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Improving private incentives for electric grid investment

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Abstract

One of the most disputed issues of the electricity industry restructuring process has been the organization of the transmission sector of this industry. It has been widely held that this sector must remain tightly regulated due to the external costs and benefits that arise from the operation and construction of transmission resources. In this paper we discuss the traditional approaches to managing these network externalities and examine the potential for a system of tradeable transmission rights, such as transmission congestion contracts, to successfully manage these externalities in a lightly regulated environment. © 1997 Elsevier Science B.V.

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1. Introduction

Of the many challenges that need to be overcome in creating a viable, competitive electricity industry, those involving the transmission sector of this industry have proved to be the most disputed and difficult to resolve. The simultaneous, and sometimes apparently contradictory, initiatives undertaken by the California Public Utilities Commission (CPUC, 1996) and the Federal Energy Regulatory Commission (FERC, 1996) have only added to the confusion. Both initiatives recognize that traditional approaches to transmission pricing, planning,

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and investment are incompatible with an industry in which competing interests vie for the usage of this key strategic asset. However, both offer little more than broad policy goals and guidelines that will need to be accommodated.

Several approaches to organizing the transmission sector have been proposed and the details of some of the more complete of these proposals are beginning to emerge (see, for example, Wu and Varaiya, 1995, Chao and Peck, 1996). In California, the approach that is currently favored involves the locational pricing of various "zones" of the network combined with a form of financial transmission "property", [1] the transmission congestion contract (TCC). While the ownership of transmission assets will remain diversified, control over these assets will be placed in the hands of an independent system operator (ISO). While many of the principles of locational pricing and financial transmission rights, known as "contract networks", have been around for some time (Schweppe et al., 1988, Hogan, 1992), and their application to the California market has been discussed for more than two years (see Garber et al., 1994), a fully comprehensive description of the organization of a transmission market in which TCCs are traded and created has yet to be articulated.

In this paper, we outline the process for grid investment that is implied by a contract network approach applied to a competitive, deregulated environment. It is not clear how far towards this vision the actual restructuring process in California will go, but it is important to understand the implications of TCCs under the competitive paradigm. We will attempt to clarify the key differences between grid investment under the present industry structure and investment in a competitive environment. We describe the relative strengths and potential weaknesses of both approaches.

In the following section we discuss the organization of the transmission sector under a competitive contract network approach and contrast it with the current organization of transmission markets. Section 3 defines the transmission congestion contract and describes its use as a hedging instrument for a locational spot market. Section 4 outlines the process for allocating new transmission contracts using the concept of "feasible" sets of contracts. In Section 5 we summarize some of the theoretical results that have been established about TCCs, grid revenues, and investment incentives. In Section 6 we conclude with a discussion of the implications of a market for transmission and the role in which TCCs could play in such a market.

[1] TCCs, as we define them here and as others have before, are a form of property that entail both rights and obligations, since a given TCC can have a negative value. It is important to note this when making comparisons between TCCs and other forms of transmission "rights" that usually provide an option to not exercise that right. Harvey et al. (1996) discuss the concept of an "option" form of TCCs.

2. Transmission market organization

Two cornerstones of the present grid investment process that will be altered significantly by restructuring are the mechanisms for fixed (or "embedded") cost recovery and the incentives for coordination and cooperation between affected parties. This is not to say that these functions will not be provided in some other form. The important distinction to be made is whether these functions will be provided through the oversight of institutions such as the ISO and regional transmission groups, or in a more decentralized fashion through the use of market incentives and tradeable transmission rights such as TCCs.

Under this second, more lightly regulated organization of transmission markets, grid investments would be made by individual, or coalitions of, unregulated companies who would receive no explicit guarantee of recovery of their capital. These companies would make the investments simply because the benefits they receive from adding transmission capabilities would offset the investment cost. Ideally, such investments could be made anywhere on a regional network, so investors can focus on the most cost-efficient way to enhance network capabilities.

The role of regulatory institutions in this process would be minimized. The notorious externalities, both positive and negative, that are created by the nature of electric flows seem to necessitate some level of institutional involvement. However, there is hope that a workable system of transmission property such as TCCs can sufficiently internalize these externalities and limit the need for regulatory intervention.

The prospects for the success of such an approach hinge upon the ability of TCCs and the rules used to allocate them to deal with these externality problems. When judging the performance of TCCs in this regard, it should be noted that the existing regulatory approaches have also had to deal imperfectly with these problems. Traditionally, the principle of fixed cost recovery has been used to deal with the positive externalities—the "free-rider" problem of network investment. Regional reliability councils and other voluntary institutions have traditionally been the arena in which disputes over the negative externalities of network usage and construction have played out. It is useful therefore to consider the deregulated contract network approach in the context of these two current "fixes" to network externality problems.

2.1. Embedded cost recovery

Historically, transmission projects, like generation projects, were considered necessary applications of utility capital. That capital, including a "fair" rate of return, would be recovered through cost-based regulation. Oversight of the decision-making process was carried out through the imperfect controls of planning hearings and prudency reviews. Before an investment in the network could be made, investor-owned utilities needed to acquire from regulators a Certificate of

Public Convenience and Necessity (CPCN). Once this was accomplished, utilities were guaranteed recovery of their investment through the rate-base and other transmission related revenues.

The efficiency of this piecemeal approach to transmission planning became increasingly strained as the effects of transmission investments reached far beyond the boundaries of any individual utility or state. Cost-based regulation placed constraints on the set of options utilities could consider. Thus, for example, no California utility would be allowed to add capacity in Idaho, even if that was the most efficient way to increase flow capacity from the Pacific north-west into California. In addition, the difficult technical questions associated with evaluating transmission expansion options created severe information asymmetries between utilities and regulators (see Baldick and Kahn, 1992).

The notion that the fixed costs of investments must be "recovered" in some fashion is still deeply ingrained in the mind sets of utilities and regulators. It is one of the principles for transmission pricing that the FERC requires to be honored in filings of transmission tariffs. As such, the Western Power Exchange (WEPEX, 1996) proposal for the California electricity market will apparently include an access charge designed to ensure that "the revenue requirement of each transmitting utility will be recovered". It is expected that the size of the access charge will dwarf any locational charges made for congestion by the ISO. Consequently, the equity and efficiency effects of these access charges is in dispute. The use of access charges to guarantee embedded cost recovery constitutes a significant departure from the original competitive vision for decentralized transmission ownership.

