Options for an Enduring Financial Transmission Rights Model for Alberta

ALTERNATIVE STRUCTURES FOR ENABLING CONGESTION HEDGING IN THE RESTRUCTURED ENERGY MARKET

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NOTICE

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Executive Summary

This report offers a preliminary description of a range of alternative models for a potential enduring Financial Transmission Rights (FTR) mechanism in Alberta's soon-to-be-implemented Restructured Electricity Market (REM). The Alberta Electric System Operator (AESO) requested this report as input to stakeholder consultation (planned for Q1 through Q4, 2026) on a potential enduring FTR mechanism in the congestion management framework of the REM.[1] In this report we were asked to: review experience in other jurisdictions; describe the role and potential value that FTRs can deliver to producers and consumers in Alberta; lay out the range of individual design elements that comprise an FTR mechanism; and identify a starting point range of models that could be considered in the REM. In developing these potential models, we take into account the AESO and Alberta provincial government's planned introduction of Locational Marginal Pricing (LMP), Optimal Transmission Planning (OTP), and Transmission Reinforcement Payments (TRP).[2] It is outside the scope of this report to examine the role of the interim FTR mechanism that may apply as one-time (temporary) arrangements for existing generators.[3]

In an LMP-based energy market, financial instruments known as FTRs can be introduced as a means to hedge congestion risks. FTRs are acquired in advance and provide a payout when congestion (and commensurate separation in energy prices) arises between locations on the transmission system. FTRs can take a range of forms depending on market design, allocation and procurement methods, settlement rules, and other design elements that are tailored to the jurisdiction-specific contexts and objectives. In Alberta, FTRs need to be compatible with the future REM design and other components of the optimal transmission planning and congestion management framework. This report sets out alternative frameworks and assessment criteria for organizing an enduring FTR mechanism in the REM.

Table 1 below describes the range of potential FTR models that we examined (including no FTRs). Each model emphasizes different design goals, sometimes in conflict with each other. The models are ordered from left to right to roughly reflect a progression from a design without any formalized FTR market toward an FTR mechanism structured around targeted design goals. The assessment criteria we considered in developing these models include informing efficient

1 Further discussion on the enduring FTR model will be completed through the Congestion Management Framework stakeholder group with discussion continuing through December 2026. See AESO, Congestion Management Framework, accessed December 15, 2025.

2 These design proposals are provided in detail here: AESO, REM Technical Design, accessed December 15, 2025; AESO, Optimal Transmission Planning (OTP), accessed December 15, 2025; AESO, TRP and Supply SAS, accessed December 15, 2025.

3 The scope and nature of the interim FTR mechanism will be discussed through the Congestion Management Framework stakeholder group with consultation continuing through Q2 2026. See AESO, Congestion Management Framework, accessed December 15, 2025.

investment decisions, enabling market participants to hedge congestion risk, protecting consumers from congestion-driven costs and risks, and minimizing administrative complexity.

TABLE 1: A RANGE OF MODELS FOR ALBERTA'S POTENTIAL ENDURING FTR MECHANISM

1. No FTRs	2. US-Style FTRs	3. Willing Buyer, Willing Seller	4. Mandate-Driven FTRs
No centralized FTR market	Adapt from US approaches	Revenue-neutral market without government or AESO position	Agency pursues specific design goals
		3A. AESO-Run 3B. Exchange-Traded 3C. Broker-Enabled	4A. Generator-Driven 4B. Consumer-Driven 4C. Hybrid Model
• Congestion rents allocated to loads or Tx offset • 3rd-party market may or may not develop (e.g., 3B & 3C)	• ISO-run auctions • Nodal • Monthly & 1-3 year forward • Auction revenue returned to consumers • FTR payouts from congestion fund	• Nodal or zonal • Variable length based on design	• Short, Mid, or Long term • Market is largely a function of design goal
Example: Ontario transition to LMP (no intra-province FTRs)	*Variants: MISO, PJM, ERCOT, SPP, CAISO, NYISO, ISO-NE*	*Examples: CAISO proposal, European zonal FTRs, gas basis futures, bilateral energy contracts*	*Analogy: Government loan guarantees, mandatory fuel hedges for vertically integrated utilities*

These alternative FTR models differ in form, purpose, and balance of design objectives, as follows:

1. **No FTRs.** If FTRs are to create value from a societal perspective, they will need to enable more efficient allocation of capital and investment signals. Under the No FTR model, the AESO would aim to provide sufficient data and market transparency to enable market participants and third-party exchanges to develop their own (bilateral) approaches to hedging. However, the AESO and government would take no other actions to create FTRs or similar products. This option would still offer reasonable hedging value to customers, considering that most customers will settle energy costs relative to a single Alberta Load Price (ALP) and considering that congestion rents collected in REM would be returned to customers, offsetting energy or transmission charges. This No FTR option also offers the efficiency advantage that generators face efficient price signals from locational marginal pricing, including any expected congestion risks. Generators are incentivized to consider physical means to manage congestion risks (e.g., by locating in different places or considering co-location with batteries or consumer off-takers). They are also incentivized to seek bilateral and load-side arrangements (such as Power Purchase Agreement (PPA) settlement structures) that can allocate congestion risk between buyers and sellers when mutually beneficial. The available physical options for managing congestion risks may be more efficient than financially managing the same risks, particularly if all involved parties have reasonably accurate information about anticipated transmission plans under the transparent, forward-looking optimal transmission planning framework. The disadvantage of the No FTR option is the lack of a transparent, liquid mechanism for pricing and transferring congestion-related price risk (as distinct from the overall investment risk); the lack of a liquid FTR market means there will be limited opportunities for price discovery on anticipated congestion differentials and market participants will have limited ability to offload congestion risk to financial third parties.

2. **US-Style FTRs.** Included primarily as a readily available comparison point, the US-style FTR structure creates liquid trading in short-term FTRs by having the ISO offer FTRs on all paths to the highest bidder in a centralized auction. This provides short-term hedging that has proven attractive to financial participants and created liquid auctions with transparent pricing (monthly and up to three years ahead). However, in our view, the US-style FTR mechanisms have achieved a relatively poor value proposition to both consumers and generators. The US-style FTR market structure offers some value for informing near-term congestion risks, but on a timeframe that is relatively short compared to generator investment needs. The standard FTR products also tend to misalign with generators' hedging needs in other ways (since the FTRs are mostly defined relative to day-ahead prices and do not align with hourly profiles of various participants such as renewable generators, peaking thermal units, and loads). Consumers also face more net costs and risks under this model, because: FTR payouts are backed by the congestion fund (a substantial portion of which is captured as FTR trader profits); consumers cannot always receive the FTR allocations to the generators with which they are contracted; and overall the systems has not tended to improve load risk management compared to simply retaining the congestion fund as an offset to customer bills.
3. **Willing Buyer, Willing Seller.** The defining feature of Options 3A, 3B, and 3C is that the FTR market would be entirely composed of matching voluntary supply and demand positions. This is the usual structure of most commodity and energy markets but differs from both US-style FTR markets and the Option 4 variants that involve the AESO or a government entity taking a net FTR position. The advantage of the Willing Buyer, Willing Seller options is that consumers are not involuntarily exposed to the risks and costs of complex or long-term FTR positions; the disadvantage is that the models may be unattractive to financial players and may not offer as much liquidity. These structures differ primarily based on the entity responsible for running the FTR market, as follows:

   3A. AESO-Run. Under this option, the AESO would host a voluntary FTR platform and act as the clearing entity, leveraging its existing settlement and credit risk management capabilities. The FTR market can have as much complexity as a US-style nodal FTR market, or (preferably) be streamlined to cover hedges to and from a smaller number of pre-determined hubs.

   3B. Exchange-Traded. An exchange-traded model would have similarities to the existing AESO forward energy markets and to natural gas basis futures, with the entity operating the exchange earning a small fee on every trade. The structure would be limited to a small number of standard products (e.g., only on congested paths) and would provide a strip of future basis price differentials (zone price to system hub price).

   3C. Broker-Facilitated. A broker-facilitated model is a more hypothetical approach in which physical players work with brokers to offload congestion-related investment and contracting risks to financial players. The generation profile, settlement nodes, and term could be defined on a bespoke, customized basis with financial entities offering the hedge at a privately agreed price. While the model offers a number of benefits to efficiency and risk allocation, experience from other markets suggests that the market would remain relatively illiquid due to a lack of natural counterparties and because the cost of providing long-term FTR-type congestion hedges is high compared to alternatives (such as physical hedging through choice of investment location or addition of energy storage). The high cost of long-term FTRs by financial plays likely reflects the difficulty in predicting patterns in congestion-driven price differentials over the long term, as well as difficulty in managing the risk or further transferring it to other parties.

4. **Mandate-Driven FTRs.** Options 4A, 4B, and 4C would all be variants of a "made-in-Alberta" FTR market tailored to serve specific objectives. All three variants anticipate that the AESO or another government agency would take on a net buy or net sell congestion-hedging position, with the design volumes and pricing of those positions driven by a specific design mandate, as follows:

   4A. Generator-Driven. In the generator-driven model, the purpose and intent of the FTR market would be to enable new generators to make more informed investment choices while providing long-term protection against downside congestion risks once the investments are made. FTRs would be available only to new generators, which would access the hedges they want under an application-based approach that allows them to customize the FTRs to their specific resource type and supply node. The downside of this approach is that the resulting hedges could shift more congestion risks to consumers (if not priced correctly), may not offer the FTR positions to the entity that values them most, and could create a risk of inefficient subsidies if the FTRs are underpriced (which in turn could exacerbate congestion risk for existing resources in the area). This subsidy would encourage supply investments of the wrong type, in the wrong places, and introduce a preference in favor of new resources.

   4B. Consumer-Driven. In the consumer-driven model, the goal would be primarily to help consumers who own or contract with generators to develop hedges to cover the congestion risk between the generator and the customer load. We also examine whether there is some hedging value that could be created through hedging on behalf of customers on a province-wide basis, but did not identify an option that would perform better than simply returning all congestion revenues directly to customers. This is particularly so considering that customers will face a system-wide ALP that already implicitly pools congestion risk across load, such that consumers would rationally choose to sell FTRs only when the expected value exceeds retaining the congestion value. However, a consumer-driven hedging model may become more relevant if a subset of customers opt-in to LMP, or if more customers face congestion exposure indirectly via their energy supply contracts or self-supply with specific generators. This model would not be expected to materially improve hedging opportunities for generators who do not contract with loads.

   4C. Hybrid Model. If the goals of the FTR model are to meet a combination of consumer- and generator-driven congestion hedging needs, then a hybrid approach can be used. Similar to option 4B, this option may offer limited incremental hedging value to consumers from a province-wide perspective. However, the design would apply certain protections and a customer-value lens to ensure that any FTR positions sold to generators would be appropriately priced, would protect generator buyers only against downside of upstream (generation pocket) congestion risks relevant from generation pockets to a system bus price, and would not exacerbate consumers' exposure downstream (load pocket) congestion risks.[4] Compared to other options we considered, generators would gain access to a more liquid and reliable hedging opportunity (with a non-zero but competitively determined cost, and less customized parameters as compared to option 4A). In addition to providing congestion hedges to loads, the hybrid model differs from the generator-driven model in 4A with a shorter term, zonal granularity, and availability to all generators (not just new generators). Relative to option 4A, the hybrid model may also support greater transparency and ongoing price discovery.

Overall, the experience in other markets and exploration of this range of models demonstrate the importance of first establishing the FTR framework's objectives and mandates before beginning the design process. FTRs are complex instruments that can deliver a strong hedge against congestion risk but do so by shifting that risk (and cost) to another party. Under some models, consumers would ultimately bear the risk of any resulting net costs (particularly Option 2 and Option 4 variants). Therefore, from a province-wide perspective, consumers would likely prefer the No FTR approach (Option 1) as a default. Among other advantages, Option 1 focuses incentives for new investment on locational energy price signals via LMP, with the expectation that the OTP mechanism will relieve congestion in a way that is economically efficient from a system perspective. The price signal from congestion is therefore simple and transparent, even if subject to uncertainty. An FTR construct would therefore need to exhibit strong customer protections and a reasonable expectation of true efficiency gains through efficient reallocation of congestion risk and potentially clarifying investment decisions (or at least not undermining efficient LMP-based investment and siting signals or transmission planning incentives).

If there are true efficiency gains achieved, then this should reduce long-run costs to consumers. However, after exploring these various options we find that it is inconclusive whether any of the FTR mechanisms have a strong likelihood of improving efficiencies compared to the default No FTR (Option 1). The answer may depend greatly on how effectively the program is designed, implemented, and coordinated with the OTP framework. With only voluntary trades, transactions under Option 3 are inherently value-creating, and it preserves the efficiency advantages of the No FTR option. However, the value to participants under Option 3 may be limited, and the implementation complexity can be significant. Other FTR mechanisms (Option 2 and Option 4A) introduce the potential to interfere with efficient price signals or transfer costs to consumers. Among the FTR mechanisms, Option 4C shows particular potential (but not certainty) to create avenues for overall efficiency gains, because the FTRs offered for sale on behalf of consumers are constrained in a way that avoids the pitfalls of such approaches: the FTR positions are limited to prevailing flow positions from generation pockets to the system-wide price; the megawatt (MW) quantity offered for sale aligns with the physical export capability of

[4] Throughout this report, we use the terms "load pocket" or "downstream" congestion to refer to congestion differentials measured from the system-wide unconstrained bus price to import-constrained areas; and the corollary term "gen pocket" or "upstream" congestion to refer to the portion of congestion measured from out-flow-constrained areas to the system-wide unconstrained bus price.

the grid to which a generator is connected; and the FTRs are offered at a competitive reservation price (and only more readily valued shorter-term FTRs are offered). Further, to be value-neutral or value-creating for customers, any FTRs sold via the Option 4C auction would need to be priced to reflect transmission value and the range of expected FTR payouts, with payouts capped at the realized congestion rent collected on the relevant path.

The Option 3 variants stand apart in that they are inherently value-creating from a societal perspective, because they reflect positions that private parties have identified as individually valuable. Further, Options 3B and 3C would reduce the need for the AESO to develop and maintain specialized financial risk-management capabilities, as they would be independently created and run by third parties with core expertise in derivatives trading, risk management, and price discovery. However, the Option 3 variants share the general uncertainty common to new or niche markets, namely that they may not develop sufficient scale or liquidity to offer generators their desired congestion hedging opportunities. Low liquidity may or may not be a problem however, depending on the reason that trades are not happening. If trading is discouraged by market failures (e.g. excess transactions costs, poor product definition, barriers to entry, insufficient information), then the FTR market could still add value if the failure is diagnosed and addressed. However, if low liquidity materializes because the physical options for addressing congestion risk (e.g., changes to siting, adding batteries, or co-locating with demand) are lower cost than buying an FTR hedge, then the low liquidity reflects an efficient market outcome where high FTR prices help to guide more efficient investment solutions. Until one of the Option 3 variants is developed and tested however, it would not be clear whether the price transparency and volumes are sufficiently informative to the marketplace to justify the cost of developing the market.

We provide a more granular discussion of design elements and options in the body of this paper, and an assessment of relative advantages in the concluding “Findings” section. Though our evaluation does not identify a clear first-best solution for the future Alberta wholesale electricity market, we believe the models meaningfully illustrate the solution space that can be considered in upcoming discussions.

I. Context and Design Objectives

Alberta's electricity market is undergoing a significant transformation with the introduction of the Restructured Energy Market (REM).[5] Historically and until today, Alberta's market had a single province-wide electricity price consistent with the Transmission Regulation (T-Reg) that planned for an "unconstrained" transmission system.[6] Under the unconstrained system policy, Alberta has not had any locational energy prices nor any version of physical or financial transmission rights (FTRs).

With the introduction of the REM, the power sector will relax the unconstrained transmission policy to allow for the economically optimal level of congestion.[7] Components of the structure will include:

- **Locational Marginal Pricing** (LMP), under which the Alberta Electric System Operator (AESO) power market will produce differentiated energy prices across different locations in the footprint. Energy market sales will settle at LMPs specific to each generator. By contrast, consumers will generally purchase energy at a single market-wide Alberta Load Price (ALP) (though a limited set of consumers can opt-in to purchase at the LMP calculated at their own load bus).[8]
- **Optimal Transmission Planning** (OTP), which aims to efficiently balance the costs of transmission investment, generation investment, and operational costs from congestion.[9]
- **Transmission Reinforcement Payment** (TRP), which will collect a one-time, up-front, location-specific, and technology-specific payment by new generators when they interconnect to the system.[10]

These components create forward-looking locational signals for generation investment and siting coordinated with efficient transmission development. This design exposes suppliers to the

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5 AESO, *Restructured Energy Market: Final Design*, August 2025.

6 More precisely, the T-Reg required AESO to "plan a transmission system that: (i) is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy referred to in section 17(c) of the Act can occur when all transmission facilities are in service, and (ii) is adequate so that, on an annual basis, and at least 95% of the time, transmission of all anticipated in-merit electric energy referred to in section 17(c) of the Act can occur when operating under abnormal operating conditions." See Government of Alberta, *Electric Utilities Act: Transmission Regulation*, Alberta Regulation 86/2007, 2007, pp. 17–18.

7 Government of Alberta, Minister of Affordability and Utilities, "*Direction Letter to AESO—REM, Tariff and Transmission Planning Policy*," July 3, 2024.

8 See AESO, *Restructured Energy Market: Final Design*, August 2025, pp. 24–25.

9 See AESO, *AESO Engage: Optimal Transmission Planning (OTP)*, accessed December 18, 2025.

10 See AESO, *AESO Engage: Transmission Reinforcement Payment (TRP) and System Access Service (SAS)*, accessed December 18, 2025.

operational value of energy at different locations on the grid, which (when congested) can be higher or lower than the province-wide ALP. Long-run investment costs may also be differentially reflected in different locations, with localized scarcity pricing and economic withholding introducing greater incentives to invest in load pockets (while over-saturated grid areas will produce lower prices and local investment incentives.)[11] Generators therefore face congestion risks depending on location. Generators in downstream-constrained locations (i.e., load pockets) will enjoy upside risks from congestion exposure, as LMPs generally increase when import limits bind. Generators in upstream-constrained locations (i.e., generation pockets) will face downside risks, with competition for limited export capability driving down local prices (and leading to local supply curtailments) when export limits are binding. Downside congestion risk will initially be limited by an energy price floor of $0/MWh (matching today's floor), declining to -$100/MWh by 2032.[12]

Consumers will be less individually exposed to congestion risk than specific generators, since the REM will settle nearly all load energy purchases at the single province-wide price ALP. However, customers collectively will still be affected by congestion because: (a) the ALP is the load-weighted-average of LMPs across the footprint (with the individual bus prices affected by congestion); (b) conventional non-controllable consumers will have a one-time chance to opt in to LMP-based pricing, while any controllable consumers will be settled at the LMP at their node; (c) congestion in the energy market will produce excess collections or "rents," which will be used to offset consumers' costs; and (d) some consumers and retail providers will be indirectly exposed to congestion costs via their self-supply or contractual relationships with generation counterparties.[13]

The transition to REM and OTP represents a major shift for market participants, who have previously faced limited exposure to congestion risks (and only through physical curtailment, not pricing). Generators have expressed concern over congestion-driven pricing discounts and curtailment exposures. The transition of incumbent resources with sunk generation investment costs faces some distinct considerations relative to the establishment of an efficient construct for future resource investments. The scope of this paper includes only a review of options for the enduring FTR mechanism that may be developed as a permanent feature of the future REM and does not review or comment on the FTR-like transition payments or other arrangements that are also in development to manage the financial impacts of congestion on incumbent generators.[14]

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11 Throughout this discussion of FTR mechanism options, we incorporate the working assumption inherent to the REM design that location-specific prices will be competitively set such that both short-run and long-run marginal costs of supply are reflected. In reality, the REM (like all markets) will at times proceed through a series of disequilibrium conditions in which the location-specific prices are above or below long-run marginal costs.

