Transmission Benefits and Cost Allocation

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"The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits." (FERC 2010, p. 91)

Benefits include reliability, economic and public policy related impacts. Turning the principle into a workable policy is important as a support for restructured electricity markets. A challenge is to make the different measure of benefits commensurable, and to find approximations that honor the principle without imposing a standard of perfection. A framework for such cost allocation uses examples from existing models and transmission investment studies to describe how the cost allocation principle could apply within the limits of available analytical capabilities.

Introduction

Cost allocation for electricity transmission infrastructure presents a challenge for regulators. In the case of established transmission networks, existing allocations of sunk costs may suffice to collect sufficient revenue while preserving a workable set of operating and complementary investment incentives. But the case is different for new investment in transmission infrastructure. Cost socialization envisions cost allocation according to a rule which is independent of the distribution of benefits, such as a load ratio share when only some of the load could be seen as beneficiaries. The beneficiary-pays principle envisions cost allocation that is reasonably commensurate with the distribution of benefits. For traditional reasons such as demand growth, and newer pressures such as developing a greener electricity system, there is an expectation of significant expansion of the transmission infrastructure. Some of this investment, such as local connection of new generation, lends itself to easy application of the principle of cost allocation to the beneficiaries. Although the same principle appeals for larger scale projects, application of a beneficiaries-pay cost allocation rule is not as easy.

Driven by the goals of efficient investment, decisions from the courts[1], and proposals from the Federal Energy Regulatory Commission (FERC, 2010), transmission investment cost allocation policy should move in the direction of reducing or eliminating cost socialization and ensuring that costs allocated to beneficiaries are commensurate with the benefits. The result of moving from cost socialization to allocation to beneficiaries could be dramatic. For example, the case that precipitated the FERC initiative dealt with cost socialization of transmission investments for lines operating above 500 kV in the PJM system (FERC-PJM, 2010). The contrast was with the allocation of costs for lower

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1 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009).

voltage lines by tracking the change in power flows on the transmission lines. Estimates by PJM showed that the two different allocation methods could change the cost allocation for some regions from essentially zero to 15% of the total transmission investment cost, with corresponding changes for other regions (Naumann, 2010). As discussed below, despite the common claim otherwise, the power flow model does not provide a good theoretical foundation for estimating benefits. But these differences in PJM cost allocation estimates are sufficient to suggest that cost allocation methodology is not a de minimis issue.

For most large scale investments, there is debate over the definition of benefits and identification of beneficiaries. The purpose here is to outline the components of a workable application of the beneficiaries-pay principle that utilizes information embedded in standard planning studies. Applying planning models and related evaluations in order to choose among possible transmission investments can be a challenging task in itself, presenting many opportunities for improved methods. However, for the present discussion the point is not to improve planning tools but rather to utilize the information inherent in planning studies that can guide the associated cost allocation. The calculations underlying the estimate of benefits provide information applicable to the separate but related task of estimating shares of benefits. In many instances, estimating the shares of benefits is easier than estimating the benefits.

Efficient Investment Framework

The underlying framework for efficient investment seeks to maximize the expected net present value of total benefits minus total costs (Baldick, Brown, Bushnell, Tierney, & Winter, 2007) (Olmos & Pérez-Arriaga, 2009). For a given level of projected demand, this would follow a familiar prescript of minimizing total costs to meet demand. In the wider framework that recognizes the potential flexibility of demand, the total value of expanded load would be compared with the total costs. The even broader social cost framework would include various policy instruments to incorporate externalities through regulation.

In a pure vertically integrated setting, where a single decision maker captures all the benefits of load and incurs the all the cost of production, the definition of benefits minus costs is conceptually straightforward. The social planner would choose the transmission expansion plan to maximize the expected total benefit of load less the expected costs of generation less the cost of transmission investment. Prices of electricity and net payments would enter only implicitly as the marginal costs at the optimal solution.

In a pure market setting, with certain regularity conditions, prices at the optimal solution would also be consistent with a market equilibrium where market participants take prices as given and optimize profits at these prices (Mas-Colell, Whinston, and Green 1995, pp. 311-343). The profit maximizing solution for load equates expected marginal benefits with expected prices; for generation the expected prices equal marginal costs; for transmission infrastructure the expected marginal congestion costs equal the marginal cost of transmission expansion. Net payments among the parties at these equilibrium prices capture market revenues. Total net economic benefits differ from the market revenues and could be partitioned into the usual components of consumer surplus, producer surplus, and transmission congestion rents.

Consumer surplus: Consumer surplus is the difference between the total load benefits and the payments made by the load. The consumer surplus is an upper bound on the additional amount that consumers would pay under a perfectly discriminatory pricing system without changing total consumption.

Producer surplus: Producer surplus is the difference between the revenue received by producers less the total cost of production. The producer surplus is an upper bound on the additional amount that producers would surrender under a perfectly discriminatory pricing system without changing total production.

Transmission rent: Transmission congestion and loss rent is the difference between the payments made by load and the revenue received by producers. This could be treated as the revenue paid to the owners of transmission rights.

These three components partition the total net economic benefit. In the pure market case the objective would be to emulate efficient investment in the social planning case by maximizing the expected total of consumer surplus, producer surplus and transmission congestion rent.

The electricity market includes both investment and operating decisions. For the present discussion the emphasis is on the expected long-run conditions. But an underlying assumption is that the short-run operations adhere to the principles of organized markets operating security-constrained, bid-based, economic dispatch with locational prices and financial transmission rights (Hogan, 2002).

In a hybrid setting there would be a mixture of regulated and market entities making consumption, production and investment decisions (i.e., private investment decisions and decisions made within a public regulatory framework). The principle for hybrid market design would be to align the different decision processes to provide a workable approximation of an efficient investment framework.

The alignment of efficient market investment incentives may break down in the absence of the assumed regularity conditions. In particular for the case of transmission investment, there is a problem when transmission investment is episodic rather than continuous, and comes in discrete lumps (Joskow & Tirole, 2005) (Hogan, 2007). With these common circumstances, transmission investment can materially change market prices. At the prices expected without the transmission investment, the investment would be profitable. But at the prices that would result after the transmission investment, the benefits that could be captured in the market would not justify the cost. This produces in an inability to recover the costs from the resulting prices (Pérez-Arriaga, Rubio, Puerta, Arceluz, & Marin, 1995). Thus efficient investment may need regulatory mandates and a regulatory cost allocation. In addition, for large entities lumpy transmission investments can inherently undermine the price taking assumption. This leads to both strategic problems where market participants may seek to benefit from price changes, and often creates free-riding concerns about beneficiaries who do not bear an appropriate share of the total costs of investment.

Other complications of hybrid markets would include the array of contracts and vertical integration between and among producers and consumers. The effect of the contracts would be to entangle incentives between consumers, producers, and transmission owners in ways that could either reinforce or distort an efficient investment framework. The outline here of an efficient transmission investment framework with workable cost allocation principles begins by ignoring contracts, and then addresses some of the implications of considering contracts.

Cost and Benefits

For purposes of a cost allocation outline, we consider two general types of transmission investment: voluntary and mandated. Voluntary investments would span the range from simple merchant investment where a party invests to obtain the incremental transmission rights, to more complicated consortia where the participants agree to make a collective investment and share costs and any transmission rights according to an agreement of their own making.

The focus here is on transmission investments that are efficient, in producing benefits greater than the costs, but where the benefits are difficult to capture through incremental transmission rights. These lumpy investments would be approved and mandated by a regulatory body, with some or all of the cost recovery through a rate base or some similar method that uses the power of government to compel payment. Mandated investments could socialize the costs according to some rule, or could envision cost allocation according to the distribution of benefits. Some of the beneficiaries may disagree about the distribution of net benefits and not support the allocation of costs; otherwise the case reduces to voluntary agreement. The mandate forces some or all of the participants to pay for the transmission investment.

