Transmission

Electricity infra – Backbone of the transition

Investment in electricity transmission infrastructure has moved from being a supporting consideration of energy policy to a core determinant of whether decarbonisation, electrification and energy security objectives can be delivered at scale. **BY BRYONY THEAKER**, partner, **CLIFFORD CHANCE.**

Ageing networks, rapid growth in renewable generation, increasingly dispersed supply and demand patterns, and greater exposure to climate-driven system shocks mean that electricity infrastructure is now the binding constraint for the energy transition in many markets. Without materially expanded, resilient and flexible transmission networks, renewable capacity additions alone will not translate into reliable, affordable or secure power systems. Against this backdrop, electricity transmission has emerged as one of the most critical and capital-intensive investment frontiers of the transition.

Historically, transmission networks have been owned, built and funded by licenced transmission owners with a natural monopoly over their respective areas, and opportunities for investment in the transmission network were accordingly linked to investment in the licensed transmission owner. Such investments are characterised by regulated revenue frameworks and long-dated, inflation-linked cashflows. In many jurisdictions, including across Europe, domestic grid assets sit firmly within a regulated asset base, with investment costs and returns recovered from consumers through network charges. This offers high predictability and downside protection, albeit with capped returns and continual regulatory engagement.

In Britain, a range of mechanisms have been introduced to encourage private investment in both domestic and crossborder transmission infrastructure and thereby accelerate deployment of this critical infrastructure. Electricity transmission infrastructure is no longer a single network utility-led asset class; it encompasses a broad and evolving set of assets that differ markedly in their regulatory treatment, construction risk, revenue mechanics and return profiles.

Alongside established domestic transmission grids sit offshore transmission owner (OFTO) assets, crossborder interconnectors and a range of emerging models, including competitively appointed transmission owners (CATOs) and offshore hybrid assets. While such assets are generally considered under the broad umbrella of 'grid' investments, regulatory and commercial model innovation in this area is creating multiple entry points for private capital with distinct risk appetites.

Domestic

- *OFTO regime* – OFTOs have become one of the most established and liquid electricity infrastructure investment classes in the UK. Introduced in 2009, the OFTO regime separates transmission ownership from generation, with assets competitively tendered and transferred post-construction to private investors. OFTOs benefit from long-term, availability-based revenues under licence, with construction risk, design and procurement risk remaining with the generator.

This structure has consistently attracted pension funds, infrastructure funds and strategic investors seeking regulated, operational assets with limited volume or price risk. A strong secondary market has developed, reinforcing liquidity and valuation transparency.

At the same time, regulatory evolution, including Ofgem's ongoing exploration of "early competition" OFTO models involving pre-construction appointment, signals the potential emergence of higher risk, higher return variants for investors prepared to take construction exposure in exchange for possibly greater upside. Early appointment of the OFTO can promote more efficient use of offshore transmission infrastructure by enabling a co-ordinated, system-led network design.

By shifting transmission planning away from generator-led, point-to-point connections and towards shared and anticipatory solutions, the "early competition" model facilitates non-radial offshore wind connection architectures that better support the scale and pace of offshore renewable deployment required to achieve net-zero targets.

- *CATO regime* – The CATO regime represents a significant development in onshore transmission investment. Although it was first mooted over a decade ago, the CATO regime is now being actively implemented, with the proposed commercial framework published last year and the first projects expected to be identified from mid 2026.

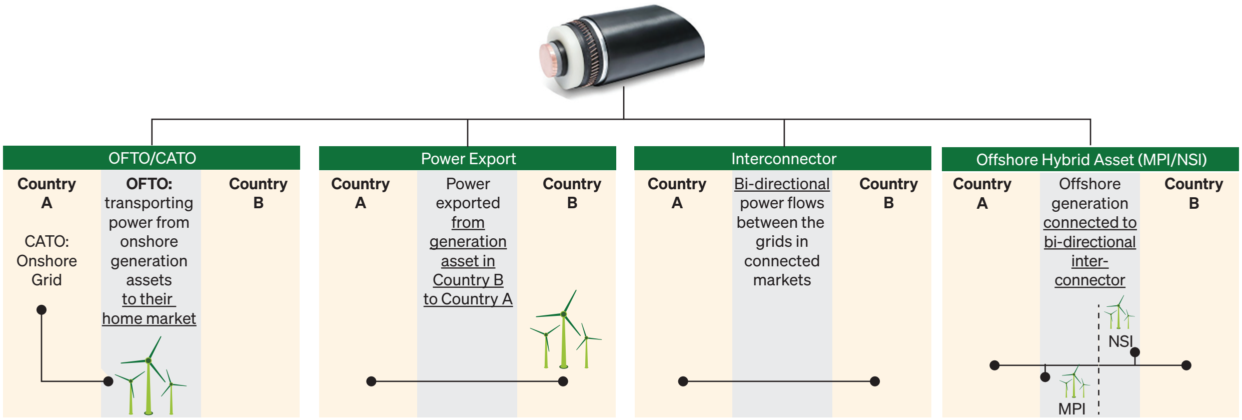
The CATO regime seeks to replicate the success of OFTOs by injecting competition and private investment into onshore grid development; however, unlike current OFTOs, the initial CATOs will be appointed under an "early competition" model at a much earlier stage of the project life cycle, before detailed design and planning are finalised. This approach aims to enhance the level of innovation in network delivery and maximise value to the consumer by embedding competition and bringing market discipline at an early stage.

