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EFFICIENT SOLUTIONS FOR ISSUES IN ELECTRICITY SEAMS

By Travis Kavulla

INTRODUCTION

In the two decades since the regulatory construct has been devised, Regional Transmission Organizations and Independent System Operators (together, ISOs) have benefited consumers by knitting together the electricity transmission facilities of individual utilities into a common marketplace. Those larger networks have become platforms where a more efficient and seamless trade in electricity can occur. An ISO therefore should be understood as an operational, corporate and regulatory innovation: a "software" solution that reduces production costs and promotes the sharing of power-generation capacity. The advent of ISOs has also had a "hardware" component. It has become easier to build transmission projects because the ISO's tariff is a vehicle that can more easily allocate costs across multiple utilities, when transmission provides benefits beyond a single one.

Yet, as ISO footprints grow or are reconfigured and as their market designs change, unforeseen issues emerge along the "seams" that exist where two or more distinct utilities or ISOs adjoin one another. Differences in trading rules, a lack of automation, disagreement about how the existing transmission system should be utilized and paid for, and impediments to how new interregional transmission assets should be planned for and approved: All of these are seams issues that merit the attention of state and federal regulators, utilities and the ISOs themselves.

To be clear, seams existed before ISOs, and would exist in their absence. Indeed, the benefits that ISOs confer are an indication of how pronounced such issues were prior to the formation of ISOs, when utilities operated in a more siloed manner. Indeed, the fact that seams issues are discussed today mainly in an ISO context should not indicate that ISOs created them but rather that the formation of ISOs merely made these particular issues more visible.

The associated policy questions that federal and state regulators, as well as ISOs and market participants, must consider essentially revolve around how to solve two problems that arise from seams. The first is how to ensure the energy markets of two ISOs can minimize costs to customers of both markets through trading between them. The second is how to ensure that there are not undue political and financial obstacles to the creation of a physical network that has sufficient capacity for economic trading of energy to occur.

Whereas the first of these is quintessentially a software problem, the second is a hardware problem. However, both are highly complex. And it is perhaps for this reason that existing literature on seams tends to commence not from the beginning, but rather from a complex status quo that has emerged over the last two decades. It also features a fair amount of handwaving about what is and is not possible rather than providing a more useful self-interrogation about the reasons for adherence to the status quo. Moreover, it frequently launches into the nuance of commercial and operational agreements that are no doubt foreign to those who are unfamiliar with electricity marketplaces.

Accordingly, the present study seeks to remedy such issues by beginning…at the beginning. It offers insights about why ISOs and utilities do the things they do on transmission topics. It purposefully minimizes detailed discussions of the operational protocols of ISOs, as these require a far more in-depth understanding than this primer is meant to provide. And, while this paper's considerations largely deal with markets that exist in the middle of the country, certain topics it raises are broadly applicable elsewhere. Finally, it should be noted that electricity markets—and their seams—are inevitably complex. This paper does not substitute for a deep understanding of them, but is more an attempt to situate ISOs and seams issues into their policy context, before offering practical suggestions that relevant actors should consider in their moves toward potential solutions.

FROM LOCAL ORIGINS TO AN INTERCONNECTED GRID

In American history, electricity service began as a local business. Throughout the early 1900s, small operating companies emerged to serve particular municipalities with systems that were technically unsophisticated sets of small generators connected to modest consumer loads. However, this did not last long. The fixed costs of running a small company were largely the same as running a somewhat larger company, and the persuasiveness of the economies of scale of the industry quickly took hold. In the first few decades of the twentieth century, small operating companies were managerially consolidated into corporate holding companies. Eventually, some of these merged their operations as well. Then, in the period between the 1930s and the 1950s, these companies themselves then interconnected with one another in certain regions of the country, especially those with higher population densities or where energy economies were driven by urgent demands, such as wartime industrialization.

In these nascent stages, there were two major governmental interventions in the industry. First, the public utility regulation was instituted—whereby formal monopolies were created but subject to state or municipal rate regulation. Second, Congress took aim at concerns around financial engineering, misleading accounting and the transparency of corporate governance. The latter effort culminated in the passage of the now-repealed Public Utility Holding Company Act of 1935 (PUHCA), which reified state regulation by trust-busting larger, interstate holding companies that had been used to obfuscate utility bookkeeping, filling rate regulation with guesswork and making it impractical.

Once reformed, the commercial interactions *between* separate utilities were subject to a lighter-touch federal regulation that deferred to the bargaining power of two or more powerful incumbents and to state regulation. Tellingly, when the U.S. Supreme Court invalidated a state's authority to set rates associated with power imported from another state in *Rhode Island v. Attleboro Steam & Electric Co.* (1927),[1] Congress acted only modestly to fill the breech. Playing second fiddle to the PUHCA adopted in the same year, the Federal Power Act of 1935 (FPA) created the Federal Power Commission to fill a vacuum of law rather than to preempt state prerogatives. This made sense in the context of the PUHCA's legislative modus operandi, which was to break up larger interstate firms to bolster the power of states. On most questions of electricity regulation, the FPA deferred to state regulation, including on questions as to how generation should be procured and how rates for retail customers should be set. Meanwhile, each of the individual operating companies was subject to a more expansive, if not essentially complex, form of regulation at the states, where their rates were set based on a historical period's actual costs, plus a fair rate of return for the value of their capital investment. Although we may now think of the grid expansively, for the better part of the twentieth century, policy tacitly recognized and promoted electricity service essentially as a local monopoly.

The passage of the Public Utility Regulatory Policies Act (PURPA) in 1978 is today known mostly for the obligation that it imposes on utilities to purchase the output of certain independently owned power plants. This implied a right to interconnect to a utility system and marked a seminal moment. It was the first time the federal government, acting in a non-wartime context, led instead of followed in requiring state-regulated utility companies to interconnect to power generators owned by a third party.[2] From there, in 1996, the Federal Energy Regulatory Commission adopted Order 888.[3] It and its progeny have defined FERC's modern legacy on transmission as one of open access, where any public utility must unbundle its transmission service in a non-discriminatory manner. For the first time, all utilities subject to FERC's jurisdiction were required to file an Open Access Transmission Tariff (OATT) that offered unbundled transmission services to those who would interconnect with them.

As a practical matter, the regulatory policy announced in Order 888 was advanced substantially through the creation of Independent System Operators in the first decade of the

1. *Public Utilities Commission of Rhode Island et. al. v. Attleboro Steam & Electric Co.* (1927) 273 U.S. 83 (47 S.Ct. 294, 71 L.Ed. 54). https://www.law.cornell.edu/supremecourt/text/273/83.

2. Subsequent amendments to PURPA made this implied right more formally established, including a requirement that a utility transmit or "wheel" through the output of PURPA projects to other utilities to whom sales would be more lucrative. 18 CFR § 292.303(c) ("obligation to interconnect") (2006).

3. See, e.g., Federal Energy Regulatory Commission, *Order No. 888: Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, Docket No. RM95-8-000, April 24, 1996. https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt.

