UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Promoting Transmission Investment through Pricing Reform	Docket No. RM06-4-000

COMMENTS OF THE TRANSMISSION ACCESS POLICY STUDY GROUP

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EXECUTIVE SUMMARY

TAPS has long emphasized that for wholesale competition to work and deliver consumer benefits, new transmission must get built. As the Notice of Proposed Rulemaking ("NOPR")[1] rightly recognizes, transmission investment is lagging, and the resulting constraints are costing consumers dearly. We applaud the Commission for looking at this issue broadly, by seeking comments "not only on the proposals herein but also on other incentives or regulatory steps that would help fulfill the purposes of FPA Section 219."[2] The key is to develop and put in place policies and rates that will work together to get needed transmission built in a way that reduces overall costs to consumers, as Congress has directed.

To succeed, the Commission needs to step back and assess what is and is not working to get transmission built. That's what TAPS did in its June, 2004 White Paper: "Effective Solutions for Getting Needed Transmission Built at Reasonable Cost."[3] Based on that effort, TAPS urges the Commission to be savvy in its use of incentives and adopt measures that are balanced — that benefit shareholders without harming consumers — and that are well-targeted

[1] 70 Fed. Reg. 71,409 (Nov. 29, 2005), *reprinted in* IV FERC Stat. & Regs. ¶ 32,593.

[2] NOPR at P 5.

[3] *Available at* http://www.tapsgroup.org/sitebuildercontent/sitebuilderfiles/effectivesolutions.pdf ("TAPS White

to actually get transmission built. Section 219(a)'s focus on benefiting consumers directs the Commission not to indiscriminately throw money at the problem, but rather to ensure consumers benefit through increased reliability and reduced delivered power costs.[4]

Lack of capital is not the obstacle to transmission investment. A strong consensus at recent technical conferences made clear that there's plenty of money seeking to invest in transmission at today's returns because it is such a safe investment once completed. The primary risks are related to development, siting and construction, and the impediments are structural — (1) license plate rates, which saddle local ratepayers with the cost of facilities with regional benefits; and (2) vertical integration of transmission owners, which brings with it retail rate regulation of the transmission component of bundled retail load, internal competition for capital, and the fact that constraints insulate from outside competition the generation resources and customers of vertically-integrated utilities. Secondary risks are the long lead time and uncertainty of the siting process and cashflow before the line goes into service. The Commission should focus on measures that directly address those structural impediments and risks.

To get major transmission lines built, the Commission should adopt measures targeted to reduce the risks of permitting and building major transmission lines, while facilitating the siting process, *i.e.*, non-return incentives that reduce risk and provide cash flow when it is most needed, grounded in a planning process that will generate broader support for siting. Such incentives should be available so long as the facility is the product of an inclusive joint or regional planning process that allows transmission dependent utility ("TDU") participation and assures that the needs of every load serving entity ("LSE") are accommodated in a least cost, integrated manner,

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Paper") (last viewed Jan. 10, 2006). A copy is attached hereto as Attachment 1.

[4] Federal Power Act § 219(a), Pub. L. No. 109-58, § 1241, 119 Stat. 594, 961 (2005).

consistent with new FPA Section 217(b)(4).[5] Vertically-integrated transmission owners should not receive incentives for building facilities that are designed to benefit their generation function, while TDUs are treated as second-class citizens.

Incentives available for inclusively planned facilities should include:

- expensing pre-certification costs to relieve cash flow during the often lengthy siting process, without increasing life-cycle costs to customers;

- allowing construction work in progress to be included in rate base in lieu of AFUDC to provide cash flow when it is most needed — during construction — without increasing costs to customers over the life of the facility;

- assuring recovery of reasonable environmental siting and community impact payments, thereby reducing regulatory uncertainty while meeting siting objections head-on;

- permitting formula rates to increase regulatory certainty and eliminate regulatory lag; and

- allowing recovery of prudent abandoned or cancelled transmission plant where the cancellation is beyond the utility's control.

Above-market returns are not needed; there is plenty of capital seeking to invest in transmission, including TDUs who have repeatedly offered and been rebuffed.[6] Further, return incentives can be counterproductive: they increase state siting resistance if applied at retail; they are anti-competitive and ineffective if applied only to wholesale customers that constitute only a small fraction of the total load.

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[5] Federal Power Act § 217(b)(4), Pub. L. No. 109-58, 119 Stat. 594, 958 (2005).

[6] *See* Written Statement of Anne Kimber on behalf of MMTG and TAPS for the December 7, 2004 Transmission Market Power Technical Conference, Docket No. RM04-7, at 11 ("Kimber Written Statement"). *See also* recent letters from TAPS members Lafayette Utilities System, Clarksdale, Mississippi, and the Missouri Joint Municipal Electric Utility Commission to Entergy, offering to invest in rebuilding the Katrina-destroyed Entergy system. Entergy has not exactly jumped on the offer. The letters are appended hereto as Attachment 2. *See generally*, American Public Power Association, *Restructuring at the Crossroads* (Dec. 2004), *available at* http://www.appanet.org/files/PDFs/APPAWhitePaperRestructuringatCrossroads1204.pdf (last viewed Jan. 10, 2006).

For these reasons, the Commission should use return incentives very sparingly and only to incent specific structural changes and reforms (beyond mere construction of new facilities) that will result in major, ongoing improvements for customers and markets. Return incentives should be tightly limited in amount and should be available only for:

- <u>independent or, better yet, inclusive transmission-only companies</u>, which have established a strong track record of getting needed transmission built, *e.g.*, the American Transmission Company LLC ("ATCLLC"). Inclusiveness means that if the transco allows passive ownership or ATCLLC-styled active ownership, all LSEs in the footprint have an opportunity to participate on a load ratio share basis, by divesting their transmission facilities or investing money in the transco. Inclusiveness aligns interests, expands support for siting, and with appropriate governance, can provide balance and diversity that prevents discrimination. Incentives are not unduly discriminatory where all LSEs in the footprint have an opportunity to invest on a load ratio basis. However, return incentives must be kept minimal to avoid state resistance to divestiture (as well as siting).
- <u>inclusive joint ownership arrangements</u> that provide each load serving entity in the footprint an opportunity to participate in upgrades to achieve, through investment equalization on a net book basis, a load ratio share ownership of the transmission system. These arrangements which provide small systems the rights and responsibilities of proportional ownership, have demonstrated success in getting transmission built, because (among other things) they minimize disputes, provide for meaningful joint planning, and expand support for siting. Once it achieves investment parity, the TDU would obtain access to the combined system

without paying additional transmission charges.[7] In this way, opportunities for joint ownership with comparable cost recovery[8] take the anticompetitive sting out of return incentives, enabling them to pass muster as not unduly discriminatory, as required by Section 219(d), and to help fulfill Section 219(b)(1)'s directive to foster investment in transmission "regardless of ownership." However, they should be narrowly limited to avoid impeding siting.

- regional rates that spread the cost of high voltage, "backbone" transmission lines across a region (rather than just locally) to match the regional benefits obtained, effectively address the equity issues that inhibit construction of major transmission facilities that provide regional benefits. They thereby reduce opposition from local consumers and state regulators, facilitating siting. TAPS supports rate designs, like the TRANSLink "highway/byway" rate design,[9] which spread regionally the cost of highway facilities and assign costs for the local area grid to both load and generation. Such designs address the "export zone" issue — customers in one transmission system unfairly bearing costs of upgrades designed to serve load outside that system — while fairly sharing the costs consistent with

[7] Joint system arrangements would be bolstered by revamping OATT Section 30.9, as discussed in TAPS' November 22, 2005 Comments at 11-18, 21-26, 87-90 in the Order 888 Reform Notice of Inquiry, Docket No. RM05-25-000 ("TAPS Order 888 NOI Comments"). If OATT Section 30.9 were revised to provide for customer credits for facilities that serve a comparable function as the transmission provider's facilities (*e.g.*, if looked at on the basis of a combined system serving the loads of the TO and the TDU), and credits were available for new TDU facilities (whether jointly planned or where the TO refused to jointly plan), the Commission would be taking a giant step towards fostering joint ownership arrangements, as well as achieving comparability.

[8] The TDUs' facilities and their revenue requirement, including applicable incentives, should be included in the transmission provider's OATT.

[9] It is described in the Commission's April 25, 2002 Order in *TRANSLink Transmission Co., L.L.C.*, 99 F.E.R.C. ¶ 61,106, at 61,465-68, *order on reh'g,* 101 F.E.R.C. ¶ 61,140 (2002) and its December 19, 2002 Order in *TRANSLink Dev. Co., L.L.C.*, 101 F.E.R.C. ¶ 61,316, PP 15-24 (2002).

> cost causation. The regionally-shared portion of new, inclusively-planned facilities should be eligible for limited return incentives that are tightly restricted to avoid creating barriers to siting.

Because of the increasing resistance to the already crushing burden of RTO costs, the Commission should rely exclusively on non-return incentives for RTO participation.

Fundamentally, the Commission should not reward with return incentives transmission providers that turn down transmission customer offers to invest in upgrades, with credits provided through OATT Section 30.9 or other comparable cost recovery. The undue discrimination prohibition in Sections 205 and 219(d) highlight the inappropriateness of providing competitive advantages to vertically-integrated utilities based on their transmission ownership, while they refuse others access to the investment club, contrary to Section 219(b)'s intent to encourage investment "regardless of ownership."[10]

The proposed rule is deficient not only by offering a range of incentives (including return and, even worse, accelerated depreciation), without tying them to major reforms, but also because it provides only upside incentives and does not simultaneously penalize poor performance and maintenance of a clearly inadequate system. Incentives should work two ways: good performance should be rewarded, but those transmission providers that fail to achieve and maintain a robust transmission infrastructure should be held accountable, by having their returns reduced to the low end of the zone of reasonableness. The Commission should make clear that in determining (in the context of a transmission provider's Section 205 filing or a customer's Section 206 complaint) whether to set returns at the low end of the zone it will demand

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[10] *See also* Federal Power Act § 216(b)(1)(B), Pub. L. No. 109-58, § 1221, 119 Stat. 594, 947 (2005) (opening the "TO club" by providing backstop siting authority for entities that would not qualify for state permits).

transmission adequacy, not merely meeting minimum reliability requirements. As described more fully below, in making that evaluation, the Commission should consider such factors as:

- failure to meet applicable reliability requirements;
- high level of congestion;
- inability to support allocation of FTRs, without proration or uplift, to existing resources backed by firm transmission rights;
- lack of ATC (or negative ATC) on paths of interest to customers, and specifically at interfaces, both in the near term and in the long term;
- failure to address congestion causers — major, known constraints;
- failure to meet customer needs through an inclusive planning process that treats the needs of all LSEs comparably;
- patterns of denial of transmission service requests or network resource designations or high interconnection costs;
- patterns of failure to process customer transmission service requests and network reserve designations in a timely manner;
- denial of reasonable access to the competitive market;
- inability of the system to accommodate very small (*e.g.*, 20 MW or less[11]) loads, transactions, or new resource designations without upgrades or other mitigation/ redispatch;[12] and
- high levels of customer dissatisfaction.

While the precise metrics may be fleshed out through technical conferences held before or after the adoption of the final rule,[13] the final rule should expressly provide for downward adjustment of returns of transmission providers that perform poorly. By announcing a policy that makes

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[11] 20 MW is the cutoff for Order 2006, Standardization of Small Generator Interconnection Agreements and Procedures, 70 Fed. Reg. 34,190 (June 13, 2005).

[12] *Compare* Kimber Written Statement at 6-7, describing how a 0.6 MW request was claimed to violate multiple flowgates.

[13] It may also be appropriate to establish metrics for those within RTOs that use LMP that are different from those

incentives a two-way street, the Commission will provide a strong incentive for transmission providers to move forward to create a robust grid. The Commission should also implement changes to the OATT to shift the risk of an inadequate grid to transmission providers. [14]

Any return incentives must be transparent, and not hidden. They must be premised on an actual return requirement and an appropriate capital structure, reflecting what is required to attract capital to the safe and stable transmission business, taking into account the effect of incentives, such as allowing CWIP, expensing pre-certification costs, and formula rates, that further reduce the risks. And they should be structured as adjustments to return on total capital, so that their effect does not vary with the recipient's capital structure.

Finally, the Commission should reject policies that undermine transmission investment or have long term adverse consequences. Participant funding and other forms of "and" pricing should be buried, once and for all, as fundamentally inconsistent with creating a robust grid. By enacting Section 220, which gives the Commission discretion to turn down participant funding plans that meet the requirements of Sections 205 and 206, Congress recognized that participant funding is at odds with the transmission expansion purposes of EPAct 2005. Accelerated depreciation incentives should be ruled out as having severe negative consequences fundamentally inconsistent with the long term support of the grid and just and reasonable and not unduly discriminatory rates to customers.

I. INTERESTS OF TAPS/COMMUNICATIONS

TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access.[15] As entities entirely or

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applied to non-LMP areas.

[14] *See* TAPS Order 888 NOI Comments at 11-18.

predominantly dependent on transmission facilities owned and controlled by others, TAPS members are acutely aware of the need to upgrade our inadequate transmission infrastructure.[16]

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II. MAJOR RECOMMENDATIONS

The purpose of FPA Section 219 and of the present rulemaking initiative is not corporate welfare. It is to advance the public interest and reduce delivered costs to customers by getting beneficial transmission built, promptly and at reasonable cost. In structuring an incentive rule, the Commission should apply and extend nationwide the approaches that are working.

A. What Works

We now know what works. Inclusive joint ownership arrangements and transcos have solid track records demonstrating that they get wires strung. For example, the American Transmission Company LLC ("ATCLLC") has increased its $2.8 billion construction program to

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

[16] TAPS has commented on nearly all major rulemakings and policy inquiries involving the electricity industry over

$3.4 billion — five times higher than the individual budgets of the utilities that divested to it.[17] CAP-X 2020, a Minnesota joint planning effort that contemplates $2.3 billion in transmission expansions,[18] has secured state legislation to facilitate cost recovery, reform siting to emphasize regional needs, and authorize transmission-only companies,[19] and may well develop into a form of the shared system model that has worked well to get transmission built in Georgia, Indiana, Minnesota, North and South Dakota, and elsewhere.[20] And we know what features make such efforts so successful.

Focus. Building transmission is the only way a stand-alone transmission-only company can grow. It has no internal competition for capital and no conflict of interest with generation ownership. Although siting is unpopular, a wires company has no choice but to deal with that issue and develop strategies. Avoidance is impossible.

Inclusiveness. ATCLLC's inclusives is a key to its success. All load-serving entities (including small municipals and cooperatives) can and do participate as ATCLLC owners, regardless whether they previously owned transmission facilities. This helps to bring all of the LSEs (both the former TOs and TDUs) to the table and to give them a piece of the investment return pie.[21] The result aligns interests and leads to a substantial decrease in tension, litigation

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the past decade.

[17] *See* September 28, 2005 ATCLLC Press Release, *available at* http://www.atcllc.com/documents/09-28-0510-YearAssessment.doc (last viewed Jan. 10, 2006), and the attached the TAPS White Paper (at 11).

[18] *See* July 18 2005 Presentation to the Minnesota Public Utilities Commission, "Realizing the Cap-X 2020 Vision, Information Briefing – Moving to Implementation, available at http://www.capx2020.com/Images/MPUC_Briefing_07.18.05.pdf

[19] *See* Minn. S.F. No. 1368, 84th Legislative Session, signed by the governor May 25, 2005, amending Sections 216B.02, 216B.16 and 216B.243 of Minnesota Statutes 2004 ("CapX Legislation").

[20] *See* TAPS White Paper, Appendix.

[21] As explained in APPA, *Restructuring at the Crossroads* (Dec. 2004), many public power systems are interested

and adversarial jockeying, as well as a more inclusive planning process and broad support for siting. Rating agencies have recognized that ATCLLC's inclusiveness is a significant benefit.[22] Its hybrid board, with stakeholder representation (through owners with wide-ranging sizes, interests, and organizational structures having the same vote), as well as independents, provides direct accountability to those who pay the bills,[23] while maintaining a significant degree of independence.[24] While not "independent" in a technical sense, all of these structures feature inclusiveness and diversity in ownership and control that make discrimination more difficult.[25]

The "Participation by Public Power" panel at the April 22, 2005 Transmission Investment Technical Conference left no doubt that public power and coops are ready and willing to invest in the grid if permitted to do with comparable cost recovery.[26] Also significant, the "Role of the Independent Transmission Companies" panel at the same conference produced a virtual chorus stating that public power and coop investment was not only welcome but was an important factor in getting transmission built.[27] PJM also pointed to its "consortium" approach as a means to

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in investing in transmission.

[22] Fitch Report, Attachment 2 to the March 12, 2002 Comments of Wisconsin Public Power Inc., submitted in *Electricity Market Design and Structure*, Docket No. RM01-12-000.

[23] RTOs with fully disinterested boards have experienced runaway costs. A better balance — independent decision-making with accountability — can be reached through inclusiveness and balanced stakeholder representation.

[24] As described in the TAPS White Paper, Vermont Electric Power Company offers an earlier example of an inclusive, transmission-only company's successfully constructing, owning, maintaining, and operating transmission facilities. TRANSLink, if it had succeeded, would have been another example.

[25] *Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission*, 111 F.E.R.C. ¶ 61,473, at n.6 (2005) ("Transco Independence Policy Statement") (noting that each American Transmission Company LLC board member affiliated with a market participant has one vote per owner, regardless of its size).

[26] *Transmission Independence and Investment,* Docket Nos. AD05-5-000 & PL03-1-000, April 22, 2005 ("Transmission Investment Technical Conference"), Sue Kelly, APPA (Tr. 256-58); Roy Thilly, WPPI/TAPS (Tr. 275). *See also* Kimber Written Statement at 11; APPA, *Restructuring at the Crossroads* (Dec. 2004).

[27] Commissioner Brownell's question ("would you welcome partners as in coops and public power?") at the Transmission Investment Technical Conference (Tr. 241) was answered resoundingly in the affirmative by Nick Winser, National Grid (Tr. 242); Paul McCoy, Trans-Elect [erroneously referenced as Mr. Boyko] (Tr. 242-43);

include public power transmission investment.[28] Thus, technical conference testimony provides strong support for making public power investment part of the solution to our transmission problems.

Where formal transcos have not yet been founded or face unresolved state-law issues, inclusive joint or shared transmission systems can provide many of the same benefits. Under this approach, transmission systems are combined by contract into a single system with single-system planning and shared responsibilities for additions, and small systems are granted the rights and responsibilities of proportional ownership. Through investment equalization, all participants can achieve load ratio share ownership of the transmission system, with all participants' shares included in and recovered through the transmission provider's revenue requirement. This approach relies on a contract among existing utilities rather than instituting a new single-purpose-utility with its own staff. Still, its inclusive planning process and pooling of facilities aligns all LSEs' interests, and provides broad support for construction and siting. Successful shared systems exist in Georgia, Indiana, Minnesota, Iowa, the Dakotas, and Wisconsin.[29] CapX, a Minnesota joint planning effort contemplating a $2.3 billion transmission expansion, involves seven utilities—IOU, muni and coop.

Dale Landgren, ATCLLC (Tr. 243); Eric Lammers, ArcLight Capital Partners (Tr. 244); and Jose Rotger, TransEnergie ("no question, public power is a part of this. They're very much a driver of investment," Tr. 244).

[28] Audrey Zibelman, PJM (Tr. 75-76). *See also* testimony at the May 13, 2005 technical conference held in Charleston, West Virginia, *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources*, Docket No. AD05-3-000 ("Coal Transmission Technical Conference") of PJM's Karl Pfirrmann (Tr. at 68) (through the consortium concept, "public power entities who have long expressed interest in ownership of transmission facilities, can now be partners in such a project").

[29] The "consortium approach" being explored by PJM, and described in the NOPR at P 62, is consistent with the shared system structure. In explaining this inclusive investment opportunity at the April 22, 2005 Transmission Investment Technical Conference, Ms. Zibelman referenced multi-utility transmission lines as a model. *See also* Coal Transmission Technical Conference testimony of TAPS member Gayle Mayo of Indiana Municipal Power Agency, Tr. at 163-64 (public power entities have money they are willing to invest in transmission, whether it is a formal joint ownership or a consortium approach).

Burden-sharing. Successful builders spread the costs of new facilities across multiple utilities, even an entire region. Spreading the cost of high voltage, "backbone" transmission lines across a region (*e.g.,* through the TRANSLink "highway/byway" rate design[30]) is not only fair;[31] it's effective in getting new transmission built, because it reduces opposition from local consumers and state regulators. In New England, cost regionalization was specifically identified as an incentive to facilitate prompt implementation of major upgrades.[32] It's working. New England's 2004 transmission expansion plan ("RTEP04") covered $2.14 billion in planned regional transmission projects.[33] Governors of California, Nevada, Utah and Wyoming, in promoting the $3.5-$5 billion "Frontier line," are negotiating towards spreading its costs broadly across California and the Pacific Northwest, to assure that it can be built at minimum cost for their citizens' maximum benefit.[34] ATCLLC's $3.4 billion expansion is being borne by five Wisconsin utilities (plus a number of other smaller systems); if, as was the case pre-ATCLLC,

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[30] *See TRANSLink Transmission Co., L.L.C.*, 99 F.E.R.C. at 61,465-68; *TRANSLink Dev. Co., L.L.C.,* 101 F.E.R.C. ¶ 61,316 at PP 15-24. This design spreads regionally the cost of highway facilities and assigns costs for the local area grid to both load and generation. It addresses the equities of the "export zone" issue – customers in one transmission system unfairly bearing costs of upgrades designed to serve load outside that system – while fairly sharing the costs consistent with cost causation and the regional benefits obtained. To be clear, a single holding company is not a region for this purpose, and thus the single-system OATT rate for a utility holding company is not a regional rate.

[31] The benefits of a regional grid (both its active use and, equally important, its availability to be accessed as needed) are spread very broadly. Cost responsibility for that grid should be spread broadly too. To avoid discrimination, all load-serving entities in the region, including a vertically-integrated utility for its bundled retail load, should be subject to the same regional rate.

[32] *See NEPOOL and ISO New England Inc.,* 101 F.E.R.C. ¶ 61,344, P 36 (2002) ("To aid in the transition to LMP, we encourage ISO-NE to work with New England market participants to identify and construct a defined set of transmission upgrades into Southwest Connecticut, and we commit to allowing the costs of such upgrades that are placed in service within 5 years from the date of this order to be spread among customers throughout New England.").

[33] *Bangor Hydro-Electric Co., et al.*, 111 F.E.R.C. ¶ 63,048, PP 160-63 (2005), *exceptions pending.*

[34] *See, e.g.,* http://psc.state.wy.us/htdocs/subregional/Frontierline040105.pdf (last viewed Jan. 11, 2006).

one of those utilities would have had to absorb the cost of a major facilities, with the benefits flowing to all five, the facilities would not likely have been built.

At recent technical conferences, many speakers stressed that the best way to promote transmission expansion was to move away from single system, license plate rates[35] and toward regional rates that more broadly spread the costs and deal fairly with equity issues associated with transmission investment.[36]

Inclusive regional or joint planning: The major new transmission efforts now underway are not the product of a single vertically-integrated utility independently planning its portion of the grid in isolation. The formation of ATCLLC combined multiple transmission systems, allowing planning for a broader footprint. The New England expansion, CAPX, and the Frontier line are all outgrowths of regional planning processes. A key to the success of shared system models is the joint planning that goes with them.

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[35] At the Transmission Investment Technical Conference, Trimaran Capital Partners' Jon Larson suggested that investment would be promoted by a tariff that does not assign all the costs of new transmission lines to the footprint where it is built (Tr. at 53-54). *See also* ATCLLC's Dale Landgren's explanation at the same conference of the importance of consolidating the customer base of four IOUs as a predicate for major transmission investments: "I know when I said size matters, it wasn't because of the size of the investment, it's the ability to pay. If we look, for instance, at our biggest project, our Duluth to West[on] project, it's being proposed by two smaller entities; they concluded that if they actually built that they could get the money, but then the rate impact on the customers would be overwhelming and they couldn't afford to do that. Similarly, in the UP of Michigan there's no way that those small utilities could afford to get the money that was available, then spend it and have to try to recover it from their local customers. We have the ability to go finance and then spread the costs of that societal benefit over a much broader footprint" (Tr. 237-38). *See also* John Houston, Centerpoint Energy, describing the dramatic transmission expansion experienced under ERCOT's single statewide postage stamp, into which all upgrades are rolled-in ("The ratepayers in the ERCOT control area have access to the generation that they're benefiting from, and therefore they share in the transmission cost equally") (Tr. 102-04).

[36] *See* Transmission Investment Technical Conference, Roy Thilly, Wisconsin Public Power Inc./TAPS, (Tr. at 283, 308-09). The need for regional pricing mechanism was echoed by Joe Welch, ITC (Tr. 81-82); Vito Stagliano, Calpine (Tr. 94); David Gates, NorthWestern Energy (Tr. 99-101); David Mohre, NRECA (Tr. 272). At the May 13, 2005 Coal Transmission Technical Conference, calls for regional rates came from AEP's Mike Morris (Tr. at 188) and National Grid's Paul Halas (Tr. at 76), among others. *See also* the November 22, 2005 Comments of AEP Operating Companies in the Order 888 NOI, Docket No. RM05-25-000, at 4-8 (stating that "[r]egional markets demand a regional rate design" and supporting a "highway/byway" approach).

This is not surprising. Due to the dynamic and highly integrated nature of the AC grid, an upgrade in one state may be required to enhance reliability and relieve congestion in an adjacent state. A transmission addition may be required in one state to enable an upgrade undertaken in an adjoining state to function as planned. Many speakers at recent technical conferences emphasized that the grid is regional and should be planned and constructed on a comprehensive basis to meet regional needs on a least-cost basis.[37] TAPS has presented the same view; its recommended planning protocol was attached to its recent comments on the Order 888 Notice of Inquiry.[38]

Timely and sure cost recovery: Most major expansion efforts rely on incentives that reduce risk and improve cashflow at crucial times, not increasing costs with above-market returns that risk siting backlash. For example, the CapX legislation focused on regulatory certainty; it permits recovery of construction work in progress and other pre-certification expenses, but expressly 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."[39] To facilitate its massive expansion program, ATCLLC proposed CWIP in lieu of capitalizing AFUDC and current year expensing of pre-certification expenses (along with adjustments to its capital structure and allowed return) as alternative incentives to the ROE basis

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[37] *See, e.g.,* Coal Transmission Technical Conference, Paul Halas, National Grid, USA (Tr. 77) ("What's really necessary in the near term, is certainly a robust regional transmission process with responsibility for, we think, taking into account, both reliability and economics in the same sorts of analyses."); and Jerry Vaninetti, Consultant, Coal Project Development (Tr. 212-13) ("I've got a David Letterman list of the top 10. I'm not quite sure what the order is. But first and foremost, regional planning is important for both generation and transmission, particularly in regions that aren't covered by RTO's."). *See also* Transmission Investment Technical Conference, Vito Stagliano, Calpine (Tr. 93); David Mohre, NRECA (Tr. 272).

[38] TAPS, *Balanced Principles for Electric Transmission Planning and Expansion* (July 17, 2002), filed as Attachment 3 to the November 22, 2005 TAPS Order 888 NOI Comments in Docket No. RM05-25.

[39] CapX Legislation § 2, amending Section 216B.16 of Minnesota Statutes 2004.

point incentive adders outlined in the Commission's Proposed Pricing Policy Statement.[40] These examples show what transmission owners that want to build transmission really need—not incentive returns to attract capital, which is no problem to attract at current rates.

