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Statement

Of the

AMERICAN PUBLIC POWER ASSOCIATION (APPA)

For the

HOUSE ENERGY AND COMMERCE COMMITTEE'S SUBCOMMITTEE ON ENERGY AND ENVIRONMENT

Hearing on "The Future of the Grid: Proposals for Reforming National Transmission Policy"

June 12, 2009

The American Public Power Association (APPA) appreciates the opportunity to provide the following testimony for the Subcommittee on Energy and Environment's hearing on "The Future of the Grid: Proposals for Reforming National Transmission Policy." I am Joe Nipper, Senior Vice President of Government Relations for APPA.

APPA represents the interests of more than 2,000 publicly-owned electric utility systems across the country, serving approximately 45 million Americans. APPA member utilities include state public power agencies and municipal electric utilities that serve some of the nation's largest cities. However, the vast majority of these publicly-owned electric utilities serve small and medium-sized communities in 49 states, all but Hawaii. In fact, 70 percent of our member systems serve communities with populations of 10,000 people or less.

Overall, public power systems' primary purpose is to provide reliable, efficient service to their local customers at the lowest possible cost, consistent with good environmental stewardship. Like hospitals, public schools, police and fire departments, and publicly-owned water and waste-water utilities, public power systems are locally created governmental institutions that address a basic community need: they operate on a not-for-profit basis to provide an essential public service, reliably and efficiently, at a reasonable price.

The great majority of APPA's members are "transmission dependent," meaning that they must pay third parties for access to the bulk transmission system in order to acquire electricity from power plants for distribution to their retail customers. There are, however, a number of public power systems that own a significant amount of bulk transmission facilities – including the Los Angeles Department of Water and Power (LADWP) and the Nebraska Public Power District, among others.

Because the Energy Information Administration (EIA) stopped collecting transmission data from public power, cooperative and federal utilities in recent years, 2003 data are the latest comprehensive statistics available by utility. Based on the 2003 data, APPA estimates that approximately 110 public power utilities own approximately eight percent of the nation's transmission lines of 138 kilovolts (kV) or greater.

Because of EIA's decision to discontinue collecting data from the entire electric utility industry, the only up-to-date comprehensive information on existing transmission investment and ownership is NERC's data on total transmission miles of lines 230 kV or greater summarized by NERC regions and sub-regions. Other information sources only cover part of the industry (for example, the Federal Energy Regulatory Commission's (FERC) Form 1 transmission data covers only FERC-regulated "public utilities," primarily investor-owned utilities – **not** publicly-owned and operated electric utilities collectively known as public power systems) or are published in inconsistent formats (for example, RTO or company announcements of billions of dollars in planned investments over a several year period). Consistent, industry-wide data would be very useful in assessing actual progress in getting needed new transmission facilities built.

As will be evident from the testimony below, there are a number of issues encompassed by the broad topic of "transmission" that are significant enough to merit their own hearings – the problems with RTO-run centralized wholesale power markets, and the implementation issues that have plagued the federal backstop siting process for transmission enacted in the Energy Policy Act of 2005 (EPAct05), to name only two – and APPA would urge the committee to consider holding such hearings.

APPA was asked to discuss the primary components of transmission policy -- planning, siting and cost allocation – but we will also address related issues such as incentive rates, joint ownership, regional transmission organizations, and the concept of "green transmission." APPA's policy on planning, siting, cost allocation and joint ownership is guided by the attached resolution, adopted in February of this year, and underpins our comments below.

<u>Transmission Investment Is Needed</u>

It is widely recognized that our current transmission system is not sufficient to meet future needs and, in many regions, is highly constrained. The weaknesses of the transmission grid not only threaten reliability, they undermine the ability of all types of generation, including renewable generation, to be developed and brought to market. Well-planned, cost-effective transmission improvements can increase the overall efficiency and reliability of the system. While improvements could increase the transmission rate paid by an end-user, the same end-user would benefit from increased reliability. Since generation and transmission are interdependent, the end-user could also benefit from lower-priced generation that would be made available with additional transmission access.