2000s.[4] Legally, ISOs may be thought of as a merger of different utilities' OATTs into a single one administered by a neutral third party. Most ISOs are not-for-profit corporations, although some are chartered as social-welfare organizations and others are chartered for the benefit of their members. How they conceive of their obligations and identity is an important consideration in the question of whom ISOs are intended to serve. Nevertheless, all of them intended to lower the transaction costs that exist when, for example, a power generator located in North Dakota wishes to transmit its power to customers in Illinois. Before the creation of an ISO, such a transaction would have required open-access reservations across multiple transmission-owning utilities; in an ISO that knits together this expanse of transmission, a single request suffices. Moreover, by having a single set of rules—albeit complex ones—ISOs created a focal point by which smaller market actors participated and understood the rules of the game. As anyone who has participated in them understands, the market-design processes of ISOs were and are intensive, but they nevertheless opened the door to more transparent business practices and eliminated some of the information asymmetries that occurred when each transmission owner operated in particular and sometimes atypical modes.

These ISOs also operated markets for electricity, and did so under a rubric that is now called "security-constrained economic dispatch." "Security-constrained" refers to the engineering limits of the use of the knit-together system of transmission the ISO operates, as well as the output range of generators. Meanwhile, "economic dispatch" refers to the concept that generators should be dispatched in a merit order of least-to-greatest marginal cost to serve load, subject to those transmission constraints. The ISO was thus the central operator of the transmission and the auctioneer for an electricity market operated on that platform. These twin roles ensured that, even if it was not necessary to serve its owner's customers, a power plant might be online if it could displace a more expensive power plant that a utility on the other side of the ISO's footprint intended to use.

To grasp the difference between what ISOs did in their new role, and what had come before, it is important to understand that the ISO innovation was not the first in the long-distance trade in energy. For decades, there had been arrangements whereby utilities in one place invested in or built generators closer to fuel resources, such as mine-mouth coal plants or hydroelectric generators, and then delivered that power through electric transmission. The right of one party to use that transmission was a valuable property right and thus questions arose as to how such a right should be quantified. For example, if the transmission line was part of a more seamless network of the ISO, where the least-cost fleet of generators would have priority access to transmission under security-constrained economic dispatch, how should that right to use transmission be acknowledged and compensated? In this situation, it was deemed necessary to create a financial right to the transmission's value in facilitating trade.

While the commodity instrument devised to reflect this value has different names in different places, it proceeds from the same general principle: Transmission costs can be offset by the option to reduce the costs of supplies elsewhere in the chain. The commodification of this right meant that those who had rights to use transmission before the ISO would be compensated, while those property rights themselves would not define the actual operation of a system on an engineering basis. This innovation allowed ISOs to become more seamless, flow-based rather than rights-based and to operate to their true security constraints. This concept is complex, but it is important because, to a large degree, seams *between* ISOs exist because trading across those seams continues to unfold in a paradigm where particular parties have a right to the use of particular transmission facilities, and have not yet moved toward a more seamless marketplace where those who had such a right are compensated for the value of transmission.

In the 2000s, numerous ISOs also engaged in regional transmission planning across a wider region.[5] Here, the ISO inquires whether congestion that results from security constraints (and leads to higher prices on one side) could be economically resolved by the addition of new transmission capacity. For example, imagine the following hypothetical: A new transmission line will cost $100 million. But the electricity transfers that the line's new capacity will accommodate will also allow lower-cost resources to substitute for higher-cost ones in the ISO's energy auction; $10 million annually is the forecasted value of these lower energy-production costs. Assuming a multi-decadal lifespan for the transmission line, its benefits are likely to exceed the costs—as long as the administrative forecasts of the production cost savings prove true. But unlike in the pre-ISO world, where a single load-serving utility built the line to access these lower-cost resources, in an ISO, the costs are allocated more broadly to supposed beneficiaries: sometimes generators, but most often consumer loads. One view regarding the spreading of these costs through the tariffs of a central administrator (the ISO) is that it is a socialization of costs upon parties that did not freely consent to it, and that the allocation is built on administrative assumptions, which can be crude or simply wrong. Another view is that transmission cost allocation is an appropriate remedy to the free-ridership that previously

4. Federal Energy Regulatory Commission, *Order No. 2000: Regional Transmission Organizations*, Docket No. RM99-2-000, Dec. 20, 1999. https://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.

5. In due time, regional transmission planning became a requirement under FERC's regulations. Federal Energy Regulatory Commission, *Order No. 890: Preventing Undue Discrimination and Preference in Transmission Service*, Docket Nos. RM05-17-000 and RM05-25-000, Feb. 16, 2007, ¶¶ 418-602. https://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

existed in a system where transmission's benefits spill over to other parties within an increasingly interconnected grid. In any case, this method of *ex ante* cost allocation is a judgment made about whom should pay the costs before the line is constructed and benefits actually accrue. Such a cost allocation departs significantly from the pre-ISO model wherein individual utilities paid for lines and obtained a more discrete set of benefits through its actual use of property rights to that transmission.

With time, regional transmission planning has occurred on an even-grander scale, embodied most clearly by the Midcontinent Independent System Operator (MISO) board's approval in 2011 of a multi-value project (MVP) scheme: a package of 17 lines, their ownership divvied up between multiple transmission-owning members of MISO, at a projected cost of $6.6 billion. The benefits of the package are currently projected to be between 2.2 and 3.4 times that cost and, while there are regional differences in where the benefits occur, everywhere the benefits exceed costs to any given region and do so by at least 50 percent.[6] The costs are allocated entirely on a load-ratio basis, meaning inevitably that some consumers will gain a greater share of benefits than others for what they will have paid. A handful of MVP lines are still under construction, but the completed projects already have transformed the energy market the ISO operates by opening up numerous loads to additional generating resources—in particular, wind.

An ISO sits always at a crossroads: between an energy auction the security constraints of which separate energy prices when and where transmission congestion occurs, and a more administrative transmission-planning function that erases this persistent congestion in the name of a more seamless market. As we enter the third decade after the emergence of ISOs, numerous studies have suggested that there is still a significant amount of transmission build that could confer benefits net of its costs. For example, the Southwest Power Pool (SPP) reported in 2016 that transmission buildout in its footprint, similar to what MISO's MVP set out to do, would yield benefits that were three times the size of its costs.[7] The National Renewable Energy Laboratory (NREL) has worked on an even more ambitious modeling exercise to study a transmission build-out that integrates the Western and Eastern Interconnections in the United States. NREL preliminarily found that benefits would outstrip costs in a number of plausible scenarios, although with narrower benefits-to-costs ratios than shown in the MISO MVP undertaking.[8] In any event, what is clear is that the era of electricity service as a provision of quintessentially local monopolies has already ended, and the question is merely how seamless the network will become.

CURRENT ISSUES IN SEAMS

A more efficient trade in electricity, occurring over long distances, is where the recent history of the sector has left us. In particular, an ISO's footprint-wide energy auction and its transmission planning function are powerful tools to use a region's supply of transmission and generation in an economically efficient manner.

