UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Promoting Transmission Investment Through Pricing Reform	Docket No RM11-26-000

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

The Transmission Access Policy Study Group ("TAPS") appreciates the opportunity to "comment on the scope and implementation of … transmission incentives regulations and policies under Order No. 679."[1] Those policies are certainly due for re-examination. Experience with the application and results of the Commission's transmission incentives policies teaches several important lessons.

- The incentives that are effective in producing net consumer benefit are those that lead to inclusive entities or consortia, reduce investment risk, and increase the certainty and timeliness of cost recovery. ROE adders, in contrast, are counterproductive and not worthwhile. See Part I, below, and Appendix A hereto.

- To be consistent with Order 1000, the Commission should limit the rebuttable presumption that projects included in the regional plan pass the benefit test of Section 219(a) to those projects selected in the regional transmission plan for regional cost allocation based on their contribution to ensuring reliability or reducing congestion. See Part II.

- Projects that are granted risk-reducing incentives like CWIP, development cost expensing, and abandonment insurance do not face substantial risk of cost non-recovery, and therefore generally do not call for incentive-heightened ROEs. Heightened ROEs for application alongside these other favorable rate treatments should be reserved for exceptional cases of

[1] *Promoting Transmission Investment Through Pricing Reform*, Notice of Inquiry, 76 Fed. Reg. 30,869, 30,869 (May 27, 2011), FERC Stats. & Regs. ¶ 35,572, P 1 (2011) ("NOI").

projects that break new ground organizationally, technologically, environmentally, or otherwise. See Part III.

- ROE adders should be the exception, not the rule. To the extent they are allowed at all, they should be limited by insisting on threshold tests, by applying the adder only while the subject investment is in service, by applying the adder only to actual project investment that falls within the anticipated cost used in project planning, by limiting to total ROE to a range of reasonableness that is determined consistently with the associated cost-based ROE, and by phasing out the use of ROE adders as an incentive for RTO participation. See Part IV.

- The Commission should foster broad participation in the building of a 21st century grid by requiring applicants who seek incentive rate treatments to consider and address joint investment, and by allowing all transmission investors to earn transmission returns comparable to the returns allowed to investor-owned utilities. See Part V.

INTEREST OF TAPS

TAPS is an association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[2] Representing entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS has long recognized the need to strengthen the nation's transmission infrastructure and to develop effective institutional structures that will work to that end. In addition, TAPS members pay transmission rates that are substantially increased when the Commission approves above-cost incentives, and participate, when possible, in transmission development projects. TAPS has therefore participated actively in numerous Commission proceedings concerning transmission planning, pricing, and incentives policies, including those underlying Order No. 679.[3]

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[2] Tom Heller, Missouri River Energy Services, chairs the TAPS Board. Cindy Holman, Oklahoma Municipal Power Authority, is TAPS' Vice Chair. John Twitty is TAPS' Executive Director.

[3] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) ("Order No. 679"), *on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10,

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COMMENTS

TAPS will address the NOI questions of greatest concern, taking them up essentially in numerical order. Part I addresses Questions 1-9; Part II addresses NOI Question 10; Part III addresses NOI Questions 19-28; Part IV addresses NOI Questions 35-41 and 45-48; and Part V addresses NOI Questions 26 and 63-64.

I. RESPONSE TO NOI QUESTIONS 1-9

The NOI invites a five-year check-up on the Commission's implementation of Federal Power Act Section 219[4] through Order No. 679. Such review is certainly warranted, and TAPS welcomes the opportunity to participate. This proceeding presents a valuable opportunity to step back, identify the stated and as-applied policies and practices through which the Commission has responded to past incentives applications, and determine whether continuing to apply those policies and practices to future applications would advance the interests of the consuming public.

2007), FERC Stats. & Regs. ¶ 31,236 (2006), *clarified*, 119 FERC ¶ 61,062 (2007).

[4] 16 U.S.C. § 824s.

TAPS believes, and will show below, that those policies and practices need substantial revision. The industry and its customers now have many years' experience with transmission incentives—not only five years' experience since Order No. 679, but also several years' prior experience under the transmission incentives policies of Order No. 2000,[5] the 2003 Incentives Policy Statement,[6] and the series of ad hoc orders that began a decade ago with the Commission's emergency response to California blackouts.[7] Through this experience, we now know which incentives approvals pay off in net consumer benefits, and which don't:

- The main barriers to timely transmission development involve not capital availability but siting, technology, planning uncertainties, and conflicts among and within the relevant public and private decisionmakers.
- Incentives enable real progress when they bring about inclusive institutional arrangements oriented towards transmission development, such as transcos owned by, or consortia open to, all load-serving entities ("LSEs") within their footprint. Such institutions lead to pro-active transmission planning and create transmission developers that have the broad support and long-term persistence needed to turn blueprints into wires. They work.
- Incentives that reduce investment risk, increasing the certainty of cost recovery without authorizing above-cost recoveries, motivate transmission developers without

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[5] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999) ("Order No. 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 nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[6] *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 FERC ¶ 61,032 (2003).

[7] *Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States*, 94 FERC ¶ 61,272, *reh'g dismissed*, 95 FERC ¶ 61,225, *reh'g granted in part*, 96 FERC ¶ 61,155, *clarified*, 97 FERC 61,024 (2001).

giving siting authorities and other decisionmakers and stakeholders new reasons to oppose transmission development. They work.

- Incentives that expedite payment to transmission developers (while recognizing money's time value) reduce risk and nourish sustained efforts to site and build. They work.
- But it is self-defeating to hand out above-cost rewards for specific projects based on an administrative guess as to whether incentives will enable their construction. Many high-visibility projects for which above-cost rewards have been authorized have not proceeded to actual construction, because transmission developer motivation is only one of many factors that determine whether a project climbs the long hill to completion. Above-cost rewards may, or may not, significantly increase the developer's desire to reach the top. But they do steepen the climb: a higher price tag makes it harder, not easier, to obtain state commission approvals for siting and investment. Such incentives don't work well and should be rethought.

These conclusions are supported by the experiences of transmission builders that do not rely on above-cost incentives, by the outcomes of past Commission incentives orders, by real-world investment-community documentation, and by common sense. Collectively, this experience bears out the policy prescriptions that TAPS offered in its 2004 whitepaper, *Effective Solutions for Getting Needed Transmission Built at Reasonable Cost* ("*Effective Solutions*").[8] That whitepaper supported construction of needed transmission and judicious use of risk-reducing incentives to that end, while opposing above-cost ROE adders. Experience since then only reinforces the whitepaper's recommendations.

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

Successful transmission development by inclusive builders and without above-cost incentives. There are plenty of examples of transmission development advancing *without* above-cost incentives. Some of those examples have come to the Commission's attention through requests for cost-based incentives like Construction Work in Progress ("CWIP") and abandonment insurance.[9] Myriad others have simply been built, without demanding incentives and therefore without necessarily coming to the Commission's attention. There is no evidence that transmission construction has been impeded because the "baseline" ROEs applied to completed projects are too low or because such ROEs will be insufficient to encourage new transmission investment once other risks are addressed through separate incentives.

Inclusive organizations and consortia have been especially effective in getting needed new facilities built on time and at cost.

American Transmission Company LLC ("ATCLLC"), an inclusive transco[10] based in Wisconsin and Michigan's Upper Peninsula, shows what inclusive institutions can accomplish without above-cost incentives. ATCLLC was formed in 2001 through asset contributions that gave it ownership of less than $650 million in net transmission investment.[11] It has since invested $2.2 billion to upgrade more than 1,650 miles of transmission line, improve 140 electric substations, and build 40 new transmission lines spanning 530 miles, and plans to invest an additional $3.4 billion over the next ten years, even before considering participation in wind

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[9] *See, e.g.*, *S. Ind. Gas & Elec. Co.*, 125 FERC ¶ 61,124 (2008) (authorizing CWIP and abandonment incentives for the Gibson-Brown-Reid project, a 70-mile, 345 kilovolt project in Indiana and Kentucky). That project entered service timely, in November 2010. *See* https://www.midwestiso.org/Library/Repository/Study/Seasonal%20Assessments/2011%20Summer%20CSA%20Final%20Public%20Report.pdf.

[10] ATCLLC has 5 investor-owned utility, 17 municipal utility, and 6 rural cooperative owners. It is a single-purpose transmission company with 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.

