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Designing Hedging Instruments for Locational Price Risks – Lessons from North American Financial Transmission Rights*

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Abstract

Locational marginal pricing (LMP) provides efficient locational dispatch and investment signals but requires a complementary congestion hedging instrument to function effectively. This paper investigates how exposure to locational price differences is managed in North American nodal electricity markets through the implementation of Financial Transmission Rights (FTRs). Drawing on insights from 15 industry experts directly involved across all major North American electricity markets, we consolidate first-hand perspectives that reveal the practical complexities of FTR design and implementation. While most interviewees view FTRs positively, their experiences uncover multiple nuanced challenges to successfully design locational hedging instruments, which are often overlooked in the academic literature. As FTR design depends on market characteristics, we apply the findings to the European electricity market and discuss implications for a possible implementation of LMP in Europe.

JEL-Classification: D44, D47, L94, Q40
Keywords: financial transmission rights, locational marginal pricing, nodal pricing, risk hedging, congestion revenue, electricity market design, contracts for differences

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1 Introduction

"The magic of the market is no sure thing. The details matter."

– William W. Hogan (2002)

Almost three decades ago, PJM became the first market operator in the United States to implement locational marginal pricing (LMP) — also referred to as nodal pricing. Since then, LMP has become the default market framework across U.S. power markets. The popularity of LMP stems, among other things, from its efficient congestion management, achieved by a least-cost dispatch model that internalizes transmission constraints directly into market outcomes through location-specific prices (Hogan, 2002). These prices provide economic signals to market participants that ensure efficient resource allocation for operation and investment of electricity supply that may not be guaranteed under zonal pricing. Furthermore, they facilitate the integration of energy and balancing markets, thereby supporting liquidity and competition. Consequently, LMP has also been adopted elsewhere; recently Ontario became the first Canadian power market to adopt LMP in May 2025.[1] Yet many liberalized wholesale markets in other countries continue to rely on a zonal pricing framework (e.g., Europe). However, with congestion relief costs rising sharply in recent years, the debate around a broader shift toward LMP has intensified there as well (e.g., Neuhoff et al., 2025b).

Despite these advantages, many European policymakers remain reluctant to adopt LMP. Critics of LMP proposals in European markets often point to reduced forward market liquidity and greater exposure to locational price risks as key drawbacks (Eicke and Schittekatte, 2022). In North America, Financial Transmission Rights (FTRs) were designed to mitigate these concerns. FTRs are financial instruments for a defined combination of source-to-sink pair, denominated in megawatts (MW), a settlement period, and a life term, and they entitle their holder to the congestion revenue arising from locational price differences between the source and sink location (Hogan, 1992, 2012). They thus serve as a hedging instrument for market participants to mitigate locational price risks arising from grid congestion. Simultaneously, the design of FTRs as a purely financial product helps ensure efficient system dispatch (Lyons et al., 2000) and to redistribute congestion revenue. However, the exact implementation and experience with FTRs is unique to each market region, reflecting differences in market characteristics and stakeholder involvement. For example, terminology itself varies, as instruments that serve similar purposes are referred to as FTRs, CRRs, TCCs, or TCRs in different market regions, operated by Independent System Operators (ISOs) (see Figure 1 for an overview). For the sake of clarity, we continue to use the term FTR across market regions.

In this paper, we shed light on the trade-offs and challenges of operating a successful LMP market by learning from the North American experience. To do so, we pursued

[1] Locational pricing is also implemented, e.g., in Chile, New Zealand, and Mexico.

15 semi-structured interviews with experts directly involved in the design and operation of LMP and FTR markets across all major North American market regions. To obtain a comprehensive overview, we selected interviewees representing diverse stakeholder perspectives. In particular, we interviewed two regulators, four market operators, one market monitor, three traders, and five leading policy advisors.[2] While many had experience in multiple market regions, we focused each interview on one particular region. Each interviewee received the same questionnaire in advance of the one-hour interview (Appendix A). We conducted the interviews between June 3rd and August 4th of 2025. They were recorded and subsequently analyzed using a structured approach.[3]

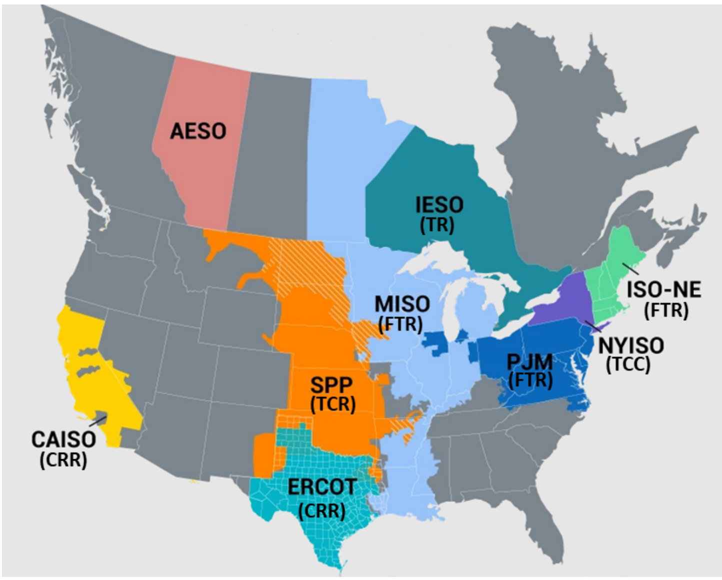
Our interview results indicate that hedging instruments for locational price risks play an important role for the successful operation of LMP markets in North America. While consumers are protected from locational price risks through the establishment of larger load zones, which sets aggregate zonal prices for consumers, most market participants rely on FTRs to hedge their exposure to locational price risks.