B. What Doesn't Work

Like the above keys to success, the keys to failure are also increasingly well-understood. They include:

Participant funding. Single-purpose transmission companies do not try to directly assign to particular market participants the costs of upgrades which, by the very nature of the AC grid, benefit all (and whose benefits and uses necessarily change over time, even if they could be pin-pointed at the outset). Participant funding (and other forms of "and" pricing) disincents transmission investment. It forces one or more market participants to bear the cost of network upgrades that provide broad benefits that change over time on a dynamic AC grid, creating enormous free-rider effects especially because of the inherent lumpiness of efficient upgrades to the grid. It invites a game of "chicken," delaying needed upgrades. Participant funding seeks to justify upgrades based on private benefits to specified market participants. That approach makes the difficult state transmission siting process even harder, because siting approvals typically require public benefits. If a market participant receives FTRs in exchange for funding an upgrade, the FTR would have no value (and potentially a cost) if the upgrade eliminated congestion; indeed, participant funding gives market participants a vested interest in maintaining congestion.

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[40] *Am. Transmission Co. LLC and Midwest Indep. Transmission Sys. Operator, Inc.*, 105 F.E.R.C ¶ 61,388, P 5 (2003).

The assumption that participant funding, spurred on by LMP pricing, will bring about needed investment has been repeatedly debunked by rating agency reports, testimony at Commission technical conferences, and experience. For example, Standard and Poor's July 1, 2004 Report, *Makeover for California's Power Markets*, explains:

> Pricing data associated with hourly nodal prices should provide market signals for use in planning for investment in transmission and new generation. Yet, generators may realize that the benefits will be ephemeral. Once generators build capacity in a load pocket to address transmission congestion issues, prices will likely reach equilibrium levels that could remove the economic incentives created by locational marginal pricing. Therefore, generators may forego developing fixes if their investments might fail to provide them with economic benefits commensurate with development risks throughout the asset's life. The same argument also could be extended to developing transmission.

Investors speaking at FERC Technical Conferences see the same flaws:[41]

> So with respect to incentives, my issue with incentives as opposed to rate-based treatment is this: That does introduce uncertainty into it and it does increase the rate. If I need to be able to predict say LICAP for the next 20 years in New England, without the rules even being clear to me how it's being done right now, much less in five years, then I'm going to price that into the returns that I require for that type of transmission investment.
>
> On the other hand, if it's been determined that a project is in the interest of ratepayers and that, based upon a regulatory approval proceeding that it is almost certain that, given a rate-based treatment of a certain new asset, that the benefits are going to offset the cost of the allowed return by the new investor, then frankly, I'll invest in that at a much lower required return.

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[41] Transmission Investment Technical Conference, Tr. 37-38 (Larson, Trimaran Capital Partners). At the February 4, 2004 Technical Conference, *Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets*, Docket No. PL04-2-000, *see* Tr. 262 (Newman, Warburg Pincus: "I think the economists like volatility, but the marketplayers don't."); Tr. 149 (Anderson, John Hancock: "Most capital for power infrastructure is provided by debt markets not equity markets. If you look at capitalization of power assets, as you probably heard this morning, we value stability. We're not in this to make a killing off of spiking peak power prices. We're putting capital into this business in opportunities that we think can provide long term stable reasonable returns and are on the low end of the risk adjusted spectrum.").

> It's the predictability of earnings. And the uncertainty is not the uncertainty of earnings in a project right now, at least with respect to the investments that we've considered; it's the uncertainty of there being a project at all.

The fundamental fallacies of participant funding are no secret,[42] and are particularly well-recognized by those whose business models are geared towards getting transmission built. *See, e.g.*, ITC's Joe Welch at the April 22 Transmission Investment Technical Conference: participant funding "does not work because it likely will result in a suboptimal expansion of the grid. Not to mention the 'free rider' effect where those who benefit from the expansion don't have to pay." Tr. at 81.[43] EEI's representative at that conference, Alan Fohrer, CEO of Southern California Edison, argued for roll-in of transmission required for the import of wind power: "It might be classified by some as a Gen-tie line. If renewables have to provide participant funding for this type of line, they will never be developed and California won't meet its RPS standard." Tr. 117. Joe Desmond, California's Deputy Secretary of Energy, described removal of the prescriptive participant funding language from the then-pending, now enacted, energy bill, as a key element important to moving the Frontier line forward. Tr. 158.

The fact that participant funding discourages transmission construction is most evident in the transmission system of Entergy, its prominent proponent. When TDUs seek to add new network resources (or to become network customers and add resources), they are faced with claims for many millions of dollars in upgrades to fix problems on the Entergy grid that have

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[42] *See, e.g.,* Transmission Investment Technical Conference, David Mohre, NRECA (Tr. 267-69); Vito Stagliano, Calpine (Tr. 94). *See also, e.g.,* Comments of Seth A. Blumsack, Jay Apt, Lester B. Lave, Carnegie Mellon Electricity Industry Center, Carnegie Mellon University, Docket No. AD05-17, at 19-20 (Nov. 18, 2005).

[43] *See al*so Dale Landgren, ATCLLC, at the Transmission Investment Technical Conference (Tr. 198) ("We would echo many comments, that we would encourage FERC to avoid rate designs like participant funding, which cause greater rather than less uncertainty with respect to cost recovery.").

existed for years due to Entergy's grid starvation policy.[44] Indeed, many parts of the nation's transmission infrastructure have become so fundamentally inadequate that a spider web of massive deficiencies shows up whenever any change is studied, no matter how small.[45] As a result, transmission customers take turns presenting individual needs and then walking away from proposed purchases or generation projects when transmission costs are disproportionate to the scale of individual benefits.[46] All the while, network upgrades that are cost-effective from a system viewpoint do not get made, leading to a cycle of increasing grid degradation and constrained supply options.

The current model is not working even in the most mature LMP markets. PJM has conceded that its current regimen, with its "participant payment principle" and sharp distinction between reliability and economic upgrades,[47] is producing "disappointing results" testifying:[48]

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[44] *See* Motion for Late Intervention, Protest, and Reply of Missouri Joint Municipal Electric Utility Commission, filed on December 7, 2005 in *Entergy Services, Inc*., Docket No. ER05-1065, which describes Entergy's Plum Point System Impact Study, which (if participant funding is allowed) shift to any would-be purchaser from the unit (except the town in which the unit is located) the cost of what are clearly long-overdue backbone upgrades. *E.g*., a combined 5 MW entitlements for two small towns is shown to require $14-28 million in upgrades, including for 500 kV facilities located near Little Rock — *i.e.*, south and west of the unit, whereas these towns are northwest and north of Plum Point — and which are long-established constraints that perennially show up as requiring upgrades in order to accommodate virtually any variety of service request. By doing so, Entergy discourages both the upgrades and coal generation.

[45] *See* Kimber Written Statement at 6 (footnote omitted), describing efforts of one small city on the MidAmerican system to take service from the Municipal Energy Agency of Nebraska ("MEAN") at the end of its power contract: "According to the MAPP-MISO 'scenario analyzer'—the tool available to market participants to test the availability of transmission service, transmission from MEAN to Callender, Iowa (0.6 MW) impacted both MAPP and MISO (Alliant) flowgates. Frankly, it is hard to believe that a transmission request this small could cause such big problems."

[46] *See* TAPS Order 888 NOI Comments at 13 n.24, for a detailed description of the massive and disproportionate costs of upgrades the Southwest Power Pool sought to assign to individual transmission customers, with the result that nothing was being built. *E.g*., nearly $30 million worth of upgrades as a condition of granting Kansas Electric Power Cooperative's request for 9 MW of long-term point-to-point transmission service from the Westar control area to the adjacent Empire District Electric control area.

[47] *Compare* National Grid's Paul Halas, speaking at the Coal Transmission Technical Conference (Tr. 77-78): "Every transmission investment will have impacts on both reliability and economic efficiency."

[48] Audrey Zibelman, PJM, speaking at the Transmission Investment Technical Conference (Tr. 69, 72); Zibelman

> Do we want a "minimalist" transmission grid that essentially serves as an "add-on" facilitating the reliable movement of power from generation sited close to load? In other words, should the transmission system merely be a facilitator for a model based on local generation? Or are we looking for a strong transmission system that, by its design, links distant generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose? The "rules of the road" and the costs to build one system versus another are vastly different….
>
> In many ways, the Energy Policy Act of 1992 answered this question in favor of the strong superhighway to support a competitive generation industry. … Assuming that we wish a strong transmission system to provide load with many options, we believe a new set of "building blocks" is needed.[49]

Above-cost payments for completed facilities. Accelerated depreciation and incentive returns are conspicuously absent from most of the recent major transmission expansion efforts. ATCLLC has been clear that an incentive return is not necessary to get facilities built, and may be counter-productive:[50]

> 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.
>
> …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.

New England's $2.14 billion in planned expansions are proceeding without approved return incentives. The Presiding Judge who considered new-facility incentive payments for New England recommended rejecting them on the ground that the payments would not induce more,

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Written Remarks for Transmission Investment Technical Conference at 5 (April 21, 2005).

[49] *Id.*

or more timely, investment than would occur without them, would not reduce the obstacles to transmission construction, and could create resistance to siting.[51] The CAPX 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," and makes no provision for accelerated depreciation.[52]

Return and accelerated depreciation incentives fail to target the actual risks involved in adding new transmission, namely, the difficulty of, and delay in, siting and constructing such facilities. They do nothing to address cash flow during construction because they kick in only after a facility is completed. They either increase local resistance to siting by raising the cost (if applied at retail) or competitively burden TDUs without significantly changing the total economics for the investor (if applied only to wholesale). Accelerated depreciation has particularly dire consequences, as described in Part III.A.4 below (response to NOPR P 30).

While a few technical conference speakers advocated costly ROE and accelerated depreciation incentives, most agreed that at current returns, plenty of investors are eager to put capital into transmission because of its low risk, assured cost recovery through roll-in and regulatory certainty.[53]

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[50] Dale Landgren, ATCLLC, Transmission Investment Technical Conference (Tr. 197-98).

[51] *See Bangor Hydro-Electric Co., et al.*, 111 F.E.R.C. ¶ 63, 048 at PP 160-63, 167, ("While the promise of a higher ROE would, in theory, encourage investment and assist … in obtaining capital, there is no evidence that such 'monetary capital' will induce the [TOs] to spend 'political capital' to overcome resistance to building projects. While there is a certain 'trickledown' logic to the argument that the [TOs] would respond to the incentive of the adder and try harder to build new transmission projects that offered this higher return, the adder will not help them overcome the problems inherent in siting new transmission. In fact, local resistance to a given project might be strengthened by knowledge that, if built, the project would result in a higher ROE for the transmission owner.")

[52] CapX Legislation § 2, amending Section 216B.16 of Minnesota Statutes 2004.

[53] *See, e.g.,* Eric Lammers, ArcLight Capital Partners, Transmission Investment Technical Conference (Tr. 203) ("A key point to reiterate what other panelists have said before is that there there's plenty of capital out there interested in investing in the industry, it's just a matter of getting the right structure around the investment."); Jose Rotger,

To be sure, during a desperate hour of the California market meltdown, the Commission did authorize a time-limited rate-of-return incentive for some of the investors in Path 15 — those who were either new to the state and business or on the verge of bankruptcy. But even in that unusual instance a major investor proceeded without ROE incentives.[54] And the International Transmission Company <u>deferred</u> rate of return bonus is an exception that proves the rule: ITC billed for several years under a stated rate, even while embarking on a major construction program. That shows that there whatever obstacles there may be to transmission investment, a lack of cash is not among them.

Indeed, as noted above,[55] TDUs have repeatedly offered to invest in transmission provider systems, but typically get rebuffed. <u>No transmission owner should be entitled to incentive returns ostensibly to attract capital if it turns down TDU capital ready and willing to invest in their system with comparable opportunity for revenue recovery/credits.</u>

C. Facilitate Inclusively-Planned Transmission Investment by Reducing Risk, Enhancing Cash Flow, and Increasing Regulatory Certainty, Without Burdening Customers

1. Condition incentives on inclusive regional or joint planning where TDU needs are treated comparably

To qualify for the non-return incentives that reduce the risk of major transmission construction, the facility must be inclusively planned—either through an inclusive joint planning process or an inclusive regional planning process.

TransEnergie U.S. (Tr. 213-214) ("Akin to ArcLight and KKR and Trimaran, the investors in our funds are principally pension funds and institutional money. All have a very long term investment horizon and are very keen to find investments in long term, stable assets"; noting the "appetite of investors to invest in electricity transmission," he commented that "impediments to ITC do not necessarily stem from the investor side"); David Mohre, NRECA, Tr. 273 (advocating incentives that reduce risk and cost).

[54] Although the Commission authorized incentives for TransElect and PG&E, *Western Area Power Admin.*, 99 F.E.R.C. ¶ 61,306, *reh'g denied*, 100 F.E.R.C. ¶ 61,331 (2002), Western did not seek incentives for its participation.

[55] *See* examples in n.6 above.

Although the OATT expressly requires the transmission provider to comparably plan for the needs of network customers, this obligation is honored in the breach.[56] The OATT contemplates joint planning with network customers, but such planning is not occurring, apparently to ward off an obligation to provide credits under Section 30.9. As discussed in TAPS' Order 888 NOI Comments (at 11-18), the Commission should enforce and enhance these OATT requirements without additional incentives. As part of awarding incentives, the Commission should at least require that TDU needs are being met. Vertically-integrated transmission owners should not receive incentives for building facilities designed to benefit their generation function, while TDUs are treated as second-class citizens, contrary to Section 217(b)(4)'s directive to treat all load serving entities comparably and to facilitate planning and expansion of the grid to meet their needs. Joint planning promotes efficient and effective investment that meet the needs of all LSEs, and broaden support for upgrades, thus facilitating siting.

If an open, inclusive, regional planning process is in place, incentives should be available only for upgrades that are approved by such process. Such limitation is consistent with the incentive package approved for ATCLLC, which limits the availability of risk reduction/cash flow incentives to facilities included in MISO's regional plan.[57] It would also promote cost-effective upgrades, as recognized in Order 2000.[58] To be consistent with Section 217(b)(4), the

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[56] OATT §§ 28.2, Preamble to OATT Part III. *See* TAPS Order 888 NOI Comments at 11-18, 87-90.

[57] *Am. Transmission Co. LLC and Midwest Indep. Transmission Sys. Operator, Inc.*, 105 F.E.R.C ¶ 61,388 at P 25.

[58] *See, e.g., Regional Transmission Organizations,* Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), *reprinted in* [1996-2000 Regs. Preambles] FERC Stat. & Regs. ¶ 31,089, at 31,164, *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), *reprinted in* [1996-2000 Regs. Preambles] FERC Stat. & Regs. ¶ 31,092, *petitions for review dismissed per curiam for want of standing sub nom. Public Utility District No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001); TAPS White Paper at 20-21.

Commission should insist that the process provide a meaningful opportunity for all load serving entities in the region to ensure that their needs are included in a least cost, integrated manner. The TO-centric RTO planning process described in the ISO/RTO Council Comments in the Order 888 Notice of Inquiry ("most ISO/RTOs have an internal process to coordinate projects with their transmission owning members")[59] is not sufficiently inclusive of all LSEs to satisfy the EPAct2005's command that the Commission exercise its authority to facilitate the planning and expansion of the system to meet the needs of LSEs, without any distinction between transmission owners and TDUs. *See* Part III.A.1 below (response to NOPR P 22).

2. Make non-return incentives available to inclusively planned transmission facilities

a) Allow inclusion of CWIP in rate base to reduce risk and improve cash flow without increasing life-cycle costs to customers

Inclusion of CWIP, in lieu of AFUDC, reduces risk by providing needed cash flow when it is most needed—during the construction process, while having a neutral effect over time for customers dependent on the transmission system for the long term. TAPS White Paper at 14-15.

b) Permit current recovery of reasonable pre-certification expenses

Allowing current recovery of pre-certification expenses reduces risk and improves cashflow during the often contentious siting process, again without increasing life-cycle costs to transmission dependent customers. *Id.*

c) Permit recovery of reasonable environmental siting and community impact payments required to get transmission constructed

Town and county budgets are very tight. Providing for reasonable payments for the visual and environmental impacts can be helpful in getting facilities built.

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[59] *See* Comments of the ISO/RTO Council, Docket No. RM05-25 (Nov. 22. 2005).

d) Align transmission costs and revenues through formula rates

Formula rates eliminate regulatory lag, thus fostering new investment. With appropriate safeguards to protect consumers, formula rates are fair to both investors and ratepayers. Because they reflect changes in all costs, ratepayers are protected, while investors achieve certainty of recovery. *Id.* at 15.[60]

e) Enhance regulatory certainty to support financing strategies that access investors seeking the stable, annuity-like returns that transmission can provide

The Commission should provide for rate treatments to facilitate Wall Street efforts to accessing capital from the large pool of investors looking for very stable, close to fixed-rate returns that technical conference panelists testified are eager to invest in transmission. To allow Wall Street to market transmission securities designed to obtain financing for major transmission projects from such investors, either through investment trusts or securitization-like bonds, the Commission, working together with affected states, could grant a life-of-facility return and designate an associated capital structure. Such treatment would not break new ground. Several states have already moved in this direction in connection with generation investment. While such mechanisms may require locking in certain rate treatments, they should foster doing so at a lower cost of capital. TAPS White Paper at 16-18.

f) Allow recovery of prudent abandoned plant to reduce risk

As discussed in more detail in Part III.A.5 (response to NOPR P 34) below, TAPS supports provision for full recovery of prudent abandoned or cancelled transmission plant if the abandonment is beyond the control of the transmission owner (including its generation function).

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[60] *See also* Transmission Investment Technical Conference, *e.g.*, Joe Welsh, ITC, Tr. 80.

D. Apply Return Incentives Transparently, Symmetrically, and Sparingly, and Tie Them to Major, Structural Reforms that Will Get Transmission Built

1. Return incentives must be used sparingly, not for mere construction or RTO participation, and must be limited in amount

As demonstrated above, return incentives are not needed to attract capital, do not address the obstacles to transmission construction, and may actually increase resistance to siting. The Commission has recognized the potential for undue discrimination if incentives are applied only at wholesale.[61] Awarding incentives for new investment by transmission owners, without tying them to reforms providing inclusive opportunities for TDU investment, would encourage the status quo and discourage the major reforms needed to achieve a robust grid.

Return incentives should not be used merely to recognize new transmission investment. They have not been shown to promote investment and are counterproductive to siting approvals. Transmission owners that turn down TDU offers to invest in their transmission system certainly should not be entitled to return incentives.

Nor should return incentives be allowed for RTO participation. Return incentives would raise the already heavy RTO cost burden, and add fuel to the concerns of state commissions and customers about RTO costs, thus undermining RTOs. Would LG&E Energy be under less state commission pressure to leave MISO if ROE incentives were added to MISO's costs?[62] Surely

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[61] *Midwest ISO, Inc. and Ameren Services Co.*, 109 F.E.R.C. ¶ 61,167, P 14 (2004) (footnotes omitted) ("The Commission recognizes that, as part of an agreement Ameren made with the Missouri Commission, the Midwest ISO-Ameren service agreement under which Ameren procures transmission to serve its bundled retail load specifically states that an incentive adder will not be included in retail bundled rates. Therefore, the applicants have not demonstrated that the adoption of the proposed incentive adder [for other transmission customers] would not be unduly discriminatory 'as compared to the rates charged for AmerenUE's bundled retail load,' as required by the Service Agreement Order. Accordingly, we will set this issue for hearing."), *quoting Midwest ISO, Inc. and Ameren Services Co.*, 106 F.E.R.C. ¶ 61,293, P 22 (2004).

[62] *See, e.g.,* LG&E Energy LLC's October 7, 2005 filing in Docket No. EC06-4 at 5 (stating that its motivation in seeking to withdraw from MISO is to keeping down rates and maintain reliability).

not; the Kentucky Public Service Commission was the lead named appellant who successfully *opposed* giving LG&E and other MISO TOs a 50-point adder.[63] Similarly, the Missouri Public Service Commission permitted Ameren to enter MISO only on the contractual commitment that it would not recover incentive returns from retail load.[64] Because RTO incentives would largely be directed to those who have long since joined RTOs, it would be particularly ill-advised and inappropriate to adopt incentives that encourage RTO disintegration.

Even where TAPS proposes that some return incentives be made available where their discriminatory impact is mitigated (*i.e.*, through independent or, better yet, inclusive transcos that apply the same FERC-regulated rate to all; inclusive joint ownership, or broadly spreading the cost through a regional rate), incentive returns must be kept limited, to avoid discouraging state resistance to siting and divestiture. Not only should they be kept within a narrowly-defined zone of reasonableness,[65] they should be further circumscribed to avoid unintended consequences.

State commission opposition can be one of the most significant obstacles to transco formation. For example, the GridFlorida transco proposal was rejected by the Florida Public Service Commission based on concerns about loss of jurisdiction.[66] State commission concerns

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[63] *PSCKY v. FERC,* 397 F.3d 1004 (D.C. Cir. 2005).

[64] *See Midwest ISO, Inc. and Ameren Services Co.*, 106 F.E.R.C. ¶ 61,293 (2004).

[65] The spread from the lowest to the highest data point may not meaningfully identify what range of ROEs would be reasonable, especially when the spread is computed from a sample that has many proxies and two data points per proxy, and whose extremes reflect diverse growth forecasts and atypical dividend yields at the highest and lowest and transient share prices of the study period. In recent cases, that spread has been more than 1000 basis points wide. *See also* Part III.B below (response to third question from NOPR P 42, concerning the zone of reasonableness for transmission ROEs).

[66] Order No. PSC-01-2489-FOF-EI, *In re: Review of Florida Power Corp.'s earnings, including effects of proposed acquisition of Florida Power Corp. by Carolina Power & Light*, Docket Nos. 000824-EI *et al.* (December 20, 2001), at 15 ("We believe that under the transco model proposed for GridFlorida, it would be difficult for this Commission to retain ratemaking and cost control jurisdiction over the retail component of transmission."),

were among the problems that led to the demise faced by TRANSLink. By discouraging state approval, return incentives can be counterproductive to transco formation. As evidenced by International Transmission Company's recent IPO,[67] there is already a very potent financial incentive to divest without burdening customers, because separating corporate functions with different risk profiles unlocks shareholder value.

2. Return incentives should work two ways

If return incentives are available to some, return penalties must be in place for poor performance. Incentives must have symmetry—rewarding those that undertake major reforms that achieve a robust grid, but placing returns at the low end of the zone of reasonableness where a company is not constructing needed facilities, with the result that the transmission system is not adequate.[68] Grid adequacy for this purpose must require more than a system that barely meets reliability requirements taking account existing uses; rather, the Commission should insist on a robust system that provides customers reasonable access to alternative supplies.

The final rule should provide that in the context of the transmission provider's Section 205 filing or a customer's Section 206 complaint, the Commission will adjust returns to the low end of the zone of reasonableness where the transmission provider fails to maintain a system that is not only reliable, but that provides customers reasonable access to the competitive market and

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available at http://www.floridapsc.com/library/filings/01/15875-01/15875-01.pdf (last viewed Jan. 10, 2006).

[67] On July 26, 2005, ITC publicly offered 12.5 million shares (out of 33.22 million shares; the rest remain privately held for now) at $23 per share. This initial public offering of a minority stake in the company brought in $287.5 million, and the shares thereby sold soon began to (and continue to) trade above their IPO price. The amount paid for this approximately one-third minority stake exceeded the $250,279 value of the entire shareholders' equity as reported (as of the end of the prior quarter) in the IPO prospectus. *See* the ITC Holdings Prospectus at http://investor.itc-holdings.com/annuals.cfm (last viewed Jan. 10, 2006).

[68] *Cf. New England Power Pool*, 97 F.E.R.C. ¶ 61,093, at 61,480 (2001) (among the "basic requirements" for PBR is that it "balance risks with rewards" and "identify a best-practices standard and then devise rewards for providing additional benefits and penalties for failing to meet the standard.").

the ability to secure new long term rights, consistent with Section 217(b)(4). In other words, the Commission's final rule should make clear that there will be financial consequences for not fixing the system.

Factors to be considered could include:

- failure to meet applicable reliability requirements;
- high level of congestion (*e.g.*, congestion charges; frequency, duration and level of TLRs;[69] frequency, duration and degree of redispatching; creation of local resource adequacy deficiencies);
- inability to support allocation of FTRs, without proration or uplift, to existing resources backed by firm transmission rights;
- lack of ATC (or negative ATC) on paths of interest to customers, and specifically at interfaces, both in the near term and in the long term (*e.g.*, import capability (say, 5 years out) as a percent of peak demand);
- failure to address congestion causers — major, known constraints (*e.g.*, whether the same constraints show up when customers make transmission requests, but are not relieved);
- failure to meet customer needs through an inclusive planning process that treats the needs of all LSEs comparably (*e.g.*, failure to include in the TO's planning, and timely make deliverable, the resources identified in the 10-year forecasts required of network customers under the OATT);
- patterns of denial of transmission service requests or network resource designations (except with exposure to significant costs beyond the embedded cost rate) or high interconnection costs;
- patterns of failure to process customer transmission service requests and network resource designations in a timely manner;
- denial of reasonable access to the competitive market (*e.g.*, documented customer opportunities for lower cost supplies lost due to lack of ATC);

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[69] The absence of TLRs, however, does not necessarily show robustness; it could be attributable to the over-conservatism in the grant of transmission requests, with customers still left without access to the market. Similarly, the absence of service denials may indicate only that customers know without asking that no transmission is available.

- inability of the system to accommodate very small (*e.g.*, 20 MW or less[70]) loads, transactions, or new resource designations without upgrades or other mitigation/ redispatch);[71] and
- high levels of customer dissatisfaction.

While the precise metrics to be used to determine inadequacy can be established with the aid of a technical conference held before or after the adoption of the final rule,[72] the rule should expressly provide for downward adjustment of returns of transmission providers that fail to do their job well.

By making incentives a two-way street, the final rule will prod transmission providers to create a robust grid; it will be costly for them to continue to starve the grid. Coordinated with these negative incentives, the Commission should implement changes to the OATT to shift the risk of an inadequate grid to transmission providers.[73]

In addition, recognizing the limits on the Commission's ability to influence vertically-integrated utility decisions where upwards of 90% of the load may be served under state jurisdictional rates, the Commission should make clear that, consistent with *N.Y. v. FERC*, 535 U.S. 1 (2002), its arsenal includes the potential assertion of jurisdiction over the transmission component of the bundled retail sales of a particular transmission provider where necessary to remedy undue discrimination in extreme cases.

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[70] 20 MW is the cutoff for Order 2006, Standardization of Small Generator Interconnection Agreements and Procedures, 70 Fed. Reg. 34,190 (June 13, 2005).

[71] *Compare* Kimber Written Statement at 11, describing how a 0.6 MW request was claimed to violate multiple flowgates.

[72] It may also be appropriate to establish metrics for those within RTOs that use LMP that are different from those applied to non-LMP areas.

[73] *See* TAPS Order 888 NOI Comments at 11-18.