[11] *See* ATCLLC, *2002 Annual Report* 12 (2002), *available at* http://www.atcllc.com/pdf/2002AnnualReport.pdf.

integration transmission projects.[12] ATCLLC has experienced generally rapid approval and no rejections of its applications to construct. For example, it was able to bring to completion the important 345 kV Arrowhead-to-Weston line, which it inherited as a controversial legacy project when it was formed. ATCLLC has achieved this track record without above-cost incentives. Indeed, ATCLLC's formula rate under Attachment O of the Midwest ISO tariff utilizes a lower ROE than that which the Commission established as the cost-based level available to all MISO TOs.

The CapX2020 transmission consortium of 11 investor-owned, municipal, and rural cooperative utilities in Minnesota and Wisconsin is another such success story. It has planned, and secured most of the necessary approvals for, a "Phase I" consisting of four 345 kV backbone transmission lines that will cost close to $2 billion, and associated with upgrades to individual systems costing about $1 billion more, that collectively will significantly strengthen the Minnesota transmission system and constitute the first set of major transmission additions completed there since the 1970s.[13] In addition, CapX2020 plans to undertake a "Phase II" set of projects that will be focused primarily on transmitting renewable energy and will cost $4-7 billion. The CapX2020 participants are likewise proceeding without any adders to the standard Midwest ISO regional return on equity.

Transcos likewise have undertaken major transmission investment programs, with or without ROE-heightening incentives. While such firms are not inherently inclusive, they have moved most rapidly and cost-effectively towards project completion when they have partnered

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[12] *See* ATCLLC, *10-Year Transmission System Assessment, Summary Report* 2-6 (2010), *available at* http://www.atc10yearplan.com/documents/2010ATCSummaryFNL.pdf.

[13] *See, e.g.*, CapX2020 frequently asked questions, *available at* http://www.capx2020.com/faq.html#1 (response to FAQ No. 2).

inclusively with affected load-serving entities. For example, TransBay Cable partnered with the City of Pittsburg, California to site and build a new High-Voltage Direct Current cable into San Francisco, which entered commercial operation in November 2010.[14] The ITC operating companies have collaborated with affected load-serving entities on a set of lines spanning south-central Kansas, which received Kansas Corporation Commission siting approval two months ago.[15]

Inclusive, institutional approaches work for numerous reasons. First, they enable the planning decision as to which new investments should be proposed for siting review to be based on technical merit rather than gamesmanship over which transmission builder will enjoy above-cost profits. Second, they open up new line routing opportunities and potentials for economies of scale. For example, the CapX2020 consortium intentionally scaled certain towers and right-of-way to a standard larger than immediately needed, allowing for a second circuit to be added in the future without additional siting or land acquisition processes and risk. By making a modest, timely investment in expansion potential, the consortium reduced anticipated long-term costs. The consortium was able to undertake such advance investment because it is in the transmission development business for the long haul, and because, having refrained from seeking ROE adders, it is not open to the charge that building in cheap expansibility is a gambit to increase the rate base that receives an above-cost return. Third, once an inclusive planning process identifies a facility to be built, inclusive opportunities for ownership mean that a broad group of utility industry stakeholders will be enlisted in pursuing needed siting approvals, persuading the general

[14] *See Trans Bay Cable LLC*, 135 FERC ¶ 61,135 P5 (2011) (noting that cable entered commercial operation November 23, 2010).

[15] *See* Order Granting Siting Permit, *In the Matter of the Application of ITC Great Plains*, Kansas Corp. Comm'n Docket 11-ITCE-644-MIS (July 12, 2011).

public that the project's costs and environmental impacts are worth bearing, and supporting, against siting opponent criticisms, decisions by state regulatory authorities to approve new lines. Fourth, by enabling LSEs to hedge the costs of transmission rate base increases through ownership participation, they enable all stakeholders to align their interests and reduce the pressures for rate litigation. In turn, that change creates a more stable, less controversial context for planning and construction. The resulting business climate promotes good long-term planning and may reduce capital costs. It also reduces the share of limited regulatory resources that must be devoted to resolving rate disputes.

Outcomes of Past Commission Incentives Orders. Those writing applications for incentives have an incentive of their own, namely to address the Order No. 697 "nexus" test by emphasizing the likelihood that contemplated projects will be built, if only they are rewarded. Consequently, reading the parade of incentives applications creates a distorted view of what has actually been happening in the real world of stringing new wires. While there certainly have been numerous applications for ROE adders for large investments, and numerous approvals of such applications, many of the underlying projects have been shelved or abandoned. A more realistic picture emerges if one takes as a sample the orders related to specific projects, and collected on the Commission's website under electric "Industry Activities,"[16] in which new ROE adders were authorized pursuant to Order No. 697.[17] In order to focus on those decisions for which sufficient time has since passed for their real-world outcome to become evident, we limit the review to orders issued in 2006 through 2008.

[16] The orders for 2006 are collected at http://www.ferc.gov/industries/electric/indus-act/trans-invest/2006.asp, and each later year has its own page with a parallel address.

[17] Given its scope, the table excludes orders in which only non-ROE incentives were authorized. The table also excludes orders that authorized the continued application of a previously-approved ROE or set the incentive ROE level for hearing.

As detailed in Appendix A hereto, of the twenty such sets[18] of orders, only two have to this point yielded projects that are complete and in service. Four are under construction. Six are in a mixed or intermediate status—still undergoing siting or environmental review, redesigned as lower-voltage facilities, having a wide range of statuses for different components of the original incentives request, or the like. But for eight of the orders, the underlying project(s) have been substantially delayed, suspended, or abandoned entirely.

Incentives are worthwhile only if they lead to valuable *incremental* facilities—real wires that would not have been strung otherwise and whose value justifies making ratepayers fund the incentives. It is difficult to ascertain whether the incentives awarded to any one project have advanced it towards completion, had the opposite effect, or had no material effect other than to increase rates. But the overall pattern identified here is meaningful. It demonstrates that the correspondence between ROE adders and worthwhile results is at best complicated and tenuous; that many factors and many actors determine whether transmission plans become transmission wires. In turn, this multiplicity suggests the wisdom of placing more reliance on inclusive institutional structures and risk-reducing, cost-neutral incentives than on trying to motivate transmission owners. If many factors and many actors bear on transmission project success, why opt for a tool that is guaranteed to heighten the opposition of many among them, and may therefore be counterproductive in determining whether transmission is actually built?

Investment-Community Documentation. Transmission owners seeking incentives have every reason to imply that return allowances that reflect the cost of capital are insufficient to enable them to raise the amounts needed for their transmission expansion programs. A more

[18] To avoid duplication, each series of orders in a given docket or set of related dockets is grouped as a single disposition (e.g., an initial order and an order on its rehearing are counted only once).

credible explanation of their return requirements can be seen in what they tell Wall Street. American Electric Power ("AEP"), for example, recently told investors that Electric Transmission Texas (a joint venture of AEP and MidAmerican) plans to invest $3 billion in ERCOT-area transmission, where that investment will garner a 9.96% ROE.[19] Far from viewing that 9.96% cost-based return level as inadequate, AEP views it as a valuable "investment opportunit[y]," which its joint venture will voluntarily undertake even though it has no obligation to serve. *Id.*

Statements by investment houses to investors are similar. The TAPS *Effective Solutions* whitepaper summarizes the debt rating agencies' longstanding view that transmission is a very safe investment.[20] More recently, UBS Investment Research recently summed up as follows its view that Northeast Utilities will take on a more attractive risk/reward profile as the transmission share of its asset base increases: "Transmission: Not Sexy, but Lucrative."[21] More generally, a recent Lazard Freres presentation explains that the riskiness of regulated, monopolistic infrastructure companies such as electric utilities (as measured by the standard deviation of their share prices' volatility) is about half that of equities in general.[22] The exception is "merchant power generators."[23] Because the Commission's Discounted Cash Flow ("DCF") method for determining baseline returns on equity looks to the risk and reward of vertically-integrated

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[19] AEP, Presentation at SunTrust Investor Luncheon 29 (June 16, 2011), *available at* http://www.aep.com/investors/present/documents/SuntrustLuncheonhandout.pdf.

[20] *See Effective Solutions* 15-16.

[21] UBS, *UBS Investment Research, US Electric Utilities* 58 (July 12, 2010), *available at* http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId=%7BDB217DCD-538F-4B82-8D90-45C55C1F58D5%7D.

[22] Lazard Asset Management LLC, *Lazard Insights Conference Call Series: The Unique Characteristics of the Global Infrastructure Asset Class* 3 (Aug. 25, 2010), *available at* http://www.lazardnet.com/confcalls/pdfs/2010/UniqueCharacteristicsOfGlobalInfrastructure_LazardInsightsCallSummary_2010-08.pdf.