The first-hand practical experience captured by our interviews finds that FTRs are generally viewed as successful hedging instruments that work in a complementary way with LMP. However, our interviews also uncover more nuanced challenges regarding market implementation and stakeholder coordination that are otherwise not reflected in the academic literature. This paper consolidates the insights from these interviews and outlines the main objectives (Section 2) and challenges (Section 3) of FTRs identified by the different stakeholders. We then illustrate the usefulness of these findings for other potential market regions by assessing the implementation of FTRs in a European nodal market (Section 4). In addition, we outline an alternative design of a hedging instrument against locational price risks based on pooled contracts for differences (CfDs). Finally, we offer conclusions (Section 5).

[2]For some interviewees, this categorization is ambiguous, as some have, for instance, switched from a market operator role to an advisory role.

[3]A similar semi-structured approach to interviews was employed by Chiappinelli et al. (2021).

Figure 1: North American ISOs and their respective hedging instrument



Abbreviations: FTR - Financial Transmission Rights; CRR - Congestion Revenue Rights; TCC - Transmission Congestion Contracts; TCR - Transmission Congestion Rights; TR - Transmission Rights. *Map source:* ISO/RTO Council (2025).

2 Objectives of FTRs

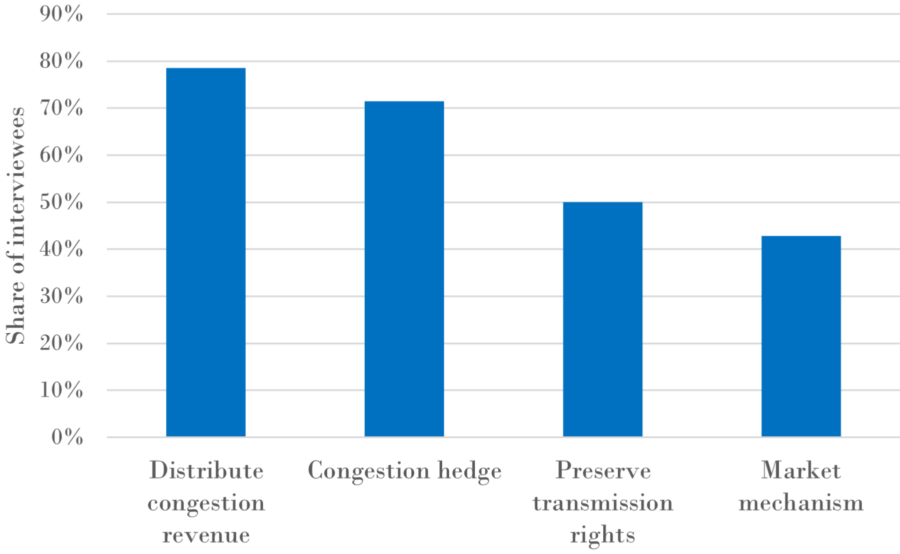
FTRs are a key feautre of LMP markets. All interviewees involved in the transition emphasized that FTRs were integrated into the market design from the outset. As one system operator noted, in North America they were "pretty much part of the process" when shifting from zonal to nodal pricing.

The fundamental theory of LMP implies that a congestion surplus is collected by the system operator that needs to be distributed either to stakeholders or used to offset grid operation costs (Hogan, 1992). FTRs specifically were chosen because they proved to be the most widely accepted tool during stakeholder processes. On the one hand, regulators required that congestion revenue be distributed either to those who paid to build the grid or to those who pay the congestion components of LMPs in energy markets. On the other hand, market participants, such as utilities or asset owners, wanted a hedge against locational price differences. FTRs were seen as an instrument that could achieve both effectively.

This view also holds today. Most of our expert panel named both distribution of congestion revenue and hedging as the two main objectives of FTRs, with 79% and 61% respectively (see Figure 2). This is consistent with ISO documents, which generally list these two purposes as guiding objectives for their implementation design.[4] We observe

[4]For example, CAISO's FTR market is designed around the following key functions: hedging, revenue distribution, and allocation to transmission payers (CAISO, 2024a). Similarly, MISO's guiding objective was to provide market participants with a hedging mechanism with the additional goal of allowing customers to access congestion revenue (London Economics, 2023).

Figure 2: Reported objectives of FTRs



Note: Answers to question Q5b, about which policy objective(s) guided the design of FTRs.

similar patterns among interviewees. On the one hand, individuals who consult for or work for ISOs typically named both objectives, while regulators emphasized a fair distribution process. By contrast, those who consult for or work at market participants, including traders, typically emphasized the need for hedging as well as the importance of having a market mechanism. About 43% of our interviewees highlighted that an open FTR market is necessary to ensure competitive price discovery and give any market participant access to the hedging instrument.