Of course, seams still exist within ISOs. Some electricity markets, such as Alberta's, take as a goal in itself the idea that the transmission network should be a "copper plate," where electricity flows seamlessly and without constraint. Yet most ISOs—and those paying for them—acknowledge that there are trade-offs between the costs of constructing new transmission and the costs that network congestion imposes. How that trade-off is weighted by the ISO's management and its most important stakeholders is crucially important. And this, in turn, requires an understanding of how transmission is paid for and who profits from its construction, as well as how an ISO incorporates new members who bring existing and future transmission projects to the table. This leads us to our first set of seams issues: those which are internal to an ISO.

The ISO's Free-Trade Zone

From a transmission utility's financial perspective, the business model of an ISO replaces an older one that derived revenue principally in two ways: through "native load" customers served by the utility as a vertically integrated enterprise, and through customers who took no service other than transmission from the utility but whose purchases or sales of energy transited through the utility's lines. The rates under this older business model were derived from the transmission owner's "revenue requirement": the sum of its costs for a certain period, plus a return of and on the capital remaining on its books. In utility regulation, once a revenue requirement is calculated, that sum is divided by usage at peak times, which results in a rate to be charged to customers at those same peak times. Usually, in transmission ratemaking, this has occurred on a basis called "12-CP," which takes into account the peak demand of each month of the year and uses this as a "billing determinant": Customers transmitting energy at peak times constitute the vast majority of the transmission utility's revenue. Under this business model, a transmission

6. Midcontinent Independent System Operator, "MTEP17 MVP Triennial Review," September 2017, pp. 4, 19. https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf.

7. Southwest Power Pool, "The Value of Transmission: A Report of the Southwest Power Pool," Jan. 26, 2016, p. 21. https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf.

8. Aaron Bloom, "Interconnections Seam Study: National Renewable Energy Laboratory," TransGridX-Symposium, July 2018, p. 99. https://register.extension.iastate.edu/images/events/transgridx/TransGrid-X-pre-Symposium-document-from-NREL---web.pdf. Notably, NREL has not released a final version of this study.

utility may turn a profit in two ways: Invest more capital in transmission infrastructure, buttressing the portion of its revenue requirement associated with a return; or, have customers who transmit more energy, especially at peak times, over its lines.

The advent of an ISO changed this business model. The ISO rolls up individual transmission utilities' revenue requirements into what resembles one very large transmission utility. Although the equations used to calculate rates may or may not fundamentally differ for an ISO, the profit function of an individual transmission owner is tied to ISO transmission policy and to systemic peaks, rather than to the quantity of megawatt-hours that transit the transmission owner's particular lines at its own peak times. This has profound practical implications, as it creates a significant profit motive to solve regional problems with transmission because the ISO may more nimbly include these regional lines into its singular revenue requirement. In a situation like MISO's MVPs, where each transmission owner gets part of the action of regional transmission development, this can mean each of the members profit by acting collectively. Indeed, MISO has seen almost $20 billion in transmission built in its footprint since 2003, a significantly greater level of spending than in the prior period.[9]

Network service, where a transmission user pays a single rate for delivery anywhere in the ISO network, and through-and-out service, where a user pays an export rate to reach the ISO's external-facing seam, may be defined in similar ways within the tariff, or OATT, of a standalone transmission utility or an ISO. But those services now have much broader territorial implications because of the ISO's scale. Without multiple transmission rates as an economic hurdle for remotely located generators, the only signals not to build in certain places are the actual security constraints and the congestion of the network. And as congestion increases due to the addition of generators in places where the best resources exist, or because of load growth in transmission-constrained areas, so too does the economic case grow that the ISO should intervene by approving additional transmission to relieve this congestion and make the system more seamless. The policy choices an ISO makes may lead to a substantial transmission buildout or the interconnection of numerous generators located remotely from large loads.

In a non-ISO market—if they occur at all—such developments would be subject to payments to multiple transmission utilities through their individual OATTs. So called "wheeling" customers were seldom a significant portion of a transmission utility's earnings, their revenues often being accounted for simply as a credit against a total revenue requirement that was expected to be paid for by core customers. But where a single OATT governs all of an ISO, that business model changes. It becomes a type of free-trade zone.[10]

This transformation has implications for those who made their own individual bets on transmission before an ISO emerged. As discussed in the historical overview section above, some utilities had built transmission lines to connect to remote resources—and before an ISO, that act essentially constituted a physical option to external resources, guaranteed by a right to the use of a physical asset (the transmission line). In some sense, an ISO that adds a lot of new transmission and generation will override the bets that previously had been made. ISOs may commodify those legacy rights, creating financial transmission rights (FTRs) to protect holders against the cost differential on two sides of a congested transmission line.

However, when new transmission lines and generation are added, the value of such FTRs inevitably will change. The transmission utility will still be paid for its revenue requirement, but it may not preserve the part of transmission's value that consisted in the price differential between an area flush with energy and an area with scarcity. This loss is in most cases outweighed by the greater good, but it points to an important feature of an ISO's political economy: In operationalizing the transmission network in a more seamless manner, ISOs do not allow actors to make individual, physical bets on transmission as existed in the past. For example, let us imagine an entrepreneur wished to relieve some transmission congestion and be paid to do so in a manner that aligned with the benefits his new transmission line provided—and not just the costs that would be rolled into a revenue requirement. At present, there would not be an easy path to do so under the ISO model, where all transmission is consolidated into a single, open-access operation.

Meanwhile, ISOs themselves attempt to make their markets larger, and thus capture additional diversity of loads and resources that drive efficiencies in a security-constrained economic dispatch. It is also likely that ISOs are motivated to make their markets larger by the same competitive pressure to grow that exists in other businesses. As noted above, for the most part, ISOs are part not-for-profit corporations,

9. MISO, "MTEP18," Dec. 4, 2018, p. 1. https://cdn.misoenergy.org/20181204%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2003a%20MTEP18%20Executive%20Summary%20+%20Book%20Summaries297949.pdf

10. It should be noted that there are mid-points short of a fully seamless network transmission rate for an ISO. For example, a market design might retain different zonal prices for transmission service, in order to reflect that two or more utilities joining an ISO may charge very different rates for transmission service. Other market designs have been devised to recognize the value of transmission owners who bring a substantial network of transmission assets to an ISO. Certain utilities have a business model wherein the electricity equivalent of taking tolls is a substantial contributor to overall revenue; these tend to be geographically sprawling, often-rural transmission utilities that do not have large native loads, but do have a system that helps connect load centers served by other utilities. When utilities in the Rocky Mountain West, for example, discussed starting a western branch of SPP, the straw market design featured a revenue bonus for a period of slightly less than a decade to the Western Area Power Administration, in recognition that it was a transmission linchpin that earned substantial revenue from wheeling.

but it is apparent that rivalry exists between them when they actively contest new potential members or explore new opportunities. This is not a bad thing. It is important that ISOs not have a "take it or leave it" attitude to their market participants, and the presence of rival ISOs no doubt causes incumbent ones to be more responsive to certain stakeholder concerns. Nevertheless, the "grabbiness" of ISOs has the prospect of leading them to make concessions to new entrants that may trade-off a maximization of social welfare.