The original vision of a transmission market organized around TCCs did not call for explicit charges related to fixed cost recovery. Investment costs would instead be justified by the benefits they created. Garber et al. (1994) use the example of a generation company located at the end of a potentially congested radial line. When there is congestion, this generator receives a relatively low locational price for his power since it is causing congestion in the network. The generator can therefore invest in increased transmission capacity to bring its locational price up to the unconstrained levels. The project is financed based upon the expected profits from the increased revenues from energy sales. The role of TCCs in this process is to guarantee that investors do not lose these benefits in the event of future congestion of the network. Congestion might agin lower the locational price, but, as we will demonstrate below, ownership of a TCC would offset this price change.

It is important to note, however, that TCCs do not allow their owner to capture the benefits that a given transmission investment may create for other parties. They only ensure that their owner does not lose the benefits he already has. Thus, to the extent that access charges and cost recovery are to have a justification, it is in capturing the benefits of potential free-riders to an investment. It is unclear how severe this free-rider effect would be. The economic concern is that the inability to capture benefits will lead to inefficiently low levels of investment. Garber et al. speculate that this problem will be mitigated by coalitions that would form to make joint investments. It is true that such coalitions have been formed in the past when there seemed to be scarcely more incentive to cooperate. [2] It is far from certain, however, that coalitions will be an adequate remedy for the free-rider problem. The question is an important topic for future research.

This discussion also illustrates an important distinction between a TCC and a more conventional form of transmission property, such as those in use today. When a transmission owner has the right to charge "tolls", such as wheeling charges, it can capture the external benefits to other users. The problem with such approaches lies in the fact that electricity flows are determined by physics, not economics. Thus, a line which effectively reduces the capabilities of the network could at the same time earn large wheeling revenues. It is equivalent to being able to reduce the number of lanes in a toll road that everyone has to drive on, and then raising the toll in response to the congestion. This is the kind of negative externality, inherent in electricity networks, that has forced utilities into forms of ad-hoc cooperation in the planning and dispatch of their transmission networks.

2.2. Cooperative planning and coordination

The interconnected nature of electricity networks has necessitated a great deal of coordination and negotiation between neighboring utilities and regulators. Utilities organized nine regional reliability councils following the 1965 black-outs in the North-East. These organizations, such as the Western States Coordinating Council (WSCC), were formed to develop consistent reliability standards and protocols and examine the regional implications of proposed new transmission projects (Kahn et al., 1995). The WSCC also has developed jointly agreed upon rules for rating the "capacities" of transmission paths, thereby setting operational limits on the use of these paths (Walton, 1993).

Public utilities commissions, in judging whether an investment was appropriate or not, were concerned primarily with the rate-payers under their jurisdiction. They were therefore less inclined to consider the negative impacts of an investment on other states. In some cases, revenues from wheeling fees were also considered as "benefits" of a transmission investment, even though such fees merely constituted transfers, without much economic basis, from one utility to another (see Baldick and Kahn, 1992). Thus the participation of local regulators in the transmission planning process did not do much to dampen the incentives utilities have for planning facilities to optimize their own benefits at the potential expense of others.

[2] For example, the Mead–Adelanto and Mead–Phoenix projects between California and Arizona were joint projects in which 13 California municipal utilities, the Western Area Power Administration, Salt River Project, and Arizona Public Service Company all participated (Lee et al., 1995).

Instead, the reason that this level of cooperation has been possible is that utilities recognize that the operational and investment decisions of an individual utility can have major impacts on other utilities in its region. The economic framework that has evolved to govern current inter-utility transactions, the contract-path framework, did not even come close to adequately addressing those impacts. Utilities have had no choice but to develop a set of governing rules and protocols in order to fill this void between the economic fiction and the physical reality of wholesale electricity transactions. Thus, in the absence of a workable economic framework for internalizing network externalities, accommodations have instead been reached through a process of negotiation, threat, and the occasional legal dispute with the FERC playing the role of final arbiter.

It is important to note that the participants in these planning and cost allocation processes were almost exclusively regulated utilities and regulators. This has allowed a degree of openness and cooperation that will most likely be muted by competitive pressures. There has been concern that when many of these parties are driven by an undiluted profit motive, this approach of voluntary coordination of transmission investment will break down. This has long been a complaint of independent power producers who have been largely excluded from the transmission planning process. Indeed, the potential for the breakdown of cooperative processes under competition is highlighted in Appendix C of the FERC (1996) policy decision, where an extensive list of anti-competitive transmission policies that have been brought to the FERC in the last decade can be found.

If a planning process that relies upon voluntary cooperation between competitors cannot be sustained, a new paradigm must be developed. Such a restructuring could take one of two approaches. First, transmission assets could be combined into a single entity that would have to be closely regulated due to its substantial market power. This approach eliminates the potential for conflict by taking competing utilities out of the transmission business altogether. The second approach, the one we have been discussing, is to explicitly recognize the underlying conflicts between competing utilities and develop new forms of network property that deal with these conflicts through a market-oriented process. The following sections define one such form of network property, the TCC, and describe the process for allocating new TCCs upon the event of an expansion to the network.

3. Nodal spot prices and hedging contracts

This section reviews nodal spot prices upon which TCCs are based, and discusses the role played by both contracts for differences (CFDs) and TCCs in hedging price risks. In some ways the discussion of the hedging roles played by these contracts is tangential because the paper is only directly concerned with the completely distinct role that TCCs could play in a solution to the transmission investment problem. However, because TCCs were invented to serve as a locational pricing hedge, and because this is their most widely discussed role, a short discussion of this role is desirable.

3.1. Definition of optimal nodal spot prices

We begin with a discussion of nodal spot pricing. *Optimal* nodal pricing is not necessary for the hedging use of either CFDs or TCCs, but it is assumed for the TCC results that concern investment incentives. [3] These optimal prices might be arrived at through several different market mechanisms including the standard ISO auction, and ''multilateral'' trading approaches, [4] but our focus here is on the *definition* of optimal prices rather than the market mechanism used to achieve them.

Optimal nodal spot pricing, which we will simply call nodal pricing, is nothing more nor less than standard marginal cost pricing applied to electric power being distributed through a power grid. At any given time the price of power at a particular node is the marginal cost to the system as whole of delivering an additional kW using the *optimal* dispatch. Computing this can be quite difficult, but that issue is beyond the scope of this paper. [5]

Optimality requires feasibility. This will be discussed in more detail in the next section, but for now we note only that the feasibility constraint on dispatches takes into account all contingency conditions, and all operating rules. These include rules concerning system behavior during outages of various types, stability limits, voltage limits, and many other complexities. We assume that these can be specified in such a way that all dispatches can be precisely classified as either feasible or infeasible.

