CHARGING AHEAD: RETHINKING TRANSMISSION TARIFFS TO REFLECT THE COSTS OF RENEWABLE INTEGRATION

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SUMMARY

Historically, transmission infrastructure has been built to link electricity generation with demand centres. Accordingly, it has been commonplace to levy transmission infrastructure charges on customers' peak demand, which has tended to drive these costs.

However, the drivers of transmission costs are changing. Large scale integration of utility-scale renewables requires significant investment in transmission infrastructure. For example, ENTSO-E identifies the offshore transmission infrastructure required to incorporate the planned renewable capacity across Europe would stretch an equivalent of 1.5 times the Earth's equator, costing around 400 billion euro by 2050.[1]

With these rising costs, designers of network tariffs now face the challenge of recovering these new costs through transmission infrastructure tariffs, which should also send price signals encouraging the efficient use and development of the grid.

Transmission costs associated with integrating renewables are not driven by the need to meet peaks in demand, so using peak demand charges (or standing charges) to recover these costs may not be cost reflective. Instead, they are driven by the need to serve customers' energy demand from low carbon generation resources. Therefore, well-designed energy-based charges can efficiently recover the transmission infrastructure costs driven by renewable integration. Such charges can be cost-reflective and adhere to the beneficiary pays principle of tariff design.

HISTORICAL TRANSMISSION TARIFF DESIGN HAS FOCUSED ON DEMAND CHARGES TO REFLECT THE COSTS OF TRANSMISSION DEVELOPMENT TO SERVE PEAKS IN DEMAND

Historically, transmission infrastructure has been built to link large, centralised power generators with demand centres. While transmission costs may vary across locations, the need for transmission infrastructure has been determined primarily by the level of users' peaks in demand, when flows across the transmission network are at their greatest. Consequently, to meet principles of cost reflectivity, transmission infrastructure tariffs have frequently used peak demand metrics as a basis for recovering transmission companies' allowed revenues while reflecting the costs customers' usage at peak time tend to impose on the system.

- Charges levied on coincident peak demand (i.e., customers' metered energy use when demand across the whole system is highest) have been used to recover "bulk," higher-voltage transmission costs, as these assets tend to be sized to meet total (or "coincident") peak demand across the system.

- Charges levied on non-coincident peak demand (i.e., peaks in customers' metered energy use across the whole year or their connection size) have been used to recover "regional," lower-voltage transmission costs, which tend to be driven by peak demand and connection capacity in local areas.

Both the Agency for the Cooperation of Energy Regulators (ACER) in Europe and the Federal Energy Regulatory Commission (FERC) in the United States (US) have encouraged the use of peak demand charges to meet the principle of cost-reflectivity.

1. ACER, in its "Report on Electricity Transmission and Distribution Tariff Methodologies in Europe," highlights that "the main cost is usually related to the development of the network, which is typically correlated with peak demand."[2]

2. FERC states in Order 888 that "the majority of utilities plan their systems to meet their twelve monthly peaks," giving rise to charging on the basis of each of these coincident peak demands or a "twelve monthly coincident peak (12 CP) allocation."[3]