FERC has been clear that membership in ISOs is voluntary.[11] And, this principle has been crucial to encourage the emergence of ISOs in the first place. It follows then that an individual transmission utility will make ISO membership decisions based upon what is most advantageous for it, which may or may not align with a choice that would maximize the economic efficiency of the entire system. For example, consider two hypothetical ISOs (ISO A and ISO B) and the decision of a utility that faces a significant amount of necessary transmission build-out in the coming years. In ISO A, transmission is subject to a greater socialization to system loads than in ISO B, which requires that transmission owners' dependent loads pay for more of such transmission build-out. In this circumstance, the utility would be foolish not to join ISO A in order to take advantage of an opportunity to have other actors pay for its transmission build, unless some other pecuniary interest in its ISO decision-making process delivers it even more substantial benefits. The same kind of gamesmanship can be expected in other contexts, such as when a transmission owner that either is vertically integrated or has a power-generation affiliate decides to join a market that is more lucrative to its generation fleet, even if another decision would have a greater net reduction in production costs.

One example where such gamesmanship was alleged was the decision of the so-called "Integrated System" (the IS)—a collection of transmission owners including cooperative and federally owned utilities in the upper Great Plains—to join the Southwest Power Pool (SPP) instead of MISO. In that situation, the IS projected that, in the coming years, it would need to build-out a substantial amount of transmission which, because of SPP's more liberal approach to cost allocation in this instance, would result in a significantly lower cost to IS's native loads than if it had joined MISO.[12] The IS, however, was largely surrounded by investor-owned utilities (IOUs) that are MISO members. In order to deal with seams issues before the IS joined SPP, certain utilities embedded within the IS and certain IOUs had a compensation arrangement sometimes referred to as "bill and keep," where the use of each other's transmission systems to serve loads or resources trapped within the other's system was exchanged free of charge on the understanding that this reciprocity both simplified matters, promoted a seamless exchange and was generally fair. Ironically, when the IS then joined SPP, this more seamless "bill and keep" arrangement was supplanted by a requirement that an IOU that was a MISO member must pay the SPP tariff when it served load within the IS. In other words, in this context the enlargement of an ISO could be argued to have *increased* seams from the vantage point of certain actors.

It cannot simply be assumed that an ISO in any configuration will maximize economic efficiency for the whole. And now that ISOs are widely deployed, this problem will likely arise more frequently. Individual utilities that have remained outside of ISOs will make opportunistic decisions of whether and which ISO to join. Or, in a different situation, particular ISO members may consider changing membership to a different ISO, or threaten to do so in order to induce a change in rules within an ISO, in ways that advantage their private profitability, but may not maximize total benefits of the whole system.

There is no systemic solution to this problem. A revision to the principle that ISO membership is voluntary would almost certainly be counterproductive. At least for ISOs' existing members, unless a change in membership conferred significant economic benefits, a change to another ISO is unlikely because most ISOs have significant exit fees. However, it is worth considering, when ISOs make tariff filings to FERC that would cause significant differences in market design between the filing ISO and a neighboring market, whether there is a potential that such changes would result in perverse incentives. At the same time, FERC must approve utilities' proposals to join an ISO. It should use such opportunities to ensure that ISO membership projects net benefits for the system relative to the *status quo ante*.

By tending to efficiencies within their own footprint and by seeking to grow that footprint, ISOs have begun to look like free-trade zones that have a relatively seamless trade within their interior, but they can impose significant, indeed intentionally significant, hurdles to trades beyond the zone's borders. One of the goals of trade policy is to establish rules that induce other parties' participation on equitable terms. There is little reason to expect that the political economy of ISOs would be dramatically different.

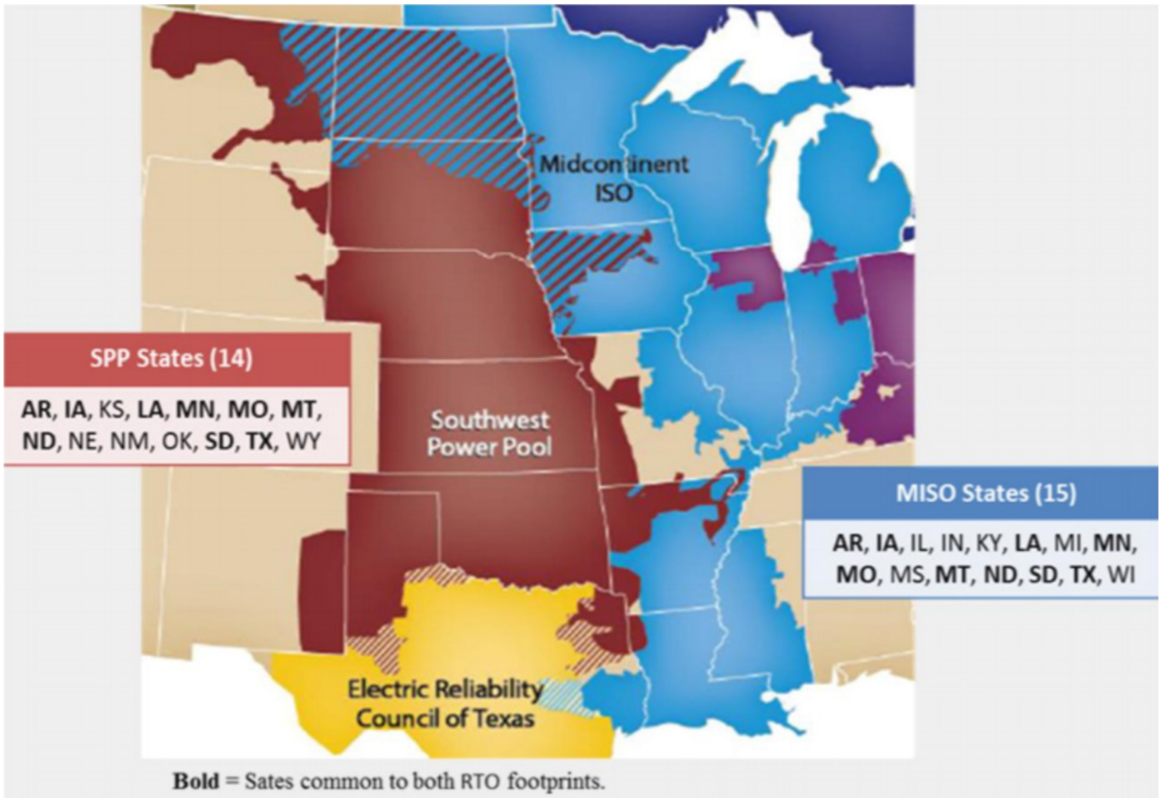
Trading Between the Seams

An ISO and the transmission owners who are its charter members have strong institutional and financial incentives to make the trading interior to the ISO more robust, in a manner than tends toward seamlessness. It is not clear that two

11. *Order No. 2000*, pp. 100-17. https://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.