[23] *Id*.

utilities with substantial involvement in merchant power generation, it already bakes in a substantial premium above the cost of capital invested in transmission, even before any equity return adder is considered.

Investment-house statements made directly to the Commission are in accord. For example, panelists at the Technical Conference on Transmission Barriers to Entry[24] agreed that ample capital was available to transmission projects eligible for recovery through regulated, cost-based rates. Marc Lipschultz of Kohlberg Kravis Roberts & Co. testified that 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." Oct. 14 Tr. 64. Roy Piskadlo of Merrill Lynch agreed that "the reason for [significant capital being available for transmission] is that transmission assets, … once they're built, offer stable, annuity-like cashflows from the regulated returns."[25] Mr. Piskadlo explained that transmission investment is attractive even during times of market turmoil like that experienced in 2008: "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."[26]

A related, global perspective was presented recently by Johannes Kindler, Vice Chairman of Germany's version of FERC (and the FCC), namely the Federal Network Agency. In his view, a cost-based ROE "is adequate and will attract sufficient capital for the [transmission]

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[24] Transcript of Oct. 14, 2008 Technical Conference on Transmission Barriers to Entry, Docket No. AD08-13-000 (Oct. 14, 2008), eLibrary No. 20081014-4031 ("Oct. 14 Tr.").

[25] *Id.* Tr. 40.

[26] *Id.* Tr. 45.

investments needed," above-cost incentives "do not accelerate investments," and "a stable[,] transparent[,] and reliable regulatory framework" is "more important than 'window-dressing' ROE changes."[27]

Common Sense. In an era of interest rates down near 3%,[28] enormous cash reserves waiting for the right investment opportunities in a slow economy, and a demographic bulge entering retirement and looking (both individually and through pension funds) for low-risk, dependable-income investments, there is no shortage of funds available for investment in rate-based transmission assets in exchange for reasonable, cost-based returns. That ample supply, and the consequent lack of need for above-cost incentives, is amplified by the ready availability of cost-neutral, risk-reducing rate treatments. Non-bypassable formula rates that automatically recover the current transmission revenue requirement ensure that transmission customers, not transmission owners, bear the risks of cost inflation, load diminution, and the like. Recovery of the full carrying costs of pre-operational transmission investment through Construction Work in Progress treatment ensures that transmission customers, not transmission owners, bear the risks of construction delays, and addresses any legitimate concern about cash flow during construction. "Pre-commercial" recovery of project development costs ensures that transmission customers, not transmission owners, bear the risks of planning, environmental, or other disapprovals. Order No. 1000[29] reinforces these recovery assurances, by providing that transmission facilities selected for inclusion in the regional transmission plan for purposes of

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[27] Johannes Kindler, Vice Chairman, Fed. Network Agency Germany, Presentation at the CEEPR Spring 2011 Workshop: Incentivizing Investments in Transmission 8 (May 6, 2011), *available at* http://web.mit.edu/ceepr/www/about/May2011/may%20handouts/kindler.pdf.

[28] See, for example, the Commission's prime-based refund interest rates, *available at* http://www.ferc.gov/legal/acct-matts/interest-rates.asp.

[29] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011) ("Order No. 1000").

cost allocation will be eligible for cost recovery pursuant to the regional cost allocation methodology, even if the project is to be constructed by a non-incumbent developer.[30] [31]

Once a transmission facility enters service and has its costs approved for recovery through non-bypassable network service rates, there is very little risk that those costs will go unrecovered. That is especially true with formula rates, which minimize the risk or regulatory disallowance and eliminate the risk that costs will go uncompensated if they grow faster than load. Owning transmission facilities for which cost recovery has been approved or will occur automatically through formula rates is like owning an annuity. Capital invested in transmission projects for which these risk-reducing and risk-shifting policies have been approved is never at much risk: Most of the capital does not begin to be invested until the project has already received siting and permitting approvals, and thus has already cleared its main hurdles. For the rare project that crosses transmission pricing borders, there has in the past been some risk that pre-construction costs would go unrecovered due to cost allocation uncertainties. However, the Commission, in Order No. 1000, has recently taken steps to substantially reduce even that risk. Once a project is approved for construction, breaks ground, and thus begins incurring the bulk of its investment cost, it is unlikely to face material further risk of cost recovery. Projects that use unproven technology may be a narrow exception. However, technology risk is one from which transmission owners typically will be, and prudent transmission owners should be, insulated through warranties and/or insurance, and in any event such risk will be largely resolved through testing before a facility enters service.

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[30] Order No. 1000, P 9.

[31] Indeed, transmission owners' actions in vigorously opposing Order No. 1000's partial elimination of federal rights of first refusal speak far more loudly than their claims that ROE incentives are needed to spur needed transmission construction.

Given the ready availability of capital and low risks, the main barriers to timely transmission development do not involve the return on equity. They involve siting, technology, uncertainties as to where and when transmission capacity will be needed, and conflicts both within vertically-integrated market participants[32] and among stakeholders. Incentives should be selected strategically to overcome, not heighten, these barriers. Strategic incentives promote the formation of inclusive and durable institutions that can be relied upon to elicit good information bearing on transmission planning, select worthwhile transmission projects, resolve issues of cost allocation in the context of broad opportunities to participate and without having to allocate above-cost charges, explain system needs to the public and to siting authorities with a unified industry voice, and carry projects to completion.

ROE adders are not strategic. When the Commission doles out ROE incentives on an ad hoc basis, it has no good way to test the claims of incentives applicants that a higher ROE will serve a useful purpose, no good way to know at what level to stop, and no good way to know when a higher ROE becomes a mere giveaway of ratepayers' limited funds. At best, ROE adders address transmission owner motivation in the hope that such motivation will "trickle down" to actual construction. But it wastes ratepayers' limited funds to rely on that indirect approach instead of "watering the roots" by supporting full recoverability of environmental impact mitigation costs and impact payments made to overcome siting objections. And at worst, ROE adders heighten the real obstacles. ATCLLC has been clear that above-cost returns are not necessary to get facilities built, and may be counterproductive:[33]

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[32] I.e., the fact that expanded transmission can expose the transmission owner's generation and loads to competition.

[33] Transcript of Apr. 22, 2005 Technical Conference on Transmission Independence and Investment and Pricing Policy for Efficient Operation and Expansion of the Transmission Grid 197-98, Docket Nos. AD05-5-000, PL03-1-000 (Apr. 22, 2005), eLibrary No. 20050422-4031 (Comments of Dale Landgren, ATCLLC) ("Apr. 22 Tr.").

> 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 requires 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.

ROE adders weaken the cost/benefit case for building transmission instead of relying on sub-optimal generation and distribution alternatives. They make siting and cost allocation harder, by increasing both the stakes and the contentiousness of those processes. State regulators, which are under extraordinary pressure to reduce or limit costs, are not favorably disposed towards approving lines that carry incentive-heightened price tags.[34] They undercut confidence that the transmission spending being proposed is the transmission spending that is most useful. For example, because large projects are more likely to be viewed as meriting above-cost incentives, transmission owners are effectively encouraged to avoid making timely small investments or maintenance expenditures, until they can substitute a large, incentives-worthy batch. Similarly, ROE adders provide the basis for a public perception that transmission owners trying to site new facilities are in it only for extraordinary profits, and raise concerns that budget over-runs will generate even more extraordinary profits. ROE adders therefore undercut the credibility of those asserting that new facilities are needed for economic and/or reliability

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[34] Consider, for example, the Maryland Public Service Commission. It has Certificate of Public Convenience and Necessity siting authority for transmission lines rated 69 kV and above. Md. Code Ann., Pub. Util. Cos. § 7-207(d)(1). It is also a body that has recently faced heavy political pressures due to rate increases. *See* Mark A. Jamison et al., Pub. Util. Res. Ctr., Warrington College of Bus. Admin., Univ. of Fla., PURC Case No. 2006-2, *Disbanding the Maryland Public Service Commission* (2006), *available at* http://warrington.ufl.edu/purc/purcdocs/papers/0627_Jamison_Disbanding_the_Maryland.pdf.

reasons. For all these reasons, ROE adders make it more difficult for regional planners and state and local siting and permitting authorities to timely grant necessary approvals.

Furthermore, even if such pushback against incentives can be avoided, ROE adders unavoidably divert ratepayers' limited funding ability away from other important investments—e.g., enhancing reliability, demand response and energy efficiency technologies, and distributed renewable generation. For all these reasons, ROE adders should be a last resort. They should be reserved for cases in which the need for and level of the adder is appropriately tested and supported, and in which the base ROE to which the adder is applied takes full account of the low risk of transmission investment and the risk-reducing nature of applicable cost-based incentives.

