Transmission Investment and Cost Allocation in Electricity Markets: A Paper in Honor of Stephen Littlechild

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Large electric power transmission investments interact with electricity markets and can produce material changes in costs and benefits. The early case of Argentina with its "Public Contest" method for investment selection and cost allocation foreshadowed later developments in organized markets in North America. A common central challenge is to define the costs and benefits within the context of market and regulatory decisions.

Introduction

Stephen Littlechild has worked in many fields. He has had an important impact as an economist and as a public official, notably in the initial reforms of the UK electricity system. Ranging from the theoretical analysis of the essentials of second-best pricing (Littlechild, 1975), and applied economics (Littlechild, 2008), to the empirical evaluation of infrastructure investment practice (Littlechild, 2012), his work has had a enduring impact over the nearly four decades of the restructuring of electricity markets.

The focus here is on the connection to transmission infrastructure investment and cost allocation in electricity markets. Particularly important work is found in the investigation of the transmission investment reforms in Argentina (Littlechild and Skerk, 2008b). See also (Littlechild and Skerk, 2008a), (Littlechild and Skerk, 2008c), (Littlechild and Skerk, 2008d), (Littlechild and Ponzano, 2008), (Littlechild and Skerk, 2008e).

The Argentine case from the 1990s presented early on many of the challenges of evaluation and payment for transmission infrastructure in the context of an organized electricity market, as compared to the related but different challenges under the model of a vertically integrated monopoly. Littlechild recognized the innovations in Argentina and foreshadowed the appearance of similar problems and possible solutions that could apply in the expanding reforms of electricity systems. An immediate connection appears in the incomplete response in the United States where the Federal Energy Regulatory Commission (FERC) is "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation" (FERC, 2024b). The echoes from Littlechild's work are clear, as are the challenges ahead.

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Markets and Incentives

In their early development, electricity systems were viewed as natural monopolies. After some experimentation, the dominant model restricted wasteful competition by mandating a single firm in a given locale with some form of regulatory oversight to set terms and prices. In this world, a key challenge was to deal with the information asymmetries between the regulator and the vertically integrated regulated monopoly. Major topics include price setting and cost allocation. This is a large topic in itself where Littlechild's contributions to pricing and investment are well known (Littlechild, 1996).

A major policy shift, driven partly by generation technology changes, was the recognition that many elements of electricity systems were not part of a natural monopoly and could be contested. In North America, generation investment was a driving force where Independent Power Providers (IPPs) could build and operate conventional power plants, sometime as coupled cogeneration, competing with each other, as well as competing with the traditional utility. The initial approach saw the traditional utility as the purchaser of the output of the independent power producer, and this launched a period of significant change as the independent generators increased in numbers.

Eventually, many electricity systems went through various combinations of new entry and generation divestiture until the dominant mode was a separation between power generators and wholesale customers, now buying and selling through an interconnected grid. The traditional challenges of regulating a natural monopoly, where the internal operations could be opaque, now were changed to developing the rules for open access to the monopoly grids and wires where competition among suppliers could discipline the market (FERC, 1996). This remains a work in progress (Hunt, 2002) (Glachant et al., 2021) (Glachant et al., 2025).

Electricity systems are complex and the details of market design matter. For the present discussion, consider the foundational market design for real-time operation along the lines of bid-based, security-constrained, economic-dispatch, with locational-marginal-prices (LMP), and financial-transmission-rights (FTRs) (Hogan, 2013) (Hogan, 2021). This so-called LMP model stands at the core of all the organized markets in North America.[2] This real-time focus covers all the actual generation and consumptions of power. Except for a limited set of short-term unit commitment decisions, everything else is essentially a forward contract that in effect settles at the real-time prices and quantities. There are other added market constructs, such as day-ahead markets and capacity markets, but these are not central to the discussion here.

Under idealized simplifying assumptions such as convexity of the embedded dispatch optimization model, the LMP framework provides the structure for a welfare-maximizing interpretation with efficient markets. Deviations from the simplifying assumptions, such as the existence of market power in the dispatch, can be addressed by relatively modest interventions such as offer caps

[2] Known as Regional Transmission Organizations or Independent System Operators (RTO/ISO). Alberta has announced but not yet implemented the LMP model.

applied selectively to large generators under prescribed conditions. Small scale non-convexities can be addressed through workable pricing approximations, as in (Andrianesis et al., 2022).

