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Via Electronic Filing

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1-A
Washington, D.C. 20426

Re: Notice of Proposed Rulemaking Regarding Transmission Planning and Cost Allocation by
Transmission Owning and Operating Public Utilities [Docket No. RM10-23-000]

Dear Ms. Bose,

Please find enclosed for filing an electronic copy of my initial Comments on the above-referenced document. I am submitting these Comments on my own behalf and I should be listed as the filing entity. These Comments do not represent the views of the Massachusetts Institute of Technology (MIT) or any organization therein and MIT should not be listed as the filing entity. My MIT affiliation is noted only for informational purposes.

Sincerely,

Ignacio J. Pérez-Arriaga, Visiting Professor, Engineering System Division

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Notice of Proposed Rulemaking Regarding)	Docket No. RM10-23-000
Transmission Planning and Cost Allocation)	
by Transmission Owning and Operating)	
Public Utilities)	

Comments of Professor Ignacio J. Pérez-Arriaga¹

Introduction

My feeling is that this Notice of Proposed Rulemaking (NOPR) recognizes several important shortcomings in the current transmission regulation and does an excellent job both in describing the need for change and in laying out a rule that would represent significant progress in addressing existing issues. I would like to focus here on two things. First, what I see as several important omissions in the principles surrounding cost allocation. This is not to say that I disagree with the framework presented in the NOPR, but I feel that it could be strengthened by the recognition of a couple of important fundamentals. Second, I wish to introduce the scheme used for the allocation of transmission costs between Transmission System Operators² (TSOs) in the European Union. Such a system would not translate perfectly to the US context – and it certainly could be improved upon from its current state in the EU – but the general concepts could be useful in the process of creating a more standardized system of inter-regional cost allocation.

A note before proceeding: while I believe that transmission planning issues are important, they have been well addressed and will not be commented on in this document.

¹ Ignacio Perez-Arriaga (PhD in Electrical Engineering, MIT, 1981) is a professor at Comillas University (Madrid, Spain) and visiting professor at MIT. He has been a Commissioner at the Spanish Electricity Regulatory Commission, is a member of the Single Electricity Market Committee in Ireland, is Director of Training at the Florence School of Regulation (European University Institute) and has been lecturer and consultant in regulatory topics in more than thirty countries.

² A TSO, while it may exist in one of several forms, is the European analog to an ISO in the US. The primary difference is that TSOs own transmission assets, frequently in exclusivity. Most European countries have one TSO, although there are three in Germany. Most of them are independent from any generation or distribution companies, or they are subject to specific rules to minimize conflicts of interest, see <https://www.entsoe.eu/>.

Cost Allocation Principle: Beneficiary Pays

First and foremost, all principled costs allocation schemes should be founded on the principle of beneficiary pays or its dual, cost causality. This principle and its importance are made very clear in the current NOPR, and so it requires little attention in this Comment³. I would, though, like to reemphasize the importance of the inclusion of all beneficiaries during the procedure for allocating cost. In some cases, this may include generators who may also benefit from the increased transfer capacity provided by new transmission projects; loads are not the only network users that stand to gain. A failure to recognize all beneficiaries could create opposition from those who are found to be responsible for payment since they may end up paying in excess of their benefit, or it could cause a justified project to be left unconstructed because not enough of the benefits (i.e. beneficiaries) have been captured to cover the costs. I also support the Commission's finding that it is very important to have a cost allocation regulation in place that is standardized and incorporated with the transmission planning process (within which the beneficiaries can be determined) as a means to avoid post-planning cost allocation disputes.

Cost Allocation Principle: Independence from Commercial Transactions

A second principle of transmission pricing holds that there should be no distinction made between different types of transactions when calculating network charges⁴. In other words

“In the internal electricity market one should not discriminate between bilateral contracts and any other kind of network use, since the efficient operation of the...power system – on which all network flows depend – should be the same, regardless of the type of transactions and dispatch mechanisms that have been actually used to put into operation the most efficient production means.”⁵

Instead, transmission charges should depend on the location of the network users within the system topology and on the temporal patterns of injection and withdrawal. While this was not

³ It is worth noting that the focus on beneficiary pays represents ideologically sound reasoning that exceeds what has been achieved elsewhere in the world. For example, Europe is still very focused on network usage methodologies – under the general notion of “locational economic signals” – and has not yet completely embraced the “beneficiary pays” principle.