12. Federal Energy Regulatory Commission, *Southwest Power Pool, Inc.*, Docket Nos. ER14-2850-000 and ER14-2851-000, (Nov. 10, 2014), ¶¶ 61-77.

FIGURE I: SEAMS BETWEEN MISO AND SPP



SOURCE: Miso and SPP. http://www.misostates.org/images/stories/Filings/SPP_RSC_Documents/SPP-MISO-RSC-OMS-Response_SPP_MISO-FINAL-on-website-Nov13.pdf.

neighboring ISOs have the same incentive with respect to trade between them. ISO members will tend to look askance at the prospect that non-members would obtain the efficiencies of the ISO marketplace, and access to their customers, without paying the dues of membership. In an ISO dominated by mostly vertically integrated utilities or by other large incumbents, the ISO can seem to play a function that is most accretive to its largest players. It is here, and in the next section of this paper about transmission improvements to alleviate seams, where greater regulatory interventions may be necessary to check economic inefficiencies that could result from the political economy of an ISO.

The trade in electricity across ISO seams has not transitioned from the older right-to-use model to something like security-constrained economic dispatch. A prominent example is MISO and SPP, together with various non-ISO transmission systems, which share a lengthy seam that cuts across the middle of the continent from the High Plains to the Delta South. The ISOs each operate their own security-constrained economic dispatch, while the non-ISOs do something that is a less-automated approximation of this. But because all their systems are networked together in the same physical Eastern Interconnection, the resource stack of an individual ISO will need to respect not just the security constraints endogenous to that ISO, but to the interconnection as a whole. Here is where things get tricky. It is possible that a generator selected within one ISO's auction uses a physical transmission path that another economically dispatched generator in the second ISO also uses, and that these generators' total output is greater than the security constraint of the jointly used transmission facility. In such instances, the tools to relieve congestion sometimes work on an economically efficient basis—and they sometimes do not. The multi-party Congestion Management Process (CMP) is still largely a rights-to-use-based agreement, but is predicated on a so-called "freeze date" of 2004.[13] The transmission uses that existed during that date, fifteen years ago, essentially still govern the rights to use—and the ordering of curtailments to relieve congestion. This is despite the many changes in generation and transmission that have occurred since then. All parties seem to agree that an update is needed, but despite discussing it for the previous five years, the stakeholder council responsible for the CMP has not arrived at a clear solution.

13. MISO and SPP, "Seams White Paper for Organization of MISO States (OMS) and SPP Regional State Committee (RSC) Liaison Committee," Nov. 2, 2018, pp. 7, 10-11. http://www.misostates.org/images/stories/Filings/SPP_RSC_Documents/SPP-MISO-RSC-OMS-Response_SPP_MISO-FINAL-on-website-Nov13.pdf.

Meanwhile, FERC typically requires ISO-to-ISO interactions to be governed by Joint Operating Agreements (JOA). One part of the JOA that controls the MISO-SPP and MISO-PJM relationship is a market-to-market settlement calculator for the purpose of relieving congestion on seams.[14] This is intended to be done in a way that mirrors security-constrained economic dispatch. Each of the ISOs identifies a reverse bid curve that is the cost to re-dispatch generators in such a way that congestion would be reduced to below the security constraints of a particular constraint along the seam. The less-expensive ISO then takes the step of relieving this congestion, and is paid based on the difference between the other ISO's actual flow across the seam and its right-to-use entitlement under the JOA.

The MISO Independent Market Monitor (IMM) has been critical of the shortcomings of the efficiency of the seams management protocols in place in the Eastern Interconnection.[15] The IMM's objections share a central theme: The trade in electricity lacks the kind of automation that provides a substantial degree of value to the auction process *within* an ISO. Recall that each ISO runs an automated economic dispatch auction atop a transmission network model that incorporates security constraints. In the inter-ISO electricity market, where two ISOs run parallel auctions but where each ISO has a particular set of jointly-used transmission facilities under its supervision, the energy auctions do not sync up easily to the physical network. MISO has adopted some reforms that cause particular constraints to be more readily identified, lowering the cost of this market failure from $37 million over a sample three-month period during winter 2018 to a mere $10 million in the same three months of winter 2019.[16] These savings were the result, in essence, of a software solution implemented by MISO.

However, these cost savings are small in the context of the total ISO-to-ISO congestion costs that exist between MISO and SPP, and MISO and PJM, which totaled $243 million in 2017, according to the IMM.[17] These costs could potentially be reduced either by a more integrated energy auction, or by physically building transmission facilities to provide more capacity and thus relieve some of the congestion. One can think of these, respectively, as a software solution and a hardware solution.

With respect to the software solution of a more integrated energy auction, it is useful to imagine a hypothetical market where all of the resources participating in these ISOs' auctions came together in a unified bid stack, and the network over which it was run was the ISOs' networked transmission. What would the additional production cost savings be if there was a single, admittedly very large, ISO? At a minimum, policymakers should be eager to obtain answers to questions like these because it would help the community of regulators understand the money that is being left on the table by the continued balkanization that prevents an automated dispatch to the full limits of much of the Eastern Interconnection's security constraints.

In the absence of a common market between two ISOs, generators typically must select an ISO to participate in: usually, the one they are interconnected into, but sometimes a higher-priced market across a seam. They do this based on their own guess of which market will be profitable relative to the other. The two bid stacks of each ISO will ultimately be known with certainty, after the submission of all bids into each auction. But of course this data is not available at the time when the bidding generator must choose between them. Nor is it known what costs transmission congestion will impose on such transactions. This information asymmetry, visited upon the bidder, prevents the benefits of having a central auctioneer from being realized. In a recent year, only two-thirds of such transactions between MISO and PJM proved to be "correct" guesses, as the MISO IMM has shown.[18] Attempts to improve this process to allow more economic transactions, meanwhile, have been attended by extremely high transmission reservation fees associated with exports and imports: the very type of tolls that ISOs, in their interior dispatch, attempt to eliminate in order to facilitate a more seamless trade.[19]

At a minimum, the economic coordination of two markets' energy auctions is an appropriate remedy to ensure that electricity is being traded efficiently across the seams. This can include an effective seams management protocol which, while more administrative in nature, can have market-like features and incorporate data from bids made within each ISO to make some of the decisions about how to minimize total production costs and maximize the efficient use of transmission. However, probably the most superior way to obtain the most valuable use of generating resources at the lowest cost is to actually have a market between ISOs. For trades between ISOs in near-real time, adding a transmission export or import fee is questionable, because the short-run opportunity cost of transmission capacity that would otherwise go unused is zero or close to it. Other pairs of ISOs, such as NYISO and ISO-New England, and NYISO and PJM, have

14. Ibid., pp. 7-9.

15. Potomac Economics: Independent Market Monitor for the Midcontinent ISO, "2017 State of the Market Report for the MISO Electricity Markets," June 2018, pp. 53-73. https://www.potomaceconomics.com/wp-content/uploads/2018/07/2017-MISO-SOM_Report_6-26_Final.pdf.