12 AESO, *Restructured Energy Market: Final Design*, August 2025.

13 *Id*., pp 24–25.

14 The most recent stakeholder materials on this topic as of this writing are included on the AESO website: see AESO, *Incumbent Transition Payments and GUOC Refunds*, accessed December 18, 2025 and AESO, *Congestion Management Framework*, accessed December 18, 2025.

It is also mostly outside the scope of this paper to review options for allocating congestion rents collected out of the future LMP market.[15] For the purpose of this paper, we adopt the AESO's working assumption that congestion rents may be partially allocated to funding incumbent transition payments and, over the long term, will be returned to customers.[16] However, the fate of the congestion fund is within the scope of this paper to the extent that a subset of the FTR models considered (e.g., the US-style FTR variants) are financially settled via payouts from the congestion fund.

The design goals we consider in developing a range of FTR market designs are somewhat different across the various Options we consider (for example, we examine some Options that only focus on efficient outcomes, while others are more explicitly focused on supporting generator needs versus consumer needs.) We understand that the AESO stakeholder consultation will explore which of the design goals are appropriate for a potential FTR model for Alberta. We nonetheless lay out a comprehensive set of assessment criteria (summarized in the following Table 2), understanding that some of the assessment criteria may ultimately be less relevant (or not relevant) to the development of a potential model. For discussion and illustration purposes, we evaluate the models relative to all the assessment criteria (see findings in Section V.D below).

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[15] Congestion rent is the excess energy market revenue collected by the Independent System Operator (ISO) in nodal and zonal energy markets, caused by the fact that, across the aggregate energy market, collections from generally higher-priced load buses exceed payouts at lower-priced generation buses. See additional discussion in Section II below.

[16] These arrangements will be further developed by the AESO, Government and stakeholders consistent with policy direction, see Government of Alberta, Minister of Affordability and Utilities, *Direction Letter to AESO on the technical design of REM*, December 10, 2024.

TABLE 2: ASSESSMENT CRITERIA FOR ENDURING FTR MECHANISM

Assessment Criterion	Description
Mitigate generator investment risks	Enable generators to hedge congestion-driven pricing and curtailment risk at the time they are making supply investments
Enable ongoing risk management	Allow market participants to actively manage short-term congestion price volatility through regular, transparent trading opportunities
Promote market liquidity	Provide market participants access to a hedge when needed; though not a primary design goal on its own, market liquidity signals that voluntary market participants see value in the product and increases the likelihood that prices accurately reflect anticipated risk; however, the importance of liquidity in FTR markets should not be overstated, as low market liquidity may indicate either a design flaw (e.g., poor product-market alignment, lack of transparency, or high transactions costs), or it may simply indicate that there is minimal value to be created through financial hedges (e.g., when the cost of providing financial hedges exceeds the cost of physical solutions for managing congestion risk)
Support efficient investment incentives	Produce more transparent and accurate locational investment pricing signals, so generators have better information on where to build supply, whether to consider other technologies (e.g., energy storage), or whether to co-locate with loads; in a theoretically ideal situation, financial hedges would be available to and from all locations at market-determined price levels (i.e., prices that are not subsidized by consumers or government), and the costs of these hedges could be weighed against the incremental cost of physical alternatives. Generally, there is a tradeoff between this criterion of signaling efficient investments against the above criterion to mitigate generator risks
Minimize net cost to customers	Ensure that consumers and others that have paid for the transmission system are positioned to enjoy the benefits of its use (including through the return of congestion rents); structure the mechanism so it does not impose additional costs on ratepayers, or award net subsidies to generators (particularly since the nature of any net subsidy would also be likely to incentivize excess investment in less efficient technologies or locations where congestion costs are likely to be high), or allow financial participants to extract more value than created by the hedges they support
Mitigate customer risk exposure	Seek FTR mechanisms that offer an equal or better risk profile to customers than what is already accomplished by returning the congestion rents (which is nearly the same as allowing customers to physically utilize the transmission for which they have paid); enable the reallocation of risks primarily if doing so would enhance efficiency (e.g., reallocating risks to entities in the best position to control the underlying risks or costs) or enable voluntary risk reallocation (e.g., risk reallocation between private entities at a mutually agreeable price)
Manage administrative complexity	Manage the complexity of products and market rules

II. Definitions: What is an FTR?

An FTR is a financial derivative product that provides its holder with a settlement equal to the congestion-driven locational price difference between two pricing points in a nodal electricity market, times the MW volume of the position.[17] An FTR pays out when the congestion component in the LMP of its defined source (or injection) point is lower than its sink (or withdrawal) point.[18] Differences in the loss component of the LMP are not considered.[19] By way of its upfront cost, an FTR effectively guarantees a fixed congestion price differential between two points.

FTRs are purely financial, as they do not provide a right to physically schedule power across transmission lines. Instead, their payouts approximately align with the value of a physical transmission right over a transmission path if the MW of the FTR were fully physically scheduled. The FTR product is analogous to a basis swap in gas or other commodity markets that settle based on locational price differentials without involving physical delivery.[20] An FTR specifies a MW quantity, a direction from source to sink point, a time profile, and a settlement period. These elements determine how the product pays and how it can be used as a hedge. FTRs can be defined as node-to-node, zone-to-zone, node-to-zone, or any combination.[21]

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[17] Pricing points can include single nodes or zonal aggregates. A zonal energy market would define FTRs based on price differences between energy market zones rather than between nodes.

[18] The most typical type of FTR product is structured as an "FTR obligation," which results in a charge (rather than a payout) to the holder when the source congestion price is higher than the sink price. Unless otherwise mentioned, the term "FTR" in this report refers to FTR obligations. An alternative product called an "FTR option" is defined to result only in positive payouts (with no payment when the source congestion price is higher). Some US-style FTR market constructs offer only FTR obligations, while others offer both products.

[19] Applying FTR payouts only to the congestion component of the LMP allows the product to faithfully reflect price differences based on the dynamics of congestion (i.e., generation offers in different areas together with constrained transmission) as opposed to physics-based marginal losses.

[20] For example, consider the product defined by the gas basis price between the most liquid trading point in the US (Henry Hub) and Alberta's gas price hub (AECO Hub). The basis swap can clear at a positive price (for downstream price points where gas is consumed) or negative price (relevant for upstream gas production locations like Alberta).

[21] A pricing "node" is an individual bus on the power grid where LMPs are established, load buses are locations of power withdrawal while generation buses are locations of power injection. Zones are larger defined areas of the power grid comprised of many individual pricing nodes and are often defined as a continuation of distribution or transmission utilities' current or historical territories. For example, Ontario's LMP market has approximately 1,000 nodes and 9 zones, while PJM's LMP market has over 10,000 pricing nodes and 22 zones. Trading hubs are aggregate pricing points that may or may not be tied to a contiguous zone or service territory but are the collection of LMPs that are aggregated to create the pricing point at which electricity forwards are settled against. For example, the "PJM West Hub" is the most liquid futures trading point in PJM, followed by "PJM East Hub" and the futures aligned with individual zones having substantially less liquidity.

The following table summarizes the standard FTR product definition and provides a simple illustrative example for an FTR position flowing from a generation-rich area (called "Wind Bus"), to a load pocket ("Load Bus"). The example assumes a load bus (i.e., a single node), but FTRs can be settled at aggregate points such as zones or defined trading hubs (including, in principle, the ALP aggregated pricing point).

TABLE 3: ELEMENTS OF FTR PRODUCT DEFINITION

Element	Description	Example
Volume (MW)	Quantity of transmission right being purchased or sold	10 MW
Path	The source and sink points that define the direction of flow	From *Wind Bus* to *Load Bus*
Prevailing vs. Counterflow	Directionality of the path. Prevailing flow means from low to high price (i.e., generally in the same direction as power flow), with expectation of an upfront cost to buy with ongoing payouts in settlement; counterflow is the opposite: holder is paid up front to take the position, but then expects to pay out the cost over the term	Prevailing flow (from the low-price *Wind Bus* to the high-price *Load Bus)*
Profile	On-peak, off-peak, 24×7 (possible to design to other profiles, e.g., wind or solar potential, but not previously implemented)	Off-Peak (11 p.m. to 7 a.m. business days, all hours on weekends and holidays)
Term	Usually monthly (and month ahead) or annual (up to three years ahead). However, in concept the product could have a shorter or longer term (e.g. as short as hourly or daily, or as long as decades)	Monthly
Delivery Period	Period during which the FTR applies	Jan 1 2027–Jan 31 2027
Purchase Price	Cost paid or received in the auction or bilateral trade	$20,720 total but usually quoted based on the unitized congestion differential between the two locations price, e.g., the buyer locks in an FTR guaranteeing a $7/MWh price differential in our example. ($7/MWh × 10 MW × 296 off-peak hours in the month = $20,720 total purchase price)
Settlement	Payout based on the price difference (LMP at sink – LMP at source)	Example LMPs are $10/MWh at sink and $5/MWh at source, payout = ($10/MWh-$5/MWh) × 10 MW = $50/hr If this is the average price differential realized over the month, then the total settlement over the month is $50/hr × 296 off-peak hours = $14,800
Profit from FTR Position (or Net Cost of FTR Hedge)	Net profit (or cost) of the FTR position	Net cost of the prevailing flow hedge is: $20,720 – $14,800 = $5,920, or $2/MWh (i.e., the difference between the $7/MWh purchase price and the $5/MWh realized average settlement price)

The above table describes an example of a 10 MW FTR position on a specific path, which can be created in any size of MW that does not necessarily have to relate to the actual MW capability of the transmission system to flow power over the defined path.

However, several (especially US-style FTR markets) *do* materially connect the MW size of FTR positions with the transfer capability of the transmission system, via the relationship between the congestion rents created on a specific path. If the MW of FTR positions exactly matches the MW of power flowing across the defined path, then the value of congestion rent created on the path in question is exactly the size of the FTR settlement payout that would be awarded to the FTR holder. This relationship holds true as long as losses and the loss component of LMPs is not included in the definition of the FTR settlement, and as long as there are no transmission outages or other factors that cause the MW of FTR awards to differ from the MW of physical flows (an assumption that rarely holds in reality, as discussed further in later sections).

To explain why congestion rents are sized equal to the FTR settlements, consider the simplest-possible two bus-system in a specific 1-hour interval with wind supply located at “Wind Bus” and demand at the “Load Bus”:

- **Wind Bus:** 110 MW of available wind at $0/MWh, with no local demand
- **Load Bus:** 100 MW of demand, and 150 MW of available gas generation at $80/MWh
- **Transmission Limit:** 60 MW from the Wind Bus to the Load Bus
- **FTR Positions:** loads at the load bus have 60 MW of FTR positions, exactly sized to match the 60 MW transmission capability

If the transmission line had greater capability of 100+ MW and were unconstrained, all 100 MW of load could be served using wind at $0/MWh. However, with only 60 MW of transmission capacity to serve load with wind power, most of the wind power must be curtailed and the remaining 40 MW of demand must be served by the more expensive local gas generator at $80/MWh.

In a nodal market, each node’s LMP reflects the cost of serving one additional MW at that location, given transmission constraints, so that (ignoring losses):

- At the Wind Bus, the marginal resource cost is $0/MWh wind, so the LMP is $0/MWh
- At the Load Bus, the marginal resource cost is $80/MWh gas, so the LMP is $80/MWh

This creates an $80/MWh congestion spread between the nodes, which gives rise to congestion rent because the ISO collects more money from consumers than what is paid to generators, as follows: the energy market settlements to loads are $8,000 (=$80/MWh × 100 MWh demand); however, payments to generators are only $3,200 (= $80/MWh × 40 MWh to the gas resource + $0 × 60 MWh to the wind resource). As a result, the ISO has collected $4,800 more from customers than what is paid out to generators in energy market prices (this is always the case because load bus prices are always equal or greater than generation bus prices). The size of congestion rents are larger in systems with more frequent congestion, as well as systems with larger differentials in the marginal cost of supply between congested areas.

The connection between the congestion fund and FTR settlement payouts comes into play if the congestion fund is used to issue payments to FTR holders. In this example, an FTR holder owning 60 MW of FTRs from the Wind Bus to the Load Bus is owed a settlement payment of: ($80/MW − $0/MW price differential) × 60 MW of FTRs = $4,800 of FTR settlement payouts. The size of the FTR settlement award is exactly what can be funded out of the congestion fund. If the 60 MW of FTRs are awarded to consumers in the load pocket, this outcome essentially mimics the outcome that would occur in a non-market scenario if the consumers had built transmission to a wind-rich area with low cost supply and use the transmission to physically deliver the power to the load center. The consumers would pay to build transmission and then receive 60 MW of low-cost supply at the marginal variable cost (but at the expense of building transmission), while the remaining supply must be purchased locally at a higher price. If, instead, the generator is the entity paying to build the transmission, the outcome is similar but in the other direction (the generator pays to build transmission, physically delivers it to load, and then has the right to collect a higher price at the delivery point). In both scenarios, an identical financial outcome is accomplished by allocating to the entity that built the transmission either: (a) the physical rights to use that transmission; or (b) an FTR expressing the financial right to use the transmission; or (c) allocating the relevant portion of the congestion fund connected to the line. Again, this textbook-style example assumes away many of the complexities encountered in the real world, where FTRs can be over-allocated, under-allocated, or not fully allocated to anyone (see additional discussion in Section III).

Before moving to broader market design considerations, we also lay out several key economic concepts that shape how FTRs function in practice. These economic drivers influence who buys and sells FTRs, how risk is allocated, and why financial participants often play a central role in FTR markets, as follows:

- **Risk Allocation and Direction of Flow**: The congestion payout on an FTR can create either a positive or negative payment stream. In a prevailing flow FTR, the holder is effectively buying insurance against congestion costs increasing in the expected direction (low price to high price). The FTR holder pays a fixed price for congestion in advance, and receives compensation if congestion turns out to be higher than expected. This makes prevailing flow FTRs risk-reducing hedges. Counterflow FTRs do the opposite, absorbing risk. They receive up-front revenue but are exposed if congestion increases. Because congestion differentials can spike unexpectedly due to outages or unusual system conditions, the risk has a "fat tail." These positions are typically taken on by financial participants who can quantify and absorb the risk in the near- and mid-term.
- **Lack of Natural Long-Term Counterparties among Market Participants**: Many markets have natural counterparties with similarly sized positions (e.g., wholesale energy necessarily has equal volumes of sales and purchases, ignoring losses and unaccounted for energy). FTRs are different because the natural counterparty of a basis-risk product is the entity that owns and controls the means of transport. For example, a shipping company is the natural seller of shipping differentials, a pipeline owner is the natural seller of gas pipeline rights, and a merchant transmission owner can sell a physical or financial transmission right. In contrast, the structure of the power market with centralized dispatch and control of transmission lines

does not create a natural physical counterparty for FTRs among market participants.[22] Both customers and generators would want prevailing flow FTRs, and no entity is positioned to sell those rights without taking on the same risk. As a result, financial players tend to step into that role, providing counterflow positions and offering hedges. However, these financial players have shown a reluctance to take on long-term positions considering that counterflow positions face substantial fat tail risk.

- **Flat MW Profiles vs. Variable Output:** FTRs are often defined as fixed-MW products across the applicable periods (e.g., on-peak, off-peak, 24×7). As a result, they hedge the ongoing price spread rather than the price spread during times that matter for the variable consumption of a buyer, the variable production of a renewable resource, or the occasional output of a peaker unit. Unless a market offers shaped or profile-specific FTRs, this flat structure makes them imperfect hedges for consumers or for resources with variable output whose production profiles may not align with the timing of congestion. A similar problem exists in other futures markets as well, in that standard products can be structured in ways that attempt to match the needs of many players but will never be exactly what a specific market participant wants.

These foundational components of the FTR product definition and economic concepts on how they can be used can unfold differently depending on a number of other aspects of the overall market design and regulatory context as discussed further below.

[22] In Alberta, the transmission system is owned by private transmission owners that earn regulated cost recovery and earn payments for building transmission but then offer the transmission to the scheduling control of the ISO who determines its optimal use to serve system-wide energy demand at least cost. The regulated transmission owners in competitive power markets therefore do not have the physical means nor financial incentive to control power deliveries (and hence offer a hedge to entities that may wish to use that transmission) in the same way that a merchant transmission owner could provide.

III. Jurisdictional Scan

We review international experience with a range of congestion hedging and FTR-like models to understand how different market structures address similar challenges. These examples span from the simplest variation of the concept (bilateral over-the-counter hedging as has been used in the Nordic markets) to more structured mechanisms developed for specific purposes (in Ontario and the US) to reform proposals in California. We provide a high-level comparison of these approaches in the table below, with each model described in greater detail in the subsections that follow.

TABLE 4: OVERVIEW OF FTR AND CONGESTION HEDGE MODELS

Design Feature	Nordic EPAD Hedging Model	Ontario Transmission Rights	US Style FTRs	California "Willing Seller" Congestion Market Reforms
Market Administrator	Bilateral: No central administrator Exchange/Over-The-Counter (OTC): Nasdaq (transitioning to Euronext in 2026) Auction: Transmission System Operator (TSO), or market operator under contract to TSO	Independent Electricity System Operator (IESO)	Applicable ISO/RTO (Regional Transmission Organization)	California Independent System Operator (CAISO)
Instrument Type	Bilateral, Exchange, Over-The-Counter (OTC), and TSO Auction: Electricity Price Area Differential (EPAD) contracts for zonal price differences	Transmission Rights (TRs) for congestion over interties into or out of the province, structured as FTR options, not obligations	FTRs	Congestion Revenue Rights (CRRs) structured as swaps traded between willing counterparties in centralized auction
Years Forward	Bilateral: any number Exchange/ OTC: 4 years Auction: 1 year	1 year	Up to 3 years	Not yet defined
Issuance and Allocation	Bilateral: Privately negotiated OTC: privately negotiated, registered on platform Exchange: Continuous exchange trading Auction: periodic auctions	Monthly, quarterly, and annual TR auctions	Auction Revenue Rights (ARRs) allocated to load-serving entities; monthly and annual FTR auctions	Central ISO clearing of matched buy/sell bids (ISO does not take sell positions)

—Table continued on next page—

Design Feature	Nordic EPAD Hedging Model	Ontario Transmission Rights	US Style FTRs	California "Willing Seller" Congestion Market Reforms
Funding and Settlement	Bilateral: Direct settlement between contract parties Exchange/OTC and Auction: Settled through central counterparty	Congestion rents and TR sales revenue go into Transmission Rights Clearing Account (TRCA); TR payouts are made from the TRCA, based on day-ahead price differences	Payouts funded by congestion rents	Fully funded by counterparties
Locational Granularity	All mechanisms: zonal	Nodal on the IESO side of the intertie (only applies to interties with external systems, not congestion within Ontario's internal transmission network)	Nodal and zonal	Nodal and zonal
Allocation of Underfunding Risk for Payouts *I.e., when congestion rents are less than payout obligations*	Bilateral, OTC, and Exchange: Not applicable (counterparties hold entire payout obligation) Auction: Transmission users (mainly consumers)	Customers/loads	Customers/loads and/or derating of payout, depending on market	Not applicable (counterparties hold entire payout obligation)
Allocation of Default/Credit Risk *I.e., when a counterflow FTR holder cannot honor their negative payout obligation*	Bilateral: Counterparties OTC and Exchange: Clearinghouse collateral system Auction: Clearinghouse collateral system	Not applicable—market participants are not obligated to make payouts	FTR market participants bear default risk	ISO bears credit risk as central counterparty, with CRR market participants or all ISO members potentially paying for unprotected bankruptcies

Sources: Midcontinent Independent System Operator (MISO), *FTR/ARR Markets Enhancements Proposal (MSC-2025-5)*. Prepared for Market Subcommittee, July 2025; PJM Interconnection, *Financial Transmission Rights Market Review*, prepared for PJM ARR/FTR Market Task Force, April 2020; CAISO Department of Market Monitoring, *Willing Seller Market Design for Congestion Revenue Rights*, October 2024. European Energy Exchange (EEX), *Trading Nordic Power on the European Energy Exchange*, September 2025; Independent Electricity System Operator (IESO), *Transmission Rights Market Review—Interim Report*, October 2020.