Two well-known properties of optimal prices will be useful in our analysis of TCCs. First, the optimal dispatch they induce maximizes (subject to all feasibility constraints) total customer benefit minus total generation cost, which we refer to as social welfare and denote by W. Second, the difference in nodal prices, $p_j - p_i$,

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[3] Recent results by Backerman et al. (1996) and Oren (1997) indicate that generators may try to influence nodal prices in an attempt to capture congestion rents that would otherwise flow to the market maker (and then to the holders of TCCs). This and other forms of market distortion obviously have the potential to affect the efficiency of the spot market. Such distortions should not affect the hedging aspects of pool-based financial instruments, and it is unclear what affect such behavior would have on the investment incentives provided by TCCs. This is obviously an important topic for future study.

[4] Wu and Varaiya (1995), Chao and Peck (1996), and McGuire (1996) have proposed methods for reaching optimal dispatches without a market-making power exchange. Though in the Wu–Varaiya system there is no obvious way to publicly discover these prices because they are only specified in private multilateral contracts. All market mechanisms for reaching optimal spot prices are susceptible to market power, and all have been subject to claims that they will fail in real-world situations.

[5] Originally articulated by Schweppe et al. (1988), this approach has been revived more recently by a number of authors.

Table 1
Using long-term contracts to eliminate nominal price risk

	Contract or market	Payment	
		Supplier at node i	Demander at node j
1	Spot market	$p_i \cdot q$	$-p_j \cdot q$
2	CFD for q at P_c	$(P_c - p_j) \cdot q$	$-(P_c - p_j) \cdot q$
3	TCC for q from i to j	$(p_j - p_i) \cdot q$	
4	Total	$P_c \cdot q$	$-P_c \cdot q$

between two nodes exactly values the social loss caused by transmitting an additional kW from node i to node j. This includes all thermal losses, and all losses from out-of-merit dispatch due to congestion. Note that these locational spot prices generally result in the ISO collecting more revenue from loads than it pays to generators. This merchandising surplus will suffice to pay the owners of TCCs, provided these have been allocated according to the feasibility rule described below.

3.2. The use of CFDs and TCCs

Nodal spot prices, by their nature, vary over both time and location. Consequently market participants may desire to hedge any long-term participation in this market. CFDs and TCCs were both designed to play this role. Although this paper is primarily concerned with TCCs, we will explain briefly how both together can be used to completely hedge a long-term bilateral contract. As will be seen, CFDs hedge the temporal variation in spot prices, and TCCs hedge the locational variation.

In the following discussion, we will assume that a supplier at node i wants to sell q MW to a buyer at node j for a fixed price of P_c over some time period extending into the unpredictable future. We also assume that each trader must trade with the ISO at the nodal price of his local node. Thus the supplier will receive $p_i \cdot q$, and the demander will pay $p_j \cdot q$. This is the spot-market transaction and is recorded in the first line of Table 1.

Since p_i and p_j will generally differ from P_c, the contract price, a hedge is need to synthesize a fixed-price contract. If the two nodal spot prices are equal but changing, the supplier will lose $P_c - p_i$ and the demander will gain an equal amount. Thus each can hedge the other's risk, and there is no cost to this risk reduction. This is accomplished with a CFD that specifies that the demander will pay the supplier $(P_c - p_i) \cdot q$, as is shown in line 2 of Table 1. [6]

[6] Of course, this payment is as likely to be negative as positive, in which case the supplier is actually paying the demander. A reverse formulation would yield the same results so long as the two nodal prices were equal. However, different formulations will result in different sharings of the locational price uncertainty.

Because of congestion and losses, nodal prices will generally differ. Unfortunately, locational differences do not affect the two traders in equal but opposite ways. Consequently, this risk cannot be costlessly eliminated. The specification of our CFD left the supplier with all of the locational risk and consequently with the need for a TCC. A TCC is a financial contract between the ISO and a private owner of the TCC which pays $(p_j - p_i) \cdot q$ to the owner, for some specific q, irrespective of the amount of power transmitted by the owner. For this example the necessary TCC is the one with $Q = q$. This TCC is costly both because its expected value is non-zero and because it must insure the supplier against risky locational price differences. [7] Line 3 of Table 1 shows a TCC owned by the supplier from node i to node j for q MW. This TCC could be purchased from a private party, of from the ISO, or could have been awarded to the supplier at the time the supplier upgraded the transmission path from i to j. Note that, as shown in line 4 of Table 1, with the acquisition of this TCC by the supplier we have achieved a fully hedged, fixed-price contract between the two traders. Of course, this was achieved at the cost of acquiring the TCC. This cost simply represents the normal ''transportation'' costs that are always incurred when conducting business at a distance.

3.3. Interpreting TCCs as firm transmission rights

Many who hear the description of a TCC as a *financial* right feel that a TCC does not at all serve the same purpose as a firm physical transmission right. In fact, within the context of a nodal spot market, and with one small addition to the auction rules, this same TCC could also be described in physical terms as follows. [8]

1. TCC t gives the owner the firm right to transmit q MW from i to j, with no charge for congestion or loss.
2. A refund will be issued by the ISO for the unused portion ($\mathrm{d}q$) of this right, in the amount of $(p_j - p_i) \cdot \mathrm{d}q$.

This interpretation would appear to satisfy the requirements of those wanting physical rights to transmission in spite of the fact that it is simply a reinterpretation of the financial TCC.

Although, as with any firm transmission right, there are contingencies that could prevent physical delivery, the probability of such an occurrence is extremely small. Unlike with other firm rights, the TCC owner would automatically receive ample compensation in such a case.

[7] It would be possible to purchase only the insurance component of a TCC and still produce the desired fixed-price contract, but we will not discuss this TCC variant.

[8] This interpretation was prompted by a suggestion from Bill Hogan. For a related discussion see Harvey et al. (1996).

To exercise a TCC as a right to firm transmission, the TCC owner merely needs to bid zero at the receiving node and the maximum allowed bid at the transmitting node. [9] The addition to the auction rules mentioned above is that the ISO will give TCC owners priority over non-TCC when bids are equal. While a maximum bid assures dispatch, the TCC insures that any costs due to a price difference between the two nodes will be fully refunded, so the net transmission cost is assured to be zero. The financial definition of a TCC guarantees the refund specified in the second point. [10]

4. The process for investment under a contract network

The restructuring process in California has stimulated a great deal of debate over the incentive properties of TCCs. A significant amount of the disagreements can be attributed to confusion about the allocation of those contracts. Wu et al. (1996) have cited ambiguities in Hogan's statements on the subject, and their subsequent analysis of the investment problem (Oren et al., 1995) does not consider any particular rule allocating contracts to those who invest in the network. The rule for allocating contracts to modifiers of the network is of crucial importance because much of the incentive to expand or otherwise modify the network is determined by this allocation of contracts, the other incentive being the consequent change in the modifier's nodal spot prices.