Historically, the challenges to improving the transmission grid have been obtaining rights-of way, environmental and land use concerns about where the transmission lines are sited, and the sheer complexity of state and local siting procedures. While these challenges still exist, one major positive development did occur in 2005 – the enactment of federal "back-stop" siting authority for transmission lines. As the Subcommittee knows, this authority was granted in Section 1221 of EPAct05, which added new Section 216 to the Federal Power Act (FPA). This section sets up a process under which: 1) the Department of Energy (DOE) designates certain corridors where transmission is highly constrained or congested as National Interest Electric Transmission Corridors (NIETCs); 2) FERC can grant siting and construction permits employing federal eminent domain authority for transmission facilities in these NIETCs if, after a certain period passes, state authorities have withheld approval of such proposed transmission facilities, a state does not have the authority to approve the siting of such facilities or to consider the interstate benefits, or the applicant is a transmitting utility that does not serve end-use customers in the state where the project is proposed. FERC must take certain issues into consideration when using its backstop siting authority. It must find that the proposed facilities will: significantly reduce transmission congestion in interstate commerce; protect or benefit consumers; be consistent with the public interest; and enhance energy independence. The proposed construction or modification must also be consistent with sound national energy policy.

DOE has completed its first proceeding designating NIETCs, and FERC has finalized its backstop transmission siting regulations. Both DOE and FERC, however, have been embroiled in litigation with states, environmental groups, and landowner groups seeking to overturn their determinations and regulations. Unfortunately, the United States Court of Appeals for the Fourth Circuit's February 18, 2009 decision in *Piedmont Environmental Council v. FERC*, No. 07-1651, has substantially undermined FERC's backstop siting authority. In that case, the Fourth Circuit held that the phrase "withheld approval" in FPA § 216(b)(1)(C)(i) does not encompass a state public utility commission's (PUC) denial of a transmission siting application for facilities within an NIETC, but only refers to a state PUC's failure to act. Hence, if a state PUC decides within one year simply to deny an application to construct transmission facilities in an NIETC, FERC has no authority to consider a backstop transmission siting application. As an intervenor on the side of FERC in this case, APPA believes that any federal transmission legislation should clarify congressional intent in EPAct05 by expressly providing FERC with the authority to consider backstop transmission siting applications when a state PUC denies an application. It is important to note that, as units of local and state government, public power utilities are not uniformly supportive of federal policy that diminishes state authority, and we have had our concerns about Congress' and FERC's attempts to expand that authority in other areas. However, the importance to the electricity industry and the customers we serve of siting interstate transmission lines cannot be understated, and resulted in our support of the compromise crafted in EPAct05.

APPA also believes that the NIETC process should be reconsidered given the controversy and litigation accompanying DOE's designation of the initial corridors. A variety of options could be considered, including: eliminating the corridor process altogether, and allowing FERC's backstop siting authority to be used, if needed, for any interstate transmission project; or retaining the corridor process, but expanding the criteria DOE considers in designating corridors, including consideration of where significant renewable resources are available but require transmission facilities to move the renewable power to market.

If new electric generation resources, especially renewable resources, are going to be brought to market to meet increasing demand and to address climate-related concerns, substantial new transmission facilities are going to be required. Both the public and Congress must understand the need to balance the concerns of states, landowners and other groups opposing specific transmission projects against the larger public good. As some in the industry have quipped, "if you are going to love renewables, you can't hate transmission."

Finally, there is a misconception, fostered by some in the industry, that higher voltage lines are always better. In actuality, the interconnected nature of the grid is such that a lower voltage line, if located strategically, could have a greater ability to relieve congestion and to enhance reliability than a higher voltage line, and could experience less local resistance to siting and cost less than a higher voltage line. Of course, there are situations where an "extra-high-voltage" line is preferable and necessary, but we want to make it clear that "bigger isn't always better" when it comes to the grid. This is one reason why regional transmission planning is so important; the impact of proposed new higher voltage facilities on the existing transmission network needs to be fully considered, so that the optimal mix of facilities can be determined.

<u>The Markets Operated by Regional Transmission Organizations (RTOs) Have Not Significantly Aided in Infrastructure Investment</u>

> APPA and its members have long expressed their disappointment with the current "Day 2" regional transmission organizations (RTOs)/Independent System Operators (ISOs) that operate wholesale electricity markets in certain parts of the country.[1]

[1] **PJM Interconnection** – Parts of Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, Tennessee, plus Delaware, Maryland, New Jersey, Pennsylvania, Virginia, West Virginia and the District of Columbia.
Midwest Independent System Operator -- Parts of Illinois, Indiana, Ohio, Missouri, South Dakota plus Iowa, Michigan, Minnesota, Missouri, North Dakota, and Wisconsin, and the Canadian Province of Manitoba.
New York Independent System Operator -- New York only.
ISO New England – Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
Southwest Power Pool – All or part of Arkansas, Oklahoma, Missouri, Kansas, Louisiana, Nebraska, New Mexico, and Texas. SPP has announced its intent to implement a Day Two market in 2012

APPA believes that FERC has effectively delegated a significant amount of its regulatory authority to these RTOs, with too little oversight or review of the actual impact of these organizations on retail electric consumers. While much of the attention on these markets has focused on high prices, other features of these markets adversely impact transmission expansion, as I discuss below.

