Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal

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Efficient electricity markets facilitate investment by generators and loads. Absent market power, price-taking generators and loads can make their own beneficial investment decisions and pay the associated costs. If there were no economies of scale and scope for transmission investment, electricity markets could follow the same competitive model for transmission where beneficiaries determine and pay for their own investments. Given the large economies of scale and scope, transmission is a natural monopoly and investment requires a central coordinator, such as Transpower. A forward-looking cost-benefit analysis provides the gold standard for ensuring that transmission investments are efficient. The same cost-benefit analysis identifies the expected beneficiaries. Assigning transmission costs to the beneficiaries preserves the efficient incentives for generation and load. The Electricity Authority proposal describes the logic and the main elements of a workable beneficiary-pays investment and cost allocation framework. The various critiques of the proposal fail to address the underlying connection between transmission cost and the allocation to beneficiaries.

Introduction

In a 2019 Issues Paper under its Transmission Pricing Review, the Electricity Authority of New Zealand set out a framework for efficient electricity system investment, cost allocation, and pricing. The basic design accords with beneficiary-pays principles. The challenges of transmission investment preclude pure market approaches and require consistency across both competitive and monopoly elements of the system. In comments on the Authority's proposal, submissions of some parties include critiques or alternative recommendations that appeal to implicit assumptions inconsistent with the basic requirements of the technology and associated electricity market components. Although perfection is only possible under narrow conditions, the Authority's framework provides a careful balance that adheres to first principles and can accommodate workable implementation.

Efficient Transmission Investment

The electricity system includes competitive sectors such as generation and load. In addition, the transmission grid is a natural monopoly with distinct characteristics implicating reliable real-time system operations and long-term transmission investment. The Authority lays out the basic requirements including: (i) Transpower's role in providing open access and non-discrimination in the use of the transmission essential facility, (ii) efficient operations through real-time security-constrained economic dispatch with locational energy prices, (iii) and cost allocation for transmission investment compatible with the competitive market sectors in generation and load. (Electricity Authority 2019b) Both generation and load decisions are affected by transmission operations, investment and cost allocation, requiring attention to maintain a level playing field.

Generation and load typically involve technologies at individually small scales to support the judgment that these sectors are workably competitive. The limited cases of an ability to exercise market power require some regulatory oversight. But the broad design for the competitive sectors is to accept decentralized decisions on contracts and pricing. The assumption is that competitive pricing leads to efficiency for both operations and investment and there is no need for central intervention in the competitive sectors.

This workably competitive assumption is not true for the transmission system. There is a requirement for more care, much more, in the design of pricing and access rules for the monopoly transmission system. The broad international response to this challenge has been to assign the responsibility to a system operator that controls reliable operations and guides efficient transmission investment. These are part of the functions of Transpower. Experience in New Zealand and elsewhere has shown that the access and pricing rules are critical for the success of the larger electricity market. (Hogan 2002) (Bushnell and Wolak 2017, 12–13)

In real-time, the successful market design takes supply and demand conditions for generation and load and determines the economic dispatch with locational marginal prices. These essential prices provide the system location marginal cost of load and the locational marginal value of generation. Furthermore, the difference in the locational prices provides the opportunity cost for real-time transmission between the corresponding locations.

In many restructured electricity markets, in early days, there was an argument that the features of economic dispatch and locational prices were not very important, and that a reasonable approximation that simplified the market by providing average price proxies, or socializing the costs by spreading costs over market participants without regard to the distribution of benefits, would work well enough. The truth was and is different. From a theoretical perspective, under principles of open access and non-discrimination, there is only one way to organize a real-time electricity market. The real-time model follows from first principles of efficiency analysis applied to the technical requirements of meshed power systems. (Schweppe et al. 1988) From a practical perspective, experience shows that deviation from this ideal soon creates material problems that require increasing intervention in the market to undo the perverse incentives and consequences created by prices that do not support efficient dispatch. (Hogan 2002) For example, after several experiments with "simpler" models, all seven of the large organized markets in the United States adopted or moved to the same real-time model as embraced in New Zealand. This is now standard practice for successful electricity market design.

The international debates about transmission investment, cost allocation and pricing include echoes of the early discussion about real-time operations. The Authority's framework appropriately adheres to an analysis from first principles. The analysis accommodates the natural monopoly characteristics of grid expansion in ways that complement the analysis for system operations.

A key efficiency prerequisite is a cost-benefit analysis for grid expansion. (Commerce Commission 2018) There is no other way of determining whether a grid investment is efficient. Whatever the purpose of the grid investment, it will only be efficient if the benefits it provides – for example, in terms of lower energy production costs or increased reliability – exceed the cost of the investment. No investment should proceed without being subject to a cost-benefit assessment which quantifies all benefits and costs. As discussed in the Appendix, this is the "gold standard" for evaluating transmission investment.

Cost allocation reflects efficient wholesale pricing in real-time which contributes revenues that help support investment, but the Authority recognizes that funding from real-time prices alone will not be sufficient to support grid expansion. There must be some added cost allocation, but this should be done in a way that supports efficient incentives for operation and investment.

The main connection between transmission investment and real-time operations is through the cost of transmission congestion.[1] As discussed in the Appendix, under restrictive assumptions about the cost of transmission, such as no economies of scale and scope, congestion revenues would be sufficient to support efficient transmission investment. If the restrictive conditions applied well enough, then the case might be stronger for moving first principles into the background and allowing for some simplified transmission pricing. However, the restrictive assumptions are not even approximately true. The difference between average congestion revenues and actual transmission investment cost implies that most of the cost of efficient investment would be uncovered after accounting for congestion costs. And the particulars of transmission cost allocation can be material.

Hence, the Authority's approach of following the guidance from first principles leads to the design of a beneficiary-pays system that is both intuitive and consistent with competitive market design for generation and load. The Authority's proposal explains:

> "The principles we have derived for the efficient pricing of transmission services can be summarised as follows:

[1] This is the Loss and Constraint Excess which includes the difference between settlements at prices for locations, for congestion and for the excess of marginal over average losses.

(a) LMP is generally the best means of restricting the use of the grid to its capacity

(b) each user should pay the cost of connecting it to the grid

(c) the charges for access to transmission services from a transmission investment in the grid should recover the total cost of providing the transmission investment

(d) subject to paragraph D.86 (e) below, charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment

(e) charges for a transmission user should be similar to those for other competing users after adjusting for their size and location

(f) any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable." (Electricity Authority 2019b, para. D86)

Implicit in (d) is the embedded discussion that the residual cost allocation should be "not so large as to make it privately profitable to disconnect from the grid; that is, provided the charges are between the incremental cost of and the stand-alone cost of supplying the customer." (Electricity Authority 2019b, para. D75) This is consistent with the essence of (f) "to affect their behaviour as little as practicable." These principles lead to a pricing structure that has two main components: a variable usage charge that is the congestion component of the LMP, and a fixed access charge that covers the covers the remaining transmission investment costs while affecting "behavior as little as practicable."

The details are not trivial, but the design exploits a fundamental feature of the transmission expansion problem. Cost-benefit principles and analysis support and guide major transmission investments. A cost-benefit evaluation should be done before the investment decision. This ex ante calculation inherently identifies the anticipated changes in the uses of the transmission grid that would justify the investment costs. And these changes in the uses of the system inherently identify the distribution of benefits and costs among the market participants. Hence, as discussed in the Appendix, consistent accounting to separate net benefits from transfer payments provides the identification of the beneficiaries. By the cost-benefit test, the net benefits would cover transmission investment costs. Furthermore, as illustrated in the Appendix and Figure 6, prices decrease for some locations and in increase for others. The gross benefits of the beneficiaries are greater than the net benefits of the aggregate cost-benefit result. And consistent with the competitive framework for entry and exit, it is the gross beneficiaries who would pay for the transmission investment. Some of the payment would come through real-time congestion revenues, and some would be allocated to cover the significant remaining transmission investment costs. The latter allocation would best be applied as a fixed access charge, leaving untouched the efficient real-time incentives. This is the essence of the Authority's pricing proposal.

For transmission expansions, the Authority's model is logical and intuitive. After acknowledging this point, within limits as in "the [Beneficiary Pays] approach can be effective in a limited number of situations" (Creative Energy Consulting 2019, 21), the submitted critiques of the proposal typically assume that the Authority is applying the same arguments to all sunk costs, or should apply some other approach to cost-benefit analysis with costs assigned to the beneficiaries. This confuses the discussion. The issues of treatment for past and future investments are properly addressed separately in the Authority's proposal, along with a consistent application of the efficient cost allocation principles.

The Authority's proposal works in theory, applying the same assumptions as required for the associated cost-benefit analysis. No other proposal offered in the various critiques even works in theory under the same assumptions. Hence, the arguments for the alternatives to the Authority's proposal rest on claims that the alternative cost allocation methods, while not supporting the efficient outcome, would be better in practice. This is partly an empirical question, but there is no evidence provided in the critiques that supports these claims when comparing the proposals under common assumptions.

The detailed analysis requires an understanding of the technical characteristics of transmission, reliability rules, conduct of system operations, forecasts of participant behavior and the associated substantial uncertainty about the future. Were it possible to avoid these details, there might be a search for an alternative to the beneficiary-pays principle. But these same details all arise in the cost-benefit analysis, as does the identification of the beneficiaries. The forecasts are imperfect, but they are necessary. Furthermore, the process of identifying the benefits and the beneficiaries elicits better information. For example, experience with the well-known "Fourth Line" case in Argentina illustrates the lessons derived from the Public Contest method and the associated focus on allocating transmission investment costs to the beneficiaries. (Littlechild 2011, 18–20) The Authority's transmission cost allocation approach simply allocates costs utilizing the same information as should be required to make the investment decision.