Furthermore, the scale of these markets in North America is such that entry and exit of individual generators and loads need not have much of an impact on overall market clearing prices, and market monitors play an important role to ensure that material deviations from these assumptions are addressed and corrected. This justifies an assumption that market participants such as generators or loads act as price-takers in the dispatch and in terms of entry and exit decisions.

Externalities, such as through the effects of air pollution, are assumed to be addressed through public policies involving various mixes of standards and pricing. The basic optimization model treats these policies as external to the electricity market with the costs internalized by the market participants.

Within this framework, and taking the transmission system as given, individual entry and exit decisions for generation and load follow from the market participants operating in a competitive market. The simplifications and assumptions satisfy the usual conditions for equivalence between the competitive market outcome and welfare maximization.

Transmission Investment

For small scale transmission investment, such as a radial connection from a new generator connecting to the grid, there are by assumption no large externalities and merchant transmission investment that acquires associated increases in financial transmission rights can support an efficient solution.

Large-scale transmission projects present a different challenge. The interconnected high voltage grid does not conform to the simplifying assumptions applicable to generation and load. There are material economies of scope and scale (Hogan, 2020, Appendix).

Economies of Scope

Power flows on a meshed network do not conform to the assumptions of a transportation system such as a controllable gas pipeline network (Hogan, 1992). The essence of the difference is that injections and withdrawals of power materially affect the flow on every parallel path in between. The operational requirement is that there must be a central coordinator that balances load and generation subject to transmission and security constraints. The short-term economic dispatch model provides market-clearing injections, withdrawals, and locational prices. The longer-term implication is that large transmission investments can have a material impact on all the dispatch prices and quantities throughout the network.

Economies of Scale

Large-scale transmissions investments are lumpy, coming in discrete sizes and exhibiting large economies of scale. The marginal cost of increased capacity is much less than the average cost, so the optimal investment is larger, perhaps much larger, than could be supported by a merchant model based on FTRs (Rivier and Olmos, 2020, p. 135). There are implications for identifying beneficiaries and for muti-part pricing (Ávila et al., 2026, p. 1). Transmission investment cost allocation and charging mechanisms become a major issue.

Regulated Investment

The result is a continuing role for central planning of large-scale and long-term transmission investments. There is a debate as to whether this is most of transmission investment (Joskow and Tirole, 2005) or that a more market-oriented approach, including merchant transmission investment, would be second-best but still workable in practice (Littlechild, 2012): "In sum, market power, transactions costs and various other conjectured limitations might in theory be serious problems for merchant transmission—but in the cases we have examined they were not serious in practice. Bureaucratic processes, interest group capture, political influence and regulatory resource limitations might in theory be serious problems for regulated transmission—and in the cases we examined they indeed often were serious in practice" (Littlechild, 2012, p. 331).

However, it is widely accepted that regulated large-scale transmission investment will play a major, if not the only, role even in organized electricity markets (Joskow, 2020). This presents a major challenge with complications both from and for electricity market design (Hesamzadeh et al., 2020). Who should decide? How should decisions be made? How should costs be allocated? What should be the pricing mechanism?

Benefits and Beneficiaries

For most large transmission investments, the traditional approach was for a central planner to select the best transmission investments and to socialize the costs across the connected loads. Many variants and details could be different in different jurisdictions, but the basic monopoly procurement and cost recovery has long been the norm.

In an organized market, consistency with competitive incentives for load and generation requires something else. The broad recasting of the principle is that mechanisms for transmission project selection should promote economic efficiency and transmission expansion costs should be allocated to the beneficiaries under the new market model.

Beneficiaries Decide and Pay

The Argentine electricity reform in the 1990s is an early example of a newly restructured electricity market with a coordinated central dispatch and locational marginal prices. The basic market design foreshadowed the later developments in the United States, and the treatment of large-scale transmission investment included commitment to the principle that beneficiaries pay.

An early investment case in Argentina was the treatment of what was known as the "Fourth Line" connecting generators in Comahue to loads in Buenos Aires. An innovative decision process known as the "Public Contest" included a transmission investment proposal overseen by the central planner, determination of the beneficiaries, ex ante allocation of the costs to the beneficiaries, and then super-majority voting according by the deemed beneficiaries to approve or reject the transmission investment.

To the disappointment of many, an initial Fourth-Line proposal under this model was not approved. This was seen as a failure of the new regime for transmission investment. However, in an important empirical contribution, Littlechild and Skerk found that the line was uneconomic at the time, and with changed economic conditions was later constructed under the Public Contest method: "far from demonstrating the failure of the Public Contest method, the Fourth Line experience taken as a whole is testament to its success" (Littlechild and Skerk, 2008b, p. 1415).