An additional policy objective that was especially relevant in the transition years is the maintenance of historical property rights. This was mentioned by 50% of interviewees. When U.S. markets were restructured to a nodal framework with non-discriminatory transmission access, previous contractual agreements were still in place. Many market participants at that time held bilateral contracts, which also included some kind of physical rights to certain transmission links. These rights had to be respected in the new market framework, which was facilitated by FTRs. How exactly this seeming contradiction was handled depended on the market region. In NYISO, which transitioned to LMP in 1999, a substantial share of FTRs were "grandfathered" to market participants that had long-term transmission agreements in place at that time. For example, if a utility company had negotiated rights to use 100 MW of a transmission owner's grid until 2020, the company would get an entitlement of 100 MW worth of FTRs for an appropriate source-sink pair through 2020. More than 210 such agreements existed when NYISO transitioned to LMP (NYISO, 2024). The large number of agreements highlights the challenges market operators and stakeholders faced when facilitating the transition to LMP. Nonetheless, they also emphasize the value of using FTRs in the North American context, as they provided the opportunity to translate contractual entitlements into comparable new contracts. Today, only a handful of these legacy agreements remain active in NYISO.

The diversity of interview responses provides an important insight. Although FTRs appear to be a suitable instrument for multiple goals simultaneously, their primary objective is not easily identifiable and depends on the stakeholder perspective. As one interviewee noted, asking three different people this question yields three different answers.

3 Challenges with FTRs

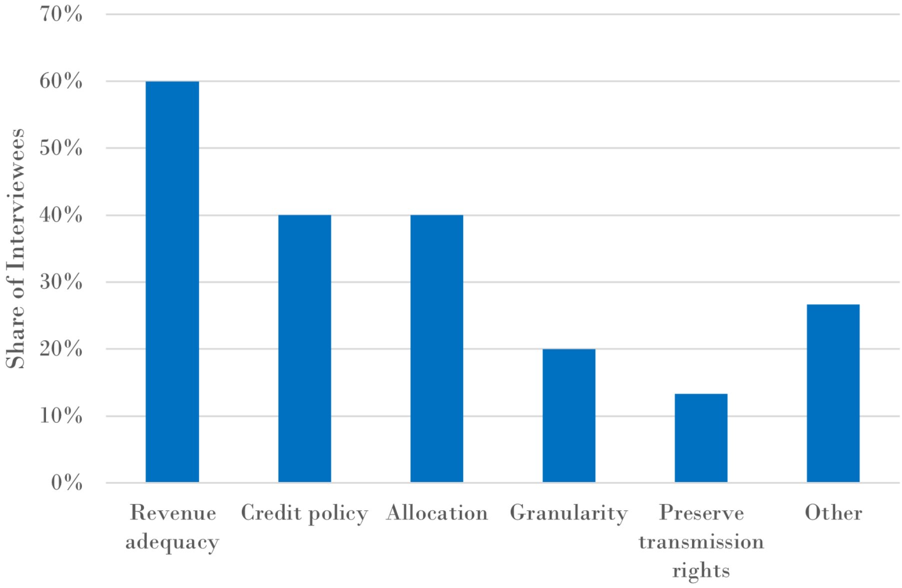
To draw lessons from the North American experience with FTRs for other market regions preparing to implement LMP, we asked interviewees to identify challenges in implementing FTRs. Figure 3 shows the share of interviewees who mentioned each of six categorical issues. In the following section, we examine these challenges in detail and place them within the broader context of ISO-specific design choices, highlighting how differences in market design influence both the nature and severity of these challenges.

Generally, in North American ISOs, FTR markets follow a two-step mechanism. In a first step, ISOs allocate FTRs to entities, which had paid for the construction of the grid. In a second step, FTRs are distributed to the remaining market participants through an auction in which bids to buy and offers to sell rights are jointly cleared to maximize net surplus (defined as bid values minus offer values) subject to the physical capacity constraints of the grid. This is usually achieved through an simultaneous feasibility test, in which the ISO ensures that the final allocation of FTRs can be accommodated by the physical grid (Harvey et al., 1996). Consequently, we group the challenges into two categories: those that concern the initial allocation of FTRs (including allocation mechanism design and preservation of historical transmission rights), and those that concern the design and performance of auctions (including revenue adequacy, credit policy and forfeiture rules, and dissatisfaction with FTR granularity).

3.1 FTR Allocation

Concerns about FTR allocation arise because FTRs are intended to fulfill two main objectives simultaneously: distributing congestion revenue in a fair manner and providing effective hedges to market participants. In line with regulatory requirements from the Federal Energy Regulatory Commission (FERC), each ISO designed its FTR allocation process to balance these often conflicting objectives (Federal Energy Regulatory Commission, 2006). Interviewees highlighted two main challenges in the allocation process: the design of the allocation mechanism itself and the maintenance of property rights.

Figure 3: Reported challenges with FTRs



Note: Answers to question Q5f, about what were difficulties observed with FTRs. *Other* includes challenges that were named by only one interviewee: complexity of auctions, revenue from speculative trading, and forfeiture rules.

Allocation mechanism design. Designing a well-functioning allocation mechanism is not straightforward, and 40% of interviewees identified it as a key difficulty. This section briefly describes two basic approaches to allocation (a simpler system involving free allocation followed by market clearing, versus a system that introduces Auction Revenue Rights (ARRs)) and discusses their advantages and disadvantages, as highlighted by interviewees.

The first approach is implemented in California. There, before auctioning FTRs, CAISO allocates some of its capacity to entities that have paid for the construction of the grid, primarily load-serving entities (LSEs), based on historical load and contractual obligations. LSEs request a portfolio of FTRs, which are then checked for feasibility and, if feasible, awarded to the LSEs.[5] If the proposed allocation of FTRs is infeasible, the LSEs may not obtain the FTRs they requested. Thus, requested FTRs are generally never guaranteed. This, combined with the typically short-term nature of FTRs (usually annually), introduces uncertainty about the quality of congestion hedges and constitutes one of the key issues for LSEs according to interviewees.