3. Return incentives must be transparent

To be transparent, return incentives must be based on a realistic assessment of the return really required to attract investment to the low-risk, highly stable transmission business. Such an approach is warranted not only by the lower risk profile of transmission, but also to recognize the impact of other incentives designed to further reduce risk.[74]

4. Return incentives should be structured in terms of return of total capital

Return incentives should be structured as incentives on total return, rather than as proportionately larger adjustments to equity alone, to facilitate their fair application to entities (like public power transmission owners) who have access to low-cost debt, and to avoid skewing those entities' capital formation efforts towards higher-cost equity.[75]

5. Return incentives must be tied to major reforms that promote transmission investment

a) Return incentives should be tied to fully inclusive or fully independent transcos, and take into consideration the package of divestiture facilities incentives provided

TAPS strongly supports inclusive standalone transmission companies as a means to facilitate the construction of needed transmission. Incentives should be designed to facilitate formation of inclusive transcos in ways that do not unduly burden consumers. Transcos, if not fully independent (*i.e.*, if they allow passive or ATCLLC-styled ownership), should meet the inclusiveness, balance and diversity requirements so that all LSEs in the footprint — TO and

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[74] *See* Parts III.A.1 and III.A.3 below (responding to NOPR PP 21 and 29, respectively); TAPS White Paper at 15-16; Transmission Investment Technical Conference Tr. 197-98 (Dale Landgren, ATCLLC).

[75] *See* Part III.A.1 below (response to NOPR P 21). For example, suppose that but for this structuring issue, the Commission would find it appropriate to apply a 50 basis point ROE adder to a 40% equity capital structure. Under that assumption, and the recommended structure, the incentive would take the form of 20 basis points of return on total capital.

TDU — may participate. To qualify, a stand-alone company cannot be a wholly-owned subsidiary of a transmission owner or two; it must consolidate several systems, be open to pro rata ownership by all load-serving entities in the footprint in order to make sure that it is responsive to the needs of all customers, and provide governance that reflects that balance and diversity, consistent with the Commission's policy statement.[76]

TAPS supports limited return incentive to fully independent (*i.e.*, no passive ownership) and, better yet, fully inclusive transcos (where all LSEs in the footprint have an opportunity to participate and thus the incentives do not put TDUs at a competitive disadvantage). However, as discussed above, state commission opposition can be one of the most formidable obstacles to transco formation. Thus, incentive returns must be minimized to avoid being counterproductive. The Commission should first determine the realistic cost of capital for a low-risk transmission-only business, and set inclusive or independent transco returns a notch above that level. (At the same time, the Commission should reduce returns for poor performers below that level.)

For fully independent transcos, the Commission should view the limited return incentives as a small part of a package of incentives that remove obstacles to divestiture, such as holding divesting former TOs harmless by neutralizing the capital gains tax where assets are sold at a regulatory book value that exceeds tax book value. *See* Part III.B.2 below, responding to NOPR P 43, and noting that such return incentives should not be additive to net premiums retained by the seller. However, TAPS urges the Commission to recognize and comparably support creation of inclusive transcos that are protective of ratepayers and more likely to gain state commissions approvals, and are structured to avoid the need for such costly additional hold harmless TO incentives.

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[76] *Transco Independence Policy Statement*.

The formation of ATCLLC illustrates how transcos can be formed without cost shifts and incentives can be provided without disadvantaging ratepayers, thereby facilitating state commission approval while still providing an attractive divestiture/investment opportunity. Each utility divested its transmission facilities to ATCLLC and received, in return, cash for 50% of the net book value and interests in ATCLLC (and the management company) for the remaining 50%. This was a tax-free transaction, so that the cash taken out was not taxed and there was no capital gain.[77] Those who went in at the beginning were able to extract the cash with no tax consequence, which is a significant advantage. The facilities went in at net book, so there was no write-up of ratebase or acquisition premium and Wisconsin law required that the deferred tax balances be transferred so they would in fact flow back to customers. There was no windfall from the deferred tax balances for the divesting utilities.

By using an LLC, the utilities avoided double taxation of dividends. If they were to divest to a corporation, earnings would be taxed at the transmission company level and dividends would be taxed at the utility recipient level and then again at the shareholder level. With an LLC, the transco does not pay tax, so there is a tax on dividends (earnings) at the utility recipient level and a tax at the shareholder level, which is the same situation as before divestiture. Thus, using an LLC removes a barrier that would exist with a corporate structure.

ATCLLC's structure also allows for the management company to sell stock to the public through an IPO. The proceeds would be invested in the LLC. The utility LLC owners will have the right to convert their LLC interests to shares of the corporation. If they do, they will be subject to the additional taxation on earnings as described above, but they also will be able to sell

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[77] This could only be done under the tax regulations on the initial formation of an LLC. If ATCLLC acquires additional transmission facilities from someone like Minnesota Power, there would be a taxable gain unless a new LLC is set up for the transaction and later merged.

their stock, so it is a very liquid investment. If they sell their stock at a multiple of book value, the gain will go to shareholders, which is a significant incentive/benefit. However, the ratebase will not be written up, so the customer is not disadvantaged. Given the significant mark-up that the ITC IPO achieved this summer, where stock is selling at almost four times book value and a multiple of almost 30,[78] the ability to exit in this manner if a utility chooses, is a very substantial incentive, as is the ability to retain the LLC structure to avoid double taxation of dividends if one does not exist. All of this was accomplished without a negative rate impact on customers.

Thus, in structuring return incentives for transcos, the Commission needs to consider the full package of incentives provided to induce divestiture and the competitive impact of the incentives. It should take account of other incentives provided for fully independent transcos to facilitate divestiture. *See, e.g.,* Part III.B.2 below (response to NOPR P 43 regarding ADIT and capital gains treatments for transcos). It should reward the formation of fully inclusive transcos through an ATCLLC structure that does not require costly, additional "TO hold harmless" incentives, that is protective of customers and thus, is more likely to secure state approval, and which allows all LSEs to share in the benefits of transco formation, eliminating competitive impacts of transco formation or incentive returns. In any event, because return incentives increase the potential for state commission opposition to divestiture, they kept to a limited increase above a realistic actual return requirement, reflecting the low risks associated with the transmission business.[79]

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[78] According to Yahoo Finance, as of January 3, 2006, ITC Holdings' Price/Earnings ratio was 29.21, and its Price/Book ratio was 3.46.

[79] The ATCLLC structure shows that it is feasible to structure a transmission divestiture in ways that obviate the special treatments that were approved for ITC and METC, such as covering capital gains associated with writing assets' tax basis up to their higher regulatory book value, offsetting sellers' capital gain on that write-up, and allowing ADIT balances to be deferred to an entity that will never pay the associated deferred tax. There may well have been good reasons to structure the ITC and METC divestiture in those forms. However, the Commission

b) Return incentives should be conditioned on joint ownership

The Commission should not accept vertically-integrated TO claims to incentives while refusing others the opportunity to participate in the upgrades and have that investment receive comparable cost recovery through inclusion in the transmission provider's rates. The Commission should tie receipt of return incentives to a demonstration that the vertically integrated transmission owner has offered TDUs in its footprint opportunities to participate as owners in the upgrade on reasonable terms, *i.e.*, on a basis that will allow TDUs to achieve ownership rights in the combined transmission system up to their load ratio share through investment equalization on a net book basis, with the TDUs' revenue requirement offsetting (and once it achieves parity, eliminating) the TDUs' obligation to pay to use combined facilities, and included (with incentives) on a comparable basis in the transmission provider's rates to third parties.[80]

TAPS strongly supports inclusive joint ownership arrangements as a structural reform to promote transmission investment. They have a proven track record of bringing in new sources of capital, minimizing disputes,[81] and getting needed transmission built.

Technical conference testimony reinforces the conclusion that the Commission should make TDU participation an important part of the cure for today's anemic grid. TAPS members are ready and willing to invest in the grid, and receive revenues (or credits) comparable to the

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should not assume that their approach will always be necessary. In case-specific proceedings to consider particular divestitures, it should entertain showings that Michigan-style incentives are not warranted because the same incentive to divest could be achieved at lower ratepayer cost under an ATCLLC-like or other alternative approach to divestiture.

[80] In an RTO, recognition of TDU investment could be achieved by creating a multiple transmission owner zone, with shared revenue distribution on a shared basis. *See, e.g.*, SPP Tariff, Attachment, accepted in *Southwest Power Pool, Inc.,* 112 F.E.R.C. ¶ 61,355 (2005).

[81] Typically, each party invests in upgrades in a way that maintains a load-ratio investment, minimizing cost-allocation disputes.

TO, but these offers repeatedly get rebuffed, both in the absence of RTOs[82] and in the RTO context.[83] Such TO refusals to accept TDU investment offers should not be permitted, much less rewarded.

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.[84] Congress' desire to expand the "TO club" is also evident in Section 216(b)(1)(B).[85] 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. Although the Commission has the authority to require joint ownership,[86] the use of incentives will facilitate achieving this goal without the delays associated with litigation. The opportunity to participate in the upgrade and to recover (through crediting or other revenue sharing mechanism) the costs of the facilities mitigates return incentives' competitive sting for the TDU; otherwise, TDUs

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[82] *See* Kimber Written Statement at 11. *See also* recent letters from TAPS members Lafayette Utilities System, Clarksdale, Mississippi, and the Missouri Joint Municipal Electric Utility Commission to Entergy, offering to invest in rebuilding of the Katrina-destroyed Entergy system. Entergy has not exactly jumped on the offer. The letters are appended hereto as Attachment 2. *See generally*, APPA, *Restructuring at the Crossroads* (Dec. 2004), *available at* http://www.appanet.org/files/PDFs/APPAWhitePaperRestructuringatCrossroads1204.pdf (last viewed Jan. 10, 2006).

[83] For example, municipal systems in New England sought unsuccessfully to obtain agreement from ISO-NE transmission owners as part of the negotiations to create RTO-New England to allow municipal investments in new transmission facilities on a joint basis, and the Commission ignored these systems' requests that approval of ISO-NE as an RTO be conditioned on third parties' having such joint investment rights. *ISO-New England, Inc.*, 106 F.E.R.C. ¶ 61,280, *order on reh'g*, 109 F.E.R.C. ¶ 61,147 (2004).

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

[85] 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.

[86] *See* TAPS Order 888 NOI Comments at 101-105.

would be required to subsidize, through incentive returns, their vertically-integrated competitor's generation sales, making the resulting incentives discriminatory, in violation of Sections 217(d), 205 and 206.

The Commission's incentive program should be paired with policy changes to facilitate achievement of its intended purpose. Specifically, the Commission should revise Section 30.9 of the OATT to make it an effective vehicle to effectively achieve joint transmission systems.[87] As interpreted by the Commission, the provision creates obstacles to TDU investment in the grid: denying recognition to existing TDU investments that are comparable to the facilities included in the transmission provider's revenue requirement, and allowing transmission providers to deny credits for new TDU investment by refusing to jointly plan. By revising Section 30.9 to look at the TO and TDU as a combined system, with recognition of all TDU transmission facilities comparable to those included in the transmission owner's revenue requirement,[88] and to eliminate the TO's ability to veto credits by refusing to jointly plan new transmission facilities, the Commission would provide a powerful mechanism to promote TDU investment to the grid as EPAct directs, as well as to eliminate the discriminatory pancaked rates now borne by TDUs for transmission within the host TO's system.

Again, the Commission needs to keep joint ownership return incentives narrowly circumscribed, so that they do not increase resistance to siting.

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[87] *See* TAPS Order 888 NOI Comments at 11-18, 21-26.

[88] *Compare Florida Power & Light Co*., 113 F.E.R.C. ¶ 61,263, PP 20-25 (2005), which emphasizes that the "integration test" as interpreted for purposes of Section 30.9 is different from and more restrictive than the integration test typically used to assess whether transmission facilities qualify for roll-in to transmission provider's rate base. The Commission explained (at n.34): "We note that our determination of which facilities are not eligible for transmission rate base inclusion is a very narrow determination aimed at achieving comparability to the test FP&L devised to test FMPA's facilities in the TX Case. In other circumstances, we would typically find these looped facilities to be integrated transmission facilities. *See*, *e.g., Northeast Texas Electric Cooperative, Inc.,* 111 FERC ¶ 61,189 at P 13-19 (2005)."

c) Return incentives must be conditioned on regional rates, with broad spreading of the costs to match regional benefits

As discussed above, regional rates that spread the costs of high voltage, "backbone" transmission lines across a region (rather than just locally) would match cost recovery to the broad regional benefits obtained, and reduce opposition from local consumers and state regulators. While the Commission has the authority to require joint rates outside an RTO,[89] incentive rates provides a means to get them in place voluntarily, without litigation. Even within RTOs, too often upgrade costs are confined largely to the license plate where they are built, or worse yet, directly assigned, with only a very limited portion of the cost of a small subset of new facilities eligible for inclusion in the regional rates.[90]

To promote regional rates,[91] TAPS supports limited incentive returns but only on the portion of new facilities' cost that is spread regionally. Where the cost of new transmission facilities are spread through a regional rate that addresses the equities associated with major transmission construction in one zone for regional benefit, including an incentive return will be

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[89] In light of the high degree of integration in many areas of the grid, the Commission may assign the costs of major backbone facilities across all regional loads even outside the RTO context. *See Ft. Pierce Utils. Auth. v. FERC*, 730 F.2d 778, 783-85 (1984).

[90] For example, in Docket No. ER06-18, MISO has recently proposed a 20% regional cost component for 345 kV reliability upgrades and 345 kV upgrades for generator interconnections to the extent not within the 50% not directly assigned to the Interconnection Customer, with 100% direct assignment of Network Upgrade costs associated with transmission service requests. SPP's regional allocation is somewhat more comprehensive, including 33% share that SPP applies to all Base Plan facilities down to 60 kV, with direct assignment of the remaining upgrade costs. For such costs to receive Base Plan treatment: (i) the customer must have at least a five-year commitment to the designated network resource ("DNR"), (ii) the addition of the DNR must fit within a capacity level equal to 125% of the customer's peak load, and (iii) the costs of the new transmission facilities needed for the DNR for which Base Plan treatment will apply are capped at a "safe harbor" limit of $180,000/MW. SPP allows a network customer whose DNR upgrade does not meet all of these criteria to seek a waiver so that some or all of its costs can be accorded Base Plan treatment. In accepting the SPP proposal, the Commission made clear that it shared concerns raised by some TAPS members regarding the impact of these restrictions and required further assessments and reports. *See Southwest Power Pool, Inc.,* 111 F.E.R.C. ¶ 61,118, PP 51-52 (2005), *order on reh'g*, 112 F.E.R.C. ¶ 61,319 (2005).

[91] To be clear, single holding company OATT rates are not a "regional rate."

less likely to have severe competitive effects and to deter siting.[92] There should be no return incentives on facilities whose cost are largely borne locally (through a license plate or subregional rate), or worse yet, directly assigned. Before awarding any regional rate related incentives, the Commission should require the elimination of any direct assignment, participant funding, or other form of "and" pricing component, to ensure that it is incenting only cost allocation plans that are designed to promote, rather than discourage, investment.

Again, to avoid increasing resistance to siting and achieve the reduced delivered costs Section 219(a) intends, return incentives must be kept very small. Further, to avoid discrimination, the regional rate must apply to all LSEs in the footprint, including for their bundled retail load.

E. Rely on Non-Return Incentives to Encourage RTOs

Although Congress directed the Commission to provide for reasonable and non-discriminatory incentives for joining RTOs, Section 219(c) did not specify which incentives should be adopted. The Conference Report that became law omits the specific incentives that had been included in the House-passed version of what became EPAct2005.[93] Thus, Congress left it to this Commission to determine what incentives were appropriate to promote RTOs.

As discussed above, return incentives would add to the already heavy RTO burden that is increasing state commission resistance to RTOs[94] and causing departures from RTOs. For that

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[92] It would be even better if TDUs had an opportunity to participate in that regionally-spread upgrade, as envisioned under PJM's consortium approach.

[93] *See* § 1241 of H.R. 6, 109 Cong. 1st Sess., as passed by the House on April 21, 2005. Although the Senate-passed bill included a provision directing the Commission to promote voluntary RTOs, neither that provision nor the Senate versions of § 1241 made any reference to rate of return or other specific rate incentives for RTO participation. *See* §§ 1232 and 1241 of H.R. 6, 109 Cong. 1st Sess., as passed by the Senate on June 28, 2005.

[94] *See, e.g.*, "Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation," *In the Matter of Xcel Energy's Petition for Affirmation that MISO Day 2 Costs are*

reason, the Commission should focus on incentives that provide "win-win" solutions by taking advantage of RTOs' geographic breadth to promote both stability and timeliness of transmission cost recovery — objectives that fight each other when all costs have to be recovered from within the service territory of a stand-alone, non-RTO transmission provider. In the RTO context, transmission owners have opportunities to pool funding of their existing and new transmission investment, and thereby promptly recover lumpy transmission investments without causing rate shocks at wholesale or retail; to apply a standard regional rate formula and rate of return, without the transaction costs of establishing their own, and without the risk that their approved ROE will vary based on company-specific unusual circumstances; to avoid interline competition from neighboring transmission providers; to increase transmission loading by unlocking capacity that would otherwise have to be reserved for balkanized transmission operators' reliability margins, *e.g.*, TRM).

Further, through the RTO, the transmission owner can participate in a regional planning process, thereby securing a regional planner's imprimatur for the prudence and regional value of new facilities, and enabling the facilities to qualify for non-return incentives discussed above (e.g., CWIP, recovery of precertification expenses, full recovery of abandoned plant). Through the RTO, the transmission owner could also participate in rates that spread costs regionally, thus qualifying the transmission owner for limited return incentives for the regionally shared portion of the cost of its new facilities, assuming the Commission adopts TAPS' suggestion.

Recoverable Under the Fuel Clause Rules and Associated Variances, et al., Minnesota Public Utilities Commission Docket Nos. E-002/M-04-1970, *et al*., dated December 21, 2005, which can be accessed at http://www.edockets.state.mn.us/Dispatcher?action_command=getDocumentContentViewer&docId=2571018 (last viewed Jan. 11, 2006). The order prompted Minnesota Power to submit, on December 23, 2005, its notice of withdrawal from MISO, and Xcel to inform MISO on December 30, 2005, that its "continued participation [in MISO] is under review."

No additional RTO-based return incentive is necessary or appropriate. Awarding additional TO-limited return incentives would be inconsistent with Section 219(c)'s express directive to provide for incentives for all transmitting utilities *and* electric utilities that join an RTO.

If the Commission finds it necessary to shape an incentive so as to increase the aggregate profitability of transmission owners who participate in RTOs, it should first take cost-justified steps to <u>reduce</u> the returns paid to those who refrain from participating. For example, the Commission has often looked to relatively risky vertically-integrated and diversified market participants as proxies for setting transmission rates, resulting in a transmission ROE that exceeds the cost of the equity capital that is actually invested in transmission. The emergence of transmission-only entities (like International Transco, which recently issued publicly-traded stock) is making it feasible to more accurately identify the cost of transmission-specific capital using standard methods, and providing a basis for a substantial reduction to the cost-based component of transmission ROEs. That more refined approach should be applied to all transmission owners whose ROE comes up for re-examination, whether they are participating in an RTO or standing alone. However, if the Commission does not take that course, it could restrict the applicability of the higher-risk proxies to RTOs where there is operational separation, thereby creating an ROE differential between RTO participants and others.

Finally, any RTO-related incentives should be made contingent, from the outset, on the recipient remaining in an RTO. That is, where a TO that has received an incentive for RTO participation seeks to leave its RTO without immediately entering another, equally independent RTO, it should have to return all of the participation incentive monies that it has received (with interest) to the ratepayer classes which paid them. If ratepayers pay for performance, they should get it, or get their money back.

F. Avoid Policies that Impede Construction

1. Reject participant funding

As discussed above and in the TAPS White Paper (at 8-9), participant funding is a recipe for little or nothing getting built. It discourages construction of the facilities Congress is seeking to encourage through new Sections 219 and 216. By treating so-called economic and reliability upgrades together and without distinction (*see* Section 219(b)(4)(A) and (B)), Congress has recognized that this artificial classification, with economic upgrades earmarked for participant funding, stifles transmission construction. EPAct2005's entirely permissive participant funding provision (*i.e.*, permitting the Commission to reject participant funding proposals even if they meet the requirements of Section 205) strongly signals Congress's skepticism about its value. *See* Section 220.

The Commission should move sharply away from participant funding and other forms of "and" pricing or direct assignment of broadly beneficial network upgrades. It should not grant incentives that raise the cost of upgrades where the recipient relies on participant funding or other form of direct assignment for network upgrades.[95] It is the customer, not the TO, that is bearing the cost and effectively making the investment decision in such instances. Piling on TO

[95] Rolled-in pricing rests on the long-accepted notion that the entire grid is interconnected and provides generalized benefits to all users. *See, e.g., Pub. Serv. Co. of Colo.*, 62 F.E.R.C. ¶ 61,013, at 61,061 (1993); *Midwest Indep. Transmission Sys. Operator, Inc.*, 98 F.E.R.C. ¶ 61,141, at 61,412 (2002); *Western Mass. Elec. Co. v FERC*, 165 F.3d 922 (D.C. Cir. 1999). *See also Northeast Tex. Elec. Coop., Inc.*, 108 F.E.R.C. ¶ 61,084 (2004) (affirming an initial decision concluding that new facilities at each of three existing delivery points "are transmission system upgrades whose construction costs must be rolled into transmission rates," *id.* at P 1, based on the conclusion that "the transmission network cannot be 'dismembered' in this manner; it is a 'cohesive network moving energy in bulk' that operates 'as a single piece of equipment.' This is true even if the facilities would not currently be needed but for a particular customer's service." *Id.* at P 50.)

incentives would discourage the transmission construction Congress is seeking to promote and chill generation competition. The willingness of TOs to roll-in (or spread regionally) the cost of facilities required to maintain a robust transmission system — one that provides *all* customers reasonable access to the market — should be a key factor in assessing TO requests for incentives on selected facilities.

2. Reject accelerated depreciation, which burdens today's consumers and creates unintended consequences for tomorrow's consumers

Accelerated depreciation should not be included as part of any incentive package.[96] It does not mitigate the hurdles to getting transmission built and will likely discourage siting because of the added cost burden. By eliminating needed cash flow to maintain the facilities over their full useful life, accelerated depreciation invites funding problems for the future, which in turn may trigger charging ratepayers a second time. Accelerated depreciation will in all likelihood substantially increase life cycle costs. *See* Part III.A.4 below (response to NOPR P 30).[97]

G. At Minimum, Require Bidding of the Capital Requirements for Major Additions Where a Vertically-Integrated Transmission Owner Refuses to Build without Above-Cost "Incentives"

If a vertically-integrated TO is unwilling to undertake the steps to qualify for return incentives (*i.e.*, permit TDU participation), but refuses to build without receiving above-cost rate treatments, the capital requirements of major projects should be put out to bid, allowing the market to determine the cost of capital required to fund transmission additions. *See* TAPS White Paper at 18-19. Plenty of investors would be pleased with a solid, long-term, cost-based return.

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[96] If, nevertheless, the Commission proceeds to permit them, they should be tied to the same positive structural and ratemaking reforms as are discussed below with regard to return incentives.

[97] *See* responses to the Commission's questions below for additional incentives proposed by the NOPR that TAPS

We have great faith that the bankers will be able to put together vehicles like transmission investment trusts that, with the help of regulators willing to provide regulatory certainty to reduce risk, would substantially lower the capital costs of infrastructure over the long term. Including a bid-out option in the final rule would be consistent with the Commission's providing for third party construction within RTOs,[98] and EPAct's provisions for inclusive investment, *e.g.*, Section 216(b)(1)(B); Section 219(b)(1).

III. COMMENTS ON REGULATORY LANGUAGE/RESPONSE TO NOPR QUESTIONS

A. Incentives Available To All Jurisdictional Public Utilities

1. Providing an ROE that attracts new investment in transmission facilities

NOPR at P 20: *[W]e seek comment on whether the Commission should consider alternatives to the DCF analysis as a way to incent investment in new transmission capacity.* .

DCF analysis serves to identify the cost of both new <u>and existing</u> transmission investment. Increasing the ROE for existing facilities does nothing to incent investment in new transmission facilities.[99] Replacing or adjusting the DCF analysis as a means to incent new investment would therefore go beyond anything the Federal Power Act could support.[100]

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opposes.

[98] *See, e.g., PJM Interconnection, L.L.C.,* 96 F.E.R.C. ¶ 61,061, at 61,241 (2001); *Cleco Power LLC, et al.,* 101 F.E.R.C. ¶ 61,008, P 117 (2002); *Arizona Pub. Serv. Co., et al.,* 101 F.E.R.C. ¶ 61,033, P 200, *reh'g denied,* 101 F.E.R.C. ¶ 61,350, PP 65-67 (2002); *Southwest Power Pool, Inc*., 111 F.E.R.C. ¶ 61,118, P 79 (2005).

[99] *See New England Power Pool*, 97 F.E.R.C. ¶ 61,093, at 61,480 (2001) (it would violate the Commission's "basic requirements" to "provide an incentive to encourage procedures that have already been completed."); *Allegheny Power Sys. Operating Cos.,* 111 F.E.R.C. ¶ 61,308 (2005) (then-Commissioner Kelliher, dissenting) (ROE adder for PJM participation should have been rejected outright, not even set for hearing, because increasing ROE for the recipient's past conduct "merely provid[es] a windfall").

[100] Whenever the Commission departs from cost-based ratemaking for monopoly transmission service, "it must see to it that the increase is in fact needed and is no more than is needed for the purpose." *City of Charlottesville v. FERC,* 661 F.2d 945, 950 (D.C. Cir. 1981), quoting *City of Detroit v. FPC,* 230 F.2d 810, 817 (D.C. Cir. 1955). It must make findings, supported by substantial evidence, that the incentive's cost is "outweighed by the benefits customers will receive," *Public Utils. Comm'n of Cal. v. FERC,* 367 F.3d 925, 929 (D.C. Cir. 2004). And it must

Furthermore, as discussed above, any incentives, including incentives for new transmission investment should (and under governing judicial precedent, must[101]) be transparent. That is, in setting a transmission rate of return, the Commission should first determine the cost of the relevant capital with as much accuracy as is reasonably possible. If incentive considerations make it reasonable to approve rates that intentionally vary from the cost-recovering level, the incentive treatment should be an explicit, separately quantified adjustment. Hiding the incentive amount by burying it in an implicitly distorted cost determination would defeat its purpose, because the actors that the incentive aims to motivate would not know (and would be unable to show those to whom they report) what they are getting in return for their good behavior. Furthermore, without such transparency, the Commission (and reviewing courts) would be unable to test whether the incentives were appropriately tailored and calibrated so as to achieve their intended objectives, and would be unable to ensure that transmission owners who perform poorly get the low-end returns they have earned.

Given the need for transparency, the Commission should not consider alternatives to DCF as a way to incent behavior. It should do its best to ascertain the actual cost of transmission equity capital, through DCF or other proven methods, and then consider incentives as an explicit second step.[102]

"calibrate the relationship between increased rates and [the desired public interest effect]" *Farmers Union Central Exch., Inc. v. FERC,* 734 F.2d 1486, 1503 (D.C. Cir. 1984). Pursuant to FPA Section 219(c), these precedents remain applicable.

101 In order to make the determinations recited in n.100 and do so consistent with the requirements of reasoned decisionmaking, the non-cost incentive amount must be explicit.

102 That said, it sometimes promotes cost-ascertainment accuracy to give supplemental consideration to non-DCF analyses as part of the first step, before turning to consideration of incentives. In particular, where the DCF proxy group is distorted by an outlier — be it an outlier at the high end or an outlier at the low end — supplemental reference to proven non-DCF cost identification techniques such as risk premium analysis may be worthwhile. The rule should neither mandate nor preclude case-by-case reference to these techniques.