This earlier appointment shifts a greater share of construction and delivery risk onto the private sector, fundamentally altering the risk-return equation. While regulatory revenue features are expected to largely mirror OFTO-style, availability-based frameworks, CATOs are likely to appeal to investors with higher risk tolerance, construction capability and a focus on value creation through efficient delivery.

Crossborder

- *Power export projects* – These are large-scale, crossborder electricity schemes designed to deliver power in a single direction, typically from remote, resource-rich regions to demand centres via long-distance HVDC transmission. Such projects are most commonly associated with hydro-export schemes or desert-based renewable developments supplying energy-constrained markets. The Xlinks Morocco-UK Power Project is an example of this model. It sought to deliver electricity generated from large-scale solar, wind and storage assets in Morocco directly into Great Britain via ultra-long subsea

FIGURE 1 - TRANSMISSION INFRASTRUCTURE



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HVDC cables, with limited expectation of reverse flows and a commercial structure focused on long-term supply rather than market coupling.

Xlinks illustrated some of the practical and regulatory challenges facing power export projects in Great Britain. Xlinks proposed a bespoke policy treatment, including a long-dated contract for difference, to manage price, volume and delivery risk, and raised strategic questions around security of supply, system integration and reliance on non-domestic generation.

In ultimately declining to support the project, the UK government pointed to its first-of-a-kind risk profile and a policy preference for homegrown generation aligned with domestic system planning. While the current focus is on power export projects in Asia Pacific, Africa and the Middle East, Xlinks stood alone as an example in the GB market prior to the withdrawal of government support. Instead, GB's regulatory frameworks treat power export as a feature of bidirectional interconnection, leaving export-only projects outside the established regulatory norm.

- *Interconnectors* – These are transmission assets that facilitate two-way trading of electricity between the electricity markets which they connect, improving system efficiency, security of supply and facilitating price convergence. A defining feature of interconnectors is their crossmarket and typically crossborder nature, which gives rise to a range of regulatory and structural complexities, including compliance with unbundling requirements in the EU and potentially differing regulatory regimes at either end of the interconnector.

In continental Europe, interconnectors have traditionally been developed by incumbent transmission system operators (TSOs) and financed on-balance sheet, with consumers bearing the majority of risk. While it is well established, this model is capital intensive and can place pressure on TSO credit metrics, increasing funding costs.

By contrast, the introduction of cap and floor regimes, most notably in Britain, Belgium and Ireland, has opened the sector to private capital. These frameworks allow investors to participate in congestion-driven merchant revenues (and, in many cases, revenues from the provision of capacity and ancillary services) while limiting downside exposure and recycling upside above the cap to consumers.

The result is a hybrid risk profile that supports project financeable structures by providing revenue predictability, attracting investors seeking moderate returns with bounded merchant risk. The cap and floor regime has been successfully project financed, with the Greenlink interconnector becoming the first such project to reach financial close in March 2022, swiftly followed by NeuConnect later that year.

The sale of Greenlink to Baltic Cable AB and Equitix in 2025 marked the first successful exit of a project-financed cap and floor interconnector into long-term infrastructure ownership, confirming cap and floor interconnectors as a mature, investable asset class.

From a consumer perspective, the cap and floor regime has also delivered significant benefits, by supporting the rollout of greater European connectivity while, to date, returning more than £200m in revenues above the cap to consumers. As of today, no interconnector project has drawn on the floor support since the regime was launched.

Despite the success of the cap and floor regime so far, questions are being raised about its future and, in particular, whether it will remain a suitable enduring mechanism to support interconnector investment under a system-led approach to network delivery. Although developer-led models in Britain, such as the interconnector regime and the OFTO regime, have successfully attracted private investment in point-to-point network assets, they do not align network buildout with the co-ordinated, long-term decarbonisation pathway required to achieve net zero.

When renewable generation was nascent, network solutions could be evaluated one project at a time; however, as the energy system transitions towards a strategically planned architecture under NESO's Strategic Spatial Energy Plan and Centralised Strategic Network Plan, the limitations of this approach are becoming more apparent. Individually promoted interconnectors are not always optimally aligned with wider system needs, particularly where interactions with offshore wind buildout, onshore transmission constraints and future meshed offshore networks are concerned. Greater central determination will be required to manage network constraints, deliver whole-system value and co-ordinate investment efficiently.