A. Nordic Hedging Model: Hybrid Market for Congestion Hedging Opportunities

Historically the Nordic countries (restructured with competitive generation, much of it hydropower) featured a zonal energy market dominated by tailored bilateral forward energy contracts.[23] Strict bilaterals are not necessarily standardized contracts and are transacted directly between two parties. By contrast, two parties can make an Over-The-Counter (OTC) trade that, while a form of bilateral, transacts a standardized product and is executed through a central counterparty. The central counterparty takes the other side of OTC transactions (i.e., selling to buyers and buying from sellers). This shields participants from credit risk associated with the counterparties they are matched with. The central counterparty remains exposed to such risk, which it manages via collateral and margining for each participant.

The Transmission System Operators (TSOs) introduced exchange trading in order to increase liquidity.[24] An exchange defines standardized products, collects bids/offers for these from an array of buyers and sellers, and automatically clears a trade when the bid/offer prices imply a match. The exchange also acts as central counterparty. In 2008, the TSOs (in the form of subsidiary Nord Pool) sold the exchange to Nasdaq, and in 2026 it will be transitioned to Euronext (a for-profit corporation that is now the majority owner of Nord Pool).[25]

The Nordic exchange set up trading of both system-price futures and Electricity Price Area Differential (EPAD) contracts. An EPAD pays out the price difference between one of twelve energy zones and the Nordic system price during a defined coverage period in time.[26] The exchange executes trades between pairs of willing buyers and sellers of identical EPADs (i.e., for the same zone and period), without regard for transmission.[27] The structure also enables participants to gain a hedge between any two bidding zones by simultaneously buying two EPADs together (e.g. from Zone A to system hub, plus system hub to Zone B).

Later, the European Energy Exchange (EEX) entered this space by offering Nordic system-price futures, and in 2024 added a new Nordic Zonal Futures product for energy in the twelve Nordic bidding zones.[28] Participants in EEX can create a hedge against locational price spreads by

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23 DNV, *Bilateral Hedging of Electricity in Sweden*, Report No. 2024-1712, Rev. 0, June 10, 2024.

24 Anders Houmoller, *The Nordic Power Exchange: Nord Pool*, in *Electricity Market Reform in Norway*, edited by Eivind Magnus and Atle Midttun, Chapter 3, May 15, 2000.; Thema Consulting Group, *Power Price Risk Hedging Opportunities in the Norwegian Market*, THEMA Report 2021-06, June 2021

25 Nasdaq, *Nasdaq OMX Acquires Nord Pool ASA*, March 17, 2010; Euronext, *Euronext–Nasdaq Clearing Agreement: Power Derivatives Transfer Set for March 2026*, May 30, 2025

26 EPADs are also available in the Baltics. Nasdaq, *European and Nordic Power Derivatives*, accessed January 23, 2026

27 Nasdaq, *Trading Appendix 4 Trading Procedures Commodity Derivatives*, May 9, 2025

28 European Energy Exchange (EEX), *EEX Nordic Zonal Futures*, June 11, 2024.

executing simultaneous linked trades for both system and zonal energy futures.[29] For example, if a participant wanted protection against the zonal spot price clearing low relative to the system price, they could sell the former (resulting in an obligation to pay the spot zone price) and buy the latter (resulting in a payment of the spot system price). In this example, when the zone price and system price match, there is no net payout from the linked futures. When the zone price is lower, there is a positive net payout. This pair of transactions creates an effective equivalent to the EPAD.

In 2023, to ameliorate continuing declines in liquidity for exchange-traded EPADs, Nordic countries started to introduce centralized auctions for EPADs.[30] In these auctions, the TSO is the seller (or buyer), with auctions run by the TSO itself (in Sweden) or by a third party on behalf of the TSO (in Norway).[31] Transactions are cleared through the same central counterparty used for the exchange (i.e., Nasdaq).[32] The positions the TSO takes are loosely backed by the congestion rent from the day-ahead energy market, in the sense that both settle against the accounts of the TSO, which in turn recovers all costs through rates. That said, it is unclear whether there is any process that links the revenues from congestion rent (and EPAD sale revenues) to the expense of EPAD payouts.[33] In practice, a small portion of the transmission system capability is auctioned off as EPADS (e.g., 10% in Sweden), limiting underfunding risk.[34]

The centralized EPAD auctions were implemented primarily to increase congestion hedging opportunities for market participants. European Union (EU) Forward Capacity Allocation (FCA) Guideline 2016/1719 requires TSOs to provide opportunities for market participants to mitigate risk of day-ahead price volatility.[35] Since the Nordic countries do not offer long-term transmission rights, the TSOs believe that the substantially liquid EPAD market that the auction supports, in conjunction with forward energy price hedging opportunities, provides sufficient risk mitigation to satisfy the requirements of FCA Guideline 2016/1719.[36]

The introduction of the centralized auction is not replacing the existing continuous trading market for EPADs on the exchange, rather it supplements the continuous trading market with increased liquidity. Thus far, the Swedish TSO, Svenska Kraftnat, has taken a measured approach

[29] European Energy Exchange (EEX), *EEX Nordic Zonal Futures*, June 11, 2024, slide 12

[30] See Svenska Kraftnat, Quarterly summary of Svenska kraftnat's auctioning of EPA contracts to improve hedging opportunities, Case no: Svk 2023/1497,Q2 2023; Statnett, *Options to Support Power Price Hedging in the Norwegian Bidding Zones*, 2024; Nord Pool, *EPAD auctions*, accessed December 19, 2025.

[31] Nord Pool, *Nord Pool wins Statnett EPAD tender*, August 20, 2024

[32] E.g., Statnett, *EPAD Auction Rules*, November 18, 2025, p. 2

[33] Statnett, *Options to Support Power Price Hedging in the Norwegian Bidding Zones*, 2024, p. 13

[34] Svenska Kraftnat, *Continued Auctioning of EPADs*, October 18, 2024

[35] Office Journal of the European Union, *Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation*, September 26, 2016.

[36] Svenska Kraftnat, *Quarterly summary of Svenska kraftnat's auctioning of EPAD contracts to improve hedging opportunities*, Case no: Svk 2023/1497, Q2 2023.

to offering counterflow positions in the centralized auctions, limiting their exposure to only a portion of the physical transmission capacity available.[37]

Takeaways for Alberta	**Strengths** • The current hybrid approach (hedge contracts via tailored bilaterals, exchange-traded standard contracts for zonal energy and congestion, and TSO-backed auctions for congestion) provides some liquidity to limit congestion risk while limiting involvement of congestion rents relative to US style markets and providing tailored hedge products via bilateral markets **Challenges** • Prior to the centralized auction of EPADs, liquidity in the congestion hedging market was a structural challenge, with a long-term decline in Nordic financial market liquidity since 2008 **Other Considerations** • The Nordic energy markets are zonal, not nodal, resulting in a less granular need for management of price-based congestion risk management

B. Ontario Transmission Rights

Ontario's market, administered by the Independent Electric System Operator (IESO), historically had a single internal price (the Hourly Ontario Energy Price, or HOEP). Internal physical congestion was therefore managed via out-of-market actions, with no need for market hedges. However, Ontario had different prices at its borders with neighbouring jurisdictions. To provide traders with a hedge on real-time border price differences for imports and exports, IESO auctioned off Transmission Rights (TRs). With a transparent price, the IESO has argued that the TR market encouraged efficient use of the interties for trade: because traders typically must commit to an import/export transaction over a path before the price is known, they often bear the risk of loss-making trades. The TR for the same path effectively provides insurance against that risk, thus potentially making it easier to commit to the transaction. In a study, IESO assumed that export volumes would go down if there were no TR market, resulting in losses to Ontario customers of potentially CAD$50 to CAD$135 million per year.[38]

The IESO conducted a market review in 2020 finding that the value of the TR market is not maximized: some TR paths were rarely used for their intended purpose and the auctions were not competitive. They concluded that adding reconfiguration auctions or expanded product types could increase TR liquidity and flexibility.[39]

37 For example, in the initial pilot, Svenska Kraftnat only offered positions in 2 of its bidding zones. See Svenska Kraftnat, *Quarterly summary of Svenska kraftnat's auctioning of EPAD contracts to improve hedging opportunities*, Case no: Svk 2023/1497,Q2 2023.

38 Independent Electricity System Operator (IESO), *Transmission Rights Market Review—Interim Report*, Public, September 30, 2020.

39 *Id.,* p. 54.

An internal FTR mechanism in Ontario has not historically existed because of its single internal energy price. Even though IESO switched to a nodal, LMP-based energy market in May 2025 (introducing internal market congestion as well as a day-ahead energy market), the IESO continues to settle effectively all loads at a single price. Unlike other LMP markets, the IESO opted not to implement internal FTRs. The IESO explained that its lack of Load-Serving Entities (LSEs) (i.e., entities that represent retail customers at the ISO, bidding their demand into the energy market) means that it does not need internal FTRs.[40] This choice is also consistent with the use of a single price for load settlements, and it accords with the mainly centralized framework used for investment in new resources, where congestion risks can be addressed through the resource planning process.

Under today's market construct, the TRs are settled against day-ahead energy prices instead of real-time, as before. In principle, this should make for a less complete hedge against the real-time energy price exposure that traders face when transacting over the interties in real time (when high-value price spikes can prompt valuable cross-border trade).

With LMP now calculated across the system, the IESO-side reference price for TR payouts is based on the congestion component of the day-ahead LMP at the border.[41] Meanwhile, the reference price on the far side of the intertie is calculated according to the same border LMP added to the Intertie Congestion Price (ICP). The ICP is derived from a market-based intertie scheduling process that clears import and export transactions.[42] The intertie scheduling process runs in the day-ahead as well as one or two hours before the trade hour.[43]

Other aspects of the TR market (below) remain largely unchanged. The Market Surveillance Panel has yet to evaluate the performance of the TR market under the renewed LMP framework.

TRs have two durations: long-term (one year, auctioned quarterly) and short-term (one month, auctioned monthly).[44] The quantity of TRs sold is based on the transfer capability of each intertie, with adjustments for expected outages, operational constraints, and over/under-funding trends to "ensure that the congestion rents collected by the IESO are balanced against the IESO's TR payment obligations for each path."[45]

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40 IESO, *Day Ahead Market: High-Level Design*, Final, August 2019, p. 52

41 IESO Training, *Transmission Rights Workbook*, Issue 3, May 2025, p. 0; IESO, *Guide to Prices in the Renewed Market*, October 2024, pp. 17–20.

42 IESO Training, *Interjurisdictional Energy Trading*, May 2025, p. 20

43 The ICP is calculated in the import/export clearing process as the shadow price of relaxing the transmission limit by 1 MW. Ibid, p. 21

44 IESO Training, *Transmission Rights Workbook*, Issue 3, May 2025, p. 2.

45 IESO Training, *Transmission Rights Workbook*, Issue 3, May 2025, p. 9.

TRs are paid out from the Transmission Rights Clearing Account (TRCA).[46] The TRCA is funded (1) from congestion rents collected on interties and (2) from TR auction proceeds.[47] A reserve of $20 million is maintained, and any TRCA surplus (at least $5 million CAD above the reserve threshold) is disbursed to Ontario customers semi-annually.[48]

If congestion rents are less than the TR payout (e.g., because of outages), then there will be a net draw on the TRCA, which reduces the TRCA funds available for disbursement to customers. Because the TRCA collects both congestion rents and proceeds from the TR auctions, the net draw effectively reduces the congestion rent value that is available to customers. However, the IESOs Financial Upper Limit mechanism attempts to reduce such shortfalls by limiting TR sale volumes such that "cumulative congestion rents collected on a specific path are sufficient to cover the cumulative TR payment obligations for the same path."[49] All told, only a small fraction of congestion rents are not returned to customers/loads.[50]

Takeaways for Alberta	**Strengths** • Stable track record • Less complex • No default risk by participants (TR payouts cannot be negative) **Challenges** • Auctions not always competitive • Not all congestion rent is returned to customers/loads **Other Considerations** • Does not address internal congestion hedging

C. US-Style FTR markets

Introduced with the shift to LMP, the ISO-run FTR markets in the US have been operating for roughly two decades. The core concept was for a financial instrument to protect vertically integrated utilities and LSEs from unexpected congestion costs and to manage how congestion rents were redistributed among the various utilities comprising an ISO. FTRs were introduced to ensure that load customers, who had historically paid for the transmission grid, would continue to receive its value after deregulation.

US-style FTRs are financial derivatives that pay (or charge) their holders based on day-ahead congestion price differentials between two grid points (including nodes or zones consisting of

46 IESO, *Market Rules, Chapter 8*, Issue 2.0, December 3, 2025, section 3.18.1.4

47 IESO Training, *Transmission Rights Workbook*, Issue 3, May 2025, p. 4.

48 *Id.,* p. 13.

49 IESO, *Transmission Rights Workbook: IESO Training*, Issue 3, May 2025, p. 5

50 IESO, *EB-2021-0243: Generic Proceeding on Export Transmission Service (ETS) Rate – Presentation Day*, August 4, 2022, slide 9.

weighted-average aggregate nodal prices). These rights are auctioned by the ISO and funded by congestion rents collected in the day-ahead energy market. The total MW of FTRs sold is constrained by a network model to not exceed the physical transmission system's forecasted capability. If actual transmission flows match auction assumptions, then the congestion rents exactly fund the FTR payouts.

The ISO runs monthly and annual FTR auctions (up to three years forward) that are cleared with a revenue-maximizing optimization. Bidders include LSEs, generators and financial traders.

Most US ISOs allocate revenues from the auctioned-off FTRs to LSEs (and, in limited cases, certain other participants), providing them with a significant share of the anticipated congestion rent.[51] Electric Reliability Council of Texas (ERCOT) and the California Independent System Operator (CAISO) allocate to LSEs on a pro rata basis (with separate accounting for in-zone vs. cross-zone FTRs in ERCOT), while other ISOs allocate such revenues via complex instruments called Auction Revenue Rights (ARRs) on specified paths.[52]

After the FTR auction, the Regional Transmission Organization (RTO) settles the FTR payments out of the congestion rent fund from the day-ahead energy market after it settles for the applicable periods. The "target payout" to the FTR holder is determined on an hourly basis by the difference in the congestion component of day-ahead energy prices between sink and source nodes multiplied by the MW of the FTR position. If the system model used in the FTR auction aligns with actual day-ahead operations, the congestion fund exactly covers FTR obligations. In practice, deviations (e.g. from outages or modeling gaps) often lead to underfunding, requiring FTR payouts to be prorated or recovered from other charges.

FTRs are used by a range of market participants. LSEs use them to hedge congestion risks between their load centers and liquid energy trading hubs (available for use as an FTR sink as a zonal aggregate of nodes) or contracted generators. Generators use FTRs to "lock in" congestion charges when delivering power to distant nodes (paying up-front to avoid facing whatever the day-ahead congestion will be), thus securing more predictable gross margins. Finally, financial participants engage in the market to speculate on congestion price differentials, adding liquidity

[51] The New York Independent System Operator (NYISO) allocates net auction revenues from FTRs (called Transmission Congestion Contracts or TCCs) to transmission owners under a facility flow-based methodology, which effectively results in an offset to transmission rates for consumers

[52] Not all FTR paths have corresponding ARRs, and ARR holders cannot necessarily claim all FTR paths. ARRs are broadly allocated to the parties that paid to build transmission; hence, loads/customers are the main parties holding ARRs. Other market participants can also gain ARR awards by contributing toward transmission costs or by developing transmission on a merchant basis. In some cases, the ARRs a load/customer is allocated correspond to their historic utilization of the transmission network to serve their load. To determine which entities have the right to ARRs on a specific path, there is a tariff-defined allocation process that can include considerations such as: 1) customers' contributions to pay for transmission infrastructure; 2) utilities' historical or current use of the transmission system; and 3) ARR paths across specific transmission line elements. Before each FTR auction, ARR holders in some ISOs can determine whether to retain ARRs and receive the corresponding FTR auction revenue or convert the ARR positions directly into FTRs (defined across the same source-to-sink path).

to auctions but potentially drawing scrutiny for capturing rents without serving load or generation.

A shortcoming of the US-style FTR construct is that a large share of congestion rent is not returned to consumers but rather transferred to financial traders. This occurs in part because FTRs are auctioned at prices that do not reflect their true value, allowing traders to capture a disproportionate share of congestion rent. In PJM, the Independent Market Monitor (IMM) reports that 30.4% of congestion rent was not returned to customers over 2011–2024, costing consumers $334 million/year on average over this period.[53] In MISO, 32% of congestion rent was not returned to customers from 2013–2023, costing consumers $314 million/year.[54] Independent market monitors in both regions have called for reforms to reallocate more congestion rent to loads.

There are other structural issues of the US FTR markets. Sale of too many FTRs has led to underfunding (where payouts exceed congestion rents), forcing reductions in hedge value (or charges to customers/loads). US FTRs do not offer a strong hedge on congestion risk for time-varying generation output or load. And critically, weak credit oversight has resulted in costly defaults, including PJM's GreenHat default in which a $179 million loss was ultimately recovered through charges to other market participants.[55]

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<td>Takeaways for Alberta</td>
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Strengths:

Provides liquid trading of shorter-term internal congestion hedges, while returning most congestion rent to customers/loads
Is an established market design

Challenges:

Failure to set an appropriate reservation price can result in failure to return full congestion fund to load/customers, and hard-to-fix misalignments between the FTR model and energy market model result in excessive sale volumes and underfunding
Requires significant administrative infrastructure and oversight; rules can be difficult for participants and interested parties to understand
Shorter term does not match investment time horizon, and on-peak, off-peak, and 24-hour contracts can be a poor match for variable load or generation profiles
Complex credit requirements are necessary to protect against participant default risk socialized to other participants

Other Considerations

Alberta would need to make an explicit decision on how congestion rents are allocated to avoid unintended cost shifts

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53 Monitoring Analytics, *2024 PJM State of the Market Report*, Section 13: FTRs and ARRs, March 2025, p. 797.

54 MISO, *ARR/FTR Transmission Customer Metric*, Market Subcommittee. April 18, 2024.

55 Utility Dive, *GreenHat Energy, traders to pay $181M to settle PJM market manipulation allegations*, August 22, 2022.

D. California Congestion Market and Willing Seller Reforms

The CAISO introduced Congestion Revenue Rights (CRRs, conceptually similar to FTRs notwithstanding design differences) with its nodal market design in 2009, with a major reform in 2018.[56] As with the other US ISOs, the goal was to enable congestion hedging through a financial instrument that reflects the economic value of firm transmission service, while returning congestion rents to customers.

The CRR framework in California shares many features with other US markets: it uses nodal pricing, monthly and annual CRR auctions, and point-to-point financial congestion instruments. However, it lacks ARRs—instead, most CRRs are allocated directly to LSEs through an annual nomination and allocation process, with only a portion offered through competitive auctions (similar to ERCOT's structure).[57] Revenues from CRR auctions are returned to all loads pro rata. After the 2018 reform, payouts to CRR holders have been made using actual energy market congestion revenue collected over a month, so CRR holders bear almost all the risk that congestion rent is less than the target payout, unlike in some other US FTR markets. For example, if a 100 MW CRR is affected by a derate limiting flow to 20 MW, only the congestion rents for the 20 MW would be paid out.