The attraction of the principle that the beneficiaries pay for transmission investment has dimensions of both fairness and efficiency. The fairness criterion is important especially because the cost allocation principles apply to mandated transmission investments that exploit the power of government to compel participation. The emphasis here, however, is on the effect of cost allocation principles on the efficiency of electricity system framework. Absent a beneficiary-pays principle, it would be difficult to maintain a mixed system of voluntary and mandated transmission investments, or provide efficient incentives for generation and load that in part compete with and in part are complementary to transmission. For particular investments, beneficiaries that might be prepared to agree to voluntary cost allocations would have strong incentives to prefer mandated investments if the mandate were to shift the cost in part to those who do not benefit. Similarly, socialization of the cost of transmission would create the demand for offsetting socialization of competing load and generation investments. However, if the effect of mandated investments were to allocate the costs to beneficiaries, there would be a reinforcement of the incentive to proceed with voluntary arrangements. Therefore, the principles for mandates transmission expansion and cost allocation stand at the center of the structure for electricity market design.

In the simplest cases, for small incremental investments that have no material effect on expected prices across locations, there would be incentives for efficient voluntary investment, even straight merchant investment where the benefits would be captured adequately by incremental financial transmission rights. More complicated cases involve lumpiness and greater scale of investment that can have a material impact on expected market prices. There can still be voluntary merchant investment in these cases, but as is often observed there may be inadequate value in the resulting financial transmission rights to support merchant investment. The expected differences in locational prices would signal the benefit of transmission investment, but the properly sized investment would so substantially reduce the price differential that the financial transmission rights (valued at the new prices) would not be sufficient to support the investment. In such cases, efficient investment could require regulatory mandates for both the investment decision and cost allocation.

The real transmission grid involves uncertainty across multiple periods, many locations and strong network interactions. However, a simplified model with expected values at two locations illustrates some of the basic concepts governing interactions between efficient investment and cost allocation.

Transmission Benefits

Consider the stylized case of an electricity system with two regions with generation, load and transmission right holders. Assume all participants within a region are price takers and their choices aggregate to a representative agent for each type of participant, generators who supply and loads who demand. The low cost region has both local demand and supply. At any given price, the net of supply minus demand defines the region's export supply. The higher cost region with its own demand and supply is connected by a transmission line. At any given price, the net of demand over supply defines the import demand. As illustrated in Figure 1, with enough transmission capacity, imports and exports would find market equilibrium. Ignoring losses, the equilibrium price where imports equal exports would be the same in the two locations.

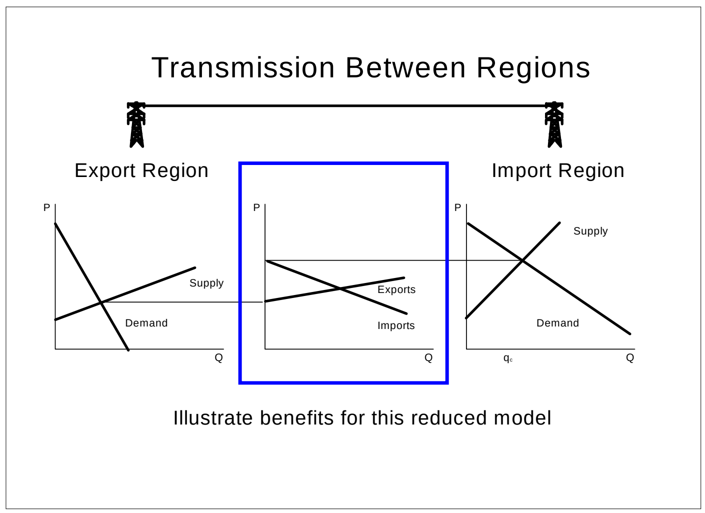


Figure 1

When transmission capacity is restricted, there is price separation between the two regions. The left vertical line in Figure 2 indicates the initial transmission capacity. The area under the import curve defines the aggregate import benefits of the existing capacity and the area under the export curve defines the export costs. The letters label areas that partition this net benefit. For the existing transmission capacity the "consumer" surplus for imports is area A, defined as the total benefit of the area under the import demand curve less the payments at the import price in the high price region. The "producer" surplus for exports is area E, the payments for exports at the export price in the low price region. The transmission congestion rent is the sum B+C+D, the net revenues for imports minus the payments for exports. The allocation of these benefits across market participants could take many forms depending on ownership or contracts. Initially, consider the case of no vertical integration through ownership or contracts.

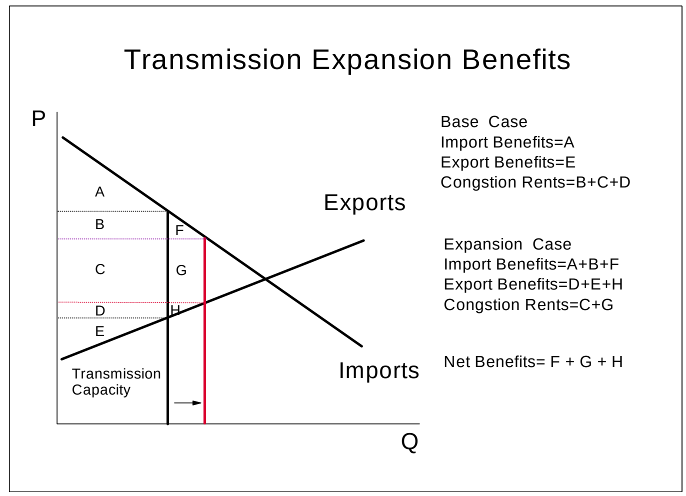


Figure 2

Expansion of transmission capacity between the two regions would create incremental benefits of F+G+H. In the absence of contracts, where everyone pays or is paid the new prevailing price, the new consumer surplus for imports would be the area A+B+F. The new producer surplus for exports would be E+D+H. The new transmission congestion rent would be C+G. Part of the increase in the import surplus is the transfer B from existing transmission right holders to the participants in the import region. This transfer is not part of the aggregate incremental benefits, but it is a net benefit to the import region. Similarly, part of the increase in export benefits is the transfer D from existing transmission right holders to the export region; this transfer does not add to aggregate benefits but is a net benefit to the export region.

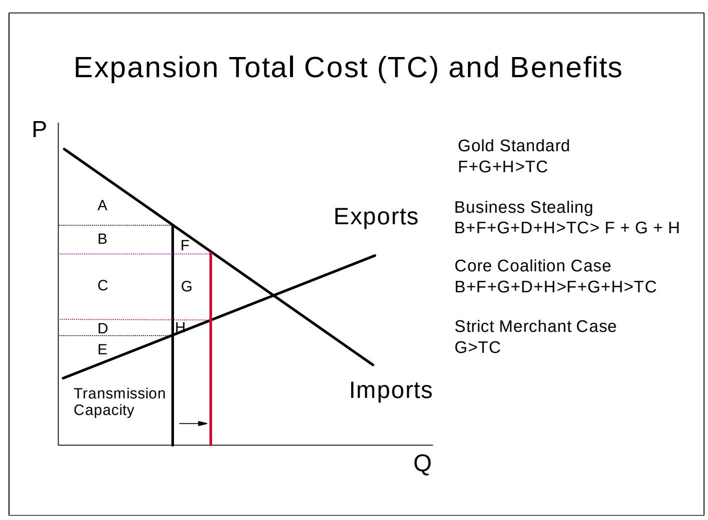


Figure 3

The incremental aggregate benefits would be compared with the total cost (TC) of the transmission investment. In the easiest of the cases illustrated in Figure 3, where G>TC, transmission investment would be an attractive opportunity for a merchant undertaking by an independent entity. The expected congestion rents (G) associated with the expanded transmission capacity would define the value of the incremental financial transmission rights. Hence, the merchant transmission benefits of expansion would be greater than the investment costs. Of course, there could be losers in the case of a merchant investment. For example, the holders of existing transmission rights would be affected by the competitive entry of new transmission investment, losing total congestion rents going forward of B+D. The new entrant transmission investor would not incur losses from the reduction of existing transmission congestion rents for existing financial transmission rights. As with any competitive entry, the investment decision and cost allocation model would not protect the incumbent losers, as long as there is efficient entry, as would be true here in the strict merchant case.

The merchant case might apply for small scale investments, where area F+H is small or effectively zero. However, when the total F+H is larger, because lumpy transmission investment affects market prices, there is a material benefit that might not be captured in the incremental financial transmission rights. The rule for the regulator would be to support transmission investment only when the incremental benefits exceeded the transmission investment cost; i.e., when F+G+H>TC. This is the test of efficient transmission investment and defines the gold standard for regulatory approval.