Parts III-IV below expand our discussion of ROE adders. Because we are addressing the NOI's questions in their numerical order, however, we turn first to NOI Question 10, concerning the rebuttable presumption that applies to projects that have been considered by entities other than the Commission.

II. COMMENTS ON REBUTTABLE PRESUMPTIONS (NOI QUESTION 10)

As noted in the NOI (P 16), although Federal Power Act Section 219(a) conditions eligibility for incentives on a Commission finding that a project ensures reliability or reduces congestion, Order No. 679 established a rebuttable presumption that a project satisfies this condition if it has received certain approvals from entities other than the Commission. The rebuttable presumption applies if the project: (i) results from a fair and open regional planning process that considers and evaluates a project for reliability and/or congestion, and is found to be acceptable to the Commission; or (ii) has received construction approval from an appropriate state commission or state siting authority. Otherwise, to be eligible for incentives, an applicant must make an independent showing that its project either ensures reliability or reduces transmission congestion. NOI Question 10 asks whether the two parts of this rebuttable presumption "serve as appropriate bases for satisfying the statutory threshold." NOI P 17.

To serve its intended purpose, the first (clause (i)) part of the rebuttable presumption needs to be updated to reflect Order No. 1000. Specifically, the presumption should apply only to projects selected by the regional planning process for regional cost allocation, and identified in documentation associated with that process as ensuring reliability or reducing congestion.

Order No. 1000 recognizes that projects not regionally evaluated for benefits may be included in the regional plan, i.e., that mere inclusion in a regional plan does not mean that a project has been regionally evaluated for benefits. That is why Order No. 1000 ties many of its directives and benefits to a "transmission facility selected in a regional transmission plan for purposes of cost allocation," which it defines as "one that has been selected, pursuant to a Commission-approved regional transmission planning process, as a more efficient or cost-effective solution to regional transmission needs." Order No. 1000, P 5. It repeatedly distinguishes facilities selected in the regional planning process for regional cost allocation from those merely "rolled up" into the regional plan, "without going through an analysis at the regional level." *See, e.g.*, *id.* P 7; *id.* P 226 (limiting partial elimination of the right of first refusal to facilities selected for regional cost allocation).[35] The Commission explained the basis for this distinction at paragraph 318:

> The Commission's focus here is on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation.[299] As Edison Electric Institute notes, in those regions relying on "bottom up" local transmission planning, a transmission facility that is in a public utility transmission provider's local transmission plan might

[35] The Commission was not alone in making that distinction. *See id.* P 306 "Edison Electric Institute asks the Commission to clarify that only an incumbent transmission owner should be allowed to propose local, single system facilities that are simply rolled up into a regional plan …."

> be "rolled-up" and listed in a regional transmission plan to facilitate analysis at the regional level. However, the transmission facility from the local transmission plan might not have been proposed in the regional transmission planning process and might not have been selected in the regional transmission plan for purposes of cost allocation by going through an analysis in the regional transmission planning process.
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> [299] In order for a transmission facility to be eligible for the regional cost allocation methods, the region must select the transmission facility in the regional transmission plan for purposes of cost allocation. For those facilities not seeking cost allocation, the region may nonetheless have those transmission facilities in its regional transmission plan for information or other purposes, and then having such a facility in the plan would not trigger regional cost allocation.

Order No. 1000 found this distinction particularly important where regions rely primarily on a "bottom up" planning process, i.e., a process that "emphasiz[es] the development of local transmission plans prior to analysis at the regional level of alternative solutions." *Id.* P 321.[36]

The Commission should update rebuttable presumption clause (i) to reflect Order No. 1000's correct recognition that merely being "rolled up" into the regional planning does not mean a facility has been evaluated for the benefits Section 219(a) requires as a qualification for incentives. Specifically, to be consistent with Order No. 1000, the Commission should limit the rebuttable presumption that projects included in the regional plan pass the benefit test of Section 219(a) to those projects selected in the regional transmission plan for regional cost allocation based on their contribution to ensuring reliability and reducing congestion.

The basis on which projects are included in a regional plan will be known. The Order No. 1000 transparency requirement for selection of proposals in the regional transmission plan for cost allocation so ensures. As described in Order No. 1000 at paragraph 328, "The evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation."[37] Thus, the Commission should certainly be able to be determine, from the outcome of the regional planning process, the basis on which a facility was selected, and use the region's assessment as to whether the facility is designed to ensure reliability or reduce congestion as the basis for applying the rebuttable presumption.[38]

Fundamentally, the rebuttable presumption constitutes empowers entities other than the Commission to make the first-instance determination of whether a project meets the Section 219(a) congestion/reliability benefits test, subject to Commission review.[39] Clause (i) looks to the regional planning process, while clause (ii) relies on the applicable state authority. The clause (i) reliance in the first instance on a nongovernmental process is not reasonable unless the decision by that process actually does represent a finding that the project meets the Section 219(a) benefits test.[40] Now that Order No. 1000 has found that regional plan inclusion may or may not represent such a benefits finding, and has required transparency in that regard, rational decisionmaking requires that inclusion in the regional plan not be automatically equated with a benefits finding.

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[36] *See also id.* PP 158, 255, and 320 (discussing "bottom up" planning processes).

[37] *See also id.* P 668, Cost Allocation Principle 5 ("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.").

[38] A facility included in the regional plan for Public Policy Requirements should not be excluded from application of the rebuttable presumption, so long as it is also found by the region to enhance reliability or reduce congestion.

[39] As is the case today, qualification for the rebuttable presumption takes the place of a specific showing that the proposed project produces reliability or congestion benefits, but it does not ensure that the facility meets the nexus test. Indeed, selection for regional cost allocation reduces cost recovery risk, and may make it *harder* to satisfy the nexus test, especially with respect to ROE incentives (as is illustrated by the heated controversy in the Order No. 1000 rulemaking over the right of first refusal to build these projects, which suggests that construction of such facilities is already an attractive investment that does not require ROE incentives).

[40] TAPS' application for rehearing of Order No. 1000 addresses the decision making process used in the regional planning process in non-RTO regions. *See* Request for Rehearing of the Transmission Access Policy Study Group at 7-14, Docket No. RM10-23 (Aug. 22, 2011), eLibrary No. 20110822-5109.

In short, Order No. 679's regional plan rebuttable presumption should be updated to reflect Order No. 1000's enhanced regional planning requirements. In light of Order No. 1000, it would be arbitrary to apply a rebuttable presumption to facilities that are merely "rolled up" into the regional plan, and are not selected for inclusion in the regional plan for cost allocation purposes to achieve the reliability enhancement and/or congestion reduction benefits identified in Section 219(a).

III. COMMENTS ON THE USE OF THE "NEXUS" TEST TO DETERMINE ELIGIBILITY FOR INCENTIVES AND ON THE INTERRELATIONSHIP OF INCENTIVES (NOI QUESTIONS 19-28)

The NOI asks (in Question 24) whether there are "aspects of the Commission's accounting and ratemaking policies, including the use of formula rates, that reduce or increase the risks and challenges of a transmission project[.]" This question is central, and its answer also answers the NOI's other questions numbered 19 through 28. Ratemaking policies like the use of non-bypassable cost-of-service formula rates substantially reduce the risks of transmission investment. When considering ROE adders, therefore, the nexus test should focus not on all of the risks and challenges that face a project developer when it comes to FERC, but rather on the risks that remain on the developer once any other rate treatments requested by the developer and approved by the Commission are taken into account. Projects that are granted risk-reducing incentives like CWIP, development cost expensing, and abandonment insurance do not face substantial risk of cost non-recovery, and therefore generally do not call for incentive-heightened ROEs.

Heightened ROEs for application alongside these other favorable rate treatments should be reserved for exceptional cases of projects that break new ground organizationally, technologically, environmentally, or otherwise. Such projects may result in "public goods" such that compensating them for their costs will not suffice to bring about an optimal level of investment. For example, if a transmission developer pioneered a way to inexpensively underground a high-voltage transmission line when it passes through environmentally significant vistas, it would advance not only its own project but also future projects facing similar siting difficulties. However, this approach only works well if the bar continues to rise. Suppose that in the prior example, two transmission developers are considering being the first to commercially deploy a promising new way to inexpensively underground a high-voltage transmission line when it passes through environmentally significant vistas. If they know they will both receive the same incentive adder, then each may seek to maximize reward while minimizing risk by going second, leaving to the other the burdens of being the pioneer. But if they both mimic Alphonse and Gaston, neither will make it through the doorway.

