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Should Diversity Rule?

Why Rate-of-Return Adders Are Unlikely to Increase Transmission Investment

The Energy Policy Act of 2005 mandated that the Federal Energy Regulatory Commission develop incentives to enhance investment in transmission. In Order 679 FERC authorized the use of rate-of-return ''adders'' as an incentive mechanism, and it has subsequently approved them in individual proceedings. The evidence suggests that such adders are unlikely to be effective tools for enhancing investment.

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I. Introduction

Many electric industry participants and observers believe more transmission investment is needed in the U.S.[1] Relative to peak demand, transmission capacity declined from 1982 to 2002.[2] Although transmission investment has been rising since 1998, it is still below the level in 1975, and the Edison Electric Institute believes projected additions fall below the optimal level.[3] PJM Interconnection reported congestion costs of $2.09 billion in 2005, up 179 percent from the previous year.[4] It is widely recognized that the U.S. electric transmission system was not designed to support large-scale intraregional trading, and that with electricity restructuring and growing electric demand additional transmission investment is likely to be socially beneficial. It is also widely understood that vertically integrated electric companies

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may have incentives to increase transmission congestion, which means that the best means of inducing increased investment in transmission has been difficult to ascertain: encouraging stand-alone transmission companies may encourage investment but may sacrifice vertical economies.[5]

Improving incentives for transmission investment is a challenging task. Transmission lies at the interface of regulation and markets, and is affected by regulatory policies at the federal, regional, and state levels. Transmission expansions can create large social gains, but they can also be socially detrimental if installed in the wrong location, and they may arouse opposition from generators whose monopoly profits they threaten. Clever allocation of financial transmission rights may be able to prevent firms from building transmission investments that make consumers worse off, but they cannot induce firms to build all needed transmission projects. As a result, most observers of the electric utility industry continue to see regulatory involvement in transmission as essential.

The Energy Policy Act of 2005 included a variety of provisions intended to enhance the transmission grid. Among them are tax incentives for transmission investment; a new Electric Reliability Organization; the creation of ''national interest transmission corridors'' that give FERC back-stop authority to facilitate siting of new transmission; and a requirement in section 219 of the Act that the Federal Energy Regulatory Commission (FERC) establish incentives for transmission investment.

In response to the mandate for incentive regulation, FERC Order 679 authorizes increases in the allowed rate of return on transmission investment (sometimes referred to as rate-of-return ''adders'') on a case-by-case basis.[6] This article draws upon the literatures on nodal pricing of electricity and on incentive regulation to assess the likely performance of adders as a means of increasing transmission investment. It concludes that adders are unlikely to be effective in enhancing investment.

The Energy Policy Act of 2005 includes tax incentives intended to enhance investment in the transmission grid.

II. Financial Transmission Rights

The most prominent idea for operating a competitive electricity network involves the use of nodal spot pricing. This notion is used by the New York Independent System Operator (ISO), the New England ISO, the PJM network, and the California ISO, and formed the basis of the FERCs proposed ''standard market design.'' Hogan (1992) and other authors have shown that this model has a number of desirable features, and allows for the operation of a competitive market for electricity on an existing transmission grid.[7] Under this system, a separate price is computed for each node of the network where power is either supplied to or taken from the network, and these prices reflect congestion on the network due to transmission capacity constraints, as well as underlying aspects of power supply and demand.

The spot prices resulting from a nodal pricing system vary significantly over the course of a day, and create price risk for market participants. These risks can be hedged using financial instruments such as transmission congestion contracts (TCCs) and contracts for differences (CfDs). A TCC is a contract that specifies a quantity t between nodes i and j, and pays the holder $t(p_j - p_i)$. Similarly, a CfD specifies a quantity t between nodes i and j, and a fixed price p_c, and pays the holder $t(p_j - p_c)$. Thus, a TCC hedges the ''locational risk'' of price variation across two points on the grid, while a CfD hedges ''temporal risk'' of price variation at a given point over time. The term financial transmission right (FTR) is used in a variety of ways, most often meaning something very similar to a TCC.

Proponents of market-driven transmission investment tend to assert (often only implicitly) that if transmission investors are granted FTRs, then this will be sufficient to induce them to make socially optimal transmission investments. Academic analyses of this question, however, are less optimistic.