Critiques of Beneficiary Pays

The Authority's consultation paper called for submissions that either supported or critiqued the main outlines of the cost allocation framework. There are a few common themes in these comments. The collective challenge of these critiques is to look for something that is simpler and that resembles ideas reflected in other commodity markets. However, underlying these critiques are implicit or explicit assumptions that are at odds with the reality of the electricity transmission investment system and the real challenges of cost allocation.

Pricing and Market Design

An implicit assumption of many of the comments ignores the critical pricing structure in the Authority's proposal. If the Authority were attempting to have only a usage charge, many of the criticisms would apply. However, the Authority includes a usage charge and an access charge, a two-part or "nonlinear" pricing structure, which is fundamentally different. By contrast, a one-part pricing regime which applies investment cost allocations to energy prices would be problematic. For example, the critique in (Creative Energy Consulting 2019) is organized according to the Authority's principles, but applies those principles to what is in effect a one-part pricing model. But the Authority's proposal is quite explicitly a two-part pricing structure.

A pricing structure with one-part pricing, often referred to as applying "linear" prices, would support an efficient market only under very narrow conditions. As discussed in the appendix, if the transmission investment costs exhibited no economies of scale or scope, then a one-part charge based on energy prices would produce efficient operations, and the associated congestion revenues would cover the costs of transmission investment. The expected congestion charges would equate to the Long-Run Marginal Cost (LRMC) of transmission expansion, and everything would be easier.

The material distinction with transmission investment is the presence of significant economies of scale and scope. This presents a series of problems: congestion revenues will be only be a fraction of transmission expansion costs, the LRMC is not even well-defined, and a one-part pricing system would create material departures from efficient operations and investment.

For example, a one-part pricing structure is an implicit assumption of the recommendations for Ramsey pricing as part of the transmission investment and charging regime. "[EA] fail[s] to apply the standard Ramsey principles" (Creative Energy Consulting 2019, iii) "Economic theory dictates that pricing of services should be inverse to the elasticity of demand for those services. That is to say, prices should be higher where demand is inelastic (i.e. consumers are less price sensitive) and lower where demand is elastic (i.e. more price sensitive). This pricing strategy, known as Ramsey pricing, provides a more efficient / non-distortionary way of recovering a given revenue requirement." (The Lantau Group 2019, 11) "[R]emaining capital costs should be recovered according to best practices for natural monopoly regulation. This implies some form of 'Ramsey pricing.'" (Bushnell and Wolak 2017, 7)

The essential idea of Ramsey pricing starts with an assumption that a one-part pricing system is required by market conditions or regulatory mandates. Efficient usage prices would not cover fixed costs, so the Ramsey approach calls for recovering the residual costs by applying different usage prices for different users or uses, all guided by the principle to charge proportionally more to those who would respond less and, thereby, minimize if not eliminate the market distortions. (Joskow 2007, 1275)

A two-part pricing structure follows a similar logic and goal, but it eliminates the constraint of the one-part price. Now the usage charge is set at the efficient level defined by the real-time locational price, and the access charges are used to recover the residual costs. Given the value of transmission access, there is a set of different access charges "not so large as to make it privately profitable to disconnect from the grid." In this way, a perfect set of access charges would produce no deviation from the efficient market outcome.[2] Therefore, the Authority's proposal follows the same dictates as Ramsey pricing, but applies the analysis to a two-part pricing structure, and the result supports efficient investment.

The alleged challenges of the LMP model in New Zealand, as in (The Lantau Group 2019, 26–27), reflect a similar neglect of the benefits of the Authority's proposed two-part pricing structure. The real-time market is not perfect nor is the LMP designed to handle all problems. To the extent that there are defects in the real-time market and the calculation of LMPs, the analysis should focus on the underlying cause and identify remedies consistent with the basic real-time model. For example, "[c]urrently, with no nodal scarcity pricing and very limit demand-side participation, it is unlikely that nodal prices live up to the theoretical ideal stated in the EA's principle." (Creative Energy Consulting 2019, 5) Adequate scarcity pricing has been a challenge in other markets without active demand bidding. An immediate solution is found in enhancements of the pricing model for operating reserves. (Hogan and Pope 2019) The Authority's planned real-time pricing reforms to be implemented in 2022 addresses scarcity pricing and other matters. (Electricity Authority 2019a) This is different than addressing the requirements of transmission cost allocation. But the workably competitive market provides the right market signals for the competitive sectors. Other challenges such as including the cost of carbon or of transmission investment require something more than just the LMPs or simple peak load charges.

A similar response applies to the concern about an absence of adequate hedges to deal with volatile LMPs. "[O]ne can ask whether highly volatile spot prices and their implications for risk taking and efficiency of risk management lead to efficient investment without availability of hedges or contracts or gentailer structures or even capacity markets" (The Lantau Group 2019, 13) Forward contracts markets, coupled with Financial Transmission Rights (FTRs), provide hedging opportunities. (Hogan 1992) If this is a concern, the solution would be to address any such problems directly rather than to use the instrument of transmission investment charging to balance other deficiencies in market design.

A related argument is that the Authority's proposal based on the beneficiary-pays principle will lead to a dilution effect which could not provide the correct signal. "Even if the user could forecast future BP charges, there is a more fundamental problem: the price signal created does not reflect the transmission cost that the user's investment decision causes and so will not promote dynamic efficiency when factored into this decision. Rather, it will be much lower than the long-run transmission cost, due a dilution effect …". (Creative Energy Consulting 2019, 15–16) An

[2] "In this case the customized/access fee A_i charged to each consumer would simply have to satisfy the condition $A_i < S_i - cq_i$ [i.e., each access fee less than the customer benefit] and there will exist at least one vector of A_i values that will allow the firm to satisfy the break-even constraint as long as it is efficient to supply the service at all." (Joskow 2007, 1277)

example is offered to support this assertion, but the example provides no analysis or assumed facts about the costs and benefits that would be needed to support the critique. (Creative Energy Consulting 2019, fig. 1) Furthermore, with no economies of scale, the beneficiary-pays model applied to this example would provide exactly the right long-run signal. Extending the analysis to the case of economies of scale and defining the benefits and beneficiaries, as explained in the Appendix, would arrive at the conclusion that the Authority's proposal would allow for an equilibrium for two-part prices that support efficient operation and investment. Hence, the "dilution" argument is both unsupported in the critique and wrong in application with or without economies of scale.

Price Direction

An analogy to price-directed competitive markets, where the only signal is the current price, stands behind several of the arguments that market participants are myopic in that they cannot forecast nodal prices or benefit-based charges. Hence, the argument goes, Transpower needs to specify a simple transmission price for today that is also the promise of the price for tomorrow. "[T]he implicit ex-ante 'shadow price' signals provided by [benefits-based] charges would not provide a predictable, accurate signal of Transpower's long-run costs to which grid users could respond." (Axiom Economics 2019, iv)

The assumption of myopic loads and generators seems unnecessary and wrong. It may be true for some customers, who may also tend to be price inelastic and therefore not much affected by the pricing model. But for large volumes at the margin, from larger commercial and industrial loads, the myopic assumption seems extreme.

The real challenge will be in providing information about the counterfactual and the likely future charges with and without the transmission expansion, rather than imposing on everyone the mandate to be myopic. Continued improvements in the analysis and allocation of the costs and benefits to make better decisions and provide better information would be important to pursue, and this is a natural part of the Authority's proposal. Hence, the solution to providing information for investment decisions is not found by setting inconsistent transmission prices, such as a current charge based on estimates of future costs.

It would be useful for Transpower to provide studies and information about expansion plans and possible cost allocations. But this information benefit is far different from suggesting that the same estimated cost allocation should also apply to current usage charges. It would be surprising if unrecouped historical average costs equaled projected system costs.

Long-Run Marginal Cost

One suggestion found in some of the critiques is to abandon the beneficiary pays approach and apply an LRMC charge that would signal the prospective expansion costs at each location. "[C]ustomers' current usage decisions must factor in the future costs that are contingent on these decisions. In short, customer decisions must be forward-looking. … This is usually, and best, achieved by designing forward-looking prices: ie LRMC pricing," (Creative Energy Consulting 2016, i) "[I]n the absence of an LRMC price (or a modified version of the RCPD charge), there would be no way for Transpower to efficiently signal its future costs." (Axiom Economics 2016, 1) "[A]n explicit ex-ante price signal of some kind would better promote dynamic efficiency, such as a long run marginal cost (LRMC) charge" (Axiom Economics 2019, vi) This would be the closest analogy to a price-directed market. Assuming the LRMC is well-defined, competitive market participants could make their own locational investment decisions, the information costs would be low, and the market would provide a workable approximation of efficient expansion.

As discussed in the Appendix, an implicit assumption of this LRMC design approach is that the underlying cost structure of transmission investment exhibits no economies of scale or scope. Absent such economies, the average cost of expansion and the marginal cost would be the same. But with material economies of scale and scope, the average cost of expansion can be quite different than the marginal cost. Charging the average cost in the real-time market (that is, an LRMC charge) would break the connection with efficient real-time pricing.