Despite the unique structure, the CAISO CRR market has faced ongoing critique, particularly from the Department of Market Monitoring (DMM). Prior to the 2018 reform, the DMM reported that only about 50 percent of the congestion revenue associated with the CRRs was returned to load, as the remainder was collected by CRR holders (primarily financial traders) purchasing undervalued CRRs through the auction.[58] Issues have included inefficient path allocations, poor price discovery in auctions and misalignments between CRR outcomes and actual grid conditions. The 2018 reform sought to improve outcomes by improving consistency between the CRR auctions and the day-ahead market (transmission outage reporting, network model constraint representation), limiting source/sink pairs to "delivery paths" and limiting CRR payouts when congestion charges collected across the specific CRR path are otherwise insufficient. After launch in 2019, these reforms reduced auctioned CRR volumes by two-thirds but improved the amount of congestion revenue returned to loads/customers.[59]

The CAISO DMM, as well as the former Chair of the CAISO Market Surveillance Committee, Frank Wolak, have proposed a "Willing Buyer, Willing Seller" concept to replace the CAISO's current

56 CAISO Market and Structure Development, *Catalogue of Market Design Initiatives June, 2009*, June 12, 2009.

57 CAISO, *Business Practice Manual for Congestion Revenue Rights*, Version 32, last revised November 18, 2025.

58 CAISO Department of Market Monitoring, *2016 Annual Report on Market Issues and Performance*, May 2017.

59 CAISO Department of Market Monitoring, *2022 Annual Report on Market Issues and Performance*, July 2023; CAISO, *CRR Market Analysis Report*, May 12, 2020, pp. 12–13.

CRR construct.[60] Wolak's model proposed a financial auction design with several features: a CRR transaction only clears if there is a willing counterparty (no ISO-supplied positions); net injections at each node in the network must be zero (so each CRR position is balanced by an offsetting one); there is no financial exposure for the ISO to the energy spot market; and there is a clearing mechanism that functions solely as a central counterparty. In this model, all CRRs would be backed by voluntary counterparties, and the ISO would solely serve as the clearinghouse and auction administrator, like conventional financial derivatives markets. The DMM's proposal adapts Wolak's concept to the CAISO's operational capabilities and constraints.

As of late 2025, the CAISO has not adopted the Willing Seller model, but it continues to receive support from the DMM, California Public Utilities Commission (CPUC) staff and LSEs. Other stakeholders, especially financial traders, oppose such structural reforms, arguing that the current auction shortcomings reflect broader market conditions rather than the fundamental design, and that financial participation supports liquidity and hedging value.[61]

The DMM-proposed Willing Seller framework would avoid many shortcomings of the conventional US-style FTR constructs. In their report, the DMM ran simulations on the profit margins of various categories of participants using the current design compared to the Willing Seller design. As shown in Figure 1 below, the current design showed high profitability for all parties except load participants, while the Willing Seller design showed modest profitability for financial participants, with losses for load and a tiny gain for generation. This illustrates the nature of the current design, which is that financial players can extract substantial rents from the ISO's sale positions. It also shows the contrast with the Willing Seller design, in which the sum of the net profits/losses across all categories is necessarily zero (with no net extraction of rents from the ISO).[62] That is, under the Willing Seller design, financial entities would no longer have access to purchase prevailing CRRs at below-market prices, as appears to occur today in US FTR markets. Instead, all CRR sales would be backed by the entity taking the counterflow position, without reverting to the congestion fund.

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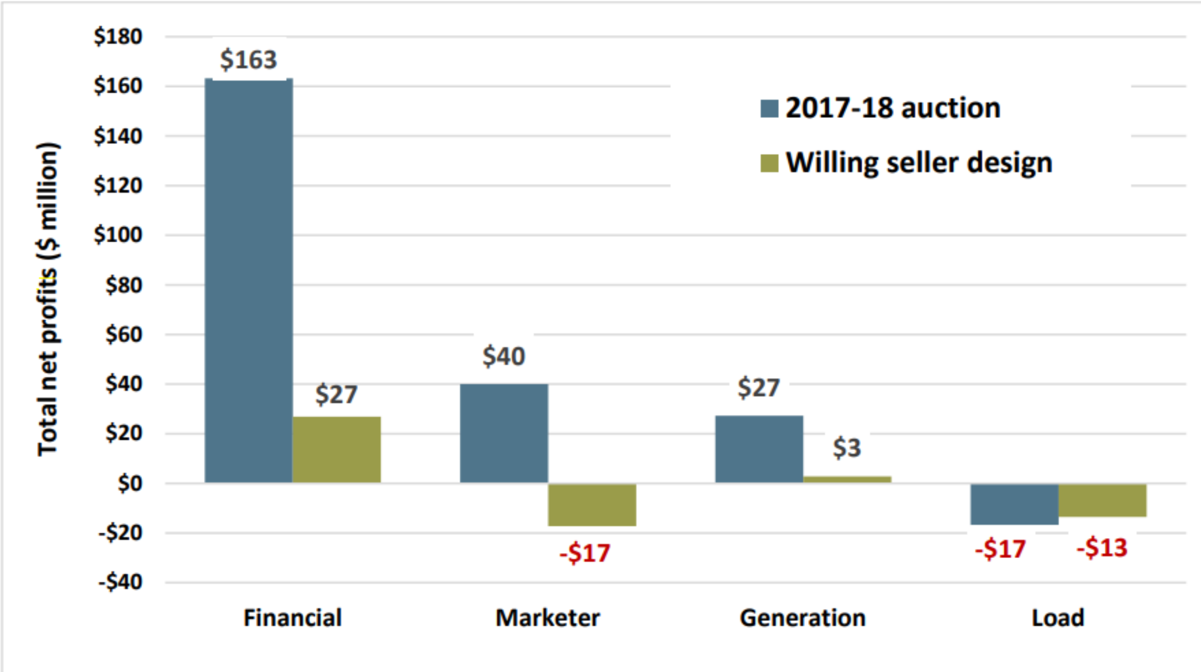
60 CAISO Department of Market Monitoring, *Willing seller market design for congestion revenue rights*, October 23, 2024.

61 CAISO Congestion Revenue Rights Enhancements Working Group, *Updated Discussion Paper*, December 3, 2025.

62 CAISO Department of Market Monitoring. *Willing seller market design for congestion revenue rights*. October 23, 2024. p. 17.

FIGURE 1. CRR PROFITS FOR FINANCIAL PARTICIPANTS SHOW EXCESS PROFITS IN CURRENT CAISO DESIGN RELATIVE TO PROPOSED WILLING SELLER DESIGN



Source: CAISO Department of Market Monitoring. *Willing seller market design for congestion revenue rights*. October 23, 2024. p. 17.

The Willing Seller design also does not suffer from underfunding issues (typically solved with backstop payments from load customers) or credit risk exposure (also backstopped by load or by all ISO members). The Willing Seller design therefore increases the portion of the congestion rent received by ratepayers.

The Willing Seller approach is likely to lead to less liquidity than existing FTR frameworks in the United States. The DMM analysis shows the total cleared CRR contracts would be approximately 40% lower if the Willing Seller approach was adopted.[63] The lower volume is driven by removing the CRR sale offers from the ISO (on behalf of ratepayers) across all paths and at any price. Instead, participants (especially financial players) would willingly choose to sell CRRs (i.e., take counterflow CRR positions) when they believe it is profitable. Withal, the DMM believes the volume in the CRR auction would be sufficient to support efficient hedging opportunities in the CAISO.[64] Because the ISO would not sell CRRs on behalf of loads, they would not be involuntarily exposed to credit risk, underfunding risk, or undervaluing dynamics which transfer congestion rent to other parties.

63 *Ibid.*

64 *Id.* p. 3.

Takeaways for Alberta	**Strengths**: • The DMM-proposed Willing Seller FTR (or, in CAISO terminology, CRR) exchange concept would avoid many shortcomings of the conventional US-style FTR construct, such as insufficient return of congestion rents to loads/customers, design complexity and administrative overhead, imposition of credit risk on loads/customers, and charges to loads/customers to backstop FTR contracts with insufficient congestion rent funding • Adequate liquidity would provide some congestion hedging opportunities to generator and load participants, albeit with some of the same definitional shortcomings as today (e.g., short terms and poorly suited hourly profiles) **Shortcomings**: • Liquidity is expected to be lower under a Willing Seller FTR design than under the CAISO status quo • The ISO still takes on some administrative burden

IV. Primary Design Elements and Choices

This section covers the primary design elements that an enduring FTR mechanism in Alberta should address. Each sub-section below discusses one design dimension and the options available, with pros and cons of each. We treat these design elements in an isolated manner in this section of the report as a means of clearly enumerating the possibilities, but note that in many cases these design choices are heavily interacting and should be selected in a cohesive way that aligns with the overall design intent (as is done in the following Section V).

A. FTR Market Administrator

The choice of FTR market administrator determines who manages trading, settlement, credit/collateral, and governance of any future congestion-hedging market in Alberta. In Table 5 below, we assess the advantages and disadvantages of the following market administrator options in detail. The options for FTR market administrator are:

- **AESO.** The independent system operator (AESO) would directly operate and settle the market, integrating it as needed with system operations and market settlements. Any net administrative costs or costs associated with net FTR positions taken on behalf of loads would be allocated to AESO market participants.
- **Crown-Mandated/Government Agency.** A provincially mandated organization would manage FTR issuance and trading. It could be tasked with offering long-term FTRs to support targeted objectives. To be effective, the agency would need to have a clear mandate for the purpose and scope of their activities (such as to support generator investments or to help manage costs and risks consumers). The agency would also need to be adequately resourced to assess FTR-related risks, and place limits on the scale of FTR cost and risk exposures to be contemplated. Administrative costs and costs of any net positions would either be funded through a government budget line item or assigned as a cost to the AESO (and from there, allocated to consumers or other market participants).
- **Private Exchange or Clearinghouse.** A market-based platform such as Intercontinental Exchange (ICE), Nodal Exchange, Nasdaq, or an EEX-type model would facilitate third-party trading. Trades would be cleared by the private exchange or clearinghouse, and the AESO's role would be limited to providing public data. Exchange-traded products are typically aligned with a small number of well-defined products that trade on a relatively short-term basis (e.g., daily or monthly). The exchange earns revenue primarily through a small transaction fee on each trade.
- **Broker Intermediaries.** Bilateral transactions between a willing buyer and seller would be arranged and sometimes settled through intermediate brokers that earn a commission from clients. Because the resulting bilateral contracts can be tailored to meet the needs of each pair

of counterparties, there can be wide variation in the contract term, nature of the contracted goods (profile, term, products procured), and assignment of risks. The format of broker intermediaries and forums can take on a spectrum of ranging from highly organized and structured (e.g., software-supported transactions for defined products and high volumes of trades) to a much more loosely organized format (e.g., bulletin board, phone calls useful for supporting smaller numbers of specialized transactions across fewer parties).

- To implement the first two options, Alberta would need to either expand the mandate of the AESO or create a new agency with this mandate.

The private exchange or clearinghouse option offers an avenue for supporting hedge trading, but through a self-funded private market where default risks are managed through the private exchange (protecting taxpayers/ratepayers from unwanted risk). If a commodity is in great demand for hedging purposes, private exchanges may develop independently even without government action (though if none materializes independently, it is possible that the AESO could partner with the private administrator initially to streamline the implementation process).

TABLE 5: FTR ADMINISTRATOR MARKET DESIGN ELEMENT OPTIONS

Design Feature	Pros	Cons
AESO	• AESO is a trusted and impartial entity • AESO has the necessary system data (network models, congestion forecasts) to successfully administer auction clearing and pricing of FTRs (particularly if the FTR mechanism requires detailed representation of the power grid) • Could ensure alignment of physical grid realities with targeted objectives • Existing governance and settlement processes with physical market participants anticipated to participate • Government can dictate the creation of the FTR mechanism and set rules aligned with the design goals	• Adds administrative burden to AESO • Some FTR mechanisms introduce net costs or risks that require cost allocation or assignment of default risks • AESO would need to add new capabilities (auction platform, enhanced credit management practices to address fat tail risks of FTRs) • If AESO is tasked with administering an FTR mechanism aimed at serving the needs of a subset of stakeholders, it may introduce tensions with other stakeholders. • Allows for what could effectively be a government subsidy which could undermine market discipline and efficiency • The AESO (and ratepayers or taxpayers by extension) would carry the financial risk of the FTRs it issues (both position risk and default risk)
Crown-Mandated/ Government Entity	• Similar to AESO-run pros, plus • Mandate of new entity can differ from mandate of the AESO (e.g., if the FTRs are to fulfill a targeted objective such as providing long-term investment hedges to new resources)	• Same as AESO-run cons, plus: • Less likely to have full access to system data and existing capabilities compared to the AESO

Design Feature	Pros	Cons
Private Exchange or Clearinghouse	• Would harness market-based expertise from entities that specialize in markets and managing financial risk • Allows AESO to remain neutral and avoid conflicts • FTR position and default risks are isolated to voluntary participants in the exchange (no mechanism to offload these risks to other market participants or taxpayers)	• No guarantee of liquidity and participant demand • Rules set by private exchange, not Alberta government (no avenue to set rules to prioritize Alberta-specific targeted objectives)
Broker Intermediaries	• Allows AESO to remain neutral and avoid conflicts • More amenable to mid- and long-term hedges than anonymized trades • Contracts can start in a standard format, but can be customized into a bespoke format that meets the specific situations of a pair of counterparties	• Participants exposed to individual counterparty risks (not pooled through an exchange) • Higher transaction costs compared to the other options (to find a counterparty and customize a transaction) • Low transparency in pricing, volumes, and contract format

B. Exchange or Auction Format

The exchange format for the FTRs determines how buyers and sellers can participate in the market or otherwise obtain FTR positions. This aspect of market design is related to the question of market administrator (prior section), because the choice of administrator may make the mechanism much more amenable to different platforms for supporting trade. Auction format will also have implications for the liquidity in the market and the information available to the market participants before and after positions are taken.

- **Application-Based:** Potential FTR buyers can submit applications to the market administrator (which would need to be AESO or another government entity) for an FTR. Generally, these applications would only be granted if the applicant has a physical interest in the FTR (e.g., a generator selling power through the line), and if the applicant qualifies under other criteria set out under the FTR mechanism design (particularly if the FTR is a net subsidy to successful applicants). The applicant would be quoted an up-front price for a long-term FTR by the government agency, which (if accepted) would guarantee a fixed congestion fee over the commitment duration. An application-based allocations process implies that the applicant gains a prevailing flow FTR, while the government agency acts as the seller/guarantor of the position (which may ultimately be backed by consumers via the congestion fund).
- **FTR Allocations:** FTRs can initially be allocated before any trading to those who have paid for the transmission system, similar to the design in many US ISOs. In Alberta's case, the transmission owners are not expected to be participants in the FTR markets, and the cost of the transmission is passed onto consumers, so initial FTRs on a path could be passed on to retailers or otherwise managed on behalf of consumers. The allocation framework can work

in conjunction with another trading mechanism described below (e.g., an allocation together with a centralized auction), but it does not need to.

- **Centralized Auctions.** The AESO or another impartial entity can administer monthly and/or annual auctions for FTRs, similar to FTR auctions in the United States.[65] The auction would be for the sale of standardized products. The auctions can be structured either: (a) on a Willing Buyer, Willing Seller basis (i.e., enabling trade amongst voluntary participants, with prices set at the intersection of supply and demand, and no net volumes taken on by the AESO); or (b) can be structured as a net sale of FTR positions (i.e., FTRs can be auctioned as a net sale as in the US FTR auctions, where FTRs are sold to the highest bidder, with customers effectively taking the other side of the FTR sale, backed by the congestion fund). In the latter case, the market administrator can set the appropriate reservation prices on each FTR path to account for the incremental risk taken on by consumers.[66]
- **Exchange-Based Continuous Trading.** Bilateral trading can be made available continuously through a centralized exchange (administered by an entity like ICE or Nasdaq). For each trade, there would need to be a willing buyer (taking the prevailing flow position) and a willing seller (taking the counterflow position). Prevailing prices and volumes would be continuously updated, with prices set at the intersection of supply and demand.
- **Bespoke Transactions via Broker or Bulletin Board.** Willing buyers and sellers could complete trades through a broker intermediary or a bulletin-board approach. The product offerings could be customized to the needs of the willing buyers and sellers.

We assess the following five options for the exchange format in Table 6 below.

[65] See Section III.C above.

[66] There are no reservation prices in US-style FTR auctions. However, this leads to traders being able to purchase FTRs for a very low price coming at the expense of consumers.

TABLE 6: EXCHANGE/AUCTION FORMAT MARKET DESIGN ELEMENT OPTIONS

Design Feature	Pros	Cons
Application-Based	• Provides opportunities for a government agency to strategically grant FTRs to support targeted objectives or investment decisions • Can support node-specific and bespoke profile positions	• Limited liquidity and access to FTR positions • Administrative burden for market administrator to accept applications and meaningfully assess prices • Risk of under- or over-valuing the FTR • Risk of over-committing FTR MW volumes • If backed by congestion fund, consumers absorb fat tail and payout risks
FTR Allocations	• Aligns initial FTR positions with parties who paid for the transmission • Can be amenable to different types of trading opportunities • Can support node-specific positions	• Without other trading components (e.g., auctions or bilateral trading), the FTRs may have limited beneficial effect on new generation development and hedging for some participants
Centralized Auctions (Willing Buyer, Willing Seller)	• Willing Buyer, Willing Seller format ensures the auctions are value creating (no fat tail risks shifted to customers, no subsidies) • Centralized approach supports larger and more transparent liquidity events • Strong opportunity for robust monitoring and mitigation • Can support node-specific positions	• Adds administrative burden to market administrator (manage auctions, manage credit risk) • Lack of natural seller of FTR positions may result in low liquidity or high prices to secure FTRs
Centralized Auctions (net sale of FTR positions)	• Centralized approach supports larger and more transparent liquidity events • Strong opportunity for robust monitoring and mitigation • High liquidity (since AESO or consumers are taking a net sale position) • Can support node-specific positions	• Risk of under-valuing FTR positions (creating inefficiencies, net subsidies, and shifting excess risks to consumers) • Adds administrative burden to market administrator (manage auctions, manage credit risk)
Exchange-Based Continuous Trading	• Willing Buyer, Willing Seller format ensures the auctions are value creating (no fat tail risks shifted to customers, no subsidies) • Enables real-time trading and continuous information updates	• Lack of natural seller of FTR positions may result in low liquidity or high prices to secure FTRs Likely to support a relatively small number of defined products (not nodal or resource-specific)
Decentralized Bilateral Trading	• Willing Buyer, Willing Seller format ensures the auctions are value creating (no fat tail risks shifted to customers, no subsidies) • Can enable long-term or customized hedges • Could be AESO-enabled or purely market-driven via brokers	• Lack of natural seller of FTR positions may result in low liquidity or high prices to secure FTRs

C. FTR Buyers

For the purpose of this report, we define FTR "buyers" as the entities taking the prevailing flow FTR position that is in the direction of positive price differential from a lower-price to higher-price location. The scope of eligible buyers for the FTR market may include market participants with a physical tie to the FTRs and/or financial entities who can profit from trading opportunities. We explore three types of buyers for the FTR market and the implications for the broader FTR market for each buyer category in Table 7 below:

- **Physical Voluntary Buyers:** The natural buyers of FTRs are entities who have physical exposure to the congestion on a transmission line. Usually this includes generators who sell power to consumers on the opposite end of the path of the FTR. In some cases, it may also include large consumers who have a contract with a generator and thus are exposed to congestion risk over the path when purchasing that power in real time. Absent an FTR position, either the generator or the load would need to take exposure to the congestion risk (or split the congestion risk via contract terms). If one of these parties purchases an FTR, they can offloads congestion risk to a third-party FTR seller.
- **Government Agency Purchasing on Behalf of Consumers:** An Alberta government agency could purchase FTRs on behalf of consumers. This category likely does not make sense in the Alberta context, considering that loads will already be largely protected (at least on a system-wide basis) from congestion risks by settlements via the ALP and return of congestion rents.
- **Financial Entities:** Purely financial entities (traders) may have interest in purchasing prevailing FTRs if they see profit opportunities. In the United States markets, traders can and do purchase prevailing FTRs in the auctions. However, if financial parties with no physical need to hedge prevailing flow congestion risks are consistently and profitably participating as buyers, this signals the risk that the FTR market may not be operating as intended (i.e., the possibility that financial entities take an outsized share of the congestion rent pool at the expense of consumers without taking on significant risk.) A more natural role for financial entities is to absorb risks from physical players to ensure that their participation is value-creating rather than value-extracting.