Littlechild (with his co-authors Panzano and Skerk) provided a wealth of information relevant to later debates in other organized electricity markets. Although later overtaken by political events and the change in its government, the Argentine experience with Public Contest method large scale transmission investment and cost allocation continues to provide insight that would be of use in other organized markets.

The basic ideas pioneered in Argentina, including the principle of efficient real-time markets, mechanisms to avoid uneconomic transmission investments, beneficiaries bearing the costs, and even super-majority voting, find echoes elsewhere (NYISO, 2023). In addition, selected projects under the Public Contest method were put out for competitive tender, with reported cost reductions of 50% of initial estimates (Littlechild and Skerk, 2008d, p. 1467). For competitive procurement, see also (Joskow, 2020).

A deficiency of the Argentine model was in defining and measuring the benefits. The so-called "area of influence" method was a version of estimating flows on lines that is conceptually defective in a meshed network and implemented in an ad hoc way that excluded obvious beneficiaries such as the loads in Buenos Aires. While explaining the defects of the method, Littlechild and Skerk did not offer an alternative approach.

Benefits, Beneficiaries, and Costs

Identifying the benefits and beneficiaries continues to be a work in progress. The conceptual framework of economic planning provides the basics, and it identifies important issues (Hogan, 2018) (O'Neill, 2020) (Rivier and Olmos, 2020). For example, treatment of public or private contracts could present impossible hurdles for identifying beneficiaries. In the vertically integrated model, essentially all generation was assumed to be owned by the utility operating under price regulation and for the benefit of loads. This was an implicit contract, and the disaggregation of aggregate benefits would involve only the loads. Correspondingly, meshed system transmission investment costs would be allocated only to loads. There would be no additional benefits assigned to generators and generators would not be allocated any investment costs for the meshed network.

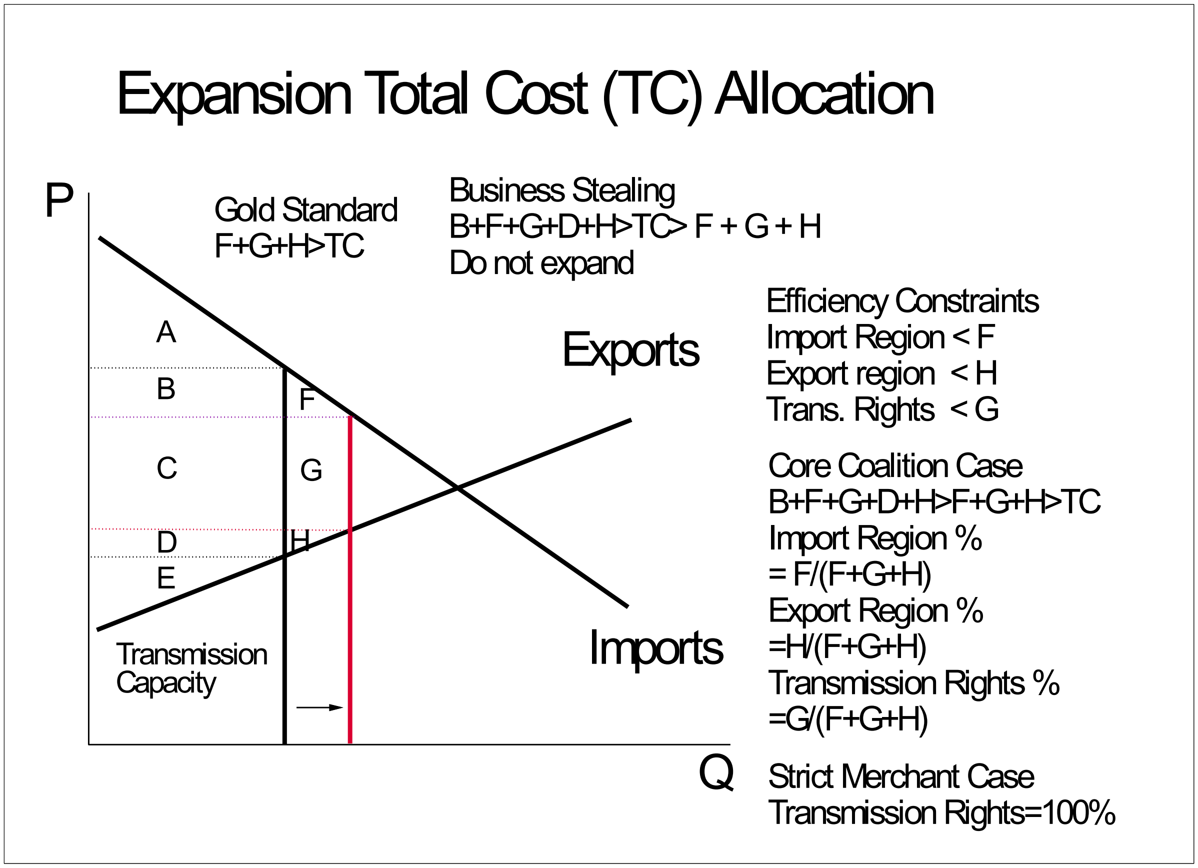
This is still partially true for systems with vertical integration outside the organized markets. However, it is not true in the organized electricity markets, such as in North America, where generation and loads are treated as distinct entities. There may be private contracts, about which the regulator knows little or nothing. However, clearly large-scale transmission investments create material benefits for some generators as well as some loads. Attempts to track the rearrangement of benefits through private contracts and derivative markets would be hopeless as a means of cost allocation.