16. Potomac Economics: Independent Market Monitor for the Midcontinent ISO, "IMM Quarterly Report: Winter 2019," March 19, 2019, p. 24. https://www.potomaceconomics.com/wp-content/uploads/2019/03/IMM-Quarterly-Report_Winter-2019_Final.pdf.

17. "2017 State of the Market Report," p. 63. https://www.potomaceconomics.com/wp-content/uploads/2018/07/2017-MISO-SOM_Report_6-26_Final.pdf.

18. Ibid., p. 69.

19. Ibid., pp. 69-70.

made more tangible progress toward this end than have the pairs of more westerly ISOs in the Eastern Interconnection.

One potential lesson that the eastern markets might borrow from the mostly non-ISO Western Interconnection comes from that region's experiment with a real-time energy market, called the Western Energy Imbalance Market (EIM). In EIM, non-ISO systems and the California ISO (CAISO) each create a base schedule of resources—similar to a bid stack. EIM then consolidates these bid stacks and reoptimizes the dispatch of the power plants that had been previously committed by individual utilities and the CAISO.[20] As in EIM, it is conceivable in the Eastern Interconnection that two or more ISOs, as well as non-ISO systems, could continue a business-as-usual unit commitment process and then, nearer to real time during the operating day, fully co-optimize their bid stacks, leading to a redispatch of units. In EIM, this takes place via transmission that is nominated by individual transmission owners for this purpose, which is then optimized through a common real-time energy market. For the Eastern Interconnection, it could work the same way. ISOs and non-ISO systems could nominate particular transmission to be used in the market. This would be an IT undertaking, and require the construction of a network model along two or more markets' seams, but it would have the benefit of fully integrating the actual security constraints that exist across those seams—rather than merely approximating them, as occurs with the current congestion management and seams coordination features of the ISOs. This would also have the effect of respecting the profound differences in how resource adequacy is paid for, because the day-ahead market, with its attendant commitments of and payments to, physical units would continue to happen in an isolated manner. Such a re-optimization would only affect dispatch costs such as fuel. Alternatively, if a single real-time energy auction were not feasible, it is conceivable that there are other, more-limited approaches one could take that would nevertheless be an improvement in what is currently a largely administrative coordination of two adjoining markets. For example, the underlying premise of ISOs' real-time electricity markets is a security-constrained economic dispatch based on bidders' upward and downward dispatch ranges. This principle could likewise be applied to the trading of energy between ISOs themselves, with a limited amount of trading capacity based on a tranche of transmission set aside to be co-optimized in the real-time market.

Integrating energy auctions in this way is an idea no ISO is proposing, despite it being the seminal idea that underlies ISOs' very existence for their intra-ISO operations. It is likely that a number of objections would be raised—some valid (the IT challenges of co-optimizing two already large markets) and some not (turf protection). Many no doubt would cite the importance of respecting regional differences in market design. This is indeed a worthy consideration—but what is it about the unique geography or political culture of Arkansas, for example, that would lead to a doctrinal attachment to a particular time schedule for the submission of bids in an intraday energy market? Regulators should consider requiring some level of analysis on these issues, and also stand ready to offer incentives sufficient to induce the realization of benefits if they exist net of costs.

Regulators themselves have some introspection to do as well. State regulators of vertically integrated utilities consider frequently whether the investments of the utilities they regulate are used and useful, and the expenses associated therewith are prudently incurred. Yet a meaningful consideration of these things cannot occur without looking beyond the boundaries of the utility and understanding its performance in the market and the optimality of the market itself. States have all the more reason to inquire about these things, because regulated utilities that have fuel and purchased power trackers often obtain no real reward from the efficient performance of their assets in a market. If analysis suggested that market improvements, a joint auction or even an ISO merger had benefits that outweighed the costs significantly, regulators would then have to ask themselves what they would be willing to do to unsettle the inefficient inertia of that *status quo*. Would a state regulator revise a tracker to include cost-sharing, and thus give an incentive to obtain lower production costs for a utility? Would it be reasonable for FERC to establish an ROE (Return on Equity) adder that was set at some fraction of the net benefits as an inducement to the two ISOs' transmission owners? It is not impossible to foresee a moment wherein the levers of financial regulation could be deployed for such a purpose, especially if the value of cross-border trade and the cost of congestion remain significant.

Hardware Solutions to Eliminate Seams

A software solution to seams issues, then, is to attempt to combine the energy-auction function of two or more ISOs—or something that incrementally works toward a more efficient end state. A hardware solution to seams, and the costs they cause, would be to better knit the ISOs together through new inter-ISO transmission projects. Put another way, this would be an approach to undertake work between ISOs that they already do within themselves.

In its Order 1000 (2011), FERC heralded a new approach to transmission planning by requiring that regional planning should occur and that where a line had regional benefits,

20. Federal Energy Regulatory Commission, *PacifiCorp: Order Conditionally Accepting in Part and Rejecting in Part Proposed Tariff Revisions to Implement Energy Imbalance Market*, Docket No. 14-1578-000, June 19, 2014. https://www.ferc.gov/whats-new/comm-meet/2014/061914/E-5.pdf.

costs then should be allocated across more than one utility.[21] To a large degree, ISOs were already doing this, and since they were defined as the "region" in question, this part of the order was a *fait accompli*. Apart from this provision, then, and boiled down to its essence, the two most important parts of Order 1000 are: requiring ISOs to cooperate with one another in transmission planning, and putting the transmission projects out for least-cost bidding that are selected as the most likely to be economical.[22]

However, these two goals are in tension with one another. An easy way to overcome the political-economy obstacles of free ridership in transmission policy, as we have seen, is to use the ISO as a platform to build more transmission while expanding the earnings of their incumbent transmission-owning members. As noted above, the MISO MVP process stands as an example of the success of a widescale transmission build-out. Yet it probably occurred only because the entitlement to build the significant number of transmission lines entailed by the MVP portfolio was spread widely among the MISO's transmission-owning membership, each of whom got a seat at the table to earn FERC's regulated return on this build-out, with practically no one left hungry. Asking again a hypothetical: What would have occurred if, up front, the ISO or FERC stated its intention to put these projects out for competitive bidding? Almost certainly, the support for MVPs would have looked much more fractious—quite possibly, to the point where the whole undertaking became unviable. It deserves again to be noted that, despite being an entitlement to incumbents, the MVP scheme has shown large net benefits.

Put another way, the innovation of ISOs was *not* to induce incumbents to give themselves up to competition—monopolies do not do this unless they are forced to—but simply to transform the incumbents' approach to earning a return on transmission investments. Indeed, if an ISO portends *more* transmission investment to alleviate seams, this is accretive for a regulated transmission owner. If the regulatory model of the ISO changes to one where non-incumbents can unseat the incumbents, one can reasonably expect that an ISO loses support for its endeavors in seamlessness from the transmission owners who—in a paradigm of voluntary membership—have made the ISO come into being in the first place.