NOPR at P 21: *We seek comment on whether ROE adders are an appropriate mechanism for requesting and receiving approval for an acceptable ROE.*

As noted in Part II.D.4 above, any incentive-based adjustment to transmission returns should take the form of an equivalent adjustment to total return (*i.e.,* return on both debt and equity), rather than making the value of the adjustment vary with the transmitter's capital structure. For example, if (after considering all issues other than this issue of form) the Commission found it appropriate to give a 100 basis point ROE adder to a transmitting utility with a capital structure of 40% common equity and 60% debt, the appropriate incentive would be a 40 basis point adder on total capital.[103]

The NOPR never explains why, assuming an above-cost incentive payment is warranted, it should take the specific form of an ROE adder. The Commission first granted a monetary bonus for RTO participation in a case where only the ROE was at issue,[104] but that was an historical accident, and that decision was reversed on appeal.[105] FPA Section 219(b)(2) directs that the rule being formulated here should include an ROE that "attracts new investment in transmission facilities (including related transmission technologies)," but that much can be accomplished with a cost-based ROE coupled with the non-ROE incentives discussed in Part II.C.2 above: the statute does not specify ROE as the vehicle for carrying incentives. To the contrary, Section 219(b)(1) makes clear that incentives are to be available "regardless of the ownership of the facilities," which makes ROE heighteners an ill-suited approach.

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[103] If the incentive is applied to the equity portion of a standardized imputed capital structure (as discussed in Part III.A.3 above), that would be arithmetically equivalent to applying a proportionately smaller incentive to total capital. The point we are making here is that it would be misguided to make the incentive payment amount turn on the utility's actual capital structure.

[104] *See* Proposed Policy at P 8, *citing Midwest ISO*, *Inc.,* 100 F.E.R.C. ¶ 61,292 (2002).

105 *PSCKY v. FERC,* 397 F.3d 1004 (D.C. Cir. 2005).

The issue being raised here is essentially one of the bonus "rate design" — *i.e.,* assuming that some bonus is to be allowed, to what measurement units should it be applied? Because a return on total capital bonus does not turn on capital structure, it has at least four compelling advantages over an equity return bonus.

One, applying the bonus to equity investment rather than total investment makes it difficult to be neutral among the business models of existing transmission owners (public governmental, public cooperative, and private investor; vertically integrated and vertically non-integrated), as Section 219(b)(1) requires.

Two, an incentive tied to equity investment alone would create perverse incentives for thick capital structures. For example, if utility A owned $1 billion in transmission facilities and had a capital structure of 40% equity, 60% debt, while utility B owned the same amount and kind of facilities but had a 50%/50% capital structure, then utility B would be eligible for a significantly larger ROE bonus in dollar terms. Hinging the effective bonus on the utility's actual capital structure would reward utilities who gamed the bonus policy by retiring debt and issuing equity in its place, which would raise transmission prices but do nothing to improve the grid. Discouraging transmission owners from leveraging their capital structures by issuing debt would impede the formation of transmission capital, and thereby fight the policy goal of spurring grid development.

Three, an incentive tied to equity investment alone would have the perverse effect of encouraging transmission owners to invest in risky ventures, and therefore to remain vertically integrated and diversified, losing their focus on transmission investments. Wall Street expects capital invested in any enterprise's equity to grow, either by taking on some financial risk through debt leveraging or by taking on operating business risk through investment in enterprises with growth potential (and the attendant risk).[106] Tying incentives to the equity ratio would tend to push transmission owners away from the first alternative, because they would want to inflate the equity component of their capital structure in order to maximize their incentive receipts. That would leave, as their path to growth, participating in relatively risky (*i.e.,* non-transmission) business. Wall Street expectation and financial market imperatives would thereby encourage the transmission owners receiving ROE-based incentives to shift their managerial and investment focus <u>away</u> from low-risk transmission.

Four state-organized institutions like the Wyoming Infrastructure Authority are emerging as vehicles for funding transmission investment with low-risk, low-cost bonds. WIA recently announced that a transmission line will be its first financing project,[107] sold $35 million in bonds to finance that project to the State of Wyoming, and arranged to loan the proceeds to Basin Electric Cooperative to finance the future line. Under those arrangements, Wyoming pays WIA a low adjustable interest rate of 25 basis points above the long-term U.S. Treasury bond yield, and Basin in turn pays 30 basis points above what WIA pays Wyoming.[108] The Commission should not discourage states from offering and utilities from utilizing such bonds.

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[106] *See, e.g.,* Michael Milken, THE CORPORATE FINANCING CUBE: MATCHING CAPITAL STRUCTURE TO BUSINESS RISK (" the simple rule of thumb is that risk in capital structure should vary inversely with volatility and risk in the basic business"), *available at* http://www.mikemilken.com/articles.taf?page=1 (last viewed Jan. 10, 2006); *reprinted in* MBA IN A BOX: PRACTICAL IDEAS FROM THE BEST BRAINS IN BUSINESS (2004), ch.3.

[107] Billings Gazette, *Group to Issue Bonds for Power Line* (Aug. 25, 2005), *available at* http://www.billingsgazette.com/index.php?id=1&display=rednews/2005/08/25/build/wyoming/35-power-lines.inc (last viewed Jan. 10, 2006).

[108] *See* the July 22, 2005 Resolution of the Wyoming Infrastructure Authority at 1-2, *available at* http://www.wyia.org/Docs/Resolutions/Resolution_2005.07.22.pdf (last viewed Jan. 10, 2006) and the associated Minutes of the Board of Directors, at 1, *available at* http://www.wyia.org/Docs/Minutes/WIAMinutes2005.07.22.pdf (last viewed Jan. 10, 2006). These documents make clear that the bonds have a twenty-year term, that their maximum board-authorized interest rate is 100 basis points above the yield on twenty-year treasuries, and that the actual back-to-back interest rates are 25 and 55 basis points, respectively, above a long-term treasury yield. Municipals infer that the treasury bond duration used in specifying the baseline long-term treasury yield is likewise twenty years.

The perceived advantage to tying incentives to ROE is illusory. Advocates of that approach seem to believe that a bonus in the judgment-laden area of return on equity will receive more judicial deference than a bonus applied to another cost-of-service component. But incentive bonuses are not based on difficulties in ascertaining the cost of equity capital; they are explicit upwards adjustments to be applied only after the Commission finds the cost-based return. The Commission has no more discretion to intentionally increase equity return above cost than it does to intentionally inflate any other component of the cost of service. Especially given FPA Section 219, there is no valid reason to seek incentives by stealth.

NOPR at P 22: *We also seek comment on whether the final rule should establish a definition of "independent regional planning process" or if the Commission should consider them on a case-by-case basis.*

The NOPR proposes to ask those requesting any of a broad range of incentives whether their new facilities resulted from an "independent regional planning process." In contrast, TAPS proposes that eligibility for non-return incentives (e.g., CWIP, precertification expenses; abandoned plant recovery) turn on whether the new transmission facilities were the product of an inclusive joint or inclusive regional planning process; TAPS would allow limited return incentives only in connection with major reforms conducive to transmission investment – inclusive or independent transcos, inclusive joint ownership, or regional rates.

As to planning, TAPS's focus on inclusiveness, as opposed to independence, reflects experience of TAPS members in RTO planning processes that too often reflect mere coordination of TO plans.[109] By enacting Section 217(b)(4), Congress made clear that the planning must be inclusive, incorporating on a comparable basis the needs to all LSEs—both

[109] *See* Comments of the ISO/RTO Council, Nov. 22, 2005 , Docket No. RM05-25, at 22 ("[m]ost ISO/RTOs have an internal process to coordinate projects with their transmission owning members.").

TOs and TDUs. A TO-centric process won't do, whether the process is nominally "independent" or not.

To the extent the Commission uses "independent regional planning" as a criterion for incentives (which TAPS urges be limited to non-return incentives), the regional planning process should have to

(1) be inclusive such that all transmission customers and other stakeholders can fully and meaningfully participate in the process of defining system needs, reviewing (subject to confidentiality commitments where necessary for CEII security) the aggregated system usage data that informs system planners, suggesting and analyzing alternatives, and otherwise informing planning decisions; the process cannot give preferential influence to the needs of one set of market participants (*e.g.*, TOs);

(2) be designed to meet the needs of all LSEs, on a comparable basis, as required by Section 217(b)(4). Thus, it must provide a platform for forward planning for meeting deliverability, delivery, and simultaneous feasibility needs (whether "reliability" or "economic"), such that facilities needed to connect load to its resources and to create a robust grid are built. The planning process must be well-designed so as to timely accommodate the needs of all LSEs for reliable delivery of network customers' network resources to their loads with long term rights hedging exposure to congestion, assure regional reliability, and allow markets to be efficient and competitive, so that delivered costs are reduced, as mandated by Section 219(a);

(3) provide effective authority to overcome vertically-integrated incumbent owners' reluctance to construct. To be effective, the regional independent process must include backstop mandating authority, to be exercised (following fair dispute resolution

procedures) if no other builder or consortium is available, unless the vertically-integrated incumbent owner has a legitimate transmission business justification to refrain; and

(4) include mechanisms for coordination with and among relevant state siting authorities, under procedures designed to minimize the ability of parochial interests to defeat broader-area needs.

Inclusive joint planning should include similar safeguards to ensure that the mandates of Sections 217(b)(4) and 219(a) are fulfilled, and that the needs of customers are treated comparably to those of TOs. The process should ensure that transmission upgrades designed required to support a TO's generation function are not entitled to any incentives if facilities required to accommodate its network customer's new network resources are not comparably planned for and rolled in.

TAPS proposes that inclusive planning serve as a criterion for non-return incentives that reduce the risk and enhance cash flow, thus facilitating construction. TAPS would allow limited return incentives only if this <u>process</u> inclusiveness is reinforced through <u>structural</u> inclusiveness: accommodating broad ownership of the facilities approved through that process. To qualify as structurally inclusive, the process should have to (among other things) allow any financially qualified entity, including public power, a fair opportunity to either (a) buy into the constructing independent entity on a load ratio basis,[110] or (b) finance and own the approved facilities, build them if technically qualified, and recover their costs through regional rates (or otherwise enable them to achieve load ratio ownership in the transmission system, as discussed in part II.D.5

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[110] *See* Part III.B.3 below (responding to NOPR P 44, and noting that inclusiveness through allowing investment in independent transco entities can substitute for inclusiveness through allowing investment in individual facilities).

above). Such an opportunity would be consistent with RTO procedures for third-party participation in construction.[111]

2. Prudently incurred construction work in progress and prudently incurred pre-commercial operations costs

NOPR at P 27: *The Commission believes that allowing public utilities to include up to 100 percent of prudently incurred transmission-related CWIP in rate base and permitting them to expense prudently incurred pre-commercial operations costs will further the goals of Section 219 by relieving the pressures on utility cash flows associated with their transmission investment programs and providing up-front regulatory certainty. We propose to evaluate the applicability of these incentives to transmission investment applications on a case-by-case basis.*

As discussed in Part II.C.2 above, TAPS strongly supports full and prompt recovery of prudent pre-operational costs of inclusively planned facilities. This proposed adjustment to the timing and certainty of prudent cost recovery, without increasing the aggregate recovery over facilities' full life cycle, is a prime example of the "win-win" approach the Commission should be pursing, as distinguished from seeking to advantage selective entities' shareholders at ratepayers' expense. Rather than requiring case-by-case consideration, TAPS would suggest providing for such recovery generically (where inclusiveness requirements are met). Principally, the Commission should encourage formulaic transmission rates and make clear that pre-operational costs of inclusively-planned facilities may flow through formulas (often as an expense, otherwise as capitalized investment). Secondarily, it should modify the CWIP rule at 18 C.F.R. § 35.25.

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[111] *See, e.g.,* PJM Operating Agreement Schedule 6 (Regional Transmission Expansion Planning Protocol), Section 1.5.7, *available at* http://www.pjm.com/documents/downloads/agreements/oa.pdf (last viewed Jan. 10, 2006) (providing for designation by the RTO of the entity that will build facilities included in the regional plan, and for a one-year "Market Window" after the initial finding that a proposed facility will be cost-beneficial, suring which any entity may offer to build that facility or propose to construct an alternative solution).

[W]e specifically request comment on (1) the types of costs that should be considered "pre-commercial operation costs"; NOPR at P 28.

TAPS recommends a broad definition that looks to whether the costs were incurred (prudently) in order to initiate the project and then bring it towards completion, *e.g.,* by identifying the need for a new transmission project, undertaking its planning or design, securing approval through a regional planning process where applicable, making interconnection arrangements with the entities that own or operate adjacent or affected facilities, securing applicable local permits or environmental or regulatory approvals, acquiring associated land rights or materials, and proceeding with construction or testing. As a particular example, payments to the local communities and other stakeholders to offset the visual and environmental impacts of a new or enlarged transmission line should be promptly recoverable, whether incurred before or after the project begins commercial operation.

NOPR at P 28: *(2) [W]hether there should be a presumption that these incentives meet the requirements of FPA Section 219 that investments ensure reliability and [[112]] reduce the cost of delivered power.*

A presumption that a planned facility ensures reliability or reduces delivered power costs (or both), such that pre-commercial costs would qualify for incentive treatment, should apply where the facility is the product of inclusive regional or joint planning In the unusual case of a facility that is unilaterally planned without either form of independent scrutiny, the standard rate case rule should apply, placing on the utility seeking recovery the burden to establish that an expense may reasonably flow through into rates. In practice, that is not a difficult burden to meet.

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[112] Section 219(a) uses the conjunctive in defining "the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." As Sections 219(b)(4)(A) and (B) highlight, the statute's use of "and" in this context does not mean that every qualifying transmission investment must do both, although that is typically the case. Someone sent to the supermarket for breakfast and dinner may

3. Hypothetical capital structure

NOPR at P 29: *[W]e propose that applicants be permitted to propose an overall rate of return based on a hypothetical capital structure, and have the flexibility to refinance or employ different capitalizations as may be needed to maintain the viability of new capacity additions.… We seek comment on this proposal.*

TAPS would oppose use of hypothetical capital structures if the imputed structure contains an equity component that is thicker than the thin one that financial markets would expect for a transmission-only firm. Thick "actual" capital structures serve predominantly to counter-balance "investor skepticism over accounting practices and disclosure, liquidity problems, financial insolvency, and investments outside the traditional regulated utility business, principally merchant generation facilities and related energy marketing and trading activities."[113] As is typical among investment analysts, Standard & Poors would expect entities focused on the low-risk transmission business to be highly leveraged, to the point that it would give an investment-grade bond rating to a typical transmission-only U.S. utility even if its capital structure was only 32%-42% equity.[114] The parental capital structure for International Transmission Company, for example, is less than 29% equity, and more than 71% long-term

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legitimately place Cheerios in his shopping cart.

[113] Standard & Poor's Corporation, *Credit Quality For U.S. Utilities Continues Negative Trend*, Ratings Direct (Jul. 24, 2003). For example, after AEP's "wash trading" scandal, investment rating agencies significantly downgraded AEP's debt ratings, citing the business risks and low earnings associated with AEP's unregulated operations. *See, e.g., Moody's Cuts AEP Credit Rating,* Columbus Business First (Dec. 12, 2002) (In downgrading AEP's rating, Moody's cited "lower results from its [AEP's] energy trading business" and "noted AEP is cutting back on energy trading, but will have to spend more money to wind up past deals"), *available at* http://www.bizjournals.com/columbus/stories/2002/12/09/daily28.html. AEP responded by significantly thickening its equity ratio, explaining that because "weak results from our unregulated investments have been detrimental to overall corporate performance," AEP would retire substantial debt and thereby achieve "measurable improvements to our balance sheet." *See* AEP's press release dated February 10, 2003.

[114] *See* Standard & Poor's, *New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised* (June 2, 2004), at 3 (debt/capital expected range for BBB-rated entities of 58%-68% associated with a business profile of 2, and 55%-65% associated with a business profile of 3).

debt.[115] Where thicker equity is carried to cushion the business risks of non-transmission investments, it should not be charged to transmission customers.[116] Base transmission rates (before application of any incentives) should be calculated using a hypothetical capital structure that is highly leveraged, consistent with financial market expectations for the low-risk transmission business. That approach would appropriately functionalize capital costs. It could also be applied so as to increase the return differential between those transmission owners who have not earned incentives and those who have.

Accordingly, the Commission should entertain hypothetical capital structures, but only the thin ones that financial markets would expect for a transmission-only entity. If it continues to set the cost-based component of transmission rates using thicker capital structures, it should recognize that allowing an equity-level rather than debt-level return on that extra equity amounts to an above-cost incentive payment. That allowance should substitute for, and obviate, other forms of equity return heighteners. *See Am. Transmission Co. LLC and Midwest Indep. Transmission Sys. Operator, Inc.,* 105 F.E.R.C. ¶ 61,388 (2003) (approving 50/50 capital structure in lieu of ROE adders).

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[115] *See* ITCH's most recent (November 2005) quarterly report, available at http://investor.itc-holdings.com/sec.cfm (last visited Jan. 10, 2006).

[116] *See PSCKY v. FERC,* 397 F.3d 1004, 1006-1007 (D.C. Cir. 2005) (calculating a transmission ROE "would be relatively easy if a utility's interest in its grid — its business as a transmission owner (TO) — were publicly traded"); *Farmers Union Cent. Exch., Inc. v. FERC,* 734 F.2d 1486, 1522-23 & n.70, 1530 (D.C. Cir. 1984) (ROE must "take account of the risks associated with the regulated enterprise"; "Obviously, there are no assurances that the returns to, say, Exxon's non-pipeline operations — which include its office systems manufacturing, oil exploration, etc. — would reflect the risks of an oil pipeline.").

NOPR at P 29: *In their applications for incentive treatment, public utilities should … provide its transmission investment plan and explain the specific projects to which the proposed return will apply. We seek comment on this proposal.*

We focus here on procedures; TAPS' view that limited "return" incentives should be available only in connection with major reforms (inclusive, or at least independent transcos, inclusive joint ownership arrangements, and regional rates) is explained above.

TAPS generally agrees that in order for a project to be eligible for a proposed incentive, it must be identified, to the extent feasible[117], in the application through which the utility seeks to adopt incentives. The present rulemaking should not complete the authorization of any particular incentive for any particular transmitting utility; rather, it should establish a framework that will govern subsequent utility-specific (or multi-utility region-specific) applications to adopt incentives consistent with the rule. When a utility (or group of utilities) files to adopt a particular incentive plan, it should be required to (a) provide its transmission investment plan (to the full extent then known), including both a listing of planned projects by anticipated in-service date and the expected cost of each project;[118] (b) detail which projects would be eligible for which proposed incentives; (c) break out the direct costs associated with the incentive plan, by incentive component and by each incentive-eligible project, and (d) state whether any of the contemplated projects are contingent on receiving a requested incentive.

4. Accelerated depreciation

NOPR at P 30: *We…propose to allow transmission facilities to be depreciated over a period of*

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[117] A project that could have been identified in the incentive plan filing, but which was omitted without good cause, should be ineligible for incentives under that plan. However, incentive plans may stay in effect for several years. Projects which are neither identified nor reasonably identifiable at the time of an incentive plan filing should not be disqualified from receiving incentive treatment solely because they arise later. Rather, if the terms of the previously-approved incentive plan covers a later-arising project, the sponsoring utility should be required to make a filing supplementing its incentive plan filing to provide, for its subsequent projects, the information listed in the text.

[118] *See also* our comments on proposed "Form X" in Part III.E below (responding to NOPR P 49).

15 years, in place of the typical Commission practice to allow depreciation over the useful life of the facilities, and seek comment on whether 15 years is an appropriate time period for cost recovery or whether the Commission should establish a presumption of a shorter or longer depreciable life for new transmission facilities. We also seek comment on whether accelerated depreciation has any longer-term negative impacts that would undermine the goals of the Act.

The NOPR proposes to disregard the well-established, and flexible,[119] criterion of economically useful life. Instead, it would sanction a truncated "depreciable life" of 15 years, regardless of actually anticipated economic life. This proposal is misguided, for multiple reasons.

First, local siting authorities respond to constituent pressures and are therefore especially sensitive to the near-term timing of investment recovery. The degree to which they are put off by accelerated depreciation may well exceed the degree to which acceleration will motivate rational transmission owners. The latter generally have no cash liquidity crunch once facilities are in service,[120] and therefore have no rational preference for retrieving their investment during years 2 through 15 rather than retrieving it with interest during years 16 through 40. Acceleration as such therefore may make transmission investment less likely, not more.

Second, the NOPR's suggested regimen of shortening the depreciable life for new facilities while maintaining useful-life depreciation for existing facilities would result in a

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[119] It has always been, and should remain, Commission policy that transmission-related investments may be depreciated rapidly in those atypical instances where the facility's useful life is short (*e.g.,* transmission software investments, or a radial to a generation plant site whose remaining economic life is short and unlikely to be renewed). However, such short life is quite the exception for networked AC facilities, which are not only physically long-lasting, but functionally flexible: They continue to provide transfer capability and earn non-bypassable payments for many decades, with little risk that they will be economically stranded if flow patterns change as load and generation grow and get re-distributed.

[120] The California market meltdown and resulting cash crunch, which produced demands for accelerated depreciation of Path 15 investment, is not typical. In fact, many transmission owners recently favored levelized transmission rates, which <u>back</u>load cost recovery. A transmission-only entity that undertakes a major transmission construction program may have a liquidity issue <u>during</u> the construction, but because accelerated depreciation kicks in later (after the subject facility is completed and enters rate base), it is ill-suited to addressing that rare circumstance.

strange and inequitable matching of ratepayer generations to investment vintage recovery. The fundamental premise of the present rulemaking is that the legacy grid is inadequate to support efficient open access markets, and must therefore be significantly upgraded to meet new and future needs. That premise suggests that the costs of re-tooling the grid should be borne by the many decades of consumers who will benefit from the re-tooling. Today's consumers are already bearing enormous transitional restructuring charges (stranded generation cost payments, reliability must-run charges, California bail-out fees, capitalized RTO administrative costs, de-pancaking transition charges, *etc.*) in order to climb the learning curve of establishing workable U.S. competitive markets and restructure the industry in ways intended to bring distant benefits. They should not also have to pay for the future carrying costs of facilities that will continue operating and providing value into the 2040's.

Third, accelerated depreciation has a major negative impact in the longer term. Once the depreciable life runs and transmitting utilities come to have small or even negative (after considering negative net salvage value) rate bases, transmitting utilities will no longer receive return on or of their investments. Tomorrow's Commission would therefore face an unattractive dilemma. It could honor the regulatory bargain of accelerated depreciation — returning investment to shareholders more rapidly at the expense of present ratepayers, but giving future ratepayers the benefit of a paid-down system — but only at the price of leaving tomorrow's transmitting utilities short of the cash needed to maintain and operate their systems. Or it could dishonor that bargain and allow a "management fee" in order to "compensate the owners… for the risks of continuing to operate… once the original investment has been recovered and provide an incentive for efficient operations," as it did in the fully-depreciated pipeline context of *High Island Offshore System, L.L.C.,* 110 F.E.R.C. ¶ 61,043, PP 105-115 (2005), thereby requiring consumers to pay twice. Today's Commission should not impose that dilemma on its eventual successor. Nor, given the likelihood of a "management fee" or other non-depreciated rate, should it pretend that accelerated depreciation is necessarily only a "timing adjustment."

Fourth, accelerated depreciation will skew transmission planning towards projects that emphasize investments in rapidly depreciable facilities rather than non-depreciating land. For example, assume that a utility faces a planning choice between two alternatives. The first would require acquisition of a few miles of expensive Right-of-Way, but would avoid the need to upgrade the voltage, and build new towers, on a long existing corridor. For clarity, assume that the two alternatives — creating a short new transmission corridor, or widening the use and increasing the impacts of a long existing corridor — are environmentally equivalent, so that this should be a purely economic decision. Accelerated depreciation would push the utility towards the second approach, even if it was the more costly one, because it would yield fast returns and the prospect of a continuing management fee after the depreciable life ends.

For all these reasons, depreciable lives should not be shortened to less than economic life. If artificially accelerated depreciation is nonetheless adopted, it should at least be modified to include market testing. To receive it, transmission owners should be required to put an economic commitment behind the implied position that transmission investment made today will have no economic value in fifteen years. They should be obliged to sell the post-depreciation-period ownership rights in the new facilities up front, for fair market value, with the proceeds credited to ratepayers over a fifteen-year amortization period.[121] At minimum, they should have to commit that after fifteen years, any facility which received the proposed depreciation rate will

[121] To avoid creating barriers to dispositions to market-independent transcos, the sales could include transco rights to recapture the future interests, for a fair price.

be auctioned or otherwise sold for fair market value, with the proceeds being credited to ratepayers.

5. Recovery of costs of abandoned facilities

NOPR at P 34: *We propose to permit recovery of 100 percent of the prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility because it will reduce regulatory uncertainty associated with investments in new transmission capacity and therefore meet the objectives of FPA Section 219. We seek comment on this proposal.*

As discussed in Part II.C.2.f above, TAPS supports this proposal when applied to inclusively planned facilities. Like the proposal to allow current expensing of transmission CWIP, this proposal to make prudent cost recovery more certain is well directed to addressing the concerns that Wall Street representatives actually expressed at the technical conferences. It therefore can benefit shareholders and ratepayers jointly, rather than benefiting the former at the latter's expense.

A few secondary issues related to such recovery require consideration, however.

First, determining when a cancellation is "beyond the control" of a transmitting utility may be difficult. For example, if a state siting authority imposes stringent conditions rather than denying a permit outright, and the utility then decides not to proceed, is that abandonment due to factors beyond the utility's control? This set of issues should not be entirely deferred to subsequent case-by-case resolution. Rather, the Commission should both add clarity and strengthen other objectives of the rule by including in the rule the following presumptions and limitation. Where the facility is planned and approved pursuant to an inclusive planning process, and the abandonment is approved by that same process due to changes in the factual premises (other than the utility's unilateral preferences) on which the earlier approval relied, the cancellation should be presumed to qualify. Similarly, if (as in the *Southern California Edison* case that the NOPR is proposing to codify[122]) the project was planned to meet the needs of unaffiliated generators and the transmission abandonment or cancellation is due to those unaffiliated generators' own change of plans, the lack of affiliation supplies the equivalent of independence, and the project should be presumed to qualify. Conversely, however, if the transmission owner planned the abandoned project unilaterally to meet its own affiliated generation needs, the cost of the abandoned plant should be functionalized to generation and remain subject to the 50/50 sharing rule of Opinion No. 295.[123]

Second, consistent with FPA Section 219(b)(1), this policy must apply even-handedly to all transmitting utilities, including public power.

Third, the timing rule of Opinion No. 295 — that the portion of costs that are allocable to ratepayers be amortized over the service life that the cancelled facilities would have had — should remain applicable.

Fourth, the Commission should not codify *Southern California Edison* without also implementing its caution in that case: "SCE faces a lower risk with these segments [due to the regulatory assurance that prudent costs of abandoned or cancelled plant will be recovered] and a lower rate of return on equity may be warranted."[124] Accordingly, as an integral part of making it reasonable (and consistent with FPA Section 219(d)) to accord this exception to the Commission's longstanding policies on plant abandonment, the Commission should also adopt the recommendations in Parts III.A.1 and III.A.3 above. The Commission's rules and practices for setting the baseline cost of equity should be made accurate and risk-reflective (which will

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[122] *See* NOPR at P 3 & n. 26 (citing and proposing to codify *Southern California Edison Co.*, 112 F.E.R.C. ¶ 61,014 at P 58-61, *reh'g denied*, 113 F.E.R.C. ¶ 61,143, PP 9-15 (2005)).

