FALL 2025, VOL. 6, ISSUE 1

EBA BRIEF

A Publication of the Energy Bar Association

The End of the Grid's Gold Rush Era: Toward Customer-Oriented Approaches to Generator Interconnection

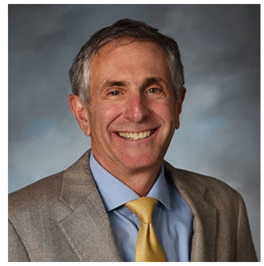
By Eric Blank and Travis Kavulla

Since 2004, the Federal Energy Regulatory Commission (FERC) has been implementing a set of large generator interconnection (LGI) policies that vest priority interconnection rights with individual generators primarily based on when they joined the relevant LGI queue. This first-in-time, first-in-right policy seemed well-tailored to an industry characterized for much of the next 15 years by large amounts of available excess transmission, interconnection, and transfer capability. In this prior environment of excess capacity, these LGI policies helped to use the grid more efficiently, enhance competition, limit incumbent market power, and lower wholesale costs.

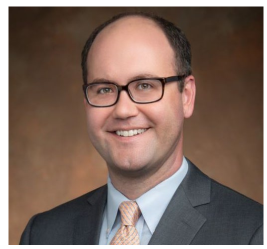
Over the past few years, however, available transmission and interconnection have become far more fully utilized and increasingly scarce. Despite this altered situation, new generation decisions—involving what type of generation can obtain priority LGI rights, and where and when they can connect—continue to be based largely on when generators first filed in the queue. As a result, critical decisions about how best to use scarce existing grid capability are not being decided in any rational way, either by system operators or by private market participants responding to price signals. It is often simply left to the arbitrary timing of when LGI filings were initially made.

Energy Bar Association
2000 M St, NW, Suite 715
Washington, DC 20036
202.223.5625
www.EBA-net.org

About the Authors



Eric Blank, a lawyer and economist, has been the chair of the Colorado Public Utilities Commission since 2021. Before that, he spent 15 years running a pioneering national renewable energy company that he co-owned and co-founded, which at one point had developed the largest operating solar projects in PJM, MISO, Georgia and Colorado.



Travis Kavulla, former chairman and commissioner of the Montana Public Service Commission from 2011-19, subsequently headed up the energy program at R Street Institute and is now vice president of regulatory affairs at NRG Energy and a lecturer in utility regulation and electricity markets at University of Chicago.

As such, under conditions of scarcity, current LGI policies fail to possess one of the principal attributes of efficient markets, which is the allocation of scarce resources based on their most valuable use. More broadly, the first-in-time, first-in right approach assumes that the transmission network is a public good that any commercially viable generator may use without reducing its availability to others: an "open access" resource, to use FERC terminology. Yet, as with any other valuable commodity—from water to wireless spectrum—open-access requires a market-based approach to efficiently allocate the increasingly scarce resource of available transmission and interconnection capacity. One critical indicator that first-in-time, first-in-right policies have failed to efficiently allocate scarce LGI rights can be seen in the backlogged queues that continue to exist in virtually every market in the United States. Simply put, generators representing hundreds of gigawatts of generation capacity are waiting in a line that likely will never be fully cleared to enable interconnection in a way that optimizes customer benefit. The grid's "Gold Rush" era has ended, and now the grid faces the reality of too many prospectors having staked a claim.

FERC recently took steps to address these issues, grouping generation projects in clusters, increasing financial deposits and other requirements on those seeking interconnection, and imposing timelines on transmission owners to conduct studies. But FERC did not fundamentally reform the first-in-time, first-in-right policy, and its reforms will not accelerate LGI to a pace sufficient to align with apparent customer needs.[1] One practical result of this approach has been the creation of a situation in which a series of exceptions to first-in-time, first-in-right must occur, because, of course, there are some priority uses for the grid that are more valuable at particular times than others. For example, recent filings with FERC by the three largest market operators—seeking to prioritize interconnection of generation that scores higher in terms of capacity accreditation, independent of queue timing—are perceived by some as necessary to maintain system reliability.[2]

Meanwhile, these LGI policies also raise broader questions. For utilities and other load-serving entities (LSE) conducting resource solicitations, first-in-time, first-in-right LGI approaches can limit competitive tension solely to those projects holding senior LGI rights. In other words, instead of more robust competition between generators based on the merits or value of their respective resources, competition is limited to projects with a senior position in the LGI queue.[3] The *status quo* environment also creates additional problems in transmission planning and investment. When large-scale transmission expansions are planned, constructed, and paid for by the customer side of an incumbent utility, generators are potentially able to control the new transmission capacity through their senior queue positions, perhaps limiting the ability of the customers who paid for the transmission to fully benefit from it.

In sum, this paper concludes that the prevailing interconnection policy is upside down under conditions of scarcity. Access to the grid should be about prioritizing the highest value generation to customers, not creating economic rent for the first generator in the LGI queue. The exact nature of any particular reform to resolve these concerns must be tailored to reflect the underlying retail market design, since some states allow retail competition while others maintain service to customers through vertically integrated utilities. Nonetheless, LGI reform that prioritizes generation based on customer value, or where there is no clear link between a particular project and a particular customer or group of customers, a reform that is predicated on a willingness to pay market value for scarce capacity, can better advance customer interests and apply market-based principles to a system that continues to be driven by the timing of LGI filings. Certain grid operators have proposed urgent measures that bypass senior LGI rights to temporarily maintain resource adequacy. As discussed in more detail in Section II.B (below), FERC recently approved such a proposal from PJM and rejected one submitted by MISO in this vein. This paper argues that it is time to move beyond stopgap measures and instead permanently move away from the Gold Rush policy of vesting priority LGI rights with a small subset of generators who filed first, an approach that is ill-suited for the grid's current and future challenges.

FERC has already allowed, on two occasions, customers and their LSEs to prioritize generation that is not at the head of the LGI queue. For example, as discussed in Section III.B.2 of this paper, the California

Independent System Operator Corporation (CAISO) has now adopted a policy that allocates voting shares to LSEs in a marketplace for LGI rights characterized by a diverse set of LSEs and some degree of retail competition, which ultimately prioritizes generation projects which produce LSE and customer value. Meanwhile, for a number of years, generator interconnection in states like Colorado has been guided by prioritizing the winning bids in a competitive resource acquisition process instead of those that filed first in the queue. Although FERC has not explicitly acknowledged this trend, we believe this is a shift that, if continued, would lead away from first-in-time, first-in-right LGI allocation toward an approach that creates far greater customer and system value, while vindicating the concepts of open access and competition that are the philosophical core of FERC's initial reforms in this space more than two decades ago.

I. First-in-Time, First-in-Right Interconnection Approaches Created Significant Benefit When Excess Transmission and Interconnection Capacity Was Available

When FERC's LGI policies were first developed over 20 years ago,[4] the United States electric system, including the large diverse organized wholesale markets which we simply call RTOs,[5] seemed to be characterized by significant amounts of excess available transmission and interconnection capability.[6] At the same time, new LGI requests were generally limited to a few thousand megawatts of applications per year, representing a small fraction of the available grid capability.[7] During this time, there was substantial headroom in the transmission system to support new generation. System embedded costs were already being fully paid for by customers, regardless of the grid's utilization, and the marginal cost to interconnect capacity and to move another megawatt-hour across the system often was or approached zero. In this context, a first-in-time, first-in-right approach made sense because it helped squeeze value from this important resource for consumers, ushered along the policy of open access and generator competition, incentivized new development, and was broadly consistent with this country's long history of making available those resources which were thought to be abundant and common to those able to efficiently use resources that otherwise would be wasted.

