MISO's claims that revised generator interconnection cost allocation methods were necessary in order to preserve the footprint given threatened departure of several transmission owners absent a change in the current cost allocation methodology); Duke Energy Answer and Motion for Leave to Answer at 12, *Duke Energy Ohio, Inc.*, Docket No. ER10-1562-000 (Aug 11, 2010), eLibrary No. 20100811-5001 (clarifying Duke Energy Ohio and Duke Energy Kentucky's decision to transition from MISO to PJM including the assertion that "PJM offers a better value.").

[80] We are not aware of any state requirements that would preclude this approach. The NOPR itself proposes the use of competitive bidding in RTO regions (P 97 n.101); and as non-governmental entities, multistate RTOs would appear to be subject to individual state competitive bidding requirements for construction projects only to the same extent as other corporations. Although individual states might impose competitive bidding requirements on the winner with respect to subcontracts for construction work subject to the state's jurisdiction or for which state funding, state property, or state authority are used, those

of Texas to select developers for projects to deliver energy from wind-rich parts of the state, after considering transmission developer capability, cost, and schedule—is still underway, but demonstrates that this approach can work.

Moreover, a competitive bid requirement inherently rewards competitors with innovative technologies. And in contrast to the NOPR's proposed priority for project sponsors, it does so through an objective performance measure—*i.e.*, the ability to deliver the desired facilities and system requirements for the lowest cost—rather than rewarding the ability to influence or control the selection of the specific facilities included in the regional plan.

As part of this competitive solicitation process, or as a further alternative in lieu of the NOPR's proposed priority for project sponsors, the Commission should favor projects jointly owned by those that must pay the bill, for the reasons discussed in Part IV.A above. The Commission has recognized the benefits of joint ownership arrangements and "encouraged" them, but has failed to make that encouragement meaningful by declining to make joint ownership a factor considered in awarding an incentive return.[81] TAPS believes that is a mistake, and that the Commission should reconsider this decision. The NOPR's focus on the right of first refusal implicitly acknowledges that the Commission's rate treatment of new transmission upgrades has made it a very attractive investment that transmission developers believe is worth fighting for. Utilities respond to incentives. Joint ownership with TDUs works, and what works should be rewarded. The Commission does precisely the opposite when it fails to require

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requirements would appear to apply, regardless of the method used by the RTO to select the winner.

[81] Order 679, PP 354-57; Order 679-A, P 102.

consideration of joint ownership in awarding the right to construct transmission upgrades—*i.e.*, instead rewarding transmission owners that refuse to offer TDUs in the pricing zone (or state) the opportunity to invest in the grid.

C. The NOPR's Proposed Minimum Qualification Criteria for Sponsoring Projects Should Be Clarified so it Does Not Create a Barrier to TDU Participation in Joint Ownership and Regional Planning

As discussed above, TAPS opposes the NOPR's proposal to establish a new priority for sponsoring projects in the regional transmission planning process, and urges the Commission to adopt alternatives, some of which would foster joint ownership with TDUs. Should the Commission decide to retain that element of the NOPR, however, it should clarify the proposed process so that it does not create new obstacles to joint ownership of transmission upgrades or prevent TDUs from participating in regional planning processes.

The NOPR (P 90) proposes:

> [E]ach public utility transmission provider must revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity's eligibility to propose a project in the regional transmission planning process, whether that entity is an incumbent transmission owner or a nonincumbent transmission developer.

Because TAPS strongly supports the Commission's goal of eliminating discrimination in the regional planning process, it urges the Commission to require that any qualification criteria established by regional planning processes facilitate joint ownership of transmission facilities, not unintentionally erect new barriers.

Qualification requirements that interfere with this proven method for getting needed transmission built would be a step in the wrong direction. For example, a number of very small systems are currently joint owners of new and proposed CapX2020 transmission facilities, and they have been important to the success of the planning and siting efforts associated with those facilities. Generalized qualification requirements could unintentionally and needlessly foreclose beneficial project participation by such small public systems. We recognize the NOPR's admonition that the criteria must not be unduly discriminatory or preferential (NOPR, P 90), but if expressed at the project level even seemingly even-handed criteria would unduly burden the ability of small entities to participate through joint ownership arrangements.

The final rule should support—not foreclose—the joint ownership model for building major transmission upgrades. It should therefore require that any new qualification criteria established by a regional planning process to determine an entity's eligibility to sponsor a project in the regional transmission planning process reasonably accommodate joint ownership, including by small entities that would not have the financial resources to fund the entire project alone.