[123] New England Power Co., 42 F.E.R.C. ¶ 61,016 (1988).

yield significantly lower ROEs) no later than the effective date for the rule's upward adjustments to rates.

6. Deferred cost recovery

NOPR at P 35: *[T]he Commission proposes to permit such utilities to use a deferred cost recovery mechanism which allows them to commence recovery of new facility costs in FERC-jurisdictional rates at the end of a retail rate moratorium. ... We seek comment on whether there are other mechanisms that the Commission could institute to provide regulatory certainty of the recovery of the costs of transmission facilities both through retail as well as wholesale rates.*

In explaining this proposal, the NOPR relies on a case in which all retail ratepayers connected to the transmitting utility's system paid the same transmission rate, because those facilities had been divested to an independent transco.[125] Where all connected retail customers see the same deferral, and where the deferral is not used to game stated unit rates, such treatment can be a reasonable way to transition from one rate structure to another. However, the rule should not grant a blanket authorization to such treatment, because it is all too open to abuse.

For example, many utilities have stated unit rates at wholesale, which were set long ago — commonly, using the costs and loads from a test year predating the Order No. 888 compliance filings that were made in 1996. The theory behind stated unit rates is that costs and loads generally grow apace, so that a unit rate set using one test year can remain appropriate for application in subsequent years. The increased revenues associated with load growth are supposed to cover the costs of new facilities to serve that load growth. The reality — the very reality that is animating this rulemaking — is that for many of these transmission owners, although transmission loads have continued to grow, transmission investment has <u>not</u> kept pace. If transmission owners with stale unit rates are allowed to defer the costs of new facilities, they

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[124] 112 F.E.R.C. ¶ 61,014 at P 61 n.49.

[125] *See* NOPR at P 35 n.28, *citing Trans Elect, Inc.*, 98 F.E.R.C. ¶ 61,142, *reh'g denied*, 98 F.E.R.C. ¶ 61,368

will collect revenues meant to cover the costs of new facilities, but defer those facilities' costs and collect them later. That would represent an unreasonable double-dip, and would be inconsistent with FPA Section 219(d).

Even worse, because bundled retail rates are set elsewhere (often using different test years that feed into this Commission's rates), the double-dip would be paid only by wholesale customers and unbundled retail customers. The result would be not only unreasonable, but unduly discriminatory. Again, Section 219(d) would be violated.

B. Incentives for Transco Formation and Transco Investment

NOPR at P 37: *In this NOPR, the Commission proposes to define a transco as a stand-alone transmission company, approved by the Commission, which sells transmission service at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility. We invite comments on this proposed definition of transcos.*

As discussed in Parts II.A and II.D.5.a above, TAPS strongly supports formation of independent or inclusive transcos and reasonable incentives for such formation. However, the proposed definition is inartfully drafted: none of the transcos that are lauded in the NOPR's explanatory paragraphs would fit under it! NOPR Paragraph 38 correctly cites the construction programs of the three Michigan-Wisconsin transcos (ATCo, ITC, and METC) as proof of transcos' value, but ATCo, ITC, and METC do not "sell[] transmission services" (P 37). They own transmission facilities which have been placed under the control of MISO, which uses them in selling <u>its</u> transmission services.

The NOPR's discussion paragraphs (PP 36-42) indicate that the Commission means to reward "properly structured transcos" (P 40), that, like ATCo, ITC, and METC, have all of the following characteristics:

(2002).

- The rates through which their revenue requirements are collected "are 100 percent FERC jurisdictional" (P 36); *i.e.,* "ratemaking for transcos is entirely subject to federal jurisdiction." (P 39).

- They are "stand-alone," for which it is not sufficient that they be incorporated separately while still being owned in common with a single parent company's generation function; rather, they must fit within "the range of independence that would be acceptable for Commission approval" (P 41) as set forth in Transco Independence Policy Statement. An affiliated transco covering a single transmission system plainly won't suffice; factors such as inclusiveness of and diversity among owners and balanced governance are key.

- They are managed and governed outside the corporate hierarchy of a single group of affiliated market participants, so that their "sole focus is on the business of transmission" (P 39), they are "better position[ed] to respond to market signals that indicate when and where transmission investment is needed," (*id.*) and are meaningfully separated from "entities that … own or control generation assets," (n.35) such that they "further ensure non-discriminatory transmission service" (*id.*) and "do not face a potential decrease in value to their generation assets as a result of additional transmission" (P 39).

- They "access … capital markets" (P 39) directly, not through market participants' holding company(ies), and therefore are positioned to realize the financing advantages of their "more focused business model," (*id.*) in a way that "eliminate(s) the competition for capital between the generation and transmission functions within corporations" (*id*).

TAPS urges the Commission to discard the NOPR's transco definition and adopt one that encompasses only entities with all of the favorable characteristics identified in the NOPR (as quoted above). We therefore suggest the following revised definition. (Its footnotes are not intended to be part of the definition; rather, they explain language for which part of the underlying reasoning goes beyond the above bullet points and quotations.)

> <u>Transco</u> means an entity[126] that owns or controls transmission facilities used to provide transmission service in interstate commerce, and that

[126] The definition should not preclude a transmission-only governmental entity from being a "transco," as might be read into the reference to "company" in the NOPR definition.

(1) If the entity is a jurisdictional public utility, charges (either directly or through a transmission provider that operates its facilities, and) rates set by this Commission that apply[127] to all load served through its facilities with no adverse distinction in the rates for transmission service to wholesale loads and unbundled transmission loads, as compared to the transmission component of bundled retail service;

(2) If the entity is not a jurisdictional public utility, charges (either directly or through a transmission provider that operates its facilities, and) rates that apply to all load served through its facilities with no adverse distinction in the rates for transmission service to wholesale loads and unbundled transmission loads, as compared to the transmission component of bundled retail service;

(3) is a distinct legal entity that does not own generation facilities or participate in generation markets;

(4) meets the standards of the *Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission,* 111 F.E.R.C. ¶ 61,473 (2005); and

(5) obtains capital for investment in transmission facilities by issuing financial instruments in its own name, or that of a parent company that does not directly or indirectly own generation assets used in interstate commerce.

1. ROE-based incentive for transcos

NOPR at P 42: *We request comment on how to factor the level of independence into any request for ROE-based incentives for transcos.*

As discussed above, any entity that seeks an incentive on ground that it is a transco should have to satisfy the factor-based test for evaluating if market participants are truly passive owners or otherwise achieve the requisite "operational and managerial independence" set forth in

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[127] The definition should be framed by reference to rates set by this Commission rather than rates that are "jurisdictional," for three reasons. First, under *New York v. FERC,* 535 U.S. 1 (2002), the transmission component of bundled retail service is "jurisdictional" too; the relevant distinction is that FERC rate jurisdiction over that component is not yet being exercised. Second, under the transitional approach that MISO adopted in the Order No. 453 remand proceedings, FERC nominally sets the rate for the service provided by MISO to its non-transco TOs and resold by them as a component of state-regulated bundled retail rates, but that rate adopts by reference the state bundled retail rate. The proposed definition's reference to the rates that "apply to all load" is meant to distinguish that structure. Third, a governmentally-owned entity that meets the criteria set forth in the text should be eligible for transco status, even if the Commission does not regulate its rates directly under FPA Sections 205-206 and instead looks to new FPA Section 211A.

the Transco Independence Policy Statement at P 9. Consistent with that policy statement, where the entity is affiliated with market participants, it should have to be open to inclusive affiliation with multiple and diverse market participants (i.e., including municipal and cooperative utilities), such that all LSEs in the transco's area have the opportunity be comparably affiliated with it, and participate in a governance structure that reflects that diversity to achieve balance. See Transco Independence Policy Statement at 9 & n.6 discussing ATC's diverse ownership and balanced governance ("each ATC board member has one vote per owner, regardless of their size").

NOPR at P 42: *We seek comment on whether the Commission should specify additional incentive levels, that remain within the zone of reasonableness, to correspond to certain levels of independence and if so, what those amounts should be.*

No, such refinement is premature. At least for now, incentives for transco formation should kept simple: entities that qualify as a sufficiently independent transco and meet any other applicable procedural and substantive requirements should be eligible for the full incentive, and entities that fail to qualify should get no transco-based incentive. That is, the Commission should not give partial rewards to entities that partially qualify. As the Transco Independence Policy Statement recognizes, independence is a multi-dimensional, multi-factor characteristic. An entity's "level of independence" is not easily graded on a scale more refined than a binary test. Rather than attempt to specify fine gradations of independence, the Commission should focus on carefully applying a good yes-or-no test.

NOPR at P 42: *We also seek comments concerning whether membership in an RTO or ISO should be considered in setting incentive-based ROEs approved by the Commission for a transco.*

TAPS recommends that the questions of incentives for transco formation and incentives for RTO/ISO participation be kept distinct. As discussed above (see Parts II.A., II.D.1, II.D.5, and II.E), TAPS supports the former and opposes the latter.

NOPR at P 42: *We also seek comment on whether the Commission should reconsider how it* *establishes a zone of reasonableness associated with stand-alone transmission companies.*

As discussed in Parts III.A.1 and III.A.3 above, both stand-alone transmission companies and transmission divisions whose owners have chosen to keep them affiliated with generation market participants should have their rate of return, and its "zone of reasonableness," established the same way: by reference to the capital structure and capital costs of transmission-only entities. Thus, the Commission should "reconsider how it establishes a zone of reasonableness" associated with all transmitting utilities, whether they are stand-alone transmission companies or not.

Under longstanding ratemaking principles, rate of return proxies must be limited to companies having financial risks comparable to the regulated enterprise for which the return is being set. *See, e.g., FPC v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (return "should be commensurate with returns on investments in other enterprises having corresponding risks"); *Farmers Union Cent. Exch., Inc. v. FERC,* 734 F.2d 1486, 1522-23, 1530 (D.C. Cir. 1984) (ROE must "take account of the risks associated with the regulated enterprise."). This principle was echoed in 2004 by then-Circuit Judge, now Chief Justice, John Roberts, writing for the D.C. Circuit in *Public Service Commission of Kentucky, et al. v. FERC*, 397 F.3d 1011 (D.C. Cir. 2005) ("*MISO Reversal*"). He pointed out that transmission ratemaking aims to identify "the capital cost of the grid," and that calculating a transmission ROE "would be relatively easy if a utility's interest in its grid — its business as a transmission owner (TO) — were publicly traded." *Id.* at 1006-07.

When the record of that case was compiled — four years ago — there were "'no publicly traded independent pure electric transmission companies,'" leaving a data gap that forced the Commission to "resort to more round-about estimations." *Id.* But such data as become available. Since *MISO*, the Commission also has found that "unregulated business and competitive generation operations" are generally "riskier" than "transmission operations"[128] and that "an independent power producer with no guaranteed customers … faces greater risk than [a transco]."[129] Wall Street agrees. For example, PPL (a major national utility, which is not alone in this regard) has turned its "stable utility transmission and distribution revenues" into senior secured bonds that were "insulat[ed] from higher business risks related to its unregulated generation business" and thereby priced "better … than would otherwise be available," [130] — yet it continues to collect from transmission customers a higher ROE based on the higher risks of the entire vertically integrated and diversified company, which it is free to and does invest in its unregulated transmission business and other non-transmission investments.

Accordingly, the Commission should make clear that in setting transmission rates of return it will now look to transcos' observable sustainable growth rates, dividend yields, and capital structures, and do so for all transmission owners whether or not they have elected to lump their transmission financing together with other financing. Otherwise, transmission customers will pay for the costs of the capital that gets invested in generation and diversified business. Even worse, so long as vertically-integrated transmission owners can include in their transmission rates the high ROEs and thick capital structures that go with non-transmission business, they will be discouraged from undertaking the structural reforms that would result in the funds supplied by transmission customers being put to transmission use.

2. Recovery of accumulated deferred income taxes (ADIT)

NOPR at P 43: *To remove any disincentive, the Commission will continue to consider proposals to include adjustments for ADIT in rates when a transco is purchasing transmission facilities. In*

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[128] *City of Vernon,* Opinion No. 479, 111 F.E.R.C. ¶ 61,092, P 101 (2005).

[129] *Calpine Fox LLC,* 113 F.E.R.C. ¶ 61,047, P 17 (2005).

[130] *See* http://www.thelenreid.com/practice/asset_securitization.htm (last viewed Jan. 10, 2006).

addition, we clarify that a transco that requests an incentive ROE would not be precluded from also requesting the ADIT adjustment.

TAPS generally[131] supports holding utilities that divest transmission assets harmless from the tax effects of selling at regulatory book value, so as to neutralize a disincentive. However, it is important that "removing a disincentive" not turn into an unacknowledged acquisition premium that goes beyond neutralizing a capital gains tax on the difference between the old tax book value and regulatory book value. Where a divestiture effects a write-up of the tax basis to regulatory book value, the purchaser will never pay the taxes that deferred tax balances have been collected to cover, because its tax basis is its acquisition price. The ratepayer-funded balance that will no longer have to be reserved for tax-payment use could be enormous.[132] Accordingly, after the seller is held harmless for its book-based gain-on-sale tax consequences (if any[133]), any remaining tax balance should flow back to ratepayers. Furthermore, where the seller receives as its divestiture price a net premium (after taking account of any associated taxes actually paid out) above its regulatory book value, that premium is, and should be recognized as, a sufficient incentive. Return incentives atop that treatment would be superfluous.

3. Other potential incentives for transcos

NOPR at P 44: *We seek comments on whether there are other potential rate treatments that*

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[131] Divestitures tend to be fact-specific, complex transactions. Each must be individually reviewed to ensure that it works as intended, properly accounts for and bases rates upon the values exchanged, is prudently structured (*e.g.,* in structuring the divestiture as a taxable event, rather than using the ATCLLC structure) and advances the public interest.

[132] *Cf. ITC Holdings Corp.,* 102 F.E.R.C. ¶ 61,182, PP 58-62 (2003) (approving, as a divestiture incentive previously approved for METC, ITC's request to "recover through the Attachment O rate formula an amount equal to the balance of accumulated deferred income tax on International Transmission's books at closing estimated to be $59 million"); *Trans-Elect, Inc.,* 98 F.E.R.C. ¶ 61,368, at 62,590-91 (2002) (approving parallel treatment for METC, at an estimated value of $35 million).

[133] Section 909 of the American Jobs Creation Act of 2004 (Pub. L. No. 108-357, 118 Stat. 1418), amends 26 U.S.C. § 451 to generally provide an eight-year period over which to recognize the capital gain associated with a transmission disposition to a qualifying transco. This new provision will substantially mitigate, and potentially may eliminate, tax consequences of the kind addressed in the ITC and METC decisions.

would provide incentives to form transcos and promote capital investment or reduce disincentives to the divestiture of transmission facilities. Do any of the incentives we are proposing need to be modified or adapted to recognize the inherent regulatory differences between transcos and traditional public utilities?

If, and only if, a transco is open to participation by all financially responsible load-serving entities in its footprint, it would be reasonable to require (as a condition to allowing broad recovery through inclusion in the transmission provider's transmission rate base) that investment in rate base transmission facilities located within that footprint be made through the transco. In effect, that would result in a franchised monopoly in the right to build rate-based transmission facilities, which would reduce the transco's risk and constitute a substantial incentive.

C. ROE Incentive for Joining a Transmission Organization

NOPR at PP 45-46: *FPA Section 219 requires that the Commission issue a rule to provide incentives to transmitting or electric utilities that join a Transmission Organization and to ensure that any recoverable costs associated with joining may be recovered through transmission rates charged by the utility or through the rates charged by the Transmission Organization. ... We will continue to consider requests for ROE-based incentives for utilities that join an RTO, in recognition of the benefits such organizations bring to customers, as outlined in detail in Order No. 2000. ... We will require a public utility to make a request for the incentive by making a filing with the Commission under Section 205 of the FPA. ...*

We also seek comment on whether the Commission should consider incentive-based ROE requests for public utilities that are not in an RTO but that join a Commission-approved regional planning organization.

As the Commission appears to recognize (by specifying Section 205 filings and referencing Order No. 2000, which included an important ratepayer-benefit test), FPA Section 219 stops short of requiring the Commission "to provide incentives to" transmitting utilities and electric utilities that join a Transmission Organization. What it requires is that the Commission issue a rule that "provides <u>for</u>" incentives, "<u>subject to</u> the requirements of sections 205 and 206 … ." Part II.E above recites why ROE adders for RTO participation are not just and reasonable, and inconsistent with the broad coverage of the statute (e.g., by applying only to transmission owners to the exclusion of other electric utilities).[134] As the Commission has recognized,[135] they are also discriminatory, if bundled retail load is excluded from paying them, as would have been the case under the MISO adder that was reversed on appeal.

RTO participation incentives also face a dilemma: payments to those who join existing RTOs would perversely reward their having stayed out of earlier formation efforts, but payments to those who joined earlier would be an unreasonable windfall. Just this week, the Commission found that the "rationale for this incentive is to encourage transmission owners to turn over the operational control of their transmission facilities to a regional transmission organization; therefore, it does not apply to transmission owners who have already done so, as they need no inducement to take such an action. Since Edison turned over its transmission facilities to the ISO almost eight years ago, we deny its request for an incentive adder for joining and remaining a member of the ISO."[136] The way to confer reasonable RTO participation bonuses without windfalls is through the substantial non-ROE benefits that well-structured RTOs can confer on participating utilities. These include (a) the potential benefits that transmission-owning and non-owning RTO members can achieve alike, and (b) satisfaction of important threshold tests for incentives applicable to new investment, without the controversy and side-effects of ROE-based incentives. As an example of the latter, those whose investments are planned through RTOs that administer an inclusive regional planning processes will have cleared an important test for recovering the costs of abandoned plant. *See* Part II.A.5 above.

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[134] The proposed rules limitation to "public utilities" is similarly inconsistent with the statutory directive.

[135] *Midwest ISO, Inc. and Ameren Services, Co.*, 109 F.E.R.C. ¶ 61,167, P 14 (2004).

[136] *S. Cal. Edison Co.,* 114 F.E.R.C. ¶ 61,018 (2006) (footnote omitted). *See also Allegheny Power System Operating Cos.,* 111 F.E.R.C. ¶ 61,308 (2005) (Chairman Kelliher, dissenting) (a PJM participation bonus should have been rejected outright rather than set for hearing, because decisions to join PJM have already been taken, and rewards for past conduct are unreasonable windfalls).

We note that the NOPR does not propose "RTO incentives" for forming entities, like Entergy's "Independent Coordinator of Transmission" ("ICT"), that do not meet the Commission's ISO and RTO requirements independent process. TAPS agrees that such modest changes do not merit monetary incentives. They will not get transmission built.

E. Commission Reporting Requirement

NOPR at P 49: *To provide a basis for determining the effectiveness of the proposed rules and to provide the Commission with an accurate assessment of the state of the industry with respect to transmission investment, proposed Section 35.35 (h) would require that jurisdictional public utilities provide information annually on their current and projected transmission investment activity.*

Pursuant to the general invitation that concludes the NOPR, TAPS suggests that Form X be modestly expanded. By collecting a modest amount of additional information that will be readily available to those filing it, the Form can be made significantly more useful as a tool for monitoring and predicting the rate impacts of new construction, and for evaluating whether existing rates remain just and reasonable. Specifically, columns should be added to the form's "Project Detail" table listing, for each project, (a) actual and projected spending by year; (b) USoA Account(s) and reporting years to which those costs have been or are expected to be booked; (c) voltage; (d) whether the project's costs are being rolled in or directly assigned, and if the latter, to whom; and (e) where a regional planning process or filed rate has provided for geographic allocation to pricing zones other than that of the building utility, an identification (by reference or otherwise) of the applicable allocation.

F. Proposal to Remove 18 CFR 35.34(e) Concerning Innovative Transmission Rate Treatments for RTOs

NOPR at P 52: *In view of Section 219's mandate to provide incentives to the entities identified therein and in order to avoid confusion that could arise from potential conflicts between innovative rate treatments available under Section 35.34(e) and the proposed incentives discussed in this proposed rule, the Commission proposes to remove Section 35.34(e) from the regulations.*

The discussions of specific incentives in Section 35.34(e)(2) should be deleted, along with the never-used Performance-Based Rate provisions of Section 35.34(e)(3) and the moot provisions of Section 35.34(e)(4). However, Section 35.34(e)(1) sets forth requirements for detailed explanations of how utilities' specific incentive proposals will benefit consumers, and their estimated costs. These must not be discarded. They remain important to meeting Section 205-206 statutory requirements that rates be just, reasonable, and non-discriminatory, which are incorporated by reference in Section 219(d) and remain applicable.

G. Other Options

1. Single issue ratemaking

NOPR at P 54 (footnote omitted): *To ensure that the approval process for incentive treatment is as streamlined as possible, thereby ensuring timely infrastructure investments, the Commission is willing to consider incentive filings that propose rates applicable only to the new transmission project. Such an incentive would be applicable to both Transcos and traditional public utilities. … We invite comments on this option.*

The NOPR poses a false dilemma, for which case-by-case litigation has already identified multiple solutions. There is no unavoidable conflict between streamlined application of incentives and the imperative that the total rate package, including incentives, be just and reasonable.

The underlying premise of the "Single Issue Ratemaking" discussion seems to be that requests for approval of incentives will come to the Commission one facility at a time — that utilities with otherwise cost-based rates will seek an incentive-based rate specific to one transmission project. That approach is neither administratively efficient nor well-designed to make incentives effective. To work well, incentives should be known and reliable early in the project planning cycle — long before the as-built cost is known and ready for use as a rate input — and structured as a coherent mechanism with sufficiently broad applicability to affect long-term corporate budgeting and staffing. *See New England Power Pool and ISO New England, Inc.,* 109 F.E.R.C. ¶ 61,252, P 29 (2004) (incentives are most effective if known "when an upgrade is first planned"). Thus, rather than just bringing individual projects to the Commission for a facility-specific incentive, utilities should be required to first file for approval their incentives plan, individually tailored to that utility where appropriate, but generally applicable to that utility's qualifying transmission investments. Subsequent facility-specific filings, to the extent they are even necessary (*i.e,* where the filed rate does not already provide for future recovery of the costs of future facilities, as formula rates do), should then be a straightforward process of applying the previously approved plan.

If incentives are considered through such forward-looking procedures, there will be no need for "single issue" ratemaking. The relationship between the incentive plan and existing rates can be considered once, when the incentive plan is filed. At that point, the Commission readily could, and should, insist on harmonizing the two, so that the costs of facilities of all vintages are recovered exactly once, with no double-dipping.[137]

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[137] *See Allegheny Power Sys. Operating Cos.,* 106 F.E.R.C. ¶ 61,003, P 32 (2004) (initiating sua sponte FPA Section 206 investigation "[i]n order to ensure that each TO does not over-recover its costs when its pre-existing rates for transmission and the rates at issue here for transmission are considered together"), *on reh'g,* 106 F.E.R.C. ¶ 61,016, P 4 & n.11 (2004) (dismissing investigation as premature, but noting that the hearing concerning proposed new-facilities charges would encompass "any changes to the proposed rates necessary to ensure that the two [the new-facilities component and existing transmission rates] are harmonized"); *Allegheny Power Sys. Operating Cos.,* 111 F.E.R.C. ¶ 61,308 (2005) (accepting as adequate harmonization an "Option 2" approach that subtracts new-vintage facility costs from existing rates, over a dissent by Commissioner Kelly that even this approach constituted improper "piecemeal ratemaking").

Ironically, the most direct way to assure such harmonization is set forth in the very case that NOPR P 54 & n.43 cites for the proposition that the longstanding ban on selective adjustments poses a difficult issue. *City of Westerville v. Columbus Southern Power Co.,* 111 F.E.R.C. ¶ 61,307 (2005) involved a fuel clause with a stated "base rate" component, which had been accepted and was no longer subject to refund, but which the filed rate provided for truing up or truing down, formulaically, to reflect actual fuel costs. In a footnote, the Commission happened to recite its longstanding policy against "spot adjustment," as redundant support for its holding that it could not retroactively adjust the base rates. But the more relevant aspect of that case is the Commission's holding that it could freely adjust how the formulaic true-up had been calculated, in order to conform it to the filed rate formula. Transmission owners that want a streamlined mechanism for passing through the costs of new facilities should adopt a formula rate, which will pass the costs of new facilities — and, of equal importance, a synchronized load divisor — through to ratepayers automatically.

The real reason that some transmission owners want single-issue ratemaking has little to do with regulatory streamlining. Rather, because they have stated unit rates set long ago on the basis of long-ago loads, have received a waiver of the Order 888 pricing concept under which a Commission-accepted cost numerator would be collected through a current load-ratio share, and have not been building much transmission even as their facilities depreciated and load growth substantially increased their revenues, they do not want to have to update their loads (rate divisors) when they update their costs (rate numerators). They want to preserve that windfall — keeping the revenues that were supposed to pay for the facilities they have failed to build — even while securing new, incentive-heightened revenues to pay for whatever new facilities they now build.

With still more irony, a second available resolution for that issue will be staring at everyone who follows into the FERC Reports the Commission's citation to *Westerville*. The very next case reprinted in 111 F.E.R.C. is *Allegheny Power System Operating Cos., et al.,* 111 F.E.R.C. ¶ 61,308 (2005). In its protest leading up to that order, the COST group (a broad coalition of PJM-area TAPS members, public power transmission owners, industrial and transmission-dependent customers, and the Delaware Public Service Commission) demonstrated that at least one major PJM transmission owner was recovering twice its annual transmission revenue requirement under its stale unit rates. In the order, the Commission directed that PJM transmission owners could file single-issue rate applications to cover the costs (and incentives, if applicable) associated with new transmission facilities, but that any such cost recovery would have to be credited against existing stated unit rates. That is another practical solution to the "harmonization" issue.

If, notwithstanding these recommendations and alternatives, a utility chooses to defer consideration of its incentive plan and of harmonization issues until it presents a facility-specific incentive filing, the Commission should require the following streamlined, "rough justice" method of making existing and facility-specific rates jibe. Where the inputs to the existing rate are known (*i.e.,* are not hidden by a "black box" settlement), the load divisor and depreciation reserve would be updated, and all other rate components (other than the new facility charge) would remain as they were. Where the existing rate was black-box, a load divisor and depreciation reserve would be imputed for these purposes by assuming that the difference between the filed-for and settled rate represented an adjustment to the rate divisor and that the settled depreciation reserve was as filed. The imputed divisor and depreciation would then be updated as above.[138]

Failing any of the above solutions, the rule should at least provide that utilities which elect to employ single issue, non-harmonized ratemaking return within three years with a full rate case to reset their rates based on current (Period II) costs and loads. Relying on individual customers to undertake the significant effort required to file Section 206 complaints to bring transmission rates into line is often unrealistic, particularly for small systems, and especially given the failure of the Commission to provide for inclusion in Form 1s of the information required to develop a transmission rate.[139] Thus, consistent with Section 219(d), further protections are required to ensure just and reasonable rates.

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[138] This "rough justice" requirement would be a condition only to facility-specific incentive rate applications not provided for under a prior, accepted incentive plan filing, and would apply only pending a further, non-single-issue filing under Section 205 or 206.