The views espoused to promote the initial LGI reforms spoke, as today, in the language of serving customers' growing demand, but they came from a perception of untapped abundance, rather than that of a scarce resource. That viewpoint was expressed clearly in FERC Order 2003, which established a single, standardized LGI procedure for utilities across the United States.

> *Interconnection plays a crucial role in bringing much-needed generation to market to meet the growing needs of electricity customers. Further, relatively unencumbered entry into the market is necessary for competitive markets. However, requests for interconnection frequently result in complex, time consuming technical disputes about interconnection feasibility, cost, and cost responsibility. This delay undermines the ability of generators to compete in the market and provides an unfair advantage to utilities that own both transmission and generation facilities.*[8]

FERC described this important reform as a necessary complement to its introduction of open access and generator competition in Order 888 and the encouragement of RTO development in Order 2000. And by nearly any measure, this policy was a success for many years. Together with wholesale and retail access to sell power to customers, the first-in-time access to a newly liberalized grid made new generating projects by third-party generators highly financeable and spurred hundreds of billions of dollars in new generation investment.[9] These LGI policies, by providing priority LGI rights to these third-party generators, also helped to limit the ability of incumbent utilities to use their transmission ownership to unfairly benefit their own generation.

To the extent that investors in new generation projects needed fixed revenue streams to finance their projects, non-traditional purchasers and creative new hedging products evolved in RTO structures to reduce risk involving financial traders, out-of-state loads, virtual power purchase agreements, and others.[10] These novel new transaction structures and counterparties likely further reduced project finance risk and accelerated new generator investment.

Because commercially viable generators[11] were given priority grid interconnection rights at incremental (meaning, often very little) cost at locations of their choosing, individual generators were highly incented to find the lowest cost or highest value interconnection points on the system. As such, these incentives encouraged new generators to begin to more efficiently take advantage of an under-utilized grid.

Given the amount of new generator headroom available, customers through their LSEs could acquire generation supplies to meet their needs from either new or existing generation projects through processes that were subject to meaningful competitive tension given the excess grid capacity. Some of the largest states sought to complement FERC's policies by also opening the retail power sector to competition. Other states retained traditional retail market structures, but FERC open access policies now enabled state-regulated retail utilities to rely upon independent power producers, so long as state regulators were willing to give them a fair opportunity to participate in appropriately supervised competitive solicitation processes.

Under these LGI approaches, to the extent it was needed, new transmission (beyond that required for reliability) was funded by the new generators, limiting the cost impact for end-use customers. Finally, given the excess available transmission and interconnection creating substantial new generator headroom, new generation could quickly obtain interconnection and the resources needed to maintain system reliability and other goals could come online as needed.

II. First-in-Time, First-in-Right Interconnection Approaches Raise Multiple Concerns Under Conditions of Scarcity

Over the past five years or so, the excess available transmission and interconnection—i.e., the headroom available to new generators (and, for that matter, new large loads)—appears, largely, to have been utilized.[12] The external drivers creating scarcity have been well documented in the FERC transmission and interconnection rulemaking proceedings and elsewhere. They generally involve: load growth; customer, utility, and governmental desires to replace fossil fuel generation with zero-emission technologies; permitting and planning challenges associated with building new transmission; and greatly improved renewable energy cost and performance, particularly for solar and storage, driving far greater interest in interconnection.[13] The net result of these factors is that the demand for LGI services often greatly exceeds the coincident peak demand of the balancing authority or RTO by as much as several multiples, such that most of the new generator headroom has been eliminated.[14] Given these conditions of scarcity, this section discusses the concerns arising from vesting priority LGI rights based on when individual LGI requests were filed.

A. The Dysfunctional Nature of First-in-Time, First-in-Right LGI Approaches

At least until recently, priority interconnection rights in RTOs have generally been awarded to those generators that file first in the LGI queue and can demonstrate "commercial viability." In the current consolidated wind, solar, and storage industries, however, most projects are now sponsored by experienced, well-capitalized developers—such that commercial viability may not be a significant differentiator.[15] As a result, the primary mechanism for distinguishing among a host of competing projects is now the timing of the queue filing, either within a specific cluster or as compared to a separate cluster with a higher (or lower) queue priority. The result of the prevailing first-in-time LGI approach is that there is increasingly no meaningful way—other than the timing of the queue filing—to prioritize among an overwhelming number of equally-well capitalized and commercially viable projects.[16]

Even when there is available interconnection, the sheer number of projects seeking to interconnect at specific locations in the cluster study process may result in outcomes that do not allow the limited available interconnect and transfer capacity to be efficiently used. This concern was outlined in more detail in comments filed by the Colorado Public Utility Commission (Colorado PUC) in the FERC interconnection rulemaking,[17] and it was echoed in a recent CAISO filing that was approved by FERC.[18]

FERC has diligently attempted to reckon with some of these problems, issuing Order 2023 and its successors to build upon earlier attempts of certain RTOs to adopt a "first-ready, first-served" approach to LGI. Although sometimes advertised to the contrary, this approach does not change the fundamental *status* *quo ante* of first-in-time, first-in-right. It instead requires a time-prioritized cluster of projects to be studied, and serially resolved, before moving on to later-filed clusters; it is best thought of as a reform to batch interconnection requests rather than deal with them serially, while retaining the same fundamental first-in-time ethos. This attempt to achieve scale in view of massive interconnection queues seems well-meaning in its desire for efficiency, but it presents its own complications because projects that become infeasible—and therefore will not take on a share of allocated costs—require subsequent restudies that consequently delay both projects in the same cluster and, naturally, any projects that filed too late to be included in that cluster. Attempting to solve the problem at scale may portend certain efficiencies, or it may entail greater delays. MISO has estimated that the current cluster cycle takes 3-4 years and that its 2025 cluster would clear projects that, if they came online at all, would have until 2036 to do so.[19] For their part, RTOs appear to lack optimism regarding the prospect of the FERC LGI reforms, as evidenced by the superseding proposals that were filed while their own Order 2023 implementation filings still have been pending.[20]

In any case, FERC's current reforms seem unlikely to solve the underlying problem. There are interconnection queues across the regions that are many times the size of the relevant markets' total peak demand. Most of the projects in these queues are never going to be constructed, even if they clear the queue. It is time, therefore, to consider inverting the paradigm by asking which projects would serve genuine customer demand or the highest and best use of the scarce interconnection available or incrementally accessible on the transmission grid.

B. With Scarcity, First-in-Time LGI Approaches May Tend to Crowd Out Investment Needed for Resource Adequacy, Limit Competitive Tension, and Raise Customer Costs

When transmission and interconnection availability are significantly constrained, some rationing of scarce new generator headroom must occur. In virtually all RTOs, this rationing is occurring by continuing to vest priority LGI rights primarily based on the timing of the cluster studies or when new generators first filed their LGI application within an individual cluster study.[21] As such, it is often the case that the only new generation that can be built under FERC's open access LGI policies are those projects holding senior priority interconnection rights.