The Commission therefore should focus the nexus test such that it rewards projects that break new ground in one or more of the following ways:

- **Organizationally:** Formal legal entities and informal project consortia that inclusively bring existing stakeholders into joint transmission building efforts lay the organizational and financial groundwork for a long-term, consensus-based program of building tomorrow's grid. Like philanthropic "seed money," rewarding the formation of such arrangements is more strategic than rewarding an existing major transmission owner for building one more line.

- **Technologically:** FERC should refocus its incentives awards so that they place more emphasis on rewarding projects that pioneer the commercial application of new technologies. The emphasis should not be on rewarding an entity for the first time that particular entity applies any given advanced technology, even if it's old hat for other U.S. utilities. For example, 765 kV facilities have been in use in the U.S. for decades. They are not the technological cutting edge, and building them in the U.S. will not advance the global state of the art. Instead, the emphasis should be on projects that demonstrate the efficacy of new technologies and drive down their manufacturing and other costs. It would be consistent with this focus to apply the ROE adder only to the costs directly related to the new technology, and thus to a more narrow incentive rate base.

- **Environmentally:** The Commission should be prepared to reward creative solutions that directly address the siting impediments to new transmission.

The nexus test can also be improved by relying on structural rather than judgmental ways to identify whether a project truly faces challenges that necessitate an above-cost incentive. In general, incentive applicants should be obligated to demonstrate that they have sought to mitigate risk and have considered alternative ways of addressing risk short of seeking an incentive. Applicants who insist on building a project themselves, without opening the project to participation on reasonable terms by LSEs that will bear the cost, should not be heard to complain that their project will not be built without incentives.

IV. ADDITIONAL COMMENTS ON THE USE OF RETURN ON EQUITY INCENTIVE "ADDERS" (NOI QUESTIONS 35-41, 45-48)

As discussed in Part I above, the most effective way to ensure that transmission construction risks do not impede transmission construction is to reduce or shift those risks, not to give transmission owners extra rewards, above their cost-based return on equity, for bearing those risks. Although the premise of ROE incentives is to encourage project investment by offering investors a return commensurate with projects' siting, construction, regulatory, and other risks and challenges, it is unclear what risks remain to be addressed if development cost amortization, CWIP, and abandoned plant incentive protections are in place, and TOs are recovering investment and expenses through formula transmission rates.

Accordingly, ROE adders should be the exception, not the rule. To the extent they are allowed at all, they should be limited by insisting on threshold tests, by applying the adder only while the subject investment is in service, by applying the adder only to actual project investment that falls within the anticipated cost used in project planning, and by limiting total ROE to a range of reasonableness that is determined consistent with the associated cost-based ROE. In addition, the use of ROE adders as an incentive for RTO participation should be phased out.

A. Threshold Tests Should Limit Which Projects Can Receive ROE Adders

ROE adders should be reserved to applicants who, in addition to meeting other standards, face risks and challenges greater than those typical of utilities that build and own vertically-integrated generation, transmission, and distribution systems, because those baseline risks and challenges are already reflected in the proxy group's implied costs of equity.

Under Order No. 679, the Commission has attempted to determine which incentive-seeking projects face risks and challenges sufficient to warrant incentives by making an administrative judgment from a paper record. With all due respect, such fact-finding is doomed to fail. It is easy for applicants to claim that building their project will be unusually challenging. But it is hard for the Commission to discern from papers the credibility of such claims and counter-claims. As the Commission itself explained in a related context, even after a live evidentiary trial one must be "skeptical" about the Commission's "ability to make carefully calibrated adjustments within the zone of reasonableness" to reflect "subtle differences in risk." *Nw. Pipeline Corp.*, 92 FERC ¶ 61,287, at 62,006 (2000), *review denied and dismissed in part*, *Canadian Ass'n of Petroleum Producers v. FERC*, 308 F.3d 11 (D.C. Cir. 2002).

Rather than relying on paper hearings to distinguish line-siting mountains from line-siting molehills, a better approach would be to subject claims of difficulties to reality testing and baseline standards.

Reality testing: Incentives should not be available unless the need for an incentive has been put to the test by opening the opportunities to fund the project to a wide range of eligible entities, including all LSEs that will be subject to the resulting transmission rate and are ready, willing, and able to provide funding. Order No. 1000, as described generally at paragraph 7, establishes the basis for real-life testing of claims that incentives are necessary, by substantially narrowing the federal right of first refusal.

Baseline standards: The Commission should identify a set of "baseline" activities in which transmission owners are expected to be engaged in return for the base ROE. Customers shouldn't be required to pay transmission owners an incentive return to reward them for fulfilling their responsibilities in accordance with good utility practice, e.g., investing in timely capitalized maintenance. The fact that a project sponsor must engage in such baseline activities should not constitute a basis for allowing an above-cost ROE. Similarly, applicants that have assumed a contractual commitment to construct new and needed facilities should not be eligible for an ROE incentive adder. Adherence to contractual commitments should be considered a baseline standard, and where a commitment to build exists, there is no need for an incentive and thus no nexus between an added charge to ratepayers and added development. At a minimum, such applicants should face a heavier burden of proof in seeking to justify an ROE adder.

B. ROE Adders Should Apply Only While the Subject Investment Is in Service

NOI Questions 59-62 and 65-67 ask whether the Commission should apply ROE adders to development expense regulatory assets, CWIP, and abandoned plant amounts. The answer is "no." Assuring and expediting the recovery of actual <u>costs</u> can promote investment by keeping cash flows liquid and by assuring investors that they will get back both what they put in and a reasonable profit. But to serve those objectives, there is no need to go beyond recovering actual costs and a cost-based return. Moreover, applicants should not be indifferent to whether projects actually enter service. Applicants should have incentives to complete their projects so that consumers begin to receive the improved service for which they are paying. Stated another way, the Commission should reward only beneficial outcomes, not unsuccessful attempts to build.

Including an above-cost ROE in pre-operational revenue requirements is also problematic because doing so would bias the planning process. Suppose that anything spent on the transmission planning process by certain utilities is paid back and then some, whereas competing planning solutions receive no assurance of anything more than cost. In that case, the incentive-holding developers will be positioned to stack meetings and fund the slickest consultant power-point slides, even if their concept is less meritorious from a technical standpoint.

For all these reasons, ROE adders[41] should apply only to projects that have entered service.

C. ROE Adders Should Apply Only to Actual Project Investment That Falls Within the Anticipated Cost Used in Planning

Federal Power Act Section 219(a) directs the Commission to establish "incentive-based (*including performance-based*) rate treatments" for transmission investment (emphasis added). To implement the italicized language, the Commission should apply the ROE adder only to actual project investments that do not exceed the project budget that was relied upon when the project was approved for inclusion in the applicable regional plan.

Limiting the above-cost portion of project revenues in this fashion is necessary to avoid several misdirected incentives. If ROE adders apply to the entire project cost including costs that exceed the budget, then project developers have incentives to incur extra costs in order to inflate the rate base to which incentives apply. After-the-fact prudence review would involve difficult judgments, and cannot be relied upon to detect and correct all such inflation. On the other hand, there is nothing punitive about limiting ROE adders to only the budgeted portion of the actual investment; the remainder is still recovered at cost, including cost-based profit.

[41] To be clear, what we are advocating be delayed until the underlying project enters service is any increment by which the ROE is set, as an incentive, intentionally above cost. In contrast, an ROE might be fine-tuned in order to more accurately match the inferred cost of equity capital. For example, the Commission might find that the Discounted Cash Flow study results for the only available proxies would not accurately indicate the actual cost of the relevant capital. We are not advocating delay of ROE adjustments made on the latter basis.

Limiting bonuses to the budgeted portion of project costs is also necessary in order to incent accurate cost forecasting. Otherwise, project developers will have incentives to low-ball their budget projections, so that their projects win out in the planning competition with alternatives. Good planning requires good budgeting, and good budgeting requires that bonuses not apply to budget over-runs.

In Order No. 1000 (P 562), the Commission

> require[d] the development of a cost allocation method or a set of methods in advance of particular transmission facilities being proposed so that developers have greater certainty about cost allocation and other stakeholders will understand the cost impacts of the transmission facilities proposed for cost allocation in transmission planning. The appropriate place for this consideration is the regional transmission planning process because addressing these issues through the regional transmission planning process will increase the likelihood that transmission facilities selected in regional transmission plans for purposes of cost allocation are actually constructed, rather than later encountering cost allocation disputes that prevent their construction.