A second, more intricate approach exists, for example, in PJM and MISO. There, a dual system with ARRs, the right to claim auction revenue resulting from the sale of FTRs, was adopted. Instead of directly allocating FTRs to LSEs, ISOs allocate ARRs to LSEs. In the subsequent auction, LSEs can then decide to "cash in" the auction revenue from the sale of the FTR associated with their ARR or to "self-schedule" the ARR by

[5] See discussion on simultaneous feasibility in Section 3.2.

effectively selling the FTR to themselves, which is equivalent to a direct allocation as in CAISO. ARRs were introduced in response to stakeholders' concerns that market actors such as large utilities might hoard their FTR portfolios without actively engaging in the market, thus denying smaller market participants the ability to obtain desired hedges. ARRs therefore aim to facilitate an open and efficient market while distributing revenue to transmission payers.

However, interviews identified some design flaws in the current ARR system. ARRs are still subject to the same feasibility test, making allocation — and thus the quality of the congestion hedge — uncertain. Some interviewees stated that the problem is exacerbated by the inflexibility of the allocation system. LSEs often struggle to align ARRs with their existing contracts because ARRs are not available for every point-to-point combination; they are usually path-based and offered for historical generator-to-load paths. One main critic of the current ARR design is the Independent Market Monitor of PJM, who argues that the current market design in PJM systematically under-allocates congestion revenue to load.[6] By restricting ARRs to specific paths, LSEs can only engage risk-free in the subsequent auctions for a subset of potential FTR paths, which may not prove to be lucrative or offer effective hedges as grid conditions evolve.

Maintaining historical property rights. Interviewees noted that one reason why ARRs are path-based was the existence of bilateral physical transmission contracts that had to be converted during the transition to a financial rights-based system. These contracts were typically defined for specific contract paths on the grid, and ARRs/FTRs were designed to mimic them. In retrospect, many interviewees agree that a system that restricts these instruments to just a predetermined subset of possible paths is not desirable. Two interviewees identified the existence of legacy contracts as a challenge in the transition to the new market framework. One interviewee, in particular, emphasized that converting these contracts was cumbersome but ultimately worthwhile in order to secure agreement on the market design from a broad set of stakeholders.

Interviewees who were concerned about the efficiency of FTR allocation processes advocated for systems that are simple. Simpler revenue allocation models exist for example in ERCOT and NYISO. In both markets, FTRs are not initially allocated and can only be purchased in auctions. Only entities with legacy bilateral contracts before the market transition have the right to obtain certain FTRs before the auction, though the volume of FTRs traded this way is relatively low in both markets. Similarly, auction revenues are not dynamically allocated as they are under ARR systems. Instead, auction revenue is assigned to load through representing entities using pro-rata sharing rules. In ERCOT, LSEs receive a share of the auction revenue proportional to the load they serve, i.e., LSEs serving a higher amount of load also receive a higher share of the auction revenue. In

[6] See, for example, the latest market report for PJM (Monitoring Analytics, 2025).

NYISO, auction revenue is allocated to the respective owners of the underlying transmission lines. Revenue received by transmission owners is used to offset costs of grid operation that would otherwise be charged to load.

Interviewees valued both these approaches for their simplicity, as revenue allocation is transparent and predictable. However, they do not necessarily increase the share of congestion revenue that ultimately accrues to load, which is an increasing concern of some stakeholders. Depending on the market region, load receives congestion revenue through LSEs from either (i) congestion revenue of allocated FTRs, (ii) auction revenue of allocated ARRs, or (iii) revenue from re-selling FTRs to other market participants. In PJM and MISO, which both operate ARR systems, roughly 70% of congestion revenue accrued to load in recent years (Monitoring Analytics, 2025; London Economics, 2023). In ERCOT, the share was about 60% during 2020–22, rising to 80% in 2023 and 100% in 2024 (Potomac Economics, 2025).[7] In CAISO, about 57% of congestion revenue went to LSEs in 2022–23 (CAISO, 2024b).[8] What share is appropriate is debated. Some interviewees argued that load should receive the full amount and questioned the role of auctions, while others emphasized the need to sustain an open, liquid market in which also other participants including (speculative) traders are rewarded for bearing congestion risk. In 2017, FERC further specified that returning 100% of congestion charges to load is not necessary for a FTR system in order to satisfy the general "just and reasonable" requirement for a market under the Federal Power Act (Federal Energy Regulatory Commission, 2017).

3.2 FTR Auctions

While revenue allocation is central, concerns also extend to the so-called efficiency of FTR auctions. In the context of FTR markets, the term auction efficiency refers to the ratio of what load receives from selling FTRs in auctions to the congestion payments ultimately made to those rights. This is a more focused concept than the total congestion-related payments received by load to total congestion revenue discussed in the previous section. A persistent gap between prices paid for FTRs in auctions and ex post congestion values has raised questions about market design (Adamson et al., 2010). Some argue that the clearing mechanism itself generates inefficiencies (Oren and Hedman, 2010), while others point to strategic trading by financial participants (e.g., PJM Interconnection LLC, 2020; Leslie, 2021). By contrast, Opgrand et al. (2022) attribute the gap to transaction costs and risk premia. Furthermore, simple calculations of ratios of, for instance, proceeds from auctions to congestion revenues do not account for the time value of money, since

[7] Authors' calculations. Given ERCOT's allocation mechanism, calculated as auction revenue plus surplus congestion divided by total day-ahead congestion revenue.