Joskow and Tirole (2000) analyze a simple two-node model of electricity supply in which the North has excess supply and the South has excess demand.[8] There is a transmission link of capacity K between the two. If K were not binding, then the market equilibrium would occur where marginal cost of supply is equal to marginal revenue. However, if K is binding, then the rationing of this capacity is accomplished by setting nodal prices that clear the markets in the North and South. The difference between these prices is the shadow price of the transmission constraint, and if merchant transmission investors receive an FTR valued at this shadow price they will expand transmission investment if the marginal cost of transmission capacity is less than the shadow price.

Unfortunately, if transmission investment involves more than an incremental expansion, problems arise.[9] In this case, the marginal profit received by the merchant investor is less than the social value of the capacity expansion. Thus, the merchant investor underinvests. The problem is akin to the standard output choice problem of a monopolist, in which the monopolist restricts output in order to keep price high. Here, the transmission monopolist restricts capacity in order to keep congestion prices high.

Further problems arise if there are more than two nodes. Indeed, transmission expansion can actually be welfare-reducing if it diverts electricity flows away from low-cost suppliers toward higher-cost suppliers who happen to be better positioned with respect to the new transmission capacity. Bushnell and Stoft (1996, 1997) propose a policy for allocating FTRs that is designed to eliminate the incentive for such welfare-reducing transmission expansions.[10] They show detrimental expansions can be prevented if the initial electricity dispatch is perfectly hedged with FTRs, and investors in the expansion are forced to take a set of FTRs that results in a feasible dispatch when combined with the existing ones. Unfortunately, these conditions for preventing detrimental capacity expansions are somewhat stringent. Moreover, even if the conditions are met, it can at best prevent bad expansions – the scheme will not induce investors to make all socially beneficial transmission investments. As a result, most industry observers have concluded that some residual regulation of transmission investment is necessary.

One solution: ISOs or RTOs could run an auction in which competing transmission companies bid for the right to construct capacity expansion.

One solution to these problems could be for the independent system operator (ISO) or regional transmission organization (RTO) to create a market for the opportunity to invest in transmission, by running an auction in which competing transmission companies bid for the right to construct the capacity expansion. If the RTO has complete information about demand and cost curves, and how they change over the course of a day, week, month, and year, then it can in principle evaluate which proposed transmission expansion produces the greatest social surplus. Alternatively, the RTO could calculate the desired transmission expansion, and solicit bids for this particular project. Unfortunately, as McGarvey (2006) points out, many RTOs lack the necessary authority to require that new transmission be built.[11] Furthermore, problems familiar in the economic literature on regulation would arise if the ISO lacked information about the cost or benefits of transmission expansion, as is likely to be the case in practice.[12]

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III. Regulation of Transmission

If markets for transmission investment are likely to lead to market failures, then it is natural to turn to rate-of-return regulation as an alternative. Under this system, variable costs are treated as expenses and passed directly into rates, and capital costs are computed by identifying the prudently incurred capital investment, and assessing the ''allowed rate of return'' on this investment that will allow the firm to raise capital.

This form of regulation has been studied extensively in the regulatory literature. Averch and Johnson (1962) were the first to present such a model.[13] They showed that a firm subject to a binding rate-of-return constraint uses a capital/labor ratio that is inefficiently high.[14] Brennan (2006) argues that it is possible the U.S. transmission system enjoyed excessive investment during years of traditional regulation, since transmission tends to be more capital-intensive than generation, although it is difficult to assess whether this was actually the case in practice. If these incentives exist, then it may be possible to elicit adequate transmission investment simply by applying traditional regulatory practices to stand-alone transmission companies.

Indeed, FERC has argued that stand-alone transmission companies (''transcos'') may perform better than traditional vertically integrated utilities because they are subject to a single regulatory jurisdiction:

> Unlike investments by traditional public utilities subject to company-wide state-level rate case risks that can undermine incentive ratemaking at the federal level, ratemaking for transcos is entirely subject to federal jurisdiction. Thus, unlike many traditional public utilities, transcos avoid potential uncertainty associated with the need for additional rate recovery approval by state regulatory agencies.[15]

This concern is similar to those raised in the early twentieth century by utilities subject to municipal franchise regulation.