These same considerations dictate that the maximum investment amount to which incentives will apply be limited to the project budget that was relied upon in project planning and the consideration of alternatives.

D. The Adder-Increased ROE Should Be Limited to a Reasonableness Range Consistent with the Associated ROE Baseline

In order to properly limit incentivized returns, the relationship between ROE adders and baseline ROEs should be made clearer and more consistent.

First, transparency is important. Any application seeking ROE adders, and any order granting them, should identify the size of the adders, the cost-based baseline ROE to which they will be added, the zone of reasonableness into which the total ROE will fit, and the resulting total ROE. Distinguishing the cost-based portion of the ROE from any incentive adders is necessary in order to know what return to exclude when recovery is limited to cost (as presumably is already Commission policy in the event of project abandonment, and as Part IV.B above explains should be Commission policy prior to commercial service). Moreover, only if the cost and above-cost portions are distinguished can the Commission and the public know how much is being spent above cost to motivate transmission developers, and assess whether these bonus payments are returning value. Both judicial precedent[42] and the Order No. 679 nexus test require that incentives be calibrated to results, and performing that calibration requires that the incentive portion of the return be identified.

Unlike some of the early rulings under Order No. 679,[43] recent Commission orders have adhered to this transparency requirement.[44] It should be made express in any successor policy.

Equally important, the zone of reasonableness that bounds the total ROE should be determined consistently with the determination of the baseline ROE. In its *Atlantic Grid Operations* order, the Commission gave clear instructions as to the calculation of the median used to determine the baseline ROE. After appropriate screens are applied to the proxy group to eliminate outliers, the Commission averages each company's high and low implied cost of equity.[45] An advantage to this step is that it moderates the impact of an implied cost of equity that, while not an unsustainable outlier, is mere basis points from being such an outlier. The

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[42] *See, e.g.*, *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1503 (D.C. Cir. 1984) (citation omitted) (noting Commission's obligation, when considering incentive-based upward rate adjustments, to "see to it that the increase is in fact needed, and is no more than is needed").

[43] *See, e.g.*, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, P 104 (2008) (determining a total ROE but declining to distinguish its cost-based from its incentive-based portion), *on reh'g in part*, 133 FERC ¶ 61,152 (2010).

[44] *See, e.g.*, *Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144, P 91 (2011).

[45] *Atl. Grid Operations*, 135 FERC ¶ 61,144, P 90 (citing *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152, P 65 n.95 (2010); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 (2010); and *Exelon Generation Co., LLC*, 132 FERC ¶ 61,219, P 25 n.26 (2010)).

Commission uses this range of averaged implied cost of equities to calculate the median that typically will establish the baseline ROE. Logically, in calculating the range of reasonableness, the Commission should use the same range of averaged numbers that the Commission uses to calculate the median used to determine the baseline ROE.

An analyst who projects high growth may do so in part simply because she was comparing a future stock price expectation to a stock price that happened to be lower than usual at the time the projection was made, and that same downward blip in stock prices might be the same reason that dividend yields on the lowest-share-price days of the sample period are high. It invites error to separately identify and treat as distinct sample points the dividend yields on high-priced and low-priced days. It is like treating as distinct sample points a baseball player's batting average on those days when he got a hit and the same player's batting average on those days when he went hitless. Under that methodology, both Ted Williams[46] and Mario Mendoza[47] could each have had the same two batting average results in a given week, even if Williams had six days of 2-for-4 hitting and one day of 0-for-4, while Mendoza had the reverse, six days of 0-for-4 and one day of 2-for-4. Notably, the Commission's DCF methodology as applied to natural gas companies does not create this artificial separation. Averaging each company's high and low implied cost of equity before determining the range of reasonableness would at least mute its effect.

Using the same range of averaged numbers to determine both the range of reasonableness and the range's median is not only required for logical consistency, it is also good policy.

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[46] *See* http://en.wikipedia.org/wiki/Ted_Williams (Ted Williams "was the last player in Major League Baseball to bat over 0.400 in a single season (0.406 in 1941)," and "holds the highest career batting average of anyone with 500 or more home runs.").

[47] *See* http://en.wikipedia.org/wiki/Mendoza_Line ("The Mendoza Line is an expression in baseball in the United States, deriving from the name of shortstop Mario Mendoza, whose lifetime batting average is taken to define the

Averaging each retained proxy company's low and high implied cost of equity before establishing the range of reasonableness ensures that wherever within the range the ROE is ultimately set, it will not be unduly influenced by just one particular input to the DCF methodology. For example, it may happen that the highest retained implied cost of equity, when calculated prior to averaging with the same proxy's low implied cost of equity, gained its position as the highest single sample point because one particular, and anonymous, investment analyst was exceptionally bullish on one parent firm's long-term growth prospects—say, because she has great expectations for earnings by its subsidiary from electricity generation on another continent. By ensuring that no single sample point defines the range of reasonableness on its own, the Commission would attenuate the influence of such statistical noise, and will therefore more precisely identify the range of reasonableness.

Finally, restraining incentive ROEs to a band that is closer to the median ROE would not stifle investment in transmission. If the assumptions underlying the Commission's DCF methodology are correct such that the median identifies the cost of capital, then by definition any incentive above that median will result in a return on equity that is more than sufficient to cover the cost of equity capital and therefore attract investment. However, restraining incentives such that they remain within a consistently-determined, and thus narrower, range of reasonableness will mitigate concerns that incentive returns will be set further above the cost of capital than is necessary to achieve beneficial results, and will limit the extent to which they distort choices between transmission and its alternatives and choices between non-routine transmission investment and routine investment/expenses.

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threshold of incompetent hitting.").

E. ROE Adders for RTO Membership Should Be Phased Out, As Originally Intended (NOI Questions 45-48)

Although ROE adders for RTO membership are now widespread, that does not make them well-founded. Amid the continuous flux in RTO membership affiliations outside of the single-state RTOs and the "landlocked" New England region (with, for example, the qualification of SPP as an RTO; the Nebraska transmission owners' decisions to participate in SPP; numerous Ohio operating companies formerly located in MISO switching to PJM; MidAmerican having joined MISO and Entergy proposing to join MISO; the Kentucky utilities having left MISO; Duquesne having planned to leave PJM for MISO and then reaffirming its membership in PJM; and Ameren and Otter Tail considering departure from MISO) what stands out is the degree to which RTO affiliation decisions are driven by generation market interests and state commission preferences. Transmission ROE adders, while significant to customers who pay FERC-regulated transmission rates, add to transmission owners' bottom line only an incremental increase in the charges for the unbundled portion of the transmission fraction of the overall system. RTO participation adders are therefore more likely to constitute a windfall than to motivate beneficial conduct. They should be phased out in an orderly fashion.

When the Commission first announced its openness to a 50-basis-point incentive for RTO participation, it proposed that qualifying transmission owners "would be authorized to receive the incentive for RTO participation until December 31, 2012." Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid, 102 FERC ¶ 61,032, P 28 (2003). The Commission also proposed to limit the adder's applicability to the investment placed under RTO control at the time the transmission owner joined the RTO, as "an incentive adder of 50 basis points on its ROE for all such facilities transferred," and to further limit its applicability to transmission owners who joined their RTO by December 31, 2004. *Id*. PP 24, 28. The RTO participation adder was intended to apply for eight years to a defined set of recipients and facilities, not as a permanent bonus for facilities built subsequently by transmission owners who joined RTOs later.

The Commission should adhere to the original sunset date of year-end 2012. At most, it should sunset the adder after eight years of applicability to each RTO region. At the very most, after year-end 2012, the adder should apply only to the applicant's transmission investment base as of the time it joined the RTO, such that the incentive amount would decline gradually over time, with the gradual depreciation of the associated rate base.

V. COMMENTS ON JOINT OWNERSHIP AND PUBLIC POWER PARTICIPATION (NOI QUESTIONS 26, 63-64)

As discussed in Part I above, the proven key to getting transmission built is effective institutional structures that are open to participation by relevant LSEs. Consortia and inclusive transcos have the broad support and transmission focus needed to get transmission built, and their track record proves it. Accordingly, the Commission should take several steps to foster broad participation in the building of a 21st century grid.

First, applicants who seek incentive rate treatments (or at least those who apply for above-cost incentives) should be required to consider and address joint investment. That is, incentives applicants should have to state whether they are open to joint investment on reasonable terms by technically and financially qualified TDUs located in the relevant footprint (e.g., the state or region), and depending on the answer, to either explain why not or identify the criteria to qualify for participation.