[139] *Accounting and Financial Reporting for Public Utilities Including RTOs*, 70 Fed. Reg. 77,625, PP 69-71 (Dec. 30, 2005), 113 F.E.R.C. ¶ 61,276, PP 69-71 (2005) ("Order 668").

2. Acquisition premiums for transco creation

NOPR at P 55 (footnote omitted): *The Commission has historically allowed acquisition adjustments (the premium paid above net book value) in rates only upon a specific showing of ratepayer benefit. However, given the positive contributions of transcos on transmission investment noted above, it may be appropriate to adopt a new policy regarding the recovery in rates of an acquisition premium for purchases of transmission facilities by a transco. We request comments on whether the Commission should make a generic determination that general benefits would accrue to ratepayers as a result of transco formation. We also seek comment on whether any change in the acquisition premium/ratepayer benefits review at the federal level would risk increased resistance to such acquisitions at the state level. And, we seek comment on whether there are other mechanisms that the Commission could institute to provide regulatory certainty of the recovery of the acquisition premium both through retail as well as wholesale rates. Also, we seek comment on what measure the Commission might use in evaluating the appropriateness of such premiums as measured against, for example, the size of the premium, the location of the assets, the level of independence of the transco, and other relevant factors.*

As discussed in Part II.B.2 above (response to NOPR P 43), the Commission's treatment of ADIT/capital gains during transco acquisitions already provides for a substantial acquisition premium, albeit one that is masked and has the benefit of being clearly capped by pre-existing tax-book differences. Such premiums should not be allowed at wholesale unless also collected at retail. However, there is no need for additional certainty that the resulting premium can be collected at retail. *Nantahala*[140] is already the clear law of the land, and it already precludes "trapping" at retail the charges collected by upstream service providers at FERC-regulated rates. By definition, a transco (or its Transmission Organization) will charge FERC-regulated rates to the state-regulated retail service providers who take transmission service over its facilities. Consequently, any acquisition premium that FERC allows and which withstands judicial review will be collectible.

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[140] *See Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 970-72 (1986). *See also Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1372 (D.C. Cir. 2004) (Roberts, then-Circuit Judge) ("If, as the MISO Owners fear, the FERC-approved application of the Cost Adder to bundled and grandfathered loads results in 'trapped' costs, their initial recourse is to their state regulators and contractual partners armed with principles of federal preemption and the Supremacy Clause — not to FERC.").

Beyond the defined (though substantial) premium that was allowed in the METC and ITC cases, no further or more open-ended acquisition premiums should be allowed. If they were, state commissions and other consumer-oriented stakeholds would have a compelling reason to block transmission divestiture. Recall the Missouri PSC decision that Ameren could not even loan its facilities to GridAmerica until it committed to refrain from including an above-cost bonus in state-regulated rates.[141] The state-level regulatory apparatus already has a strong parochial motivation to oppose transco formation: it effects a transfer of applied jurisdiction from state to federal regulators, as the NOPR forthrightly acknowledges, at P 39. This Commission should not pour on that fire the fuel of a well-grounded, consumer-oriented reason to act on that motivation.

H. Other Issues for Comment

1. Performance-based ratemaking

NOPR at P 58: *We seek comment on ways performance-based regulation might apply to for-profit transcos and traditional public utilities, and not-for-profit public utility ISOs and RTOs. In the case of for-profit entities, we seek comment on specific transmission performance metrics and other relevant quality-of-service measures that should be subject to a performance standard.*

TAPS supports PBR in concept, if well-designed and symmetrical — rewarding reductions in the cost of congestion, responsiveness to customer needs, and inclusive planning and LSE investment rights, while holding transmission owners accountable for poor performance. As discussed above, any return incentives should be structured not as one-way incentives, but two-way performance-based, with returns for those utilities who have planned and built a weak transmission system (one which flunks minimum requirements for providing all customers reasonable and reliable access to power markets) set at the lowest reasonable rate.

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[141] *See* Part II.D.1 above.

The attached TAPS White Paper (at 21-22) provides supporting details. TAPS knows of no utility that has actually filed for comprehensive performance-based rates (as distinguished from indiscriminate rewards that do not turn on performance), notwithstanding many years of Commission invitations for such filings. Transmission owner preferences for one-way incentives with no accountability, however, provide no basis to limit incentives in that manner, especially given Section 219(a)'s express inclusion of performance based rates as incentive rates.

2. The role of public power

NOPR at P 63: *Given the importance of public power participation and the requirements of Section 219, we request comments on what actions the Commission should take in this rulemaking to encourage public power participation in new transmission projects.*

It is essential that the rulemaking encourage public power participation in joint transmission systems, jointly-sponsored individual-facility projects, project-based consortia, and transcos. Such inclusiveness is needed not only because Section 219 explicitly aims to promote new investment by all transmitting utilities, but because inclusiveness is essential to forging effective transmission-building institutions. Incumbent transmission owners should not be allowed to set up exclusive clubs that will devolve toward spending their energies conspiring against non-members. All stakeholder segments should be focused on building the 21st Century's grid, together. TAPS therefore supports limited rate of return incentives for structural inclusiveness. *See* Part II.D above.

3. Advanced technology

NOPR at P 65: *We ask for comments on whether, in applications for incentive-based treatment, we should require a technology statement. This technology statement could, for example, describe what advanced transmission technologies were considered and, if those technologies were not employed, why not.*

Although such a statement might have value in some circumstances, TAPS fears that if it is generically required, it could all too easily become a rote procedure. The Commission is historically, and understandably, reluctant to second-guess the technical judgments of utility engineers, who know their own systems better than the Commission can. Unless the Commission is prepared to institute some form of peer review and regularly deny incentives to imprudently mundane transmission investments, the proposed statement would do little other than add an unnecessary burden to incentives applications.

NOPR at P 65: *We also seek comment on any other incentives that the Commission could offer to fulfill the goals of Section 219(b)(3) regarding transmission technologies.*

Under Commission precedent, EPRI dues are excluded from transmission rates on the ground that wholesale-level transmission customers make their own direct contributions to EPRI.[142] That precedent should continue to be followed wherever FERC-regulated transmission rates do not apply to bundled retail customers. However, where all network/native load pays the same transmission rate, the Commission should consider allowing the transmission rate to collect a matching contribution to EPRI, to be dedicated to furthering research on the technologies listed in FPA Section 219(b)(3).

NOPR at P 66: *We seek comment on whether performance-based benchmarks for transmission costs would provide incentives for the deployment of advanced technologies. In this risk-sharing approach, the project sponsor would be allowed to recover costs up to a benchmark level and ratepayers would be protected from costs above the benchmark level. If the new technology is adopted and fails to live up to expectations, how are those costs shared with ratepayers? And, if the new technology is successful, how are the gains shared with ratepayers?*

See our comments in Part III.H.1 above (response to NOPR P 58) on Performance-Based Rates. Allowing full recovery of prudent investment in cancelled or abandoned plant, which TAPS supports as discussed in Part II.C.2.f above, would place on ratepayers the risk that prudently-undertaken technological experiments will not succeed. Also, the Commission should permit broad geographic spreading of the costs associated with technologies that are

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[142] *See, e.g., S.C. Elec. & Gas Corp.,* 63 F.E.R.C. ¶ 61,218 at 62,600 (1993).

experimentally deployed in one pricing zone, but which if successful will provide a beneficial proof of concept for other pricing zones.

CONCLUSION

TAPS urges the Commission to adopt incentives and policies that work together to get needed transmission built at reasonable cost, thus achieving EPAct2005's purposes of reducing customers' delivered costs and meeting the needs of all load serving entities.

Respectfully submitted,

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Attachment 1

Effective Solutions for Getting Needed Transmission Built at Reasonable Cost

TAPS

JUNE 2004

TAPS

TAPS is an informal association of transmission-dependent electric utilities located in 35 states.

TAPS is an effective voice in the fight for open and equal transmission access and for strong protections against the exercise of market power in electric markets.

TAPS supports vigorously competitive wholesale electric markets.

TAPS participates in policy proceedings at the Federal Energy Regulatory Commision, the Department of Energy, the Federal Trade Commission and other federal agencies that deal with electric transmission and market power in the electric utility industry.

TAPS testifies before Congress and educates members of Congress and their staffs on the need for regional open access transmission provisions and market power protections in federal electric restructuring legislation.

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EXECUTIVE SUMMARY

The interstate transmission grid needs billions of dollars of new investment to provide essential reliability and to make competitive electricity markets work. Over the last twenty years, investment in transmission has fallen increasingly behind previous levels. There are a number of reasons for this failure to invest, including regulatory uncertainty, unpopularity of siting, retail rate freezes, cost responsibility disputes, internal competition for capital in vertically integrated utilities and fear of competition. We must reverse this trend and take steps that will get needed new transmission built promptly at reasonable cost. This White Paper proposes a comprehensive set of structural changes and regulatory actions to remedy this critical problem.

One successful structural solution is the "transmission-only" company, open to ownership by all load-serving entities ("LSEs") that depend on the grid. Such a company can grow its business only by investing in transmission and is not burdened by the internal competition for capital that occurs within vertically integrated, investor-owned utilities. Nor is a transmission-only company faced with the disincentive to construct that is present for transmission owners that also own generation. Current examples of transmission-only companies include the American Transmission Company in Wisconsin and the Vermont Electric Power Company.

Another successful structural model is the shared or joint system. By agreement, the transmission facilities of two or more LSEs are combined into a single system. Each participating LSE has the obligation to invest in new transmission facilities on a proportionate basis. Successful examples of this approach are in effect in Georgia, Indiana and the Upper Midwest.

Where open to all LSEs in an area, these models expand sources of capital, reduce regulatory conflict and facilitate siting through joint planning, ownership and operation of the transmission grid.

In addition to working with other policymakers to strongly encourage inclusive stand-alone transmission companies and shared systems, regulators should take a number of other actions that will facilitate needed grid investment, while minimizing the cost to consumers. They should:

(1) provide for current recovery of reasonable pre-certification expenses, and include construction-work-in-progress ("CWIP") in rate base, to reduce risk and improve cash flow, without increasing life-cycle costs to customers;
(2) align transmission costs and revenues through formula rates to eliminate regulatory lag;
(3) set equity returns and require use of capital structures that reflect regulated transmission's low-risk profile;

For generation competition to work for consumers, the grid must be robust, not marginally adequate.

(4) develop new financing strategies to access investors seeking the stable, annuity-like returns that transmission can provide;
(5) require bidding of the capital requirements for new major improvements (debt and equity return, capital structure, depreciation and taxes) where a vertically integrated transmission owner refuses to build without an above-market "incentive" return or rates reflecting accelerated depreciation;
(6) allocate the cost of high voltage, backbone transmission on a regional basis to spread the cost burden and match cost responsibility to the broad regional benefits that will be realized from a robust grid;
(7) require regional, least-cost transmission planning for major additions; and
(8) set performance-based rates that reward reductions in the cost of congestion, responsiveness to customer needs, inclusive planning and LSE investment rights, while holding transmission owners accountable for poor performance.

These targeted solutions are preferable to, and more effective than, the above-market equity returns and accelerated depreciation rate incentives some investor-owned transmission owners are seeking, or relying on "participant funding" to shift the costs of network additions away from transmission owners. These initiatives will not get needed transmission built on a cost-effective basis, and in some cases will mean that needed transmission is not constructed. Return incentives and accelerated depreciation for ratemaking purposes will burden consumers, adding to state resistance to transmission additions, while injuring competitive generation markets and doing little to address the real risks associated with transmission investment. Participant funding, which depends on individual market participants to fund transmission upgrades, is likely to delay needed construction and create new vested interests in maintaining congestion, instead of efficiently expanding the grid to reliably meet the needs of all users and providing the infrastructure required for vigorously competitive generation markets. For generation competition to work for consumers, the grid must be robust, not marginally adequate.

THE PROBLEM

Need for Transmission Investment

Almost everyone agrees that the interstate transmission grid must be expanded to improve reliability and provide the infrastructure needed for competitive wholesale markets. Since 1982, transmission capacity relative to peak transmission use has declined steadily.[1] In the twenty years between 1979 and 1999, transmission investment fell by more than half.[2] According to one widely cited study, simply maintaining transmission adequacy at 2000 levels will require quadrupling currently planned expenditures to $56 billion by 2011.[3] Increasing transmission adequacy to the higher levels that existed prior to 2000 will require even more investment.[4] Investment is needed not only to expand the grid, but for research and development of new technologies, such as superconducting materials, to increase the capacity of existing and future transmission facilities.[5]

The August 2003 Blackout has focused attention on transmission adequacy.[6] At its extreme, the failure to invest in transmission can lead to blackouts. A robust grid provides operators with the ability to keep the lights on in the face of multiple contingencies, including major storms, generator outages and high loads. Redundancy is essential for reliability in a highly integrated network, where problems in one utility's system can spread rapidly to neighboring systems.

In addition to undermining reliability, inadequate transmission creates bottlenecks in the transmission system that have significant economic consequences. These bottlenecks, also known as constraints, foreclose, disrupt and add costs to the delivery of power supply. While transmission congestion is not new, its frequency is. In many areas, congestion is present more than half of the hours in a year.[7] During the summer of 2000, consumers across the country paid at least $1 billion in additional costs due to congestion.[8] In New England, congestion costs range from $125 million to $600 million per year.[9] On one transmission path alone in California, congestion costs amounted to nearly a quarter billion dollars over the 16 months prior to December 2000.[10] Clearly, congestion is costly, threatens reliability and increases risks of price volatility and price spikes.

Competitive generation markets will not work with an inadequate transmission infrastructure. Vibrant markets depend on the ability of many suppliers to reach many buyers. Buyers must have choices for competition to flourish. Where the grid is characterized by congestion, choices narrow rapidly and prices rise. Those suppliers that benefit from congestion have an incentive to maintain it. In many areas, inadequate transmission is clearly forestalling the development of competitive generation markets.

A robust grid also is needed to enable utilities to achieve and maintain fuel diversity. Nearly 94% of new generation

facilities run on natural gas.[11] The economy's vulnerability to rising natural gas prices and concerns about security of supply will increase to unacceptable levels if we rely too heavily on gas-fired plants. Efficient clean-coal plants and renewable resources, such as wind, are viable options, but often must be sited distant from population centers. Excessive transmission congestion costs can put these resources out of reach. A weak infrastructure will force us to put far too many of our eggs in the gas basket.

Today's grid is inadequate to reliably support competitive generation markets for a number of reasons. The grid primarily reflects the planning and investment decisions of vertically integrated utilities that generate electricity and transport it over their own transmission lines to their own retail customers. They planned their systems to support their integrated operations, not to provide a robust infrastructure to support regional markets.

New investments in transmission have not kept pace with need due to a number of factors. They include regulatory uncertainty; unpopularity of siting; state retail rate freezes; concerns about a mismatch between the benefits and cost responsibility;[12] internal competition for capital within vertically integrated utilities that have been more interested in pursuing unregulated businesses; and the need to maximize profits by protecting generation investments that will be exposed to competition by a more robust grid. This last factor creates an inherent conflict of interest when it comes to funding transmission expansion to support competitive markets.[13] As the Federal Energy Regulatory Commission ("FERC") recently observed:[14]

> *Market participants also complain that companies that own both transmission and generation under-invest in transmission because the resulting competitive entry often decreases the value of their generation assets. Much of this problem is directly attributable to the remaining incentives and ability of vertically integrated utilities to exercise transmission market power to protect their own generation market share.*

Finally, the lack of a regional planning process focused on providing the foundation for vibrant regional markets has retarded construction and the development and implementation of new technologies to expand the transfer capability of existing transmission facilities. Due to the dynamic and highly integrated nature of the AC grid, an upgrade in one state may be required to enhance reliability and relieve congestion in an adjacent state. Also, a transmission addition may be required in a state to enable an upgrade undertaken in an adjoining state to function as planned. This can lead to a mismatch between the regional benefits of additions and localized rate recovery for their costs.[15] The grid is regional and should be planned and constructed on a comprehensive basis to meet regional needs on a least-cost basis.

If transmission is not built, consumers will be struck with declining reliability, high congestion costs and uncompetitive markets.

Commonly Proposed Solutions Won't Work

While the reasons why transmission systems have become inadequate are multiple and subject to some debate, it is clear that the status quo is not working. If we are to achieve the goal of a robust infrastructure, significant changes in structure and regulatory policy must be made. Unfortunately, the solutions that have been most commonly proposed to date are very costly and will not work.

1. Return and Accelerated Depreciation Incentives Are Costly and Likely Ineffective

Some investor-owned transmission owners claim that a regulated return sufficient to attract and maintain capital for new transmission investment is not enough to induce needed improvements in the grid. They want incentives, such as elevated returns on equity and accelerated depreciation of new transmission facilities for ratemaking purposes. Such incentives would result in billions of dollars of additional cost for consumers.

Proponents claim that without these incentives essential transmission will not be built.[16] Their claims put consumers in a lose-lose situation. If transmission is not built, consumers will be stuck with declining reliability, high congestion costs and uncompetitive markets. With such incentives, some transmission may be built, but only by burdening consumers with costs above the actual construction and capital cost of the upgrades. Although transmission represents a relatively small percentage of power costs, inflated rates of return and accelerated depreciation will make a significant dent in the expected savings from competitive generation markets. In addition, a vertically integrated transmission owner will be able to use incentive revenues to subsidize its generation sales, giving it an unfair leg up on competitors and making the owner appear to be a more efficient producer than it is. As a result, consumers will wind up paying more for transmission but not realize the full benefits of competitive markets.[17] Further, increasing returns above the actual, reasonable cost of capital violates the regulatory compact for monopoly facilities.[18]

Rate of return and accelerated depreciation incentives are also unlikely to overcome the hurdles to getting transmission built. These incentives fail to target the actual risks involved in adding new transmission, namely, the difficulty of, and delay in, siting and constructing such facilities. They do nothing to address cash flow during construction because they kick in only after a facility is completed. They also fail to address the mismatch between the benefits of regionally significant upgrades and localized cost assignment, or the conflict of interest created by generation ownership.

Participant funding invites a game of chicken where would-be beneficiaries may sit back in the hope that others will step forward to bear the cost of an upgrade.

Finally, in many cases, FERC transmission incentives may be recovered from only the relatively small percentage of transactions that are at wholesale, excluding the great bulk of the transmission usage – the transmission owner's use of the grid to serve its retail customers. This use remains largely under the control of state regulators,[19] who may not look kindly on FERC incentives that increase rates. In deference to state concerns, FERC recently approved a Regional Transmission Organization's ("RTO") service agreement that barred application of rate of return incentives to the transmission owner's bundled retail load.[20] If the FERC incentives apply only to wholesale transactions, they will not yield the revenues claimed to be necessary to prompt transmission investment, much less overcome the potent disincentive to construct that affects some vertically integrated, investor-owned utilities. Instead, the incentives will end up competitively burdening transmission dependent utilities ("TDUs") who will pay for them (assuming discriminatory application of incentive rates passes muster under the Federal Power Act), while doing little to promote needed transmission construction.

2. Participant Funding Will Make Matters Worse, Not Better

Some blame lack of transmission construction on state resistance to raising retail rates to recover the cost of upgrades that benefit a utility's competitors and hail "participant funding" as a means to overcome this concern. As this approach is now implemented,[21] transmission expansion depends on individual market participants agreeing to fund an upgrade. Instead of receiving the assured return obtained by transmission owners, the funding entity would receive rights, in the amount of the incremental transmission capability produced by the upgrade, to uncertain revenue streams associated with future congestion along the grid segments the upgrade decongested. This mechanism is poorly adapted to a dynamic AC grid, where benefits and beneficiaries of an upgrade are many, difficult to assign, change over time and can be enjoyed by "free riders" (i.e., entities other than the funding entity). Participant funding invites a game of chicken where would-be beneficiaries may sit back in the hope that others will step forward to bear the cost of an upgrade. Meanwhile, transmission construction and the associated benefits to consumers are delayed. It should come as no surprise that some of the strongest proponents of this approach are likely to benefit significantly by forestalling new generation construction and keeping independent generators out of the market. The result also may be to undermine regional markets by trapping low-cost generation.

At a time when getting transmission built promptly is imperative, it is unwise to rely on this untested mechanism. Recent developments raise questions whether this model is feasible even for new merchant DC transmission lines, where benefits and beneficiaries can readily be identified and do not change over time, and access can be controlled. Of the few DC projects, including merchant lines, that have been proposed, some have had difficulty attracting investors using a participant funding approach.[22]

Finally, participant funding's justification of upgrades based on private benefits to specified market participants, rather than public benefits typically required to be demonstrated to achieve state approval, will make the difficult state transmission siting process even harder.

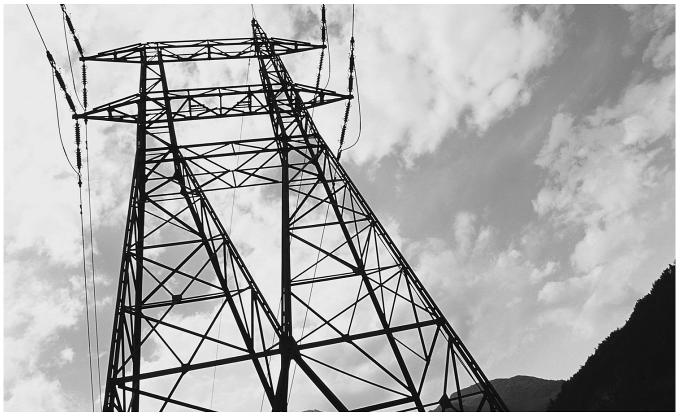
Structural Solutions

1. Inclusive Stand-Alone Transmission Companies

Stand-alone, transmission-only companies that provide the opportunity for passive TDU investment offer a strategy that will get needed transmission built promptly. Their sole focus should be the ownership, operation, construction and maintenance of a robust transmission system. Corporate separation and a restriction on participation in generation markets will free transmission from the internal competition for capital that exists within a vertically integrated or holding company structure and eliminate the disincentive to build transmission that affects generation owners.

Transmission-only companies should be very attractive to investors seeking stable, low-risk returns. Network service or access charges ensure a very stable and safe stream of revenues to pay dividends and internally fund a portion of new construction, in addition to supporting the favorable bond ratings needed to attract low-cost capital. For these reasons, investment interest in the few stand-alone transmission companies that exist today has been strong.[23]

Municipal and cooperative utility participation in transmission-only companies will enhance the companies' viability and attractiveness. These utilities serve over 25% of the retail customers in the U.S.[24] and, as discussed



ATC demonstrates that stable, regulated revenue streams give the financial community the assurances it needs to provide capital for expansion without use of high-cost incentives.

below, generally have stronger credit ratings than investor-owned utilities. Participation by these entities will significantly broaden the base of support for new transmission. Such participation also will enlarge sources of investment capital and expand the facilities that can be transferred to the stand-alone company, creating a better coordinated, regionally operated grid without the gaps that will exist if municipal and cooperative utilities are excluded.

American Transmission Company, LLC ("ATC") shows how this model can work. Pursuant to Wisconsin law,[25] ATC was formed by several formerly vertically integrated utilities with operations in Wisconsin, Michigan and Illinois, and a Wisconsin municipal joint action agency. Four of its founding members, We Energies, Madison Gas & Electric Co., Wisconsin Public Service Corp. and Wisconsin Power & Light Co., divested their transmission assets to ATC. In exchange for their facilities, these members received 50% of their transmission investment back in cash on a tax-free basis and ownership interests in ATC representing the remainder of their contributions.[26] The fifth founding member, Wisconsin Public Power Inc., had no transmission assets and so contributed cash in exchange for its ownership interests. Since its founding, ATC's membership has grown to 28 members, including 21 municipal and cooperative utilities. While they have different ownership interests, each of the founding members has only one director on ATC's board, with an equal vote. The founding members' voice is balanced by four independent directors and an independent CEO. To ensure non-discriminatory operations, the company has turned over operation of its transmission facilities to the Midwest Independent Transmission System Operator ("MISO").

ATC demonstrates that stable, regulated revenue streams give the financial community the assurances it needs to provide capital for expansion without use of high-cost incentives. In April 2001, barely three months after its start-up, ATC successfully sold $300 million of bonds in a private placement. The bonds were rated "A-" by S&P, "A1" by Moody's and "A" by Fitch. ATC's current credit ratings have risen to A1/A.[27] These high ratings were not the product of an incentive rate of return or accelerated depreciation. Rather, the ratings are attributable to the stable revenues generated from ATC's sale of transmission services. Addressing "Key Credit Considerations" in its March 2001 report on ATC, then a brand new company, Fitch deemed highly significant that more than 95% of ATC's revenue requirements is guaranteed recovery from transmission customers serving loads on the ATC system.[28] Fitch specifically cited as a key positive credit consideration the company's structure that permits investor-owned, cooperative and municipal utilities to participate, which encourages cooperation and support among stakeholders, including state regulators.[29]

ATC has succeeded in greatly accelerating transmission construction.[30] During the four-year period 2001-2004, the formerly vertically integrated members of ATC intended to spend $246 million on transmission construction. ATC's initial budget for the same period more than doubled that amount to $646 million. ATC's most recent ten-year budget (2003-2012) includes up to $2.8 billion of new transmission investment.[31] In the next five years, municipal and cooperative utilities are likely to contribute up to an additional $60 million to fund ATC's transmission expansion plan, more than tripling their initial investment. ATC attributes its success to its concentrated focus as a single-purpose transmission company committed to meeting the transmission needs of all its customers, as required by its authorizing statute.

Vermont Electric Power Company ("VELCO") offers an earlier example of an inclusive, transmission-only company's successfully constructing, owning, maintaining and operating transmission facilities. VELCO was created in the 1950s by Vermont's investor-owed utilities. Initially excluded, municipal and cooperative utilities won the right to participate in VELCO in the 1970s through conditions placed on nuclear plant licenses to address situations "inconsistent with the antitrust laws."[32] Today, municipal and cooperative participation is an integral part of VELCO's mechanism for financing transmission investment.

Vermont's investor-owned, municipal and cooperative utilities own VELCO through equity contributions based upon each participant's share of the total customer load connected to the system ("load ratio share"). The resources available to municipal and cooperative utilities to finance their equity contributions help VELCO raise capital. VELCO places debt and calls for additional equity from the owners when financing transmission expansion, such as its ongoing $250 million effort. Recently, VELCO changed the debt-equity ratio for such financings from 90/10 to 75/25, making the equity participation of municipal and cooperative utilities more significant and demonstrating that safe transmission investments can be leveraged to reduce total capital costs.

VELCO plans for and serves the transmission needs of Vermont's electric utilities. VELCO also makes its transmission facilities available for service under the New England regional tariff. Development of the regional transmission grid is advanced through facilities constructed as part of VELCO's state-wide network, as well as through VELCO's participation in the New England regional planning process.

Another example of an inclusive, stand-alone transmission company is TRANSLink. Like ATC and VELCO, TRANSLink was structured to accommodate municipal and cooperative contributions of facilities and investment, as well as investor-owned participation. The intent of the

In addition to lessening disputes, the joint system model creates a community of interest that facilitates construction of a least-cost system, rather than one reflecting the competitive interest of a single dominant owner.

TRANSLink proposal was to form a transmission-only company to operate the existing facilities of its participants and to plan, finance and own needed new facilities. Although TRANSLink's development is now on hold because of "continued regulatory and market uncertainty,"[33] the model was approved by FERC and enjoyed broad support.[34] Its participants would have come from Colorado, Illinois, Iowa, Kansas, Michigan, Minnesota, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wisconsin. FERC's Chairman called TRANSLink's apparent failure "horrible" and expressed hope that TRANSLink can be salvaged and expanded.[35]

2. Shared System Model

A structural alternative to the stand-alone model that provides many of the same benefits is the shared or joint system. Under this model, the transmission facilities of two or more utilities in an area are planned and operated jointly, as a single system, pursuant to a long-term agreement. Ownership in the joint system generally is in proportion to each participant's load ratio share of the customer load connected to the system. In exchange for its investment, each owner has undivided use rights over all the facilities comprising the joint system, generally with no additional charges.

