Attachment 1

Transmission Reservation Detail 76138671 REFUSED

Create New TSR | Back

Seller	Source Sink	POR POD	Service	Request Type	Start (CS)	Stop (CS)	MW Req	MW Grant	Bid Price	Offer Price	Ceiling Price	Price Unit
MISO	AMRN MOWR	AMRN MPS	MONTHLY FIRM POINT_TO_POINT FULL_PERIOD FIXED	ORIGINAL	2005-01-31 23:00	2005-02-28 23:00	5				9999.0000	$/MW-Month

Path:	OASIS Account:	Preconfirmed: Yes	Competing: No	Negotiated: No	Nerc Priority: 7	Affiliate: No
_/MISO/AMRN-MPS//	WRGS	☑	☐	☐	☑	☐

Comments		Times (CS)		References
Status:	[illegible]	Queued:	[illegible]	Deal
Seller:	[illegible]	Updated:	[illegible]	Sale
Provider:		Response:		Posting
Customer:		Re-Start:		Request
Impacted:		Re-Stop:		Reassigned
				Seller
				Related

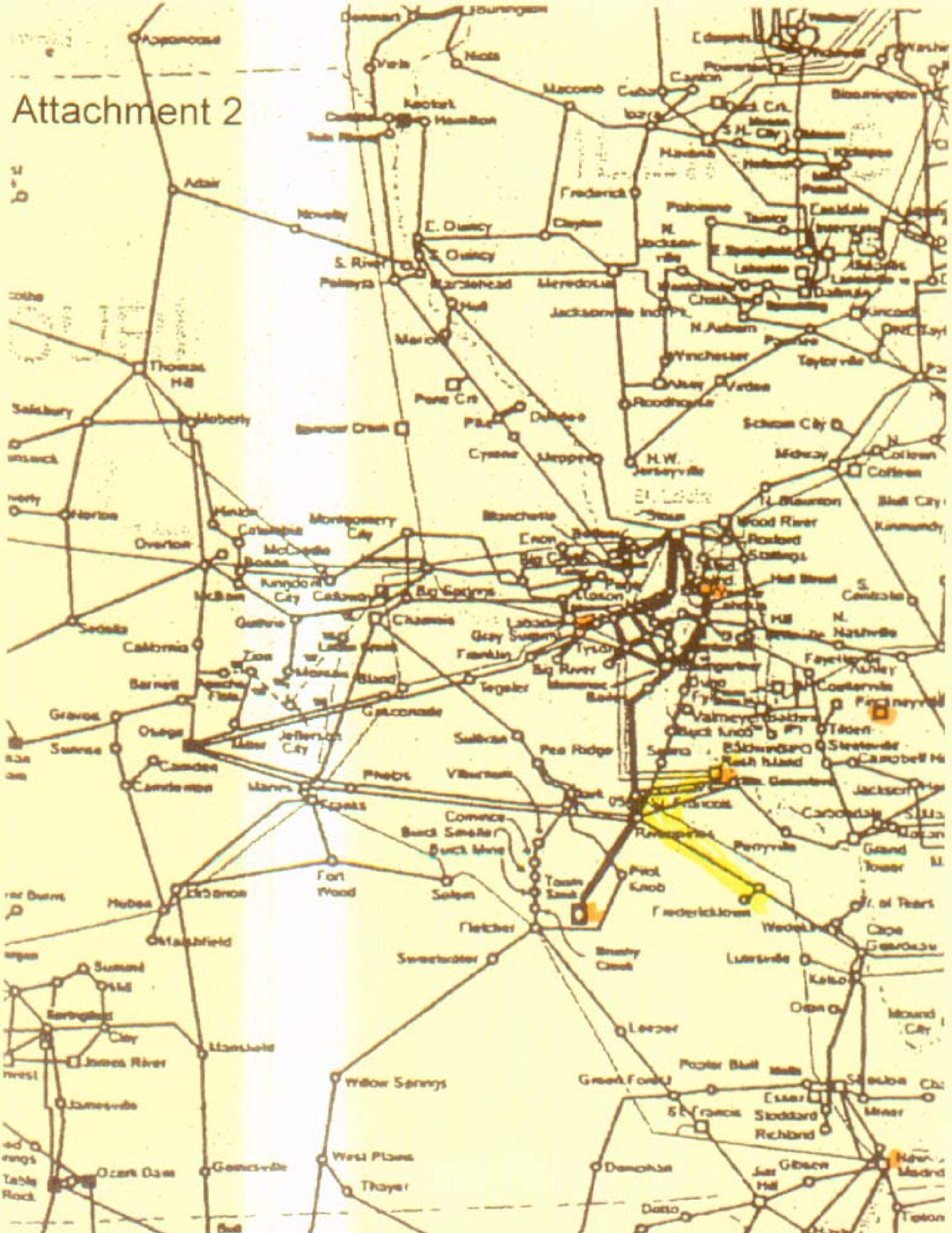
Status Notification:

Anc Service Link: SC:(MISO:AR 74976898:5); RF:; EI:; L:; SP:; BS:; DT:; SU:; RV:(MISO:AR 74976898:5);

Anc Required: SC:M;RV:M;RF:O;EI:U;SP:O;SU:O;DT:U;L:U;BS:U;

Customer: WRGS		Seller: MISO	
Name	Marie Rogers	Name	MISO_TA
Phone	785-575-8477	Phone	317-249-5523
Fax	785-575-6010	Fax	317-249-5860
E-mail	marie_rogers@wr.com	E-mail	tariffadministration@midwestiso.org

Attachment 2



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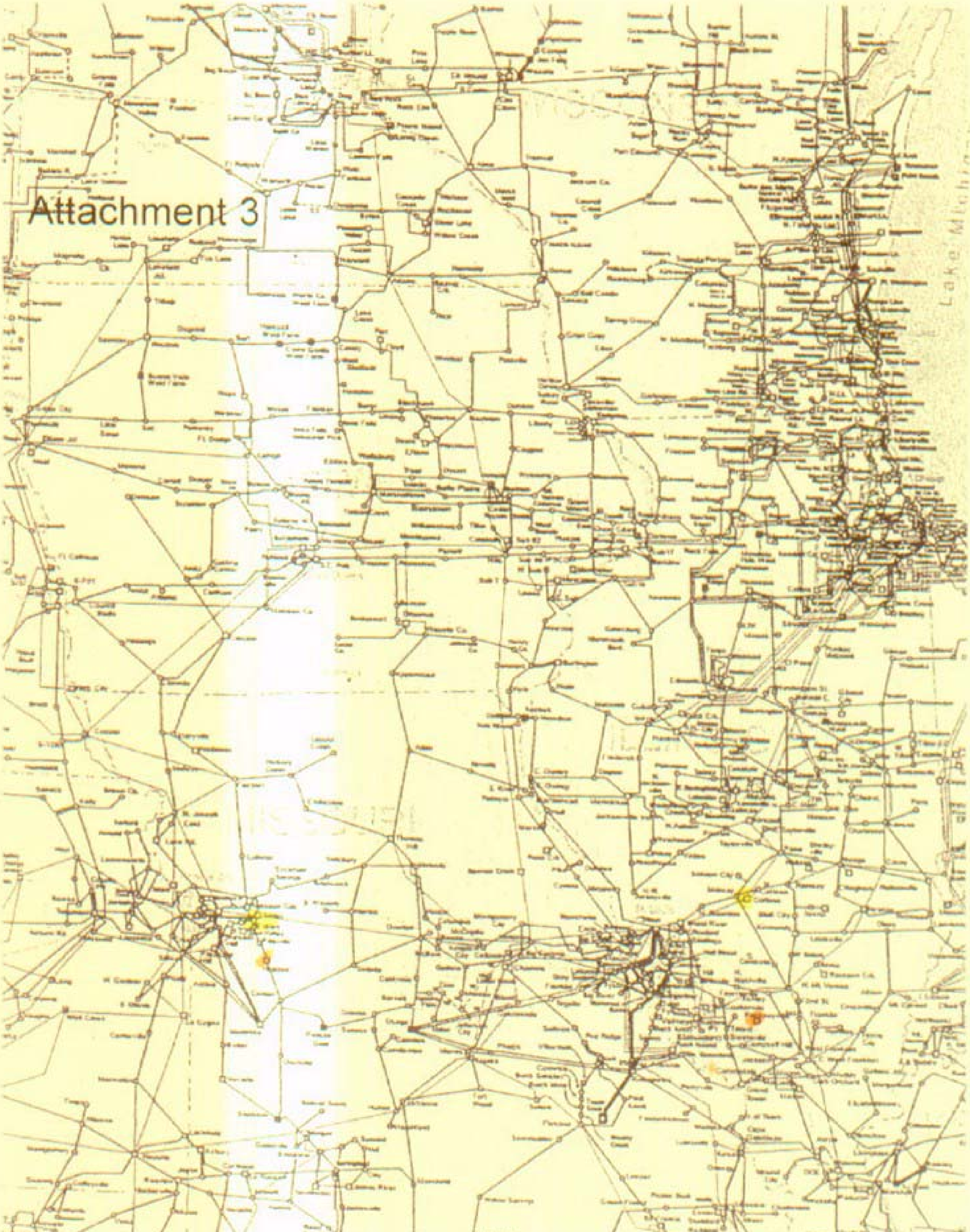