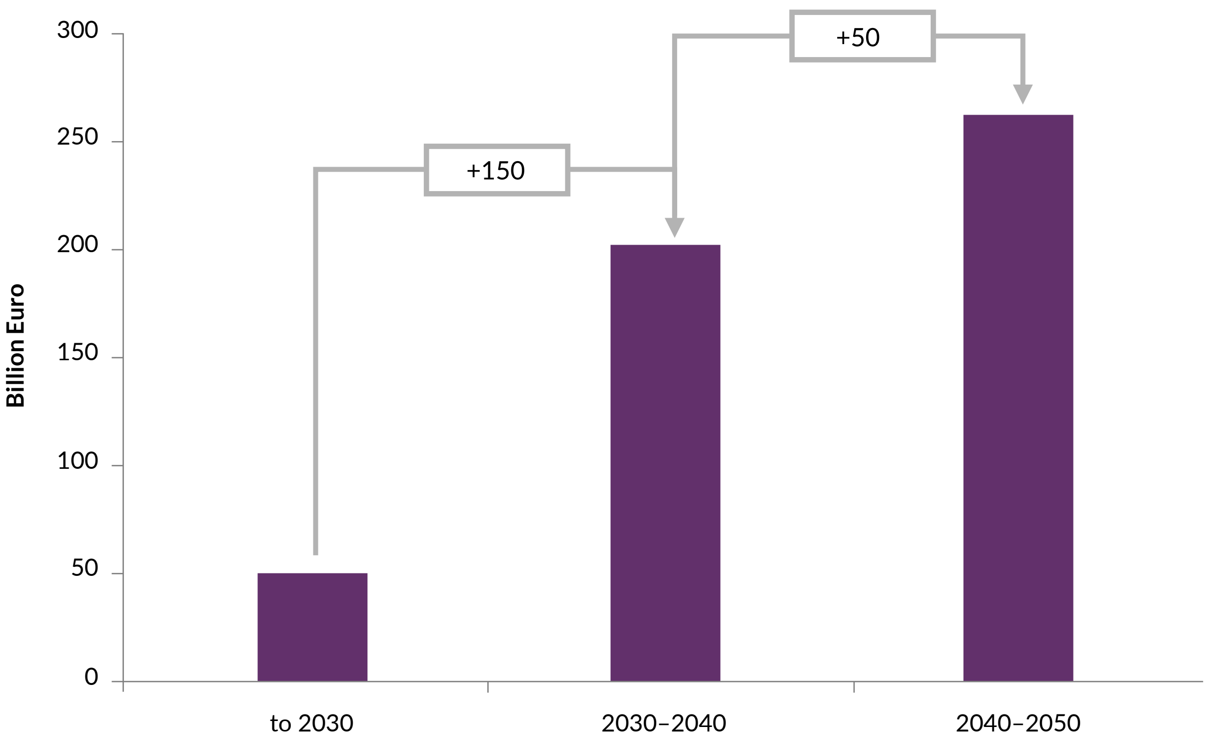
Many jurisdictions continue to recover transmission costs by charging transmission users based on peak demand metrics, including Great Britain,[4] jurisdictions across Continental Europe (e.g., Belgium, Finland, France, Portugal, and Spain),[5] and in markets in North America (e.g., ISO-NE, MISO, and Alberta).[6]

THE DRIVERS OF TRANSMISSION COSTS ARE CHANGING DUE TO RENEWABLE EXPANSION, CALLING TRADITIONAL TRANSMISSION TARIFF DESIGNS INTO QUESTION

Enormous investments in transmission infrastructure are needed to integrate renewable generation resources into global power grids since areas of high renewable potential are generally located far from areas of high electricity demand (and from existing thermal generation).[7] In Europe, while demand is highest in central regions, areas such as the North Sea provide high potential for offshore wind generation.[8] In the US, central states with high onshore wind and solar potential are far from load centres on the East and West coasts.[9]

ENTSO-E's Offshore Network Development Plan estimates the offshore transmission infrastructure required to incorporate planned renewable capacities across Europe would stretch 48,000–54,000 kilometres, equivalent to 1.5 times the Earth's equator, and cost around 400 billion euro by 2050.[10] Figure 1 illustrates that expected transmission expenditure in the North Sea alone totals 260 billion euro.[11]

Figure 1. **Estimated Cost of Interconnected Offshore Infrastructure for the North Sea**



Source: ENTSO-E.[12]

Much of this cost will need to be recovered through transmission infrastructure charges, which also play a role in conveying price signals to customers and generators about the costs their usage imposes on the transmission system. Efficient price signals would not be conveyed through traditional transmission tariff designs alone, which assume transmission costs are driven by growth in peak demand.

THE BONBRIGHT PRINCIPLES OFFER A "TRIED AND TESTED" FRAMEWORK FOR SOLVING NEW TARIFF DESIGN CHALLENGES

Well-known regulatory principles developed by James Bonbright[13] have shaped tariff design proceedings for decades. Bonbright outlines five principles of tariff design, which state a tariff should:

1. Promote economically efficient consumption decisions by providing price signals to users that reflect the costs (i.e., cost-reflectivity or cost causation) different patterns of grid usage tend to impose;

2. Recover the revenue requirement;

3. Be a fair, objective, and equitable method to recover costs through the allocation of costs across groups of customers and usage behaviour;

4. Be stable and predictable over time; and

5. Be practical to implement and update.

Often, regulators and tariff designers prioritise cost reflectivity in tariff design. A tariff design that reflects the costs of providing transmission may be both fair and objective because differences in tariff costs across customers reflect differences in costs caused by those customers' usage patterns. However, there may be trade-offs between other considerations, such as between practicality, stability, and predictability, versus the complex methods sometimes used to ensure tariffs reflect the transmission costs associated with individual users' demands. As recent policy debates in Great Britain have highlighted, the current transmission tariff design, while seeking to reflect the locational differences in transmission costs, produces unpredictable tariffs for generators and demand customers, therefore performing poorly against the predictability criterion.[14]

THE COSTS INCURRED TO INTEGRATE RENEWABLE GENERATION ARE DRIVEN MORE BY ENERGY CONSUMPTION THAN PEAK DEMAND

The significant transmission upgrades required to integrate renewable generation into the power system are largely unrelated to growth in peak demand (coincident or non-coincident). In most jurisdictions, even if peak demand did not grow, climate change policies would require that renewables be integrated into the transmission network to decarbonise supply to existing demand.