A challenge for the regulator would be to recognize those cases where a subset of the market participants might find it in their interest to proceed with the transmission investment even though the transmission cost was greater than the net benefits; i.e., TC>F+G+H. An example of this would be the business stealing case (Mankiw & Whinston, 1986); i.e., where B+F+G+D+H>TC>F+G+H. Then a sufficiently large coalition of private beneficiaries could capture enough transfers in B+D to make the investment privately profitable but socially inefficient. In this case, voluntary funding would not be consistent with efficient transmission investment.

The simple example conceals another complication that can arise in a real transmission system. There may be cases where privately profitable voluntary transmission investment could reduce transmission capacity. This is analogous to adding a weak link to a strong chain. Although it is possible to use financial transmission rights to mitigate or eliminate these incentives (Bushnell & Stoft, 1996), as a practical matter regulators will be required to approve all transmission investments, and part of this process should include application of the gold standard for efficient investment. In the case of voluntary investment that fails the gold standard test of efficient transmission investment and reduces overall efficiency, the regulatory mandate should be to preclude the investment.

Approval of efficient voluntary investment does not require cost allocation to other parties. However, when transmission investments meet the efficiency test but not the merchant funding test, then the framework presented here envisions mandates for investment and cost allocation.

Cost Allocation

Mandatory cost allocation arises as a necessity when voluntary investment may not be sufficient to support efficient expansion; i.e., when F+G+H>TC>G. This condition presumes a material change in prices and a scale of transmission investment that substantially exceeds the scale of individual generation or load. In other words, if individual load in the importing region is too small to capture all but a fraction of F, or of H for generators in the exporting region, then there is an effective externality from the cost of aggregating many small participants. The benefits that are easy to capture, namely G and a small fraction of F+H, would not be enough to cover the cost TC. Without some way to aggregate the beneficiaries and share the costs voluntary, efficient transmission investment would not be supported.

If there is a close call, and the estimate of incremental benefits approximately equals the total cost, it may be difficult to allocate the costs and support the investment well enough to preclude substantial opposition from the supposed beneficiaries. Less than perfect estimation of the benefits and their distribution could be problematic. Even with transmission mandates, this may lead to some such expansions failing to go forward. This would be a loss. From a societal perspective, however, this would not be much of a loss because by assumption the investment is about a net zero benefit.

The more interesting case is where the net benefits are substantially greater than the transmission cost. If voluntary merchant investment is not forthcoming, efficient investment could follow the mandatory route with regulated cost allocation. An important observation is that in these cases cost allocation may by definition not require perfection in the estimation of the benefits or the distribution of benefits. By assumption, in this case there is a substantial excess of benefits F+G+H over the cost TC. Furthermore, in the absence of contracts, the regulators have the added advantage that the private interests of market participants diverge from efficient investment in ways that could make cost allocation easier rather than harder.

Consider the importers. If there are no contracts, then importers would capture a transfer of B in addition to the net aggregate benefit F. From the point of view of importers, a cost allocation for a share of TC that was less than B+F would be privately beneficial. Of course, they would be happy to pay less, but only when the cost allocation exceeded B+F would the importers be better off with no expansion. Similarly, exporters would now see D+H as the upper bound on the cost allocation where transmission expansion is better than no expansion.

An implication is that a simple decision rule might be to allocate incremental transmission rights to importers, and assign transmission costs equal to the net benefit including these rights. Assume the incremental transmission rights are assigned to the loads. Let the allocation shares *s* for the import and export regions follow the distribution of the aggregate net benefits:

$$s_I = \frac{F+G}{F+G+H},\ s_E = \frac{H}{F+G+H}.$$

Then the import region cost allocation would be s_ITC. The balance of the transmission cost would be assigned to exports, or s_ETC.

If there are no contracts, then the benefits to the importing region are B+F+G>F+G>s_ITC. The import region participants would be net winners. And since D+H>H>s_ETC, the export region participants would be net winners.

The cost allocation to the participants within regions would be to loads in the importing region and generators in the exporting region. Of course, generators in the importing region would be incurring a loss of market benefit as a result of the transmission investment. As usual, support of competitive entry implies that transmission investment would not protect these competing incumbent generators, nor would it assign any costs to these generators in the importing region. Similarly, the load in the exporting region would see a loss of market benefit. Load in the exporting region would not be protected, but also would not be assigned any cost of the transmission expansion.

Existing holders of transmission rights would see a loss of value to the degree that prices fall in the importing region and rise in the exporting region. Again, support of competitive entry would not protect the value of the existing financial transmission rights. The financial transmission rights would remain, and be protected through adherence to the simultaneous feasibility test requiring that the aggregate of new and old transmission rights produce feasible flows with no other network uses (Hogan, 1992), but the value of the existing rights would fall by the amount of the change in the price difference between regions. Assignment of the new rights to load in the importing region is a convenient choice, or the rights might be auctioned with the revenues used to reduce the amount that must be recovered through the transmission rate base.

This unpacking of the change in benefits and costs within each of the regions reinforces the above observation about the acceptability of workable approximations in the transmission cost allocation percentages. As illustrated in Figure 4, increased transmission capacity raises prices in the export region and reduces prices in the import region. This change in prices produces different responses and impacts for load and generation. Absent perfect matching of contracts between generators and load within a region, the implicit aggregation into exports and imports conceals another form of pecuniary benefit where the private benefits of the beneficiaries would be greater than the net societal benefits. There could be additional transfers within regions that do not contribute to overall net benefits. This condition would be helpful in arranging for cost allocation.

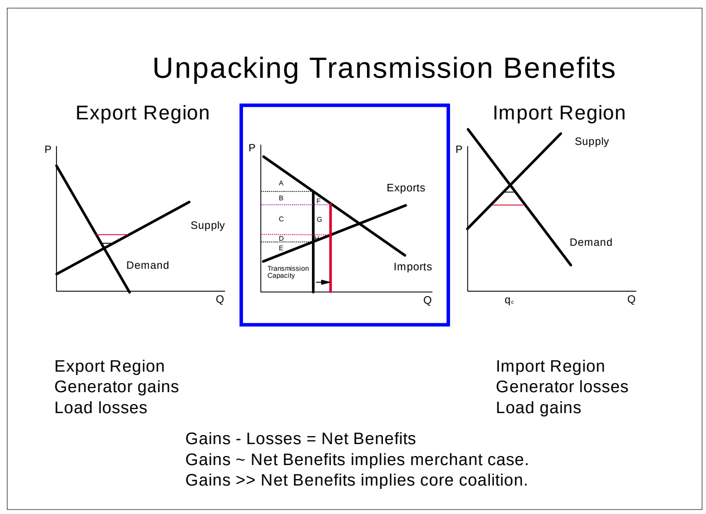


Figure 4

For example, Figure 5 expands to illustrate more detail. The net benefit in H for exporters understates the potential benefit for generators in the export region. In the absence of contracts, there would be further transfers from load to generation within the export region, with the net benefit to the region represented by H. Without contracts, the incremental benefits to generators could be I+D+H. The transfers from load to generators would not add to aggregate benefits, but would be seen as a private benefit by generators. Symmetrically, there is a similar situation for load in the importing region, where the gross benefits for load may be greater than the net benefits in F. These transfers within regions create more room for error in the cost allocation without upsetting the conclusion that the aggregate beneficiaries of transmission expansion are still net beneficiaries after the allocation of the costs.

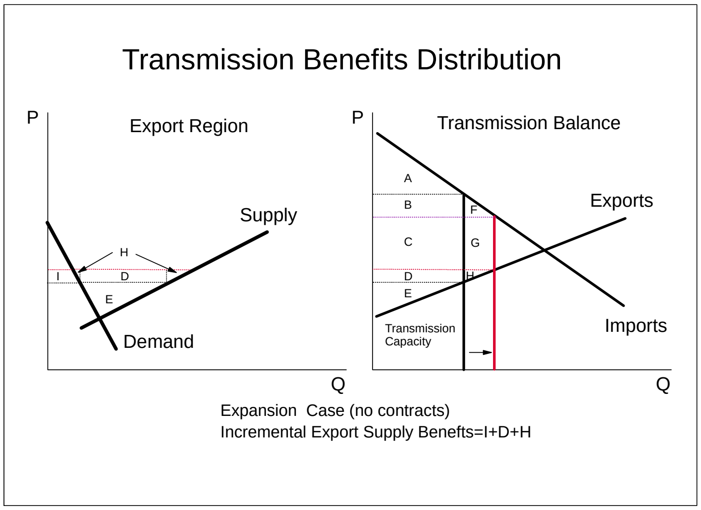


Figure 5

Contracts and Diversity

Contracts by their nature redistribute costs and benefits. For example, consider the case of a load in the import region that is constant and predictable and that matches the fixed capacity of a generator. The load could contract with a generator for a fixed price, arrange a financial transmission right, and ensure a fixed cost of delivery. For this load and this generator, transmission expansion does not produce any benefits. The contract may have been a hedge against higher costs, and the load gave up the lower cost possibility just as the generation gave up the higher price outcome. The hedge may have been privately beneficial, but the change in costs of transmission expansion would not create net benefits for the particular load or the particular generator. Hence, any allocation of transmission expansion costs to this load or generator would exceed their net benefits. Other loads and generators may benefit, but not this particular pairing.