This can only be avoided by relying on locational marginal prices to provide the price signal and having a fixed charge unrelated to grid use to appropriately recover the cost of the investment. If there are defects in real-time pricing, these should be addressed directly. The fixed charge is most logically applied after the investment is made and the benefits accrued. And announcing a prospective fixed charge to be applied after the expansion returns us to the same beneficiary-pays design problem that the Authority has addressed.

There is an inherent contradiction in making the efficiency arguments for LRMC based on marginal analysis precisely when the marginal analysis does not apply; or in making arguments for LRMC using assumptions which make LRMC unnecessary. Hence it would be wrong to conclude that applying an explicit ex-ante price signal of Transpower's future investment costs, such as an LRMC charge, would better promote dynamic efficiency.

Peak Demand Charging

Intuition suggests that peak demand conditions drive transmission investment and, therefore, transmission investments costs should be recovered through prices applied to actual usage at the coincident peak. The Authority proposes to move away from a peak demand charge and various commenters argue that this will provide inefficient incentives with inadequate forward-looking price signals. The critiques do not analyze the conditions that drive transmission investment or provide a proper accounting for the underlying analysis of peak-load pricing, and largely ignore the continuing role for residual cost allocation under a two-part pricing structure. "[A]pplying Ramsey principles would mean that residual tariffs should also apply primarily at peak time." (Creative Energy Consulting 2016, 19) "The key insight is that, because scarcity prices, and other high nodal prices, will tend to occur around the times of peak load, these averaged prices will also be highest around peak demand and could be approximated by the sort of peak charging structure that we have currently." (Creative Energy Consulting 2019, 11) "One of the advantages of retaining some form of the existing RCPD-based interconnection charge – or introducing an LRMC-based charge – is that it would enable Transpower to send a signal – albeit an imperfect one – to customers to curtail their usage during times of peak demand as capacity constraints start to emerge in a region" (Axiom Economics 2019, 49)

Although intuitive, the peak demand idea is misplaced in at least two ways. First, transmission expansion produces many benefits that in some cases have little to do with system peak. Even in the New Zealand system, with the North and South Islands, the flow of power is not always in the same direction. In meshed systems, with widely distributed generation and load, the greatest stress on the transmission system does not necessarily come at the system peak. At these times, essentially all generation would be required and the flows on the high voltage network could be well within the system capacity. In some cases, peak usage of the transmission grid would be when local generation was too expensive to meet local load, and large amounts of power was moving to meet the distant load. The stressed part of the system could change regularly and differ from the aggregate system coincident peak. This will be even more true with expansion of intermittent renewables where net load, not peak load, will be an important factor.

Second, the real-time pricing model already accounts for the cost of congestion through the locational prices in the wholesale spot market for energy. This is a variable demand charge that provides the formal connection to the intuition and the theory of peak load pricing. (Joskow 2007, 1283) Adding another variable charge on top of congestion cost would create perverse real-time incentives for load management to avoid such transmission charges. Customers who could identify the peak period would see transmission charges that were (sometimes much) larger than the congestion costs of real-time pricing and would reduce their load to avoid the transmission charges and shift the transmission costs to others. This behavior could easily appear during periods when there was no congestion and the transmission system had excess capacity. Real costs would be incurred to avoid the allocation of sunk costs. For example, this has been the experience in Texas which applies a coincident peak charging mechanism for transmission cost allocation. (Hogan and Pope 2017)

In the presence of economies of scale and scope, with average costs of expansion greater than attributable marginal costs, preserving short-and-long-term efficiency calls for a two-part pricing structure that is a fixed access charge coupled with real-time energy LMPs. This efficient two-part pricing is a core feature of the Authority's proposal.

Benefit Revelation

Estimation of the benefits, and identification of the beneficiaries, is an inherent part of cost-benefit evaluations which should be performed for transmission expansion. One objection to the use of this information to guide cost allocation is that the prospective beneficiaries will have an incentive to understate their benefits in order to avoid the associated cost allocation. "[M]arket participants have a strong incentive to inflate their claimed benefits when such claims might make the difference in building a project, but underestimate their claimed benefits if they view a project as likely to be chosen." (Bushnell and Wolak 2017, 12)

While there is a partial logic to support this claim, the argument ignores closely related facts. First, the strongest version of this incentive would apply in cases of ex post evaluation of benefits after the transmission investment was sunk. Under the principles of transmission operations, there would be no exclusion and the beneficiaries could try to avoid the costs by obscuring the benefits. This is one reason why the Authority's proposal envisions a future regime that, after a period of transition, does not revise the cost allocation for existing assets.

The distinction between allocation of sunk costs and new investments is important. For the case of new investments, the beneficiaries face conflicting incentives. They would like to get the product (the transmission investment) but they would like to pay as little as possible without walking away from the agreement. This tension is inherent in any system that guarantees open access while charging users for the cost of the grid. It is avoidable only in the case where the investment is for a sole beneficiary, as in the case of a simple connection investment for a generator. This is one reason that the cost-benefit analysis will depend on Transpower's forecasts and estimation of benefits. Transpower can elicit information from market participants, but in the end the complex interactions on the grid and the effects on many participants requires an independent evaluation of the costs and the benefits. This same independent evaluation would provide the required information for the allocation of costs. Hence, the Authority's proposed beneficiary pays approach for cost allocation does not require any new information beyond the essential elements of the associated cost-benefit analysis that should be carried out to ensure the efficiency of the investment.

Dispersed Benefits

Transmission expansion produces many benefits. Some of these benefits would be difficult to quantify and could be broadly dispersed. The usual example is "reliability" which is hard to value and has the characteristics similar to those of a public good. "Crucially, the relevant approvals process, itself, must also be clear and comprehensive in relation to how all of the various types of benefits are to be treated, such as reliability, safety, competition, option value/development, and other economic benefits, as each has different potential beneficiaries under different conditions and at different points in time." (The Lantau Group 2019, 16) The suggestion is that there should then be simpler "broad-based" charges.

The example of transmission investments dominated by reliability constraints will be relevant, but this does not imply any need for changing the basic principles in the Authority's framework. There are two additional considerations which should address the main parts of this dispersed benefits argument. First, although it is difficult to value reliability benefits, it is not impossible. The basic cost-benefit analysis outline includes concepts like the value-of-lost-load (VOLL). A goal of reliability upgrades is to ensure that there are no cascading blackouts, and that involuntary load curtailments are kept to a low level. The value of avoided involuntary curtailments is included in the cost-benefit analysis, and it should be assigned to the beneficiaries identified as the avoided curtailments. This could be a material part of the cost of expansion.

Second, to the extent that there is a public good condition, complete as in for all of New Zealand, or partial as in for the North Island, the dispersed benefits lead naturally to a dispersed allocation of the costs. Hence, the existence of some dispersed benefits is neither inconsistent with the beneficiary-pays framework nor a justification for abandoning the framework of cost-benefit calculation and the associated cost allocation as proposed by the Authority.

Cost Socialization

The dispersed benefits argument is not the same as the argument for cost socialization, which assumes spreading the costs over market participants without regard to the distribution of benefits. Such cost socialization is appealing because of a superficial simplicity. "A benefits-based transmission cost recovery methodology is not needed (will not better promote the statutory objective or result in material benefits) and will increase dispute costs in almost all cases where benefits are already clearly broadly based. If the Authority intends to proceed with any benefits-based methodology it should be limited to specific situations where there is unambiguous localisation of benefits (such as more than 60 or 70 percent), otherwise cost recovery should default to a broad-based framework for simplicity and costly dispute avoidance." (The Lantau Group 2019, 8). However, cost socialization creates perverse incentives as outlined in the Authority's proposal.

If the costs of transmission investment were de minimis, such as for many ancillary services , there could be a case that the perverse incentives would be acceptable and comprise a small loss of overall efficiency. However, the existence of the Authority's proceeding and the expressed concerns about cost allocation stand for the opposite proposition. Transmission investment costs are material and have materially different effects on different market participants. Under a cost-socialization approach, a simple charging mechanism would be accompanied by calls for market interventions, such as prohibiting new generation in some areas and requiring it in others, supporting some and harming others, that could be at least as complex as the cost-benefit approach, but without the added benefit of guiding efficient investment. Hence, broadly ignoring benefits and socializing costs is not simple and would be inconsistent with the Authority's market efficiency goals.

Variable Pricing and Fixed Benefits

Closely related to cost socialization are the implied proposals that investment costs in excess of congestion revenues should be recovered through variable prices. Conversion of fixed costs to variable costs would be inconsistent with the basic goals of efficiency that provide the foundations for the Authority's proposal. Treating fixed costs as variable costs is another path to creating perverse incentives, as discussed for the case of peak load charges.

In practice, implementation down the chain to the final market participants may lead to some compromise between imposing fixed access charges and variable energy prices. This is less of a problem at the wholesale level that is the focus of the Authority's proposal. But at any level, the basic guidance would be the same. First, after charging users the short run marginal cost of using the grid, allocate the remaining costs to the beneficiaries as fixed access charges as much as possible. Second, as the Authority proposes, modify these allocations as needed in the limited cases where the result might be otherwise uneconomic disconnections. Third, when necessary to convert to variable charges, the efficiency distortion in usage prices increases approximately as the square of the deviation from marginal costs. (Hogan 2014) Hence, the policy should be to spread the allocated fixed charges as widely as possible within the beneficiary group. In short, this calls for something like allocation across all the participant's energy usage, in contrast to creating the problems arising from allocations to peak usage or some other narrow measure.