⁴ This principle has been accepted by the European Commission and an example of its codification can be found in Article 14 of “Regulation (EC) No. 714/2009 of the European Parliament and of the Council” of July 2009.

⁵ From a discussion paper entitled “Transmission and Trade of Electricity in Europe” submitted to the European Electricity Regulation Forum in Florence in 1998.

contradicted in the NOPR, it was also not articulated. I believe that it would be worthwhile in the final rule to include this requirement for any future cost allocation procedures.

The wisdom of decoupling transmission charges from commercial transactions can be illustrated by a simple example. Suppose a set of generators and loads in a specific area are asked to establish commercial transactions to buy and sell electricity in order to ensure that all loads are served for a specific time period. Given that any load-generator pair can execute a transaction, and that everyone has information about the costs of each generator, when the arrangements are completed all demand will be met using the lowest cost set of generators. This experiment could then be repeated one million times, and the specific transactions will vary because of chance occurrences during each iteration (e.g. contact order between generators and loads, limited bandwidth over internet connections, finite number of phone lines and operators). What is significant is that in every instance all of the loads would be served with the same set of least cost generators, resulting in the exact same flows over the network. Thus, if commercial transactions have no influence on the physical network flows, then charges for network utilization should not depend on commercial transactions.

Alternatively, some suggest that transmission payments should be linked to the type of transaction that a network user participates in as power is bought and sold. Based on the above reasoning, it should be clear that this is an illogical approach. This type of charge operates on the assumption that a seller injects power onto one point on the network, the power travels over a specified path, and a buyer extracts the same power from another point. Because of the nature of electricity networks, such distinctions lose meaning in practice and would require an arbitrary rate-setting process to associate transactions with network costs. Further, in a well functioning wholesale market, actual generator dispatch should not depend on prior arrangements between buyers and sellers but on economically efficient utilization of resources. In light of this, network prices should instead be based on location within the network, whether a user is producing or consuming, and the time of day of the network usage. Network prices may even depend on the benefit derived from certain network developments, but under no circumstances should depend on commercial transactions⁶.

⁶ Rivier Abbad, Michael. Electricity Power Transmission. In *Training Course on Regulation of Energy Utilities* Florence: Florence School of Regulation, European University Institute, <http://www.florence-school.eu/>

Cost Allocation Principle: *Ex Ante* Establishment of Network Cost

The third cost allocation principle that I support addresses the importance of specifying who will pay for a transmission line over the life of the investment. Like the principle of independence from commercial transactions, this principle is not contradicted in the current NOPR, but I feel it should be recognized specifically moving forward.

There are two primary options for allocating the cost of new transmission lines to network users. The first option (to be called here: *ex post*) is to recalculate the allocation of cost on a regular basis. In theory, an *ex post* approach would allow the system to update beneficiaries over time and thus capture changes in network topology, load growth, and generation installations. In practice, there are two major impediments to implementing an *ex post* system. First, updating cost allocation *ex post* creates technical difficulties and tends to lose meaning as the network evolves over time. Generally, the benefits of an existing line are examined by removing it from a system model, running the model, and observing the results. When this process is performed, some cases will indicate that removing a line has drastic negative consequences and other cases will show very little apparent impact. To try to update cost allocation in this way implies a comparison to an unrealistic counterfactual wherein the line in question was not built. In many cases, even if a specific line had not been built, a similar line would have taken its place or network users would have adopted alternative measures. Furthermore, the system continued to evolve around the line in question, rendering the comparison to a system without such a line meaningless. The second issue with an *ex post* approach is that a cost allocation scheme that updates regularly distorts and weakens the long term price signal to generators and loads, creates investment risk, and reduces the likelihood that the project will be undertaken.