This concern is similar to those raised in the early twentieth century by utilities subject to municipal franchise regulation. They argued that shifting from municipal to state regulation would streamline the regulatory process and reduce regulatory uncertainty by consolidating regulatory authority in the hands of a single state regulatory body instead of a multitude of individual city-level commissions. Jarrell (1978) found that the shift to state regulation led to an increase in electricity prices, but did not explore whether this increase in prices induced an increase in investment.[16] Unfortunately, Lyon's (2007) study of this question finds that, if anything, state regulation resulted in a reduction in investment rather than an increase.[17]

The economic literature on regulation suggests that how rate-of-return regulation affects investment depends upon details of the regulatory structure, including the regulator's ability to commit not to appropriate all profits the utility earns through enhanced performance. The discussion below begins with traditional rate-of-return regulation and then turns to a discussion of more recent alternatives, such as price cap regulation.

A. Rate-of-return regulation

Under traditional rate-of-return (ROR) regulation, a company's rates include variable costs (which are normally passed through directly into rates) plus an ''allowed rate-of-return'' on all capital included in the company's ''ratebase.'' Typically the most contentious aspects of a rate case involve setting the allowed ROR and determining what capital items may be included in the ratebase.

Northeast Utilities provides a good example of ROR regulation as applied to transmission. Transmission rates are divided into two parts: (1) Regional Network Service (RNS), and (2) Local Network Service (LNS).[18] Regional Network Service is paid for using an historical rate base model. All companies in the New England ISO compute their ''regional'' transmission assets, and these are pooled. Revenue requirements are determined on a regional basis, and allocated to individual companies based on their percentage of total load. The RNS rate is updated annually.

Local Network Service is paid for primarily using a forecasted test year, and picks up any shortfall between RNS revenues and actual costs. For a company such as Northeast Utilities, there is an annual true-up.[19] The result of this system of regulation is to create something very close to a classic cost-based regulatory system in which profits are subject to a binding allowed-rate-of-return constraint. This corresponds closely to the model pioneered by Averch and Johnson (1962) and Wellisz (1963), and elucidated by Baumol and Klevorick (1970).[20]

In a classic rate-of-return model, the firm chooses capital and labor inputs subject to a constraint on its allowed rate of return on capital. The familiar result of Averch and Johnson is that the firm's capital/labor ratio is higher than would obtain for an unregulated profit-maximizing firm.

More important, for our purposes, is that the firm's choice of the *level* of capital to employ is actually decreasing in the allowed rate of return, as was demonstrated by Baumol and Klevorick. This result is easiest to understand graphically with reference to **Figure 1**.

The profit ''hill'' shows the firm's profits for different combinations of capital (K) and labor (L). In the figure, there is an optimal amount of capital and labor, which in the simple illustrative example plotted here would involve six units of capital and six units of labor. The two planes cutting through the profit hill represent different constraints on the allowed rate of return on capital. Consider first the lower plane, corresponding to a lower allowed rate of return. It is easy to see from the figure that the most profitable point for a firm subject to a rate-of-return constraint is found by identifying the point on the intersection of the profit hill and the rate-of-return constraint that uses the greatest amount of capital. It is also easy to see that when the allowed rate of return increases, thereby causing the ROR constraint to tilt upwards, the firm's optimal choice of capital *decreases*.

The foregoing analysis is hardly new, but it appears to have been forgotten in policy discussions regarding incentives for stimulating transmission investment. The policy implication is simple: rate-of-return ''adders'' for transmission may very well lead transmission companies to *reduce* rather than *increase* their transmission investment!

B. Rate caps

For companies with extended moratoria on transmission prices, e.g. companies operating under transmission rate caps, the rate-of-return constraint is no longer continuously binding. It may seem a contradiction to speak of an allowed rate-of-return in the context of price cap regulation, but in fact this is not strange at all. In this type of regime, an increase in the allowed rate of return amounts to an increase in the price cap faced by the firm. If regulators can commit not to ''true up'' the firm's prices and profits until the end of a pre-specified period (presumably of multiple years), then the firm truly operates under a fixed price