Second, all transmission investors should be allowed to earn transmission returns comparable to the returns allowed to investor-owned utilities, even if that requires a hypothetical capital structure. Allowing comparable returns widens the field of investors in transmission, encourages inclusive consortia and consensus, and is the proven way to get transmission built. Moreover, tax-exempt governmental and government-financed utilities that earn comparable returns on equity, while flowing through to ratepayers their tax savings and their lower cost of debt in proportion to their effective debt ratio, will have a lower overall revenue requirement per rate base dollar than do investor-owned utilities.[48] Comparable returns are an essential predicate for the realization of these consumer savings. Without them, the benefit of consumer-owned systems' low bond rates would be disproportionately diverted to transmission customers, to the point of raising "private use" tax law concerns. Conversely, consumer-owned systems that are not allowed comparable returns will likely be unable to justify investing their owners' funds in transmission instead of leaving those funds with the owners to be invested elsewhere.

In addition to being justified by these beneficial "end results,"[49] allowing a comparable capital structure is also necessary as a matter of reasonable, cost-based ratemaking. In economic substance, investment in transmission by consumer-owned municipal and cooperative systems is not funded solely through debt. Such systems typically fund their investments through Generation & Transmission Cooperatives ("G&Ts," in the case of coops) or joint action agencies (in the case of municipals). When such wholesale-level consumer-owned entities issue bonds to fund transmission, those bonds are backed by their entire revenue stream, and thus by member distribution systems' retail rates. In addition, in the case of joint action agencies, there is often an implicit or explicit guarantee of those revenues through the municipal taxing authority. It is the backing of the wholesale-level risk by the member municipal utility or distribution

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[48] *See, e.g.*, *The Conn. Light & Power Co. & The Conn. Transmission Mun. Elec. Energy Coop.*, Docket No. EC11-31-000, 134 FERC ¶ 62,091 (2011); *Cent. Minn. Mun. Power Agency & Midwest Mun. Transmission Grp.*, Docket No. EL08-32-000, 134 FERC ¶ 61,115, PP 30-33 (2011); and the cost-of-service analyses and testimony submitted by CTMEEC and CMMPA, respectively, in those proceedings.

[49] *See FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944).

cooperative that enables wholesale-level consumer-owned entities to issue debt at low rates, and to flow the resulting debt cost saving through to customers.[50] The financial backing provided by the member municipal utility or distribution cooperative is not covered by the low debt rate, but is an implicit cost and deserves recognition in the cost of service. Recognizing that financial backing as an equity equivalent by applying a comparable capital structure is a cost-based, reasonable approach.

It is also important to recognize that the alternative to consumer-owned systems earning comparable returns is not a revenue requirement that covers only debt interest. At the latter rate, consumer-owned systems cannot invest because the effect is to divert to transmission customers the benefit of the tax-exempt financing that funds the member distribution systems that provide the equity discussed above. Thus, the alternative to consumer-owned systems earning a return on equity is that the transmission either is not built or is built by a for-profit enterprise at that entity's ROE and capital structure. Neither of these alternatives is better for consumers than the existing policy under which consumer-owned systems are allowed to earn comparable returns.

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[50] *See, e.g.*, Prepared Testimony of James Pardikes at 7, Docket No. EL11-45-000 (June 15, 2011) (attached as Ex. No. MRES-6 to Petition of Missouri River Energy Services for a Declaratory Order on Transmission Rate Incentives and for Exemption in Lieu of the Applicable Fee), eLibrary No. 20110616-0201. ("MRES members are required to make[] payments on the debt associated with Fargo 2&3 and Brookings even if revenues from other sources are insufficient. MRES members have to back the debt of these projects whereas IOU shareholders (the owners of IOUs) do not have to back their bonds if debt service payments are not made by the IOU. As a result of having its members guarantee the debt service payments, MRES receives a higher credit rating and lower financing costs.").

CONCLUSION

TAPS appreciates the opportunity to participate in this five-year review of the Order No. 697 incentives policies, and recommends substantial policy changes as discussed above.

Respectfully submitted,

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APPENDIX A
TO TAPS COMMENTS IN DOCKET NO. RM11-26

Distribution of principal outcomes from the detailed table (below) of project outcomes:

Principal Outcome	Projects Sorted by Principal Outcome	Number of Projects per Principal Outcome
Abandoned, suspended, in abeyance, or similarly delayed	Projects 2, 4, 7, 8, 11, 14, 15, and 16	Eight
Mixed outcomes, voltage reduced, still under environmental/siting study, or other intermediate outcomes	Projects 1, 5, 9, 12, 18, and 20.	Six
Under construction	Projects 3, 6, 10, and 19.	Four
Complete/In Service	Projects 13 and 17	Two

Detailed table of project outcomes:

No.	Docket/Orders	ROE Incentive Award	Status
1.	**December 2, 2008** - Tallgrass Transmission, LLC and Prairie Wind Transmission, LLC (ER09-35-000 and ER09-36-000), eLibrary No. 20081202-4000.	Tallgrass Transmission proposes to construct, at an estimated cost of approximately $500 million, a 765 kV transmission project in Oklahoma and Prairie Wind transmission proposes to construct, at an estimated cost of approximately $600 million, a 765 kV transmission project in Kansas. The Commission approved a 1.5 percent adder for each of the projects.	Regional and environmental reviews pending. Prairie Wind plan has been revised to a double-circuit 345 kV line.[51]

[51] *Available at* http://prairiewindtransmission.com/faq.aspx.

No.	Docket/Orders	ROE Incentive Award	Status
2.	**November 17, 2008** - Central Maine Power Co. and Maine Public Service Co. (EL08-77-000), eLibrary No. 20081117-3037.	150 bps for approximately 200 miles of new 345 kV line.	Project has been abandoned. *See Cent. Me. Power Co. and Me. Pub. Serv. Co.*, 135 FERC ¶ 61,236, P 7 (2011).
3.	**November 17, 2008** - Northeast Utilities Service Co. and National Grid USA (ER08-1548-000), eLibrary No. 20081117-3038.	125 bps adders for "New England East-West Solution" project, consisting of several related additions to New England's 345-kV transmission system with an overall estimated cost of $2.1 billion.	Construction underway.[52]
4.	**October 31, 2008** - Pepco Holdings, Inc. (ER08-1423-000), eLibrary No. 20081031-3080.	150 bps adder for Pepco Holdings Inc.'s Mid-Atlantic Power Pathway (MAPP) Project, a 500 kilovolt, 230-mile transmission line from Virginia to southern New Jersey.	PHI has already requested a delay in the project timetable, and may be about to seek a further deferral.[53]
5.	**October 21, 2008** - PacifiCorp (EL08-75-000), eLibrary No. 20081021-3048.	200 bps for eight line segments in California, Idaho, Oregon, Utah, Washington and Wyoming, planned to go on-line between 2010 and 2014.	One segment in service; construction scheduled to begin on a second; siting and permitting of the six other segments remain in process.[54]

[52] *Available at* http://www.transmission-nu.com/residential/projects/news/default.asp.

[53] Press Release, Pepco Holdings, Inc., PHI Requests Procedural Delay for MAPP Project (Jan. 8, 2010), *available at* http://webapps.powerpathway.com/file_depot/0-10000000/0-10000/41/folder/66/PHI_Requests_Delay1.pdf; Pepco Holdings, Inc., Presentation at June 2011 Investor Meetings 5 (June 27-28, 2011), *available at* http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NDMxNDMzfENoaWxkSUQ9NDQ5NDAyfFR5cGU9MQ==&t=1.

[54] *Available at* http://www.pacificorp.com/energygateway.