While expressing strong concerns with the centralized RTO-run "Day 2" wholesale power supply markets, APPA recognizes that RTOs provide services that have substantial value. Such positive features include: administration of regional open access transmission tariffs (OATTs) on a non-discriminatory basis; elimination of pancaked transmission rates (allowing transactions to take place over a broader geographic area); and strengthening of regional transmission planning processes. But these substantial accomplishments have been overshadowed by the costs and problems created by the centralized day-ahead and real-time spot markets for energy, ancillary services, and capacity.

APPA is concerned that the operation of such highly complex markets has distracted the RTOs' attention away from their core mission of ensuring adequate investment in the regional transmission system. RTOs have instead largely relied on the use of "price signals," such as locational pricing, to achieve needed transmission investment. A central element of RTO-operated energy markets is "locational marginal pricing" (LMP), under which electricity prices set in the RTO's spot markets vary by system location. When demand for use of specific transmission facilities exceeds those facilities' physical capacity to move power (known as congestion), it is not possible for electricity to reach every part of the system at the lowest overall cost. In the constrained portion of the grid, prices rise when only higher cost generators are able to deliver electricity to the customer, even if generators offering lower prices exist elsewhere in the RTO's footprint.

Advocates of LMP, including the RTOs and FERC itself, argue that the higher costs charged when congestion occurs on the transmission system provide "price signals" to market participants to fund the construction of new generation and transmission facilities to alleviate transmission congestion. FERC stated over 10 years ago that LMP would "send price signals that are likely to encourage efficient location of new generating resources, dispatch of new and existing generating resources, and *expansion of the transmission system*."[2] (Emphasis added.)

California Independent System Operator – California only.
The Electric Reliability Council of Texas (ERCOT) – Texas only, and it is not subject to FERC oversight because the Texas electric power grid does not interconnect with other states.

[2] In its original November 25, 1997 order accepting the PJM Interconnection's (PJM) filing to restructure the PJM Pool to implement LMP, the Commission found: "We believe that the LMP model will promote efficient trading and be compatible with competitive market mechanisms. In this regard, we find that the LMP approach will reflect the opportunity costs of using congested paths, encourage efficient use of the transmission system, and facilitate the development of competitive electricity markets. By pricing the use of constrained transmission capacity on the basis of opportunity costs, the proposal will also send price signals that are likely to encourage efficient location of new generating resources, dispatch of new and existing generating resources, and expansion of the transmission system." *Pennsylvania-New Jersey-Maryland Interconnection,* , 81 FERC ¶ 61,257 (1997) at p. 81, *on rehearing,* 92 FERC ¶ 61,282 (2000), *vacated and remanded on other grounds, Atlantic City Electric Co., et al. v. FERC,* 295 F. 3d 1 (D.C.Cir. 2002), *on remand*, 101 FERC ¶ 61,138 (2002), *on rehearing,* 103 FERC ¶ 61,170 (2003), *on petitioners'*

The RTOs themselves make the claim that the markets produce "accurate price signals that reflect the value of electricity across time and place, revealing both resource scarcity and transmission congestion."[3] There is no real disagreement that the use of LMPs "reveals" transmission congestion; rather, the dispute is over whether the use of LMP has actually spurred substantial new transmission facilities investments. When discussing actual transmission investments in their regions, RTOs attribute such investments to the success of their regional transmission planning processes[4] – processes that are not necessarily connected to or reliant on the LMP-based markets.

Pricing differentials produced in hourly spot markets, given their short-term nature and substantial volatility over time, are not necessarily the best guide to making very long-lived capital investments in transmission and generation facilities. Other factors, including the regional mix of generation, estimated growth in demands, state renewable portfolio standards and utility resource plans, provide a better foundation for long-term investments.