The Commission should also clarify that the NOPR's new minimum qualification criteria for "propos[ing] a project in the regional transmission planning process" (*id.* P 90) relate to *sponsoring* a project for purposes of claiming a priority right to construct. In other words, the final rule should clarify that any stakeholder can propose projects for consideration as part of the regional planning process, and that the qualification criteria are relevant only to whether the stakeholder can "sponsor" the project for purposes of claiming a priority right to construct it.

D. Merchant Transmission Developers Must Be Required to Participate in Regional Planning Processes

The NOPR (P 99) proposes that a transmission developer would not be required to participate in the regional planning process, unless it seeks to use the regional cost allocation process. Regional cost allocation, however, is not the only reason for participation in the regional planning process.

The NOPR's proposal, which would allow transmission developers to plan and construct regional transmission facilities without coordinating and vetting those facilities through the regional planning process, effectively creates a dual-track system. The result could relegate the NOPR's *mandatory* regional planning process to planning around *ad hoc* merchant projects that trump regional-plan-approved projects. And the construction of unplanned, participant-funded merchant lines would also undermine the major benefits of regional planning—*e.g.*, right-sizing of transmission upgrades, avoidance of multiple and duplicative siting procedures, and coordinated evaluation of both transmission and non-transmission solutions.

The dynamic, integrated nature of the AC grid means that once a new line is connected, it becomes part of the network, affecting and being affected by everything else going on in the system and changes thereto. This characteristic creates not only the potential for "free riders,"[82] but the need to assure that grid additions are beneficial. Placement of a line in one location with particular characteristics will affect operations (not necessarily for the better), and will inherently alter and limit future planning options available to meet regional needs. A "market-based" approach to transmission, even with

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[82] *See, e.g.*, Order 890, P 561; NOPR, P 124.

a reliability check that the NOPR seems to envision (P 99), will not ensure that each upgrade wisely uses available corridors, minimizes environmental impacts, efficiently expands capacity, and effectively reduces congestion.

Merchant HVDC lines similarly must be subjected to the planning process. While the transmission capacity of an HVDC is less susceptible to influence by the surrounding AC system, its terminals are the equivalent of interconnecting a large generator into the AC grid, which must be able to integrate the resulting output or inflow. To efficiently build needed infrastructure and get it sited, merchant HVDC lines must be considered as part of the planning process.

Thus, merchant or independent transmission projects should be required to participate in the planning process once they have identified a potential project, and to advise planners of any alternatives studied to reduce potential duplication of effort. Otherwise, our nation will be saddled with transmission that is inefficient, both in terms of the delivered price of electricity and of the utilization of scarce resources and political capital in the often difficult transmission siting process.

V. INTERREGIONAL COORDINATION

TAPS generally supports the NOPR's enhancement of interregional planning with neighboring regions. TAPS sees the need for mandatory interregional planning, as reflected in an agreement to be filed with the Commission. NOPR, P 114. Interregional planning with neighboring regions is essential for accomplishing the Commission's goals. For example, it is crucial to accessing the wind potential from non-RTO regions adjacent to RTO regions. We also appreciate and support the Commission's intent not to require interconnection-wide planning or otherwise interfere with the Eastern Interconnection Planning Collaborative process. *See id.* P 115.

However, the NOPR's discussion of interregional planning agreements suggests it may be a TP-only club. The NOPR's description of the development of the interregional planning agreement mentions only TPs. *See id.* The only suggestion in the required elements for interregional planning that the process goes beyond TPs is the reference to a commitment to develop a website or e-mail list. *Id.* P 117. That is not enough, particularly where non-RTO regions are involved.

Given the potential impact of decisions made in the interregional planning process, the process for developing and implementing the interregional planning agreements must be inclusive, open, and collaborative. It should not just be TPs that participate in developing the interregional planning agreements and making the interregional planning decisions that will have significant cost allocation implications for others, in particular the TDUs that will likely be expected to bear the costs. Absent such balanced decisionmaking, the interregional planning process could operate as a tool for undue discrimination, in violation of the FPA's dictates. Nor would the Commission be performing its duties under Section 217(b)(4), which requires the Commission to facilitate planning to meet the needs of all LSEs, not just TPs.

Thus, the final rule should make clear the Commission's expectation that TDUs at least will have a seat at the table in developing interregional planning agreements and in their implementation. The interregional process should meet the same Order 890 principles as the regional planning process, with balanced decisionmaking and other enhancements proposed by TAPS playing an important role, especially in non-RTO regions. *See* Part II.C above.