As a result, critical decisions about how best to use scarce existing transmission and interconnection capability are often not decided in a rational way either by system operators or market signals. It is often simply left up to the arbitrary timing of when prior LGI filings were made, which is generally well in advance of any planned request for proposals due to longer lead times required for study completion. This is the tail wagging the dog, and far from vindicating a competitive process that surfaces the best projects, the status quo stifles them.

This mismatch between system need and the entities that hold senior LGI rights can be most clearly seen in recent RTO filings seeking emergency exceptions to circumvent FERC's LGI rules to maintain system reliability. The fundamental problem is that some projects that have higher capacity accreditation values, and may be more urgently needed to maintain resource adequacy in particular locations on the grid, do not necessarily hold senior rights to priority interconnection. As such, LGI procedures often act as a barrier to the highest-value generation as these projects cannot timely get priority LGI rights given the overwhelmed LGI queue processes. Ironically, the LGI procedures generated by Order 2003 now seem to run contrary to its stated aspiration of "bringing much-needed generation to market to meet the growing needs of electricity customers" without undue delay.[22]

PJM, MISO, and SPP have each sought FERC's blessing for a jump-the-line proposal to depart from the normal LGI operating procedures that are embodied in Order 2003. While these requests have often been characterized as limited, one-time exceptions to the policy *status quo*, they result from a system that is largely broken, from which we will need repeated and ongoing exceptions to continue to operate. In PJM, the market operator proposed the Reliability Resource Initiative (RRI), a procedure to allow a subset of generators to achieve a faster interconnection relative to the overwhelming *1,059 projects* which were generally eligible to seek interconnection, 60% of which were intermittent resources with lower capacity values relative to the PJM market's forecasted capacity needs.[23] PJM's jump-the-line proposal relied upon an administrative scoring mechanism that departs from first-in-time queuing, and instead utilized considerations including market impact, commercial operation date, and a consideration of the level of support from the relevant state regulator .[24] FERC approved the proposal in February 2025, and the RRI received 94 applications totaling more than 26 gigawatts in generation, which the RTO whittled down to 51 new and uprated projects representing 9,300 megawatts of new capacity.[25]

Meanwhile, MISO has filed its own proposal with FERC—the Expedited Resource Addition Study (ERAS)—which, in a similar vein as PJM, cites near-term reliability assessments that show the market at "high risk" for resource inadequacy, concluding that "MISO *must* address resource adequacy and reliability needs in the next five years."[26] Of the existing LGI procedures, MISO concluded, "They will not, without an interim process, be sufficient to meet certain resource adequacy needs."[27] Unlike PJM, where most states rely principally on the capacity purchase obligation that is usually cleared through PJM's own market to demonstrate resource adequacy, the MISO landscape is somewhat different. MISO is populated mostly by vertically integrated utilities whose state regulators approve utility acquisitions that build up to a resource-adequate portfolio, subject to MISO's review of the state findings and a backstop "planning resources auction" conducted to MISO to clear residual imbalances.

As such, perhaps the key element of the MISO jump-the-line proposal is the acknowledgement of a "relevant electric retail regulatory authority" that the project in question will be used to meet an identified resource adequacy or reliability need, together with an attestation by the regulated utility that it will self-build, or has entered into a Power Purchase Agreement (PPA), build-own-transfer, or other contractual relationship between the generation resource and the load-side entity.[28] A bipartisan group of former FERC commissioners rightly observed that the MISO approach could lead to "self-dealing by utilities to advance their affiliated generation" because the proposal did not apply any criteria to the state selection process for "independence or the prevention of undue discrimination" in which generation projects emerging from the state-overseen resource acquisition process would receive a designation for speedier interconnection.[29] In May, the Commission rejected without prejudice MISO's ERAS proposal.[30] Refiling the proposal shortly thereafter, MISO put a hard cap on the number of the projects that could qualify for jump-the-line treatment and provided an express carve-out to the two jurisdictions within the market footprint, Illinois and Michigan, that have retail competition.[31] Satisfied that the ERAS 2.0 proposal would not contain so many exceptions as to swallow the LGI rule, FERC approved it—though the entire process seems to underscore the remedy as a band-aid rather than an enduring treatment of the underlying problem.[32]

Finally, SPP filed with FERC in May a proposal that is similar to the MISO approach—indeed, it is also called ERAS, for Expedited Resource Adequacy Study. The SPP proposal also is intended to expedite utility-designated generation projects for LGI.[33] FERC approved the SPP proposal on the same day it gave approval to MISO's ERAS.[34]

PJM's RRI, MISO's ERAS, and SPP's ERAS all have in common a tacit acknowledgment that the *status quo* first-in-time LGI procedures are not aligned to promote system resource adequacy. Yet, the concern about bringing online the resources that create the most customer and system value likely goes well beyond issues associated with resource adequacy. For example, the optimal mix of new wind, solar, storage, natural gas, and other dispatchable resources, by location and commercial operation date, that should obtain access to scarce interconnection may also bear little relationship to those individual projects that hold senior queue positions and can timely get through the LGI process.

This concern can be better understood in the context of a recent resource acquisition process in Colorado. In Colorado's bilateral market, priority interconnection is awarded to the winners of a competitive resource acquisition process independent of when individual LGI filings were made and without the requirement for firm upgrade cost estimates.[35] This information is analyzed later in the process. Given this flexibility, a review of the actual bid results from a recent resource acquisition suggests that the generators that won the competitive process—in terms of having the lowest bid prices or the highest value—were often not the projects that had senior LGI rights. Overall, this flexibility to open the Colorado competitive process to all bidders and to select the highest value projects independent of LGI queue position significantly lowered resource acquisition costs in ways that may save customers as much as a billion dollars.[36]

These concepts can be applied elsewhere. In RTO contexts, it is likely that limiting new generation projects to those that have senior vested interconnection rights based on the timing of the cluster study is significantly constraining competitive tension in customer and LSE resource acquisition processes. For those entities seeking to acquire the output of new resources, bids will generally be limited to those that have senior priority interconnection rights and not all entities that could potentially perform. This first-in-time, first-in-right LGI approach thus creates both substantial unnecessary costs for customers as well as economic rent for more speculative generation projects that have senior rights.[37] This reality also likely incents new generators to file as many projects as possible in the queue to win the "LGI queue lottery," further worsening the backlogs.

C. Under Conditions of Scarcity, First-in-Time, First-in-Right LGI Approaches May Distort New Transmission Investment Decisions

In addition to the concerns about how scarce new generator headroom gets allocated, current LGI approaches may also be skewing new transmission investment decisions. One element of this concern arises because RTO approaches often make individual generators responsible for paying the full incremental impact study result costs for new transmission and network upgrades that are caused by that generator. This approach appears to have worked adequately for many years in funding incremental transmission and network upgrades, given a robust existing transmission network that allowed for a relatively small number of generators to interconnect with limited resource adequacy concerns. Over time, this approach may be a significant contributing factor to the under-investment in new transmission, as an *ad hoc* process of funding new transmission based on the financial incentives of individual generator queue applications seems unlikely to lead to an optimal transmission system.