Yet, a consumer may reasonably ask why competition is not the watchword for transmission when a competition between power generators is exactly the thing for which the ISO platform is ultimately advantageous. This is a sound question. Where competition for particular transmission projects has occurred under the auspices of Order 1000's requirements, the winning bidders have come in 40 percent below the ISO's average initial cost estimate. Incumbent entitlements, meanwhile, have been completed at 34 percent *more* than the ISO's cost estimate—with those excess costs rolled into consumer rates. [23] This is not surprising, as competition leads bidders to be more precise. Second, incumbents regulated under a classical cost-of-service paradigm actually stand to profit from cost overruns, because the return in a revenue requirement is a function of the regulated rate of return multiplied by the total amount of capital investment.

Ultimately, this political trade-off will be one for FERC to make. If FERC had the political fortitude to do so, it could both mandate competition over the objection of locally and nationally influential incumbents, and require ISOs to continue their efforts toward seamlessness. This would require an impressive amount of vigor from the regulator. Or, FERC could take a more transactional route, whereby realizing that the benefits of transmission build-out are so substantial, the regulator may choose to sacrifice some of the benefits of competition to grease the skids of the already-difficult program of transmission expansion. Or, alternatively, it could be more modest in the hope to build-out transmission, foregoing certain economic gains that greater seamlessness might lead to, in favor of making the existing institutions more competitive. Thus far, FERC has embarked on a relatively generic "Inquiry Regarding the Commission's Electric Transmission Incentives Policy,"[24] but noticeable in its absence is any signal that the Commission intends to forcefully double-down on competition policy in transmission. The framing of the inquiry itself is a tacit indication that the regulator may take a grease-the-skids approach, focusing on financial inducements to make economically efficient transmission build occur.

Order 1000 was premised on regulatory decrees and oversight. As the FERC's recent inquiry seems to recognize, a more meaningful power that FERC possesses is the power of financial incentives. Accordingly, it should recognize that different transmission projects have different risks. Those projects aiming to capture other benefits, including wider-scale economic benefits associated with unlocking new

21. Federal Energy Regulatory Commission, *Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Docket No. RM10-23-000, July 21, 2011. https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

22. In places where there is no ISO, transmission planning does not exist in a robust way even at a "regional" level. While FERC's Order 890 caused the establishment of administrative bodies that engage in transmission planning and Order 1000 furthered this requirement, such bodies often simply roll up the resource selections of the integrated resource plans made by the vertically integrated utilities that dominate such markets. Because transmission planning typically serves to re-allocate resource selection to places where resources are less expensive, a transmission plan that hardwires resources ex ante into the transmission planning process largely renders it a nullity.

23. J. Pfeifenberger et al., "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," The Brattle Group, April 2019. https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf.

24. Federal Energy Regulatory Commission, *Notice of Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, Docket No. PL19-3-000, March 21, 2019. https://www.ferc.gov/whats-new/comm-meet/2019/032119/E-1.pdf?csrt=12367813467093557179.

resource-rich zones for development, are clearly a heavier lift than smaller projects. First, these projects cover much more terrain and are thus likely more difficult to site. Many such projects transverse federal land. (It is a paradox of the modern era that it has become harder to site public-use projects on public land than on private land.) Such projects may also face the political-economy obstacle of crossing the territory of multiple incumbents, who presumably do not like being competed against, and of going through a much more complex development and proposal process into one or more ISOs. The risks of those who would develop such projects should be reflected in FERC's authorized returns on equity.

Currently, the proxies that FERC uses to establish ROE make no differentiation on these counts. An ROE premium for these reasons will add to the cost of such projects, necessarily lessening their net benefits. If the benefits significantly overwhelm the costs, this should not be a consideration that hampers the project altogether. Conversely, FERC should recognize that certain transmission projects are significantly de-risked. This is particularly the case where the project is short-haul, built per an ISO plan and undertaken by an incumbent who does not face competition. Asymmetric competition for transmission today exists in the United States, and if FERC does not act to further competition, it should then be rigorous in considering appropriate returns on equity for non-competitive projects. It is ironic that a competitively selected project that covers a wider swathe of terrain would have a lower return on equity (albeit as a result of its self-constraining bid) than a monopoly incumbent that has a right of first refusal. Why not reform the latter for the sake of equitableness toward the former?

In Section 219 of the Federal Power Act, FERC also has a largely unexcavated provision of statute that allows it to establish "performance-based regulation" for transmission. Although the provision was ahead of its time when it was adopted in the Energy Policy Act of 2005, it is now time for FERC to determine what it means. It is conceivable that projects that open up market efficiencies should be entitled to a share of them for a time, as long as they can readily and transparently be measured. In this sense, "performance-based" regulation would return to the concept of building transmission with the expectation of receiving *ex post* benefits that were accomplished as a result of its construction. This could encourage innovation in the type of projects that are proposed in the first place and in the technologies through which transmission is achieved.

One possible way to do this, ironically, is by cutting against the grain of open-access, seamless use of a new transmission asset. If a significant transmission line is added to relieve congestion, its immediate effect will be to level the prices on either side of that congestion once the line's capacity relieves it. But imagine a scenario wherein for the first five years after it was constructed, the owner of a new transmission line was offered the opportunity to operate it in a "merchant" manner, rather than as part of an integrated grid. The owner could use the asset in an economic manner in relation to generators, offering its capacity for sale to a high-value generator that wants access across a seam, or it could facilitate an energy trade that explicitly arbitrages the value of congestion. In essence, such a construct would allow such a transmission line to fill the role that a merchant generator does, which has an incentive to be sited next to a congested load pocket to obtain the market's highest energy prices. If a return on capital is the only game in town—something that competition, as we currently conceive of it between transmission owners, does not actually supplant—then the door will be closed to such creative applications.

Regulation's default is to simply muddle through, in which case ISOs, each affected by their unique institutional cultures, will largely set the terms of the approach to transmission. But as discussed above, the culture of ISOs can tend toward insularity and a risk exists that they will not act nimbly to alleviate the seams issues that exist between them. Order 1000 requires only "coordination" between ISOs, as opposed to the more formal planning that is required within them. As a practical matter, compliance with Order 1000's mandate for interregional coordination requires only periodic forums with an information exchange between ISOs. Some processes go further than this, but not significantly.

Several pairs of ISOs have in common a cumbersome process for actually bringing an interregional transmission facility online that is referred to as a "triple hurdle." This requires the evaluation of a project by separate regional processes and then, again, by an interregional process, which then round-trips to each ISO's management and board of directors for approval of any project that survives this run through the planning gauntlet. Naturally, having more choke points will tend to prevent more projects, even economical ones, from becoming a reality. MISO and SPP have been discussing a filing to remove one aspect of the hurdle—the separate interregional process—in order to simplify the approach to planning. Nevertheless, in order to be successful, joint projects would have to be evaluated under two regional frameworks that share common assumptions within their planning models.