VI. COST ALLOCATION

A. TAPS Generally Supports the NOPR's Cost Allocation Principles

TAPS generally supports the NOPR's proposal to link cost allocation to the regional planning process (assuming the Commission adopts improvements to the process as proposed by TAPS to ensure that it does not become a new tool for discrimination), and its proposed cost allocation principles. These principles appear to be consistent with the *Illinois Commerce* decision and cost-causation principles.

Specifically, citing *Illinois Commerce*, the NOPR would require (P 164, principle 1): "The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits" (footnote omitted). *See also* NOPR, P 173. TAPS agrees with the "roughly commensurate" standard.

TAPS recognizes that determining cost causation is challenging on an integrated AC grid where beneficiaries are hard to identify and can change over time with alterations in grid topology and power supply economics. Many benefits of very important network upgrades are difficult to quantify, such as enhanced reliability, local area resource reserve needs, optionality, and flexibility. By increasing LSE choice, a robust grid can help reduce volatility and buffer the effects of unpredicted changes. Improved transmission allows LSEs to capitalize on unanticipated opportunities and avoid price spikes, and it provides a hedge against major disruption from facility outages. A stronger grid will also expand the areas suitable for siting new generation, provide enhanced access to renewable generation, make maintenance easier and less costly (since the facility outages needed for maintenance or upgrades will not threaten the provision of reliable service), and reduce electrical losses and congestion. All these benefits are hard to quantify, but critical to a robust, reliable grid. Thus, we agree that the identification of benefits needs to go beyond the narrow energy production cost savings typically modeled for such quantifications.

However, the benefits used to support cost allocation should not include generalized social or environmental benefits. Inclusion of such generalized benefits as justification for transmission cost allocation would be unlikely to achieve acceptance because it would be viewed as a cover for assigning costs to those who receive little or no benefits. On the other hand, an LSE's ability to meet its renewable portfolio requirements imposed by state or federal public policy requirements clearly merits consideration as part of the generation projections and benefits of a proposed transmission project. The NOPR's reference (P 164; *see also* P 174) to consideration of the benefits of "meeting public policy requirements established by State or Federal laws or regulations that may drive transmission needs" needs to be construed in this light, consistent with FPA Section 217(b)(4)'s directives (footnote omitted).

The NOPR's second cost allocation principle states: "Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities." NOPR, P 164, principle 2. *See also* NOPR, P 173. TAPS agrees with this principle, but believes it should be clarified to better track the *ICC*'s prohibition on allocation if benefits are "trivial" in comparison to the costs to be allocated. In the *Illinois Commerce* decision, the Court instructed (576 F.3d at 476):

> FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members.

This requested clarification is important to emphasize that the Commission will not accept cost allocation methodologies that assign costs regionally based on the presumption of some general, unquantified regional benefits or vague assertions of possible future benefits. As explained by the Seventh Circuit, the Commission "cannot use the presumption to avoid the duty of 'comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.'" *Illinois Commerce*, 576 F.3d at 477**,** quoting *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004).

TAPS also supports the NOPR's fifth principle: "The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility." NOPR, P 164, principle 5. Indeed, as discussed in Part II.C above, the same principle should be applied to require non-discriminatory criteria to justify inclusion or exclusion of upgrades in the regional plan, rather than applying a rule of thumb that might unjustly operate to exclude facilities located solely within one TP's service territory even if they are necessitated by loopflow from transactions on other systems. Thus, the final rule should modify the NOPR's generalized service area presumption (P 169) and subject decisions as to which facilities are included in the regional plan to justification and objective evaluation to prevent discrimination and unjust and unreasonable rates.

TAPS strongly endorses the NOPR's conclusion (P 168) that:

> [A] cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, exacerbates the free rider problem that the Commission described in Order

> No. 890. Such a cost allocation method would not satisfy the proposed principles.

TAPS has long opposed participant funding, which forces one or more market participants to bear the cost of network upgrades that provide broad benefits that change over time in a dynamic AC system, as antithetical to the robust grid the Commission is seeking to encourage.

Finally, we agree with the Commission's determination not to propose interconnection-wide cost allocation, which would generate widespread opposition. More generally, in proceeding to articulate and apply the NOPR's cost allocation principles through the compliance filing process and thereafter, we urge the Commission to adhere to a middle ground to secure acceptance by stakeholders and state commissions, *e.g.*, for siting and other purposes.