Market participants in certain regions without Day 2 RTO markets have implemented innovative regional approaches to transmission system management and planning. An example of a promising approach is the ColumbiaGrid in the Northwestern United States. This is a not-for-profit membership corporation formed in 2006. ColumbiaGrid does not own transmission; its members and the parties to its agreements own and operate an extensive network of transmission facilities. ColumbiaGrid provides single-utility based transmission planning for the combined network of its participating utilities.[5] In April 2007, FERC accepted ColumbiaGrid's proposal to coordinate transmission planning and expansion in the Pacific Northwest.[6] While different models may be appropriate for different regions, new initiatives such as ColumbiaGrid demonstrate that there are effective and consumer-friendly alternatives to the use of RTO-based market regimes to manage regional grids.

APPA has advocated that FERC place a moratorium on the establishment of any new Day 2 RTOs and on the establishment of new RTO-run markets for additional products and services within existing RTOs, unless accompanied by a demonstration of net benefits to consumers from those new markets. APPA also recommends that the current Day 2 RTOs be restructured to enhance the transmission and reliability focus of RTOs, and to put more emphasis on bilateral contracting, rather than centralized energy markets. We have proposed a plan, the Competitive Market Plan (attached), that outlines one possible way achieve these reforms. APPA believes that electricity should be bought and sold primarily through bilateral contracts, with spot markets being used primarily for balancing and optimization functions. Deemphasizing the operation of complex centralized markets would allow RTOs to focus on their core transmission functions,

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petition to enforce mandate, Atlantic City Electric Co., et al. v. FERC, D.C.Cir. No. 97-1097 (May 20,2003)

[3] *Progress of Organized Wholesale Electricity Markets in North America*, ISO/RTO Council, October 16, 2007, p. 4, http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC40A08DC3003829518EBD%7D/IRC_State_of_the_Markets_Report_103007.pdf

[4] ISO/RTO Council, October 16, 2007, section beginning on p. 5 titled "Regional System Planning Processes Are Producing Much-Needed Transmission Upgrades"

[5] For more information on Columbia Grid, see www.columbiagrid.org

[6] http://www.ferc.gov/news/news-releases/2007/2007-1/04-03-07.asp#skipnavsub

including independent and collaborative regional transmission and generation interconnection facilities planning. Such planning should involve affected stakeholders, including state authorities, thus building the regional support required to obtain siting authority for needed new transmission facilities and upgrades.

Transmission Incentives Are Being Over-used as a Tool to Spur New Transmission Investment

New Section 219 of the Federal Power Act (FPA) was added by Section 1241 of EPAct05. Section 219(a) required FERC to establish by rule incentive-based rate treatments for the transmission of electric energy in interstate commerce by FERC-regulated "public utilities" (this is a defined term under the FPA and generally covers investor-owned utilities, **not** publicly owned and operated public power systems). The purpose of the incentives is to ensure reliability and reduce the cost of delivered power by reducing transmission congestion. Section 219(d), however, made clear that these incentive rate treatments were to be subject to the requirements of FPA Sections 205 and 206 that rates be just, reasonable, and not unduly discriminatory.

FERC in its Order Nos. 679 and 679-A[7] fulfilled its statutory requirement to issue a rule regarding incentive-based rate treatments for public utility-owned transmission facilities. In so doing, however, it seemed to regard Section 219 as a statutory requirement to offer a smorgasbord of different transmission rate incentives to public utility TOs, including rate of return on equity (ROE) adders, recovery of construction work in progress (CWIP), hypothetical capital structures, accelerated depreciation, and recovery of abandoned project costs. Despite the strong concerns expressed by APPA and other consumer-side interests regarding the potential adverse cumulative impact on consumers of offering all of these incentives, the Commission brushed aside such considerations, saying that an applicant would be required to demonstrate that the total package of incentives it sought were tailored to address the demonstrable risks faced by the applicant in undertaking the project.

Unfortunately, it appears that public utility TOs have been helping themselves to the incentives smorgasbord, and that the Commission has not taken a sufficiently disciplined approach to awarding transmission rate incentives. Furthermore, while prior to this year, then-FERC Commissioner Jon Wellinghoff and Commissioner Suedeen Kelly issued a series of strong dissents to Commission orders granting transmission rate incentives for various transmission projects,[8] a recent granting of an array of transmission rate incentives to the proposed Green Power Express project in an order the Commission issued on April 10, 2009, in Docket No. ER09-681[9] indicates that such concerns may still be merited, notwithstanding the change in leadership at the Commission. The Commission approved a menu of incentives for the Green Power Express project,

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[7] *Promoting Transmission Investment through Pricing Reform,* Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. and Regs. ¶ 31,222 (2006); Order No. 679-A, 72 Fed. Reg. 1152 (January 10, 2007), FERC Stats. and Regs. 31, 236 (2007); Order on Rehearing, 119 FERC ¶ 61,062 (2007).

