Electricity (and Natural Gas) Transmission under Transformation—An Introduction

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1. INTRODUCTION

There may exist various factors that could potentially hinder the efficient development of electricity markets, such as poorly defined property rights, incomplete markets, increasing trade of electricity among different control areas, inefficient operation, and maintenance, as well as bottlenecks in transmission capacity due to lack of investment for grid expansion. Regarding the latter, different authors have broadened and deepened the analysis recently, designing a range of mechanisms for optimal electricity transmission enhancement.[1] The aim has been to understand the different determinants of optimal network pricing—along with the corresponding allocation of costs and benefits among different types of consumers—and the adequate regulation of transmission grids to foster expansion. These analyses have gained relevance, both in theory and practice, due to liberalization processes in various electricity systems that prioritize unbundling of electricity generation and transmission, and that eventually also rely on independent system operators (ISOs).

Electricity transmission is typically a natural monopoly so that it requires some type of external public intervention to achieve efficiency in its development. Usually, transmission sectors suffer from congestion "traps" where congestion rents are so high that marginal revenues from keeping a network stalled in congestion are more profitable for a transmission company than expanding the grid. Additionally, designing optimal regulatory mechanisms for transmission is especially complex in electricity markets given the specific physical characteristics of electricity networks like negative local externalities due to loop flows, i.e., flows obeying Kirchhoff's laws (Schweppe et. al., 1988). One approach to transmission expansion has been traditional central planning either carried within a vertically integrated utility, an ISO or by a regulatory authority. This planning approach is usually complemented with some type of transmission tariff regulation frequently relying on cost-of-service regulation or, sometimes, on revenue caps for maintenance costs (Kemfert et al, 2016). In contrast, and at least from an analytical perspective, transmission decisions could also be determined in a fully decentralized non-regulated way, relying on some form of incentive price-cap regulation (Hogan et al., 2010).

1. For instance, Léautier (2000), Vogelsang (2001), Rosellón (2003), Kristiansen and Rosellón (2006), Rosellón (2007), Tanaka (2007), Léautier and Thelen (2009), Rosellón et. al. (2011) and Hogan et al. (2010).

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This EEEP symposium is dedicated to issues on transmission network policies, mainly focused on the electricity sector, but also touching on the natural gas and the natural gas–electricity network nexus. Recent experiences and future challenges are highlighted, with a particular focus on cross-border questions (or "seams" issues), and the challenges of expanding the scope of transmission planning beyond national and/or state borders. The symposium brings together deep analyses on incentive network regulation and planning, cost and benefit allocation methods, comparison of electricity and natural-gas network institutional regimes, lessons from transmission pricing that can be learned in pricing electricity distribution networks under distributed energy resources, as well as various international experiences on transformation of the energy networks in North America, Europe and Oceania. Likewise, transmission expansion planning is analyzed taking into account future lower carbon electricity mix, and the change of focus from central to distributed resources. All these topics lie at the heart of the analytical and practical nature of the expansion dilemma for energy networks.

2. STRUCTURE OF THE SYMPOSIUM

This EEEP symposium puts together seven contributions focusing on transmission expansion issues. The contributions share the common view that transmission enhancement in the electricity sector is quite complex but crucial for the efficient functioning of electricity markets, especially under the transformation of power generation technologies toward renewables, as well as under the distributed-generation revolution. We present balanced discussions on a rich diversity of topics by highly qualified specialists in the field, respecting EEEP's aim to provide in-depth, non-technical overviews of policy analyses and recommendations, as well as conceptual questions that motivate further academic research.