B. The Commission Should Provide for Implementation of Regional Cost Allocation in Non-RTO Areas Through Regional Tariffs with Non-Pancaked Rates Covering All Service

Within RTO regions, there is a clear mechanism through which the regional cost allocation principles articulated in the NOPR can be applied: the RTO's regional transmission tariff. But in a non-RTO region, there is no regional rate or other ready mechanism available to implement the NOPR's regional cost allocation proposal, as the NOPR recognizes (P 41).

TAPS urges the Commission to address allocation of costs of projects that go beyond existing boundaries of an RTO or individual TP where the grid is integrated. The Commission should recognize and exercise its long-established authority to order joint, non-pancaked rates where transmission systems are integrated. *Fort Pierce Utils.*

Auth. v. FERC, 730 F.2d 778, 783-85 (D.C. Cir. 1984) ("*Fort Pierce*").[83] Many, if not all, regions would meet that test. The NOPR's demonstration of the need for enhanced regional planning and regional cost allocation (*e.g.*, NOPR, PP 32-36; 40-41; 150-154) confirms the appropriateness of a finding of integration. The fact that TDU loads and resources often span multiple transmission systems within a region supports a finding of integration and signals the need for joint rates.

The Commission should use all its sources of authority to incentivize TPs to adopt regional rates that eliminate pancaking and foster transmission investment that meets the needs of LSEs, as Congress directed in enacting Section 217(b)(4). For example, market-based rate determinations can be tied to a TP's willingness to provide customers effective access to a broader market through participation in non-pancaked regional or joint rates. It can also be made a factor in assessing the return to be earned under jurisdictional transmission rates, and whether individual TP tariff administrative charges are just and reasonable.

For non-RTO regions, requiring joint tariffs with non-pancaked rates would provide a vehicle to deal with cost allocation of regional upgrades that extend or have impacts beyond an individual TP's transmission system, and may reduce the disincentive for formation of new and expanded RTOs. It would also go a long way toward addressing concerns with and costs of accommodating loop flow, which can extend beyond an individual TP's system, and requires a regional approach. *See* NOPR, P 143. Such a rate would also eliminate the rate pancaking that the Commission has long

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[83] *See also Permian Basin Area Rate Cases*, 390 U.S. 747, 776-77 (1968) (Supreme Court approving Commission's use of area rates, noting that "the width of administrative authority must be measured in part by the purposes for which it was conferred") (internal citations omitted).

recognized as a competitive barrier.[84] Elimination of pancaked rates greatly expands the market, consistent with the regional planning contemplated by the NOPR.

Absent requiring a joint regional tariff, with non-pancaked rates covering both existing facilities and new facilities, the NOPR's proposal for regional cost allocation in non-RTO regions creates numerous issues. For example, if the Commission were to require non-RTO regions to simply allocate costs within the region, would that cost allocation be a rate schedule? What service would be provided? If no service is provided, how is it just and reasonable to charge a rate? It certainly would not be just and reasonable for an LSE to pay a share of the upgrades included in the regional plan, and then have to pay multiple TPs pancaked transmission charges (for the existing and/or new facilities) to use the regional grid for the transactions contemplated by the plan.

Nor is it reasonable to handle the regional cost allocation for service using new regionally-planned facilities separately from the existing regional grid. For example, how would the capacity under the "new facilities schedule" be separately determined and assigned in response to transmission or interconnection requests? In a dynamic AC system, ATC needs to be determined for the system, not a particular upgrade. Even if it could be segregated, which TP in the region would be able to sell and receive the revenues for use of the capacity from an upgrade whose costs were regionally shared? How could there be a separate queue for new and old facilities? A two-tiered system of a regional tariff for regionally-planned facilities layered on top of existing individual TP

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[84] *See* Order 2000, at 31,004 ("[T]he NOPR explained that pancaked transmission rates (where a separate access charge is assessed every time the transaction contract path crosses the boundary of another transmission owner) restrict the size of regional power markets. The Commission added that the balkanization of electricity markets hurts consumers who pay higher transmission rates and have access to fewer generation options") (footnote omitted).

tariffs would not provide a rational vehicle for provision of the expanded transmission service contemplated by the NOPR's reforms, nor result in just and reasonable rates.