A common feature of these arrangements is joint planning. Responsibility for funding transmission expansion is generally based upon each participant's load ratio share, and need not be tied to additions contiguous with the participant's system. Joint planning provides the opportunity to optimize the size and placement, and accelerate the timing, of additions to meet the needs of all load serving entities, so that all load is efficiently and reliably served, conflicts are minimized and support for siting of new transmission facilities is broadened. In addition to lessening disputes, the joint system model creates a community of interest that facilitates construction of a least-cost system, rather than one reflecting the competitive interest of a single dominant owner.

Shared system arrangements have a long history of success in Georgia, Indiana, Minnesota, North and South Dakota, and elsewhere. The Appendix to this White Paper describes specific examples of TDU investment in joint transmission systems.

The success of inclusive, stand-alone transmission companies and shared systems is not surprising. These models align the interests of area LSEs, broaden the planning process and provide new sources of capital. TDU investors have strong incentives to keep costs down, because the capital costs of grid expansion directly impact the delivered price of power to customers, the principal economic driver for municipal and cooperative systems.

Policymakers should look with suspicion at requests for incentives by those who deny TDUs the opportunity to invest in the grid on comparable terms, and should support the efforts of TDUs ready, willing and able to share responsibility for our nation's grid.

Their strong credit ratings enable them to access needed capital.[36] Grid investment also provides TDUs with a long-term, steady revenue stream that hedges against rising power supply costs, in the same manner as vertically integrated, investor-owned utilities enjoy.

Engaging all LSEs in the planning process and the resulting investment not only ensures that the grid meets the needs of all consumers, but also broadens support in the often contentious siting process. These models reduce the regulatory conflicts inherent in a system where transmission "haves" control access to and planning of facilities needed by transmission "have-nots" and impose transmission charges that can be used to confer a competitive advantage in their competition with the "have-nots."[37] Further, dispersing control among multiple participants in a shared system provides a potent counterweight to a dominant owner's disincentive to construct transmission that may reduce the value of its generation. In short, by minimizing conflicts and opening up the planning and expansion process, the inclusive stand-alone and shared system models bring a broader perspective to meeting the transmission needs of the participants and the region.

Although many TDUs have long sought to invest in the transmission grid, they have been turned down by investor-owned utilities.[38] Ironically, some investor-owned utilities have demanded rate incentives to build at the same time they have refused to permit investment by TDUs.

Policymakers should look with suspicion at requests for incentives by those who deny TDUs the opportunity to invest in the grid on comparable terms, and should support the efforts of TDUs ready, willing and able to share responsibility for our nation's grid.

Regulatory Solutions

1. Ratemaking Devices to Reduce Transmission Investment Risk and Attract Capital at Reasonable Cost

The risks of adding transmission primarily involve the difficulty of, and delay in, siting and constructing the facilities. To site transmission, utilities often must incur significant pre-certification expenses that are at risk if a permit to build facilities is not granted. They also must commit substantial amounts of capital to transmission construction with recovery of such dollars delayed until facilities are put in service. Incentive rates of return and accelerated depreciation for ratemaking purposes do not address these risks.

In contrast, each of the six ratemaking strategies discussed below is designed to address the real risks and deterrents associated with transmission investment. Not only should such measures attract transmission investors by making such investment safer, but they also should reduce the cost of capital for transmission and result in

more equitable assignment of upgrade costs. Because they minimize transmission costs borne by consumers rather than increasing them, these strategies are more likely to be adopted in a coordinated manner by both state and federal regulators, and to reduce state resistance to transmission additions. In short, instead of allowing above-market equity returns and accelerated depreciation incentives, regulators should adopt the policies discussed below, which have a real chance to get needed transmission constructed at reasonable cost.

(a) Allow current recovery of pre-certification expenses. In many jurisdictions, costs incurred for new transmission lines before receipt of siting and other regulatory approvals may not be expensed as incurred. Instead, these costs are held to be capitalized as part of the project if it goes forward. If the project is not completed, recovery is at risk. This treatment (i) creates investor uncertainty because of the controversy that inevitably occurs in siting major transmission projects; and (ii) adds to construction cash flow problems because the transmission owner spends money on what can be a lengthy, contentious certification process without current recovery. A win-win solution is to permit current recovery in rates of reasonable and prudent pre-certification expenses for major new transmission projects, an approach that FERC has approved for ATC.[39] This treatment shields investors from risks associated with required pre-certification activities without increasing the life-cycle cost of the transmission facility to consumers.

(b) Allow construction-work-in-progress (CWIP) in rate base. Currently, most regulatory bodies do not allow utility rates to include a return on (or to treat as an expense) construction funds invested in projects until the project goes into operation. Instead, these costs are carried by the utility and added, along with the carrying costs incurred during construction, to its rate base when the project is put in service, increasing the amounts on which the utility may earn a return and recover depreciation over the life of the facility. The alternative would be to allow a current return in rates on transmission construction funds. For investors, including CWIP in rate base will increase the certainty of recovery and provide significant cash flow to support construction of needed transmission facilities with less reliance on external sources of capital.

In a recent application, ATC said that its proposed CWIP treatment, which FERC accepted,[40] would allow it to maintain its financial ratios and ratings during its aggressive construction program and complete the program more quickly, while requiring $107.2 million less debt and $118 million less equity compared to traditional CWIP treatment.[41] Over a twenty-year period, ATC calculates that this mechanism will save its customers almost half a billion dollars compared to elevated rate of return incentives.[42]

Strategies that demonstrate a commitment to minimizing the costs to consumers of construction should diminish opposition to needed grid investments.

Inclusion of CWIP in rate base increases rates to consumers somewhat in early years, while decreasing rates in later years. Recovery of CWIP raises significant issues of inter-generational equity in connection with generation investments. However, those issues are minimized in the transmission context, where on-system customers have no choice but to use the grid. By spreading the costs over the construction period and the life of the facility, the effect on rates is minimized. In contrast, accelerated depreciation amplifies inter-generational issues and the cost burden on consumers by significantly increasing rates for a period of time far shorter than the life of the facility.

(c) Allow "formula" transmission rates. Transmission costs are primarily fixed and represent a small portion of a utility's total costs. Because rate cases are costly and time consuming, transmission rates may not keep pace with new investment. A solution is to allow "formula" rates, subject to audit by FERC and customers, so that transmission rates accurately track current costs — when they increase or decrease. FERC has approved formula rates for transmission owners participating in MISO and, recognizing that they provide "timely recovery of the cost of transmission expansion," has recently suggested them to PJM transmission owners.[43] The FERC-approved, customer-supported formula transmission rate for ATC was one of the key credit considerations underpinning ATC's high credit rating.[44] A high credit rating improves access to capital and reduces the cost of both debt and equity.

(d) Conform equity cost and capital structure to transmission's risk profile. The regulatory measures discussed above are designed to reduce risk and therefore encourage transmission investment. Regulators should ensure that consumers realize the associated capital cost benefits that result from these measures and that equity returns reflect the low-risk profile of transmission. Strategies that demonstrate a commitment to minimizing the costs to consumers of construction should diminish opposition to needed grid investments.

For example, S&P's 2003 Corporate Ratings Criteria find transmission/distribution systems less risky and generators more risky, requiring very different capital structures and coverage ratios to achieve the same rating:[45]

> *[U]tilities scoring is from 1 to 10—with 1 representing the best. Companies with a strong business profile—typically, transmission/distribution utilities—are scored 1 through 4; those facing greater competitive threats—such as power generators—would wind up with an overall business profile score of 7 to 10.*

S&P combines its business profile evaluations and financial profile (quantitative) evaluations to determine a company's rating. A utility with a strong business profile rating (like the transmission and/or distribution ("T&D") companies) can have less financial protection (i.e., more

Regulators and transmission owners should develop strategies to access capital from the large pool of investors that is looking for very stable, close to fixed-rate returns and is not willing to take the risks entailed in ventures that offer the potential to earn higher returns.

leverage) than one with a weaker business profile (vertically integrated or generation company) and still achieve the same rating. For these reasons, S&P's financial ratio guidelines for investment grade ratings show lower debt ratios and higher coverage ratios as targets for utilities with generation than for T&D companies.[46]

State and federal regulators should insist that the rates to consumers reflect an equity return and a capital structure that comport with the lower risk profile of transmission investment. Texas regulators have already done so. In establishing the capital structure to be used by transmission and distribution utilities in unbundled cost of service cases, the Texas Public Utility Commission established a 60/40 debt/equity capital structure, rather than the 50% equity capital structure more typical of vertically integrated utilities. The Texas Commission found this structure will allow transmission/distribution companies "to attract sufficient capital at reasonable rates, while minimizing costs to the ratepayers" and that "any increase in the financial risk due to the higher debt leverage is offset by the lower business risk" faced by these utilities.[47] Because the cost of debt is considerably lower than the cost of equity, the difference between a 50/50 and 60/40 debt/equity structure will produce significant savings for consumers, especially when combined with a return on equity that also reflects the lower risk posed by transmission investment.

In addition to accurately reflecting equity costs in rates and using more leveraged capital structures, regulators and transmission owners should examine the use of preferred stock as another means of reducing the overall cost of capital for transmission.

(e) Develop strategies to access investors seeking solid, low-risk monopoly infrastructure investments.
In addition to the foregoing traditional regulatory approaches to keeping rates reasonable, regulators and transmission owners should develop strategies to access capital from the large pool of investors that is looking for very stable, close to fixed-rate returns and is not willing to take the risks entailed in ventures that offer the potential to earn higher returns. Such investors would include pension funds and IRA and 401(k) investors.

These strategies may come in several forms. They would include the promotion of inclusive, transmission-only companies discussed above, and development of new investment vehicles that would allow Wall Street to market transmission securities designed for such investors, either through investment trusts or securitization-like bonds. Representatives of the investment community recently told FERC that they are looking for precisely these kinds of low-risk opportunities in the electricity industry.[48] While legislation would help provide regulatory certainty (as it has in states with laws regarding the securitization of stranded costs in the transition to retail competition),[49] even without legislation the near-assured stream of revenues associated with transmission should support transmission investment trusts, revenue bonds and similar instruments designed to achieve a lower overall cost of capital than traditional utility financing.

For example, "income trusts" have been used in Canada to finance infrastructure projects and other ventures with very stable revenues. Investors in these trusts seek the solid, relatively certain returns that can be achieved by a pledge of revenues to the trust. Securitization bonds work in a similar fashion. Generally, a state law allows a non-bypassable charge on a utility bill for stranded costs or environmental improvements, along with a pledge of the revenues from the charge to secure bonds used to fund the costs. Almost no equity is required, producing a capital cost much lower than traditional utility financing.

To facilitate such innovative devices for major transmission projects, regulators could grant a life of facility return and designate an associated capital structure. Such treatment would not break new ground. Several states have moved in this direction in connection with generation investment.

For example, a 2001 Iowa law permits utilities to request state regulators to set "advance ratemaking principles" for items such as the definition of rate base and the return on common equity for the life of proposed generation. This law provides regulatory certainty not previously available to Iowa utilities, which (like those in many jurisdictions) had to wait until new facilities were in service before learning how regulators would treat their investment initially, with such treatment remaining subject to change by future regulators.[50] The law has already helped support development of a large new coal plant.[51]

Recent Wisconsin legislation permits energy utilities to issue "environmental trust bonds" to fund environmental control activities (e.g., adding pollution control equipment or retiring polluting plants). Non-bypassable charges create a steady revenue stream dedicated to servicing the bonds. The issuing utility can use the revenues for no other purpose. Among the criteria applied by the state regulator when considering a request for bond approval is whether this financing vehicle will reduce overall costs to customers.[52] The trust vehicle also can improve a utility's overall balance sheet, and thereby lower financing costs for other capital requirements. One utility has projected that this mechanism will yield savings of $500 million over ten years for environmental enhancements costing $1 billion.[53]

In contrast, participant-funded investment is high risk—supported by an uncertain long-term stream of congestion revenues in the area where congestion is relieved, at least

to some degree, by the upgrade. High-risk investments have high capital costs.[54] Infrastructure investments in a monopoly service context should be funded largely by low-cost debt and equity, not through experimental mechanisms that create unnecessary risk.

(f) Require competitive bidding of capital requirements, where utilities demand return and depreciation incentives. Another alternative to the "no transmission without incentives" demands of some investor-owned utilities is the capital market. Where an owner insists on return and accelerated depreciation incentives as an inducement, regulators should require that entity to bid out the capital component of major projects. A competitive solicitation will allow the market to determine the cost of capital required to fund transmission additions. The investment would be passive; control of the construction and operation of the project would remain with the transmission owner or RTO. Through this mechanism, low-risk, long-term transmission infrastructure investments may be matched with investors seeking the kind of stable, annuity-type investment returns that have successfully sustained the electricity industry for years.

The bidding requirement should not apply to stand-alone transmission companies because it would undermine their business model, which already includes a potent incentive to invest in new transmission. However, transmission companies should be required to demonstrate that their construction and ownership costs are just and reasonable, and neither return incentives nor accelerated depreciation should be permitted.

The requirement for a competitive solicitation would be triggered at the time a major transmission upgrade or expansion is identified for which the owner asks for an incentive return or accelerated depreciation. For example, where an RTO's planning process identifies a needed project, the RTO could issue a request for proposals to fund the capital requirements if the owner is reluctant to make the investment. Interested investors, or pools of investors organized by investment firms, would submit bids that fix the overall return cost, capital structure, taxes and depreciation for the project. These pools could be structured with debt and/or equity options for different investors. The RTO would select the bid or bids that will fund the project at the lowest overall cost. Where a vertically integrated utility, rather than an RTO, is responsible for the transmission planning and expansion process, the utility should be required to contract with an independent third party to conduct the competitive solicitation.

There should be no shortage of interested bidders. A significant segment of investors, such as pension funds, need choices that provide stability and security, as opposed to high potential returns with significant risk. The opportu-

Broadly spreading "highway" transmission costs not only will match cost imposition to those who benefit, including remote beneficiaries of a grid upgrade, but also will reduce consumer burden and therefore resistance to construction.

nity for a year-in, year-out safe, regulated return should look very good to many people with 401(k) accounts compared to recent experience. TDUs also may take advantage of this opportunity to invest in transmission.

To work well, this bidding solution will require regulatory policies or legislation that provide certainty on rates of return, capital structure and depreciation, along the lines discussed in the previous section.

2. Spread the Cost of High Voltage, Backbone Lines Across Broad Regions

Due to the dynamic and highly integrated nature of the AC grid, high voltage, backbone transmission lines provide benefits beyond the immediate geographic area where they are constructed. In recognition of this fact and to respond to one of the major criticisms of "license plate" pricing (where a subset of customers benefited by such lines must bear the entirety of their costs), FERC should assign the costs of major backbone facilities across all regional load. Broadly spreading "highway" transmission costs not only will match cost imposition to those who benefit, including remote beneficiaries of a grid upgrade, but also will reduce consumer burden and therefore resistance to construction.

One approach would be adoption of pricing similar to that advocated by TRANSLink.[55] The TRANSLink proposal addresses both the need to spread the costs of regionally significant upgrades and the problem of unfairly burdening an area with transmission costs for generation built to serve load in other areas. The proposal better aligns transmission pricing for both existing and new facilities to cost causation. Under the TRANSLink rate design, the costs of regional highway facilities would be spread to everyone in the region and the costs for the local area grid would be paid by both the load and the generation in the local area. Similarly, in New England, FERC has approved recovering the costs of "Pool Transmission Facilities" (or "PTF") on a region-wide basis because of their "diffuse network benefits," while the costs of "non-PTF" facilities are recovered on a local system basis.[56] Such approaches are most easily adopted in the RTO context, but the absence of an RTO should not bar their use in regions without an RTO, given the highly integrated nature of the regional grid.[57]

Failure to spread the costs of regionally significant facilities is likely to cause needed transmission not to be built because of objections from those who would be unfairly assessed its costs, or cause facilities to be built at less-than-optimal size in order to make them affordable. Regional highway pricing is far better than participant funding, which further localizes upgrade costs on individual market participants. Unlike participant funding, broadly spreading the cost of regionally significant facilities recognizes that transmission upgrades almost always

Effective regional transmission planning is an essential component of the solution to grid inadequacy, as recognized by both federal and state officials.

have multiple and changing beneficiaries.[58] It also avoids the difficult and unrealistic task of trying to differentiate between reliability and economic additions, and then seeking funds from entities willing to speculate on potential congestion revenues.

Adoption of a regional highway approach to funding transmission would also reduce uncertainty over what the rules of the transmission game will be. For example, under the planning and expansion process recently approved for PJM, each economic upgrade (identified as one not immediately required for reliability) needed to reduce "unhedgeable congestion" (constraints causing congestion hedgeable at some cost, no matter how high, would not be covered by this process) would be subject to specific cost allocation, determined after conducting a cost-benefit analysis showing the upgrade to be beneficial. The upgrade must then be shelved for a year, to give the market a chance to respond with alternative proposals.[59] During the years taken up by this potentially contentious allocation process and then the siting and construction process, consumers subject to the unhedgeable congestion would continue to be burdened. Participant funding holds even greater prospects for delay, while market participants wait for others to step up to fund upgrades from which they too will benefit.

3. Regional Planning to Achieve Cost-Effective and Efficient Solutions

Effective regional transmission planning is an essential component of the solution to grid inadequacy, as recognized by both federal and state officials. The Department of Energy has called for "open regional planning processes that consider a wide range of alternatives, accelerating the siting and permitting of needed facilities, taking full advantage of advanced transmission technologies, and incorporating appropriate safeguards to ensure the physical and cyber security of the system."[60] The National Governors Association supports the use of regional, interstate mechanisms for transmission planning, consistent with regional electricity markets.[61] Several western governors have cited regional planning as critical to a large grid where expansions in one area, such as the Rocky Mountains, will yield benefits to consumers throughout the West, including fuel diversity.[62]

State and federal regulators should require that major grid additions be planned on a regional basis to meet the needs of all LSEs on a least-cost, integrated system basis. Regional planning will result in a lower cost, more efficient system than the balkanized planning of many individual owners focused only on their own needs and influenced by conflicting competitive objectives. The regional planning process should consider all viable alternatives, including

Performance-based rates designed to spur efficient grid investment and operation by transmission owners and to make RTOs accountable to customers and regulators should be adopted.

new technologies to increase the transfer capability of existing facilities and distributed generation. Regional, inclusive planning of major additions should reduce siting controversy, facilitate state needs assessments and eventually lead to regional siting mechanisms.

RTOs, inclusive stand-alone transmission companies and shared systems all facilitate regional planning. Where these structures do not exist, regulators should exercise their conditioning authority, and employ both the carrot and the stick, to achieve a strong regional planning process.

4. Performance-Based Rates to Hold Transmission Owners Accountable

Performance-based rates designed to spur efficient grid investment and operation by transmission owners and to make RTOs accountable to customers and regulators should be adopted. Such rates should be designed to reward desired outcomes. Transmission owners that exceed specific performance goals should be rewarded. Conversely, transmission owners that perform poorly should be penalized. Reasonable performance measures include (i) promptly eliminating or minimizing congestion costs (in light of existing and planned uses, and load growth); (ii) planning and building transmission through an open and inclusive regional process for the benefit of all users; (iii) providing opportunities for TDU investment in transmission; (iv) significantly shortening interconnection and transmission request queues; (v) adopting innovative approaches to attract low-cost capital for transmission additions; (vi) rendering excellent customer service; and (vii) maintaining exemplary reliability. Within a non-profit ISO/RTO structure, management compensation should be tied to performance, including customer satisfaction and cost controls, to achieve accountability.

Experience in telecommunications suggests that performance-based rates "can deliver (1) lower prices, (2) increased network modernization, and (3) higher earnings, with (4) no pronounced reduction in overall service quality."[63] Performance-based rates are finding increasing acceptance in the electric utility industry, specifically in the area of transmission services.[64]

FERC has long embraced the concept of performance-based rates. Specifically, FERC Order 2000 invited performance-based rates that met the regulatory standards of its 1992 incentive rate policy.[65] Order 2000 also required that PBR proposals be prospective; encompass both rewards and penalties; provide quantifiable benefits to consumers; not be applied piecemeal; create incentives for efficient operating and investment decisions; maintain quality of service; and not compromise reliability. FERC specified that benefits of PBR should be shared with customers. Rewards and penalties should be prescribed in advance based on

It is essential that regulators and other policy makers focus their attention on effective strategies to dramatically improve our nation's electric transmission infrastructure.

known and measurable benchmarks.[66] However, care must be taken not to adopt PBR mechanisms such as rate freezes that may impair the ability to finance transmission expansions and create disincentives to construct.

It is not surprising that investor-owned transmission owners generally prefer rate-of-return and accelerated depreciation incentives that entail no potential for downside adjustments if the incented benefits do not materialize. As far as TAPS is aware, FERC has received no true PBR proposals for transmission, but many requests for incentives.[67] Well-crafted, performance-based rates, as used by a number of state commissions,[68] are a far better approach than one-way incentives that raise costs to consumers without accountability.

CONCLUSION

It is essential that regulators and other policymakers focus their attention on effective strategies to dramatically improve our nation's electric transmission infrastructure. Health and safety, as well as a strong economy, depend upon promptly reversing the downward trend of investment in this crucial area. This must be done in ways that will be effective and at the same time minimize the cost to consumers. This White Paper proposes a number of specific steps that can and should be taken to achieve this important goal.

APPENDIX

Examples of Shared System Model

Georgia: In Georgia during the 1970s, the Municipal Electric Authority of Georgia ("MEAG"), the City of Dalton and Oglethorpe Power Company, a cooperative, joined with Georgia Power Company (part of the Southern Company) to create the Georgia Integrated Transmission System ("ITS"). Participants' investment responsibility is based upon their load ratio shares. At the ITS's inception, MEAG, for example, made an initial investment of some $85 million in Georgia Power's transmission facilities to satisfy its load ratio investment obligation. Since then, MEAG has invested more than $200 million in the ITS. Through a joint planning process, participants are also assigned responsibility for new facilities in order to maintain a load ratio sharing of total ITS investment. Each ITS participant is responsible for the costs, including maintenance costs, of its own facilities. The ITS facilities themselves are operated by Southern Company, which offers service on the combined ITS facilities under its open access transmission tariff.

Indiana: In Indiana beginning in the late 1970s and continuing into the mid-1980s, municipal utility Indiana Municipal Power Agency ("IMPA"), cooperative utility Wabash Valley Power Association ("WVPA") and investor-owned utility PSI Energy (now part of Cinergy) agreed to a series of joint transmission and power coordination agreements which formed the Joint Transmission System ("JTS"). IMPA purchased transmission facilities from PSI in order to provide IMPA with JTS ownership reflecting its load ratio share of total JTS investment. (WVPA already owned transmission facilities that it dedicated to the JTS.) Since formation of the JTS, IMPA has invested approximately $65 million in the grid. IMPA's investment is currently slightly higher than the load ratio share corresponding to its 570 MW load in the Cinergy area. In exchange for their investments, the JTS participants receive interests as "tenants in common" to use the JTS. Annually, the participants compare actual use to their investment. If a party's use is more than its investment, it makes a deficiency payment to the surplus party or parties. The joint planning process carried out under the parties' agreements can result in the assignment of responsibility for construction of new facilities in order to maintain investment proportional to participants' load ratio shares. PSI Energy operates and maintains the JTS, and it offers transmission service on the combined JTS facilities under the Cinergy, now MISO, open access transmission tariff.

Minnesota, North Dakota and South Dakota: In the mid-1980s, Missouri Basin Municipal Power Agency, which is today known as Missouri River Energy Services ("MRES") (acting as agent for Western Minnesota Municipal Power Agency), and Cooperative Power Association, which is today known as Great River Energy ("GRE"), each entered into arrangements with Otter Tail

Power Company that created partially overlapping MRES-Otter Tail and GRE-Otter Tail integrated transmission systems ("ITS"). Under the ITS agreements, each utility is responsible for owning and financing its load ratio share of the transmission facilities. At the outset of the MRES/Otter Tail ITS, MRES purchased facilities from Otter Tail to bring its actual investment in line with its load ratio share investment obligation. Over the years, MRES has increased its transmission investments, which today exceed $25 million. Like other joint arrangements, there is an equalization mechanism that provides opportunities and, in some cases, obligations to purchase transmission assets from the other party to maintain load ratio share investment responsibility. In the MRES/Otter Tail area, MRES is responsible for approximately 30% of the transmission facilities; in the GRE/Otter Tail area, GRE is responsible for approximately 50% of the transmission. While there is no three-way agreement, the net effect of these two arrangements is to share the transmission responsibility among Otter Tail, MRES and GRE in the overlap area on a proportional basis. In exchange for their investments, the ITS participants have use rights across the shared system without the necessity of paying an additional rate. The system is jointly planned. Presently, Otter Tail operates and maintains the combined ITS facilities and offers transmission service on them under the Otter Tail, now MISO, open access transmission tariff.

Minnesota: During the early 1980s in Minnesota, municipal, cooperative and investor-owned utilities entered into a series of "Shared Transmission System" or "STS" agreements. Like the joint arrangements discussed above, the STS agreements in Minnesota were based on the principle that participants would invest in, construct and own transmission in amounts reflecting their share of the loads connected to the STS. In exchange for the investments, participants would receive rights to use of the STS, which would be operated on a joint basis. Municipal utility Southern Minnesota Municipal Power Agency ("SMMPA") entered into STS agreements with cooperative utilities Dairyland Power Cooperative and United Power Association (the latter now part of Great River Energy) and with investor-owned utilities Interstate Power (now part of Alliant) and Northern States Power (now part of Xcel Energy). SMMPA contributed already-constructed transmission, purchased facilities and constructed new ones to reach its load ratio share level of ownership under the agreements with each of these companies. SMMPA's transmission, which today has a book value of more than $100 million, is operated by SMMPA's STS counterparts who offer transmission service on the combined facilities under open access transmission tariffs.[69]

NOTES

[1] Eric Hirst & Brendan Kirby, Transmission Planning for a Restructuring U.S. Electricity Industry, at 5 (June 2001), available at http://www.eei.org/industry_issues/energy_infrastructure/transmission/transmission_hirst.pdf (last visited May 13, 2004).

[2] Id.

[3] Id. at 8-10.

[4] Id. at 8.

[5] National Energy Policy Development Group, National Energy Policy (May 2001) at Chapter 7, page 6, available at http://www.energy.gov/engine/doe/files/dynamic/1952003121758_national_energy_policy.pdf (last visited May 13, 2004).

[6] The U.S. – Canada Power System Outage Task Force's Final Report on the August 14, 2003 Blackout recommends the commissioning of an "independent study of the relationships among industry, restructuring, competition, and reliability" including taking account of factors such as "[l]ack of new transmission investment and its causes; [r]egional comparisons of impact of wholesale electric competition on reliability performance and on investments in reliability and transmission; [and] [t]he financial community's preference and their effects on capital investment patterns." U.S. – Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," at 148 (April 2004), available at https://reports.energy.gov/BlackoutFinal-Web.pdf (last visited May 13, 2004).