Transition

In the long run, real-time transmission pricing would continue to provide efficient operating incentives at the locational marginal prices. The associated congestion revenues, obtained through real-time operations, would contribute to payment of sunk transmission costs. But these congestion payments would not cover the total of past transmission costs. Repeated application of a beneficiary-pays approach would lead to a diverse set of access charges for each location, built up over time from episodic transmission investment decisions. The result would be like the structure known in the United States as a license plate access charge that differs by location but provides access to the full system.

Except by serendipity, these accumulated access charges would bear little resemblance to the anticipated costs of future transmission expansion. (Bushnell and Wolak 2017, 10) Hence, the ex post access charges would not provide the right incentives for prospective transmission investment. The basic efficiency argument is that real-time LMPs and the best estimate of the future transmission investment costs not recovered through LMPs would provide the best available incentives. Transpower could provide information about future investment costs without being restrained to make future transmission charges somehow equal the costs of past investments. There would be no socialization of costs. Practical implementation would preserve the two-part structure of access fees for the beneficiaries and real-time prices for all as far as possible, down to the point of interconnection of individual market participants. Any conversion of the fixed access charges to variable fees would be limited as much as practicable for broad allocation within, but not across, groups of beneficiaries.

The existing system did not arise under such a beneficiary-pays approach. Hence, there must be some, likely contentious, decisions to reallocate sunk costs. Much of the various critiques is really about these sunk costs rather than the proposal for future investments. Failing to recognize the distinctions confuses most of the analyses. The Authority's proposal addresses this requirement by applying its principles to approximate an efficient system in the few cases where the existing charges create inefficient incentives, and then to reallocate the sunk costs so as to affect future behavior as little as possible. The transition is constrained by basic principles, but the efficiency principles alone cannot dictate the details of a workable implementation for the transition from prior cost allocations.

Conclusion

The Authority's framework using a prospective cost benefit analysis to evaluate transmission investments and allocating the associated costs, provides the practical foundation for supporting efficient transmission investment within the context of a competitive electricity market model. Real-time operations are efficient with open access and real-time locational marginal prices. Market participants see the necessary incentives to participate in and follow economic dispatch as organized by Transpower. The associated real-time congestion revenues provide some of the needed payments to recover the cost of transmission investment. But the structure of transmission investment costs dictates that the real-time payments cannot cover the full cost of investment. With the transmission cost not recovered through LMPS assigned as access charges for the prospective transmission investment beneficiaries, the Authority's proposal provides the missing piece in a workable and economically efficient two-part pricing scheme. The various criticisms of the Authority's proposal are either incorrect or are based on implicit assumptions that do not apply to the real transmission system.

Appendix: Transmission Investment and Cost Allocation Basics

Overview

The economics of electric power transmission investment are both important and challenging. The natural monopoly characteristics of transmission and distribution wires preclude simple analogies for market solutions, and some combination of regulatory oversight and public principles are necessary for achieving and funding efficient transmission expansion. The regime of vertically integrated monopolies met its challenges with a variety of regulated investment models. With electricity market restructuring, to support competition among generators and loads, there are new requirements for a market design that incorporates a framework for transmission investment, access and pricing compatible for the combined monopoly and competitive segments.

Context

Changing technology for generation and new approaches to retail supply for load were the focus of electricity restructuring. At the wholesale market level, a key feature was unbundling to separate the competitive generation and load from the monopoly elements of the high voltage transmission grid. In turn, it was soon recognized that the grid embodied two monopoly activities. One was the maintenance and expansion of the grid to provide interconnection for generation and load. The broad principles were for open access and non-discrimination, to allow entry and competition in generation and load. The monopoly maintaining and operating the grid had to allow for a level playing field in access to this transmission essential facility.

The other monopoly function was in providing dispatch service and coordination for using the grid in real-time. Dispatch of power plants is the principal means for controlling the flow of power on the high voltage grid and meeting the many demands of various operating reliability constraints.

Analysis from first principles arrived at a market design for real-time operations based on the framework of bid-based, security-constrained, economic dispatch with locational prices. A major innovation was to recognize this is the role and the requirement of an Independent System Operator. The New Zealand electricity market was an early leader in establishing this design and creating the now accepted functions for Transpower as the system operator.

In addition to the necessary requirements of system operations, Transpower's mandate includes responsibility for planning and executing an investment program to maintain and expand the high voltage grid.

The two functions interact with each other, and exploit Transpower's expertise. The necessary regulatory oversight includes a requirement that short-term dispatch operations and long-term transmission investment meet the objectives of supporting aggregate economic efficiency. It is part of the explicit mandate to set welfare maximizing objectives and the associated efficiency of operation and investment as the touchstone for designing and operating the restructured electric power system. (Commerce Commission 2018)

The efficiency objective implicates the market design for pricing and investment. There is a need for a hybrid system that provides the right incentives for the competitive sectors but recognizes added requirements for the monopoly components of the transmission investment system.

For example, it is often recommended that the costs of monopoly transmission investment should be socialized, perhaps to achieve simplicity. However, cost socialization would create perverse incentives for the competitive sectors. Generation and load investments are sometimes in competition with transmission expansion, and sometimes serve as complements to transmission investment. If transmission costs were socialized to a material extent, then local generators would face the reality that they might have more efficient options but their efficient generation investments near the load could not compete with the socialized transmission investments that supported complementary generation located far from the load. To achieve efficiency under a policy of socializing transmission investment costs, there would need to be some offsetting intervention in the competitive market. In principle, this process could continue until much of generation investment was removed from the incentives and discipline of the competitive market.

For efficiency reasons alone, this conundrum leads to a different approach to transmission expansion and cost allocation. The key requirement has three dimensions. First, there has to be some mechanism for identifying efficient transmission investments. This decision cannot be left to the market alone. Fortunately, identifying and implementing efficient transmission investments is a mandate and an acknowledged function for Transpower. As a complement, short term-pricing wholesale energy pricing must be based on LMPs. This too is part of the New Zealand market design. And, finally, investment in the transmission system should adhere as much as possible to a beneficiary-pays system. When the beneficiaries pay, transmission cost is not socialized and the monopoly transmission expansion function does not distort the incentives for the competitive sectors of the electricity system.

This latter requirement is the focus here. Taking as given the operation of an efficient and reliable dispatch, and a framework of cost-benefit analysis which should be performed for transmission expansion, the task is to describe the main elements of a beneficiary-pays system, and to compare the conceptual foundations of this system with other proposals, including cost socialization. Although perfection is elusive, the choice is not between a perfect beneficiary-pays design or full cost-socialization. And following the principles of beneficiary-pays as far as possible will help mitigate the remaining problems of imperfect estimation of costs and benefits.

Transmission Line Expansion, Cost Allocation and Pricing

Transmission operation and investment is a dynamic process, with multiple facilities, diverse locations, and a variety of activities. There are many affected market participants, comprising all those connected to the electrical grid. To start the conceptual discussion, a simplified model provides a framework for describing the key components. The simplifications are selected to allow for a workable system that meets the tests of short-run and long-run efficiency. Subsequently, various relaxations of the assumptions identify critical features of the real system and the implications of approximations of the perfect design rules.

The initial focus is on transmission expansion, for which the simplest model is a two-period approach of the past and the future. The past defines the state of the existing grid. At each point of connection, the load and generation entities are assumed known to Transpower. Furthermore, these entities satisfy the competitive assumption of being price-takers. There is no attempt to manipulate or game the system. Dealing with market power goes beyond the scope of the present discussion. The intent is to craft a market design that works under the competitive assumption. At a minimum, a good market design should be compatible with this assumption.

For sake of simplicity, the analysis addresses real power flows, and ignores energy losses and other features usually treated under the heading of ancillary services. There are no transaction costs, and all market participants are risk neutral.

Importantly, the transmission pricing model is treated as a two-part design consisting of: (i) a fixed access charge assigned to each generator and load, and (ii) a variable price that is a function of the real-time generation or load. This is critical. Many analyses of transmission pricing assume, explicitly or implicitly, that there must be a one-part price applied to actual production or consumption. As will be illustrated, assuming one-part pricing rules out complete efficiency in all but the simplest case.

System operations, dispatch and associated prices will vary over real-time during the future. However, assume there is complete information in the sense that the future distributions of supply and demand conditions are known to everyone, including Transpower. In other words, every dispatch in the future can be different, but there is no disagreement about expected costs or benefits.

Transpower performs or should perform a cost-benefit analysis of a proposed transmission expansion which comes as close as possible to fully quantifying all benefits and costs. This analysis takes the form of a base case without the transmission investment, assuming the market responds according to the known supply and demand functions. The alternative case is with the transmission investment. The cost-benefit analysis consists of comparing the market outcomes and changed positions of all the participants, integrated across all the dispatch periods. The cost-benefit analysis addresses the fundamentals, and ignores voluntary contracts between the parties to share the costs and benefits. (Rivier, Pérez-Arriaga, and Olmos 2013, 296) (Hogan 2018, 28)

The net benefits are compared to the transmission investment cost. The “Gold Standard” is that the net benefits should exceed the total transmission cost. In some cases, regulators apply a threshold test requiring a premium of net-benefits over costs, but that is outside the present framework.