Movement toward non-pancaked regional tariffs for service on existing and new facilities would not only accommodate the regional cost allocation called for by the NOPR, but it would address the discrimination against and increasing burdens on TDUs with loads and resources on multiple transmission providers. While transmission owners enjoy the full economic and reliability benefits of their entire fleet (which, by history or design, is typically within their often very large control area boundaries), TDUs whose loads and resources transcend control area boundaries (drawn by others)[85] must plan and operate their resources to serve their loads on a suboptimal, split basis.[86] The only way such TDUs can do what the vertically-integrated transmission providers do—*i.e.*, optimize all their resources to reliably and economically meet all their loads—is to pay multiples of what the transmission provider's native load pays for comparable service.[87]

Regional tariffs with non-pancaked rates would also address the problems associated with transmission upgrades needed in neighboring systems to accommodate new transmission service requests. The Commission's existing cost allocation rules call for dramatically different treatment of such upgrades, depending on whether they are located within the service territory of the TP from whom the LSE takes transmission

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[85] *See Alliance Companies*, 89 FERC ¶ 61,298, at 61,922 (1999) (rate pancaking found unduly discriminatory because it maintains preference for TOs, whose resources tend to be located within their corporate boundaries).

[86] Network resources designated to the TDU's load on one transmission system are treated as non-firm and subject to curtailment if used, for economic or reliability purposes, to serve its load on another transmission system.

[87] *See, e.g.*, Order 888-B at 62,096 ("a network customer that seeks network service for all of its loads in multiple control areas may designate all such loads as network loads" *i.e.*, in each such control area) (footnote omitted).

service or whether they are located in a neighboring system; cost allocation treatment also differs depending on whether the upgrade is required for interconnection service (with repayment in twenty years of any upfront payment of construction costs on affected systems) or transmission service (which makes no such provision for repayment).[88]

Movement towards non-pancaked regional rates through a regional tariff does not require formation of RTOs. SPP had a regional tariff covering first point-to-point, and then network, service before it became an RTO.[89] MAPP also offered a regional tariff with a regional rate for certain transactions,[90] although that rate is being phased out given the reduction in membership resulting from members joining SPP or MISO.[91] Other examples of joint tariffs with non-pancaked rates include the Black Hills Power, Inc./Basin Electric Power Cooperative/Powder River Energy Corporation joint OATT.[92] State jurisdiction over the transmission component of retail rates can also be preserved depending on how the rate and the service taken by TPs under the tariff are structured.[93]

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[88] *See SPP, Inc.*, (setting for hearing network service agreements that would assign the costs of upgrades on the Southwest Power Administration ("SWPA") transmission system to SPP network customers); *SPP, Inc.*, 131 FERC ¶ 61,072 (2010) (accepting extension of SWPA's arrangement, without addressing requests to address the allocation of the costs of network upgrades on the SWPA system that SWPA declines to pay).

[89] *SPP, Inc.*, 98 FERC ¶ 61,038, at 61,103 (2002).

[90] *Mid-Continent Area Power Pool*, 69 FERC ¶ 61,347 (1994).

[91] *See* MAPP's September 1, 2009 certification under Section 2.1 of the MAPP Schedule F that the minimum Transmission System size threshold was not satisfied so that no new reservations would be made effective September 1, 2009, *available at* http://toinfo.oasis.mapp.org/oasisinfo/MAPP%20Xmsn%20Extent%2020090901.pdf.

[92] The joint OATT was first filed in 2004. *See Black Hills Power, Inc*., 106 FERC ¶ 61,119 (2004) (the three entities combined their respective transmission systems located in the Western Interconnection into a single system (Common Use System) and provide open access transmission service (including both network and point-to-point) over the Common Use System at a non-pancaked rate under the proposed Joint Tariff).

[93] *See, e.g.***,** *Midwest Indep. Transmission Sys. Operator, Inc.*, 98 FERC ¶ 61,141, at 61,412-14 (2002) (bundled retail service exempt from most MISO tariff rates during the transition period); *Carolina Power & Light Co.*, 94 FERC ¶ 61,273, at 61,999 (2001), *clarified*, 95 FERC ¶ 61,282, at 61,991 (2001) (providing for contractual accommodation of the transmission component of bundled retail rates).

A regional tariff covering all transmission service within the region also avoids the potential for severe injustice to TDUs. It would be unduly discriminatory and unjust and unreasonable for TDUs to pay twice or three times for regional upgrades. Many TDUs own their own transmission facilities, but also must pay for network service and/or point-to-point service on multiple TP systems; they should not be assigned a share of the upgrade costs as a TP, as well as pick up additional shares as a transmission customer. A non-pancaked regional rate covering all transmission service within the region would avoid these problems.

The Commission's authority to require joint rates provides a tool to eliminate undue discrimination, address inter-TP cost allocation, and advance other pro-competitive policy objectives. A regional tariff, with non-pancaked rates, can be implemented using a range of rate designs for both new and existing facilities, and produce rates, terms, and conditions that are just, reasonable, and not unduly discriminatory.