Overall, the primary buyers in the FTR market should be voluntary buyers who have a physical interest in reducing congestion risk on transmission lines. This may include either generators who physically deliver to consumers over the prevailing flow of the line or in some cases consumers who have contracted with a generator over a line.

TABLE 7: COMPARISON OF ELIGIBLE BUYERS IN THE FTR MARKET

Design Feature	Pros	Cons
Physical Voluntary Buyers	• Buyers can hedge risk through FTRs, leading to more efficient market outcomes • May be used to secure financing for new generation projects	• Potential to send the wrong incentives for physical investment if long-term FTR contracts are subsidized • Liquidity is lower if only physical voluntary buyers are eligible
Government Agency Purchasing on Behalf of Consumers	• Allows consumers to hedge risk (if congestion fund isn't otherwise returned to them)	• Likely not necessary or relevant in Alberta's context
Financial Entities	• Increases liquidity • Theoretically may lead to more efficient pricing outcomes (as long as no other design or pricing flaws exist)	• In practice, profit opportunities for financial firms to buy FTRs might come at the expense of consumers (particularly if they participate primarily as buyers of prevailing flow positions) • Competition with physical voluntary buyers who need FTRs to hedge risk can increase prices, may be perceived as undesirable

D. FTR Sellers

Sellers in the FTR market are parties willing to take the counterflow position on FTR paths from higher-price to lower-price locations. These positions absorb congestion risk (i.e. they are paid up front but must take on the fat tail risks associated with the possibility that congestion costs become large). We assess the following potential sellers and the implications of each seller type for the broader FTR market in Table 8 below.

- **Physical Transmission Rights Holder.** The logical party to take the counterflow position for FTRs would be the physical firm transmission rights holder, as they would be physically capable of delivering the power on the line, thus giving rise to potential congestion rent to back the FTR. However, internally within Alberta there are no firm physical transmission rights and thus this is not an option.
- **Government Agency, with Positions Backed by Consumers via the Congestion Fund.** Since there are no physical transmission rights holders in Alberta, the next closest natural seller would be consumers backed by the congestion fund. A government agency acting on behalf of consumers could choose to sell FTRs in the marketplace, taking on risk in exchange for compensation from buyers. If Alberta pursues this approach, it is important that the government agency sets efficient reservations prices for the FTRs being sold. In US markets, there is often no reservation price in auctions of FTRs on behalf of load. This leads to opportunities for undervalued FTRs such that customers take on risk for too little financial gain. The agency responsible for selling FTRs on behalf of consumers would need to have a sophisticated approach to setting reservation prices that account for the expected congestion level of the FTRs being put up for sale, including the risk of lower-than-expected congestion

rents (e.g., due to an unplanned generator outage). A government agency could also choose to sell or allocate FTRs for policy reasons.

- **Financial Entity Absorbing Risk for Pay.** Financial entities like traders can play a key role in agreeing to take the counterflow position (creating value for physical players that are willing to pay a premium to offload this risk). These financial entities can have a higher risk tolerance than other FTR market participants and thus would be able to set sophisticated reservation prices to ensure their losses remain limited in the aggregate.
- **Load Entity Selling Unwanted FTRs.** This option is less relevant in Alberta than in the US markets, since we anticipate that consumers will be allocated congestion rents directly (rather than indirectly through FTR allocations). However, if consumers are allocated FTRs, some may wish to sell them if they do not match their risk management needs. For example, if nodally settled controllable loads were issued FTRs that sink at the ALP (i.e., effectively sinking at load nodes across the province), they may sell FTRs corresponding to load nodes they are not settled on in the energy market.

In Alberta's context, the relevant sellers of the FTRs are either financial entities absorbing risk from physical players, and (possibly) also the AESO or another government agency. If a government agency takes this role, any positions it offers should be grounded in targeted goals with the reservation price commensurate with the risk being taken on behalf of consumers.

TABLE 8: COMPARISON OF ELIGIBLE SELLER OPTIONS IN THE FTR MARKET

Design Feature	Pros	Cons
Physical Transmission Rights Holder	• Natural party to take the counterflow position	• Not possible in Alberta
Government Agency, with Positions Backed by Consumers via the Congestion Fund	• Potential for FTRs to be used to assist in realizing targeted objectives • May increase liquidity in the market	• Shifts congestion risk to ratepayers/taxpayers • Adds administrative burden to government agency (specifically to set the reservation prices for counterflow positions) • Supply of FTRs for targeted objectives may erode market incentives (particularly if awarded FTRs are underpriced and hence act as a subsidy)
Financial Entity Absorbing Risk for Pay	• Shifts congestion risk to financial entities • May allow for more efficient pricing outcomes	• May not be sufficient liquidity (or high prices) if financial entities are hesitant to take on risk
Load Customer Selling Unwanted FTRs	• Allows load customers to reconfigure risk management as needed, providing revenue and enhancing risk profile for buyer	• Less likely to be relevant in Alberta (unless FTRs are allocated to load entities, rather than directly allocating congestion rents)

E. Relationship to Congestion Rents

The relationship to congestion rents is fundamental to the structure of an FTR market. Congestion rents should arguably be returned to the party that paid for the transmission lines that enabled the congestion rent to be collected (i.e., transmission ratepayers). However, the process by which congestion rent gets allocated back to consumers varies and is not always clear or comprehensive. We explore the advantages and disadvantages of three options in Table 9 below.

- **Congestion Fund[67] is Distributed Directly to Transmission Ratepayers.** This option would directly allocate congestion rents to consumers and others that paid to build transmission infrastructure (accomplished via an offset to customer bills or contribution to transmission charges). We understand that this is the eventual plan for congestion rents in Alberta (though this will not be accomplished until legacy arrangements that compensate existing generators in transition are expired). This option aligns with the economic principle that the entities that have paid to build transmission should have the right to the economic benefits created by its use (by either using the transmission directly, or profiting from its most valuable use). This option provides a transparent and straightforward way to achieve that goal. In this approach, there would be no relationship between the FTR auction and congestion rents, and the latter would be distributed back to customers through offsets to their bills.
- **Congestion Fund Backs FTR Sales.** In this approach and the next, FTR payouts are backed by the congestion fund. In return, parties that otherwise would have rights to the congestion fund are allocated a share of the revenues from the FTR auction. In this variant, FTR auction revenues plus additional proceeds from the congestion fund (from paths in which FTRs are not purchased) are distributed to all transmission ratepayers ex-post on a proportional basis based on total annual energy consumption.
- **Congestion Fund Allocated to Consumers Who Are Specifically Exposed.** Like the preceding approach, this one also backs FTR payouts from the congestion fund. However, in this variant there is an additional mechanism to award FTRs (or the congestion rent equivalent of a particular FTR path) to specific consumers that have exposure to a particular path or portfolio. Some loads may have a unique congestion exposure, for example if they opt in to LMP in a load pocket, or if they are exposed through contracts or self-supply from specific generators. To accomplish a load-specific congestion rent or FTR allocation equitably, there would need to be specific criteria for determining which of the consumer entities can apply, while ensuring that other transmission ratepayers are adequately and equitably protected and compensated for the transfer.

Distributing the congestion fund directly to consumers provides the simplest way to protect the financial interest of consumers and their stake in congestion rents. It is a transparent method

[67] We use the terms congestion fund and congestion rents nearly synonymously in this paper, but as a minor distinction, we tend to use "congestion rent" to refer to the portion of congestion charges that arise across a particular path or transmission line and tend to refer to the "congestion fund" as the total quantity of net congestion rents summed across the footprint over a particular period.

that avoids the pitfalls of FTR markets in the United States where customers bear the cost of transmission, but financial entities accrue a significant share of the benefits of that transmission.

TABLE 9: COMPARISON OF CONGESTION RENT DISTRIBUION OPTIONS

Design Feature	Pros	Cons
Congestion Fund Distributed Directly to Transmission Ratepayers	• Simple and transparent • Allows for loads and others who pay for physical transmission lines to be compensated for the congestion value they create	• Hedging backed by the congestion fund is not available to generators exposed to congestion risk • Loads with unique congestion exposure do not have a means to hedge in a customized way
Congestion Fund Backs FTR Sales	• Allows for (most) of the congestion fund to allocated to transmission ratepayers (mainly via FTR auction revenues) • Provides opportunities for more entities to hedge congestion risk and boost FTR market liquidity	• Administratively complex • A similar approach used in US markets has led to consumers receiving a smaller portion of the congestion rent than anticipated (a substantial portion being captured as profits by FTR traders) • Tail risks of counterflow FTR payouts shifted to loads (via congestion fund)
Congestion Fund Allocated to Consumers who are Specifically Exposed to Congestion	• Avenue to align a portion of congestion fund disbursement (or FTR allocation) to consumers that have unique exposure to congestion risk (e.g., those that opt in to LMP in a load pocket)	• Administratively complex • Risk of inequitable treatment via allocations process

F. Product Definition

Existing FTR markets primarily include standard product offerings. However, it is feasible to introduce bespoke offerings more aligned to the needs of buyers. We examine three types of product offerings in Table 10 below.

- **Standard products.** Includes on-peak, off-peak, or 24×7 profiles. These definitions are aligned with standard energy market commodity futures, which allow market participants the flexibility to pursue more complete hedges (e.g., an energy future at the more liquid system hub plus an FTR from generation zone to system hub provides a strong hedge within the generation zone.) This type of FTR is currently used in US FTR markets. The buyer of the FTR gets a hedge on congestion over the path, but the hedge they purchase is not specific to their load or generation profile. It is also possible to define "standard" products in ways that have a more complex profile (e.g., aligned with a standard wind or solar profile), an idea that has been proposed but not previously implemented in the context of standard FTR product trades.
- **Bespoke Positions.** If the transfer of FTRs is done bilaterally between a willing buyer and a willing seller, the profile of the FTR can be customized to align with the buyer's needs. For example, a renewable generator could purchase an FTR based on the daily shape of their renewable generation profile provided there is a willing counterparty to take the counterflow position. This type of FTR product has not been implemented at scale, but it is theoretically

feasible and could be a more effective method to hedge risk for generators or consumers with predictable load or generation patterns.

- **FTR Options.** The product offerings described in this section are FTR obligations, in which any FTR holder must pay out in case congestion price differentials occur in the counterflow direction. An alternative product design is an FTR option, in which buyers receive only positive payouts for a path.[68] The reservation price of options should naturally be higher than obligations since the options have no downside risk. Similarly, the cost and tail risks associated with selling an FTR option are also much higher. FTR options can be significantly more valuable than FTR obligation, depending on circumstances, as follows. Internally within Alberta, we anticipate that most paths will have a clear directionality in that the direction of congestion differentials will be known in advance (i.e., gen pockets will always have lower prices than the system and the system always lower than load pockets). However, interties illustrate a different situation, in which the directionality of price differentials may switch frequently throughout the day, month, season, or year. On a path with switching directionality of congestion, an FTR obligation will frequently switch from a prevailing flow to counterflow position (so one cannot know in advance if the FTR purchaser will owe money or be owed money once settlements are due). In this situation, an FTR option is a much more valuable product, since the FTR option can only return a payout to the prevailing flow FTR purchaser (payouts are made in energy market intervals with a positive payout, but zeroed out whenever the payout would be negative). One simplifying feature of FTR options is that the seller is not exposed to default risk (since in no circumstance does the buyer need to pay).

Standard product offerings are preferable to allow for sufficient liquidity in the market. While the standard products do not align precisely with the hedging need of physical buyers, they still provide adequate congestion risk mitigation. Depending on other design options, the broker-facilitated exchange of bespoke products may be beneficial to enhance efficiencies and meet the specified needs of the buyers and the sellers.

[68] FTR options exist in some US FTR markets including ERCOT and PJM.

TABLE 10: FTR PRODUCT DEFINITION OPTIONS

Design Feature	Pros	Cons
Standard Products	• Significantly more liquid than other products offerings • Provides reasonable hedge for those exposed to congestion	• Potentially less effective than bespoke offerings to meeting individual participants' needs
Bespoke Positions	• Customized to the buyer's needs in an individualized negotiation • More effective risk hedge relative to standard products	• Higher administrative burden and transaction costs than standard products • Less liquid (concern can be mitigated if introduced in conjunction with standard products) • Harder to set a reservation price
FTR Options	• Best and most valuable hedge for buyers if the flow direction on a path is uncertain (most potential buyers will only need the congestion hedge on one direction of the path, and wish to avoid counterflow risk) • Seller does not face default risk from buyer (particularly useful if ISO is the primary or sole seller)	• Higher price and tail risk for seller (compared to FTR obligations) • Even fewer financial or other counterparties willing to take on risk of selling FTR options

G. Term

An FTR provides a hedge against congestion over a specified period of time, the term of the FTR. In some cases, the buyer of an FTR would prefer a short-term hedge (e.g., daily or monthly positions), while in other cases they may desire a longer-term hedge (e.g., a multi-year timeframe relevant to investment hedging). Table 11 below explains the advantages and disadvantages of these two types of FTRs.

- **Short-Term.** May include daily, monthly, or annual hedges of less than 3 years. Congestion patterns are determined by the makeup of the power system at a certain point in time. Short-term FTRs are likely to provide more informed pricing signals since the configuration of the power system can be meaningfully predicted during the term of the FTR. There is still risk in the pricing of short-term FTRs driven by extraordinary unplanned outages of generators or transmission lines, fuel price shocks, or extreme weather conditions.
- **Long-Term.** Includes FTRs of a length of 3+ years (longer than currently available in US-style FTR constructs). Longer-term hedges could potentially be used by generators to support financing for new projects. However, the risk to the seller is higher as congestion patterns can be extremely unpredictable in the future, which makes the costs and risks of offering these hedges very high.

Shorter term FTRs should be offered as the foundation to the FTR market. If there is a continuing need for longer-term FTRs over time, they may be offered in addition to shorter-term FTRs.

TABLE 11: COMPARISON OF FTR TERM OPTIONS

Design Feature	Pros	Cons
Short-Term	• More accurate pricing based on nearer-term information • Higher liquidity in the market	• Not always aligned with the needs of the buyer • Limited support for managing congestion risk for investors in new generation
Long-Term	• Creates opportunities for generators to secure hedging at a timeframe that may support financing for new projects	• Difficult to calculate the long-term congestion risk and to set an appropriate price for taking on the tail risk of a counterflow FTR over a period of many years (true whether the hedge is offered by a government or financial entity) • Lower liquidity

H. Locational Granularity

The locational granularity of an FTR product refers to the geographic scope of the price differentials included in the FTR compensation (i.e., nodal vs. zonal). Table 12 below shows the advantages and disadvantages of the locational granularity options.

- **Nodal.** FTRs cover the source to sink of a path based on the price differential between individual pricing nodes (i.e., individual buses or aggregate nodes such as zones or hubs). Provides the locational granularity necessary to fully cover the congestion of a generator selling power to consumers in a nodal LMP market.
- **Zonal.** FTRs cover the price differential between zonal or hub prices, rather than the congestion for a specific path. This approach can be suitable for consumers that are not exposed to nodal congestion, and (depending on zone definition) can cover most congestion risk mitigation needs for nodally settled participants.
- **Interties.** As in the Ontario approach to TRs, transmission rights (physical, financial, or some combination) can apply specifically across interties. If FTRs or a related instrument are created relevant to intertie transactions, it would likely be in the context of other energy market or intertie trading reforms aimed at improving the overall efficiency of intertie schedules.

Nodal FTRs should be adopted to align outcomes with Alberta’s upcoming LMP pricing. Zonal FTRs may be offered as simplified products for liquidity, but the lesser granularity leads to lower alignment with the hedging needs of entities with physical exposure to congestion.

TABLE 12: COMPARISON OF LOCATIONAL GRANULARITY OPTIONS

Design Feature	Pros	Cons
Nodal	• Provides more precise hedging opportunities which are likely to be more sought after by buyers with physical congestion exposure	• Complex, with greater administrative burden • Likely to reduce liquidity since innumerable individualized paths dilute trading interest
Zonal	• Simple and more liquid • Easier to monitor the market	• Less precise (and likely less aligned with needs of physical buyers)
Interties	• Simple and more liquid • Can be customized to support specific needs for intertie scheduling and congestion hedging (example in Ontario)	• No coverage for intra-provincial congestion risks

I. Assignment of Default Risk

An FTR market design that can require payouts from FTR holders has the potential for a participant default. This is a particular concern for entities taking the counterflow position, which can be subject to large fat tail risks that can be up to an order of magnitude larger than an expected average payout in the event of acute congestion outcomes. If entities (and collateral requirements) fail to effectively manage their risk and extraordinarily high-congestion market conditions develop (e.g., due to extreme weather events or grid outages), there is the potential that an FTR holder is unable to pay its obligations. Credit screening and collateral requirements should be included in any centrally cleared FTR market design in order to limit the likelihood of defaults. However, the risky nature of the prevailing flow position means that some defaults will happen. To manage that possibility, the FTR market (like all ISO and commodity markets) must have clear rules about which party takes on the risk of a default, for which we describe options in Table 13 below. The options are:

- **Bilateral Counterparty:** A simple assignment of default risk would be to the bilateral counterparty in the transaction of the defaulting party. For example, if the entity taking the counterflow position on the bilateral transaction defaults, the entity on the other side of the transaction (taking the prevailing flow) would not be paid for all the congestion that occurs on the path of the FTR in question.
- **All AESO Market Participants.** In this option, if an individual entity with FTR positions defaults, the costs of uncollected settlements would be socialized across all AESO market participants (e.g., consumers and generators), regardless of the products or services in which they participate. Many ISO prudential requirements are structured in this way, with default costs levied in proportion to the dollar size or MW size of each participant's funding share. This approach has been greatly criticized in the past (e.g., in the aftermath of the PJM Greenhat

default),[69] since the costs of the risky positions are then socialized to other participants that have not benefitted from those positions nor participated in the FTR markets at all.

- **FTR Auction / FTR Market Participants:** Alternatively, the default risk could be spread across only the subset of market participants participating in the FTR market (one of the recommendations of the PJM market monitor). If one entity were unable to fund their position, the funding shortage would be socialized across all buyers and sellers in the FTR market, again, in proportion to position size (measured in dollar or MW terms). If the FTR market and associated credit requirements are operated by a private entity (not the AESO or other agency), then default risk would be naturally pooled among voluntary participants in that market.
- **FTR Product Design with Less or No Default Risk.** Some variations of FTR or congestion allocation design carry far less or even no default risk. For example, if voluntary FTR positions are limited to expected prevailing flow positions, backed by the congestion fund (counterflow position), and the payouts are limited to the congested funds collected, this would lessen the avenue for large market participant defaults. Or, offering only FTR options (vs. FTR obligations) would moot the risk of default, since payouts can only be positive.

The assignment of default risk depends on the other market design options. Socializing the default risk to all AESO market participants should be avoided since it shifts additional risk to consumers, taxpayers and/or other market participants without any compensation. Under all options, the credit requirements should fully consider the scale of fat tail counterflow position risks. We would recommend incorporating design elements that manage exposure to the maximum possible size of these default risks and that limit default risk exposure on the part of other market participants.