The alternative to applying a cost allocation method to a line repeatedly over time is to apply it once and leave it untouched (here: *ex ante*), at least for a long period (e.g. 10 years). An *ex ante* approach avoids the technical and financial issues associated with re-allocating costs *ex post* while maintaining adherence to the important long-term price signals needed to spur efficient transmission investment. There is no reason to update a long-term price signal soon after a project has been completed, as that project's investors have already responded to the signal and are committed to a single course of action once steel is in the ground. After a period of time that is sufficient to allow for certainty on the part of investors, the cost allocation of a line *could* be

revisited and treated as an old line, perhaps shifting the cost allocation basis from beneficiary focused to user focused.

Aside from providing proper signals about where and when to build new generation or load, it is desirable to send the proper locational transmission signals to generators that might be thinking of retirement. Because system topology shifts over time, the original transmission charge may be very wrong for old generators. For this reason, it may be necessary to eventually update the signal to reflect the current situation. For example, in some cases plant retirement may impose reliability violations on the system and the transmission charge should reflect this. As mentioned above, this goal can be achieved by updating charges very occasionally (and smoothly) after the initial post-investment period (e.g. 10 years). Updating signals in the middle of a transmission facility's life, or some years after a new generator was installed, would not have a significant impact on rate stability for transmission investors and allows proper signals to be conveyed to users.

The European Inter-TSO Compensation Mechanism

The Commission has recognized, and rightly so, the need to provide guidance on cost allocation for interregional transmission facilities, the likes of which may become more common in the near future. To this end, I would like to introduce Europe's Inter-TSO Compensation (ITC) mechanism – in case the Commission was not aware of its existence – that could provide a conceptual and principled model for an eventual US regulation that calls for the allocation of the cost of transmission across regions. This is not to suggest that the European system should or even could be directly copied by the US, but to show that there are innovative concepts in cost allocation that are being used elsewhere and that could be incorporated into US regulations.

The EU power system represents an interesting comparison to that of the US; it serves a reasonably similar population (309M for the US vs. 501M for the EU) that consumes a similar amount of electricity (3.9M TWh for the US vs. 3.3M TWh for EU). The system is, for the most part, interconnected and synchronous, and thus loop flows from some countries end up influencing power transmission in other countries. Further, different countries within the EU – all of them integrated into a common electricity market with system-wide open access, though each with their own regulatory procedures – may be considered analogous to RTOs in the United

States. Large European countries – Germany, France, Italy, UK, Poland or Spain – are similar in size, electrically, to PJM, MISO, CAISO, ERCOT, NY ISO or ISO NE. As in the US, Europe is considering very large wind and solar developments, which might require significant reinforcements of the transmission network. Unlike the US though, Europe has already developed and employs a mechanism that recognizes the desirability of “inter-RTO” network enhancements and the inevitability of unintended system usage. Because of the similarities between the power systems, there is reason to believe that a similar approach to cost allocation could be promising.

The current EU system, called the inter-TSO compensation mechanism (ITC), has been in place since March of 2002⁷. This system was developed in response to a 1996 directive by the European Parliament to ensure the development of an Internal Electricity Market (IEM) for Europe. The primary concern was that existing cross-border and transit charges were an impediment to cross border trade. In particular, the regulation at the time led to pancaking of transmission network tariffs, whereby each TSO would levy a charge on transactions crossing its territory in order to cover its system costs. When multiple TSOs were involved, the high price of pancaked rates would discourage trade. In a world without political boundaries and with infinite regulatory flexibility, a common network tariff scheme – the so called “single system paradigm” – would probably be ideal to solve this problem. However, given the wide diversity of national approaches to transmission tariffs and the multiplicity of interconnected wholesale electricity markets, a complete harmonization of EU-wide cost allocation schemes was deemed impossible. Instead, the ITC system was developed.

At its heart, the ITC mechanism involves three steps:

- “Determination/calculation of the compensation that each TSO is entitled to receive (from other TSOs) for the costs incurred for hosting cross-border flows in its network;
- Determination/calculation of the compensation that each TSO is required to pay for the costs incurred by other TSOs in relation to the cross-border flows arising from injections into and withdrawals from the TSO’s grid; and

⁷ The current system was meant to be provisional and to be replaced by 2003 with an improved future scheme. A more theoretically rigorous framework is in development but has not yet been approved due to political and procedural roadblocks.