Effective Solutions for Getting Needed Transmission Built at Reasonable Cost

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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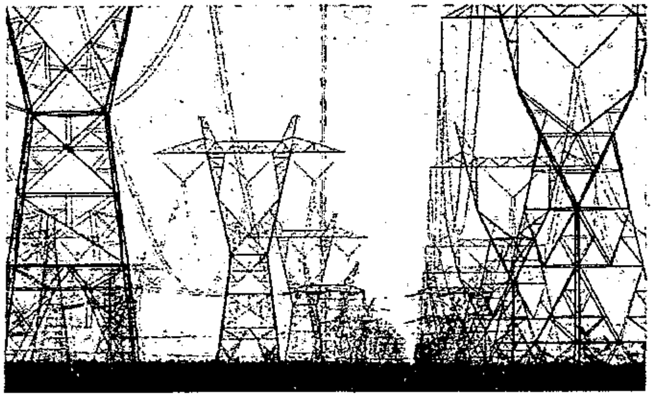


EXECUTIVE SUMMARY

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

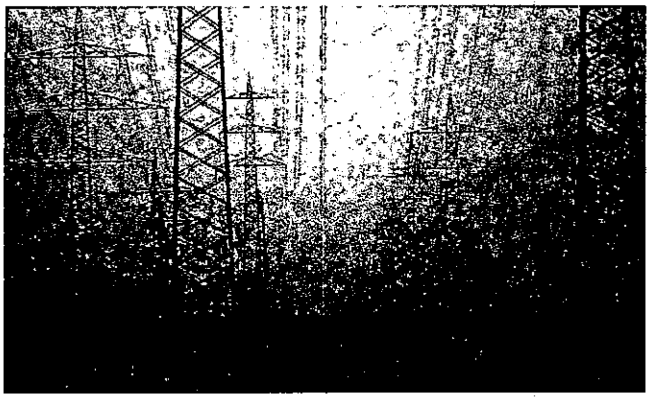
Almost everyone agrees that the interstate transmission grid must be expanded to improve reliability and provide the infrastructure needed for competitive wholesale markets. Since 1982, transmission capacity relative to peak transmission use has declined steadily. In the twenty years between 1979 and 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. 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.

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.

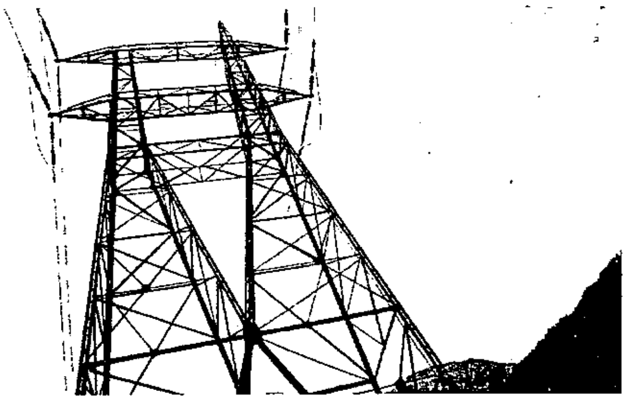
Structural Solutions

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.

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. 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." 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. 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." 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. Ironically, some investor-owned utilities have demanded rate incentives to build at the same time they have refused to permit investment by TDUs.