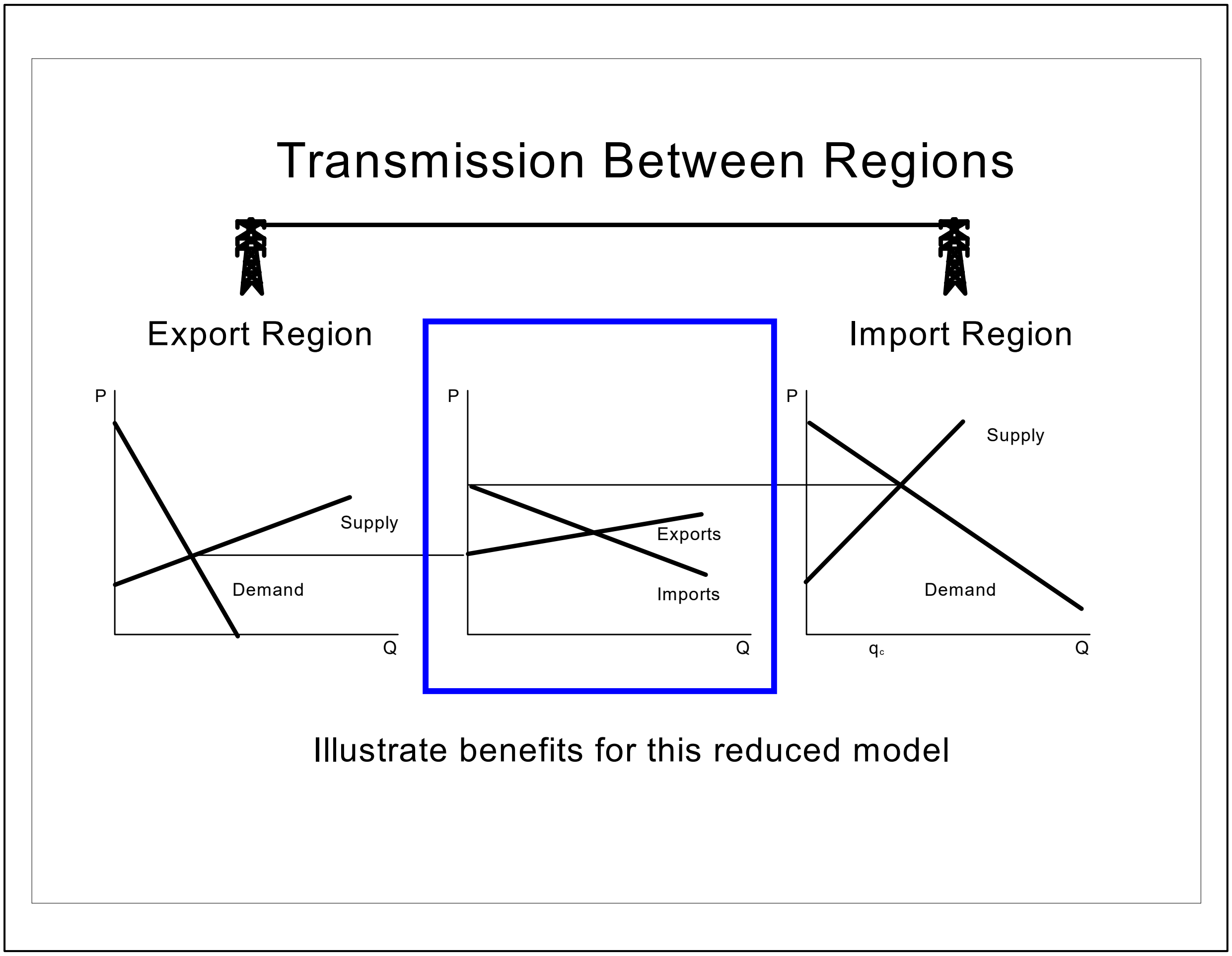
The cost benefit analysis inherently identifies the changes in the positions of all those connected to the grid. Some entities will see increased benefits (such as load seeing reduced prices) while others will see reduced benefits (such as generators facing the same reduced prices). A basic principle is that beneficiaries will pay, but costs will not be allocated to those that have not gained from the transmission investment.

The cost structure of the transmission investment can be complicated for many reasons, including discrete choices of available technologies, different economies of scale and so on. (Pérez-Arriaga et al. 1995) The discussion here starts with a very simple structure of smooth expansion with no economies of scale. This is not realistic, but it is important both as a baseline and because it is an implicit assumption behind many of the one-part pricing proposals or cost socialization arguments. (Schweppe et al. 1988)

Transmission Line Expansion

To illustrate, consider a stylized example of a single line between an export region and an import region. There is supply from Generators and demand from Load in both regions, as in Figure 1.

Figure 1

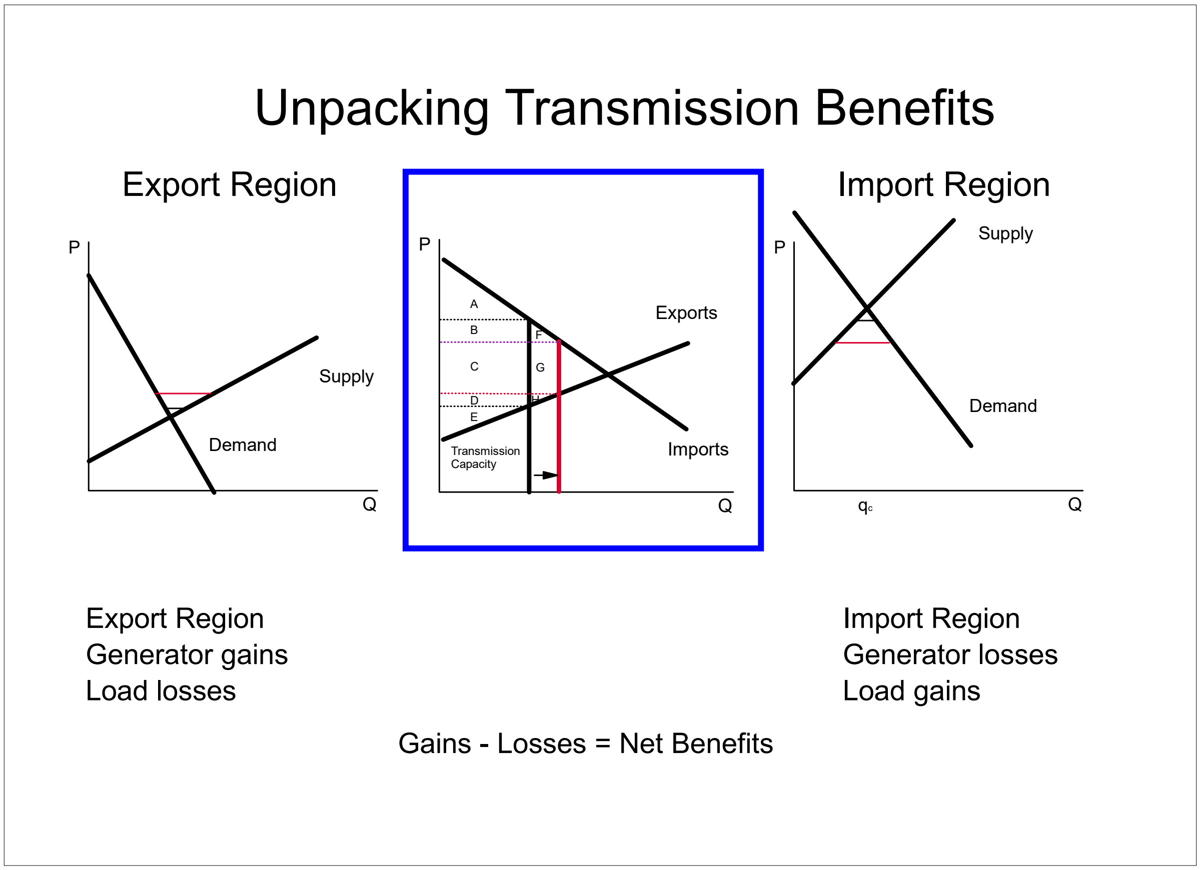


For the initial example, the importing region has a higher equilibrium price than the exporting region. Hence, there is an efficient transmission opportunity between regions and a flow in the direction of the importing region.

The net of supply and demand in the exporting region yields an export supply curve. Similarly, the net from the import region yields a demand curve for imports. Hence, the problem can be recast as a single equilibrium between import demand and export supply, as in the central box in Figure 1. If there is enough transmission capacity, the supply demand balance produces an equilibrium with a common price for both regions.

If transmission is constrained, as in Figure 2, there is a price separation between the regions with the transmission flow limited by the line capacity. The difference in the prices between the two regions defines the congestion charge for transmission capacity. The proposed expansion of transmission capacity changes the market equilibrium and creates benefits and costs compared to the no-expansion case.