The logical implication is that a beneficiary-pays system must define and estimate the benefits to market participants while ignoring the effects of contracts that rearrange the benefits. This is the standard (implicit) assumption in system planning optimization models that regulators should maintain as part of a beneficiary-pays design.

The essential implications of the benefit-cost framework with real-time optimization are summarized in the accompanying figure adapted from (Hogan, 2018). This is a simple example of export supply and import demand with a single transmission line connecting two regions. The basic principles apply to a meshed network that covers a large region with multiple locations.

A key feature is the illustration of the effect of economies of scale. The assumed transmission expansion is large and yields large changes in dispatch and prices. The counterfactual expansion case compares to the base case without expansion, and it creates material transfers of benefits and costs that rearrange but do not add to total benefits. For example, area B is a gain for the loads and a loss for the existing generators in the importing region, and area D is a gain for the generators and a loss for the existing load in the exporting region. But these do not contribute to the total net economic benefits which are defined by the area F+G+H. A standard production cost model could produce the total amount, and the associated clearing prices would provide the decomposition of the net benefits into the components. Underlying the illustrative supply and demand curves would be exiting generation and load, where investment costs are sunk, and new generation and load where investments costs are included in the cost benefit analysis.

The cost of the transmission expansion illustrated here is TC. The gold standard is the total benefits should exceed the cost of expansion or F+G+H>TC, a benefit-cost ratio of at least 1.0. However, because of the material transfers, there may be a coalition that can capture the gross benefits which are greater than the transmission expansion costs, which are in turn greater than the net benefits, or (B+F+G+D+H>TC>F+G+H). From the perspective of such a coalition of market participants, total benefits would exceed net benefits due to the transfer payments from the losers to the winners. This is analogous to the business stealing condition with lumpy investment (Mankiw and Whinston, 1986). A task for regulators is to recognize and prevent such cost-shifting transmission expansions incented by transfer payments and which reduce aggregate welfare.



At the same time, for efficient investments this permits a great deal of flexibility in the assignment of responsibility for transmission cost recovery, subject to the efficiency constraints. An allocation proportional to net changes could set the cost share as F/(F+G+H) for loads in the importing regions, G/(F+G+H) for the incremental transmission rights, and H/(F+G+H) for the generators in the exporting region. The same logic applies to a meshed network, reliability constraints, forward looking investment in transmission, generation, and load, and with uncertainty under a long-term planning framework (Hogan, 2018, Figure 6). For a more extended discussion see (Shu and Mays, 2025).

In principle, the same forward optimization applies to the regulated model which seeks the most efficient outcome. The market framework differs in utilizing the implied pricing and dispatch results to define the benefits.

This high-level outline of the theory of benefit-cost analysis and cost allocation is a starting point. The translation from theory to practice is quite different and is much in flux in the organized markets under FERC regulation.[3]

Building for the Future

In the organized markets of North America, a milestone event for transmission cost allocation was the definitive turn towards a beneficiary-pays system, at least in principle, as discussed in the landmark decision in the matter of the Illinois Commerce Commission versus the FERC. The court decision, worth reading in detail, outlines many of the continuing debates about defining benefits, costs and beneficiaries. The main judicial conclusion rejected the arguments against pursuing a beneficiaries-pay approach: "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members" (ICCvFERC, 2009, p. 9). The key requirement was that transmission costs could not simply be socialized and would require a cost allocation "roughly commensurate with the benefits" (ICCvFERC, 2009, p. 11).