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This is apparent not just in network planning but also in procurement. Unlike national TSOs, which can leverage system-wide investment pipelines and aggregate demand across multiple network assets, interconnector developers must negotiate bilaterally with a concentrated global supply chain for high-value components such as HVDC cables and converter stations.

This fragmented approach weakens bargaining power, limits scope for portfolio discounts or framework agreements and exposes projects to greater cost volatility and delivery risk at times of constrained supply. As competition for specialist equipment intensifies across offshore wind, grid reinforcement and interconnection, the absence of co-ordinated procurement can undermine value for consumers.

While licensed transmission owners benefit from Ofgem's Advanced Procurement Mechanism through the electricity transmission price control regime, allowing them to commit to early procurement during periods of acute supply chain pressure, private interconnector developers are constrained as they must continue to bear early-stage procurement risk ahead of final regulatory approval, with no equivalent mechanism for portfolio-wide or system-backed advance allowances. This reinforces the growing distinction between regulated system infrastructure and standalone project-led assets, particularly in a global market where early access to HVDC supply chains is increasingly crucial.

- *Offshore hybrid assets* – In Europe and Great Britain, regulatory and policy attention is gradually focusing on the evolution of crossborder transmission, from point-to-point interconnectors to offshore hybrid assets (OHAs), which combine transmission from offshore generation assets with crossborder interconnection.

OHAs represent one of the most complex but potentially transformative transmission models as they include both multi-purpose interconnectors, where the offshore generating asset is within territorial waters, and non-standard interconnectors, where the offshore generating asset is outside territorial waters. The shift reflects system-level pressures created by the scale and geographic concentration of offshore wind in the North Sea, as well as growing constraints around seabed use, onshore landing points and public acceptability.

By combining transmission asset functions, OHAs enable the efficient use of infrastructure and lower overall deployment costs; however, they also raise unresolved regulatory questions around market design, revenue allocation and compatibility with existing support schemes such as contracts for difference. In response, regulators are exploring adaptations to market frameworks and regulatory regimes; for example, "offshore bidding zones" under which electricity pricing is determined at the level of the connected zone where capacity is available, rather than the generator's home market.

OHAs are increasingly seen as the first practical step towards a meshed electricity grid in the North Sea. This marks a conceptual shift away from discrete bilateral links and towards a regional system architecture, aligned with political commitments to deeper North Sea cooperation. Critically, it also reframes infrastructure resilience. Whereas point-to-point assets can represent single points of failure, a meshed configuration provides alternative pathways for power flows, improving system robustness in the face of shocks.

That distinction has taken on sharper relevance amid heightened geopolitical risk. Recent conflicts, including disruption risks in strategic corridors such as the Strait of Hormuz, have underlined the vulnerability of long, linear energy supply chains to sabotage or political interference. In contrast, a meshed offshore grid can defray sabotage risk by design. The loss of one cable does not sever supply but instead reroutes flows through parallel paths.

Delivering that resilience, however, requires pan-European cooperation on planning, standards and operation. Initiatives such as the European Grids Package and declarations at North Sea Summits reflect a growing recognition that international cooperation and alignment (on matters ranging from infrastructure planning to financing and defence) is vital if the North Sea is to fulfil its potential to act as a shared energy system which can enhance Europe's energy resilience.

The prize is significant, but so too is the cost. Meshed offshore transmission infrastructure represents a scale of capital deployment far beyond incremental interconnector investments, making it essential to avoid bespoke, one-off solutions that drive up risk premiums and delivery costs. Convergence around replicable asset structures, common technical standards and aligned regulatory approaches will be key to reducing costs and accelerating deployment. In this respect, regulatory thinking on both sides of the Channel appears to be moving in parallel.

Ofgem is exploring a shift away from a purely developer-led interconnector regime, while at EU level the Clean Energy Investment Strategy explicitly calls for greater mobilisation of private capital into strategic grid infrastructure and notes that public funding should be used to catalyse private investment, not as a primary funding source. In both cases, unlocking investment at scale will depend on the same underlying condition; a clear, reliable and durable framework that gives investors confidence that today's offshore hybrid assets are building blocks of a coherent system which can provide stable, long-term returns.

What's next

Electricity transmission infrastructure is no longer a single asset class but a spectrum of investment opportunities with sharply differentiated risk, regulatory exposure and return characteristics.

Regulators are increasingly designing frameworks that maximise the mobilisation of private capital by catering to the return expectations of different investor types – from low-risk, long-duration institutional capital to sponsors and funds seeking construction exposure, merchant upside or development-stage value creation.

For sophisticated market participants, the opportunity lies in understanding where each asset sits on this spectrum and deploying capital accordingly. Those able to navigate evolving regulatory regimes and structure investments around these differentiated return profiles will be best placed to capture long-term value as electricity systems are fundamentally reshaped. ■