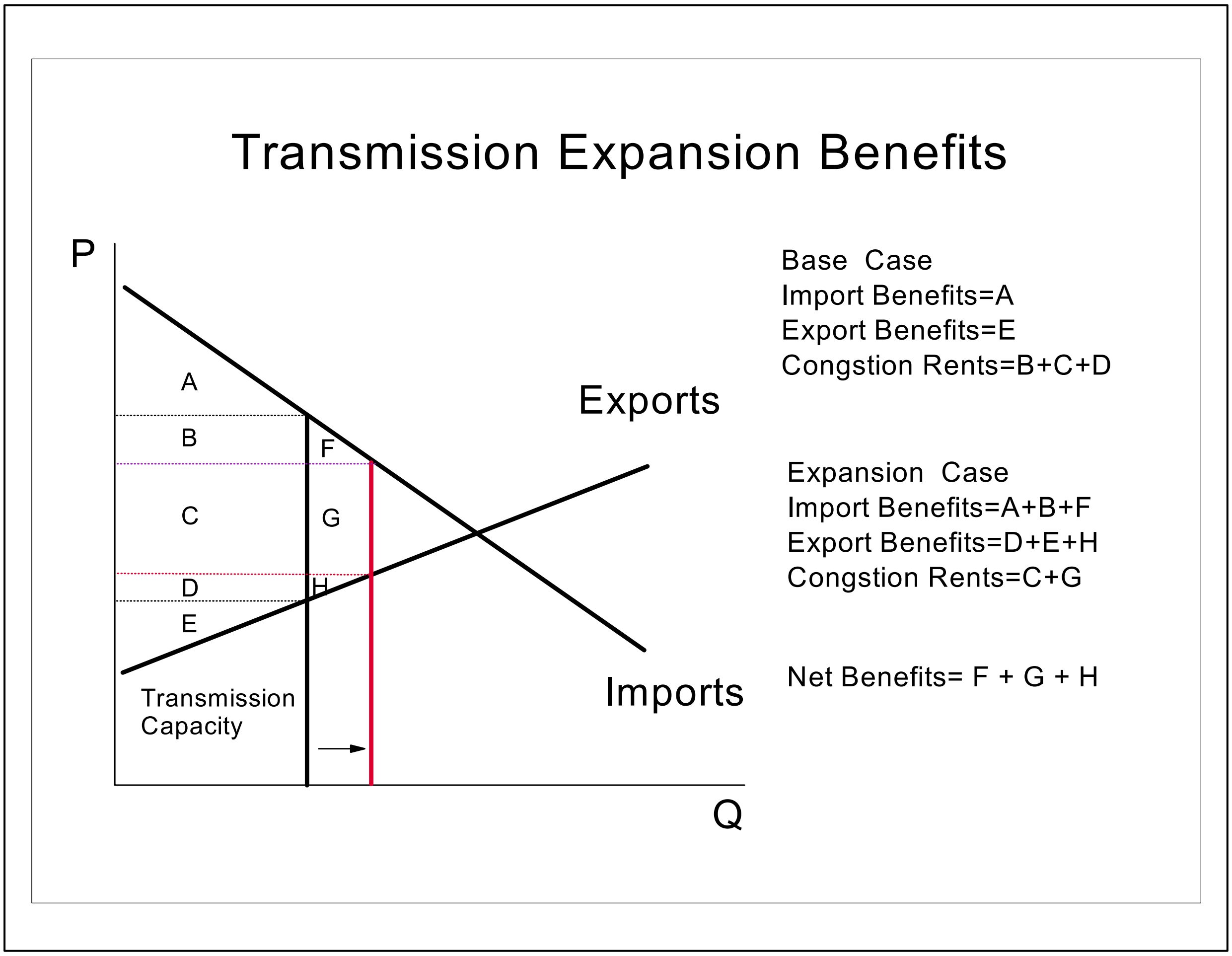
Figure 2



The graphic in Figure 3 expands the export-import analysis with the associated interpretations of the benefits and beneficiaries before and after a proposed transmission expansion from the initial transmission limit defined by the vertical black line to the expanded transmission limit defined by the vertical red line. The basic components are the benefits for imports and exports, and the congestion payments for transmission. The expansion reduces the congestion price differential. The net benefits for the importing region equals the area F; the net benefits for the exporting region equals the area H. Area C+G defines the resulting congestion payments. The areas B & D identify transfer payments from holders of transmission rights to loads and generators. Transfer payments do not count as part of the net welfare gain in economic efficiency.

The cost-benefit test for proceeding with the transmission expansion is that the total cost of the expansion is less than the aggregate increase in welfare of F+G+H. The magnitude and structure of the costs of transmission expansion provide the next piece of the evaluation.

Figure 3

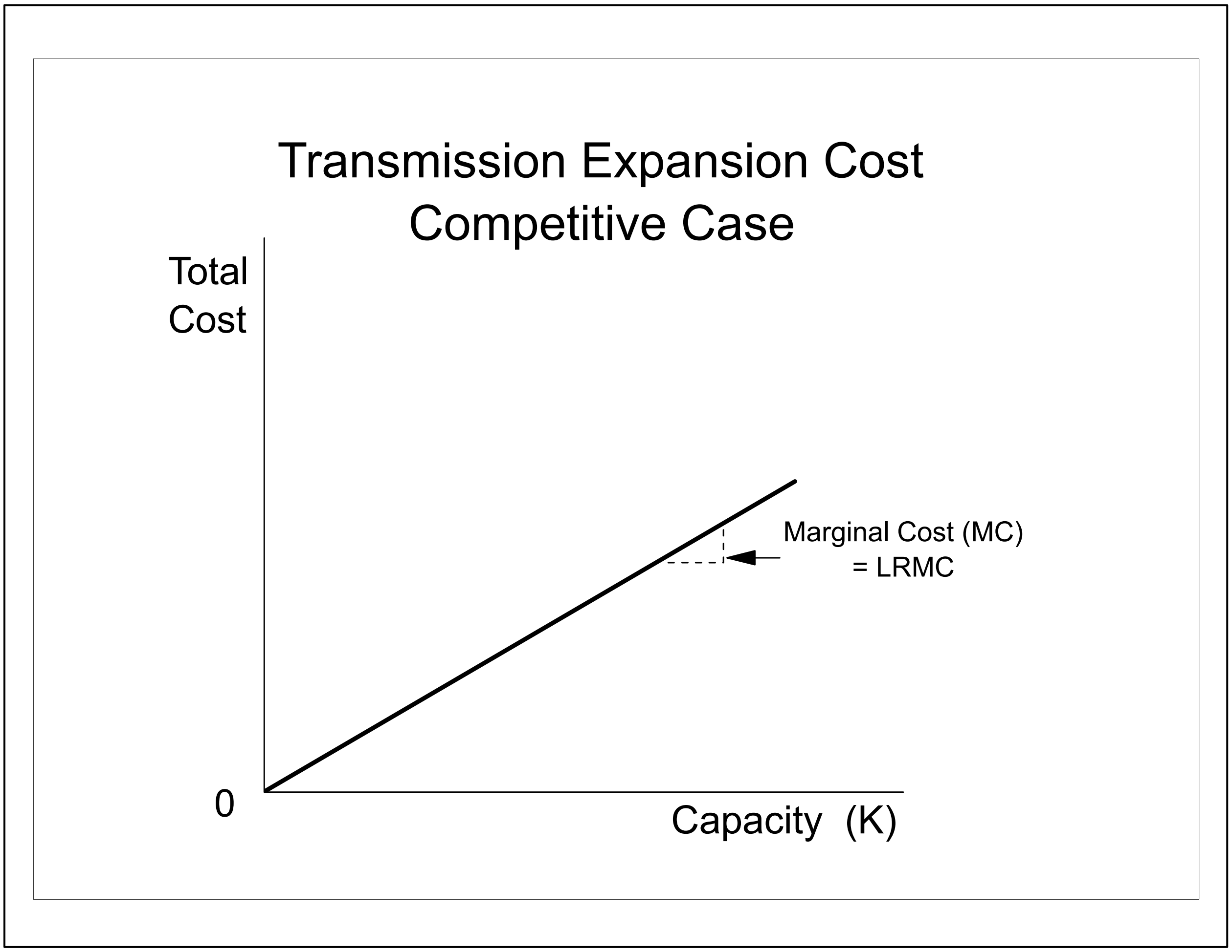


No Economies of Scale

The simplest case that illustrates important assumptions in analyses of transmission cost allocation would be the condition of no economies of scale. The illustration in Figure 4 captures the essential feature of a linear relationship for a continuous total cost. Expansions can come in any size, and the marginal cost of expansion is the same at all levels. Very small expansions cost very little; choosing an expansion that is twice as large requires twice the cost.

This cost function is consistent with a pure competitive case. Increments to transmission on the single path can be made in arbitrarily small quantities, produce the usual price-taking behavior with transmission usage priced, on average, at the marginal cost of expansion. In this sense, the marginal cost of transmission expansion (MC) has an interpretation as the Long-Run Marginal Cost (LRMC).

Figure 4



For full efficiency, the actual price for transmission for each dispatch interval would have to vary according to the short-term value of transmission congestion. Hence, the literal price of transmission would not be a constant at the LRMC. The equilibrium would hold only on average across all dispatch intervals.

This transmission pricing approach could be implemented as a one-part energy price. The implied transmission price in each interval is equal to the interval's transmission congestion price, with the transmission owner capturing and keeping the accumulated transmission congestion payments. This is the idealized case of the efficient competitive market organized around market-clearing prices.

This case yields a beneficiary pays model with the payments made by either the generators or the loads that arranged for transmission usage. The resulting transmission payments would accumulate to the area C+G in Figure 3. The expansion revenues would be area G. Importantly, the equilibrium conditions would produce this expected revenue just equal to the total cost of the transmission line MC*K. There would be no other investment cost and, therefore, no remaining transmission cost allocation problem.