[7] Department of Energy, National Transmission Grid Study, at 13 (May 2002), available at http://www.ntgs.doe.gov/ (last visited May 13, 2004) (hereafter "NTGS").

[8] Federal Energy Regulatory Commission, Electric Transmission Constraint Study, Presentation at 9 (Dec. 19, 2001), available at http://www.ferc.gov/cust-protect/moi/constraintstudy.pdf (last visited May 13, 2004).

[9] NTGS, supra n.7, at 17.

[10] Id. In its order on the Path 15 transmission project, FERC noted that the upgrade's cost was $306 million, compared to congestion cost of $222 million during 16 months of relatively normal operations. Western Area Power Admin., 100 F.E.R.C. ¶ 61,306, reh'g denied, 100 F.E.R.C. ¶ 61,331 (2002), aff'd Pub. Util. Comm'n of Calif. v. FERC, 2004 U.S. App. LEXIS 9423,____ F.3d ____ (D.C. Cir. May 14, 2004).

[11] Energy Information Administration, Annual Energy Outlook 2004 with Projections to 2025, at 81 (Jan. 2004), available at http://www.eia.doe.gov/oiaf/aeo/download.html (last visited May 19, 2004).

[12] An upgrade on one system may relieve a regionally significant constraint, but the cost is typically imposed on ratepayers of the system making the upgrade, deterring needed construction.

[13] Regional Transmission Organizations, Order No. 2000, [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,089, at 31,004 (1999), order on reh'g, Order No. 2000-A, [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,092 (2000), affirmed, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (2001); 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, [1991-1996 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,036, at 31,682 (1996), clarified, 76 F.E.R.C. ¶ 61,009 (1996), modified, Order No. 888-A, [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 F.E.R.C. ¶ 61,248 (1997), aff'd in part and remanded in part sub nom. TAPS v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd on issues reviewed sub nom. New York v. FERC, 535 U.S. 1 (2002) (No. 00-568), order on reh'g, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998).

[14] Proposed Pricing Policy for Efficient Operation and Expansion of the Transmission Grid, Notice of Proposed Policy Statement, Docket No. PL03-1-000, 102 F.E.R.C. ¶ 61,032, P 15 (2003).

[15] After reviewing the decline in transmission investment over the last 15 years and noting that transmission represents a small portion of the vertically integrated utility's assets, FERC's Chairman, in Congressional testimony following last year's Blackout, pointed to a reluctance of vertically integrated utilities with regard to transmission "expansions that may benefit another utility's customers." Testimony of Pat Wood, III, Chairman, Federal Energy Regulatory Commission, Before the Subcommittee on Oversight of Government Management, the Federal Workforce, and the District of Columbia, Committee on Governmental Affairs, United States Senate, at 4 (Sept. 10, 2003), http://www.ferc.gov/pressroom/ct-archives/2003/09-10-03-wood.pdf (last visited May 13, 2004).

[16] See, e.g., Thomas R. Kuhn, President, Edison Electric Institute, "Encouraging Capital Formation in Key Sectors of the Economy," Testimony Before the Commission on Financial Services, Subcommittee on Domestic Monetary Policy, Technology, and Economic Growth, U.S. House of Representatives, at 9 (April 18, 2002), available at http://www.eei.org/about_EEI/advocacy_activities/Congress/020418_Kuhn.pdf (last visited May 13, 2004); Stanford L. Levin, Electricity Competition and the Need for Expanded Transmission Facilities to Benefit Consumers, Prepared for Edison Electric Institute, at 15 (Sept. 2001), available at http://www.eei.org/industry_issues/energy_infrastructure/transmission/Transmission_Electricity.pdf (last visited May 13, 2004).

[17] While FERC Regional Transmission Organization (RTO) regulations authorize independent RTOs to propose "innovative rate treatments" including adjustments to rates of return and traditional depreciation schedules, such proposals are subject to cost-benefit analyses, including rate impacts. Regional Transmission Organizations, 18 C.F.R. § 35.34(e) (2004).

[18] FPC v. Hope Natural Gas Co., 320 U.S. 591, 605 (1944).

[19] While FERC may in the future assert jurisdiction over the transmission component of bundled retail rates to remedy undue discrimination (New York v. FERC, 535 U.S. 1 (2002)), in areas without RTOs or retail competition, transmission is now included in state-regulated bundled retail rates. Even in areas with RTOs, FERC rate incentives may not apply to the transmission owner's retail customers because of deference to a transmission owner's state-set retail rates. While FERC requires transmission owners in an RTO to take service for bundled retail customers under the same terms and conditions as other transmission customers, FERC has said that it would apply a state-regulated rate to such service to the extent consistent with the Federal Power Act. See White Paper on the Wholesale Market Platform, Docket No. RM01-12-000, at 4-5, Appendix A at 4-5 (April 28, 2003); Southwest Power Pool, Inc., 106 F.E.R.C. ¶ 61,110, P 109 n.136 (2004).

[20] Midwest Indep. Transmission Sys. Operator, Inc., 106 F.E.R.C. ¶ 61,293 (2004).

[21] See, e.g., Notice of Proposed Rulemaking, Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, RM01-12-000, 67 Fed. Reg. 55,452 (Aug. 29, 2002) ("SMD NOPR"), PP 191-202.

[22] Recently, Conjunction LLC, a merchant transmission developer of the Empire Connection project proposed to bring 2,000 MW of much needed electricity to New York City via a DC line, canceled a planned auction of capacity on the line due to lack of interest attributed to the inability of utilities, electric merchants and potential investors to obtain the credit approvals necessary to make an upfront commitment. The auction was supposed to have produced contracts for use of the line that would provide revenue guarantees to secure roughly $500 million in construction loans. See www.pulp.tc/html/investors_cancel_auction_of_li.html (last visited May 13, 2004).

[23] Kohlberg Kravis Roberts & Co. and Trimaran Capital Partners, LLC cited these factors in deciding to acquire International Transmission Company from DTE Energy. See http://www.dteenergy.com/pressRoom/pressReleases/iTcSale4.html (last visited May 19, 2004).

[24] http://www.appanet.org/about/statistics/stats/Numelecproviderscust2002.pdf. (last visited May 19, 2004).

[25] The Wisconsin legislation that enabled the formation of ATC provides that the company will have "as its sole purpose the planning, construction, operating, maintaining and expanding of transmission facilities that it owns to provide for an adequate and reliable transmission system that meets the needs of all users that are dependent on the transmission system and that supports effective competition in energy markets without favoring any market participant." Transmission System Requirements, Wis. Stat. 196.485(1)(ge) (2003).

[26] To protect consumers, the facilities transferred were valued at net book cost, and deferred taxes reserves and investment tax credits were transferred to ATC.

[27] Application of American Transmission Company, LLC to Revise Rate Formula, Docket No. ER04-108-000, Exh. ATC-11 at 4 (Oct. 30, 2003), available at http://ferris.ferc.gov/idmws/common/OpenNat.asp?fileID=9939011 (last visited May 13, 2004).

[28] Fitch Report, Attachment 2 to the March 12, 2002 Comments of Wisconsin Public Power Inc., submitted in Docket No. RM01-12-000, Electricity Market Design and Structure, available at http://ferris.ferc.gov/idmws/File_list.asp?document_id=2253392 (last visited May 13, 2004).

[29] Id.

[30] The facts here are drawn from "Comments of American Transmission Company LLC," submitted to the Federal Energy Regulatory Commission in Docket No. PL03-1-000, Proposed Pricing Policy for Efficient Operation and Expansion of the Transmission Grid (March 13, 2003), available at http://ferris.ferc.gov/idmws/common/OpenNat.asp?fileID=9657129 (last visited May 13, 2004).

[31] American Transmission Company, 10-Year Transmission System Assessment, at 9 (Sept. 2003), available at http://www.atcllc.com/documents/2003tya/Executive%20Summary.pdf (last visited May 13, 2004).

[32] Atomic Energy Act of 1954, 42 U.S.C. § 2135(c).

[33] Press Release, TRANSLink Utilities Suspend Development Activities (November 21, 2003), available at http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_5929_8634-7116-0_0_0-0,00.html (last visited May 13, 2004).

[34] TRANSLink Development Corp., Certificate of Uncontested Offer of Settlement, 103 F.E.R.C. ¶ 63,031 (2003) and Letter Order Accepting Settlement, 104 F.E.R.C. ¶ 61,001 (July 1, 2003).

[35] FERC's Wood Hopes for TRANSLink Regeneration, Energy Info Source (January 28, 2004) available at http://www.energyinfosource.com/aoi/news-details.cfm?id=21030&FLink (last visited May 13, 2004).

[36] Standard & Poor's analyst Peter Murphy recently observed that: "Public power utilities nationwide continue to adapt both operationally and financially to new challenges, which bodes well for credit quality." "Stability Expected in the U.S. Public Power Sector Despite Increasing Risk & Market Volatility" (Jan. 16, 2003), available at http://www2.standardandpoors.com (subscription required). Similarly, all of the generation and transmission cooperatives recently rated by Standard & Poor's have investment-grade ratings reflecting "operational and financial profiles and business strategies that have largely insulated these utilities from some of the extreme volatility that has plagued many energy companies in recent years." Standard & Poor's, Update on U.S. Electric Cooperative Sector Ratings (February 19, 2004), available at http://www.seminole-electric.com/sections/news_financials/ratings_reports/Ratingsreport-2004-02.pdf) (last visited May 13, 2004).

[37] Fitch cited the joint participation of investor-owned, cooperative and municipal utilities in ATC as a positive credit consideration. See Fitch Report, supra n.28. In Vermont, the addition of municipal and cooperative ownership in VELCO has similarly increased cooperation and decreased conflicts among the state's load serving entities with respect to transmission issues.

[38] TDU efforts to invest and refusals to allow them to participate continue today. In California, municipal utilities offered to participate in transmission investments to fix the notorious Path-15 constraint, a source of some the country's worst congestion (see n. 10 supra), but were rebuffed. Ultimately, the Secretary of Energy, acting on his own authority, directed the Western Area Power Administration to construct the line, which it did with the assistance of private capital.

In New England, municipal systems have sought to participate in reliability and economic grid investments, including as part of proposals for RTO-NE. There, too, TDU dollars have been turned down. See, e.g., Filing Parties' "Answer to Motions to Intervene, Protests, Answers, and Comments," FERC Docket No. RT04-2-000, et al., at 114-16 (December 23, 2003), available at http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10024056 (last visited May 18, 2004).

[39] American Transmission Co., LLC, et al., 107 F.E.R.C. ¶ 61,117 (2004).

[40] Id.

[41] Application of American Transmission Co., LLC, supra n.27, at 16.

[42] Id. at 14.

[43] See Midwest Indep. Transmission Sys. Operator, Inc., 84 F.E.R.C. ¶ 61,231, order on reconsideration, 85 F.E.R.C. ¶ 61,250, order on compliance, 87 F.E.R.C. ¶ 61,085 (1998); PJM Interconnection, LLC, 104 F.E.R.C. ¶ 61,124 at n.31 (2003).

[44] See Fitch Report, n.28, supra.

[45] Solomon B. Samson, S&P 2003 Corporate Ratings Criteria (2003), at 17, updated version available at http://www2.standardandpoors.com/spf/pdf/fixedincome/CorpCrit2003r-jun.pdf (last visited May 13, 2004).

[46] Id. at 54. S&P affirmed its conclusions about the lower risk of T&D companies in its March 11, 2004 Report: Keys to Success for U.S. Electricity Transmission and Distribution Companies, available at http://www2.standardandpoors.com (subscription required).

[47] Interim Order Establishing Return on Equity and Capital Structure, Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURPA Section 39.201 and Public Utility Commission Subst. R. 25.344, Docket No. 22344, Order No. 42, (Tex. PUC., Dec. 22, 2000).

[48] See Testimony of John Anderson on behalf of John Hancock Financial Services, February 4, 2004 Conference on Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets, Docket No. PL04-2-000, Transcript at 149, 207-209, available at http://ferris.ferc.gov/idmws/common/OpenNat.asp?fileID=10071892 (last visited May 13, 2004).

[49] See, e.g., 2000 MICH. PUB. ACTS 142.

[50] Iowa Utilities Board Press Release, IUB Approves Ratemaking Principles for Proposed Electric Generating Plant (May 29, 2003), available at http://www.state.ia.us/government/com/util/docs/NewsReleases/2003/0529_Plant.pdf (last visited May 13, 2004).

[51] Id.

[52] Office of Wisconsin Governor Jim Doyle Press Release, Governor Doyle Signs Worker's Comp Bill (March 15, 2004), available at http://www.wisgov.state.wi.us/pressreleases_detail.asp?prid=434 (last visited May 13, 2004).

[53] Testimony of Allen Leverett, Chief Financial Office of Wisconsin Energy Corp. before

the Wisconsin State Assembly Committee on Energy and Utilities (January 28, 2004).

[54] Testimony of John Anderson, supra n.48, Transcript at 149, 207-209.

[55] The approach is described in the Commission's April 25, 2002 Order in TRANSLink Transmission Co., L.L.C., 99 F.E.R.C. ¶ 61,106, at 61,465-68 (2002), and its December 19, 2002 Order in TRANSLink Transmission Co., L.L.C., 101 F.E.R.C. ¶ 61,316, at PP 15-24 (2002). See also TRANSLink's November 15, 2002 SMD Initial Comments at 30-31 & n.47.

[56] New England Power Pool, 105 F.E.R.C. ¶ 61,300 (2003).

[57] Depending upon the degree of grid integration, FERC might assign the costs of major backbone facilities across all regional loads even outside the RTO context. See Ft. Pierce Utils. Auth. v. FERC, 730 F.2d 778, 783-85 (D.C. Cir. 1984).

[58] See Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003-A, 106 F.E.R.C. ¶ 61,220, P 585 (2004) (citing Pub. Serv. Co. of Colo., 59 F.E.R.C. ¶ 61,311 (1992), reh'g denied 62, F.E.R.C. ¶ 61,013 (1993)).

[59] See PJM Interconnection, LLC, 105 F.E.R.C. ¶ 61,123, PP 20-24 (Oct. 24, 2003), Order on Rehearing and Compliance Filing Regarding Transmission Expansion Projects Needed to Promote Competition, Docket No. RT01-2-009.

[60] NTGS, supra n.7, at 8.

[61] National Governors Association, Policy Position NR-18, "Comprehensive National Energy and Electricity Policy" (2003-2005), available at http://www.nga.org/nga/legislativeUpdate/policyPositionDetailPrint/1,1390,2445,00.html (last visited May 18, 2004). See also National Commission on Energy Policy, Reviving the Electricity Sector (August 2003) at 8, available at http://www.energycommission.org/news (last visited May 18, 2004).

[62] Governor Michael O. Leavitt (UT), Governor Dave Freudenthal (WY), "Sub-Regional Transmission Planning for the Rocky Mountain States" (September 12, 2003), available at http://psc.state.wy.us/htdocs/subregional/plan2.pdf (last visited May 18, 2004).

[63] David Sappington, Johannes Pfeifenberger, Philip Hanser & Gregory Basheda, The State of Performance-Based Regulation in the U.S. Electric Utility Industry, THE ELECTRICITY JOURNAL, Oct. 2001, at 73.

[64] Id. at 71-72, 79.

[65] See October 1992 Policy Statement on Incentive Regulation, 61 F.E.R.C. ¶ 61,168 (1992), described in Regional Transmission Organizations, Order No. 2000, [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,089, at 31,182 n.637 (1999), order on reh'g, Order No. 2000-A, [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,092 (2000), appeal dismissed, Pub. Util. Dist. 1 v. FERC, No. 00-1174 (D.C. Cir. 2001).

[66] See Order No. 2000 at 31,183-85.

[67] See, e.g., New England Power Pool, 97 F.E.R.C. ¶ 61,093 (2001) (rejecting incentive proposal because, among other reasons, it had no downside for transmission owners if promised benefits did not materialize), order on reh'g, 98 F.E.R.C. ¶ 61,249 (2002).

[68] David Sappington, et al., supra n.63, at 75.

[69] The STS agreements with Interstate Power and Northern States Power were later terminated as part of those companies' separate merger proceedings during the late 1990s. SMMPA became a customer under the utilities' open access transmission tariffs, under which it receives revenues recognizing its investments.

TAPS MEMBERSHIP

ALABAMA
Alabama Municipal Electric Authority

ARIZONA
Navajo Tribal Utility Authority

CALIFORNIA
Northern California Power Agency

COLORADO
Municipal Energy Agency of Nebraska

CONNECTICUT
Connecticut Municipal Electric Energy Cooperative
Northeast Public Power Association

FLORIDA
Florida Municipal Power Agency

ILLINOIS
City of Geneva Electric Department
City of St. Charles
Illinois Municipal Electric Agency

INDIANA
Indiana Municipal Power Agency

IOWA
Iowa Association of Municipal Utilities
Missouri River Energy Services

KANSAS
Kansas Municipal Utilities
Municipal Energy Agency of Nebraska

KENTUCKY
Municipal Electric Power Association of Kentucky

LOUISIANA
Lafayette Utilities System

MAINE
Kennebunk Light & Power District
Northeast Public Power Association

MASSACHUSETTS
Braintree Electric Light Department
Concord Municipal Light Plant
Georgetown Municipal Light Department
Holden Municipal Light Department
North Attleborough Electric
Northeast Public Power Association
Shrewsbury Electric Light Plant
Taunton Municipal Lighting Plant
Templeton Municipal Light Plant
Town of Ipswich
Vermont Public Power Supply Authority
West Boylston Municipal Lighting Plant

MICHIGAN
American Municipal Power-Ohio

MINNESOTA
Minnesota Municipal Utilities Association
Missouri River Energy Services
Rochester Public Utilities
Southern Minnesota Municipal Power Agency

MISSISSIPPI
Clarksdale Public Utilities
Mississippi Delta Energy Agency
Municipal Energy Agency of Mississippi
Public Service Commission of Yazoo City

MISSOURI
City Utilities of Springfield
Missouri Joint Municipal Electric Utility Commission

NEBRASKA
Lincoln Electric System
Municipal Energy Agency of Nebraska

NEW HAMPSHIRE
New Hampshire Electric Cooperative Inc.
Northeast Public Power Association
Vermont Public Power Supply Authority

NEW MEXICO
Navajo Tribal Utility Authority

NORTH CAROLINA
ElectriCities of North Carolina

NORTH DAKOTA
Missouri River Energy Services

OHIO
American Municipal Power-Ohio
Ohio Municipal Electric Association

OKLAHOMA
Oklahoma Municipal Power Authority

PENNYSLVANIA
American Municipal Power-Ohio

RHODE ISLAND
Northeast Public Power Association

SOUTH CAROLINA
City of Newberry
Piedmont Municipal Power Agency

SOUTH DAKOTA
Missouri River Energy Services

UTAH
Navajo Tribal Utility Authority

VERMONT
Burlington Electric Department
Northeast Public Power Association
Vermont Public Power Supply Authority

VIRGINIA
Blue Ridge Power Agency
Virginia Municipal Electric Association No. 1

WEST VIRGINIA
American Municipal Power-Ohio

WISCONSIN
Madison Gas and Electric Company
Manitowoc Public Utilities
Marshfield Electric & Water Department
Municipal Electric Utilities of Wisconsin
Wisconsin Public Power Inc.

WYOMING
Municipal Energy Agency of Nebraska

TAPS www.tapsgroup.org

Attachment 2

LAFAYETTE CONSOLIDATED GOVERNMENT

LAFAYETTE UTILITIES SYSTEM

LUS

TERRY J. HUVAL, P.E.
DIRECTOR

1314 WALKER ROAD
P.O. BOX 4017-C
LAFAYETTE, LOUISIANA 70502
TEL: (337) 291-5804
FAX: (337) 291-8318

October 6, 2005

ADVANCED E-MAIL

Mr. J. Wayne Leonard
Chief Executive Officer
Entergy Corporation
500 Clinton Center Drive
Clinton, MS 39056-5630

Dear Mr. Leonard:

The recent devastation wrought by hurricanes Katrina and Rita throughout much of Louisiana, Mississippi and Texas has destroyed much of the electric system owned by investor owned utilities, municipal systems and electric cooperatives. The costs to repair these systems, while still largely undetermined, may well be in the billions of dollars.

It has occurred to us that this may also be a time of unique opportunity for the power consumers of this region. The Entergy transmission grid is a vital component of not only Entergy's system but of ours as well. We are therefore vitally interested in seeing a transmission system rebuilt that will better serve all electric consumers, stronger and more reliable than before. And we think this is a time when a new approach could redistribute costs in a way that could reduce the need to seek support from the nation's taxpayers to share in the cost of reconstruction.

The changes in our industry have led to much debate concerning the rights of transmission dependent utilities such as ours. We agree that those who expect some certainty from the transmission system should be willing to invest in that system, although we do not think that the so-called participant funding approach will work. As we work to restore the grid we have the opportunity to resolve a number of divisive issues and share the burden of improving the transmission system together.

We write on behalf of a number of transmission dependent utilities who would be willing to invest our own funds to help rebuild Entergy's transmission system to the point where it is capable of serving all consumers better, including investment in needed facilities not necessarily affected by the storms in order to free up Entergy's capital for restoration. We believe such an investment would ease Entergy's search for funds to repair its system and result in an improved system overall.

We would be interested in seeking solutions that would allow our organizations to build and own segments of the grid that would improve the system and cost share with Entergy where it makes sense. We would be willing to contract with Entergy to manage and maintain these segments, or participate in an RTO if Entergy should choose to join one. We think that Section 30.9 of your transmission OATT, or in some cases, a like provision in an existing grandfathered contract, offers a good way for our costs to be recovered, and it appears that this method of ownership and operation would be cheaper for all of your transmission customers than if Entergy were to be forced to own and finance all of the facilities that are required. We understand that when you were at Cinergy, you had a Joint Transmission System arrangement with IMPA and Wabash Valley, which we understand worked well, and which might serve as at least a partial model.

If you are at all interested in this approach, please let us know. We recognize that time is of the essence in getting the system rebuilt, but we see this as a unique opportunity to build a stronger and less expensive system that better serves all electric customers in the region. Together we can turn this disaster into a positive for all concerned.

Sincerely,

Terry Huval

Terry Huval, Director
Lafayette Utilities System
1314 Walker Road
Lafayette, LA 70506
thuval@lus.org
(337) 291-5804

Robert D. Priest/agc

Robert D. Priest, General Manager
Clarksdale Public Utilities
P.O. Box 70
Clarksdale, MS 38614
priest@cableone.net
(662) 627-8402

Missouri Public Utility Alliance
Missouri Association of Municipal Utilities
Municipal Gas Commission of Missouri
Missouri Joint Municipal Electric Utility Commission

2407 W. Ash
Columbia, MO 65203-0045

Mr. J. Wayne Leonard
Chief Executive Officer
Entergy Corporation
500 Clinton Center Drive
Clinton, MS 39056-5630

October 24, 2005

Dear Mr. Leonard:

Please consider this letter an expression of strong interest by the Missouri Joint Municipal Electric Utility Commission (MJMEUC) in any opportunity to invest in the Entergy transmission system along the lines recently proposed by Lafayette Utilities System and the Arkansas Electric Cooperative Corporation.

MJMEUC currently uses point-to-point service on the Entergy system in connection with its power supply contract for Entergy service to MJMEUC's Missouri Public Energy Pool #1, which serves twenty-six municipal utilities. Additionally, we are planning a significant investment and ownership interest in the Plum Point Energy Station project being developed in the Osceola, Arkansas vicinity with direct interconnection to the Entergy transmission system. MJMEUC's interest in the plant would serve several Arkansas and Missouri municipal utilities directly connected to Entergy or to the Southwestern Power Administration grids. We are exploring with those cities the potential development of two new full requirements power pools, one serving the participating municipalities within each transmission system.

An opportunity to invest and obtain an interest in the Entergy transmission system that serves these municipal utilities, on a load ratio basis, could serve the long term interests of all system users and end-use customers, while relieving Entergy's investment burden during this stressful period of hurricane recovery. I hope that you will include MJMEUC in discussions of this concept and permit us to participate in a promising solution to the challenge of ongoing investment in a more robust transmission system as well as immediate disaster recovery.

Thank you for your consideration, and we look forward to further discussions.

Sincerely,

Duncan Kincheloe

Duncan Kincheloe
General Manager & CEO

Commissioners and Mike Proctor, Missouri Public Service Commission
MJMEUC Executive Committee
Robert McDiarmid, Spiegel & McDiarmid

Entergy

RECEIVED

OCT 31 2005

DIRECTOR OF UTILITIES
LAFAYETTE CONSOLIDATED GOVERNMENT

Entergy Services, Inc.
P. O. Box 31986
Clinton, MS 39286

Tel - (601) 339-2876
Fax - (601) 339-2388
Email – wleonar@entergy.com

J. Wayne Leonard
Chief Executive Officer

October 25, 2005

Mr. Terry Huval
Director
Lafayette Utilities System
P.O. Box 4017-C
Lafayette, Louisiana 70502

Dear Mr. Huval:

I would first like to express my sincere gratitude to you for all of the assistance that your crews provided to Entergy in the aftermath of Hurricane Katrina. Please extend my thanks and appreciation to every lineperson that assisted in the restoration efforts as well as those that stayed behind so that others could be deployed. As you know, hurricanes Katrina and Rita caused unparalleled damage to the energy infrastructure in Texas, Louisiana, Mississippi, and Alabama, but because of the unified and unprecedented response from you and other utilities across the country, we have been able to restore service to the vast majority of our customers with remarkable speed.

To this point our entire focus has been on restoring service to our customers in a safe and reliable way as quickly as reasonably possible. While we cannot divert attention from these efforts, I did want to respond to your letter to me. I appreciate the thoughtfulness of the letter and share your goal of ensuring the continued reliability of the transmission grid. We, too, are interested in evaluating ways to improve the transmission grid on terms that provide an appropriate sharing of the cost of such improvements. However, I do not agree that the restoration effort presented a reasonable opportunity to construct a different transmission system. I believe that the inevitable delays and reliability issues associated with trying to design a "stronger and less expensive" transmission system in real-time would have served only to delay and further complicate the restoration efforts.

Nonetheless, once the restoration efforts and associated administrative tasks are completed and service is restored to our customers, there will be opportunities to evaluate incremental improvements to the transmission system and to explore ways in which you and other transmission dependent utilities may assist in the funding of those upgrades, including through the potential ownership of those facilities. While I do not want to rule it out prematurely, I am not convinced at this point that the crediting provision of the Open Access Transmission Tariff that you reference in your letter will have the effect of reducing the burden on Entergy's customers of the cost of restoration; instead, it may merely result in a change in the ownership of the facilities. I continue to believe that the best opportunity for mitigating the rate impacts on our customers (including wholesale customers such as Lafayette and Clarksdale) of restoration costs and of the loss of a significant portion of the customer base in New Orleans and the surrounding areas is through the on-going efforts of elected officials, other utilities, and Entergy to obtain Federal financial assistance similar to that assistance provided to municipal and cooperative systems. Given the effect that these storms have had, and potentially could have, on the entire Gulf Coast region, I would hope that you and the other transmission dependent utilities would join in support of this effort.

With that said, though, I am interested in working with you to further evaluate solutions that could improve the transmission system and ensure an appropriate allocation of cost responsibility for the grid, including the possibility of joint ownership arrangements. I have discussed your letter with Renae Conley as she will be the individual leading this effort from Entergy's standpoint. I am sure that Renae will be contacting you in the near future to initiate these discussions.

Sincerely,

Wayne

J. Wayne Leonard

cc: Renae Conley