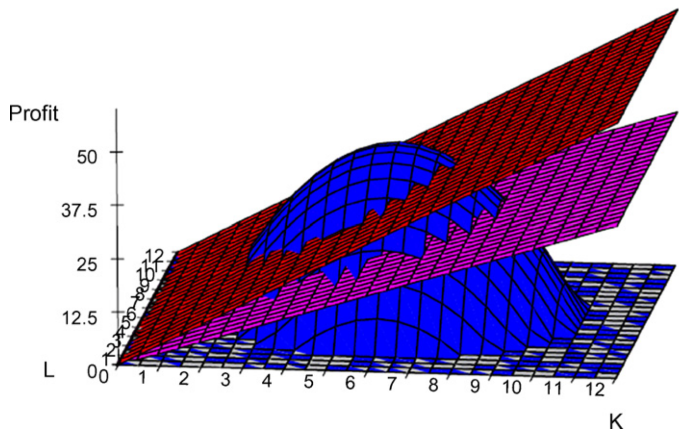

Figure 1: (K, L) Choices for Different Allowed Rates of Return

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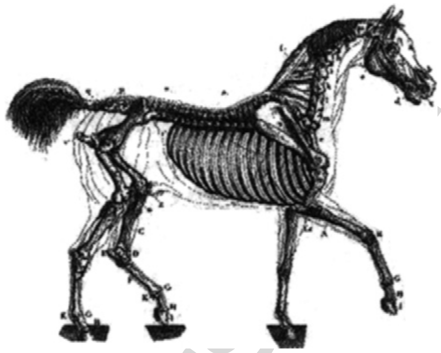
for a fixed period. In this case, an increase in allowed rate of return raises prices and decreases quantities sold, thereby decreasing the firm's incentive to invest in capital. Again, a rate-of-return ''adder'' has undesired effects on investment.[21]

C. Performance-based ratemaking

There is a large literature in economics devoted to the design of regulation that provides proper incentives for behavior by regulated firms. In general, this literature does not recommend either pure rate-of-return regulation or pure price cap regulation, but instead acknowledges that somewhat more sophisticated schemes are needed. Of particular interest for this article, Vogelsang (2001, 2004) presents promising performance-based regulation (PBR) mechanisms tailored to electric power transmission.[22] Vogelsang argues that PBR can improve short-run incentives for allocative efficiency, but he also recognizes that providing long-run investment incentives is difficult, due to the inability of current regulators to bind future regulators. As a result, well-intentioned price caps tend to be renegotiated when profits become excessively high or low. He concludes that with regard to transmission investment, rate-of-return regulation with prudence reviews may be as much as the U.S. is able to commit to in practice.

IV. Prudence Review and Adders

As mentioned briefly above, rate-of-return regulation includes an opportunity for the regulator to assess whether a utility's capital investments were prudently incurred. Some electric utility observers argue that ROR adders are appropriate as a way to



compensate firms for the risk of cost disallowances. The concern is that some prudent investments may nonetheless be judged imprudent, or not ''used and useful,'' by regulators, hence depriving a utility of a fair return on its investment. In a nod to these concerns, FERC (2005) suggests guaranteeing 100 percent recovery of abandoned plant that is canceled due to factors beyond the firm's control.

Interestingly, there is a literature in regulatory economics showing that the threat of prudence disallowances can indeed reduce utility investment. However, this literature also shows that prudence reviews are necessary parts of the regulatory compact, which help to redress the incentives for overinvestment that exist under traditional rate-of-return regulation.[23] Thus, the risk of prudence disallowances is only a problem for investment if regulators are politically motivated and opportunistic in their disallowance decisions.

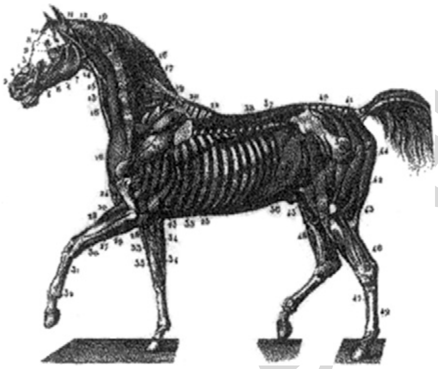
Lyon and Mayo (2005) present the most detailed empirical study to date on the effects of cost disallowances on investment.[24] They study the time period 1970–1991, when over $19 billion of investments were disallowed. They consider various possible hypotheses regarding the nature of the cost disallowances, and conclude there is little evidence of regulatory ''opportunism.'' Their methodology involves searching for the presence of ''reputational spillovers,'' where one utility reduces its investment behavior in response to the way the regulator treats another utility in the same jurisdiction. Such a response would be strong evidence that utilities viewed the regulator as opportunistic. However, the data provide little evidence of this. Firms that suffered disallowances cut back their investments, but other firms in the same states did not. This indicates that other firms interpreted the disallowance as something unlikely to happen to them, presumably because it was punishing bad behavior by one particular firm, rather than signaling a wholesale change of strategy by FERC.