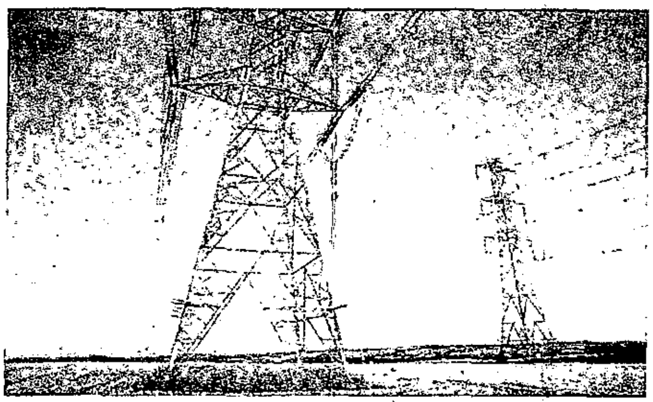
Policymakers should look with suspicion at requests for incentives by those who deny TDUs the opportunity to invest in the grid on comparable terms, and should support the efforts of TDUs ready, willing and able to share responsibility for our nation's grid.

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. The FERC-approved, customer-supported formula transmission rate for ATC was one of the key credit considerations underpinning ATC's high credit rating. 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:

> *[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.[16]

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.[17] 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.[18] 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.

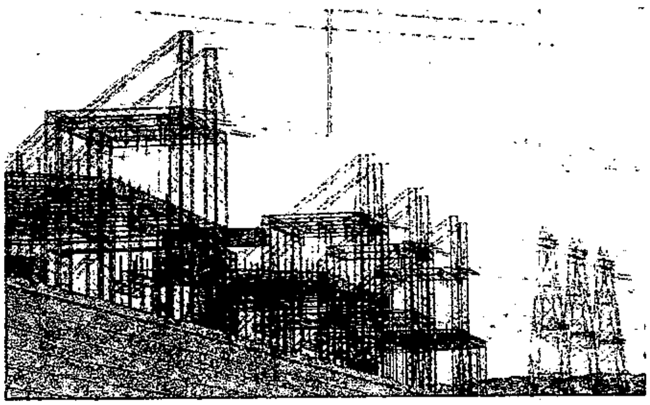
For example, "income trusts" have been used in Canada to finance infrastructure projects and other ventures with very stable revenues. Investors in these trusts seek the solid, relatively certain returns that can be achieved by a pledge of revenues to the trust. Securitization bonds work in a similar 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. TDI's 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. 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. 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.

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.

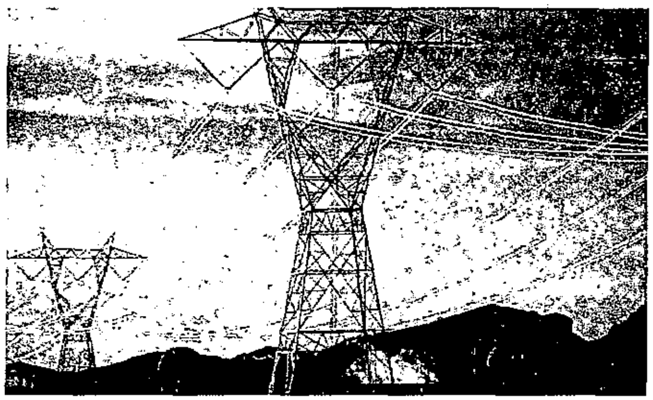
RTOs, inclusive stand-alone transmission companies and shared systems all facilitate regional planning. Where these structures do not exist, regulators should exercise their conditioning authority, and employ both the carrot and the stick, to achieve a strong regional planning process.

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." Performance-based rates are finding increasing acceptance in the electric utility industry, specifically in the area of transmission services.

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. 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.

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.[9]

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 found 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., 99 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/press-room/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/ITcSale-i.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=[illegible]&Link
(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, 2004), 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.[illegible].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=[illegible]
(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 [illegible] 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=454
(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

PENNSYLVANIA
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

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing pleading by electronic means or by U.S. mail, postage prepaid addressed to all parties and pending Applicants for Intervention by their attorneys of record as disclosed by the pleadings and orders herein.

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Dated: January 31, 2005