TCCs and other forms of transmission rights were developed in order to eliminate the risk that network congestion might affect the ability of generators and traders to reach their markets at a reasonable cost of transmission. A "right" to either the physical flow capacity or the nodal price difference provides insurance against the consequences of this congestion. Most of the discussions about transmission access have therefore been concerned with this hedging role. Because TCCs are a form of network property, the rules for allocating them will also directly influence the incentives for investment and maintenance of grid resources. This section specifies how the capacity of the network can be used to define a feasible set of TCCs and how additional TCCs can be assigned as a result of network investment.

[9] Typically, nodal pricing auctions include a maximum bid price, e.g. Norway, and we assume that here.

[10] This refund may be negative, but this will happen only when a TCC covers a helpful flow, such as a counterflow, and the TCC owner fails to supply this flow. Such flows are rewarded via nodal spot price differences by the ISO. A TCC on such a directed path must pay a negative amount in order to cancel the positive payment for transmission.

4.1. Defining network capacity in a contract network

We now turn our attention to the concept of network capacity. Flow constraints on shorter lines are set by thermal limits, and on longer lines by stability limits. But capacity constraints on a network are set by a combination of flow constraints on lines and a contingency criterion, such as the $N-1$ contingency criterion which requires that no flow limits be exceeded in the event of the loss of any single component of the transmission grid. Although our analysis can incorporate contingency criteria, it is possible to illustrate all important properties of TCC allocation using example grids for which we specify only line flow limits. In spite of this simplification, it is not obvious how line limits should translate into limits on the allocation of TCCs, which are not defined on lines, but instead are defined on arbitrary injection pairs.

Since TCCs are financial contracts that have no influence on the specific flows in a network, unlike flow-based physical capacity contracts there is no physical capacity limit on the number of TCCs. There are, however, both financial and incentive considerations that favor limiting the set of outstanding TCCs to reflect the underlying physical capabilities of the network. This is accomplished by applying the notion of feasible dispatches to a set of TCCs.

If one assumes that TCCs are to be used primarily as an instrument for hedging locational spot prices, then each TCC implies an underlying physical power transaction—the transaction for which that TCC constitutes the perfect hedge. For example, the TCC $t=(-1,1,0,\ldots,0)$ would provide a price hedge for a party wishing to inject 1 MW into node 1 and withdraw it from node 2. If each TCC implies injections and withdrawals from the network, a complete set of TCCs implies a complete hypothetical dispatch of that network. If that hypothetical dispatch satisfies whatever network constraints that would be applied to an actual dispatch, we consider the corresponding set of TCCs to be a feasible set.

We will demonstrate this concept using a simple three-line, three-node network and applying the basic DC-load flow model. We assume that there are no losses in this network and that the only significant constraints are the thermal limits on each line. Fig. 1 illustrates this network and the respective thermal flow limits of each line. If the admittances on each line are all equal, then the network flows and

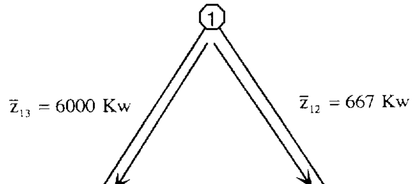

Fig. 1. Three-node, three-line network with flow limits.

limits can be written as a function of injections into nodes 1 and 2, y_1 and y_2 through the following set of equations:

$$-\bar{z}_{13} \leq \tfrac{2}{3}y_1 + \tfrac{1}{3}y_2 \leq \bar{z}_{13}$$
$$-\bar{z}_{23} \leq \tfrac{1}{3}y_1 + \tfrac{2}{3}y_2 \leq \bar{z}_{23}$$
$$-\bar{z}_{12} \leq \tfrac{1}{3}y_1 - \tfrac{1}{3}y_2 \leq \bar{z}_{12}$$

where the dual inequalities of each equation represent the thermal limits for flows in either direction on each line that must be met. Each of these constraints can be illustrated as a line separating the space of simultaneous injections into feasible and infeasible sets. The intersection of each of these feasible sets forms the set of injections that satisfy all thermal limits (see Fig. 2). Thus any set of TCCs that, when added together, produce a vector that lies in this feasible set would be considered a feasible set of contracts.

The concept of limiting the number and type of TCCs to a set that implies a feasible dispatch was proposed by Hogan (1992) as a way to ensure the solvency of the ISO. He showed that if transmission contracts are restricted to be in the feasible set, the payments earned by those contracts cannot exceed the surplus that is generated from operating a locational spot market. This result is discussed in more detail in Section 5. The restriction of TCCs to the feasible set has been criticized, in the context of revenue adequacy, as "unnecessary and meaningless" (see Oren et al., 1995). But regardless of the importance of the feasibility restriction on ISO revenues, the notion of feasibility also plays a crucial role in the allocation of new TCCs to investors in the network.

4.2. Allocating new transmission contracts in a contract network

The allocation of the transmission property or "rights" that result from network expansions has long been a difficult and somewhat contentious problem.

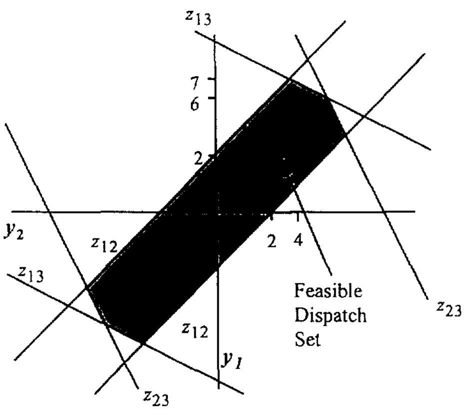

Fig. 2. Feasible set of simultaneous network injections.

This is due to the externalities created by loop flow and the effect that network expansions can have upon loop flow. It is important to note that systems for allocating transmission rights and access should be able to govern more than just the additions of new lines. Upgrades in both line capacities and other physical characteristics, the "degrading" of line capabilities, and the installation of FACTs technologies can all have important consequences for the abilities of agents to use the grid.