[8] See, for example, *Baltimore Gas and Electric Co.*, 121 FERC ¶ 61,167 (2007); *PPL Electric Utilities Corporation, et al.*,123 FERC ¶ 61,068 (2008); *Bangor Hydro-Electric Co., et al.*, 122 FERC ¶ 61,265 (2008).

[9] *Green Power Express LP*, 127 FERC ¶ 61,031 (2009), *rehearing pending.*

including recovery of abandoned plant costs, deferred cost recovery through the creation of "regulatory assets," inclusion of 100% of construction work in progress (CWIP) in rate base, use of formula rates, use of a hypothetical capital structure, and a total of 160 basis points (1.6%) in add-ons to its proposed rate of return on equity (resulting in an overall ROE of 12.38%). The Commission "pre-granted" these incentive rate treatments even though this high voltage transmission project was initially developed outside any Commission-approved regional transmission planning process. Orders such as this one lead APPA to be concerned that the granting of transmission rate incentives has become the "new normal" standard for transmission ratemaking at the Commission. APPA is not totally opposed to the use of transmission rate incentives. The federal government should consider the judicious use of incentives when they would spur construction of facilities that will substantially enhance reliability or provide broad access to more economical power supplies not currently available to the market. But regional assessments of needed new transmission facilities should consider both higher and lower voltage transmission requirements to ensure that reliable and economic power supplies in fact reach regional retail consumers. Moreover, the total package of transmission rate incentives granted should be no more than required to reduce the overall risk of the project to acceptable levels.

For these reasons, we appreciate the letter recently sent to FERC by Chairman Markey inquiring about its policy of granting of transmission rate incentives, and urge the Subcommittee to further investigate FERC's ratemaking practices in this area.

Proposals to Mandate a Limitation on the Types of Electricity Generation to Be Transmitted over Transmission Lines Fail to Recognize the Integrated Nature of the Grid and the Urgent Necessity for Additional Transmission to Support All Types of Generation

Until intermittent renewable energy resources can be used reliably at anytime (as opposed to when the wind blows or the sun shines), base-load generating plants like those powered by large-scale hydropower, natural gas, nuclear energy, and coal must be used to produce electricity, to "firm up" intermittent renewable resources. As the CEO of the North American Electric Reliability Corporation (NERC) remarked last year, renewables "need a dance partner."[10] With that in mind, legislative initiatives that would mandate renewable usage or otherwise prescribe what generation sources can interconnect to a given bulk transmission line are not feasible from an operational or reliability standpoint. Furthermore, once these lines interconnect to the rest of the grid, such a requirement would be extremely hard to enforce. The laws of physics are such that electrons will flow where they will. Subsequent high voltage additions could well change transmission system configurations substantially, causing changed power flows -- some of which would be non-renewable -- that even the engineers did not anticipate in advance.

In addition, the variability of available generation resources and transmission assets from region to region dictates the need for regional, rather than national, solutions. Even the

[10] *Electric Utility Week*, July 28, 2008 edition at 13 (reporting on Rick Sergel's July 20, 2008 presentation to the collaborative of the National Association of Regulatory Utility Commissioners and FERC on Demand Response).

federal back-stop siting authority that APPA strongly supports as delineated above envisions extensive state and regional consideration before the federal government steps in using its backstop authority. Significant initiatives to access renewable energy have occurred and are continuing at the state and regional levels. APPA members have participated in and will continue to participate in these types of initiatives, as well as others initiated by public power entities.

APPA has strong concerns about congressional mandates to build transmission to support only certain types of generation resources when the focus should instead be on getting transmission built pursuant to regional transmission planning processes.

Regional Planning and Appropriate Regional Cost Allocation Strategies Are Essential to Getting More Transmission Built

As I have already discussed, transmission improvements should be made to provide the greatest benefit to the regional system as a whole. Because of the physical properties of electricity, an improvement at one point in the regional system can increase (or decrease) system efficiency in a different part of the region. Optimally, utilities should construct transmission facilities based on where the greatest benefits would occur, and these decisions should be made in consultation with other regional utilities. This is doubly true because of the substantial political and policy barriers to transmission siting. Successful regional planning has occurred throughout the country, but not at the pace or volume necessary to meet demand for electricity while maintaining high reliability.