[8] Authors' calculation. Given CAISO's allocation mechanism, calculated as payments to LSEs (directly through FTRs or from re-selling free FTRs) divided by total day-ahead congestion revenue.

auction proceeds are received up-front while congestion revenues accrue later. Auction efficiency is therefore contested and subject to ongoing monitoring in all regions. Most interviewees considered the general auction structure sound but highlighted three challenges for maintaining the effectiveness of FTR hedges and financial integrity of auctions: revenue adequacy, credit policy design, and limited granularity of FTR products.

Revenue Adequacy. The most frequently mentioned challenge of FTRs is ensuring revenue adequacy, as identified by 60% of the interviewees. Revenue adequacy is satisfied when congestion revenue collected in a market (usually, day-ahead) is sufficient to cover payouts to FTR holders for the same market. Harvey et al. (1996) show that revenue adequacy can be checked by running a simultaneous feasibility test to ensure that the amount of FTRs allocated and auctioned corresponds to physically feasible power flows under the modeled network topology.

In practice, however, revenue *inadequacy* does occur, often caused by various factors mentioned both in our interviews and in the academic literature (Alderete, 2012). First, because FTRs are issued months or even years before settlement, network topology can change between the simultaneous feasibility test and actual dispatch.[9] Causes include derates due to thermal limits and especially scheduled or forced outages. Second, loop flows across market regions not accounted for in the FTR allocation and auctions can cause underfunding.

Consequently, ISOs face the dual challenge of how to minimize revenue inadequacy and how to deal with shortfalls when they do occur. One approach is to allocate FTRs conservatively with a safety margin (Hogan, 2013). However, this limits the effectiveness of FTRs to serve as hedging instruments and return congestion revenue to load. Moreover, it is important that regulation consider loop flows (as done in PJM and NYISO) and that the financial responsibility for making up shortfalls sets incentives for minimizing the duration and impact of planned transmission line outages. One interviewee brought up that in NYISO, transmission owners cover the shortfall of FTRs and are thus penalized if they fail to report planned outages in advance of auctions. Alternatively, FTR holders could cover the shortfall by assigning a haircut to all FTR payouts. Both approaches socialize the shortfall either to transmission owners or to FTR holders. To prevent this, CAISO changed its policy in 2018 from having load cover underfunding to derating only certain FTRs. ERCOT uses a similar approach, distributing shortfalls more granularly based on the respective network constraints that caused the underfunding.

Finally, it is worth noting that there can also be a surplus of congestion charges collected when too few FTRs were issued. This raises the question of how such surplus should be allocated, as ISOs are mandated to distribute it. In 2018, PJM changed its

[9] Oren and Hedman (2010) provide a stylized numerical example of how transmission line outages can lead to underfunding.

policy from allocating any surplus to FTR holders to allocating it to ARR holders, but only after using it to cover prevailing and potential FTR shortfalls in the ongoing planning period (London Economics, 2020).

Credit Policy. Credit policy was the second-most frequently stated challenge, mentioned by 41% of interviewees. One interviewee even called it "[...] the biggest operational challenge in the early years." Credit policy sets the collateral that market participants must post to ensure they can cover potential losses from their FTR portfolio, making it central to protecting the market from defaults and shaping who can participate in it. Setting credit policy requires balancing these two objectives: overly strict requirements can prevent market participants from entering the market, and thus reduce competition and liquidity. On the other hand, permitting inadequately capitalized or inexperienced participants into FTR markets through loose credit standards can lead to financial distress or even bankruptcy.

Credit policy is necessary because FTRs are obligations, meaning the right to receive congestion revenue can turn into an obligation to pay if source LMPs exceed sink LMPs. If the FTR portfolio is large, these losses can amount to a level at which the holder goes bankrupt. As the counterparty is a non-profit ISO, resulting costs are socialized among other market participants.

The most prominent default, which was also referred to by most interviewees who highlighted credit policy as a key design feature, is the 2018 GreenHat default in PJM, which at the time held the system's largest FTR portfolio. Between 2015 and 2018, the firm bought long-term FTRs selected to minimize the required level of collateral. GreenHat then sold positively valued FTRs bilaterally to other market participants, making a profit of $13 million for its owners. Negatively valued FTRs were held in the portfolio and led to bankruptcy once the first FTRs settled in June 2018. Losses totaled approximately $179 million, backed by only $559,447 in collateral (Federal Energy Regulatory Commission, 2021). Utilities and ultimately consumers covered a large amount of theses losses.

At the time of the GreenHat default, PJM required that every FTR participant must post base collateral of $500,000, in addition to FTR-specific collateral tied to its bid price and projected value (Spiegel & McDiarmid LLP, 2022). By purchasing only FTRs with projected values above their bid prices, GreenHat avoided additional collateral. The bankruptcy prompted FERC-mandated reforms of credit policy across market regions. Collateral in PJM now depends on a mark-to-auction process, in which the collateral per FTR is adjusted to new valuations of the same FTR path in subsequent auctions (PJM Interconnection LLC, 2025a). Furthermore, a minimum collateral of 10 cents per MWh also applies.

Interviewees who raised credit policy issues agreed that these changes are positive and that credit policy is now robust in most ISOs. One interviewee cited SPP as an exception, as there was still no mark-to-auction mechanism in place at the time of the interview. However, several stakeholders are pushing SPP to make progress in this regard, and in March 2025 FERC accepted SPP's revisions to introduce a mark-to-auction mechanism (Federal Energy Regulatory Commission, 2025).