In part to remedy these concerns over *ad hoc* transmission expansion, transmission in many areas now is being funded on a wider geographic scale. Yet in this circumstance, current LGI approaches may also be distorting new transmission investment decisions. For new transmission, some of the value arises from altering the dispatch of existing generating plants,[38] but under conditions of scarcity, most of the value is likely based on the ability to facilitate and control the construction of new generation. Indeed, in many situations, the associated new generation investments can be four or five times greater than the cost of the new transmission that made the new generation possible.[39] A core problem with allocating priority rights based on the timing of queue filings is that it may transfer much of the value of the new transmission (in facilitating new generation) away from the end-use customers funding that new transmission and toward the generators that can get through the LGI queue process first. This phenomenon may further encourage developers to engage in gamesmanship by filing as many interconnection "lottery requests" (i.e., LGI applications) as possible, seeking to privatize the value of these transmission investments.

This concern has shown up in the context of a specific new transmission line in Colorado. In 2022, the Colorado Public Utilities Commission (PUC) approved $2 billion in new transmission investment from a Colorado regulated utility to support the interconnection of up to 10,000 megawatts of new generation.[40] Once the new transmission was approved, Colorado quickly launched a competitive all-source resource solicitation to acquire third-party bids (expected to be half of the acquisition) and utility-owned resources that were needed to maintain system reliability and meet statutory emission reduction requirements.[41]

At the same general time, however, a third-party generator filed a complaint, pursuant to FERC's open access LGI policies, seeking priority interconnection rights to the new transmission line for the benefit of itself and its customers,[42] arguing it had filed first in the queue.[43] If this complaint were successful, the regulated utility and customers that sponsored and paid for this new transmission may not be able to realize the value that supported the investment. As such, the generation that is urgently needed by the regulated system may struggle to obtain senior interconnection rights and the benefits of the new transmission may accrue to whatever entity files first in the LGI process.[44]

D. Broader Pricing, Fairness, and Access to Scarce Transmission Arising out of First-in-Time, First-in Right LGI Approaches

The concern that the entity sponsoring new transmission cannot be assured of realizing the value of its investment is exacerbated by proposals to price transmission service under FERC-approved Open Access Transmission Tariffs (OATT) based on average embedded cost. Such an approach is problematic because the actual incremental cost of building new transmission in Colorado and elsewhere (not even including all the political capital that is expended to overcome permitting and other challenges) is far above the OATT price since new transmission is significantly more expensive than the historical average. As a result, open access transmission pricing, when combined with first-in-time LGI approaches, may require utilities to provide transmission and interconnection services to third-party generators at a loss—below the actual cost of building the new transmission—if individual generators are awarded priority interconnection rights at the OATT rate.[45]

Other significant concerns about access to scarce transmission could arise in markets like Colorado, where seven municipal and cooperative utilities seek to enter SPP RTO West, a full RTO.[46] An RTO and its attendant energy market furnishes a new hub for those wishing to liquidate their energy production, even without a corresponding LSE offtake. In at least some settings, "virtual" PPAs between primarily renewable generation resources and buyers who may have no retail load in the relevant balancing authority can serve a variety of different purposes for the buyer, including by serving as a source of environmental claims or off-system financial hedges. In the newly created RTO, these interests, which this paper refers to as "Non-Native Load Interests," may be enabled to compete for LGI rights in a way that may allow for a far broader range of potentially financeable new generation projects that could limit interconnection options for the projects that the utility and regulators seek to bring online to meet reliability and other state policy goals.

Non-Native Load Interests may thus have their own financial motivations regarding generation project development that may have little to do with creating value or maintaining resource adequacy for RTO end-use customers. When there was substantial excess headroom available for new generators, additional Non-Native Load Interest projects may have helped to lower wholesale market costs. Under conditions of scarcity, however, they may clog up LGI queues and, to the extent they can obtain senior LGI rights, they may significantly limit the interconnection options for those generation projects that may be most needed to maintain reliability, lower customer rates, and meet emission reduction and other state goals. Given this reality, it is not clear why customers should pay for the costs of both existing and new transmission to benefit these Non-Native Load Interests under scarcity.

In a bilateral market, or in a bilateral market shifting toward a full RTO, the challenge is that the transmission planned as part of an integrated resource planning process (IRP), or something like it, may become alienated from the IRP's essential purpose, which is to facilitate generation development to serve and benefit a specific set of customers. This mismatch is a problem because load on the system generally will pay all or nearly all the costs to expand the grid, while interconnecting generators serving Non-Native Load Interests will not or, to the extent they are subject to transmission rates, will pay an average-cost-based rate.[47] In RTO markets, with greater numbers of market participants, the landscape looks different but perhaps is no less troubled.

In the larger RTOs, transmission may be planned at a broader, regional scale, where grid expansion is at least partially premised on the very type of speculative interconnection queues that this paper regards as problematic in terms of creating customer and system value. Absent the kind of LGI policy reforms for RTOs discussed below, the costs associated with a far-reaching regional transmission plan would then be subject to a regional cost allocation to all consumers. In such a case, the *status quo* LGI procedures could confer much of the benefit of the newly expanded grid onto those projects having first-in-time queue positions in the RTO instead of the projects that add the most customer and system value as determined through some competitive process. While the authors of this paper may have viewpoints that differ in nuanced ways regarding the merits of regional transmission planning—a related topic beyond the scope of this paper—we are in agreement that generators holding priority rights to scarce interconnection access should have either a corresponding relationship to the customer or pay for the value of scarce interconnection capacity. The LGI *status quo* appears to fall far short of that goal, and FERC's most recent transmission planning reform[48] would be improved if it were accompanied by fundamental reform of LGI policies.

III. Toward an Open Access LGI Approach Based on Customer and System Benefit

As discussed above, open access should remain a core principle of interconnection policy in the United States, but regulators should continue to shift away from first-in-time, first-in-right approaches, which are rooted in the faulty premise that the grid is a common and public good to which access may be granted freely without diminishing the availability of its benefits to others. Gold Rush rules quickly unlocked substantial value from the grid in the past, but they now have become a barrier, not an expedient, to meeting customer demand reliably. Based on the analysis above, this paper recommends approaches that allocate scarce interconnection to the projects that create the most value to customers and the system.

A. Key Features of an LGI Approach Based on Customer and System Benefit

A new approach to managed LGI access based on customer and system benefit might have three key features. First, end-use customers or the LSEs that serve them should be able to prioritize the interconnection of projects from which they intend to purchase based on some objective measure, such as the size of the customer of the LSE's market share. Transmission rates generally are paid directly by these customers or through the LSEs that serve them. A replacement to the broken first-in-time LGI procedures should prioritize customer value creation in determining which generators get scarce LGI access. This shift already seems underway in several places.

Second, and more specifically, to ensure customer and system benefit, FERC should require some form of competition at the LSE or RTO level to clearly identify those projects that provide the greatest benefits to customers. The best approach will differ depending on the structure of a given market. In bilateral markets and for state-regulated utilities, this may mean a state-sanctioned competitive solicitation by the retail utility, overseen by a diligent independent evaluator. In a restructured marketplace characterized by retail competition, it may be either an LSE's or customer's nomination of a specific generation project, or its selection through an RTO auction or similar process. Regardless, FERC will need to ensure that adequate safeguards are in place to guard against transmission owners benefiting their own generation, just as FERC has done since Order 888 and Order 2003.