Overall, Lyon and Mayo conclude that the regulatory ''contract'' performed surprisingly well during a very difficult time for the industry. However, they do find some evidence of opportunism with regard to utilities that were building a nuclear plant they also planned to operate. These owner-operators did reduce investment when they saw the regulator disallow cost recovery of other firms in the same state, although utilities with an ownership share in a nuclear plant, but who were not planning to operate the plant, did not change their investment behavior.

What is the risk of transmission disallowances compared to disallowances for nuclear plant owner-operators? To begin with, history suggests the risk is small: there have been no examples of transmission disallowances, so far as I can ascertain. This should not be surprising. Transmission investments are generally smaller in magnitude than the cost of a nuclear plant, and are hence less likely to arouse the ire of consumers facing rate shock. Furthermore, transmission does not carry with it the risk of a dangerous accident that could threaten the lives of customers, which also reduces the likelihood of consumer concern. As a result, disallowances on transmission appear unlikely to be major stumbling blocks to investment.

V. Conclusion

Improving incentives for transmission investment is a challenging task. Clever allocation of financial transmission rights may be able to prevent welfare-reducing transmission investments, but cannot be counted upon to induce all welfare-enhancing ones. As a result, most observers of the electric utility industry continue to see regulatory involvement in transmission as essential.



However, there is as yet no consensus on the appropriate means for regulating transmission.

FERC Order 679 has proposed a variety of incentives for transmission investment, including ''adders'' that increase the allowed rate of return on transmission investment. This article has argued that rate-of-return adders for transmission investment are a problematic incentive tool, and may very well end up reducing rather than increasing investment. This is true whether the firm faces traditional rate-of-return regulation or price cap regulation.

My analysis suggests regulatory attention would be better devoted to alternative means of enhancing transmission investment. In light of the substantial local and regional political barriers to transmission expansion, regulatory efforts to spur transmission investment are crucial, and the Energy Policy Act's creation of national interest transmission corridors is a welcome change. In addition, it would be helpful for RTOs to have authority to compel the construction of new transmission when market forces are unable to bring it forth. Finally, the industry would benefit from a greater consensus on the importance of vertical economies in electricity. If they are large, as studies cited by Brennan (2006) suggest, we may be better off moving back towards a world of regulated vertically integrated utilities. If they are modest, then we should move forward toward a world with greater separation between generation and transmission. Progress on any of these dimensions is likely to improve our transmission situation more than will rate-of-return adders for transmission.■

Endnotes:

1. The issue has received attention in several recent articles in *The Electricity Journal*, including Ed Gray, *Electric Transmission One Year after the Energy Bill*, ELEC. J., Aug./Sept. 2006, at 86–91, and Joe McGarvey, *Transmission Investment: A Primer*, ELEC. J., Oct. 2006, at 71–82.

2. Eric Hirst, *U.S. Transmission Capacity: Present Status and Future Prospects*, Edison Electric Institute, Aug. 2004.

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3. A recent survey by Edison Electric Institute shows that transmission investment has been increasing since 1998, though it still falls below levels expected to be needed for reliability and robust wholesale competition. See Edison Electric Institute, 2005, *EEI Survey of Planned Transmission Investment: Historical and Planned Capital Expenditures (1999–2008)*, Washington, DC.

4. PJM Interconnection, 2005 State of the Market Report, at 290, available at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20060411-som-web-4.pdf.

5. For a detailed discussion of vertical integration and its relation to transmission capacity, see Timothy J. Brennan, *Alleged Transmission Inadequacy: Is Restructuring the Cure or the Cause?*, ELEC. J., May 2006, at 42–51.

6. Federal Energy Regulatory Commission, ''Promoting Transmission Investment Through Pricing Reform,'' Docket No. RM06-4-000; Order No. 679, Issued July 20, 2006.