One interviewee offered a historical rationale for PJM's initially loose credit policy: FERC feared that too strict credit policy would exclude smaller market participants from the FTR market, especially small municipalities seeking to hedge their basis risk. The interviewee proposed that a better solution would have been to introduce a stricter credit policy while giving exemptions for small entities serving physical load.

Forfeiture Rules. Another policy aimed at preventing market manipulation in FTR trading is the use of forfeiture rules, as raised by one interviewee. These rules target strategies in virtual markets that intentionally create congestion to profit from their FTR portfolios (Joskow and Tirole, 2000). If detected, the market monitor can require them to forfeit those profits (Hopkins, 2020).

As with credit policy, these rules must strike a trade-off between limiting market manipulation and fostering liquidity in trade. One interviewee emphasized that these rules are highly complex as it is very difficult to define and uncover market manipulation. Forfeiture rules therefore vary across ISOs. When asked to compare the rules across ISOs, one interviewee described forfeiture rules in PJM as the strictest with a low threshold for triggering forfeiture. In MISO, ERCOT, ISO-NE, and SPP, the rules are more moderate. CAISO's clawback rule was described as a "happy medium". CAISO calculates whether a participant's bid on the virtual market at a binding transmission constraint meaningfully increased congestion revenue for the FTR holder. To qualify, bids must exceed 10% of transmission capacity, in which case FTR revenues are "clawed back".

Limited Granularity. Another challenge concerns the limited range of FTR products offered by ISOs, which was reported by 20% of interviewees. Products vary by term (monthly, seasonal, annual), time-of-use (TOU, such as on-peak or off-peak), location (point-to-point or generator-to-load), and type (obligations or options). In practice, ISOs usually provide only a subset, e.g., annual or monthly obligations for broad TOU categories, leaving gaps between market needs and available instruments. Interviewees noted that current maturities, typically capped at one or two years, are too short to serve as effective long-term hedges for physical participants, whose planning horizons are much longer. Similarly, the traditional peak/off-peak split is increasingly outdated in systems with high renewable penetration and storage. To improve hedging effectiveness, FTR definitions may need greater granularity tailored to residual load profiles. For example, the California Department of Water Resources recently proposed a "super-peak" product to CAISO to cover the sharp evening demand spike that follows the decline in solar generation at sunset (CAISO, 2024a).

Inflexibility is even more pronounced with ARRs, which tend to be more restricted than FTRs. For example, PJM historically issued ARRs only as annual, 24-hour baseload products, until reforms allowed self-scheduling of on-peak and off-peak FTRs as well (PJM Interconnection LLC, 2025b). Such limitations reduce their effectiveness as hedging instruments, since specific congestion exposures of market participants rarely align with those products.

Similar concerns arise when instruments are restricted to specific source–sink pairs, as in the ARR systems of PJM and MISO. A recurring theme in the interviews was therefore CAISO's 2018 restructuring of its FTR market. The reform discontinued FTRs on "non-delivery" paths, such as generator-to-generator routes, because they accounted for much of the auction revenue shortfall and deviated from the original purpose of hedging power delivery (CAISO, 2024a). At the same time, CAISO introduced a haircut mechanism, reducing payments to particular FTR holders whenever congestion revenue proved insufficient for the relevant network elements. Given the system's persistent underfunding, actual FTR payouts were reduced on average by 25%. This led to increased auction efficiency, if measured as the ratio of FTR auction revenue to ultimate FTR payments for the rights sold, which increased from 50% to around 65% since 2019.

From CAISO's perspective, the 2018 reform was successful: auction efficiency improved, and revenue adequacy was secured. Market participants, however, view the policy less favorably as our interviews highlight. By restricting FTRs to specific paths and introducing payment uncertainty, the instruments lost some of their appeal, raising concerns about market liquidity as total bidding volumes in CAISO auctions fell by half (CAISO, 2020). Moreover, once haircut effects are excluded, the efficiency ratio, auction revenue relative to actual congestion payments, remained roughly unchanged at 50% (CAISO, 2024a). It is therefore unclear whether the reform really enhanced efficiency in terms of price discovery. This skepticism aligns with the model intuition of O'Keefe (2025). Because FTR auctions are cleared subject to simultaneous feasibility, bidders compete for physical grid capacity; by restricting paths (source-to-sink pairs) on the market, competition across different paths is reduced and rent extraction on the remaining ones can increase.

4 Applicability to Europe

As highlighted, FTRs serve two primary objectives in North American electricity markets: (i) distributing congestion revenues to load, and (ii) providing a hedge against locational price differences. A similar requirement regarding the first objective applies in Europe. European consumers pay for the transmission system and would therefore have an equivalent claim to congestion revenues under a nodal framework as in North America (ACER, 2025). The core rationale for FTRs thus extends naturally to the European context.

Nevertheless, our analysis underscores important differences in how congestion revenue is used to hedge local price risks. The experiences with FTRs in North America thus offer valuable lessons for European policymakers. In this section, we examine the potential implementation of a spatial hedging instrument in Europe along four key market characteristics that distinguish European electricity markets from North American ISOs: prevalence of bilateral legacy contracts, degree of retail competition, share of renewable generation, and financing structures of renewables investments.