Third and finally, access to new transmission should generally not be priced lower than the actual incremental cost or, in some cases where the allocation of scarce capacity is particularly essential, its market-based value. Transmission should not be priced at an average rate if the incremental cost is higher, and there should be consideration for broad cost allocation to generators in circumstances when generator interconnection is the driving force for not just direct costs of interconnection but for the much larger expense of network upgrades, including perhaps also those undertaken through regional transmission planning focused on benefitting those projects with LGI rights.[49]

B. Examples of Open Access LGI Approaches Designed for Customer and System Benefit

Several examples of these new open access LGI approaches, where all generators can compete for priority interconnection independent of when they filed in the LGI queue, now exist in Colorado and CAISO. With some adaptation, new approaches focusing on customer and system benefit could also be implemented in other RTOs.

1. The Colorado Approach

In Colorado, new transmission and system upgrades are comprehensively planned, constructed, and funded for the benefit of all native load retail electric service customers, with the costs socialized across all customers and generally not placed on individual generators. As described above, this approach has supported highly cost-effective, multi-billion-dollar new transmission investments.[50]

To date, FERC has also allowed Colorado to define commercial viability in a way that allows Colorado's transmission utilities to award scarce LGI rights to the winning bids in state-supervised competitive resource acquisition processes, given the functioning of Colorado's bilateral market. This flexibility allows all generators to effectively compete for scarce interconnection, almost completely independent of when individual queue filings occur. As such, the right to allocate scarce interconnection is vested in the state-regulated process, and not with individual generators. This is a key factor that makes the Colorado LGI and resource acquisition process highly functional, enabling customer-funding for new transmission.

Colorado's statutory and regulatory approach to the resource solicitation and acquisition process also addresses FERC's concerns about the MISO ERAS proposal not being "objective and transparent" are mitigated.[51] MISO had proposed that state or local regulatory authorities would need to submit only a notice that an interconnecting generator "should be considered for the ERAS process in order to meet a resource adequacy and/or reliability need."[52] Yet, as Commissioner Lindsay See explained in a separate concurrence to the Commission's May 2025 rejection of the original MISO ERAS proposal, "this notice does not need to explain the factors that placed the project on the list or how [the state or local regulator] tailored its processes to target only those projects most essential for reliability or resource adequacy. Nor does the notice ask if [the state or local regulator] compared similarly situated projects or how it chose the ones best positioned to meet near-term resource adequacy needs."[53] MISO's revised proposal, FERC concluded, went some degree further by establishing "multiple sub-requirements that provide a level of uniformity" for state regulators in the approval of projects for a jump-the-line exception to FERC's ordinary LGI rules.[54] However, it falls well short of establishing a clearly competitive and non-discriminatory yardstick for states to adopt.

By contrast, the Colorado approach checks all of these boxes. Specifically, state law and regulation establish an open, transparent, competitive solicitation process. Indeed, the state expects the utility to meet roughly half its needs from independent third-party generators. All utility self-build or rate-base projects must also compete against third-party alternatives with limits on the costs and risks customers will accept for utility-owned generation. The competitive process is overseen by an independent evaluator and subject to review and approval by the Colorado PUC in the context of a litigated proceeding.[55] In its further review of proposals that effectively require FERC to rely upon states to determine whether generators' prioritization fits the parameters of the federal regulator's open-access principles, Colorado's approach could be used as a yardstick for approaches in vertically integrated states.

By allocating scarce priority interconnection rights to the winning bidders through a highly competitive resource acquisition process open to all generators, the Colorado process effectively transfers to the regulated system the ability to allocate scarce interconnection to the projects that create the most value. As such, through the Colorado competitive resource acquisition process, the regulated system in Colorado can determine what type of capacity is brought online, when and where it is needed, in the context of a long-term plan and through a state-regulated process that can limit the ability of the transmission owner to benefit its own generation.

Finally, through the competitive process in Colorado, where individual generators bid into a single set of all-source Requests for Proposals (RFP), the value of the new transmission and interconnection directly benefits customers through lower utility offtake pricing. Again, this stands in contrast to the situation in most current RTO structures where the contract right to priority interconnection is allocated to individual generators with senior rights in ways that may privatize that value.

2. The CAISO Approach

The footprint of CAISO has many more LSEs than Colorado, and the CAISO marketplace is characterized by some degree of retail competition, as many Californians have a choice between two energy suppliers, the incumbent, investor-owned utility and a community choice aggregator. Still others, primarily larger commercial and industrial customers, may procure their supply through a wider variety of competitive retailers as part of the state's capped Direct Access program. Still other LSEs defy any of these three classifications, while others remain traditional monopolies with no retail competition. There are 98 LSEs registered in California, ranging in size from fewer than 1 megawatt to more than 13,000 megawatts.[56] Meanwhile, the generation interconnection Cluster 15 study process, which evaluates projects seeking to connect to the CAISO system by 2028, includes 541 new interconnection proposals representing 354,000 megawatts of generation and storage capacity—several times the market's all-time peak demand.[57] In other words, there are no customer relationships or links for the vast majority of projects seeking interconnection in CAISO, and the market faces the same problem that we have described in this paper of a highly overstocked and speculative interconnection queue. In view of this situation, CAISO took action to create a more lasting structural reform to its LGI procedures, distinct from the one-time emergency procedures discussed above that PJM, MISO, and SPP have undertaken. Approved by FERC in September of 2024, the CAISO approach to new transmission and interconnection is consistent with the principles outlined above and structured to provide system and customer benefit.[58]

Under the updated CAISO LGI approach, when there is not enough transmission capacity to accommodate all LGI requests in a specific delivery zone, CAISO will use a weighted scoring system to allocate priority LGI rights. The scoring system allocates "commercial interest points" to LSEs—on behalf of their customers—and those LSEs may vote their points toward one or more of the resources in the queue to grant it a higher-priority status.[59] LSEs will naturally tend to vote their points toward projects that are under some form of contractual or other arrangement. Anecdotally, certain power purchase agreement terms improved to the buyer's advantage in exchange for the provision of points to the generator, which eliminated interconnection and commercial-operation-date uncertainty that otherwise would inflate the price of the PPA.

In California, investor-owned utilities face restraints from direct generation ownership, so self-dealing is automatically minimized, and further protections also exist in the FERC order accepting CAISO's filing.[60] In CAISO, regional transmission planning is the norm, with new transmission centrally planned and paid for across all utility customers for the benefit of utility customers, and consequently the allocation of "points" to these customers' LSEs is a mirror to the benefits they receive by being able to designate resources for which they have contracted to come online at a higher priority.[61]

The CAISO reform is a work in progress. In the first tranche, roughly only one-third of LSEs exercised their allocated points, though this limited participation is likely due to the hurried regulatory approval and implementation of the procedure. In future iterations, the CAISO approach should create a marketplace where willing buyers and sellers come together more readily, using priority interconnection rights as a means of creating value, not rent.

While CAISO is unique among RTOs, it stands as an example where the allocation of scarce priority LGI rights vests with customers and their respective retail LSE. In achieving this reform, CAISO has effectively ended the practice of vesting priority LGI rights based on the timing of prior LGI queue filings and allows all generators equal access to competitive processes—a more genuine conception of open access. CAISO has essentially redefined commercial viability to shift away from a generator-centric approach based on the timing of prior queue filings and toward a system where all generators can compete equally, with the winning projects being those that create the most customer and system value.