An advantage of voluntary transmission investment, whether through merchant investment or more complicated consortium projects, is implicit treatment of existing contracts. The parties presumably know their respective contract situations. They will voluntarily incur additional costs only if there are net benefits relative to their current situation. Voluntary investment does not free the regulator from applying the golden standard of efficient expansion, but it does avoid the complication of mandating a particular cost recovery. The parties can consider their contracts in the negotiation of the cost recovery.

It would be quite another matter to call for a mandatory regulatory cost allocation to reflect the impact of private contracts. The information and enforcement requirements would seem overwhelming, and would create perverse incentives to create contracts designed to avoid transmission cost allocations, even for beneficiaries.

Assuming no contracts at all would be a natural extreme case. In the simplified example above, this would imply a wide range for the total benefits and allocation of costs. For example, in Figure 5, for the generators in the exporting region the total benefits would be I+D+H, and any cost allocation up to that amount would be better than no expansion. The private benefits of the generators are higher than the social benefits of the exporting region. This could complicate the investment decision, and thus requires the application of the gold standard for efficiency; but the same fact would simplify cost allocation to the beneficiaries because the private benefits of generators in exporting regions and loads in importing regions are larger than the net benefits of the region which for efficient investments are larger than the costs.

The cost allocation rule above does not fully exploit the no-contracts assumption. The cost allocation rule is conservative in that it allocates only in proportion to incremental benefits H, the minimum that could be allocated to the export region and guarantee that the aggregate cost allocation rule would always support efficient investment. This conservative position implies that in many cases the private benefits to the generators in the exporting region would exceed the cost allocation.

The simplified rule treats all loads and generation within the export or import region as being otherwise in the same condition. This is the representative agent perspective hidden in the aggregation to a single supply or demand summary for each region. But not all loads in the exporting region will be the same. There is diversity among participants of each type. In general, expansion of generation from the export region will not just be proportional for all generators. In other words, different conditions of different entities will result in different shares of H within the region. Cost allocation by the above rule within the region would differentiate between load and generation, but is silent on the allocation among individual loads or individual generators. Although the beneficiary-pays principle guides cost allocation across different locations, and between generation and load, the simple model provides no further guidance on the allocation among loads at a particular location. In this sense, workable application of the principle could include some socialization of the benefits across different parties at the same location. At least the analysis is silent on the allocation of costs among these parties.

Workable Models

The simplified model above serves as a metaphor for discussion of transmission investment and cost allocation. The analysis provides a number of implications for application of workable models of transmission investment and cost allocation.

Ex Ante Determination

Transmission investment will last for many years and transmission planning is inherently a dynamic problem. The framework presented is essentially a two stage approach. In the first stage there is a consideration of the existing transmission grid. The expectations for the future with that grid determine the current estimate of aggregate benefits. This base case defines the counterfactual to the construction of the particular transmission investment (Pfeifenberger, Fox-Penner, & Hou, 2010). This is the ex ante perspective, before the investment is made.

The analysis hypothecates a particular expansion of the transmission grid and estimates the benefits under this alternative case. The critical information to calculate would be the analog to areas F, G, and H. Given regional prices p and trade quantities q before (0) and after (+), treating imports as positive and exports as negative, with locations k, import benefits $b_k\left(q\right)$, and net local investment and operating cost for exports $c_k\left(q\right)$, we could approximate these expected present value of benefits as:

$$
\begin{aligned}
F_k &= b_k\left(q_k^+\right) - b_k\left(q_k^0\right) - p_k^+\left(q_k^+ - q_k^0\right) \approx \frac{1}{2}\left(q_k^+ - q_k^0\right)\left(p_k^0 - p_k^+\right), \\
G &= \sum_k \left(q_k^+ - q_k^0\right) p_k^+, \\
H_k &= p_k^+\left(q_k^0 - q_k^+\right) - \left(c_k\left(q_k^+\right) - c_k\left(q_k^0\right)\right) \approx \frac{1}{2}\left(q_k^0 - q_k^+\right)\left(p_k^+ - p_k^0\right).
\end{aligned}
$$

Importantly, the components of these calculations are byproducts of standard planning models. Transmission investment is inherently locational, and the planning models incorporate locational differences for generation and load. The dispatch calculations simulate the resulting locational quantity and price outcomes. The transmission investment decision involves changes in operating costs of existing generation and load at a location, and facilitates changes in investment in new generation and load. These investments and changes in operating costs are an essential part of the choices analyzed in a planning model. The estimate of the distribution of benefits follows from these calculations.

For example, in an importing region, the increased gross benefits between the investment case and the counterfactual would be $b_k\left(q_k^+\right) - b_k\left(q_k^0\right)$. The net benefits subtract the payments in the same location for the increased imports $p_k^+\left(q_k^+ - q_k^0\right)$ valued at the locational price. The net benefit would be the change in "consumer" surplus F_k at the import location. These cost and payment estimates could be estimated directly from the planning investment analysis model results or, for small changes a by the linear representation in Figure 2, approximated as $\frac{1}{2}\left(q_k^+ - q_k^0\right)\left(p_k^0 - p_k^+\right)$. A symmetric description applied to calculating the net increment to "producer" surplus H_k at an export location. As for the value of the increment of transmission capacity in G, the expanded volume of transmission is valued at the new prices across locations.

In general, while it is possible in principle to calculate the change in the aggregate congestion rents in G, there still remains the problem of allocating the rents to the particular regions. This is simplified by the existence of incremental financial transmission rights which have the same aggregate value. The idea would be to allocate some or all of the incremental transmission rights to the loads, and attribute the incremental benefits to the loads. An analytical similar approach would be to auction the incremental transmission rights for G, and subtract this sum from the transmission cost TC to be allocated through mandates through the rate base.

The general case is a network and not a single line. The comparison with a counterfactual is simplified in the ex ante perspective before the incremental expansion. In a sufficiently dense network, any attempt to estimate the benefits ex post, after a particular transmission expansion has been made, would be confounded by the daunting task of separating the network effects and reconstructing a counterfactual that identifies and removes all of the collateral investments in generation, load, and other transmission. The long history of discussion of transmission rights that led to the reform of transmission rights as point-to-point financial rights, rather than describing any particular path in the network, revealed that there is in general no known method for ex post valuation of transmission based on separate flows on individual facilities (Hogan, 2002). However, attempts to fashion cost allocation policies often assume the opposite or ignore the issue. When compounded with the regulatory challenges of constantly reopening the cost allocation box, explicit or implicit embrace of an ex post determination of the distribution of benefits creates such inherent difficulties that it can lead quickly to arguments for cost socialization (Baldick, Brown, Bushnell, Tierney, and Winter 2007, pp. 56-57) . Since cost socialization ignores the distribution of benefits, changes in the distribution of benefits do not matter for the socialization approach.

Note that there is nothing in the transmission investment decision or ex ante cost allocation rule that depends directly on examination of the power flows across individual lines or other transmission facilities. The estimate and comparison with the counterfactual is made at the first stage. This ex ante perspective is unavoidable in evaluating the investment decision. Given the complexity of network interactions, where the power flows across individual lines do not describe actual use or value in any economically meaningful way, the only available methodology based on first principles is to allocate costs according to the same estimates of the benefits the future outcomes. This is consistent with the perspective for the beneficiary-pays principle as described by FERC: "Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities" (FERC 2010, p. 91). The cost allocation is made ex ante based on the same analysis that is and must be made before the investment goes forward. The cost allocation does not depend on the ex post utilization that actually occurs, which is difficult to even define much less measure. This ex ante perspective is particularly significant in the context dealing with uncertainty.