7. W. Hogan, *Contract Networks for Electric Power Transmission*, J. REG. ECON. (1992) 4, at 211–242.

8. P. Joskow and J. Tirole, *Transmission Rights and Market Power on Electric Power Networks*, RAND J. ECON. (2000) 31(3), at 450–487.

9. For a detailed analysis of these problems, see P. Joskow and J. Tirole, *Merchant Transmission Investment*, J. IND'L. ECON. (2005) 53, at 233–264.

10. Under this rule, the transmission investor is allowed to claim any set of transmission congestion contracts (TCCs) so long as the combination of new TCCs plus existing ones constitutes a feasible dispatch under the new system.

11. See note 1.

12. For a comprehensive treatment of these issues, see JEAN-JACQUES LAFFONT AND JEAN TIROLE, A THEORY OF INCENTIVES IN REGULATION AND PROCUREMENT (Cambridge, MA: MIT Press, 1993).

13. Harvey Averch and Leland Johnson, *Behavior of the Firm under Regulatory Constraint*, AMER. ECON. REV. (1962) 52, at 1052–1069.

14. However, empirical work has had a hard time confirming the presence of overcapitalization in regulated companies. For a good discussion of this empirical work, see P. Joskow and N. Rose, *The Effects of Economic Regulation*, in HANDBOOK OF INDUSTRIAL ORGANIZATION (Amsterdam: Elsevier, 1992).

15. Federal Energy Regulatory Commission, ''Promoting Transmission Investment through Pricing Reform,'' Docket No. RM06-4-000, Issued Nov. 18, 2005, at 24.

16. Gregg A. Jarrell, *The Demand for State Regulation of the Electric Utility Industry*, J. LAW & ECON. (1978) 21, at 269–295.

17. Thomas P. Lyon, 2007, ''Capture or Contract? The Early Years of Electric Utility Regulation,'' Working Paper, Univ. of Michigan.

18. Personal communication, July 28, 2004, with Steven Cadwallader, Chief of Utility Regulation, Connecticut Dept. of Public Utility Control.

19. Congestion revenue rights (CRRs) are typically held by the load rather than the utility.

20. Harvey Averch and Leland Johnson, *Behavior of the Firm under Regulatory Constraint*, AMER. ECON. REV. (1962) 52, at 1052–1069; Stanislaw H. Wellisz, *Regulation of Natural Gas Pipeline Companies: An Economic Analysis*, J. POLIT. ECON. (1963) 71, at 30–43; William J. Baumol and Alvin K. Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, BELL J. ECON. & MGMT. SCI. (1970) 1, at 162–190.

21. Transmission rate caps may also facilitate collusion in reducing transmission investment, as shown by Christiaan Hogendorn, *Collusive Long-Run Investments under Transmission Price Caps*, J. REG. ECON. (2003) 24, at 271–291.

22. Ingo Vogelsang, *Price Regulation for Independent Transmission Companies*, J. REG. ECON. (2001) 20, at 141–165; Ingo Vogelsang, ''Electricity Transmission Pricing and Performance-Based Regulation,'' mimeo, Boston University, 2005.

23. See Thomas P. Lyon, *Regulation with 20-20 Hindsight: Heads I Win, Tails You Lose?*, RAND J. ECON. (1991) 22, at 581–595, and Richard J. Gilbert and David M. Newbery, *The Dynamic Efficiency of Regulatory Constitutions*, RAND J. ECON. (1994) 25, 538–554.

24. Thomas P. Lyon and John W. Mayo, *Regulatory Opportunism and Investment Behavior: Evidence from the Electric Utility Industry*, RAND J. ECON. (2005) 36, at 628–644.

❖ MEETINGS OF INTEREST ❖

Conference	*Date*	*Place*	*Sponsor*	*Contact*
Transmission and Distribution Automation	July 19–20	San Antonio	ACIUS	http://www.acius.net/conference.php?mode=overview&cID=278
6th International Decommissioning Workshop	Oct. 23–25	Vienna	EPRI in cooperation with IAEA	http://guest.cvent.com/EVENTS/info/summary.aspx?e=baedbe60-103e-4217-a115-bb59a6854439
Energy Modeling and Forecasting	Nov. 6–9	New York	Timberlake Consultants	http://www.timberlake.co.uk/training/public/electricityusa.html