3. Fully Restructured Markets

The problem of interconnection in fully vertically disaggregated RTOs—those characterized by a greater diversification of ownership and a higher degree of competition in retail sales—is largely the same as it is in Colorado and California. First-in-time, first-in-right procedures have led to backlogged LGI queues that include a wide variety of projects for which there is no real avenue to commercialization, while imposing barriers to entry on those lower-queued projects that might more efficiently address pressing resource adequacy concerns and create greater customer value. The solution to this problem, however, is necessarily different and possibly more complex than it would be for a vertically integrated marketplace like Colorado, where the buyer of generation is largely obvious, or for California which has far fewer LSEs and where purchases of new resources tend to be facilitated through long-term contracts mandated by state resource-adequacy and clean-energy policies. Simply put, customers and generation resources are often less obviously linked in eastern markets than they are in Colorado and California. So in this section we ask: Would the reform agenda we contemplate above work in fully restructured markets?

In the eastern markets of PJM, ISO-New England, and the New York Independent System Operator Inc (NYISO), more than a dozen states have chosen to vertically disaggregate under state laws that permit greater retail competition. In these states, more than half of all commercial and industrial customers choose their own supplier of energy, with 85% of such customers making that election in Pennsylvania to a low of 56% in Delaware.[62] Sometimes, these customers, through their LSE, know pretty much exactly what they are buying, such as when Microsoft recently entered into a long-term PPA predicated on a restart of Constellation's Three Mile Island.[63] Yet, on most occasions, these supply arrangements are shorter term and lack any identifying markers for what generation resources are behind the arrangement. Sometimes, it may be implied, as certain LSEs are affiliated with power generation, and they conceive of these generation assets' costs as a physical hedge and to some extent informative of the price offers they make to their retail customers. So, while there may be no direct contractual linkage between a resource and a customer, the business model often assumes the availability of these generation resources to the LSE in question.

However, many LSEs in these markets do not own generation at all; they buy power from the open wholesale market, and these purchases are typically not in the form of a unit-contingent contract. Rather, they are financial trades that entitle the LSE to buy power at a certain price, and for a certain duration, and then typically settle as a contract-for-differences against the day-ahead and real-time spot auctions that the RTO runs.[64] The counterparties to such deals may be entities that own a generation portfolio, or they may be financial intermediaries—so, again, the source of generation and the link to individual customers and LSEs may not be clear.

Finally, customer shopping activity is not universal in these east-coast jurisdictions. Only 5% to 51% of residential customers, depending on the state,[65] take service from a third-party LSE, yet even these customers do not receive energy supply service from a utility's dedicated set of resources. Instead, utilities (or state agencies like the Illinois Power Agency) bid non-shopping customers' needs into the wholesale market, and offers are made by wholesale suppliers to meet that customer demand.

What would a customer-centric approach to interconnection look like in this context, where the customer is unlikely to know the resource that will ultimately be used to serve him? One possibility for reform is simply to extend the premise of CAISO's reform to this somewhat messier world, as far as it applies. To the extent an LSE is bringing online a power resource to serve a particular customer, then that arrangement should be sufficient to get a place higher in the queue on some *pro rata* basis. That resource, after all, has a customer, or at least an LSE, willing to link it with individual customers through a retail offer. The same logic that applies to the reforms in Colorado and CAISO would apply in this context as well, which is that the customers who pay for the grid should play an influential role in determining the resources they buy out of it and obtain priority LGI rights.

Meanwhile, there are other resources that will be developed on a presumably more "merchant" basis—not on the prospect of having any given customer but instead looking to liquidate its output into the centralized market, or into the capacity auction of PJM and to sign relatively shorter-term bilateral arrangements with financial intermediaries and others to hedge its energy revenues. These power plants have no customers—or perhaps it's better to say *all* the customers within the RTO are partially theirs. In this circumstance, a clear remedy is needed to allow these generators to access the grid, while addressing the primary concern that first-in-time approaches fail to apply either market-based principles or an alternative value-creating approach to the allocation of scarce LGI rights in order to properly value them.

One approach to remedying this concern would be a network open season, which incorporates a competitive-solicitation approach to the allocation of both existing and incremental transmission access.[66] Open seasons have long been used to grant rights to shippers on the interstate natural gas pipeline system. The pipeline system's physics lends itself to the ability to clearly delineate a right to transmit energy along a piece of point-to-point linear infrastructure (as opposed to at least the alternating-current power grid's lattice-work, where electrons flow fast and in often counterintuitive ways). However, this concept can find application, if not in a right to transmit electrons, then in how interconnection of projects to the grid in the first place can be secured. Rather than devising a grid build-out in response to senior-most LGI filers, a grid planner could plan an expansion that it reckoned was right-sized and cost-effective in view of the probable demand for interconnection—but then the planner's proposition would be tested (and ultimately funded) through the open season and interconnecting generators' willingness to sign up and pay for that right. (Indeed, the same concept could apply not just to generation but to large loads seeking grid interconnection, which would have the benefit of both right-sizing and directly allocating the costs of grid expansions necessary to accommodate growth.) The rights to interconnect obtained in this process could then be traded in a secondary market.

Alternatively, a more direct auction-based process could be used to allocate both incremental and existing capacity on the system, directly measuring the willingness of a customer to pay. Rather than seniority being defined by the timing of one's claim, it would be defined by an actual expression of value. This approach could be similar to how certain markets choose to auction off the right to transmission congestion.

Obviously, transmission topology and the technical features of grid interconnection are important considerations in any reform that seeks to make a tradeable market out of the right to access a complex grid. But barring a reform that elegantly matches customers to projects, as described Section III(B)(1) and (2) above, a robust trade for "a place in the LGI line" could be created in the retail-restructured markets that today is based on the seemingly arbitrary timing of individual LGI queue filings. One can even imagine a scenario where a value-based auction trades heavily on "speed to market"—the thing that large loads appear to want dearly—in ways that would produce surplus revenue beyond incremental cost. This market-based approach would stay faithful to an "open access" paradigm, but with added market-based features to better allocate grid capacity in conditions of scarcity.

Conclusion

FERC has taken the first steps to provide RTOs and individual states with the flexibility to start moving beyond the traditional first-in-time, first-in-right, generator-centric LGI approaches and toward more open approaches that allow all generators to compete equally on some other basis to provide customer and system benefit. Initial examples of these evolving approaches are currently being implemented in both California and Colorado. The lessons from these states are at least partially applicable to jurisdictions with a higher degree of restructuring and, to the extent they are not, other market-based approaches to valuing interconnection may obtain. Done right, these reforms should be understood to promote open access and competition, in contrast to the Gold Rush mentality of first-in-time, first-in-right. Flexibility and creativity in policy approaches are essential as existing transmission and interconnection capability becomes even more scarce in ways that ultimately may significantly impair core goals of resource adequacy and affordability.

---

[1] So, for example, the first cluster to be studied would be a group of generators at the front of the interconnection queue. *See generally* Order No. 2023, *Improvements to Generator Interconnection Procedures and Agreements*, 184 F.E.R.C. ¶ 61,054 (2023) (to be codified at 18 C.F.R. pt. 35). As described below, the Midcontinent Independent System Operator (MISO) and PJM Interconnection, L.L.C. (PJM) each have noted that, even under the reformed "first ready, first served" LGI procedures, clearing their respective interconnection queues will take many years. Restudies will be necessary due to projects that drop out after having been found not to be "ready," and projects that ultimately clear the process may not come online (if at all) until the later part of the next decade. *See infra* Section I.A, below.

[2] *See infra* Section I.B, below.

[3] The authors surmise this is perhaps the primary reason for a backlogged queue, which is that the queue position itself creates economic value that must be bought out or ultimately discharged, in some case potentially long after the underlying project may have become undevelopable or uneconomic.