Uncertainty

The treatment of uncertainty is especially relevant given the long life of projected transmission investments. The future is uncertain and there will be many anticipated and unanticipated changes in conditions. In the extreme, the uncertainty about the future might average out to an ex ante cost allocation that amounts to de facto socialization of the costs across all participants. "For example, a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a facility or class or group of facilities (e.g., all transmission facilities at 345 kV or higher), *especially if the distribution of benefits associated with a class or group of facilities is likely to vary considerably over the long depreciation life of the facilities amid changing power flows, fuel prices, population patterns, and local economic developments*" (FERC 2010, p. 94, emphasis added) .

The emphasis here is on the recognition of uncertainty and the ex ante perspective. The implication is that the evaluation of the prospective benefits should include a range of possible outcomes for the uncertain variables. In the extreme, if the uncertainty is such that that expected benefits are uniformly distributed, then cost socialization would be equivalent in outcome to ex ante allocation to expected beneficiaries. But absent such uniform distribution, the calculation of benefits and cost allocation would be based on the expected values of the benefits and beneficiaries. Dealing with uncertainty is a standard part of the analysis of investment decisions. Treatment of uncertainty is not simple, but it is unavoidable. The investment decision and cost allocation both can utilize the expected values of benefits and costs across a range of conditions. The scenario analysis is an approximation, but this is not fatal for either the investment evaluation or the cost allocation. The existence of uncertainty does not imply or require cost socialization.

Approximations

Transmission planning and dispatch models involve a variety of details (Latorre, Cruz, Areiza, & Villegas, 2003). The basic elements include evaluation of the costs and benefits of generation and load, subject to a variety of network contingency constraints, energy balance, reserve requirements, and operating costs. There may be an explicit consideration of outage conditions and the associated probabilities, as shown in Figure 6. The basic structure in this figure abstracts from the dynamics with emphasis on the two stages of the evaluation of expected outcomes. The evaluation fixes the transmission scenario and calculates the expected benefits and costs for the counterfactual. The alternative case assumes the envisioned transmission investment and estimates the difference in the expected benefits and costs. This includes prospective investment in generation and load facilities, as well as operating costs and benefits. The planning model inherently seeks to represent to an acceptable degree the network with locational differences in load and generation. Locational differences are of the essence of transmission planning evaluations which involve changing the movement of electric power from here to there. Implicit in the solution of such as model are the prices and quantities at each location that can be used to estimate the change in net benefits to compare with the expected cost of the transmission investment. Such

Economic Planning and Dispatch Model

Benefits less Costs

Outage Conditions

Non-Transmission Investments

$$\underset{\substack{y^i,d^i,g^i,r,u\in(0,1)\\Cap^0,Cap^i}}{Max}\; p_0\left(B^0\left(d^0\right)-C^0\left(g^0,r,u\right)\right)+\sum_{i=1}^{N}p_i\left(B^i\left(d^i,d^0\right)-C^i\left(g^i,g^0,r,u\right)\right)-Inv\left(Cap^0,Cap^i\right)$$

$s.t.$

$$
\begin{aligned}
& y^i = d^i - g^i, && i=0,2,\cdots,N,\\
& \iota^t y^i = 0, && i=0,1,2,\cdots,N,\\
& H_i^j y^i \le b_i^j, && i=0,1,2,\cdots,N,\\
& g^0 + r \le u \bullet Cap^0, &&\\
& g^i \le g^0 + r^i, && i=1,2,\cdots,N,\\
& r^i \le r^i_{\max}, && i=1,2,\cdots,N,\\
& g^i \le u \bullet Cap^i, && i=0,2,\cdots,N,\\
& A^i d^i = B^i g^i, && i=0,2,\cdots,N.
\end{aligned}
$$

Contingencies i=0,1, …, N

Transmission Scenario j

RPS/REC Requirements

Figure 6

planning models are widely used and provide the canonical extension of the metaphor above to include multiple locations, periods and constraints for calculating the distribution of expected benefits.

In practice, application of these models has always made the distinction between economic investments and reliability investments. Economic investments would be designed to reduce congestion and expand economic performance of the electricity sector. Reliability investments would be designed to ensure that the future grid and the expected configuration of load and generation meet certain established reliability standards.

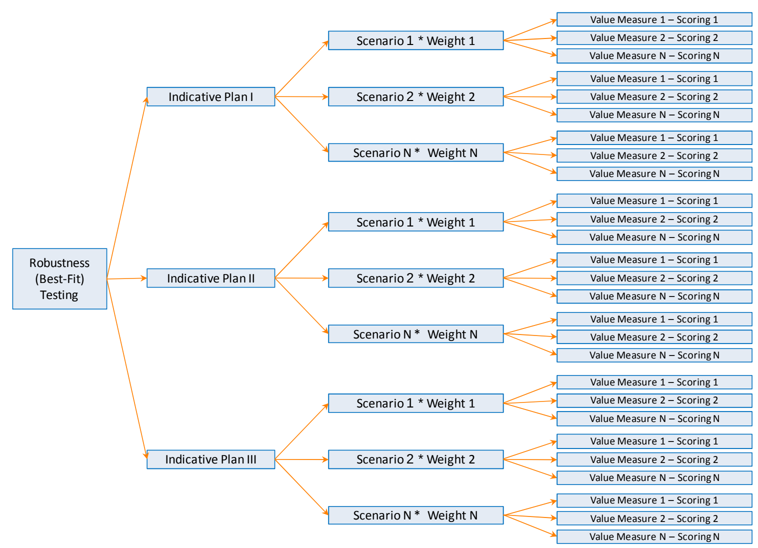
In the new policy proposed by FERC, there is the added distinction of policy investments needed to meet other goals such as environmental constraints that would arise under renewable portfolio standards, cap and trade policies or possible carbon taxes (FERC, 2010).

Strictly speaking, the framework in Figure 6 embraces all of these perspectives. Importantly, all transmission investments affect economics, reliability and policy. Hence, the challenge is not so much to classify the investments as it is to provide commensurable estimates of the benefits and their distribution for cost allocation. The combined estimate of benefits of each type would apply to allocation of costs.

In practice, implementation of the different perspectives raises slightly different issues and criteria that need to be made consistent with estimation of benefits and costs.

Economic Expansions

Economic evaluation of transmission investments follows most closely the framework in Figure 6. There is some art to the construction of scenarios and evaluation of the forecasts, but the art involves workable attempts to approximate the costs and the benefits. Different scenarios capture the major uncertainties included in the expected value analysis. Different outcome measures are aggregated to define the costs and benefits. Inherent in this analysis is the difference in outcomes across locations.



Indicative Robustness Testing Decision Tree Diagram

Figure 7

For example, Figure 7 illustrates the process from a Midwest Independent System Operator (MISO) planning exercise. There is an explicit treatment of scenarios and uncertainty. For given scenarios, there is optimization across the grid. In the MISO Regional Generation Outlet Study (Midwest

ISO, 2010a), the details include specification and quantification of the relevant costs and benefits. The subjective estimates include the scenario probabilities used to weight the benefit outcomes calculated with the transmission planning model. The range of costs and benefits considered includes a range of components worth reciting in some detail:

> *As a key component of transmission value assessment, the following financially quantifiable measures have been considered for making comparisons on the performance of the three (3) RGOS plans:*
>
> *a.* ***Adjusted Production Cost Savings*** *where total annual generation production costs include fuel, variable operations and maintenance (O&M) and start up costs, and are adjusted with off-system purchases and sales. The off-system purchases and sales are quantified using load weighted LMP and gen weighted LMP respectively. Adjusted production cost savings can be achieved through reduction of transmission congestion costs and more efficient generation resource utilization.*
>
> *b.* ***Load Cost Savings*** *where load cost represents the annual load payments, measured by projections in hourly load weighted LMP. Load cost savings and adjusted production cost savings are essentially two alternative benefit measures to address the single type of economic value and are not additive measures. Load cost savings is not used to calculate the total value of the RGOS plans in MTEP10.*
>
> *c.* ***Capacity Loss Savings*** *where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour. The intent is to capture the value of reducing the amount of capacity reserves that are required to maintain system reliability. The avoided capacity investment due to loss reduction is quantified using a generic overnight construction cost of $960,000 per MW.*
>
> *d.* ***Capacity Savings Due to Planning Reserve Margin Reduction:*** *The intent of this measure is to capture the value associated with transmission plans by potentially lowering the overall Planning Reserve Margin requirement through congestion relief. Recognizing a relatively small reduction in reserve requirement would allow a significant amount of benefits to accrue, this measure is under consideration for inclusion in future evaluation of transmission plans/portfolios.*
>
> *e.* ***Carbon Emission Reduction Cost Savings:*** *To address carbon reduction legislation in some future scenarios, a certain cost on carbon is placed combined with uneconomic coal retirement deployment to achieve the high level carbon reductions. The cost of carbon is modeled in a way to only impact the unit dispatch as a penalty and exclude the costs associated with carbon emissions from production costs. The benefits of carbon emission reduction are additive to the adjusted production cost savings described above. The corresponding carbon cost modeled in each scenario is used to quantify the dollar value of carbon emission reductions.*
>
> *f.* ***Generation Revenue Due to Wind Curtailment Reduction:*** *With the new transmission corridors to access the remote wind resources, the curtailment level of wind energy is minimized substantially, particularly for the futures with aggressive RPS requirements. The revenue is quantified using annual generation weighted LMP for the RGOS footprint as an estimate. The intent of this measure is only to provide a standalone value associated with wind curtailment reduction and is not included in the overall value calculation, as this value is embedded in adjusted production cost savings described above.*
>
> *Robustness testing for the three (3) long-term strategies has been focused on financially quantifiable measures as a starting point. There are other benefit measures including qualitative and risk factors that need to be taken into account to provide a more thorough analysis and allow a more complete value to be captured*

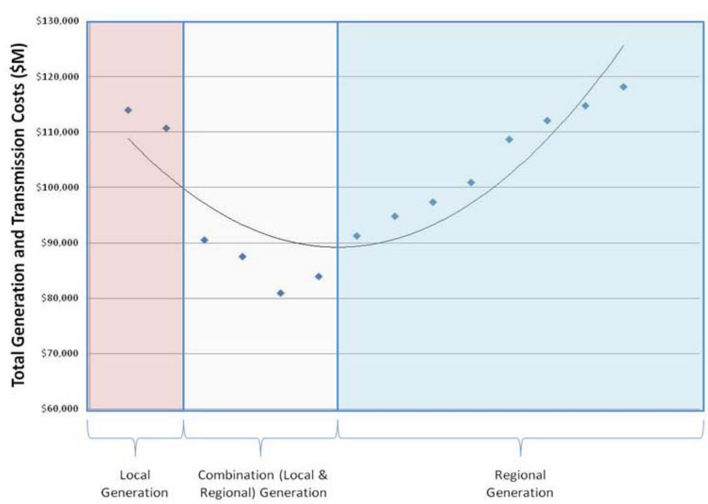
through the robust business case development process. Midwest ISO will continue to collaborate with stakeholders on further development of value measures as an ongoing effort in the next few planning cycles. (Midwest ISO, 2010b, pp.153-154)

Importantly, as discussed for the simplified model, the MISO calculations recognize the impacts on revenues or payments by load and to generators, but these are "not included in the overall value calculation." The model calculates the costs and benefits A through H, and keeps track of the major transfer payments B and D. But the transfer payments through load savings or generator revenues are not included in the aggregate net benefits in F+G+H.

> "Load Cost Savings where load cost represents the annual load payments, measured by projections in hourly load weighted LMP: Load cost savings and Adjusted Production Cost savings are essentially two alternative benefit measures to address a single type of economic value and are not additive measures. Load cost savings were not used to calculate the total value of the RGOS plans in MTEP10. … Value of transmission plan (per future) = Sum of values of financially quantifiable measures = Adjusted Production Cost savings + Capacity loss savings + Carbon emission reductions." (Midwest ISO 2010b, pp. 153-154)

Applying the appropriate locational version of the calculations, which must be embedded in the model detail, would allow utilization of this framework to handle the estimation of the locational net benefits that would be used as outlined above to determine the cost allocation.

Inherent in this estimation of the costs and benefits is a tradeoff between transmission investment and other investment and operating costs and benefits. As illustrated in Figure 8, taken from the same MISO study, relying primarily on local generation increases total costs. Investing more in transmission to reach more distant but cheaper new generation lowers total costs. But eventually transmission investments intended to reach ever more distant generation sources would not be compensated by lower total costs. The optimal balance is a combination of transmission investment with local and regional generation. This economic tradeoff between transmission and the location of new generation is inherent in the investment problem and has important



RGOS Zone Scenario Generation and Transmission Cost Comparison

Figure 8

implications for both total costs and cost allocation according to the principle of beneficiary pays.

Reliability Expansions

Traditional reliability planning has not been in the form of an explicit cost-benefit analysis. The characteristic description of reliability planning postulates a future distribution of load. The probability of deviation from that load is combined with the probability that generation will be able to produce adequate power and transmission will be able to deliver the power to the given load. This explicit probability calculation is compared with a reliability standard. Typically the idea is that load would exceed generation no more than one in ten years (Wilson, 2010). If the violation is because of a lack of generation capacity across the full region, then generation investments would be indicated. Often the violation of the standard would be location dependent. If the calculation indicates a violation of the standard for a particular location, then planners would select a cost effective transmission investment that would meet the standard (PJM, 2010a).

Although not explicitly involving a cost benefit tradeoff, there is an inherent locational characteristic in the case of transmission investments. Violation of the reliability standard involves a probability, an amount, and a location where load would have to be curtailed in order to prevent a cascading failure. Absent the transmission expansion, the cost of this lost load would be imposed on the load in the constrained region. A reasonable approximation of the net costs and benefits, therefore, would be to calculate this expected value of loss of load in each location (PJM 2010a, pp. 45-63). If the reliability model is using a zonal approximation for the transfer constrained area, then the expected value of lost load would be socialized across all loads in the zone.

The value of lost load might be very high, but the difference in the expected value of the loss of load could be low. For example, using the parameters from (Wilson, 2010), if the occurrence is for 5 hours valued at $20,000/MWh with a probability of occurrence one day in ten years, then the total expected benefit would be of the order of $10 thousand per MW-year for a reliability line that completely eliminated the possibility of involuntary curtailment. This is an upper bound on the implied annual reliability benefit, with the expected value being determined by the change in the probability and the expected curtailment. By comparison, for an illustrative example PJM estimates the cost of the PATH transmission line at $2.1 billion for overnight construction and providing 4800 MW of incremental reliability transfer capability (PJM 2011, pp. 129-133). Even if we assume that all the increment translates into a corresponding reduction in expected lost load, the reliability benefit would be only a small fraction of the carrying cost of the transmission expansion.[2] The change in the expected value of lost load, with and without the transmission investment, could be added into the benefits from the economic analysis of the same investments. If the reliability standard is justified, then the calculation could be considered as just a better approximation of the tails of the distribution of the model that would apply in Figure 7.

---

[2] Compare an upper bound of $48 million in annual change in expected loss of load benefits to $315 million annualized transmission cost at a capital recovery factor of 15%.

If the reliability standard is too restrictive, reliability rules may still require an investment that does not meet the gold standard that estimated benefits exceed costs (Wilson, 2010). The reliability standard may in this case trump the cost-benefit analysis. This could be good policy recognizing the reality of imperfect model calculations and the severe consequences of reliability violations. But the argument to proceed with the reliability investment as needed despite the implications of the cost benefit calculations does not extend to the cost allocation. The same distribution of cost allocation to the beneficiaries would apply to a portion of the cost, even though aggregate estimate of benefits was less than the total investment cost. The remaining cost could be treated as for the difficult-to-quantify benefits discussed below.

Policy Expansions

Identification of transmission lines needed to meet policy objectives seems to set up a different category (FERC, 2010). However, there are simple ways to incorporate many different types of policies within the framework of Figure 6.

Consider the simplest case of a tax on carbon emissions. The tax would be part of the operating cost of generation, with more or less impact depending on the carbon emissions of particular generation technologies. This variable cost would be included in the operating cost parameters. In organized markets with generation offers, the carbon tax would be part of the costs internalized in the market offers. This fits immediately into the cost-benefit framework. There is nothing new required.