Following this decision, FERC undertook an extended implementation process, launched with its Order 1000 (FERC, 2011). This FERC decision set out the broad principles and directed the subject regulated entities to file appropriate plans implementing the broad principles. The immediate outcome was summarized most succinctly by the title in a subsequent review of a group of the initial filings: "*Very* Roughly Commensurate" (Radford, 2013). In part the deficiencies could be explained by unfamiliarity of the approach and the challenges of changing the paradigm from traditional cost socialization.

However, part of the lingering difficulty of implementation was in the nature of the mandates in Order 1000. For example, the guidance was on the types of benefits but not on how to measure the benefits or define the beneficiaries. There was discussion of distinctions among economic, reliability and public policy benefits to the point of treating different transmissions investment differently depending on which category applied. This problematical categorization of transmission lines persists. For example see (NYISO, 2023, p. 1) where, like the Public Contest method in Argentina, economic lines have a supermajority voting according to benefits but reliability and public policy lines are developed in a separate process with different cost allocation rules.

Large scale transmission investments do not sort according to the type of benefit; all lines affect all types of benefits. Some systems recognize this interdependence, such as the Southwest Power Pool (SPP) "Highway-Byway" methodology or the Midcontinent Independent System Operator

[3] The author submitted testimony in a matter before FERC regarding the benefit-cost analysis in a case for the "Tranche 2.1" transmission investments in the case of *Concerned Commissions and MISO*, 2025, Complaint of North Dakota Public Service Commission, et al. v. Midcontinent Independent System Operator, Inc. under EL25-109.

(MISO) Multi-value Projects (MVP) approach (Pfeifenberger, 2021, p. 27). But the absence of a consistent framework for defining and estimating benefits, costs, and beneficiaries presents a problem, especially for large-scale and long-term transmission investments regulated by FERC.

With the many pressures on the electricity system, the calls for more large scale transmission investment with better rules for defining and allocating costs are growing (FERC, 2025a, p. 4) (Mai et al., 2026). More than a decade after issuing its Order 1000, FERC found the need to take up the topic again with an increasing focus on and urgency of "Building for the Future". A Notice of Proposed Rulemaking stimulated voluminous comments, "the largest record ever filed at the Commission" (FERC, 2025a, p. 3), including recommendations for comprehensive reforms as illustrated in a briefing to the Commission Staff (Pfeifenberger, 2021, pp. 42-43).

The resulting FERC Order 1920 took up again the main issues of transmission benefits and cost allocations (FERC, 2024b). "In Order No. 1920, the Commission found that there is substantial evidence to support the determination that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation to meet Long-Term Transmission Needs is not occurring on a consistent and sufficient basis, and that the absence of such processes is resulting in piecemeal transmission expansion to address relatively near-term transmission needs. The Commission found that the status quo approach results in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates" (FERC, 2025b, §142).

A history of the problems after Order 1000, the development of the legal foundations for the allocation of cost roughly commensurate with benefits, and remaining challenges after Order 1920, can be found in (Macey and Mays, 2024). The implications for bridging the gap between principles and practice remained unclear. Partly reflecting on these problems, shortly afterward FERC issued a revised Order 1920-A (FERC, 2024a), then revised again as Order 1920-B in (FERC, 2025b).

The difficulties in this process stem in part from the tensions with states and state regulation (Felder, 2020). In addition, FERC regulation covers a variety of grids, only some of which operate as open access RTO/ISOs. The challenge of being general enough to cover all the competing demands of different regulated entities obfuscates critical issues.

These FERC Orders provide no conceptual discussion of (i) how to do benefit cost analysis and (ii) how to connect this to allocating costs to beneficiaries. For example, there is no discussion of the differences between fully vertically integrated systems versus the case with markets and distributed ownership of generation assets. Hence, there is only a brief mention of the benefits to generators, separate from loads, but no description of how to characterize those benefits (FERC, 2024b, §1053).

The principal direction is to list types of benefits, without any explanation of the benefits model. And then the direction is for the transmission entities to file their implementation plans with little further guidance and clear confusion about the underlying challenges. "The seven required benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning, which we describe in greater detail in the discussion of the individual benefits below, are: (1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme weather events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses" (FERC, 2024b, §720).