C. Interregional Cost Allocation

The arguments in Part VI.B above in favor of implementing regional cost allocation through non-pancaked rates may apply, in particular cases, to interregional cost allocation. Applying *Fort Pierce*, the Commission could require joint rates that go beyond a particular region, where it determines, on a case-by-case basis, that the regions entering into the interregional agreement are integrated. Joint rates may be appropriate where there are significant interconnections and transfers across a regional seam (*e.g.*, where one region is relying on significant renewable resources from neighboring systems and constructing substantial interregional facilities to accommodate that reliance, or where the regional seam bifurcates TDU loads). Adoption of a laissez-faire approach to the definition of regions (contrary to TAPS' suggestion in Part II.A above) would make joint interregional rates more frequently justified, but regional seams that fail to reflect trading patterns and flows can also cause that to be the case (*e.g.*, RTO boundaries artificially defined by individual TP RTO choices, or a TP's decision to remain outside an RTO). When justified on a case-by-case basis, non-pancaked rates that extend across a regional boundary can address the many difficult implementation issues associated with interregional cost allocation (such as those highlighted above with respect to regional cost allocation in non-RTO regions) and support the interregional service contemplated by the interregional upgrade, while eliminating undue discrimination and expanding access to competitive markets.

Moving toward joint rates that extend beyond an RTO will facilitate allocation of costs of interregional facilities, limit the ability of TOs to exert influence over RTO cost allocation decisions by threatening to withdraw, and diminish the perceived advantages of remaining outside an RTO's boundaries or switching RTOs. However, with respect to RTO seams, care must be taken to assure that if entities outside of the RTO are given the benefits of RTO membership, they must be required to contribute their fair share of its costs. For example, the Commission should avoid arrangements such as proposed MISO Market Coordination Service, which the Commission properly rejected because it would have created new incentives for current MISO members to withdraw by allowing them to keep the benefits of having access to energy markets "while escaping a significant portion of the costs associated with those benefits (*e.g.*, RECB costs)." *Midwest Indep. Transmission Sys. Operator, Inc.*, 126 FERC ¶ 61,139, P 67 (2009).

VII. PARTICIPATION BY NON-JURISDICTIONAL UTILITIES

The NOPR (P 43) states its expectation that non-public utility transmission providers will participate in the expanded regional planning and cost allocation process, as an extension of the approach to reciprocity adopted in Order 890. TAPS supports this approach. Expanded regional planning will not achieve the Commission's goals if major gaps are created by failure of large non-jurisdictional TPs (including the transmission-owning federal power marketing agencies) to participate. TAPS also supports the Commission's decision not to invoke its authority under Section 211A.

VIII. INCENTIVE RATES

To implement Section 219 of the FPA, as enacted as part of EPAct 2005, the Commission issued the Order 679 series of orders adopting Section 35.35 of the Commission's regulations, 18 C.F.R. § 35.35. Section 219 expresses the goals of providing benefits and reducing costs to consumers (*see* Section 219(a)), to "promote reliable and economically efficient transmission and generation" (Section 219(b)(1)) and "provide a return on equity that attracts new investment in transmission facilities" (Section 219(b)(2)). The Commission's incentive rate regulations similarly describe incentive rates as including "[a] rate of return on equity sufficient to attract new investment in transmission facilities." 18 C.F.R. § 35.35(d)(1)(i). The applicant must show that the proposed upgrades ensure reliability or reduce the cost of delivered power by reducing congestion, "that the *total* package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project, and that the resulting rates are just and reasonable." 18 C.F.R. § 35.35(d). The incentive regulations establish a rebuttable presumption that facilities that result from a regional planning process satisfy the required demonstration that the project ensure reliability or reduces congestion. 18 C.F.R. § 35.35(i)(1)-(i)(1)(i).

Although the incentive rate rule leaves the Commission ample ability to make sure ratepayer dollars are spent wisely, to date it has been implemented in the form of "FERC candy" that offers returns above the level needed to attract new investment, and produces a package of benefits for transmission developers that is far beyond what is needed to address the demonstrable risks and challenges of a particular project.[94] In *Virginia Electric and Power Co.*,[95] for example, the Commission approved a 125 basis point incentive for facilities that the Commission described as necessary for load growth. And in *Potomac-Appalachian Transmission Highline, L.L.C.*,[96] the Commission approved an excessive incentive ROE of 14.3%.[97]

The issuance of the instant NOPR requires reevaluation of the application of the incentive rate rule, so that it does not needlessly add to the burdens on our economy and on citizens paying for the transmission build-out required to meet renewable objectives, and so that it does not make siting and cost allocation issues even harder than they would otherwise be. The NOPR's findings (*see, e.g.*, P 87) as to the need for elimination of the ROFR to avoid undue discrimination in the opportunity to construct facilities included in the regional plan are inconsistent with the assumption that rate of return incentives are needed to induce transmission investment. TO reluctance to give up the ROFR further

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[94] TAPS shares the concerns about the current application of the Commission's incentive rate policy expressed by the American Public Power Association and others in their Joint Comments on Transmission Rate Incentives and Cost Allocation Issues, as filed in this proceeding today.