If all these activities can affect the feasibility of injections into the grid, they can also affect the feasibility of a given set of transmission contracts. A market where TCCs are limited by the concept of feasible dispatches must therefore also have a structure for allocating (or eliminating) TCCs when the set of feasible injections is changed.

The simplest rule for allocating new TCCs upon an alteration to the grid would be to assign a set of TCCs exactly equal to the change in the flow capacity of the individual line(s) effected by that alteration. For example, if a 1000 MW line connecting nodes 1 and 2 is upgraded to 2000 MW, the investor would receive a TCC matching the implied flow of 1000 MW either from 1 to 2 or vice versa, $t = (-1000, 1000, 0, \ldots, 0)$. This appears to be the intended procedure to be adopted by the newly formed WEPEX, judging from that organization's filing with the FERC.

> The ISO will also define TCCs and administer TCCs which will be allocated to the parties that are paying the costs of new inter-zonal transmission facilities to enable them to obtain the benefits of their investment. The new facilities will become a part of the ISO grid. However, the TCCs will provide the market participants investing in the facilities the financial equivalent of firm rights. The holders of these TCCs may use up to the *amount of the incremental inter-zonal capacity* associated with the new facilities, without paying the ISO the usage charge *for the inter-zonal interface on which the new facilities are located.* (WEPEX, 1996, emphasis added)

Such an allocation rule makes TCCs in effect equivalent to what Oren et al. (1995) termed "link-based rights". Problems with this approach become readily apparent when one considers that a given TCC may actually have a negative value. In such a case, the owner of a TCC associated with the flow over a given line would have the incentive to destroy (or, more subtly, not maintain) that line in order to give up that negative valued TCC. Such problems were at the root of the criticisms Oren et al. leveled against the contract network approach.

However, one can see that this problematic allocation rule is fundamentally inconsistent with the injection-based definition of a TCC. The above approach allocates the financial benefits of additional injections, but bases that allocation upon a change in the capacity of flows on a given line. This is plausible in a radial network, where there is no meaningful difference between flows and injections. In a meshed network assigning injection-based rights based upon changes in a line's flow capacity makes no sense. It is therefore not surprising that incentive problems result from such an approach.

The alternative is to examine the change in the feasible set of injections that result from a grid alteration. Unfortunately, this network approach is more complicated than a line-based allocation rule. The method we have examined places most of the calculation burden upon the investors. The approach is to award an agent that has made an investment in the grid any set of TCCs that it wants, provided that the new set of TCCs, when combined with the previously allocated set, meets the feasibility conditions of the new network configuration.

Feasibility rule: The investor selects a vector of contracts t_{new} with the restriction that $t_{\text{new}} + t_{\text{old}}$ satisfies all system constraints.

The advantage of this method is that it captures the external effect of a change to a given line upon the capabilities of all lines in the network. Often the net effect is mixed. The addition of a line to a meshed network can make new dispatches feasible, while making some old dispatches infeasible. To judge the ''benefits'' of such a new line, therefore, one must consider how the network is expected to be used. If the newly feasible dispatches allow loads to be served at lower costs, then the loss of other, sub-optimal ones is irrelevant. If, however, a new line allows increased injections of expensive power and less power from cheaper suppliers, this network ''expansion'' is clearly inefficient. Unfortunately, if an independent body such as a regulatory agency was to assess these factors, it would require information about the costs and benefits of existing users of the network as well as their plans for added capacity and consumption in the future. This is clearly the private information of grid users, some of whom would have strategic reasons for distorting it.

Consider the following example, for which we again draw upon the same three-node, three-line network featuring lines of equal admittances. Assume now that nodes 1 and 2 are supply nodes and that all demand is located at node 3. Initially the network consists of two radial lines, each connecting a supply node with the demand node (Fig. 3). Now consider the effect of adding a third, smaller capacity line which connects the two supply nodes. As shown in Fig. 4, this new

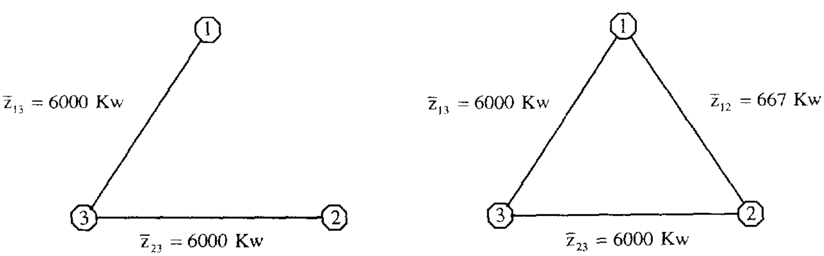

Fig. 3. Example network ''expansion''.

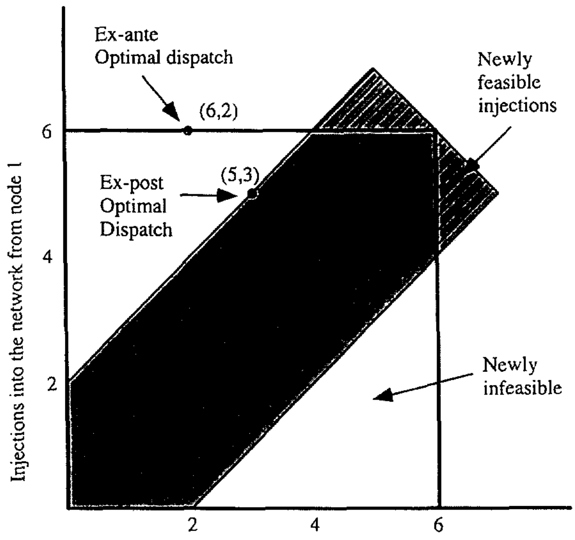

Fig. 4. Effects of a new line on feasible injections.

line eliminates from feasibility dispatches that are "unbalanced", i.e. those that draw much more power from one supply node than another. At the same time, the ability to ship additional power to node 3 through more "balanced" dispatches is somewhat enhanced.

Fig. 4 also illustrates the choice of TCCs available to the investor who built the line connecting nodes 1 and 2. Assume that before this line was built, the allocation of TCCs matched the actual dispatch of the system, $t_{\text{old}} = (-6, -2, 8)$. The investor therefore must select amongst the TCCs that will move the aggregate from this point into the newly defined feasible region. Note that the investor does not have the option of taking zero TCCs as t_{old} no longer represents a feasible dispatch of this new network. In fact, as we will discuss in the following section, the most profitable set of TCCs this investor can select is the set that moves the aggregate from ex-ante optimal dispatch to ex-post optimal dispatch. In this case, the investor would maximize its TCC revenue by selecting $t_{\text{new}} = (1, -1, 0)$.