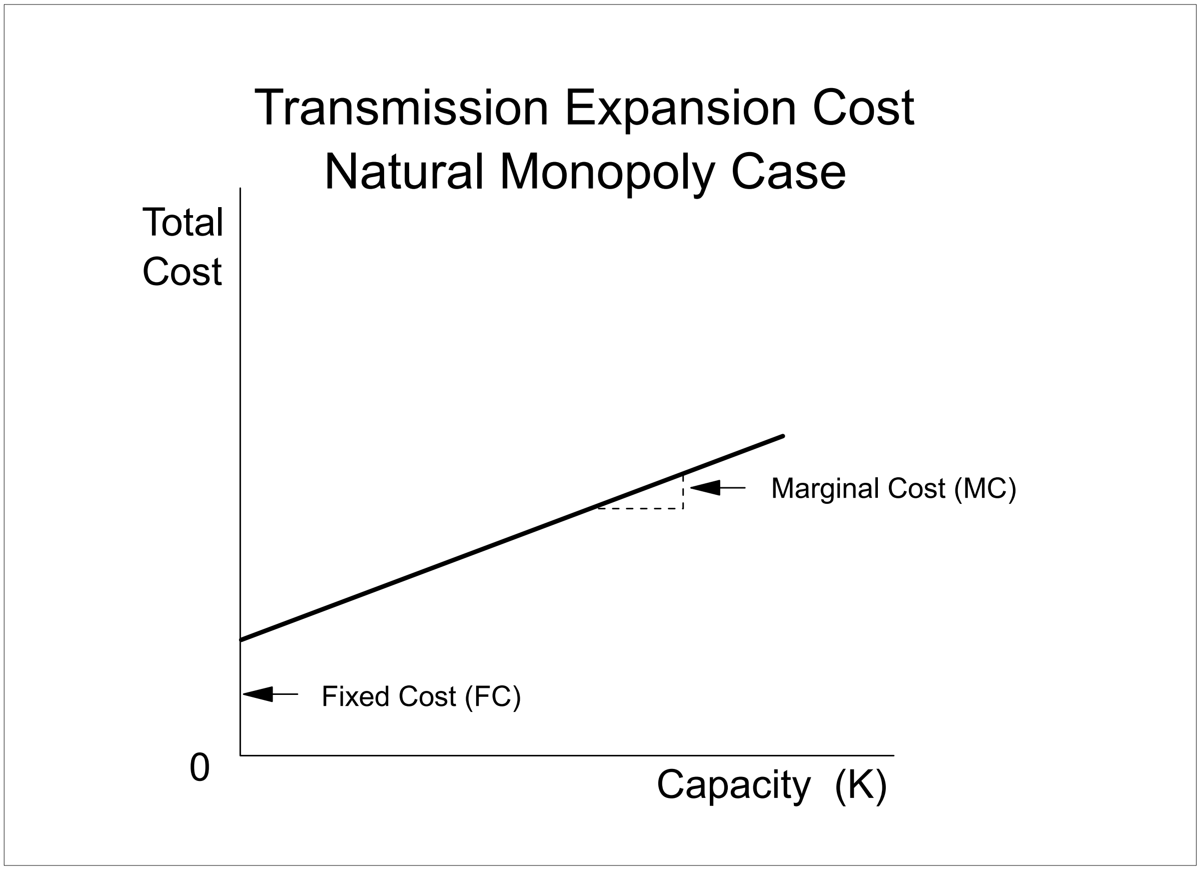
Strictly speaking, therefore, the assumption of no economies of scale implies that transmission expansion is a continuous process and the expected congestion price at the margin is always equal to the marginal cost MC, and the beneficiaries pay.

This case of no economies of scale, with the implications of a pure competitive one-part pricing solution, is divorced from the reality of the transmission grid. The absence of economies of scale is worthy of mention both because it is often an implicit assumption, and because it serves to highlight the importance of two-part pricing, with fixed access charges and variable usage fees, to achieve efficient expansion and cost allocation for a real transmission system.

Economies of Scale

The complexity of the cost structure for real transmission systems arises from many underlying features. To illustrate the basic efficiency principles, the stylized case of economies of scale captures the most important feature.

Figure 5

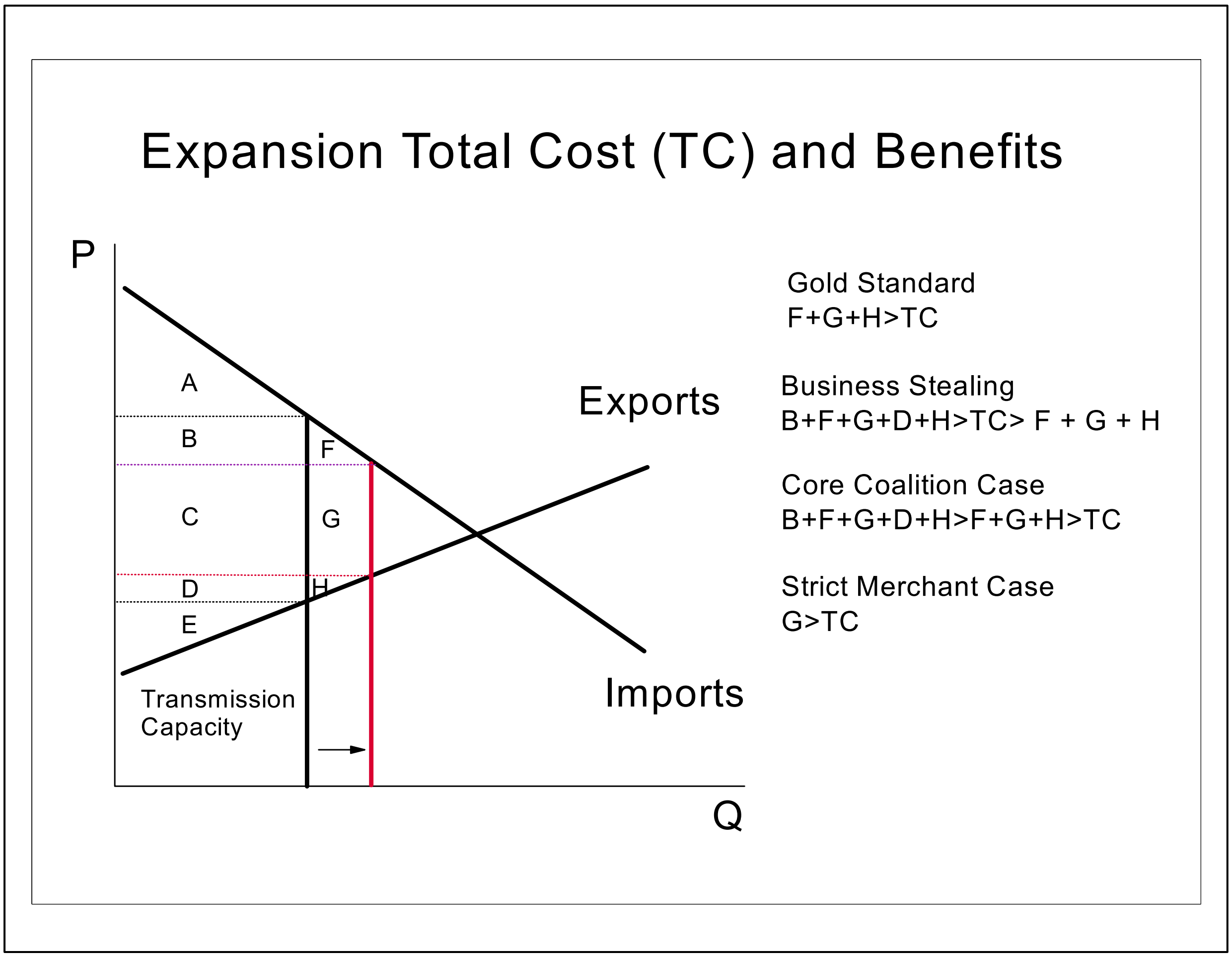


Perhaps the simplest example of a cost structure displaying economies of scale would be when there is a fixed cost of expansion combined with a linear total cost for the scale expansion. As in Figure 5, there would be a fixed cost FC, say for the right-of-way and transmission towers, but a constant variable cost MC associated with the size of the wires. The essence of economies-of-scale is that the marginal cost of expansion is always less than the average cost.

This cost structure creates a natural monopoly condition where the lowest-cost option would always be to have a single transmission provider. The monopoly would only incur the fixed cost once, whereas many small competitors would have to incur the fixed cost for each component of the total expansion.

For different capacity levels (K) the average cost would be AC(K)=MC+FC/K. The efficient expansion plan would size the line to match the variable transmission cost MC with the ex post expected congestion price defined by the expected difference of the energy price across regions. The expansion decision would now face two tests. First, the expansion should imply the equality of marginal costs and future congestion costs. Second, the total costs should be no greater than the net benefits F+G+H in Figure 6. The presence of the fixed costs requires the use of both tests, and now the optimal expansion size is lumpy, requiring an expansion large enough to produce benefits F+H that will have to be greater than the fixed costs.

Figure 6



In Figure 6, the efficiency Gold Standard requires the net benefits F+G+H to be greater than the transmission expansion costs TC. The gross benefits are at least B+F+G+D+H, which are larger than the net benefits by the amount of the transfer payments B+D. The full gross benefits would be determined by unpacking the gains and losses in both regions, as in Figure 2. In the Business Stealing case, the transfer payments might allow a coalition to justify investments that are advantageous for the coalition but reduce overall welfare and do not meet the Gold Standard. This is an example of inefficient entry. (Mankiw and Whinston 1986) The similar core coalition case could justify a coalition that acted to invest based on the gross benefits, but it would meet the cost-benefit test. Likewise, the Strict Merchant case is where congestion revenues alone would support efficient investment with no cost allocation required.