[95] 124 FERC ¶ 61,207 (2008) *request for reh'g pending.*

[96] 122 FERC ¶ 61,188 (2008) *request for reh'g and uncontested settlement pending.*

[97] *Id.* P 104.

confirms that the supposed "burden" of expanding the transmission rate base on which the TO is entitled to earn a return is greatly overstated, especially where the TO rebuffs TDU offers to participate in ownership of the project.

The reforms proposed in the NOPR, if adopted, would further reduce the risks of transmission investment. The NOPR's proposal to require a regional plan, and to tie regional cost allocation to inclusion in the plan, further decreases the risks associated with transmission investment. Inclusion in a regional plan, especially if developed with state input, should reduce siting risk, and establishing the cost allocation up front lessens cost recovery risks. The NOPR thus adds significantly to the risk reduction already achieved through non-ROE elements of the Commission's incentive program that increase the certainty of recovery of transmission investments included in rate base.

As explained by Roy Thilly, TAPS Chairman and CEO of WPPI Energy in a statement reflecting his comments at the October 14, 2008 Technical Conference on Transmission Barriers to Entry:[98]

> The FERC has done a good deal in my judgment in limiting risks for transmission development through its rate recovery policies. Substantial certainty of recovery is very important. For ATC and others, the Commission has approved formula rates with true-ups and has permitted construction work-in-progress in rate base, as well as recovery of prudent pre-certification expenses. The major risk on the transmission side is the development stage through permitting. Once a facility is permitted, risk is greatly diminished. Recovery of prudently incurred pre-certification costs, regardless of whether a line is built, is a very major step in overcoming this risk barrier. A number of the other panelists confirmed that cost recovery certainty, such as the formula transmission rates approved by the Commission, will make transmission investments

[98] Oct. 14 Tr. 6-7 (Roy Thilly) (footnotes omitted).

> attractive to investors and should reduce the return required to attract needed capital.
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> With the policies described above the Commission has made transmission an extremely attractive business, particularly when you add relatively high equity returns, high equity ratios in capital structures and incentive adders. In the current financial markets, I don't know where you can get close to 12+% return available in the Midwest ISO with as little risk. People would line up from here to Omaha to participate in a transmission investment with this risk/return profile. Or perhaps the guy from Omaha would be at the front of the line. I fear that making transmission too attractive through high (and in my view unwarranted) incentive returns may actually further discourage larger systems from entering into joint ownership arrangements and sharing the bounty. And the added cost may increase state resistance.

Mr. Thilly was not the only speaker at the October 2008 technical conference who highlighted the value to investors of the low risk associated with recovery of transmission investment included in rate base recovery.[99] Nor was he the only one to raise concerns that ROE incentives could make it harder to secure siting approvals. For example, the then-Chair of the Maine PUC, Sharon Reishus, commented: "With all due respect, state regulators have and will continue to argue that this has created an unwarranted bonus to the transmission project that would have been built anyway via … the opportunities for full cost recovery." Oct. 14 Tr. 83.

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[99] *See, e.g.,* Oct. 14 Tr. 40, (Roy Piskadlo from Merrill Lynch: "the reason for [significant capital being available for transmission] is that transmission assets offer, once they're built, offer stable, annuity-like cashflows from the regulated returns, as Marc [Lipschultz, Kohlberg Kravis Roberts & Co. ("KKR")] was alluding to a moment ago"); *id.* at 40, (Marc Lipschultz from KKR: "Certainly, as an investor we are drawn to formula-like rate structures, a tracker-type structure, a way to get a near-term recovery, the time value of money, [imparts] more certainty. But I think having the ability to employ capital … and having a way to achieve a return sooner and with certainty will allow you to draw capital at a lower return, all things being equal.") Mr. Piskadlo explained that even given the current market turmoil transmission investment is attractive: "Obviously, there are issues in the markets today, but that's what makes cashflows that come from these types of assets, seem more attractive, not less." *Id*. at 45. *Cf.* Edward Stern from Neptune Regional Transmission System and Hudson Transmission Partners, preferring "more certainty and a lower rate." *Id.* at 114.