This example illustrates how the feasible allocation rule can force investors to take TCCs when their investments eliminate existing dispatches from feasibility. Such investments can be thought of as "restricting" the capacity of the network. These kind of investments also typify the negative externality problems that exist in transmission planning. The value of these TCCs remains to be determined. This is dealt with in the following section, in which we discuss the known investment incentive properties of TCCs.

5. TCCs and network externalities

During the process of restructuring and deregulation of the electric power industry in California, it has been repeatedly stated that the generation sector of this industry should no longer be considered to be a natural monopoly. The CPUC has also stated that it believes that transmission and distribution remain natural monopoly services, and it has generally been believed that significant market failures plague the transmission sector of this industry. These market failures were believed to obviate the possibility that market-based incentives in the transmission sector would be workable. As we have already stated, the three principle market failures that arise in electricity transmission are the market power of an entity that owns the only transmission capabilities in a given region, the difficulty in capturing the external benefits of transmission investments, and the negative external effects of some transmission investments on the effective transmission ''capacity'' of others.

Under the contract network framework being devised for California, the market power concerns are dealt with by placing the control of all transmission assets in the hands of the ISO. The remaining barriers to market-based transmission investment are therefore the positive and negative externalities that are present in this market. Several insights into the ability of TCCs to deal with these externalities have emerged. We summarize these below.

In order to discuss these results, we need to introduce network notation and generalize our definition of TCCs. This generalization seems necessary when working with a lossy network, and is extremely useful when analyzing and describing the investment incentive properties of TCCs.

First, we specify the network to have N nodes (also called buses) that are indexed from 1 to N. A dispatch of this network consists of a vector of injections, $y=(y_1,\dots,y_N)$. A withdrawal of power by a load is represented simply as a negative injection. A set of nodal prices is also represented as a vector, $p=(p_1,\dots,p_N)$. Finally, we more formally define a TCC as a contract that pays $t\cdot p$ (or $\Sigma t_i p_i$) for any contract vector, t. As a convenient shorthand, we will often simply refer to the vector t as a TCC. With this definition we can define the total allocated set of TCCs to be simply the vector sum of all individual TCCs. Although in the examples above the TCC vector had two non-zero elements of equal size and opposite sign, there is no need to restrict TCCs to be of this form.

To describe the effects of transmission investment on the users of the grid, we define the net benefit of these agents to be the sum of their contract revenues, their spot-market revenues, and their generation costs: $NB(p,T)=\Sigma_I[p_i t_i + p_i y_i - C_i(y_i(p))]$ for the set of nodes $I=(1,\dots,N)$. In this definition, the spot-market costs and consumption benefits of an agent that is consuming power $(y_i<0)$ rather than supplying it are treated as *negative* spot revenues and generation costs, respectively. To measure the social welfare effect of a transmission investment, we ignore transfer payments and therefore define the change in social welfare as the change in net generation costs: $\Delta W=\Sigma_i C_i(y_i(p_{\text{new}}))-\Sigma_I C_i(y_i(p_{\text{old}}))$.

Result 1 (Bushnell and Stoft, 1996). If TCCs match dispatch in aggregate, $-T = y$, the net benefit of the users of the network cannot decrease with a change in prices.

This can be easily seen by the definition of net benefit, when $-T = y$, $NB(p,T) = \Sigma_i C_i(y_i(p))$. Since the production and consumption levels, y, are self-selected by the agents using the grid, they will only change their production levels if they can increase their benefits (or reduce their costs) from doing so. Therefore, if the allocation of TCCs in a network matches the actual dispatch on that network, the aggregate net benefits of the users of that network cannot be lowered by a change in prices, including one that is caused by a change to the network. In Bushnell and Stoft (1996), it was also shown that if user's costs (benefits) were strictly convex (concave), the net benefits of these users must increase.

Result 2 (Hogan, 1992, Wu et al., 1996). If TCCs are required to be feasible then the maximum value of those TCCs will equal the surplus generated by operating the nodal spot market: $-\Sigma_i p_i y_i \geq \Sigma_i p_i t_i$. Consequently, $NB(p,T) \leq W(y(p))$.

Result 2, concerning net benefit, falls directly out of the definitions of net benefit and social welfare. This is the "revenue adequacy" result first shown by Hogan (1992) and revisited by Wu et al. (1996). It shows that if TCCs are restricted by feasibility, the market maker will never have to pay out more in TCCs than it takes in from operating the market. An interesting side-note to this result is that in California, the ISO and market-making functions will be split into two entities. Apparently the market maker, WEPEX, will collect the surplus but the ISO will be responsible for TCC payments. The ISO will therefore have to collect the merchandising surplus from WEPEX through some form of transmission charge.

5.1. Externalities and negative investments

We now discuss two results that deal directly with the impact of the feasibility rule on the externalities of network investments.

Result 3. If TCCs initially match dispatch and T_{new} is allocated under the feasibility rule, then the value of new contracts will be no greater than the change in social welfare, $p_{\text{new}} \cdot T_{\text{new}} \leq \Delta W$.

This result follows from Results 1 and 2. Result 2, along with the feasibility rule tells us that

$$W(y(p_{\text{new}})) \geq NB(p_{\text{new}} T_{\text{old}} + T_{\text{new}}) = NB(p_{\text{new}}, T_{\text{old}}) + p_{\text{new}} \cdot T_{\text{new}}.$$

Since contracts match dispatch before the expansion, $NB(p_{\text{old}},T_{\text{old}}) = W(y(p_{\text{old}}))$. Therefore

$$W(y(p_{\text{new}})) - W(y(p_{\text{old}})) \geq NB(p_{\text{new}},T_{\text{old}}) - NB(p_{\text{old}},T_{\text{old}}) + p_{\text{new}} \cdot T_{\text{new}}.$$

From Result 1, we know that $NB(p_{\text{new}},T_{\text{old}}) \geq NB(p_{\text{old}},T_{\text{old}})$. Therefore, we have that

$$W(y(p_{\text{new}})) - W(y(p_{\text{old}})) \geq p_{\text{new}} \cdot T_{\text{new}}.$$

Result 3 is a generalization of Theorem 2 in Bushnell and Stoft (1996), which dealt only with expansions that reduced social welfare. This result illustrates how TCCs deal both with the negative and positive externality problems of grid investment. First, if social welfare is reduced by a given transmission investment, the value of the TCCs the investor will be required to take will be negative. Thus, to revisit an earlier analogy, there can be no profit from reducing the capacity of a toll road that everyone must drive on.