Where seams issues have been most pronounced—near particular, recurring constraints near ISOs' borders—ISOs should have an easier time reaching agreement on interregional projects. First, such projects are likely to be smaller in size and cost. Second, they are fundamentally economic projects, the costs of which can be measured against the cost of congestion, for which the ISO's security-constrained economic dispatch allows a transparent measurement. While the interregional planning process can pose hurdles to such projects, institutional incentives also exist that actually favor them: again, investor-owned utilities have a profit motive tied up in deploying more capital to build transmission, and in terms of siting and construction, such projects may be easier wins than most. Yet for more creative or ambitious projects, interregional planning and transmission pose a dilemma that neither Order 1000 nor the institutional culture of ISOs is prepared to solve.

In light of its well-intentioned aspirations that have yet to be realized, FERC should consider several things if it revisits Order 1000 in the future. First, it should consider how interregional planning between ISOs can look more like the more robust transmission planning that takes place within an ISO footprint. While most transmission-planning cycles are biennial, such an interregional undertaking could be only periodically done—but it should be done with the same rigor as exists on a single-ISO basis, especially when those ISOs are tightly woven together, such as MISO and SPP, and MISO and PJM. Second, in spite of Order 1000, many non-ISO areas barely engage in meaningful regional transmission planning at all. FERC might consider requiring such areas to have transmission-planning requirements that include scenarios incorporating expected load growth and resource retirements, but that also allow the transmission plan itself to select transmission based on expectations of where a rich measure of resources exist to fill the incremental need. This would prevent transmission planning to be simply a "long staple" exercise of various integrated resource plans, with preconceptions about which resources are optimal. Nothing would require states, the arbiters of generation resources, to make resource selections on this basis—but it could be a useful tool to measure the delta of costs of a genuinely regional portfolio against one that is more geared toward parochialism. Third, FERC should consider where it is appropriate to further its policy of competition, acting deliberately and conclusively on this question.

CONCLUSION

The electricity sector has moved gradually toward seamlessness over more than a century, both because market participants have found it in their financial self-interest and because pro-competition regulatory interventions have made it so. Yet as the preceding sections note, there are serious questions about whether the *status quo* leaves significant consumer benefits on the table associated with greater interregional energy trading and a more robust physical network to accommodate it.

Seamlessness in itself is not a goal, but to the degree that seams pose uneconomic barriers to the provision of electricity service to customers, they should be eliminated. And, each of the major players in electricity policy has a role to play in this important question.

Independent System Operators—ISOs have conferred significant advantages in terms of the efficiency of the American power sector. Yet by becoming free-trade zones unto themselves, in some ways, they make it difficult for those outside the ISO to trade into it. ISOs should therefore cooperate with neighboring ISOs and non-ISO systems to make energy trading and transmission between them more efficient. ISO boards should establish this as a priority for ISO managers.

Since regional transmission planning requires the judgment of ISO bureaucrats about future costs and projected benefits, there is reason to be skeptical but it must also be viewed as a necessary evil. ISOs should require a clear demonstration that benefits significantly exceed costs, as opposed to merely outstripping them slightly based on forecasts before transmission is built. After identifying transmission that is projected to have such benefits, ISOs should be assertive about constraining its costs, whether through competitive means or through the imposition of cost caps. ISOs should also find a way to encourage their members and others to "prospect" for benefits unlocked by transmission, perhaps using Section 219's "performance-based regulation" as a vehicle for this. While open-access transmission policy has benefited customers immensely, a brief concession for transmission lines that act as "merchants" may be in order for those developers that take the risk and are successful in breaking the logjam of particularly uneconomic congestion.

Meanwhile, on energy trading, security-constrained economic dispatch has been a gold standard for an economically efficient way to run an ISO's energy market as seamlessly as the grid permits. ISOs should have a trade in energy between their and other markets that emulates the auction process they run internally as a goal.

State Regulators—Most utilities in MISO and SPP, as well as some in PJM, are subject to state regulation that passes all their costs associated with fuel and purchased power to a captive set of customers with minimal regulatory oversight. States should consider reforming these trackers to a performance basis. Instead of simply tracking dollar for dollar whatever costs a utility incurs, states should establish a sharing mechanism whereby a utility may benefit (or be penalized) for the efficiencies they obtain (or fail to obtain). Utilities no doubt would contend they have no control over the market. However, this is clearly false, as they are first among equals when it comes to how the ISOs' market is designed, including how congestion along seams is remedied both through market mechanisms and through transmission. Providing a financial incentive for the largest market participants to advocate for an efficient market design is a smart way to regulate, because it is unrealistic for regulators to expect that they themselves have the technical resources and political acumen to achieve meaningful reforms.
States should also insist that ISOs or their market monitors

conduct production-cost modeling to ascertain the possible benefits of a wider-area market in energy between two ISOs or an ISO/non-ISO market. In other words, states should expect a model of an aspirational energy market where, as with the ISO's free-trade zone itself, no hurdles other than the transmission network's security constraints impose a barrier to energy trading. Then, depending on the size of the benefits, regulators can understand whether it is worth pursuing them via policy options, which no doubt have certain costs that would erode some of those gross benefits. The results of such modeling might even become a baseline of the fuel and purchased power tracker that a utility's actual results are measured and shared against. States should insist that such studies assume certain scenarios that work their way up to a full trade, including a more modest re-optimization or trading across certain significant seams. Regulators in MISO and SPP already have begun to meet on seams issues. Their work is laudable and should become a permanent feature wherever two ISOs have a large seam that has the potential for significant inefficiencies.

The Federal Energy Regulatory Commission—Put simply, FERC needs a clearer policy on electric transmission; one that establishes predictable regulatory treatment for its planning, procurement and compensation. Currently, Order 1000 is largely aspirational on this front and for this reason, FERC's rate- of-return regulation for transmission utilities is a muddle.

Financial incentives are the most robust tool that FERC has in this regard. The agency should therefore award returns in line with known practical barriers to building the most difficult types of transmission projects: those that cross physically or politically difficult terrain. The agency should also use its "Inquiry Regarding the Commission's Electric Transmission Incentives Policy" to consider forms of performance-based regulation that allow innovative transmission developers to capture rents that are some fraction of the benefits a transmission solution actually delivers. This differs from administrative planning's *ex ante* cost allocation regime, which is a necessary and simplified tool to build transmission in an ISO, but may limit certain innovations that performance-based regulation could unlock.

Finally, on regional transmission planning, FERC should also encourage and approve filings that reduce the interregional transmission planning barriers that have prevented meaningful transmission development across the seams.

ABOUT THE AUTHOR
Travis Kavulla is the director of energy and environmental policy at the R Street Institute. He also serves as a member of the governing body of the Western Energy Imbalance Market, one of the largest real-time electricity markets in North America. Prior to his role at R Street, he served for eight years as a commissioner on the Montana Public Service Commission, a position to which he was first elected in 2010 and re-elected in 2014. In that role, he served at various times as chairman (2011-2012) and vice chairman (2015-2019).