ATC, which has accepted an equity return *lower* than the standard MISO return,[100] has been clear that an incentive return is not necessary to get facilities built, and may be counter-productive:[101]

> I would like to stress that encouraging transmission companies to be formed or to invest in new facilities does not automatically equate into higher rates of return. Different business models have different needs which require flexibility.
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> …We have found that ROE adders exacerbate rate pressures in regions where significant investments are being made; and in fact ATC's ROE is below that of any other Midwest ISO transmission-[owning] member, and yet we are investing more than every single one of them.

The CapX2020 legislation provides for a "return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest."[102] Paying incentive rates to transmission developers for the risk and difficulty of siting problems, when those siting problems are aggravated by the incentive rates themselves, is worse than merely a foolish waste of money.

As part of the instant rulemaking in which it poses measures to further reduce the risks associated with transmission investment, and to make it even more common that the facilities for which incentives will be sought are included in the planning process (triggering the rebuttable presumption under 18 C.F.R. § 35.35(i)(1)), the Commission needs to revisit the application of its incentive rate rule. Specifically, the Commission

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[100] Offer of Settlement and Settlement Agreement, *American Transmission Company LLC*, Docket No. ER04-108-000, (Mar. 26, 2004), eLibrary No. 20040329-0088, approved by the Commission in *American Transmission Co. LLC*, 107 FERC ¶ 61,117 (2004).

[101] Transcript of the April 22, 2004 Technical Conference on Transmission Independence and Investment at 197-98, Docket Nos. AD05-5-000 & PL03-1-000, eLibrary No. 20050422-4031 (Dale Landgren, thenVice President, Asset Delivery and Chief Strategic Officer of American Transmission Co.).

[102] CapX Legislation, 2005 Minn. Laws Ch. 97, Art. 1, § 2 (amending Minn. Stat. § 216B.16).

should refine the incentive rule's application, so that it better serves the Commission's planning and expansion objectives, federal and state policy requirements, and the consumer benefits intended by Section 219. The Commission should take a fresh look at the "demonstrable risks or challenges" of pursuing projects included in the regional plan and assess in a new light whether the package of incentives is truly tailored to address those risks and challenges if it includes incentive ROEs that make the project more costly to consumers, more controversial, and more difficult to site.

The incentive rate rule leaves the Commission the flexibility to move away from ROE incentives that increase the cost of major new transmission expansion and aggravate cost allocation issues, and instead to focus on incentives that reduce risks in the early stages of the process and support cash flow without increasing life-cycle costs (*e.g.*, CWIP, precertification expense). Nothing in FPA Section 219 or the Commission's incentive rate rule requires the Commission to authorize returns greater than that necessary to attract new investment in transmission facilities. The ROFR debate and the NOPR's proposed project sponsorship priority highlight that transmission expansion with recovery through rate base is a sought-after privilege, not a burden requiring as an enticement, returns above the level otherwise determined to be reasonable.

Finally, if the Commission nevertheless retains ROE incentives, and if it also rejects TAPS proposal to condition retention of the ROFR on a commitment to not request ROE incentives and to offer joint ownership to TDUs (as discussed in Part IV above), the Commission should tie ROE incentives to joint ownership arrangements that have a proven track record of helping to get transmission built. *See* Part I.C above.

Specifically, the Commission should tie receipt of ROE incentives to a demonstration that the TO has offered TDUs in the pricing zone (or state where the facilities will be built) meaningful opportunities to participate as owners in the upgrade on reasonable terms, as discussed in Part IV.A above. Consistent with Section 219(b)(1)'s directive to promote transmission investment "regardless of the ownership of the facilities," the Commission should use transmission incentives to promote inclusive joint ownership arrangements.[103] Congress' desire to expand the "TO club" is also evident in Section 216(b)(1)(B).[104] The use of incentives to foster inclusive joint ownership arrangements and the associated joint planning would be consistent with the Commission's obligation under Section 217(b)(4) to facilitate the planning and expansion of the grid to meet the needs of all load serving entities, not just transmission owners.

CONCLUSION

For the reasons discussed above, the Commission should adopt a final rule that takes account of TAPS comments.

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[103] *See* EPAct 2005 § 1241, FPA § 219(b)(1).

[104] This provision makes available backstop federal siting authority for designated corridors where the applicant is not eligible to receive a state permit because it does not serve retail load in the state.

Respectfully submitted,

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