No.	Docket/Orders	ROE Incentive Award	Status
6.	**October 20, 2008** - Central Maine Power Co. (EL08-74-000), eLibrary No. 20081020-3022, *reh'g denied*, **May 19, 2011** - Central Maine Power Co., (EL08-74-001), eLibrary No. 20110519-3005.	125 bps adder for "Maine Power Reliability Program" project, involving "construction of approximately 255 miles of new and rebuilt 345 kV transmission line and approximately 229 miles of new and rebuilt 115 kV transmission line," and "expected to cost approximately $1.4 billion."	Transmission construction preparation underway.[55]
7.	**February 6, 2007** - Duquesne Light Co. (EL06-109-000, et al.), eLibrary No. 20070206-3052; **October 10, 2008** - Duquesne Light Co. (ER08-1402-000), eLibrary No. 20081010-3060; 123 FERC ¶ 61,139 (2008).	By settlement, 100 bps for the "DTEP" and "Brady Project" additions in the Pittsburgh, Pennsylvania area. At the time of the Commission's order, the Brady Project was "expected to be in service by June 2012 and to cost approximately $291 million."	Mostly unbuilt. *See* FERC Form 730, eLibrary No. 20110418-5192. Initial list of DTEP projects partly completed, partly under construction, and partly delayed indefinitely due to siting issues. "Brady Project" delayed and mostly unbuilt. Bulk of project not scheduled for completion until 2016.
8.	**September 18, 2008** - New York Regional Interconnect, Inc. (EL08-39-000), eLibrary No. 20080919-3037.	On September 18, 2008, the Commission authorized 275 bps of ROE adders for a proposed 190-mile-long electric transmission line into New York City.[56]	By April of the following year, however, after failing to secure OATT roll-in of its revenue requirement, NYRI had withdrawn its siting application to the New York Public Service Commission. [57]

[55] *Available at* http://www.mainepower.com/index.htm.

[56] *N.Y. Reg'l Interconnect, Inc.*, Docket No. EL08-39-000, 124 FERC ¶ 61,259, PP 2, 3 (2008).

[57] *See N.Y. Reg'l Interconnect, Inc. v. FERC*, 634 F.3d 581, 586-87 (D.C. Cir. 2011) (citation omitted).

No.	Docket/Orders	ROE Incentive Award	Status
9.	**August 29, 2008** - Virginia Electric Power Co. (ER08-1207-000, -001), eLibrary No. 20080829-3037.	125 and 150 bps adders for 11 transmission projects in Virginia expected to be constructed between 2008 and 2012.	Mixed results: some completed, some on schedule, some delayed, and one cancelled. *See* FERC Form 730, eLibrary No. 20110418-5193.
10.	**August 22, 2008** - Pepco Holdings, Inc. (ER08-686-000), eLibrary No. 20080822-3068.	150 bps adder for eight transmission projects in Maryland, New Jersey, and the Delmarva Peninsula.	Modest-sized projects (with a total projected cost of approximately $270 million) completed or on schedule. *See* FERC Form 730, eLibrary No. 20110418-5206.
11.	**April 22, 2008** - PPL Electric Utilities Corp., Public Service Electric and Gas Co. (EL08-23-000), eLibrary No. 20080422-3015.	125 bps for the Susquehanna-Roseland Line, to "span 130 miles across Pennsylvania to northern New Jersey."	Project delayed, for 2-3 years.[58]
12.	**March 24, 2008** - The Nevada Hydro Company, Inc. (ER06-278-000, et al.), eLibrary No. 20080324-3025.	Return "within the upper end of the zone of reasonableness" for a 500 kV Talega-Escondido/Valley-Serrano Interconnect project (TE/VS Interconnect) in Riverside County in Southern California.	Nevada Hydro Company (TNHC) has filed with the California Public Utilities Commission (CPUC) an Application (A.10-07-001) for a Certificate of Public Convenience and Necessity (CPCN), and environmental impact studies are underway.

[58] *See* PJM Markets and Reliability Committee, *Transmission Expansion Project Report* 4 (2011), *available at* http://www.pjm.com/~/media/committees-groups/committees/mrc/20110427/20110427-item-15c-transmission-expansion-projects-update.ashx.

No.	Docket/Orders	ROE Incentive Award	Status
13.	**March 24, 2008** - Westar Energy, Inc. (EL08-31-000 and ER08-396-000), eLibrary No. 20080324-4002.	100 bps incentive for 345 kV Wichita-to-Reno-to-Summit Line and associated facilities.	In service.[59]
14.	**February 29, 2008** - Potomac-Appalachian Transmission Highline, L.L.C. (ER08-386-000), eLibrary No. 20080229-4002.	Incentive-inclusive ROE of 14.3% for a proposed 290-mile, 500 kV transmission line from West Virginia to Maryland.	Project in abeyance. *See* FERC Form 730, eLibrary No. 20110418-5098.
15.	**July 20, 2006** - AEP (EL06-50-000), eLibrary No. 20060720-3059, *reh'g denied*, **January 19, 2007** - AEP (EL06-50-001), eLibrary No. 20070119.	ROE in "the high end of the zone of reasonableness" for 765-kilovolt, 550-mile transmission line from West Virginia to New Jersey.	Project in abeyance. *See* FERC Form 730, eLibrary No. 20100421-5098.
16.	**July 20, 2006** - Allegheny Energy, Inc., et al. (EL06-54-000), eLibrary No. 20060720-3057, *reh'g denied*, **January 19, 2007** - Allegheny Energy, Inc., et al. (EL06-54-001), eLibrary No. 20070119-3054.	ROE in "the high end of the zone of reasonableness" for a 500-kV transmission line from southwestern Pennsylvania to Virginia.	Project in abeyance. *See* FERC Form 730, eLibrary No. 20110418-5098.

[59] *See* Press Release, Westar Energy, Phase Two of New, High-Capacity Transmission Line from Wichita to Salina Complete (Aug. 31, 2010), *available at* http://www.marketwire.com/press-release/phase-two-of-new-high-capacity-transmission-line-from-wichita-to-salina-complete-nyse-wr-1312247.htm.

No.	Docket/Orders	ROE Incentive Award	Status
17.	**November 16, 2007** - Baltimore Gas & Electric Co. (ER07-576-000, -001), eLibrary No. 20071119-3000, *related proceeding*, **January 17, 2008** - Baltimore Gas & Electric Co. (ER07-576-003), eLibrary No. 20080117-3058, *related proceeding*, **June 13, 2008** - Baltimore Gas & Electric Co. (ER07-576-000, -004), eLibrary No. 20080613-3051.	100 bps incentive approved for 115 kV Downtown Cable and Northwest to Finksburg projects.	Apparently completed.[60]
18.	**November 16, 2007** - Southern California Edison Co. (EL07-62-000), eLibrary No. 20071116-4005, *reh'g denied*, **June 23, 2008** - Southern California Edison Co. (EL07-62-001), eLibrary No. 20080623-3034.	125 bps for a line from Palo Verde No. 2 in Arizona through the Blythe area near the California-Arizona border, and on to the Devers substation in California and for the Tehachapi Project (>200 miles of 500 kV transmission line, and related facilities); 75 pbs for the Rancho Vista Project, which includes a proposed new 500 kV substation.	Mixed. After the Arizona Corporation Commission rejected siting of the Arizona portion of the Palo Verde line, SCE shelved plans for that segment.[61] Tehachapi Project segments vary from in-service to construction pending.

[60] *See* BG&E FERC Form 730 of May 12, 2010, eLibrary No. 20100512-5017.

[61] Letter from Pedro J. Pizarro, Exec. Vice President, S. Cal. Edison Co., to Kristin K. Mayes, Chairman, Ariz. Corp. Comm'n (May 15, 2009), *available at* http://asset.sce.com/Documents/Environment%20-%20Transmission%20Projects/090515_DPV2_SCELettertoACC_Pizarro.pdf.

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19.	**June 5, 2007** - Commonwealth Edison Co. and Commonwealth Edison Co. of Indiana, Inc. (EL07-41-000 and ER07-583-000, -001**)**, eLibrary No. 20070605-3050, *on reh'g*, **January 18, 2008** - Commonwealth Edison Co. and Commonwealth Edison Co. of Indiana, Inc. (EL07-41-001 and ER07-583-003), eLibrary No. 20080118-3041, *reh'g granted in part and denied in part*, **September 8, 2008** - Commonwealth Edison Co. and Commonwealth Edison Co. of Indiana, Inc. (EL07-41-002), eLibrary No. 20080908-3025.	150 bps for Phase II of the West Loop Project in Chicago.	Under construction.
20.	**May 31, 2007** - Trans-Allegheny Interstate Line Co. (ER07-562-000, -001), eLibrary No. 20070531-3073, *reh'g denied*, **October 2, 2007** - Trans-Allegheny Interstate Line Co. (ER07-562-002, -003), eLibrary No. 20071002-3020; 124 FERC ¶ 61,075 (2008).	By settlement, 100 bps for TrAIL Project (500 kV line from southwestern Pennsylvania through West Virginia to Northern Virginia) and Black Oak SVC.	Partially complete, partially abandoned. *See* FERC Form 730, eLibrary No. 20110418-5152, and application in Docket No. ER11-3064 related to abandonment of Prexy Facilities.