69 *GreenHat Energy, LLC*, 175 FERC ¶ 61,138 (2021)

TABLE 13: COMPARISON OF DEFAULT RISK ASSIGNMENT OPTIONS

Design Feature	Pros	Cons
Bilateral Counterparty	• Defaults are handled within the deal, across two willing counterparties • No additional parties are subject to risk without compensation	• No system-wide safeguards (each individual transaction comes with higher counterparty risk) • Credit screening is individualized and credit risk is not pooled, increasing transaction costs
All AESO Market Participants	• Can guarantee settlement certainty, especially for long-term hedges • Risk is spread out over a larger number of participants	• Socializes risk to ratepayers, taxpayers or other market participants without compensation or commensurate benefits
FTR Market Participants	• Maintains default risk to the subset of the market participants engaging in FTR positions (who presumably see sufficient benefits to continue participating)	• Smaller number of market participants can be left covering large shortfalls • Default risk may be priced into willingness to pay for FTR positions, adding a higher risk premium or transaction costs to all FTR prices
FTR Product Design with Less or No Default Risk	• Eliminates (or greatly reduces) default risk	• Limits scope of design options (particularly, limiting or reducing the role of private entities providing counterflow FTR positions) • If participants are limited in ability to sell counterflow positions, primary option remaining is to put the AESO/consumers in the role of selling them (and absorbing the associated fat tail risk via the congestion fund)

V. Alternative Models for Alberta’s Enduring FTR Mechanism

To support upcoming discussions amongst the AESO and stakeholders, we developed a suite of potential models for a potential enduring FTR mechanism. Table 14 summarizes the design elements included in each of these mechanisms, with each variant developed to form a cohesive overall structure and to align with a specific concept or design goal. For example, Options 4A and 4B are specifically crafted with the idea of articulating a “wish list” of components that would serve the aims of new generators (4A) or consumers (4B), respectively, while the hybrid model (4C) articulates a balance. Each of these options has a number of specific design elements that can be further customized, but collectively the range of options substantiate the possibility space and trade-offs that can be considered.

TABLE 14: DESIGN ELEMENTS OF ALTERNATIVE FTR MODELS

	1. No FTRs	2. US-Style FTRs	3. Willing Buyer, Willing Seller			4. Mandate-Driven FTRs		
			3A. AESO-Run	3B. Exchange-Traded	3C. Broker-Facilitated	4A. Generator-Driven	4B. Consumer-Driven	4C. Hybrid Model
FTR Market Administrator	None	AESO	AESO	Private exchange (e.g. ICE, EEX)	Individual brokers	Crown corp. or gov. agency	Crown. corp. or gov. agency	Crown corp. or gov. agency
Exchange or Auction Format	None (unless private parties voluntarily create an exchange)	Initial allocation (ARR) + monthly/annual auctions	Monthly/ annual auctions	Continuous trading	Bilateral contracts	Interconnecting generator application (e.g. loan guarantee)	Monthly/ annual auctions (to purchase hedges for loads)	Monthly Auction (to sell hedges to gen, above reservation price)
FTR Buyers	n/a	Voluntary FTR buyers (can be gen, load or financial entities)	Voluntary buyers (mainly generators)	Voluntary buyers (mainly generators)	Broker clients (voluntary, mainly generators)	Generators (at time of new resource investment)	Crown corp buys hedges for load; some loads voluntarily buy	Voluntary buyers (mainly generators)
FTR Sellers/ Counterparties	n/a	AESO/loads (mandatory, backed by congestion fund)	Voluntary sellers (mainly financial entities)	Voluntary sellers (mainly financial entities)	Broker clients (voluntary, mainly financial)	Crown corp./loads (mandatory)	Financial entities	Crown corp./loads (mandatory)
Relationship to Congestion Rents	Congestion rents returned to loads	Congestion fund backs FTR sales/payouts	Congestion rents returned to loads	Congestion rents returned to loads	Congestion rents returned to loads	A portion of congestion fund backs FTR sales/payouts	Congestion rents returned to loads	A portion of congestion fund backs FTR sales/payouts
Product Definition	n/a (or bespoke bilateral agreements)	Standard (on-peak, off-peak, 24×7)	Standard (on-peak, off-peak, 24×7)	Standard (on-peak, off-peak, 24×7)	Bespoke (defined by resource node & anticipated profile)	Bespoke (defined by resource node & anticipated profile)	Proportional to load profile	Standard (on-peak, off-peak, 24×7)
Term	n/a	Monthly, annual (<3 years)	Monthly, annual (<3 years)	Monthly (<3 years)	Long term	Long-term	Short term	Mid-term
Locational Granularity	n/a	Nodal	Nodal	Zone hub to system	Nodal	Nodal	System to load hubs	Zonal gen hub to system
Risk Shifting Enabled by FTRs	No risk is shifted (remains based on LMP exposure)	From FTR holders (including financial entities) to loads	From physical to financial entities	From physical to financial entities	From physical to financial entities	From generators to loads	From loads to financial entities (if net FTRs are purchased)	From generators to loads
Assignment of Default Risk	No default risk	Other FTR market participants	Other FTR market participants	Exchange participants	Bilateral counterparty	No default risk (but FTR payouts limited to congestion rent)	Loads	No default risk (but FTR payouts limited to congestion rent)

A. Option 1: No FTRs

The simplest option would be to proceed with REM implementation with no FTR market. Under this option, the focus would be on the transition to the REM and the various components of the optimal transmission policy, including LMP, OTP, TRP, and mechanisms to manage incumbent transition. The AESO's implementation of LMP would focus on transparency in historical data, drivers of locational pricing and congestion risks, and information to help private entities privately manage and predict future congestion via transmission planning and interconnection processes. Over time, market participants would become more familiar with these components of the new transmission and congestion regime and may determine that private means of managing congestion risk are sufficient to meet most hedging needs. The transparent and available data could also make it possible for third-party exchanges and private hedging to develop independently (see further discussion under Option 3 variants below). Finally, the No FTRs option is more accurately described as a deferral rather than a permanent decision, since the AESO and stakeholders could always update the REM design to implement an FTR market or other congestion hedging mechanism in the future after gaining a few years of experience to more clearly articulate market participants' needs under the new regime.

From a consumer perspective, the No FTR option may be the most attractive model, as long as the design intent continues to be that the congestion fund will be returned to loads (e.g., as a bill offset or as a deduction to transmission charges). This is similar to the Ontario transition to LMP, which also introduced load settlement based on a system-wide price (also offset by a bill deduction from congestion rents). In Alberta, consumers as a group are partially exposed to the costs of congestion via the system-wide ALP (aggregated from individual load LMPs), but the congestion rent refund will naturally offset congestion-driven load charges on a system-wide basis. For this reason, Alberta consumers will be relatively more protected from congestion risk compared to consumers in US ISOs. However, a subset of customers will be individually exposed to congestion rents, via their contractual and self-supply arrangements with generators. For these individually exposed customers, the No FTR option does not offer an ISO-administered hedging mechanism.

From the generator perspective, the No FTR option is less attractive because there is not a readily available financial congestion hedging market. Generators would still have physical means for hedging congestion risk, such as by developing supply in locations that have more exposure to upside congestion risk (and less exposure to downside risk); adding storage to an existing or new project; or co-locating with demand. Requiring generators to consider physical means of addressing LMP risks offers efficiency benefits on a system-wide basis, since the efficient pricing signal will encourage investments in more cost-effective technologies and locations. Generators can also seek out financial entities that may be willing to take on some of the congestion risks through bilaterally negotiated arrangements, but the generator would only follow through on such an arrangement if the cost of the financial hedge is lower than the cost of a physical hedge. The downside for generators is that, while bilateral arrangements for hedging may be available, they would not be available through a liquid or transparent hedging market, and transaction costs of these bespoke arrangements would be higher than in the other models.

Overall, the No FTR option creates a baseline or starting point that should be expected to produce a reasonably strong value proposition for customers and efficient locational pricing signals for generators. Other FTR options should offer a clear improvement above this baseline in order to be considered for implementation.

TABLE 15: ADVANTAGES & DISADVANTAGES OF FTR DESIGN MODELS
OPTION 1: NO FTRS

Option	Pros	Cons
1. No FTRs	• **Simplicity and low cost:** Easiest to implement as there are no new auction platforms or complex financial instruments. AESO and market participants avoid the administrative burden and expenses of running FTR markets • **Congestion rent to ratepayers:** All congestion rents are returned to customers, providing a strong value proposition to customers (both by returning expected value of congestion rents, and by offering customers a natural hedge since congestion charges and refunds would be aligned in time) • **No speculative or credit risk:** With no financial market, there is no exposure to FTR market manipulation, defaults or funding shortfalls • **Efficient nodal signals:** Generators are fully exposed to LMPs, incentivizing efficient siting decisions and technology mix	• **No financial congestion hedge for generators:** Generators (and their contractual counterparties) would lack any readily available mechanism to gain visibility or financially hedge congestion price volatility

B. Option 2: US-Style FTRs

For completeness and as the most immediate available benchmark for comparison, we examine the option of adapting a US-style FTR market to the Alberta Market, following the design used in markets such as PJM, ERCOT, and Midcontinent Independent System Operator (MISO). Under this model, the AESO would auction off FTRs on behalf of consumers, and allocate the FTR auction revenues to consumers. The auctions would use the US convention of structuring FTR auctions as revenue-maximizing sale of FTR positions, up to the volume of MW positions that is physically aligned with the predicted volume of transmission capability (noting that if FTR sales exactly match this capability at all times, the result will be that the congestion fund is exactly sized to fund FTR payouts). FTR position payouts would be funded via collected congestion rents. Experience in the US indicates that this structure would attract substantial participation from financial entities and create a relatively liquid market through which market participants could secure FTRs between any nodes on the system.

Several aspects of the US-style FTR model can be customized to align with Alberta's context and to somewhat improve market performance without changing the overall nature of the design. These elements include:

- **Settlement Against Real-Time Congestion Prices:** Since Alberta does not plan to operate a day-ahead energy market, FTRs would settle against the congestion component of real-time LMP differences (rather than the day-ahead LMP that is used in the US markets).
- **Allocation of Congestion Rent and FTR Auction Revenues:** Several US markets use ARR-style mechanisms to determine which entities are awarded entitlements to revenues from FTRs sold on behalf of transmission ratepayers (see Section III.C above). ARRs are awarded on specific paths or aligned with specific distribution territories. However, ARRs may not be immediately relevant or transferable to the Alberta context, because of the single shared transmission ratebase and lack of internal physical transmission rights historically.[70] A simpler way to refund FTR auction revenues (and excess congestion rent not otherwise allocated) is pro rata to all loads (similar to CAISO's approach), either in proportion to energy consumed or in proportion to transmission charges paid, or by directly refunding the transmission owner ratebase (such as in NYISO).
- **FTR Auctions of Remaining Available Transmission Capability**: Auctions would follow the US approach of auctioning off all remaining transmission capability in a revenue-maximizing auction format that enables any combination of buy and sell positions, subject to a simultaneous feasibility test. The auction would allow positions between any two represented points (nodes or zones/hubs), in any direction. To mitigate the potential for FTR underfunding, the auction would aim to utilize a transmission model that is equivalent to the one used in the real-time energy market, accounting for known physical transmission outages and realistic limits.
- **Settlements Backed by (and Capped by) Path-Specific Congestion Rents:** Following the US model, settlements would be paid from the congestion fund. However, to eliminate the risk of FTR under-funding, we would recommend adopting the CAISO approach of capping FTR payouts to the actual realized value of congestion rent collected across each path in each settlement interval. More aptly described as CRRs under this format, this approach ensures that real-time energy market revenues are sufficient to fund the CRR payouts and corrects for any differences between network models in the FTR auction vs. real-time, for example due to unexpected transmission outages.
- **Limiting FTR Sales in Recognition of Incumbent Payments**: Over a transition period after REM implementation, a portion of congestion rents may be allocated to funding transition payments to incumbent generators. For this reason, the congestion fund would not be fully available to back other FTR sales. The volume of FTRs awarded in early years of REM may need

[70] A more complex option that could suit the Alberta context is to allow loads to be eligible for ARR awards on a specific path if they demonstrate congestion exposure via their generation contracts, incremental exposure due to opt-in LMP in downstream locations, or self-supply (e.g., potentially relevant for municipal utilities that own generation). However, equity and fair treatment issues would be likely to arise, considering that the ARR awards have substantial economic value, ARRs are limited in supply, and many loads do not have staff capacity to fully participate in complex ARR processes. Because ARR awards are generally granted for free (subject to defined eligibility criteria) it may be challenging to identify rules for ARR awards that manage the needs of individual congestion-exposed loads, without awarding an ARR giveaway at the expense of other loads collectively.

to be limited to align with only a portion of the transmission network, with that volume increasing and eventually covering the entire MW of physically feasible transmission over time as incumbent payments expire.

- **Credit Requirements and Default Risk:** Implementing this model would require strong credit risk control, with collateral requirements sized to minimize the risk of FTR defaults (particularly in cases where financial traders take on large counterflow FTR positions that have fat tail risk, as occurred in the PJM Towers default example).[71] FTR credit requirements account for the known financial portfolio of participants across multiple FTR positions, and could also account for the default risk mitigation of any non-FTR entitlements to congestion rent (e.g., held by consumers). We would also recommend limiting the scope of impacts from FTR defaults by allocating default risks only to other FTR market participants (rather than extending that risk to also affect energy or ancillary service market participants), potentially in proportion to the financial or volumetric extent of their trading.

While the US-style FTR construct offers the benefits of transparency, liquidity, and implementation experience, in our view it is not the most relevant option for Alberta even after customizing these design elements. The structure was designed in part to limit congestion exposure for US consumers transitioning to LMP from a prior model of multi-utility areas and physical transmission rights, but such circumstances do not hold in Alberta. Generators in the US benefit from access to a liquid FTR market for available hedging, but the timeframe is short at no more than 3 years compared to the timeframe of investment decisions.

Further, the value proposition for consumers of a US-style FTR market is relatively poor, and worse than simply having congestion rents returned directly (as in Option 1). If outcomes follow US experience, consumers would lose a share of the congestion fund to pay FTR positions of financial traders, without much improvement in their already-low congestion exposure. We attribute this poor value proposition largely to the imbalanced structure that is mandatory for sellers (loads, represented by the ISO) and voluntary for others (mostly financial traders). The mandatory sell side requires loads to back all FTR sales via the congestion fund, with sales awarded to any bidder as long as revenue collected is greater than $0. Meanwhile, traders and other sophisticated participants can opt-in to voluntary FTR purchases whenever projected FTR payouts exceed the purchase price on a particular path. Considering the complex nature of congestion patterns and millions of source-sink pairs where a position can be taken, the risks, cost, and complexity of participation is high. Financial traders can effectively analyze and limit these risks, but one of the most obvious strategies for limiting risk is to take only prevailing flow positions (in which case, the traders in question would not absorb any risk from physical players). As a result, the US-style FTR model would likely need to be further modified in order for the value created to exceed the profits that may be extracted by imbalanced positions.

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71 See FERC, Order on Complaint, Docket No. EL08-44-000, April 30, 2008.

TABLE 16: ADVANTAGES & DISADVANTAGES OF FTR DESIGN MODELS
OPTION 2: US-STYLE FTRS

Option	Pros	Cons
2. US-Style FTRs	• **Returns more than half of congestion rent to loads:** Through FTR auction revenue allocations, this model indirectly allocates a portion of congestion rents, offsetting what consumers pay in the LMP market • **Enables near- and mid-term nodal risk management:** Supports risk management up to three-years forward by attracting substantial liquidity into monthly and annual FTR auctions (this "pro" is also a "con" if the liquidity is created from subsidization) • **Established blueprint:** The AESO can draw on decades of implementation experience with the US model	• **Cost and risk to loads from underpriced FTRs:** US experience indicates that offering to sell FTRs at any above-zero price will result in net costs and more risk to customers (compared to the simpler option of returning congestion rents to them directly) • **Complex and resource-intensive:** This model is administratively intensive (requiring new FTR auction clearing engines, auction processes, and FTR auction revenue allocation processes) • **No long-term hedges:** New generators would still not have a mechanism for securing long-term hedges on timeframes aligned with asset life

C. Option 3: Willing Buyer, Willing Seller Variants

The Willing Buyer, Willing Seller concept is the most market-oriented option approach to an FTR market, and is the model proposed by California's market monitor to address identified imbalances in the US structure.[72] Variants of this model aim to support a marketplace for the exchange of a defined product between willing buyers and sellers at a mutually agreed price. A Willing Buyer, Willing Seller market would be inherently value-creating, since every transaction is voluntarily agreed to between parties that see their private value enhanced by the risk transfer in the FTR trade. The structure is also more similar to other commodity markets, in that the aggregate of sales must match purchases in both MW and dollar value. That is, every FTR buy position has an offsetting sell position on a market-wide basis.[73] This structure means that (like other commodity markets), the market is inherently revenue-neutral and has no relationship to the congestion fund. As such, there is no risk of FTR underfunding, no transfer of portions of the congestion rent fund to financial entities, no need for alignment with incumbent transition payments, no credit risk for loads that are not party to the transaction, and no systematic concerns from inconsistencies associated with mismatches in the transmission model.

Similar to the No FTR model, all congestion rents would be returned to loads, which would be aligned in both size and timing with congestion costs they face. However, the Willing Buyer,

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[72] CAISO Department of Market Monitoring, *Willing seller market design for congestion revenue rights*, October 23, 2024.

[73] This is true on a market-wide basis but need not be true for each individual transaction. For example, two 5 MW buy-side positions can be offset by one 10 MW sell position on the same path. As another example, a 10 MW buy position from node A to node B plus another buy position from node B to node C can together be offset by one sell position from node C to node A.

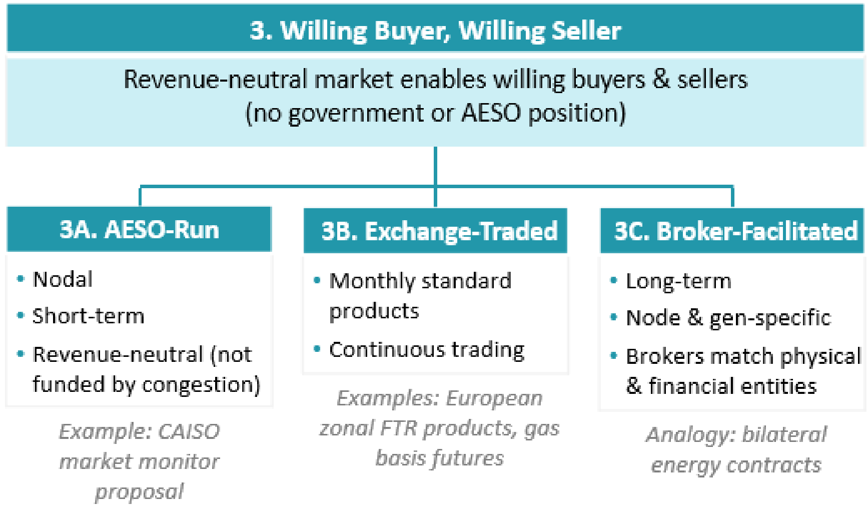
Willing Seller model may offer incrementally more value to loads that are individually exposed to congestion to the extent that a sufficient scale of voluntary FTR market arises to enable hedging.

From an efficiency perspective, the Option 3 variants include the most attractive FTR models we considered. The structures enable participants to hedge congestion risks on the operational and/or investment timescales, without shifting that risk to consumers or transmission ratepayers. Physical market participants will face the full costs and risks of nodal LMP markets and have the incentive to pursue physical solutions for risk management to the extent they are cost effective (and more cost effective than buying hedges through the voluntary FTR market). The prices of FTRs would be set by competitive forces, with voluntary market participants conducting their own assessments of expected levels of congestion and pricing uncertainties to inform their offer prices (and offering at prices that make sense consistent with the risks involved, with the private seller absorbing the cost if they under-value that risk).