Regional planning and support from a broad array of stakeholders is equally important to siting transmission to renewable facilities as it is to traditional power plants. The major difference between traditional power plants and some renewable generation facilities is that often renewable facilities, like wind projects, for example, must be sited remotely from population centers because that is where the resource is located. Hence, an added challenge to siting transmission lines to most renewable facilities is the length of the lines and the remoteness of the locations. Public power systems, like LADWP, have taken a lead role in promoting transmission projects to renewable facilities. Two LADWP transmission projects are in the planning phases that will enable southern California to access thousands of megawatts of new renewable generation capacity. One of these projects is a joint ownership arrangement as noted below:

1. Barren Ridge Renewable Transmission Project: LADWP is proposing the Barren Ridge Renewable Transmission Project to access renewable energy resources in the Tehachapi Mountain and Mojave Desert areas of Southern California. The project is in Kern and Los Angeles Counties, and is approximately 75 miles in length from Barren Ridge Switching Station to Rinaldi substation and 12 miles in length from Castaic power plant to the proposed Haskell Switching Station. The project will consist of:

    - Construction of a 230 kilovolt (kV) transmission line from the LADWP Barren Ridge Switching Station to Haskell Canyon on double-circuit structures (involving approximately 13 miles of National Forest Service (FS) lands and four miles of Bureau of Land Management (BLM) managed public lands);

- Addition of a 230 kV circuit on the existing double-circuit structures from Haskell Canyon to the Castaic power plant (involving approximately four miles of FS lands and 300 feet of BLM managed public lands);

- Upgrade the existing Owens Gorge-Rinaldi 230 kV transmission line with larger capacity conductors between the Barren Ridge Switching Station to Rinaldi Substation (involving approximately 13 miles of FS lands and four miles of BLM managed public lands);

- Construction of a new electrical switching station at Haskell Canyon.

2. Green Path North Project: The Green Path North Project (GPNP) is a proposed new electrical transmission system being developed by interested parties: the City of Los Angeles Department of Water and Power (LADWP), Imperial Irrigation District (IID), and the Southern California Public Power Authority (SCPPA). The goal of GPNP is to connect to world-class geothermal renewable energy, as well as solar and wind power resources from the Salton Sea area of Imperial Valley. The proposed line is in the early planning stages and no decisions have been made regarding the route, or other specific elements of the project. LADWP is looking at a variety of alternative routes and technologies. Generally, the line would be designed to connect a new electric switching station, or substation, near Hesperia with a new substation to be built near Palm Springs.

APPA appreciates the transmission planning provisions included in the committee-passed version of the American Clean Energy and Security Act, as we believe that they will bolster, rather than duplicate or further complicate, the existing and extensive transmission planning processes occurring at the regional and sub-regional levels across the country.

The manner in which transmission facilities' costs are allocated among generators, transmission owners, transmission dependent utilities and other stakeholders is one of the most controversial topics related to transmission, and getting it wrong can have an extremely adverse impact on getting transmission built. APPA, along with numerous other electricity stakeholders, strongly supported the language included in Section 1242 of EPAct05 that underscores FERC's flexibility in determining the appropriate transmission pricing methodology, and does not impose the one-size-fits-all participant funding mandate that was considered during the lead-up to passage of the bill. While APPA does not always agree with the decisions made by FERC on transmission cost allocation issues, we continue to believe that Congress had it right in leaving these decisions, with appropriate stakeholder input and administrative due process, to FERC to determine under Sections 205 and 206 of the Federal Power Act.

The issue of who pays for major new transmission facilities that provide regional benefits is a difficult one as such facilities can provide present and future system benefits that extend well beyond the specific entities for whom the facilities are constructed. Therefore, APPA urges FERC to provide greater guidance on cost allocation for major new transmission facilities that afford regional benefits. The costs of such facilities should be recovered through cost-based rates that are just and reasonable, and not unduly discriminatory, consistent with cost-of-service ratemaking principles. APPA does not support allocation of the costs of such facilities to regions, sub-regions or entities that will receive little or no benefit from the facilities, and therefore opposes a federal statutory requirement to allocate such costs on an interconnection-wide basis.