The expected congestion revenues would cover the variable cost of expansion, but not the fixed cost. If the line passes the cost-benefit test, the benefits for Loads in the importing region and Generators in the exporting region would be sufficient to cover the total fixed cost (FC) recovered in access charges. The beneficiaries would see the reduced price of congestion, and the net benefits would be greater than the fixed cost of the line.

The theoretical point of the illustration captures the main structure of the cost recovery problem. It is no surprise that transmission is a natural monopoly, and therefore that competitive pricing structures will not apply or cannot support an efficient energy market and transmission expansion. (Creative Energy Consulting 2019, 22) What is perhaps more surprising is the scale of the numbers. Early on, studies of real transmission systems estimated that the efficient real-time locational dispatch prices would produce congestion revenues on the order of 25%-30% of the annual cost requirement to recoup the transmission investment. (Rubio-Oderiz and Perez-Arriaga 2000)

By these accounts, the simplifying assumptions of one-part pricing and no economies of scale are far off the mark. Absent some external source of funds (e.g. tax revenues), maintaining efficient investment but recovering the costs of the transmission investment creates a cost allocation requirement. Since the assumed net benefits are positive, there is room for choice in allocating the costs to the beneficiaries while leaving the individual net benefits positive and not creating an incentive to disconnect from the network. The net benefits of interconnection are typically quite large relative to the cost of transmission investment. Hence, the large benefits of connection and the efficiency test of expansion costs imply that there could be a substantial surplus of benefit above the allocated transmission cost. For efficient expansion, the beneficiaries pay framework provides a method to achieve efficiency as in the illustration.

Transmission Network Expansion

The real transmission expansion problem is more complicated than as illustrated for a single line. However, the simple case illustrates the basic principles and supports the allocation of transmission charges in excess of congestion revenues applied as a fixed access charge for the transmission beneficiaries.

Although estimating these access charges is not easy, the critical assumptions and information are embedded in the cost-benefit analysis that should precede the decision to expand the transmission network. The details of the cost-benefit study will depend on the particulars of the expansion plan, but we can outline how various relaxations of the simplifying assumptions would affect the cost-benefit analysis and the associated allocation of costs to beneficiaries.

Flows in Both Directions

The illustration simplifies by assuming energy flows in only one direction. Even for a single isolated line the expectation would be that changing conditions over the dispatch cycles would produce flows in both directions. Now beneficiaries are Loads and Generators in both regions in proportion to the relative time with the direction of flows.

There are different prices for Generators and Loads at the expected cost of congestion for the different flows. The sum of the expected congestion prices is equal to the marginal cost of transmission expansion (MC), but this is less than the total cost of the expanded transmission connection. However, the same condition applies that there is a possible allocation of the fixed costs to all the beneficiaries that leaves them with net benefits and covers the cost of the transmission expansion. The cost-benefit analysis would simply choose the order of the regions in the figures, and apply the same analysis based on the direction of flows. The allocation of fixed access charges to the beneficiaries remains, with different benefits for different locations depending on the expected usage.

Losses and Ancillary Services

The assumptions of no losses and ignoring ancillary services simplify the illustration, but this should have no material effect on the basic conclusions of benefits or cost allocation. The details would be included in the normal conduct of the cost-benefit analysis.

Network Expansion

Actual transmission investments apply to a meshed network of many transmission lines and related facilities. The investments tend to be lumpy, coming in discrete sizes. Typical cases exhibit both economies of scale, where doubling the size does not double the cost, and economies of scope, where the same investment serves multiple parties and locations. These effects imply that literal marginal costs are only part of the problem, and average costs can be much larger than marginal costs.

These features and more must be addressed by Transpower in evaluating the costs and benefits of any system investment. The details will be many and relevant, but for cost allocation purposes the complications do not introduce anything qualitatively different. The problem present with economies of scale will remain with these added details. The marginal cost of a small increment of expansion will be part of the critical determination in sizing the investment, but the average cost of the investment will be larger, perhaps much larger, than the marginal cost. To maintain efficient pricing in operations, marginal costs should determine the operating conditions and the balance of the fixed costs would be recovered through fixed charges assigned to the beneficiaries identified in the cost-benefit analysis. The basic outline of the analysis remains with the same principles applied to a network expansion.

Uncertainty

The assumption of known supply and demand conditions across each future dispatch interval is a version of complete information along with no uncertainty. Of course, the future is uncertain in important ways. A large part of the challenge of good market design is to set the pricing model so that it operates using essentially the same principles across a range of possible conditions. This general principle applies to the transmission expansion and cost allocation problem.

Treatment of uncertainty is unavoidable in the cost-benefit analysis. By construction, the point of a cost-benefit analysis is to look ahead, make forecasts, and evaluate performance under different conditions. A decision analysis framework with multiple scenarios, associated probabilities, and various decision points provides a conceptual framework. While always imperfect, the explicit consideration of forecast uncertainty is important. Within each scenario, the evaluation of operating projections and benefit calculations proceeds as outlined for the case with no uncertainty. Then weighting the alternative futures across probabilities for the scenarios provides the expected values of benefits and costs. (MISO 2010) The allocation of the costs to the beneficiaries can proceed with the same information.

Risk Aversion and Transaction Cost

The assumptions of no risk aversion and no transaction costs underly the equilibrium defined by the expected value of marginal conditions in operations and the investment decisions for transmission expansion. This simplifies the analysis. Relaxing these assumptions to include risk aversion, across the dispatch and across alternative futures, would create a risk premium for investments and introduce various hedging instruments such as financial transmission rights. Although important real conditions, the extensions would complicate the illustrative analysis without changing the basic implications of the need for a transmission cost allocation mechanism that goes beyond efficient real-time prices and follows the principles of beneficiary pays.

Benefit Updates

With uncertainty about the forecast, the actual outcome will differ from the anticipated expected value. In particular, the actual beneficiaries and benefits will be different from the weighted average calculated based on the scenario analysis. With the passage of time, natural questions arise about whether, how and when to update the benefits calculation and the implied cost allocation for recovering past transmission investments.

The principle of making the transmission cost allocation compatible with the rest of the market design implies that there should be no benefit updates. Consider the analogous case of investments in generation that competes with transmission. The competitive market framework calls for the owner of the generation to make its own forecast and investment decisions. If actual conditions differ from the forecast, then the generation owner reaps the benefits or absorbs the cost. There is no reallocation of the generation investment to other parties. A level playing field would imply the same treatment for transmission investment.

The exception for the generator might be something like bankruptcy. The analogous case for transmission cost allocation might be the condition where otherwise viable market participants would be driven to disconnect from the network because of the burden of the transmission cost allocation. In this limited case, the forward-looking efficiency argument would support a reallocation of the fixed access charges.

By contrast, a policy of repeated allocation changes based on ex post estimation of benefits would face a great challenge in actual defining and measuring the benefits. The prospective cost benefit analysis has the feature of defining the counterfactual to the investment case as the continuation of the existing grid. But after not too long additional changes in the grid configuration would make it problematical to go back and construct a meaningful counterfactual. The overlapping impacts of a sequence of investments, with economies of scale and scope, would be difficult to untangle.

From strictly an efficiency perspective, if reallocation of fixed costs did not materially affect continued interconnection decisions, there would be no efficiency gains from a benefits update. There could be other policy objectives, but the efficiency arguments provide little guidance beyond the argument to maintain a level playing field with the other elements of the electricity market.

New Entrants

In some cases, new entrants to the market will be identified as part of the forecast applied in the cost benefit analysis. The case of transmission investments to provide capacity for prospective renewable investments in a region where the developers are expected but not yet identified would be a prominent example. The cost benefit analysis should anticipate these investments, and so too should the cost allocation apply to these beneficiaries when they appear.

In other cases, where the arrival of new entrants is a surprise, the strict efficiency arguments would not dictate the policy, since the assumption of the cost allocation is that the fixed charges are not sufficient to change the behavior of the existing market participants. In order to avoid perverse incentives to reorganize a firm to adopt the guise of a new entrant, an allocation to all new entrants would be required even if they were not recognized at the time of the investment.

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Energy Trading LLC, Duquesne Light Company, Dyon LLC, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Authority New Zealand, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Energy Endeavors LP, Exelon, Financial Marketers Coalition, FirstEnergy Corporation, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Israel Public Utility Authority-Electricity, Koch Energy Trading, Inc., JP Morgan, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan Ventures Energy Corp., Morgan Stanley Capital Group, Morrison & Foerster LLP, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., Powhatan Energy Fund LLC, PPL Corporation, PPL Montana LLC, PPL EnergyPlus LLC, Public Service Company of Colorado, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Red Wolf Energy Trading, Reliant Energy, Rhode Island Public Utilities Commission, Round Rock Energy LP, San Diego Gas & Electric Company, Secretaría de Energía (SENER, Mexico), Sempra Energy, SESCO LLC, Shell Energy North America (U.S.) L.P., SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, TransAlta Energy Marketing (California), TransAlta Energy Marketing (U.S.) Inc., Transcanada, TransCanada Energy LTD., TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Twin Cities Power LLC, Vitol Inc., Westbrook Power, Western Power Trading Forum, Williams Energy Group, Wisconsin Electric Power Company, and XO Energy. Thanks go to Susan Pope for important assistance. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).