The downside of the Willing Buyer, Willing Seller variants is our expectation that the markets will not attract as much liquidity and participation, risking less meaningful congestion price transparency and fewer opportunities for hedging. An FTR market with poor liquidity may still be an efficient outcome, particularly if the cost of providing risky financial hedges is more than the cost for generators to pursue physical solutions to limit the same risk. However, the outcome is not as efficient if physical players are willing to pay the required premium for FTR hedges, but those hedges are unavailable due to other market failures such as excessive transactions costs, insufficient information, asymmetric information, barriers to entry, product-market mismatch (e.g. poorly defined FTR products), or missing markets (e.g., no FTR market).

We examine three variants of the Willing Buyer, Willing Seller model as summarized in Table 17 below. The model's three variants are differentiated primarily based on the administrative market structure wherein 3A is AESO-Run, 3B is exchange-traded, and 3C is broker-facilitated. The nature of the market administration in many cases aligns naturally with other market features such as product and term.

TABLE 17: VARIANTS OF THE WILLING BUYER, WILLING SELLER FTR MARKET MODEL



OPTION 3A: AESO-RUN

The AESO-run variant of the Willing Buyer, Willing Seller option incorporates auctions structured similarly to the US-style FTR market. The auction would have monthly auctions (for monthly or annual terms), allow node-specific positions to be taken, and feature simultaneous multi-party clearing. The primary difference is that the auction only enables trade between willing buyers (mainly physical players bidding for prevailing flow FTRs) and willing sellers (mainly financial entities offering sell or counterflow FTR positions). The buyers seek to gain an FTR hedge and will need to pay an FTR clearing price at a premium above the expected level of congestion, with the premium high enough to compensate for the risk. Sellers would earn the payment commitment up front and absorb the risk that real-time congestion differentials may become higher than expected at the time of auction.

The objective function in the FTR auction clearing is surplus maximizing (to maximize the benefits of trade across cleared positions), subject to the constraint that the MW of net injections/withdrawals in the FTR auction model must be zero at each node.[74] Since there are so many positions that could be taken in these auctions, it may be challenging to create a structure that attracts a sufficient volume of sell offers on each path where a buyer may wish to hedge. To address a potential liquidity problem, the market could incorporate a multi-round auction structure (so that if buyers place high willingness to pay on a specific path, round 1 of the auction will reveal a price premium that more traders can compete for by rebidding in round 2). Another means to improve liquidity could be to reduce the number of paths by switching from a nodal to a zonal FTR structure, so that market participants' interest would be focused on a smaller number

[74] This differs from the objective function of US-style FTR auctions, which seek to maximize revenue for the sale of available transmission, up to the constraint that the maximum MW volume of FTR sales cannot exceed the physical transmission system. Several of the US markets also incorporate somewhat conservative MW limits on the volumes of FTR sales, as a means to limit the scale of potential congestion rent under-funding relative to notional FTR payouts.

of paths potentially with more bids. Positions could be taken to/from any zone and could be offset by a combination of counterparty positions as long as the total volume and source/sink pairs are matched in aggregate.

To avoid reducing liquidity further, the model might start by considering fewer products, e.g., limiting to only on-peak, off-peak and 24-hour FTR profiles. On the other hand, some market participants would be interested in proposing alternative structures, e.g., a profile aligned with zonal average wind and solar output. Such a profiled product could be more readily developed and launched in the Willing Buyer, Willing Seller model (all options 3A–3C) as compared to in Options 2 or 4 because there would be no need to evaluate whether the more complex product profiles interact with the size of the congestion fund and other FTR-created claims on a share of the congestion fund. Instead, whether the profile is flat or wind-/solar-adjusted, the structure would be more simply and directly revenue neutral (with prevailing flow positions paid out from settlements with counterflow participants). Another option is to support multiple auctions for the same product but over different terms (annual, monthly, weekly, daily), which would allow traders to alter positions as real time approaches (managing congestion risk, rather than investment risk).

A downside of this structure is that it is administratively complex for the AESO, including requirements to introduce sufficient credit requirements and settlements (which are significantly more complex and risky than today). Further, if a liquid level of participation fails to materialize, it may not be obvious whether the lack of liquidity is an efficient outcome (e.g., the costs of financial hedges exceed the costs of physical hedges) or whether another market failure is present (e.g., product profile is misaligned with need). The other downside is that the structure is unlikely to produce hedges over more than a monthly or annual term, making it less useful for derisking generator investments compared to Option 4A and 4C.

OPTION 3B: EXCHANGE-TRADED

The concept underpinning Option 3B is similar to 3A, but the auction administrator would be a third-party exchange, similar to the FTR products supported in the EEX exchange and gas basis swap products supported by ICE.[75] The exchange would support continuous trading of a small number of defined products, such as on-peak, off-peak, and 24-hour. Locational granularity would be defined from zone to hub, and participants could create zone-to-zone positions by stringing multiple positions together.

Since the exchange is continuously traded (rather than centrally cleared in a periodic auction format) it would produce a continuously updated forward view of anticipated congestion differentials, though this visibility into market expectations on congestion would be limited if some paths attract minimal participation. Similar to the AESO-run format, the exchange could launch or experiment with more interesting products such as wind- or solar-profile FTRs, with the

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[75] For additional discussion, see Section II above. Alberta-Henry Hub basis is traded on ICE as the AB NIT Basis Future product.

exchange administrator incented to create attractive products and more volume, since they earn a small commission on every trade.

Commodity exchange markets can materialize on their own and without government intervention, as long as exchange companies anticipate earning sufficient commission from trade to justify the overhead costs of running the exchange. However, if Alberta wished to guarantee that such an exchange is developed, it may need to specifically contract for and commission the services of a qualified exchange. In the US, private FTR exchanges are scarce, but this may be because the US ISOs already support this need through their centralized auctions. The EEX exchange examined in Section III.A above does support continuous trading of products equivalent to zonal FTRs and is privately funded by participants without any government mandate or support.

The advantages and disadvantages of an exchange format are similar to the AESO-run Option 3A, but with the additional advantages of lower administrative complexity for the AESO, and potentially higher likelihood that the exchange can identify a strong product-market fit. The continuous trade format would offer a more frequent and potentially farther-forward visibility into participants' congestion expectations (though this is only true if there is sufficient liquidity, as an auction format from 3A would occur less frequently but be more likely to clear at least some volume given that all bidders would be mobilized into those periodic liquidity events). A disadvantage relative to the AESO-run Option 3A, is that this zonal structure (necessary to support continuous liquidity) would not be able to support the more numerous nodal paths.

OPTION 3C: BROKER-FACILITATED

A final variant of the Willing Buyer, Willing Seller option is a broker-facilitated model built around bilateral contracts. The same drivers for hedging and wiling participants would apply as in Options 3A and 3B, but the nature of the transactions would be around bilateral contracts between two counterparties. The contracts to transfer congestion risk could be negotiated between the parties and could include longer terms (including up to the full asset life) and align with the supply nodes and output profile of the specific generator in question.

As one example, assume a consumer in Alberta is exposed to the system-wide energy price but wants to secure a long-term energy contract with a wind generator in a generation pocket as a means to hedge energy costs and contribute to green energy goals. Neither the consumer nor the generator wants to retain exposure to the congestion-driving pricing risk between the generation supply node and the system price, and so the two parties seek a bilateral contract for offloading the congestion risk to another party (a financial player). If a financial off-taker of that risk is identified, then the consumer and generator can both enjoy the benefits of a long-term energy hedge (having paid a premium to eliminate the congestion risk).

The advantage of this option compared to 3A and 3B is that the terms of the bilaterally negotiated agreement could be tailored to the specific circumstances of the parties, including their settlement nodes and supply profile. The term of the agreements can also be longer than in a more standardized market format. However, the bespoke nature and longer term also mean that there would be fewer deals made, that the prices would not be transparent, and liquidity may be poor. Brokers can sometimes improve liquidity of such bespoke bilateral markets by acting as a matchmaking hub between willing counterparties and taking a commission for the service. If sufficient value in this type of hedging exists, we find it likely that private parties and brokers would emerge to serve this need (but transactions costs would be higher than in the other options we considered).

Though this model is attractive from a theoretical efficiency and benefits perspective, we are concerned that the transaction costs and risks may be too large for a liquid market to emerge. To date, there is relatively poor liquidity in this type of bilateral FTR-type hedging in the US markets, despite the fact that many parties (particularly renewable generators in remote locations and their contractual energy buyers) are interested in offloading congestion risks on a long-term basis. In many cases, it may be that the reason for the lack of a substantial broker-enabled market of this type may be that insufficient value is created by financial risk management, such that the physical players find it more appealing to share congestion risks in different ways between the energy buyer and seller via different contract terms, as well as by pursuing physical means of hedging (siting, adding storage, or co-locating with demand).

To improve the chances of a material bilateral market emerging, the AESO or another government agency could provide some support by developing standard-form contracts or by hosting a bulletin-board style market that provides some information on the term and nature of a deal that a specific entity is seeking. Overall, Option 3C has the benefits of efficient incentives and great capability for customized arrangements to fill participant needs but may not materialize at an attractive scale.

RELATIVE ADVANTAGES AND DISADVANTAGES

Each of the three Willing Buyer, Willing Seller variants offers distinct trade-offs in terms of complexity, liquidity, risk allocation, and administrative burden. The table below summarizes the relative advantages and disadvantages of each approach.

TABLE 18: ADVANTAGES & DISADVANTAGES OF FTR DESIGN MODELS
OPTION 3: WILLING BUYER, WILLING SELLER VARIANTS

Option	Pros	Cons
All Option 3 Variants (pros and cons that apply to 3A, 3B, and 3C)	• **Not funded by congestion rent:** No risks of under-funding, under-priced FTRs, or conflicts with other uses of congestion fund (e.g., for incumbent payments) • **No cost or risk shifted to loads and non-FTR market participants:** Same advantages as the No FTR model: customers are not required to back FTR positions • **Efficient pricing signals**: Participants face the full risk of LMP, and can hedge only at privately quoted risk premiums (not subsidized) • **Flexibility in product profile:** Wind-profile or other interesting products can be created without concerns about misaligning volumes with available transmission or congestion rents	• **Liquidity:** Participation is voluntary, so liquidity may be limited and fewer hedging opportunities may be available (but more liquidity in 3A and 3B compared to 3C)
3A. AESO-Run	• **Transparency and guaranteed pricing information:** Even if cleared volumes are small, the regularized auction formats will create regular liquidity events and transparent congestion price signals • **Near- and mid-term hedging opportunities** (months and up to ~3 years ahead) • **Nodal granularity enabled** (Though zonal may be more liquid)	• **Operational burden on AESO:** Requires FTR auction execution, expanded credit management and settlement support • **Limited long-term support:** Monthly/annual auctions may not meet long-tenor hedge needs (multi-year timeframes relevant for investments)
3B. Exchange-Traded	• **Minimal AESO administrative cost,** though exchange may need to be contracted for service if volumes are insufficient for self-funding • **Continuous trading:** offers continuous hedge opportunities and transparent forward pricing (no need to wait for auction events), as long as the market is liquid • **Familiar platform for traders** • **Product innovation** can be pursued by exchange (incentives provided by commission-based revenue)	• **Limited long-term support:** Monthly/annual auctions may not meet long-tenor hedge needs (multi-year timeframes relevant for investments) • **No nodal granularity** • **Potential for insufficient liquidity** to meet continuous interest in FTR purchases
3C. Broker-Facilitated	• **Fully customizable terms:** Contracts can reflect project-specific risks, locations, and generation profiles, enabling precise hedge design • **Suitable for long-term hedges:** Enables multi-year hedges tailored to specific assets, which can improve revenue certainty for financing and contracting purposes • **No ISO administration required:** Entirely handled by counterparties and brokers, with no operational burden on AESO	• **Higher transactions costs and lower liquidity** than other options built around shorter-term, standard products (potentially no liquidity)

D. Option 4: Mandate-Driven FTR Variants

Options 4A, 4B, and 4C are all made-in-Alberta FTR models that are designed to serve targeted objectives. They are less market-oriented than Option 1 (No FTRs) and the Option 3 (Willing Buyer, Willing Seller) variants, in that the Option 4 variants anticipate that the AESO or another government agency will be taking a net-sell position in the FTR market. The volumes, willingness to pay, and other aspects of the design would be established by government in order to serve a specific mandate. The following Table 19 describes the three mandate-driven FTR variants that we examine including: (4A) Generator-Driven FTRs that aim to support generators to hedge long-term congestion risks they face at the time of resource investment; (4B) Consumer-Driven FTRs, where the mandate is to hedge consumers from congestion-driven risks on a market wide basis, and enable individually exposed consumers to hedge as well; and (4C) a Hybrid Model that aims to serve a mixture of generator and consumer hedging needs.

The advantage of a mandate-driven FTR model is that it can be tailored to a specific congestion risk management objective, using the congestion fund as the revenue source backing any net costs from the hedges created by the model. Considering that hedges are funded and potentially subsidized, they will be more certain to be available in higher liquidity (unlike in Option 3 variants that may have low trade volumes). The disadvantages of the Option 4 variants are that they are relatively administratively complex and introduce the potential for risks and costs to customers (e.g., to the extent that FTRs are sold at too-low prices). Further, any under-priced FTRs also introduce economic inefficiencies, since generators may have the incentive to invest in lower-value locations or resource types if they have access to subsidized congestion hedges (foreclosing the opportunity for a siting or technology choice that would be more cost-effective solution absent the subsidy).

One challenge with a Mandate-Driven FTR model is the risk that the FTR construct goals can change over time, and as such would create the risk of instability or inefficiency if the nature and role of the FTR structure is regularly shifting in favor of certain market participants or resource types. We therefore develop these structures assuming that the structure would be initiated with a clearly defined mandate that would persistently and perpetually underpin the structure.

TABLE 19: VARIANTS OF THE MANDATE-DRIVEN FTR MODELS

4. Mandate-Driven FTRs

Agency pursues
specific design goals via FTR hedging

4A. Generator-Driven	4B. Consumer-Driven	4C. Hybrid Model
• Congestion hedge provided at time of investment • Long term • Bespoke positions (individual gen profile & node) • Application-based, agency approval • Agency prices FTR based on projected payout cost and risk	• Short-term, standard products • Auction-based procurement of customer hedges • Agency assesses value of hedges to consumers	• Mix of 4A & 4B • Mid-term, standard products • Generators compete for limited FTR volume out of gen pockets • Consumer cost, value & risk drives reservation prices in FTR auctions
Analogy: Government loan guarantees	*Analogy: mandatory fuel hedges for vertically integrated utilities*	

OPTION 4A: GENERATOR-DRIVEN FTRS

In the generator-driven FTR model, the design would be focused on the primary objective of enabling generators to hedge congestion risks at the time of resource investment. Generators would make an up-front commitment to pay a fixed price for the FTR (potentially to be paid out in fixed installments over the life of the asset), and by doing so would gain a hedge against realized congestion costs for the duration of the FTR agreement (likely a long-term, multi-year commitment in order to be relevant for hedging investment costs). Like the US-style model, payouts to the FTR holder would be sourced from the congestion fund that would otherwise be returned to loads.

Some of the features and design elements to be refined in a generator-driven FTR model include:

- **Eligibility:** Since the primary objective is to mitigate congestion costs for new investment, eligibility would be limited to new generators at the time of investment. By making an up-front payment or commitment for fixed payments to the market, the buyer earns protection against congestion costs over the duration of the commitment, including the risks that other new generators may over-build in the same location or that optimal congestion-relieving transmission upgrades may be slow to come online. (We also note that the first-come, first-served nature of the award creates an inherent level of subsidy or protectionism to the selected awardees, who will enjoy more investment security and are less exposed to competition compared to later entrants. The outcome may reduce the level of competition and efficiency, particularly if FTRs are awarded at a too-low price or to a generator that is not otherwise the least-cost competitor).

- **Path:** The FTR path that is most relevant in the generator-driven model is from the individual generator's LMP node to the unconstrained system price bus (i.e., to protect generators in outflow-constrained pockets where they are exposed to downside pricing and congestion risks). Generators would not pay for FTRs into inflow-constrained load pockets however, as generators located in load centers would rather retain and benefit from the upside congestion risks (and in fact may see these risks as a material portion of the business case for locating there). Meanwhile, customers may be willing to sell off FTR awards on the generator-to-system paths, while retaining the congestion rents for the system-to-load buses as a means to naturally offset their risk of upside congestion exposure in the load pocket.
- **Output Profile:** Similarly, generators would most strongly prefer a generation profile that is aligned with their own output (or a class average). Customizing the profile to meet an individual generator's output offers the most valuable hedge, albeit by further complicating and limiting the ability to offer hedges to more parties considering that they are all paid out from the same limited pool of congestion funds.
- **MW Volume of FTRs Awarded:** The question of volumes to be awarded presents a conundrum. An approach that only serves generator interests would make FTRs available in unlimited supply to all generators that seek them. However, this would quickly put customers on the hook for risky and underfunded FTR obligations that cannot be paid for only out of the congestion fund. A more sustainable option is to limit the volume of FTRs awarded based on the physical MW of available transmission export capability from each generation zone, which would then produce a more natural alignment between the scale of congestion rents and FTR payouts. Further, new generators would more immediately gain feedback when new generation cannot be supported by anticipated transmission capability in particular zones, because there would not be sufficient FTR volume to grant their FTR hedge request. The result may be to limit entry in particular locations to better align both timing and volume with transmission capability.
- **Limits on Funding Payouts from Congestion Rents:** To prevent the issuance of FTR obligations that exceed the size of available congestion rent funds, several protections could be applied, including: (a) limiting the MW of awarded FTRs to align with physical capability of the transmission system; (b) further limiting the volumes of awarded FTRs (in both $ and MW) based on the portion of the congestion fund that is already allocated to fund incumbent transition payments; (c) awarding FTRs in the form of CRRs, such that the payouts never exceed the congestion rents collected (calculated on a path-specific and line-specific basis); and (d) limiting the paths that can be awarded to prevailing flow paths from generator nodes to the unconstrained system bus price (while returning congestion rents associated with load pockets to customers).
- **Process for Awarding a Limited Volume of FTR Awards:** As a starting point, we assume that the process for awarding FTRs would be a first-come, first-served process that looks a bit like a government loan guarantee. Generators wishing to gain an FTR would need to demonstrate eligibility criteria (e.g., sufficient progress in site control, permitting, or interconnection processes) and make an application. If approved, they would be granted an FTR award. However, if many more generators are interested in the FTRs than can be supported by the

transmission system and congestion fund, then the government agency tasked with these approvals would need to find an alternative means to prioritize among qualified applicants. One way to do so would be to award longer-term FTRs through competitive auctions (discussed more under Option 4C below).

- **Reservation Price for FTRs:** To be awarded a valuable FTR hedge, generators would need to pay a fair price that is commensurate with the cost and risk that customers take on by backing it via the congestion fund. The government agency responsible for pricing these hedges should apply similar concepts to those that would be considered by private entities offering such a hedge, including a financial forecast of the projected congestion price differentials over the duration of the commitment. Accurately assessing these fat tail counterflow risks would be a challenging task (which, if done poorly, could result in excess costs imposed on consumers for many years to come). A reasonable reservation price should account for all the risks involved in offering such a hedge, considering that congestion differentials are subject to periodic pricing extremes for which loads would not wish to absorb the risk. The scale of the risks that customers absorb would be lower (and reservation prices can hence be lower) if the FTR payouts are limited to congestion rents collected on the relevant path. We would recommend that reservation prices be developed after assessing value to consumers in the following ways: (a) the embedded cost and/or incremental cost of the transmission infrastructure (paid for by loads) indicated by the FTR definition, understanding that it would be financially dedicated to serving physical exports from the generator in question;[76] (b) the discounted value of expected future congestion costs, considering a modeling forecast of future prices including accounting for anticipated transmission development and risk scenarios (fat tail and otherwise); and (c) market-wide willingness to pay, e.g., by using an auction format to collect the highest sales price from competitive generators that each seek to secure the FTR.