First, bilateral legacy contracts were a central reason for adopting FTRs in North America, as these instruments facilitated a smooth transition to nodal pricing by converting existing physical bilateral agreements into equivalent FTR positions. When European electricity markets liberalized in the early 2000s, many similar legacy contracts were in place in Europe as well. However, the European Commission restricted long-term contracts, as it viewed them as a barrier to competitive markets (European Commission, 2007). Since then, the number of legacy contracts has continuously decreased and they play a less relevant role in today's European electricity market, compared to North American markets when they transitioned to LMP. Consequently, European policymakers have greater flexibility in designing spatial hedging instruments. This offers an opportunity to also consider alternative hedging instruments, for example a simpler hedging mechanism for the overall need of consumers, rather than the more complex hedging of all individual transactions.

A second key difference relates to retail competition. While it is standard across all EU countries and consumer segments, many North American regions still rely on vertically integrated utilities with defined service territories (Borenstein and Bushnell, 2015; Littlechild, 2021). This institutional feature strongly influences how congestion revenues are allocated. Without retail competition, granting regulated utilities long-term property rights in terms of access to FTRs on behalf of their consumers may be reasonable. In contrast, with retail competition, this would offer an advantage to incumbent firms and hence undermine competition and thus also the opportunity for consumers to benefit. Therefore, ERCOT and NYISO, both allowing free entry of new retail LSEs, primarily distribute FTRs through auctions, returning revenue to load via simple allocation rules. Accordingly, one could envisage a mechanism such that congestion revenue or rights to congestion revenue are passed to retail firms proportional to their market share in the relevant consumer segment. Like any liability for grid charges, the amount would be adjusted, if consumers switched to another retailer. A similar mechanism was part of the French ARENH (Regulated Access to Historic Nuclear Energy) mechanism that granted access to long-term contracts with nuclear power stations to retailers on behalf of their consumers (Ambec et al., 2025).

Third, European power systems already feature a higher share of renewable generation than their North American counterparts (International Energy Agency, 2025). When asked whether this requires adjustments to nodal market operations, most North American interviewees agreed that the fundamental principles of LMP and FTR markets remain sound in high-renewable environments. In fact, greater renewable penetration strengthens the case for LMP, as it makes the patterns of congestion less predictable and increases the need for accurate congestion pricing. The intermittency of renewable output also raises congestion volatility, reinforcing the value of effective hedging instruments. Hence, more granular FTR products aligned with renewable generation profiles are repeatedly brought forward in North American markets (see, for example, the proposed "super-peak" FTR product in California mentioned above (CAISO, 2024a)). While granular time-specific FTR products may help renewable producers with relatively predictable production output, they may be a less effective hedge where production patterns are more difficult to predict in the longer term, e.g., for wind or for solar in regions with more cloud coverage. As a response, "volume-based" FTRs are proposed in the literature to hedge the basis risk proportional to the renewable production at that point in time (Hesamzadeh and Biggar, 2021; Kim et al., 2023). However, there are concerns that they could jeopardize the policy objective of revenue adequacy as simultaneous feasibility tests become more complex and less reliable predictors of congestion patterns.

The fourth dimension is the financing structures of renewables. In many North American markets, large LSEs procure renewables through portfolios that aggregate off-take contracts from multiple geographically dispersed projects. This portfolio approach allows LSEs to diversify and thus partially hedge basis risk, reducing the need for explicit locational hedging at the project level (Gabrielli et al., 2022). By contrast, in Europe, a substantially larger share of renewable generation is developed and financed on a project basis (Steffen, 2018), and the vast majority is backed by long-term contracts. The EU commission proposes the concept of tripartite energy contracts to bring the benefit of public long-term contracts, e.g., CfDs with renewables, to the consumers (European Union, 2024). If all projects are hedged against a (average) national price, projects face higher exposure to node-specific revenue risk, increasing the relevance of effective hedging instruments against local price risks for renewables, needed to lower financing costs and support investment (Neuhoff et al., 2025b).

Given these considerations, an easier path for Europe might be to focus on developing a hedging instrument tailored specifically to generation covered by tripartite energy contracts, rather than to implement a full-scale FTR market. As discussed, a complementary hedging instrument in a nodal market should fulfill the two primary policy objectives identified in the interviews: (i) distribute congestion revenue back to load and (ii) provide a hedge against locational price risks. One option, which achieves both objectives in line with Europe's institutional setting and most recent policy guidance, is a CfD pool

(Neuhoff et al., 2025a). In this approach, renewable generators are hedged with tendered CfDs, the main instrument in European low carbon energy strategy.[10] In a second step, the CfDs would be aggregated and passed on to consumers, who are then entitled to a share of the pooled production at the average CfD strike price.[11] This two-sided approach establishes a long-term price hedge for both generators and consumers at their respective nodes.

While the hedge brings investment certainty, it might undermine locational incentives. This could be dealt with by including non-price criteria in the auctions of CfD contracts, as proposed by recent guidance for CfD design by the European Commission (2025). Spatial mismatches between where renewable electricity is produced and consumed may nonetheless leave the pool with a deficit, when net difference payments to consumers and generators are positive. Allocating a share of congestion revenues to the pool could address this deficit, while any remaining congestion revenue is distributed to consumers on basis of simple pro-rata allocation rules, as done in the FTR markets of ERCOT or NYISO. This is also consistent with EU regulation, which requires that CfD benefits (and associated costs) be passed through to final consumers (European Union, 2024).