[4] *See generally* Order No. 2003, *Standardization of Generator Interconnection Agreements & Procs.*, 104 F.E.R.C. ¶ 61,103 (2003) [hereinafter Order No. 2003].

[5] RTOs are assumed to include: PJM, MISO, Southwest Power Pool (SPP), CAISO, New York Independent System Operator, Inc. (NYISO), and ISO New England Inc. (ISO-NE).

[6] *See, e.g.*, Joseph Rand, *Queued Up: Status and Drivers of Generator Interconnection Backlogs*, LAWRENCE BERKLEY NAT'L LAB'Y (June 2023) at 5, https://www.energy.gov/sites/default/files/2023-07/Rand_Queued%20Up_2022_Tx%26Ix_Summit_061223.pdf (showing active interconnection queues in 2010 as being relatively small compared to installed capacity comprised of mostly wind and thus concentrated).

[7] *See id*. at 4 (showing annual megawatt capacity and number of requests in national interconnection queues back to 2000).

[8] Order No. 2003, *supra* note 6, at P 11.

[9] *See generally* Mark Haggerty, *The Evolution of U.S. Electricity Generation Capacity*, HEADWATERS ECON. (Apr. 22, 2020), https://headwaterseconomics.org/economic-development/evolution-electricity-generation/ (showing new installed generation in the United States over time with substantial additions occurring after FERC's open access policies were implemented).

[10] *See* Initial Comments of the Colorado Public Utilities Commission at 22, FERC Docket No. RM22-14-000 (Oct. 12, 2022) [hereinafter Initial Comments of the Colorado PUC].

[11] FERC standards evolved requiring generators to show that they were "commercially viable." These standards seemed like a reasonable minimum floor to help avoid spending transmission utility or system operator resources evaluating speculative, poorly designed, or under-capitalized projects that may have been prevalent in the earlier days of RTO operation.

[12] *See, e.g.*, Notice of Proposed Rulemaking, *Improvements to Generator Interconnection Procs. & Agreements*, 179 F.E.R.C. ¶ 61,194 at P 20 (2022) (noting that "available transmission capacity appears to have been exhausted in many regions").

[13] Unlike wind energy projects that are often restricted to unique geographic locations, utility-scale solar and storage development can occur across a far wider range of sites and regions and are now responsible for most of the backlog in interconnection queues. *See* Rand, *supra* note 8, at 5 (showing that solar and storage projects account for the overwhelming majority of queue filings).

[14] See generally id.

[15] *Id*. at 2-3.

[16] *Id*. at 6-7.

[17] *See* Initial Comments of the Colorado PUC, *supra* note 12, at 21-25.

[18] *See Order on Tariff Revisions*, 188 F.E.R.C. ¶ 61,225 (2024) (approving CAISO amendments to its Large Generator Interconnection Procedures OATT provisions).

[19] Midcontinent Independent System Operator, Inc., *Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff: Expedited Resource Addition Study Filing*, FERC Docket No. ER25-1674-000 (March 17, 2025) at 21 (for 3-4 year timeline for current study cycle) and Prepared Direct Testimony of Andrew Witmeier at 30 (for online date of 2025 cluster).

[20] *See infra* Section II.B (discussing proposals by PJM, MISO, and SPP).

[21] For example, recent conversations with SPP staff suggest that over 7,000 megawatts of new LGIAs have been executed with priority rights going to projects in the earliest cluster studies.

[22] *See supra* note 10.

[23] PJM Interconnection L.L.C., *Tariff Revisions for Reliability Resource Initiative*, FERC Docket No. ER25-712-000, at 2-3 (Dec. 13, 2024).

[24] *Id.* at 30-33.

[25] *PJM Chooses 51 Generation Resource Projects to Address Near-Term Electricity Demand Growth*, PJM INSIDE LINES (May 2, 2025), https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/.

[26] Midcontinent Independent System Operator, Inc., Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff: Expedited Resource Addition Study Filing, FERC Docket No. ER25-1674-000, at 3 (March 17, 2025).

[27] *Id*.

[28] *Id.* at 17-18.

[29] Comments of former FERC Commissioner James J. Hoecker et al., in opposition to Midcontinent Independent System Operator's [ERAS proposal] at 2, FERC Docket No. ER25-1674-000, (Apr 7, 2025).

[30] We discuss this action by FERC more extensively in Section III.B.1, and believe that the Colorado example this paper offers provides a clear example of how such proposals relative to vertically integrated states can be approached in the future. *See Order Rejecting Tariff Revisions*, 191 F.E.R.C. ¶ 61,131 (2025) (rejecting the MISO ERAS proposal).

[31] Midcontinent Independent System Operator, Inc., Revisions to the Open Access Transmission, Energy, and Operating Reserve Tariff: Expedited Resource Addition Study Filing, FERC Docket No. ER25-2454-000 (June 6, 2025).

[32] *See Order Accepting Tariff Revisions, Subject to Condition*, 192 F.E.R.C. ¶ 61,064 (2025) (accepting the MISO ERAS 2.0 proposal).

[33] *SPP Board Approves Expedited Generation Interconnection Process to Help Meet Regional Resource Adequacy,* Southwest Power Pool, (May 6, 2025). dd, https://www.spp.org/news-list/spp-board-approves-expedited-generation-interconnection-process-to-help-meet-regional-resource-adequacy/

[34] *See Order Accepting Tariff Revisions, Subject to Condition*, 192 F.E.R.C. ¶ 61,062 (2025) (accepting the SPP ERAS proposal).

[35] *See* Initial Comments of Colorado PUC, *supra* note 12; *see also infra* note 43 and accompanying text.

[36] *See generally* PSCo 2021 ERP, Docket No. 21A-0141E, Phase II Report, March 2023, at Appendix P (showing the Highly Confidential bid results by project).

[37] *See* Initial Comments of the Colorado PUC, *supra* note 12, at 24 (quantifying very large developer premiums in the context of a single 200-megawatt solar project located in SPP south).

[38] Given the potential impact of new transmission on altering dispatch and reducing RTO wholesale market prices, several incumbent generators have aggressively opposed new transmission investments, particularly in vertically disaggregated RTOs. *See* Alissa J. Schafer & Dave Anderson, *NextEra Spent $20 Million to "Ban" Clean Energy Transmission Project in Maine*, ENERGY & POL'Y INST. (Nov. 3, 2021), https://www.energyandpolicy.org/nextera-spent-20-million-to-ban-clean-energy-transmission-project-in-maine/ (describing a situation where incumbent generators spent over $20M to fund efforts to kill a cost-effective new transmission line that, as proposed, would have created large customer benefit by lowering wholesale market prices); Clark Mindock, *Key Leases for Hydropower Transmission Line Upheld by Maine Top Court*, REUTERS (Nov. 29, 2022, 7:09 PM), https://www.energyandpolicy.org/nextera-spent-20-million-to-ban-clean-energy-transmission-project-in-maine/ (describing same).

[39] In Colorado, the generation associated with new transmission will have a total cost of $10-15 billion, as compared to a cost of $2 billion for new transmission.

[40] *See* Colorado Public Utilities Commission, Proceeding No. 21A-0096E, Decision No. C22-0270, issued June 2, 2022 [hereinafter Colorado PUC Decision No. C22-0270].