A cap and trade policy would have a similar impact. The effect of the cap (with its likely safety valve prices) could be modeled through a proxy carbon tax, or it could be included explicitly through an added constraint in the dispatch model. The constraint would induce a price (the implied carbon tax) and the price would alter the calculation of costs and benefits in the planning model. This calculation would be inherently locational, and would fit naturally into the collateral calculation of the net benefits as outline above. In principle, there is nothing new required here.

A renewable portfolio standard (RPS) would have a similar treatment. The standard could be administered through creation of renewable energy credits (REC). The total standard would dictate a certain number of required credits. Different generation technologies would produce different volumes of credits. Again the constraints would give rise to a projected implicit price of the credits that would be incorporated in the calculation of expected net benefits. There is nothing new required, other than to modify the planning model to incorporate the RPS policy. The details could involve treating separately different standards in different regions, and modeling the linkage in the application of RECs to different standards to avoid double counting. For example, nuclear power may be included in one state RPS and excluded in another. This would be a modest change in the models compared to the complexities of dealing with issues like reliability and contingency constraints that have already been addressed.

Benefits Beyond

Current planning and production cost models involve inherent approximations that can limit or ignore representation of the full benefits of transmission expansion (Pfeifenberger, Fox-Penner, & Hou, 2010). For example, the usual scenario based methods for evaluating uncertainty ignore the option value that arises in the sequential resolution of uncertainty over the dynamic future. This is the option value that comes from being able to change your mind later when new information is revealed. Inevitably, it is and always has been true that part of the decision for any investment involves judgment about benefits that are harder to quantify. The only necessary criterion to proceed is a judgment that the expected benefits are greater than the costs.

This difficulty has slightly different implications for evaluating the decision to go forward with an investment and for the associated cost allocation. If the quantifiable benefits that fit into the modeling framework are greater than the cost of the investment, there would be a relatively easy decision to go forward with the transmission expansion. The harder case would be when the reverse holds, and the decision keys on the evaluation of the putative additional benefits. This would depend in the end on the judgment of regulators who would make the policy decision. Identifying the additional benefits and providing an estimate of the aggregate size would be an important topic that may depend on the particular details of the investment (Pfeifenberger & Hou, 2011).

The implications for cost allocation would be somewhat different. The existence of difficult-to-quantify benefits does not lead inexorably to cost socialization. The quantifiable benefits and their distribution could still be estimated using the existing modeling approximations. If the total quantifiable benefits exceed the transmission investment cost, then allocating in proportion to the quantifiable estimates would be consistent with efficient investments. The beneficiaries would be better off with the expansion and this allocation than they would be without the expansion.

In the case that the easily quantifiable benefits are less than the investment cost, but the subjective estimate is that the total benefits are greater, the challenge would be to estimate the subjective distribution of those subjective benefits. In the extreme case, the regulator could decide that the subjective benefits are evenly distributed over all load or all generation. Whatever the subjective estimate, a simple rule would be to allocate the costs equal to and according to the quantifiable benefits (F, G, H) and then allocate the residual costs (TC-F-G-H) according to the regulator's subjective distribution of benefits. This would preserve as much as possible the principle of allocating costs to beneficiaries, and revert to cost socialization only when indicated by the distribution of benefits, or when applied as a last–not a first–resort. Only in the limiting case, when all the benefits are subjective and evenly distributed would this result in a cost allocation equivalent to full socialization.

A complementary transmission expansion policy would involve the beneficiaries in the decision to make the investment. With imperfect estimation of the benefits and their distribution, it is possible that the regulators are wrong; or at least that the intended beneficiaries have a different view about the benefits. Voluntary investment where the participants pay is one attractive solution, but as discussed above it does not exhaust all cases of efficient transmission investment. Mandated investment with payment through the rate base provides another solution. But there is a spectrum in between that provides a workable balance of voluntary and mandatory features.

The case of New York illustrates the idea of allowing the putative beneficiaries some room to disagree, but without fully recreating the problems of free-riding that partly motivate the need for mandated investment. Now embodied in the tariff of the New York Independent System Operator (NYISO), the idea was succinctly explained in the initial proposal:

> "The proposed cost allocation mechanism is based on a 'beneficiaries pay' approach, consistent with the Commission's longstanding cost causation principles. … Beneficiaries will be those entities that economically benefit from the project, and the cost allocation among them will be based upon their relative economic benefit. … The proposed cost allocation mechanism will apply only if a super-majority of a project's beneficiaries agree that an economic project should proceed. The super-majority required to proceed equals 80 percent of the weighted vote of the beneficiaries associated with the project that are present at the time of the vote." (NYISO 2007, pp. 14-15)

The votes are weighted according to the same distribution as the proposed cost allocation. Only the beneficiaries can vote. The assumption is that if more than 20 percent of the beneficiaries disagree with the estimate of the benefits, the proposal should not go forward. The details of the implementation might be different from the NYISO case, where only loads are presumed to be beneficiaries, and the fraction for super-majority approval could be different. But the idea illustrates a design of a hybrid system that is compatible with the larger goals of efficient market design.

Cost Allocation Reform

The outline above, using the simplified metaphor of a single transmission line to guide application of existing planning models, points in the direction of a workable implementation and points away from certain current practices as surveyed in a PJM report on cost allocation methods (PJM, 2010b).

The Southwest Power Pool (SPP) previously used a transmission decision making and cost allocation methodology that focused on a portfolio of transmission projects (SPP, 2009). An important feature of the SPP approach exploited the vertical integration of the participants and their ownership of generation needed to serve the load. This avoids the distinction between the benefits to load and the benefits to generation, as the benefits are merged in one organization. In deciding on expansions and allocating the costs, the SPP Balanced Portfolio Model (BPM) uses the language of cost socialization with system wide postage stamp rates and additional locational charges. However, this is misleading because a key part of the analysis and negotiation is to rebalance the mix of local charges and system wide charges until the benefits exceed the costs for each participant and the parties agree on the expansion portfolio and cost allocation (SPP 2009, p. 23). Therefore, the SPP BPM model is consistent with the principle that beneficiaries pay and costs are not socialized. The SPP balanced portfolio approach is essentially voluntary and the beneficiaries pay. The model may not translate well to other regions that do not enjoy the same degree of vertical integration, but it does conform to support of efficient transmission investment and illustrates an application of the beneficiary pays principle using existing planning tools.

This example of a beneficiary pays model was later replaced by the SPP Highway/Byway approach that assigns costs to different regions according to the voltage level of the transmission facilities (FERC-SPP, 2010). The Highway/Byway model socializes the cost of lines above 300 kV, splits the cost for intermediate lines, and assigns the full cost to the local zone for lines below 100 kV. The justification cites power flows over the lines (¶ 23). But the power flows reflect only the impact of different impedances of different voltage levels, not the distribution of benefits which are driven by quite different factors such as transmission constraints. As illustrated in the FERC decision, the effect of the same line and constraint can be dramatically different at different locations (¶ 25). The power flows do not describe the distribution of benefits.[3]

The SMARTransmission study provided an extensive analysis of transmission investment in the Midwest (Tan, Maghdan, & Gentile, 2010). The summary reports "that the differences in the economic performance are small across the various generation futures run for the study year 2029" (p. 9). However, a key assumption was the exogenous choice that "incremental wind generation in the study footprint was then allocated among the states in proportion to the wind capacity" (p. 13). The effect of different transmission profiles was to change the dispatch but not the location of the investment in wind and other generating plants. This approach is not consistent with the central tradeoff illustrated in Figure 8 that balances new generation location and transmission construction. The SMARTransmission approach answers a narrow question, but is not consistent with identifying the total net benefits or estimating the distribution of those benefits to guide transmission investment or cost allocation.