In conceptual terms, using a CfD pool to hedge locational price risks shares similarities with the flexible-volume FTRs discussed above, aligning hedging volumes with renewable output. Similarly, using congestion revenue to fund the CfD pool effectively allocates revenue back to load by ensuring lower prices for consumers. As such, a CfD pool mirrors the policy objectives of FTRs, while avoiding the complexity and efficiency challenges associated with FTR auctions. Moreover, a CfD pool ensures long-term revenue certainty and investment incentives for renewables, which FTRs may fail to provide in Europe due to their short-term nature and renewables' unpredictable production profiles. Lastly, it resembles the North American market design in that retail consumers, for their hedged demand share from the pool, are exposed only to a zonal electricity price – the CfD pool strike price.

5 Conclusion

Transitioning to LMP is a complex yet manageable challenge, as the North American experience shows. The experts we interviewed are convinced of the advantages of LMP, but they emphasize that its implementation must be accompanied from the outset by instruments that hedge basis risk and allocate congestion revenue. Consequently, interviewees largely discounted the concerns about the practicality of LMP commonly raised

[10] CfD design affects operational incentives under LMP. The European Commission thus proposes "fusion CfDs" which are production-based, unless, e.g., electricity prices are negative. Then they are production-independent, preserving exposure to price signals (European Commission, 2025).

[11] The hedge could be passed on to consumers via their retailers, such that they continue to manage the demand profile of their customers.

by policymakers in regions with zonal electricity markets. All North American ISOs implemented FTRs alongside aggregate price zones for load and trading hubs, which together substantially mitigate locational price risks for consumers and support market liquidity. Nonetheless, differences in market implementation across ISOs illustrate the trade-offs that arise when designing hedging instruments in newly transitioning markets.

When asked about the main lessons from implementing and operating FTRs, interviewees were generally positive and considered difficulties as manageable when they arose. Overall, they highlighted the following nuanced challenges. The allocation process must ensure that sufficient congestion revenue is returned to load. Distributional questions require intensive stakeholder engagement. Mismatches between congestion revenue and FTR payouts warrant detailed discussion of how to minimize and manage revenue inadequacy. Auction design should balance market liquidity with entry restrictions. In this regard, the GreenHat case is a reminder of the importance of adequate credit policy. It must be designed to maintain credit worthiness and focus markets on FTRs that provide hedges for likely patterns of energy trades rather than FTRs whose value is speculative.

Some North American transitions began decades ago prior to large-scale advent of renewables and many countries now rely heavily on renewable generation. Interviewees highlighted that intermittency can increase congestion volatility, raising the need for hedging instruments that are suitable for less predictable congestion patterns. While FTRs are generally considered fit for this purpose, more granular FTR products may better reflect renewable generation profiles. Developments in this regard, such as proposed "super-peak" or "volume-based" FTR products are steps in this direction. Although such changes add complexity to the FTR market, some interviewees mentioned that improvements in modeling and computational capacities can help manage them. Beyond FTR implications, several interviewees stressed the growing importance of LMP in general for integrating renewables successfully.

Finally, it should be noted that no market region can simply copy any of the exact market designs adopted in North American electricity markets. Designs must always reflect local electricity market characteristics - *"details matter"*. Our interviews underscore that any complementary hedging instrument — such as FTRs, load zones, or CfD pools — should be shaped through extensive stakeholder engagement and careful simulations of the hedging effectiveness and cost distributions they would yield. Considering European market characteristics, a CfD pool could be a solution to hedge both renewable generators and consumers against locational price risks, in line with the two main objectives of hedging instruments identified in the interviews. More broadly, the North American experience offers an encouraging outlook: despite numerous challenges, market operators have successfully adapted over time, providing valuable lessons for other regions considering a transition to nodal pricing.

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Appendix A Questionnaire

Hedging of locational price risks in locational marginal pricing: Experience from the adoption in the US

To inform the European policy debate as well as our research, we are seeking to learn from the North American experience how locational price risks and differences can be hedged.

Q1: In which US market regions have you been most actively involved?

Q2: What was your role during the implementation of locational marginal pricing, or risk management systems to address locational price risk in such market environments?

Q3: What aspects of locational price differences and risks do you consider relevant?
Please **rank**: *Price differences between node and regional hub*, *Price differences between regional hubs*, *Uncertainty about future grid access charges*, *Risk of curtailment*, *Other*

Q4: In the absence of hedging mechanisms, which actors would be most exposed to locational price risks and differences?
Please **rank**: *Trading and retail*, *Investors in conventional generation*, *Investors in renewable generation, Industrial and commercial consumers, Household consumers*

Q5: Let's focus on FTRs/CRRs

a) When were FTRs/CRRs implemented: before, during or after shift to LMP?
b) What policy objective(s) guided the design? To what extent have these been achieved?
c) Was one objective to create or to avoid locational incentives and was this successful? Please answer separately for each of the user groups: (a) conventional generators (b) renewable generators (c) industrial/commercial consumers (d) household consumers?
d) Which actors participate in the FTR/CRR-market and what are their motives? How is this influenced by the respective market structure?
e) How long did it take to develop sufficient liquidity, what supported/hindered progress?
f) What were difficulties observed with FTRs/CRRs? Have these been resolved over time?
g) How has the increasing forecast uncertainty of wind and solar power influenced the design or operation of FTRs/CRRs?
h) What potential developments do you see to allow for hedging of locational price risks in systems with increasing shares of wind- and solar power?

Q6: Has another important mechanism been used to address locational price risks? (Answer **Q5** for this mechanism as well)

Q7: Looking at the bigger picture – what were your main lessons from hedging mechanisms for locational price risks…

a) during the implementation of LMP?
b) in the context of the overall successful operation of LMP?