[41] *See* Proceeding No. 21A-0141E, Verified Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan, filed March 31, 2021.

[42] See Salsa Solar Energy LLC, et al. v. Public Service Company of Colorado, 190 FERC Paragraph 61,067 (2025) on rehearing, 192 FERC Paragraph 61,067 (2025). .

[43] *See, e.g.,* Colorado Public Utilities Commission, *Motion for Leave to File Comments Out of Time and Comments*, FERC Docket No. EL24-50 (Feb. 16, 2024) (commenting on the IPP complaint seeking interconnection access and transmission service at a new Xcel Energy Colorado 345 kV line and at a fraction of the cost to Colorado customers of building that line). The complainant asserted it had a contract to serve native load of a Colorado electric cooperative utility. While the authors might be more supportive of awarding scarce priority interconnection to the Colorado cooperative based on its pro-rata load share and long history of paying to use the PSCo transmission system, that was not the basis of the complaint, which argued that the priority interconnection right should be allocated based on the generator's first-in-time generator filing seeking interconnection rights that were far larger than the LSE's pro-rata share of load in the PSCo Balancing Authority.

[44] *Id*.

[45] See Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540-01 (1996) (to be codified at18 C.F.R. pts. 35, 385) [hereinafter Order No. 888]. The challenges associated with average cost pricing can also be seen in Municipal Energy Agency of Nebraska, et al. v PSCo, 189 FERC paragraph 61,099 (2024), on rehearing 190 FERC paragraph 61,158 (2025), where a group of municipal customers who use the PSCo transmission system were unhappy with the increase in average transmission costs resulting from the $2 billion in new transmission that was largely for the benefit of PSCo retail electric customers. In an environment where marginal costs start to significantly exceed the average, average cost transmission pricing approaches may start to break down and some form of unbundling may be needed.

[46] See Order Accepting Tariff Revisions, Subject to Condition, 190 F.E.R.C. ¶ 61,169 (2025).

[47] It is true that Non-Native Load Interests that cause the construction of generation in remote markets also will dump that energy onto the market, reducing supply prices in the absence of incremental native load. This benefit may or may not be commensurate with the cost of transmission, however, and in the current LGI regulatory model, no distinction is made between generators principally designed to serve native load and those that are brought online for Non-Native Load Interests' reasons (e.g., environmental and sustainability goals or for speculative purposes).

[48] See Order. No. 1920, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 187 FERC ¶ 61,068, P 101-102 (2024).

[49] Entry fees, like the ones proposed by SPP in its proposed Consolidated Planning Process are an example of this approach. Another example, discussed below, is a Network Open Season.

[50] *See, e.g.*, Colorado PUC Decision No. C22-0270, *supra* note 34.

[51] *See Order Rejecting Tariff Revisions*, 191 F.E.R.C. ¶ 61,131 (2025) (rejecting the MISO ERAS proposal) P 203.

[52] *See Concurring Opinion of Comm. Lindsay See, id*, at 6 (quoting MISO, Tariff, proposed attach. X (169.0.0), § 3.9.1.

[53] Id.

[54] *See Order Accepting Tariff Revisions, Subject to Condition*, 192 F.E.R.C. ¶ 61,064 (2025) (accepting the MISO ERAS 2.0 proposal) P 102.

[55] *See* § 40-2-125.5(5)(b), C.R.S. ("The qualifying retail utility shall utilize a competitive bidding process, as defined by the commission in rules, to procure any energy resources to fill the cumulative resource need … The commission shall allow the qualifying retail utility, inclusive of any ownership by its affiliates, to own a target of fifty percent of the energy and capacity associated with the clean energy resources and any other energy resources developed or acquired to meet the resource need, as well as all associated infrastructure, if the commission finds the cost of utility or affiliate ownership of the generation assets comes at a reasonable cost and rate impact). *See generally* Colorado Public Utilities Commission, Rules Regulating Electric Utilities, 4-CCR-3-323, Rules 3600-3619 (for an overview of the Colorado resource planning and acquisition process);., Colorado PUC Decision No. C24-0052, PSCo Electric Resource Plan Application, Phase II, Proceeding No. 21A-0141E, January 23, 2024, at p.33-34, paragraph 94 (reducing utility-owned resources from the initial utility proposal, in part, to move toward a rough 50/50 utility versus third-party resource acquisition allocation).

[56] Electric Load Serving Entities registered with the state of California: (1) California Open Data Portal, California Energy Commission, Electric Load Serving Entities (IOU & POU), available at: https://data.ca.gov/dataset/electric-load-serving-entities-iou-pou. (2) California Open Data Portal, California Energy Commission, Electric Load Serving Entities (Other), available at: https://data.ca.gov/dataset/electric-load-serving-entities-other; (3) California Public Utilities Commission, Registered Electric Service Providers, available at: https://apps.cpuc.ca.gov/apex/f?p=511:1:0::NO (last updated: Apr. 7, 2025, 1:33 PM).

[57] Neil Millar, Vice President, Infrastructure and Operations Planning, Presentation to CEC IEPR Commissioner Workshop on Clean Energy Interconnection – Bulk Grid (May 4, 2023) (available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=249991&DocumentContentId=84722).

[58] *See Order on Tariff Revisions*, *supra* note 20 (approving CAISO amendments to its Large Generator Interconnection Procedures OATT provisions).

[59] CAISO divided the overall project scoring into three main categories: 30% for commercial interest points, 35% for project viability, and 35% system need, the latter two being determined by the CAISO.

[60] The Electric Utility Industry Restructuring Act (AB 1890), enacted on September 23, 1996, introduced competition into the state's electricity market, mandating the separation of generation, transmission, and distribution services, a process known as "unbundling." 1996 Cal. Legis. Serv. Ch. 854. *See, e.g.*, California Public Utilities Commission, Executive Summary, available at: https://ia.cpuc.ca.gov/environment/info/esa/divest-pge-two/eir/chapters/s-summary.htm.

[61] *See, e.g., The California ISO's Transmission Planning Process – A Brief Overview*, CAISO www.caiso.com/documents/transmission-planning-process-overview.pdf (last accessed Apr. 7, 2025).

[62] U.S. Energy Info. Admin., Annual Elec. Power Indus. Rep., Form EIA-861 (2023) available at: https://www.eia.gov/electricity/data/eia861/ [hereinafter US EIA Form-861].

[63] *Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to the Grid*, CONSTELLATION (Sept. 20, 2024), https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html.

[64] A common misconception of these markets is that these competitive retailers are broadly exposed to the RTO locational marginal price that arises from the spot auction. This is a misunderstanding of how these markets work. As a rule, retailers attempt to hedge the vast quantity of their expected load; indeed, prudent retailers may even over-hedge to account for weather risk, a kind of 'reserve margin' practice in the competitive retail community that is intended to prevent severe financial consequences in the event of a blow-up in the wholesale market price. *See, e.g.,* Comments of NRG Energy, Inc. before the Pennsylvania Public Utility Commission, Docket No. M-2024-3051988 (Jan. 9, 2025).

[65] Delaware and Massachusetts, respectively. US EIA Form-861. *Id.*

[66] *See* Comments of NRG Energy, Virginia State Corp. Comm. Case No. PUR-2024-00144, Ex parte: Electric Utilities and Load Growth, at 23-27. https://www.nrg.com/assets/documents/energy-policy/nrg-comments-on-virginia-commission-data-center-technical-conference.pdf