Seabron Adamson kicks off the symposium with a comparative analysis between the U.S. electric and interstate natural gas transmission networks (Adamson, 2018). These share numerous characteristics such as a federal cost-of-service regulation, but the historical regulatory development of the two sectors has been rather different. The economic regulation of natural-gas network expansion is just simpler than in electric power. On the one hand, natural gas pipeline developments have been kept decentralized and operated under the contract carrier model. Pipeline costs are recovered directly from gas transmission customers. On the other hand, after some limited merchant transmission line development, the U.S. electric industry has returned to cost-of-service regulation for most new open-access transmission projects. The U.S. experience then offers some policy implications: In the first place, a decentralized contract carrier model can be effective in gas pipelines, and help in creating new gas transmission capacity in response to changing supply shocks. Meanwhile, there are much more limited circumstances where decentralized "merchant" development can be effective in electricity transmission. Externalities related to electricity networks are significant, as are economies of scale and lumpiness. The U.S. restructuring process has shown the dominant role that centralized transmission planning continues to play in identifying new electricity transmission lines. Additionally, while competition between new interstate gas pipeline projects has been effective, implementing competition for new regulated electricity transmission projects takes time and has required frameworks for evaluating different transmission proposals. Adamson considers that the possibility exists for more innovative transmission solutions in the electricity sector, but only at the expense of increased complexity and applicability. For large regional projects, cost allocation methods are critical. Moreover, the detailed analysis of costs and benefits using transmission models may be the only way to ensure that the costs of new projects are allocated in a plausible way.

William W. Hogan retakes this last discussion addressing theoretical and practical problems related with cost allocation of electricity transmission infrastructures based on the beneficiaries-pay principle (Hogan, 2018). He argues that this principle is a workable approximation that makes transmission cost socialization a measure of last resort. In fact, Hogan thinks that available analytical tools make cost allocation commensurate with the distribution of benefits for new transmission investment. This follows directly from the information that must be produced as part of the evaluation of new transmission investment in standard network expansion planning studies since the analysis of the value of such investment requires calculation of locational impacts on generation and load. This is typically carried out within a power-flow model environment. In this process, the beneficiaries are made better off while respecting the principle that those in regions which do not benefit do not pay. However, the beneficiary-pay principle is actually not straightforward in applications, and many different complex issues take place when trying to apply it in different circumstances. Hogan's paper extensively discusses various these problems and proposes workable and well-argued solutions.

Luis Olmos, Michel Rivier, and *Ignacio Pérez-Arriaga* follow the discussion on cost-allocation matters, especially focusing on the calculation of benefits to consumers due to enhancement transmission projects (Rivier, et al, 2018). They first argue that setting up the adequate institutions—and the interactions among them—to guarantee the efficient development of the transmission grid is especially challenging when a market covers various regions in independent jurisdictions or countries. The corresponding institutional design should especially take into account cost-allocation arrangements, and benefits created by transmission network expansions. Calculating benefits associated to grid reinforcements is usually a complex task due to the multiple uncertainties involved in network systems. Such benefits must be correctly determined since they guide decisions related to welfare-maximizing development and cost allocation in transmission grids, and they are also needed by planning and regulatory authorities to build a framework to assess and, eventually, approve network reinforcements. Benefits are also crucial to define the structure of network charges that drive welfare optimal investment decisions. The authors study in detail the computation of costs and benefits of expansion projects, how benefits guide the grid development process and, also, how they define transmission charges.

Ingo Vogelsang next presents a regulatory-economics analysis on incentives to foster efficient expansion of electricity networks (Vogelsang, 2018). An electricity transmission network is a natural monopoly that requires to be regulated. Both theory and practice coincide in this. Regulation should then achieve that private profit maximization by an independent transmission company (Transco) matches social surplus maximization. Desirable regulatory mechanisms are primarily those who do not require the regulator to know in detail the private information that the Transco possesses over its cost and demand functions. The mechanisms are then auto-implemented by the Transco (through maximizing its preferences) so that the regulator only requires limited monitoring. Likewise, regulatory mechanisms seek to induce optimal investments in network capacity from a social-welfare perspective. In his paper, Vogelsang analyzes incentive regulation for electricity transmission networks. He carries out a comprehensive overview on the literature of this subject and then proposes a new mechanism (the H-R-G-V mechanism) that blends together two main traditional regulatory approaches, one based on subsidies/taxes and another based on price-cap constraints. The new proposal is shown to apply well to electricity transmission pricing and investment. In particular, it induces immediate optimal pricing/investment. While not perfect, the H-R-G-V mechanism marks a substantial improvement over the rest of currently available regulatory mechanisms. Although at a normative stage in its current form, the H-R-G-V mechanism shows a favorable assessment for practical applications. *Vogelsang* illustrates this by comparing the adjusted H-R-G-V mechanism with a central planning approach and a stakeholder bargaining approach to transmission investment. Such comparisons highlight the tradeoffs among these approaches, confirming the potential for the practical use of incentive regulation to efficiently expand electricity networks.