The accompanying "Explainer" repeats the names of the types of benefits, but does not explain how the components should be implemented or how they should be integrated in a benefit-cost analysis such as outlined in the section above (FERC, 2025a, pp. 6-7). To name is not to define, and the definitional challenge remains.

"The Commission also maintains Order No. 1000's light touch as to regional cost allocation: '[i]t does not dictate how costs are to be allocated. Rather, the Rule provides for general cost allocation principles and leaves the details to transmission providers to determine in the planning processes'" (FERC, 2024a, §192). Further, "…even if one state's public policy is a driver of a Long-Term Transmission Need, the costs of a Long-Term Regional Transmission Facility that transmission providers select will be allocated to transmission customers only to the extent that they benefit from that facility and only to a degree that is at least roughly commensurate with the benefits that facility provides to them" (FERC, 2024a, §108). And to "..'require transmission providers in each transmission planning region to include in their OATTs a general description of how they will measure each of the seven benefits included in the required set of benefits that we require them to measure and use in Long-Term Regional Transmission Planning" (FERC, 2024b, §837).

Further, "[i]n response to requests that a beneficiary-pays approach be used rather than a postage stamp load ratio share model for cost allocation methods, we reiterate that any cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent. Load ratio share, which charges transmission customers in proportion to their use of the transmission system as measured by their relative share of load, is a cost allocation method that may be consistent with the beneficiary-pays approach. The Commission will evaluate whether a proposed cost allocation method allocates costs in a manner that is at least roughly commensurate with estimated benefits on a fact-specific basis, relying on the record in a given proceeding" (FERC, 2024b, §1305).

An important issue arises in the dissent to Order 1920 by Commissioner Christie. "In a sharp dissent, Commissioner Mark Christie argued that the Order forces states to pay for neighboring states' clean energy programs" (Macey and Mays, 2024, p. 210). After an extended discussion, Macey and Mays summarize that: "…the most straightforward way to calculate public policy benefits, differentiate them from reliability and economic benefits, and assign them to particular states or customers is to explicitly include them in the planning model formulation. Without including the influence of public policy in the planning process, there is no straightforward way to identify the related benefits and beneficiaries. In other words, Order No. 1920 supports an approach wherein customers are allocated cost commensurate with the benefits they are projected to receive, whereas the dissent seems to make such an allocation impossible" (Macey and Mays, 2024, p. 237).

The debate is important because Commissioner Christie's concurrence in Order 1920-A asserts that his dissent to Order 1920 was ultimately embraced: "Order No. 1920-A also clarifies that, for purposes of cost allocation, states in PJM and other diverse multistate regions can now choose a new ex ante process that will enable the states to request that the transmission provider run additional scenarios, including a baseline scenario that contains only optimal reliability or economic projects and excludes public policy-driven projects, so that states can compare the costs of the baseline scenario versus the larger, multi-driver scenarios that include public policy-driven projects. Most importantly, states can agree that the difference in costs between the baseline scenario and the larger, multi-driver scenarios that include projects derived from state policies or other policy goals will be allocated to the states whose policies are the source of the added costs and will not be regionally cost allocated" (FERC, 2024a, Christie Concurrence p. 3).

This argues that the baseline scenario counterfactual would exclude the effect of public policies in other states when analyzing the comparison with the transmission expansion. But implementing the public policies will affect the actual outcomes, and an analysis omitting the public policies would thereby misstate the benefits to everyone.

The details here would matter, but absent a more complete specification of the benefit-cost framework and the connection to cost allocation, there is no answer to the criticisms in (Macey and Mays, 2024) or sufficient guidance on how this should affect cost allocation in practice. As it stands, the FERC guidance in the various Orders 1920 does not yet clarify the issues not addressed in Order 1000. Without more detail on the model of benefits and costs, it is an open question if the subject entities can provide implementation details that surpass the standard of "*Very* Roughly Commensurate".

Conclusion

The challenge is considerable to move from long-standing central planning with associated cost socialization for large scale transmission investments to a method that is consistent with liberalized electricity markets, supports economic efficiency, and allocates costs to beneficiaries. In the FERC regulated systems, the extended process leading to Order 1000, followed by the many defects which precipitated an attempted reform of the reforms, in Order 1920, reveals a large and continuing gap between the stated goals and the details of the policies to define a workable system for efficient transmission expansion under the principle of assigning the costs to beneficiaries. As an early pioneer, Stephen Littlechild recognized the difficulties and made important contributions with emphasis on the empirical effectiveness of second-best solutions. The task remains to specify the first-best design from which to evaluate the practical compromises in implementation.

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