- Determination/calculation of the net position of each TSO as the difference between the level of the compensation the TSO is entitled to receive and the compensation payments it is required to make.”⁸

After the compensations are calculated at the end of each period, countries reimburse each other for the network usages. Once the costs of transmission use have been allocated to each country, they are then free to set internal transmission tariffs, which take into consideration the net balance of compensations and charges to that country. The only requirement is that the countries have to adhere to a set of common guidelines for their internal cost allocation. Chief among these guidelines is the mandate that the domestic tariff should not hamper international trade, which in turn enables the implementation of a competitive market at the EU-wide level. The countries may then choose to differentiate transmission charges by spatial and temporal means or by another method of their choice⁹. In this sense, the EU ITC system is a hierarchical system that allows for cost allocation procedures to be implemented at both a national/interconnection-wide level and at a regional level. Such an approach could be a workable compromise within the US framework, allowing regions to maintain their own distinct cost allocation procedures while, at the same time, creating a standardized method for allocating costs between regions.

From a technical standpoint, the ITC system is founded on the concept of network usage as a proxy for benefits in the process of compensating different TSOs for the utilization of their networks¹⁰. As it stands, a transit-based¹¹ method is used to calculate the utilization of each country’s network by every other network. This method assumes proportional allocation of responsibility for network usage for each TSO between transit and local flows (a simplified version of the WWT method described below). Similarly, a proportional allocation is also assumed for the allocation of responsibility of transits to net imports and exports, regardless of

⁸ FSR. 2005. A Study on the Inter-TSO Compensation Mechanism. edited by European University Institute: Florence School of Regulation. Complete text may be found at:

http://www.eui.eu/RSCAS/Research/FSR/pdf/051031-ITCStudy-FinalReportCover_000.pdf

⁹ European Commission. 2002. Benchmark of Electricity Transmission Tariffs. prepared by Universidad Pontificia Comillas. Complete text may be found at :

http://ec.europa.eu/comm/energy/electricity/publications/doc/bench_trans_tarif_en.pdf

and additional similar references are available from <https://www.entsoe.eu/>.

¹⁰ A pure application of beneficiary pays is deemed impossible because every country has a different pricing scheme. For this reason, network usage is accepted as a reasonable proxy.

¹¹ A transit is loosely defined as a power flow that affects a TSO’s grid but originates and ends in another TSO’s grid. Similarly, a cross-border flow may be defined as a power flow that crosses at least one border.

the location of the involved countries. The current approach was intended to be provisional, and eventually be replaced by a more rigorous, long term method. Unfortunately, nearly a decade after its establishment, political interests have hampered the ITC's update and its present formulation deviates significantly from the ideal; it is both inelegant and does not successfully incorporate all cross border flows.

There is still hope that eventually a more developed ITC system will replace the current provisional method. Two primary approaches have been presented as options¹²:

- Allocation of Individual Use¹³ (similar to Average Participations, or AP, methods): This type of method attempts to establish a meaningful path – for the purpose of network cost allocation – followed by power injected or withdrawn by every agent on a system for a number of representative snapshots of the actual system flows. With this knowledge, the utilization of every network asset by every network user can be computed. In the context of ITC, the external and internal utilization of any country's grid can be calculated by aggregating the individual utilizations. The ability to attribute flow on each line proportionally to a specific subset of users is a distinct advantage of this method.
- With and Without Transit (WWT): Cross-border methodologies compute the utilization of a country's grid by observing the flows of electricity across its borders. In this case, transit is defined as the fraction of flows on a single country's grid that is not generated or consumed by internal network users. A more precise – and arbitrary – definition of transit is necessary to be able to perform any required computations. This method also only takes into account the part of cross border flows that are considered to belong to a transit, rather than the total flows on all cross border lines. Unfortunately, the necessary assumptions can result in absurd situations and counterfactuals that make no logical sense and that are made even worse when losses are considered.