Joint Ownership Would Improve Transmission Investment

Encouraging proportional joint ownership of transmission facilities by those load-serving entities, including public power utilities, providing electric service in a given region is another way to get more transmission built. If the responsibility for building and owning the transmission grid is spread more broadly among those entities serving loads (*i.e.* demand) in a region, then joint transmission planning will be facilitated, simply because there are more participants at the planning table supporting the needed projects. If network service transmission customers of a dominant regional transmission provider are encouraged to own their load ratio share of the transmission system, transmission usage and ownership will be more closely aligned, and the frictions between transmission-dependent utilities and transmission owners can be reduced.

Public power utilities have participated in jointly-owned transmission arrangements for many years. One model of joint ownership that has worked for public power is investment in a transmission-only company. A second model is ownership in a shared transmission system. There are two transmission-only companies that are partially owned by public power utilities. These are the American Transmission Company in Wisconsin and the Vermont Electric Power Company. In shared or joint transmission systems, two or more load-serving utilities combine their transmission facilities into a single integrated system. Examples of public power participation in shared transmission systems are found in Indiana, Georgia, Minnesota, and the upper Midwest region. Unfortunately, not all investor-owned utilities see the benefits of jointly owning transmission facilities with other load-serving entities in their regions.

One impediment to expansion of joint transmission facilities ownership is the "private use" restriction imposed on tax-exempt financing that I discuss in more detail below. While public power systems can use other types of financing mechanisms when private use restrictions apply, this situation is not ideal from a parity standpoint with investor-owned utilities that have federal financial incentives at their disposal for building new transmission facilities.

Removing Limits on the Use of Tax-Exempt Financing Would Help Get More Public Power-Owned Transmission Built

Traditionally, our federalist system of government has respected the right of state and local governments to pursue activities that are in the public interest and the interests of the citizens they serve. Congress has promoted and protected the right of government to issue municipal bonds for "government owned and operated projects and activities."

Public power systems are just that – government-owned and -operated systems similar to other local infrastructure projects such as water systems, prisons, hospitals, and transportation lines.

While outside the scope of this committee's jurisdiction, APPA wants to emphasize that Congress should continue to recognize a basic tenet of the federal system of government -- the constitutional doctrine of reciprocal immunity. Under this doctrine, the federal government cannot tax the interest on obligations issued by state and local governments for public purposes and state and local governments cannot tax the interest on federal obligations.

In addition to continued access to tax-exempt bonds to finance electricity infrastructure, it is important that Congress provide adequate flexibility for public power utilities to partner with private entities in the financing and use of certain facilities, as is discussed above. Congress has recognized this necessary flexibility by allowing a certain amount of "private use" from output facilities financed with tax-exempt bonds. Prior to the 1986 Tax Reform Act, the limitation on private use was set at 25 percent for all governmental issuers. However, the 1986 legislation reduced the amount of private use to 10 percent. In addition to the reduction of the private use limitation from 25 percent, the federal tax code also provides that for certain output facilities – public power and public natural gas generation and transmission facilities – the private use limit is the lesser of 10 percent or $15 million. Private use restrictions limiting the benefits available to private entities from publicly financed facilities are based on sound and appropriate public policy considerations. However, the restrictions should apply equally to all governmentally financed and operated facilities.

The special $15 million private-use limitation that applies only to publicly owned electric and gas facilities is not supported by any public policy justification. It may force local governments that provide transmitting facilities to have their surplus capacity sit idle rather than having it sold to others in order to avoid the private use limitation. This provision should be repealed because it is discriminatory and it encourages practices that are neither environmentally nor economically sound. It also discourages an expansion of the joint ownership model that has been so successful in some regions, and could be used to improve the bulk transmission system in others.

Conclusion

The major impediments to getting new transmission built continue to be siting and cost allocation. I urge Congress to clarify and strengthen the federal back-stop siting authority included in EPAct05. Because of the local and state opposition to siting transmission lines, as many regional electricity stakeholders as possible should be included in their planning and ownership. Joint ownership of transmission facilities can help address thorny transmission cost allocation issues. Congress should therefore encourage and support joint ownership of transmission and should eliminate financial barriers to such ownership like the private use restrictions for tax-exempt financing. Finally, in the rush to support construction of new transmission facilities, the need to maintain existing transmission facilities should not be forgotten. Existing transmission facilities should be upgraded and maintained based on the requirement to serve as opposed to the availability (or non-availability) of transmission rate incentives.