The next two papers get deep into the relationship between energy network expansion and the increasing development of distributed energy resources (DERs). *Michael Pollitt* first explores pricing methodologies at the transmission network level that might be applied at the distribution level, as distribution networks increasingly behave like transmission networks (Pollitt, 2018). This is every time more needed due to DERs within distribution areas, such as rooftop solar PV, electric vehicles, and distributed electricity storage. However, this solution is not obvious, as transmission network pricing methodologies also vary substantially in their sophistication across the world. The complexity of network charging principles for the electricity distribution network in the light of DERs—and the corresponding smart metering—make distribution charging methodologies an extremely complex task. One problem is that DER investments need clearer price signals in the short run—due to their higher discount rates and shorter time horizons—than the ones that are typical of long-term network investments. *Pollit* discusses different charging principles, outlines the problems posed by the development of DERs in distribution networks, and proposes potential solutions on how regulators should change current distribution-charging methodologies.

Bruce Mountain and *Jamie Carstairs* further study the arrangements for transmission planning and development when battery technologies (both grid-scale or distributed) become more competitive (Mountain and Carstairs, 2018). This is done in the context of needed security of supply in South Australia where intermittent renewable generation is every time more used, combined with declining conventional fossil fuel generation. The authors explain that batteries are developing rapidly in South Australia—the world's largest battery is even expected to be operational soon. Together with batteries, planning and developing regulated transmission assets, including interconnectors, are also receiving renewed focus. But new transmission might compete with non-network alternatives, especially when transmission planning is carried out by an incumbent monopoly. The close substitutability of batteries and transmission lines then make relevant that transmission is developed through competitive tenders (under build-own-operate-transfer contracts) rather than remaining with the existing regulated transmission company. The authors further suggest an ISO structure for South Australia as well as the abolition of exclusivity to develop new projects by the transmission incumbent. The authors study how such structures would eliminate the incentive to prefer network solutions at the expense of batteries, which are an increasingly competitive option.

Anna Grigoryeva, *Mohammad R. Hesamzadeh*, and *Thomas Tangerås* close the symposium discussing the challenges for transmission regulation in the context of energy transition in Nordic countries (Grigoryeva, et al., 2018). Four critical main market dilemmas are discussed, including possible options to address them: (i) further market integration, (ii) ensuring generation adequacy, (iii) the increased need for flexibility and (iv) frequency control due to reduced inertia in the system. Due to a mature and well-functioning market design, as well as the strong regional cooperation between Nordic countries, the analysis in this study provides insights for other countries, especially considering the increasing shares of renewable generation in Europe. Transmission expansion issues are discussed in the context of market reform quandaries such as the need of capacity markets or adjustments of market procedures to remunerate flexibility. Political perspectives are considered too. With regards to market integration issues, transmission enhancement is key to ensure an efficient allocation of cross-border generation and network development. On resource adequacy, transmission regulation could contribute to generation adequacy in a regional setting, considering demand-side management as well as new DER technologies. On the flexibility issue, transmission development is also an option to placing of new flexibility resources among national electricity systems and strengthen future regional cooperation in Nordic countries.

3. CONCLUSION

Transmission network expansion is vital for the development of energy sectors. In this EEEP symposium, the reader will be able to deepen into various core issues in the current debate on this subject. Of course, many other topics remain pendant, such as the trade-off between grid expansion and the development of distributed energy resources in developing countries (as was pointed out in the first EEEP symposium 6(1) of 2017 on prosumage). This is, of course, a potential exciting topic to develop in future EEEP symposia.

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