¹² Perez-Arriaga, Ignacio J., Luis Olmos and Rubio, F.J. 2002. Report on cost components of cross-border exchanges of electricity, prepared for the Directorate General of Energy and Transport, European Commission, http://ec.europa.eu/comm/energy/electricity/publications/doc/revised_ccbt_final_report_v112_en.pdf

¹³ Several methods have been proposed in the technical literature to estimate the utilization of the different facilities of a network by its users. For the particular problem at hand the method of Average Participations (AP) has been found far superior to others, thus, in principle, it can be recommended, see http://ec.europa.eu/comm/energy/electricity/publications/doc/cbt_commillas_final_report.pdf

On its face, WWT methods seem both easy to understand and easy to apply. While this may be the case – and a method currently in place as part of the ITC – both theoretical and empirical evidence suggest that on closer inspection AP methods are superior in nearly every respect. For one, AP methods agree most closely with the “single system paradigm”, the desire to have the final cost allocation outcome mirror as closely as possible the outcome that would take place in the absence of political boundaries and constraints. Further, AP schemes indicate both how much a country is using its native grid and how much other countries are using it. WWT methods only compute how much other countries are using a country’s native grid, leaving open the question of how to charge this use to other countries. Finally, AP methods rely on more reasonable assumptions and lend themselves to a more comprehensive transmission regulation approach. Should the US consider a hierarchal scheme like the European ITC on an interconnection level or even on a level that only encompasses pairs of regions, the AP methodology should be viewed most positively.

There are a couple of additional points worth making about the ITC method. First, when establishing an ITC-like arrangement there is a need to determine on what standards of cost reimbursements between regions are going to be based. This can become contentious, so it is best to either accept each region’s local scheme for determining network revenue requirements or to set a single standard for all of the regions involved. Second, the financial transfers involved in an inter-regional cost allocation scheme such as the one described tend to be quite small. If Europe’s experience is any indicator, then the transfers will usually make up 1-2% of each region’s transmission costs, which themselves tend to be between 5-10% of the all-in cost of electricity.

A cursory reading of this description may lead to thinking that the ITC departs from the principles of cost allocation presented in the first part of this text, namely, allocation to beneficiaries and *ex ante* establishment of network costs. I would like to clarify that this is not the case. First, as was noted, a network usage approach to cost allocation is an acceptable proxy for beneficiary pays in many cases. This acceptance is a practical recognition of the challenges of applying a pure beneficiary pays approach, especially in the context of additional challenges presented when allocating costs across regions with different pricing schemes. Second, though inter-regional transfers may vary somewhat year-to-year, these changes would be small

compared with the total transmission costs within a region, and therefore the scheme is perfectly compatible with regional transmission charges that have been computed and established *ex ante*. The goal of this type of system is not to send precise, time-variant locational signals; that is the role of the intra-regional cost allocation scheme. Instead, a hierarchical inter-regional cost allocation method is aimed at establishing cross-regional fairness and ensuring that all network costs are borne by those who incur them. Because such a system will likely not involve large annual payments or significant variation from one year to the next, there should not be a problem with setting stable transmission charges to network users based on familiar projections of network usage and development.

Communications

Communications with the authors regarding this comment can be addressed to:

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Conclusion

In this comment, I set out to introduce several cost allocation principles that were noticeably absent from the current NOPR. I applaud the continued recognition of the importance of beneficiary pays and also suggest that the FERC embrace the additional principles of independence of transmission charges from commercial transactions and the importance of *ex ante* allocation of costs. Following the discussion of principles, the concept of a hierarchical system for inter-regional cost allocation was introduced, using Europe's ITC as a case study. I believe that such a methodology could be promising in the US context, not least because it recognizes the distinct interests of different regions while simultaneously providing a standard costs allocation scheme for any future inter-regional transmission projects. I respectfully urge the Commission to take my Comments into account as it develops a Final Rule.

Respectfully Submitted,

Ignacio J. Pérez-Arriaga
September 9, 2010