Second, it is quite possible that the value of the new contracts will not reflect the full increase to social welfare resulting from a given positive investment. This is consistent with the notion that transmission lines would be built for the benefits of their use, not for the TCC revenue that they create. However, since the benefits of many agents might increase as a result of a beneficial expansion, the positive externality or free-rider problem is not eliminated by the presence of TCCs. Indeed, if users' costs are strictly convex, the stronger form of Result 1 applies and the weak inequality in Result 3 becomes a strict one. That is to say, the value of new contracts will be strictly less than the change in social welfare. Unless contracts are allocated such that the investor, or coalition of investors, captures all of this increase in social welfare, there will be free-riders. We discuss this issue in more detail below.

It is important to note that the above results are concerned with the *aggregate* benefits and welfare of the agents in this market. They show that TCCs, on their own, cannot generate profits from detrimental investments. However, individual agents may still profit from damaging investments if their own commercial interests on the network improve to a degree that more than offsets the negative value of the new TCCs. For example, consider once again the three-node network and the line addition of Section 3, where there is an inelastic demand of 8 MW at node 3. Assume that the TCCs allocated before the network expansion matched the dispatch and in addition were all owned by the generator at node 2. Fig. 5 and Table 2 summarize the generation cost, revenues, and profits at each node and from the TCCs both before and after the expansion. [11]

[11] The examples in this section assume that agents are not exercising market power when setting locational prices. While we consider the problems of investment and market power to be somewhat separable, preliminary results by Oren (1997) indicates that, under some circumstances, the ability to influence nodal prices may distort the value of TCCs.

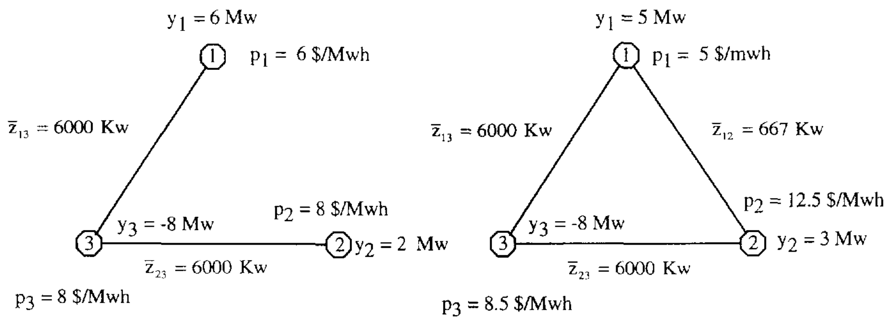

Fig. 5. The costs and benefits from adding a new line.

Table 2 shows exactly where the profits and losses from this particular network expansion accrue. If, as we have assumed above, the generator at node 2 owns all the TCCs, his net profit from the expansion is the sum of the last row of the "node 2" and "TCCs" columns, or \$4.00. Note that this expansion was not efficient; total generation costs increased from \$26.00 to \$30.50. As Result 3 tells us, the net value of the new TCCs, the last row in the "TCCs" column, is negative with a value of −\$6.00. However, generator 2's increased generation profits more than offset the negative value of the new transmission contracts. Since generator 2 profited from this expansion, the difference was made up in losses by generator 1 and the higher price paid by the customers at node 3.

Why would generator 2 own all the TCCs, if they are primarily hedging instruments? Consider instead that the TCC at each node is owned by the agents at each node. This distribution of TCCs and changes in TCC revenues are shown in Table 3. In this case, it becomes clear that if the TCCs are used by each agent as a perfect hedge for their own supply or demand, the full negative impact of the detrimental expansion is felt by the investor who undertook it, generator 2. This illustrates a fourth result about the incentive properties of TCCs.

Table 2
Benefits and revenues of a network expansion

Revenue source	Generation and consumption			TCCs
	Node 1	Node 2	Node 3	$t=(-6,-2,8)$
Generation cost	$0.5y^2$ \$/MWh	$2y^2$ \$/MWh		
Cost before expansion	\$18.00	\$8.00		
Revenue before expansion	\$36.00	\$16.00	−\$64.00	\$12.00
Change in quantity	−1 MW	1 MW	0	(1, −1,0)
Costs after expansion	\$12.50	\$18.00		
Revenues after expansion	\$25.00	\$36.00	−\$68.00	\$6.00
Change in profits	−\$5.50	\$10.00	−\$4.00	−\$6.00

Table 3
Benefits when contracts match dispatch

Agent	Node 1	Node 2	Node 3
Original TCCs	$t=(-6,0,0)$	$t=(0,-2,0)$	$t=(0,0,8)$
Newly awarded TCCs		$t=(1,-1,0)$	
Change in TCC revenue	\$6.00	−\$15.00	\$4.00
Change in net benefit (includes generation profits)	\$0.50	−\$5.00	\$0.00

Result 4 (Bushnell and Stoft, 1996). If TCCs match dispatch individually, then the allocation of TCCs under the feasibility rule ensures that no one can benefit from making a network investment that reduces social welfare.

Result 4 shows the condition under which the negative externalities of transmission investment are completely eliminated. This condition is that everyone has hedged their spot positions perfectly. Since none of these agents can be harmed by a negative investment, and social welfare does decrease, the difference must be made up out of the TCCs and spot benefits of the agent making the investment. This matching can be achieved on an individual level either through TCCs or CFDs. The revenue effects of CFDs do not enter into the aggregate measures of net benefit or social welfare as they constitute payments from one agent to another and therefore cancel each other out in aggregate.

We have seen that TCCs partly, but only partly, eliminate the potential externality problems of transmission markets. The implications of these findings for the evolution of transmission markets is discussed below.

5.2. Externalites and under-investment

Result 3 showed that TCCs are not likely to capture the full benefits of a beneficial expansion to the network. Thus, there is a potential free-rider problem that is not directly addressed by TCCs. The concern, from a policy-making standpoint, is that this positive externality may lead to under-investment in the network since the benefits seen by individual investors will be smaller than those seen by the network as a whole. It is important to note that the fact that external benefits are generated from an investment decision does not, in and of itself, imply that there will be under-investment. The important concern is whether the marginal benefits experienced by all users exceeds the marginal benefit of the individual making the investment at that individual's optimal investment quantity. The existence and potential severity of this problem will require a more detailed analysis of the specific markets in question.