Overall, the generator-focused model introduces a number of design questions and administrative complexities that would need to be resolved before implementation. If implemented with design flaws or without some of the consumer protections we have laid out, there is a risk that FTRs could be awarded in excess volumes or at a too-low price (in which case loads may be unintentionally assigned excess costs and risks that were not fully appreciated at the time of the FTR awards, and that persist for many years to come). Further, if FTRs are under-priced relative to their true cost (noting that the most reasonable reservation price may be challenging to develop), the result would be to subsidize less efficient investment choices from generators.

The potential advantages and benefits of the model include that the model is more likely than the Option 3 variants to create a meaningful hedging opportunity over the timeframes relevant

[76] The conceptual basis behind this consideration is that the entities that have paid to build transmission should have the rights to economic benefits created by its use (i.e., the congestion fund allocation). If generators wish to secure the congestion rent, one way to ensure customers are adequately compensated is to ensure that they receive payment for the costs of transmission they would otherwise pay (i.e., either the embedded historical costs or future anticipated transmission costs, both of which may serve to deliver power from the new generation entrant seeking an FTR).

for new generator investment. A further efficiency advantage is that if the MW volumes awarded align with the physical size of the transmission system available, the mechanism could play a more meaningful role in guiding and signalling investment decisions (more clearly delineating the timing and volume of generation that can be supported by existing and planned transmission projects, which may more substantially discourage over-building in saturated generation pockets). Further, the scale, timing, and location of generator interest in FTRs could be examined as one input for consideration in separate AESO transmission planning processes.

Consumers would not directly benefit more from this model as compared to a No FTR model, but exploring this option does at least illustrate a range of protective measures that can be applied to protect consumer interests. The primary ways that customers could theoretically realize net value under this model would be if either: (a) loads are able to access lower-cost generation supply contracts (if their counterparties are more hedged); or (b) if on a market-wide basis, there are efficiency gains due to better coordination between investment decisions and physical transmission capability and/or lower cost of capital for generation investment. However, considering the potential for FTR awards to incorporate elements of both subsidization and some inefficiency, it is more likely that customers will face some increase in long-term costs associated with Option 4A.

OPTION 4B: CONSUMER-DRIVEN FTRS

In developing the consumer-driven FTR model, we examined the nature of design elements that could be put into place that would offer value to loads beyond what is already captured in Option 1 (No FTRs). Our immediate observation is that most load interests are already largely served in the No FTR model, and so there may be limited opportunities for FTRs to enhance customer value outside the circumstances of a small subset of customers that are individually exposed. Still, the exercise of examining the question helps to articulate the cases where loads can benefit from FTRs as well as the protections that customers may want to avoid excess costs or risks under other FTR models. In this exercise, we separately review the situations of: (a) loads as a group, considering their aggregated exposure to congestion via the system-wide ALP; versus (b) a subset of loads that are individually exposed to congestion risks by their choice to opt in to LMP, through their contracts with generators, or through self-supply (e.g. for municipalities).

For consumers as a group, they are exposed to the risks of congestion to the extent that congestion costs are incorporated into the system-wide ALP. Load LMPs are exposed to upside congestion risks because load buses are located in downstream locations and load centers, such that the system-wide load-weighted average ALP incorporates downstream (high-price) congestion costs. The largest and most direct way to protect customers from this risk is to return congestion rents to customers as an offset to their bills or transmission charges (as is already accomplished in the No FTR model). The size of congestion rent returns is limited by the volume of the physical transmission system however, and so will never be enough to fully hedge customers from upside pricing exposure. For that reason, there is room for a government agency to organize the purchase of prevailing flow FTRs from financial entities, with the willingness to pay for those hedges established in ways that reflect customer value and willingness to pay to limit exposure to high congestion-driven prices. We incorporate a mechanism for prevailing flow FTR purchases into the consumer-driven model but observe that it likely makes more sense to pursue reforms to hedge total ALP price if additional load hedges are needed (rather than only hedging on the congestion component through FTRs).

Consumers as a group are also indirectly exposed to the reverse side of congestion risks, in that upstream (low-price) congestion risks in generation pockets create more congestion rent. Congestion rents from upstream pricing risks in generation pockets yield categorically different impacts for customers, such that the downside risks faced by constrained-down generators is enjoyed as a cost offset (via congestion returns) to customers. Customers would not benefit from hedging against these downside pricing risks through FTRs. The timing of when large downside congestion rents will be collected is tied to the timing of generator and transmission development, with more congestion rents collected when certain generation pockets become oversaturated and before additional transmission can be built. For that reason, the congestion rent refunds do not necessarily align with the primary drivers of customer pricing risks (downstream congestion risk, fuel prices, emissions prices, and reserve margins). However, the gen-pocket congestion rents are precisely the funds that most naturally align with and can be offered to back FTRs to generators. In the consumer-driven model we assume that these downside congestion rents will be directly returned to loads, but we do point out that customers should be largely indifferent as to whether the value of these congestion rents are refunded immediately as the congestion occurs or if the customer refunds are returned on an averaged-out basis over time (as long as loads receive a fair price on average).

Customers that are individually exposed to congestion rents face a unique situation. A customer opting-in to LMP at a relatively higher-price bus would be exposed to load-pocket-type congestion costs and would likely never be willing to make that opt-in choice unless they were also awarded access to a share of the congestion fund that is tied specifically to their exposure at the higher-price load bus. Once opting in to a higher-price LMP, the individually exposed customer may place some value on gaining an FTR or similar hedge (such as what may be available in an auction or under other FTR models). Meanwhile, customers at low-price buses would have a simpler incentive to opt-in to nodal settlement since the lower LMP presents an immediate savings.

Similarly, any consumers with generation self-supply or contracts may individually benefit from purchasing FTRs associated with those arrangements. These consumers may value access to a liquid market for hedging, whether that is available via one of the Option 3 variants or if the hedges are backed by the congestion fund.

Offering congestion-fund-backed FTRs to a subset of customers (i.e., nodally settled ones, or those with arrangements with specific generators) requires answering the same analytical and equity questions discussed under the generator-driven model under Option 4A above. For all customers to be treated equitably, any subset of customers seeking individual FTR positions backed by the congestion fund would need to pay for that FTR at a price that fairly compensates other loads for the costs and risks transferred via the hedge. Further, the same protections would need to be in place to ensure that the payouts of any FTR positions (whether to customers or to generators) would be limited in both MW (tied to physical transmission limits) and in dollars (tied to the size of the constrained-down congestion revenues).

OPTION 4C: HYBRID MODEL

The Hybrid FTR model aims to serve a mixture of generator-driven and consumer-driven interests as described above. It has a greater focus on the former, given that load interests are already mostly served in the No FTR option by returning congestion rents directly. For that reason, the model incorporates a mixture of elements that seek to provide some opportunities for generator hedging, but in ways that incorporate sufficiently strong protections that most customers are held indifferent. The main benefit to customers is by supporting the hedging needs of the subset of customers that are individually exposed, and by incrementally improving some combination of generation and transmission investment decisions and lowering system costs by a commensurate amount.

The structure we suggest for the hybrid model would involve zonal FTR paths (not nodal), with auctions to support short- and mid-term hedging needs. The auctions would ideally be for FTRs of sufficient term into the future to inform and incorporate market expectations regarding the timeframe and volume of the next phase of transmission deployments. FTR auctions would be structured as a sale of FTR positions with the MW volume aligned with the physical capability of the transmission system, after accounting for any volume limits associated with prior FTR sales and subtracting awards for temporary incumbent transition payments. Payouts for congestion-rent-backed FTR sales would also be limited to the congestion rents collected on a path-specific basis. Further, to ensure consumers always get the upside congestion rents associated with load pockets, only downside congestion rents and generation-pocket FTRs would be offered for sale. To achieve this, congestion rents associated with load pockets would be tracked separately and directly returned to loads. The reservation price for each FTR sale would be set by the government agency, with a mandate to sell the available FTRs only if the price is at or above the level deemed to be neutral or value-creating for loads as a group (taking into account considerations such as embedded and/or incremental transmission costs, expected congestion rents, and market value; see discussion under the "reservation price" element of Option 4A above). We suggest that the zone-to-system description of FTR paths is likely the simplest option for supporting market liquidity and competition, while reducing the number of paths over which the government agency must analyze the most relevant reservation price on behalf of consumers.

Unlike in the generator-focused model, eligibility in a hybrid model would be opened more widely to a range of entities (loads and existing and new generators). This broader participation would result in competition for access to FTR hedges by new resources, but at the same time could potentially make it more feasible for individually exposed loads to access hedges and would allow consumers as a group to receive a more competitive price for any FTRs sold.

Once some experience with the FTR auctions is gained, they could be further expanded to enable additional volumes of FTR trade on a Willing Buyer, Willing Seller basis (i.e., by expanding access to FTR sales by financial parties). These voluntary trades may have more capability to be offered under alternative profiles, considering that there is no requirement to align with the size of the congestion fund.

RELATIVE ADVANTAGES AND DISADVANTAGES

Mandate-driven FTR models (4A-4C) are designed to meet targeted objectives by allocating congestion risk and value based on specific goals rather than pure market forces. The table below summarizes the relative advantages and disadvantages of each variant, highlighting trade-offs between investment support, ratepayer protection, market efficiency and administrative complexity.

TABLE 20: ADVANTAGES & DISADVANTAGES OF FTR DESIGN MODELS
OPTION 4: MANDATE-DRIVEN FTR VARIANTS

Option	Pros	Cons
All Option 4 Variants (pros and cons that apply to 4A, 4B, and 4C)	• **Targeted objectives** can be articulated and pursued	• **Consumer risks and costs:** complex, long-term financial positions introduce the potential for unanticipated risks and costs, particularly if FTR sales are under-priced or payouts are not capped to the scale of constrained-down congestion rents • **Reliance on administrative judgement** (rather than market forces) to set proper FTR MW volumes and reservation prices • **Administrative complexity** and costs exceed Options 1, 2, and 3, may involve creation of a new government agency (or expansion of AESO mandate)
4A. Generator-Driven	• **Supports investment certainty:** Generators receive long-term FTRs to protect revenue and support financing at the time of investment • **Tailored hedging:** FTRs can be customized to fit generation profile and location (e.g., hourly profiles of renewables, load, or peaker units) • **Simple for participants:** No trading required, as FTRs are granted via application and approval	• **Risk of inefficiently muted congestion signals:** Generators may ignore more efficient siting, co-locating, and technology solutions if FTRs are subsidized or offered at a discount compared to their full cost • **Eligibility limited** to new generators and long-term commitments (raises fairness questions, does not meet hedge needs of existing generators or individually exposed loads)
4B. Consumer-Driven	• **Consumer protection:** Returns congestion value to customers and may protect against high ALP prices • **Hedges for some consumers:** Allows nodally settled consumers and those with contractual or ownership relationships with generators to obtain path-specific congestion hedges	• **Modest or no improvement to customer hedging** profiles, since congestion returns already cover most needs and a full energy hedge may be more useful than a congestion-only FTR hedge • **Minimal or no hedging value to generators:** Since the model procures only load hedges, and does not support a broader market
4C. Hybrid Model	• **Consumer value:** goal is that consumer value is equal or greater than in the No FTR model (upside congestion rents returned to loads, downside congestion rents offered as backing for FTR sales) • **Hedging opportunities:** regular, transparent auctions allow generators and others access to hedges at competitive price	• **Complexity and overhead cost:** higher than other models

VI. Findings: Assessment of Alternative FTR Design Models

The best FTR or congestion hedging framework for Alberta depends on the balance of assessment criteria that are to be pursued. Table 21 below provides a summary scorecard comparison of the initial design models described above, considering potential assessment criteria. Takeaways that we suggest the AESO and stakeholders should consider include:

- **Option 1: No FTR** is the simplest option, and the option to beat from a consumer interest and efficiency perspective (i.e., for any other option to be relevant or meaningfully considered, it should perform better than Option 1 on at least one and ideally several dimensions). Even without FTRs, consumers' exposure to congestion risks is modest (due to the system-wide ALP and return of the congestion rents); and new generators have physical (and likely efficiency-enhancing) options to mitigate congestion risks by considering development opportunities in different locations, by adding storage, or by co-locating with demand off-takers. The market performance concerns in other jurisdictions highlight that there are advantages to a do-nothing option. Even if the primary advantage is to avoid the pitfalls of complex derivative instruments that may have large financial consequences for consumers in the event that the risk or magnitude of large or long-term positions are under-appreciated at the time they are introduced. Finally, the No FTR option is not a permanent choice, considering that third-party entities could launch a voluntary FTR market (e.g., Option 3 variants), while the AESO could introduce one in the future after some REM experience is gained. Deferring implementation of one of the other FTR models is likely a better overall outcome than implementing a partially baked FTR design sooner (with any inefficient or unfair elements locked in for years to come). The downside of Option 1 is that it offers no immediate solution for addressing the congestion exposure challenges faced by generators and a subset of customers, and it does not offer any transparent market-driven information on the outlook for congestion pricing.
- **Option 2: US-Style FTR** markets is included in this paper primarily to offer a benchmark comparison and illustrate experience with several design elements but is unlikely to serve the needs of the future Alberta market considering the substantial differences in Alberta's context and identified performance gaps. The US market designs were aligned to enable allocation of congestion rents to protect utilities with complex self-supply and contract books in the transition to large RTO footprints and a set of issues that are less relevant in Alberta's context. Further, the performance gaps in the US markets result in a relatively poor value proposition to both consumers and new generators. The main advantages of the US approach are the high liquidity and market transparency offered over an outlook of a few years, though the value created by that transparency appears low compared to the scale of profits extracted by financial participants.
- **Option 3: Willing Buyer, Willing Seller** variants offer the appealing feature of being the most market-oriented approaches that can most efficiently reallocate risks to financial entities that can best manage those risks. The downside of Option 3 is our expectation that the markets

could be thin on liquidity, in which case they offer minimal advantages compared to a No FTR options model.

- **Option 4: Mandate-Driven FTR** variants offer the opportunity to pursue specific design goals, but should all be considered only in service of well-articulated goals. Enumerated examples include support for generator investments (Option 4A), hedging customers from congestion risks and/or allowing a subset of customers to reallocate access to congestion rent refunds in ways that better align with individualized risks (Option 4B), or a mixture of these goals (Option 4C). The downside of the Option 4 variants is the complexity for a government agency in making decisions on the level of risk that should be borne and by who, with consumers bearing the costs of any underpriced FTR sales. Further, if the FTRs offered for sale are underpriced or offer excess protection from congestion risks, the result could be to subsidize generators for making inefficient investment decisions (e.g., by over-building renewables into an already over-saturated part of the grid). For these reasons, the Option 4 variants should also be considered only if the government agencies in question have a clear mandate on the role and purpose of the mechanism, sufficient resourcing to effectively assess and manage the risks and incentives being introduced, and guardrails that protect consumers from excess risk and cost.

Though these models do not represent the full possibility space of design options, they provide a suite of approaches that are each individually self-consistent and focused on particular goals.

TABLE 21: ASSESSMENT OF ALTERNATIVE FTR DESIGN MODELS

	1. No FTRs	2. US-Style FTRs	3. Willing Buyer, Willing Seller			4.Mandate-Driven FTRs		
			3A. AESO-Run	3B. Exchange-Traded	3C. Broker-Facilitated	4A. Generator-Driven	4B. Consumer-Driven	4C. Hybrid Model
Mitigating generator investment risks	No long-term FTRs	Short-term FTRs mitigate only a few years of risk	Short-term FTRs mitigate only a few years of risk	Monthly FTR futures mitigate only near-term risks	Strong hedge on congestion risk (though that still covers only a small portion of total investment risk)	Strong hedge on congestion risk (though that still covers only a small portion of total investment risk)	FTRs aligned with customer hedge needs (not gens)	Mid-term FTRs helps to inform investment hedges
Ongoing Risk Management (month to month)	No short-term FTRs	Monthly auctions enable repositioning	Platform with standard products allows for active monthly trading but volumes may be low	Platform with standard products allows for active monthly trading but volumes may be low	Bilateral trades are illiquid and long-term oriented	Long-term FTRs limit risk, but minimal ability to adjust positions monthly	Customer-oriented positions may not help gens	Monthly auctions enable repositioning, oriented to load & gen needs
Market Liquidity	No liquid market	ISO-run auction with standard products leads to many bidders (capped by feasible Tx)	Can support many bidders (but no guaranteed volumes)	Exchange with standard products (but no guaranteed volume)	Few bespoke transactions	Few bespoke transactions	Monthly volume procurements (but value-add clearing volumes could be low)	Monthly auctions, likely to attract many bids (capped at feasible Tx from gen pockets)
Efficiency of Resources (location/ resource type)	Efficient exposure to LMP risk (but minimal forward transparency)	Some short-term price visibility, but incentives affected by cong. rent & ARR allocation	Efficient exposure to LMP, some short-term price visibility	Efficient exposure to LMP, some short-term price visibility	Efficient exposure to LMP & privately quoted prices for hedging (if counterparties exist)	Subsidization may reduce locational signals (built in areas where it is not economically efficient)	Some short-term locational visibility (but mainly to load pockets)	Visibility of congestion pricing, some risk of subsidy if FTRs are under-valued
Net cost to customers/tax payers	No customer cost	Ratepayers take liability of FTR payouts	Funded by market participants	Funded by market participants	Funded by market participants	Taxpayers take liability of FTR payouts	Some cost, but only if hedges deemed valuable	Goal is no net cost to customers (but possible FTR is underpriced)
Customer/tax payer risk exposure	Congestion risk limited due to system-wide price & refund of congestion rent	Loads take on the risk of FTR payouts	Congestion risk limited due to system-wide price & refund of congestion rent	Congestion risk limited due to system-wide price & refund of congestion rent	Congestion risk limited due to system-wide price & refund of congestion rent	Loads take on the risk of FTR payouts (limited by share of congestion fund)	Modest improvement relative to no FTRs	Somewhat more risk than no FTR case
Administrative Complexity	Simplest, no FTRs	ISO-run nodal auctions	ISO-run nodal auctions	Exchange maintains operations	Decentralized bulletin board trades	Application approvals	ISO-run, zonal positions	ISO-run, zonal positions

List of Acronyms

AESO	Alberta Electric System Operator
ALP	Alberta Load Price
ARR	Auction Revenue Right
BRA	Base Residual Auction.
CAD	Canadian
CAISO	California Independent System Operator
CEAC	Clean Energy Attribute Credit.
CPUC	California Public Utilities Commission
CRR	Congestion Revenue Rights
DER	Distributed Energy Resources.
DMM	Department of Market Monitoring
DOEE	Department of Energy and Environment.
DSO	Distribution System Operator…
EEX	European Energy Exchange
ELCC	Effective Load Carrying Capability.
EPAD	Electricity Price Area Differential
ERCOT	Electric Reliability Council of Texas
EU	European Union
FCA	Forward Capacity Allocation
FTR	Financial Transmission Rights
HOEP	Hourly Ontario Energy Price
ICE	Intercontinental Exchange
IESO	Independent Electricity System Operator
IMM	Independent Market Monitor
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
LMP	Locational Marginal Pricing
LSE	Load-Serving Entity
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt Hour

NYISO	**New York Independent System Operator**
OTP	**Optimal Transmission Planning**
PJM	**PJM Interconnection, Inc.**
PPA	**Power Purchase Agreement**
REM	**Restructured Electricity Market**
RTO	**Regional Transmission Organization**
SPP	**Southwest Power Pool**
T-Reg	**Transmission Regulation**
TR	**Transmission Right**
TRCA	**Transmission Rights Clearing Account**
TRP	**Transmission Reinforcement Payment**
TSO	**Transmission System Operator**