The MISO Multi-Value Project (MVP) methodology is another innovation in transmission planning and cost allocation. Like the SPP BPM methodology, the idea is to develop portfolios of projects that might produce a broader array of benefits and beneficiaries. Unlike the SPP BPM methodology, the MVP does not envision voluntary participation or approval by the beneficiaries. Rather the essence of the idea is to identify projects that have economic, reliability and policy implications, and whose impacts touch the whole region to at least some degree. Since all transmission investments have economic, reliability and policy impacts, the extension to have some impacts across the region eliminates some investments (like direct connection), but it is a low threshold. Once the portfolio passes this threshold, and the mandated investment is approved by the regulator, cost allocation reverts to socialization with postage stamp rates across the MISO footprint, sharing the total cost 80% with load and 20% with generators (Midwest ISO, 2010c) (FERC-MISO, 2010). There is no explicit connection to the degree of impact or the distribution of benefits. Adopted before the resolution of the issues raised by the beneficiary pays principle, this MVP cost socialization approach is inconsistent with the framework described above.

Treatment of incremental net benefits separate from transfer payments between participants is not well embedded in current practice for transmission investment and cost allocation. For example, following direction from FERC, the PJM Regional

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[3] Ironically, FERC approved the SPP Highway/Byway cost socialization model, replacing the beneficiary pays Balanced Portfolio Model, on the same day it promulgated the Notice of Proposed Rulemaking embracing the beneficiary pays principle, June 17, 2010.

Transmission Organization (RTO) defines transmission investment benefits as a weighted mix of net benefits and transfer payments:

> "The Energy Market Benefit component of the Benefit/Cost Ratio is expressed as: Energy Market Benefit = [.70] * [Change in Total Energy Production Cost] + [.30] * [Change in Load Energy Payment]. … Reliability Pricing Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * Change in Load Capacity Payment]." (PJM, 2010, p. 75)

In other words, the benefit cost ratio is based only in part on F+G+H in Figure 2, and includes the transfer payments B+D that are not an addition to aggregate net benefits. This calculation of benefits cannot be consistent with either efficient transmission investment or cost allocation according to the principle that the beneficiary pays. It is clear from this description that the PJM analysis and models produce the necessary information to determine aggregate net benefits and the distribution of benefits. But application of that information will require a reframing of transmission decisions and cost allocation.

Applications

A common first question applies to the case of a new generator connecting to the transmission grid. The transmission line linking the generator to the network presents an opportunity for evaluating the distribution of benefits. Application of the analysis described above would accept the constraint that the new generation plant is constructed. Hence, the investment cost in the generator would not be part of the analysis. However, the operating cost of the generator would be relevant. The base case would be no connection to the transmission grid, in which case the benefits to the generator would be zero. The alternative case would be connection for total investment cost TC. With the generator connected and the line in place, the planning model would simulate the investment and dispatch scenarios with associated prices and quantities. If prices in the rest of the grid were largely unaffected, then the net economic benefit of the connection would be limited to the implied dispatch profits of the new generator. In this case, application of the beneficiary pays principle would allocate essentially all of the transmission investment costs to the new generator. Only in the case where the new generator's dispatch materially affected prices or other benefits in the rest of the grid would there be an allocation of costs to other beneficiaries.

In the case that the new generation is a collection of generators, such as wind farms across related locations, the benefits for the collection of anticipated benefits would be estimated and the costs assigned in proportion to the benefits. If the expected new generators are not known, there may be a chicken-and-egg problem that requires a regulatory decision to go forward with some interim financing and partial socialization of the new line until the anticipated new investment occurs and costs are assigned to the generator beneficiaries. For example, this is the approach in the California tariff for Location Constrained Resource Interconnection Facilities (CAISO 2010, pp. 33-35).

In the event that the new generation and its transmission may not be constructed, the analysis would be similar. The comparison would be between the base case without the construction and the alternative case that considers the investment cost of the generation.

The expected dispatch benefits for the new generator would be the same. However, the cost of the generation could be subtracted from the new producer surplus, reducing the estimate of H. If the new generator and transmission connection had no material effect on market prices, then we would have $F+G \approx 0$ in Figure 2. If the net benefit of H exceeded the transmission cost TC, then the project should go forward and the cost of the new transmission should be assigned to the generator. If the benefit in H is less than TC, then the generator would presumably choose not to go forward, and this would be the efficient expansion decision because the costs exceed the estimate of the social benefits.

The prior SPP BPM analysis illustrated the application under a more general case of a network with many components and strong network interactions (SPP 2009, p. 23). As shown in Table 1 for an example portfolio, the SPP region divides into a number of zones

Table 1

Portfolio Balance With Transfers for Portfolio 3-A at 345 KV Costs

#	Zone	Benefits	Costs	Transfer Allocation	Transfer Out	Transfer Net	Net Benefit	B/C	Original B/C
1	AEPW	$20,880,672	$24,939,597	$14,640,350	-$18,699,275	-$4,058,925	$0	1.00	0.84
2	EMDE	$5,828,820	$2,923,755	$1,716,339	$0	$1,716,339	$1,188,726	1.26	1.99
3	GRDA	$1,797,527	$2,170,293	$1,274,032	-$1,646,798	-$372,766	$0	1.00	0.83
4	KCPL	$8,337,354	$8,571,771	$5,031,907	-$5,266,324	-$234,417	$0	1.00	0.97
5	MIDW	$1,590,879	$798,241	$468,593	$0	$468,593	$324,045	1.26	1.99
6	MIPU	$1,598,074	$4,491,010	$2,636,368	-$5,529,303	-$2,892,935	$0	1.00	0.36
7	MKEC	$5,294,897	$1,243,893	$730,206	$0	$730,206	$3,320,798	2.68	4.26
8	OKGE	$44,982,968	$15,731,003	$9,234,607	$0	$9,234,607	$20,017,358	1.80	2.86
9	SPRM	-$29,773	$1,719,556	$1,009,435	-$2,758,764	-$1,749,329	$0	1.00	-0.02
10	SUNC	$389,069	$1,185,151	$695,722	-$1,491,804	-$796,082	$0	1.00	0.33
11	SWPS	$43,102,775	$12,809,661	$7,519,685	$0	$7,519,685	$22,773,429	2.12	3.36
12	WEFA	$11,792,345	$3,508,023	$2,059,323	$0	$2,059,323	$6,224,999	2.12	3.36
13	WRI	$23,072,688	$12,818,241	$7,524,722	$0	$7,524,722	$2,729,725	1.13	1.80
14	NPPD	-$608,956	$8,896,109	$5,222,303	-$14,727,368	-$9,505,065	$0	1.00	-0.07
15	OPPD	-$472,047	$6,896,029	$4,048,192	-$11,416,267	-$7,368,075	$0	1.00	-0.07
16	LES	-$145,808	$2,130,072	$1,250,421	-$3,526,301	-$2,275,880	$0	1.00	-0.07
Total		**$167,411,485**	**$110,832,404**	**$65,062,205**	**-$65,062,205**	**$0**	**$56,579,080**	**1.51**	**1.51**

All numbers in the above table represent annualized costs for Portfolio 3-A over a ten-year period. Transfers out of a zone represent the dollars that must be moved from the zonal rates to a region-wide rate in order to achieve balance.

for evaluation of transmission costs and benefits. The original cost of construction of new transmission facilities in the portfolios includes expenditures in zones that may not provide adequate net benefits in all the zones. However, the SPP BPM methodology involves transfers of costs among the zones in the region until the benefit cost (B/C) ratio is at least equal to unity in every zone. The cost allocation does not follow the location of the facilities or tracking of power flows. The cost allocation does reflect the ex ante estimate of benefits (PJM 2010b, p. 50). The result does not go to precise allocation of costs according to the benefits to the individual load or generator, but it is far from a default to cost socialization. The SPP BPM methodology is an example of a workable transmission cost allocation approach according to the principle of allocating costs commensurate with benefits.

These illustrations demonstrate that in some cases estimating the shares of benefits can be easier than estimating the benefits. And in more complicated cases, the difficult task of estimating benefits provides the underlying detail to estimate shares for cost allocation. In all cases, the framework helps define measures of benefits and distinguish among beneficiaries.

Conclusion

A workable system of cost allocation commensurate with benefits for new transmission investment is within reach using available analytical tools. Cost allocation commensurate with the distribution of benefits follows directly from the information that must be produced as part of the evaluation of the investment. Transmission is inherently about moving electric power between locations, and the analysis of the value of such investment requires calculation of locational impacts on generation and load. A consistent parsing of the benefits allows for estimation of cost allocation shares that make the beneficiaries better off while respecting the principle that those in regions who do not benefit do not pay. The procedures are not perfect, but they provide a workable approximation that makes transmission cost socialization a last, not a first, resort.

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