There is also a second source of concern about under-investment. This is due to the revenues from the TCCs. Consider the following example of a two-node network. At node 1 there is a high-cost producer with costs $C(y_1)=2y_1^2$ and two consumers with fixed demands of 2 MW and 3 MW, respectively. At node 2 there is a low-cost producer with cost $C(y_2) = 0.5y_2^2$. Initially, there is no transmission line connecting these nodes. Table 4 shows the benefits to each consumer of adding transmission capacity as well as the TCC revenue that will accrue to the agent who makes the investment.

Assume for a moment that the marginal cost of transmission capacity was a constant $5 per MW. The socially efficient level of investment would be 3 MW of capacity (the marginal benefit would be equal to the marginal cost at node 2 less the marginal cost at node 1, or $p_2 - p_1$). However, customer 2, acting alone, would prefer to build a 2 MW line as this capacity maximizes the sum of customer 2's cost savings and TCC revenue, less the cost of building the line. The TCC is essentially a monopoly product for this customer, and is therefore provided at a level below what is socially efficient. In this example, customer 1 could still add the additional MW of capacity on his own, since we had assumed transmission costs were constant. Unfortunately, transmission costs are not constant, but instead exhibit significant economies of scale (see Baldick and Kahn, 1992). The scale economies would make it inefficient for multiple lines to be built.

This example also points to a potential barrier to the formation of coalitions for joint transmission investments. An agent who wanted to join in an expansion of the transmission line in this example would have to not only provide the incremental cost of additional investment but also compensate customer 2 for any loss in TCC revenue that would result from further expansion beyond customer 2's optimal transmission capacity. It appears that one of the most important factors that will influence the efficiency of investment is the ability of an individual player to prevent others from adding capacity to certain transmission paths. Such barriers to entry of competing investors, along with the declining marginal costs that characterize transmission facilities would greatly increase the potential for under-investment in any market-based organization of the transmission sector. One important remaining role for regulators, therefore, is to oversee the coalition process and prevent barriers to investment along transmission paths.

Table 4
Optimal transmission capacity

Line capacity (MW)	p_1 ($/MWh)	p_2 ($/MWh)	Customer 1 (node 1) demand = 3 ($)	Customer 2 (node 1) demand = 2 ($)	Line cost ($)	TCC revenue ($)	Total generation cost ($)
0	20	0	−60	−40	0	0	50.0
1	16	1	−48	−32	−5	15	32.5
2	12	2	−36	−24	−10	20	20.0
3	8	3	−24	−16	−15	15	12.5
4	4	4	−12	−8	−20	0	10.0

6. Conclusions

In this paper, we have outlined a process by which transmission planning and investment would be undertaken by competitive entities in a lightly regulated environment. The role of cooperative organizations such as regional transmission groups would be to establish technical reliability standards, but not to adjudicate and approve transmission expansion plans. The investment incentives provided by the feasibility restriction on new TCCs would replace the reliance upon negotiation and legal disputes as the primary solution to the negative externality problems presented by grid investment decisions.

Investments would be made by companies who would benefit from the additional transmission capacity through increased access to either cheaper power or more lucrative markets. These companies would have no guarantee of recovering their investment costs, but would instead have to rely upon the increased benefits provided by the transmission facilities and the revenue generated by the additional TCCs they receive to justify the costs of their investment. While these firms would have no control over the transmission capacity they create, they would be protected against future costs of congestion by the TCCs that would be awarded to them by the ISO.

The primary barriers to a workable competitive market for transmission have been vertical market power concerns and the externalities, both positive and negative, that are inherent in electric transmission networks. We have demonstrated how TCCs, when allocated according to the concept of feasible injections, can internalize the negative externalities of investment decisions and shown the extent to which this internalization depends upon the degree of ''matching'' of the allocated contracts to the actual dispatch of the system. The complete elimination of the possibility that negative externalities may distort investment decisions is dependent upon each individual completely hedging their consumption with either CFDs or TCCs. However, when one considers the costs of building transmission lines, it seems plausible that destructive investments could be deterred if only some reasonable fraction of network injections is accurately hedged.

A more vexing problem for the lightly regulated contract network approach appears to be the potential for under-investment in the network. There are two contributing factors to this concern. The first is the result that TCCs do not capture the full benefits of network expansions. Thus there is potential for free-riders on a grid investment. Much of these external benefits, however, are infra-marginal and would therefore not affect the efficiency of individual investment levels. The second factor that causes some concern over under-investment is the revenue generated by the TCCs themselves. An agent assessing the optimal capacity for a new or expanded line would factor in the marginal revenue produced by additional TCCs as well as their own generation or consumption benefits from the new line capacity. The transmission capacity decision therefore contains an element of monopoly power, yielding a capacity that is lower than the socially efficient level.

This effect is exacerbated by the large-scale economies that are typical of transmission investments.

This analysis points to several important roles for regulatory institutions that would remain even under this relatively market-driven investment process. Ideally, the regulatory functions would be provided in a manner of general procedural oversight, rather than detailed examinations of the costs and benefits of each proposed expansion. Such detailed analyses are bound to suffer from significant information asymmetries and be vulnerable to protracted disputes. The most important and active function regulators could provide would be to facilitate the formation of investment coalitions when it is economically efficient for such coalitions to form. In order to prevent the monopoly investment problem, regulators should make sure that any party that wants to expand the scale of a project at their own expense is allowed to do so. Barriers to investment along a given path would therefore be significantly reduced.

The other important role for regulators would be to assess the market-investment process and determine whether the incentives outlined by the theory are sufficient to encourage the proper outcomes. TCCs, allocated under the feasibility rule, are not likely to completely eliminate either the positive or negative externality problems. However, it is important to assess the severity of these shortcomings in the proper context. Many of these same problems have plagued the transmission sector of this industry for decades. The forms of localized and cooperative regulation that have developed to deal with these issues seem likely to be hard pressed by the conflicts of interest that will be brought to the surface by competition. The presence of scale economies, severe information asymmetries, and network externalities make it very difficult for any market organization, competitive or regulated, to achieve "first-best" outcomes for the transmission sector. We may therefore be left with making choices about the relative severity of the problems created by alternative approaches.

In its current form, the proposal by WEPEX before the FERC for creating an independent system operator and adopting some form of the contract network approach to transmission pricing is a blend of partially formed concepts of a TCC market and the current cooperative approach to transmission planning. Potential problems with both components of this blend have been discussed here, and care must be taken to examine the implications of this proposal in light of these potential difficulties.

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We would like to acknowledge the helpful comments of Severin Borenstein, William Hogan, and two anonymous referees. This research was partially supported by the California Energy Commission under contract no. 700-93-003.

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