Consequently, the traditional practice of recovering costs from charges levied on peak demand is unlikely to be cost reflective. The size of the transmission network is increasingly determined by the need to accommodate peaks in flows from renewable generation resources to load centres, which occurs in sunny or windy conditions, even if demand is below its peak. Indeed, in some geographies like northern Europe, peak demand conditions are commonly associated with cold winter nights when solar output is zero.[15]

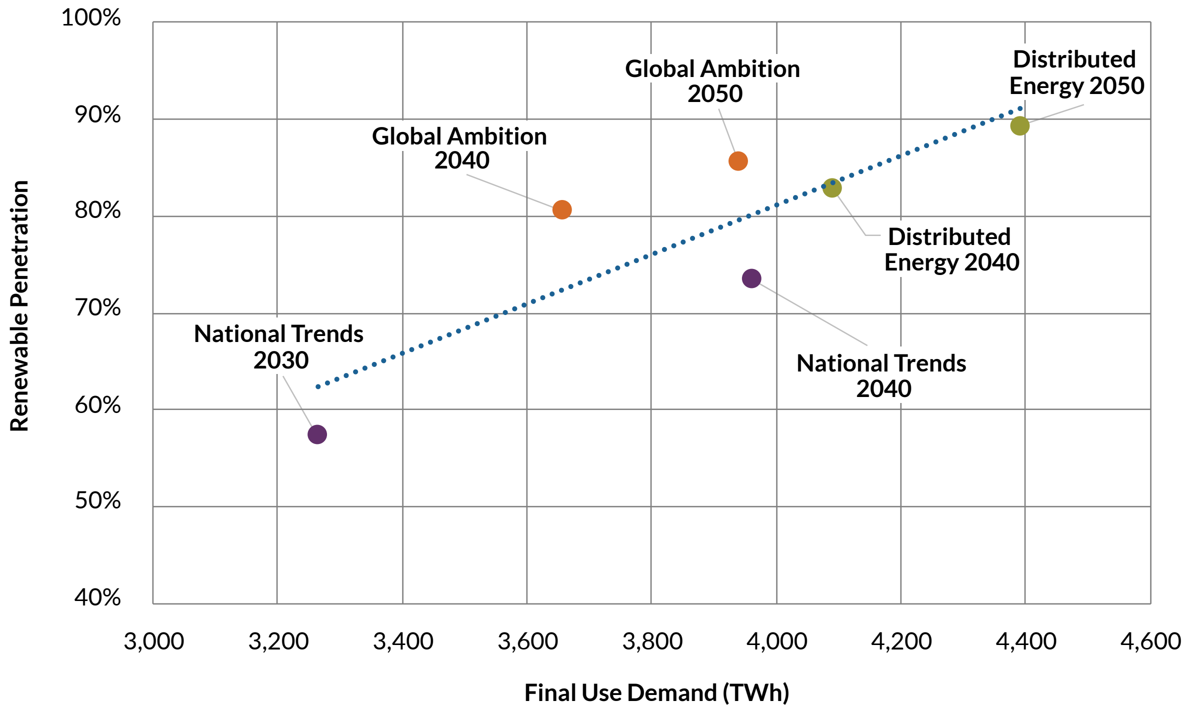
Instead, renewable generation resources, and the transmission that incorporates them into the power system, are developed to meet demand for energy across the year as a whole, not just at time of peak demand.[16] Hence, the historical assumptions embodied in the FERC and ACER guidance—that the transmission system is predominantly planned to accommodate peak demand—may now be incorrect to some extent. New investments are driven instead by the need to integrate renewables, not serve peak demand.

There is therefore a case for recovering some elements of transmission costs, either from the generators who benefit from expansions to the grid or—reflecting that the ultimate beneficiaries of transmission systems are customers—from a volumetric charge on users' energy consumption (i.e., an energy charge).[17] A transmission tariff that utilises an energy charge to recover the transmission costs associated with integrating renewable generation can meet the principles of cost reflectivity.

CHARGING FOR ELECTRICITY TRANSMISSION INFRASTRUCTURE THROUGH ENERGY CHARGES CAN BE COST REFLECTIVE

Variable and intermittent renewable generation resources like wind and solar play little role in securely meeting peak demand but rather contribute to meeting energy demand across the year. Higher energy consumption across the year, therefore, increases demand for the development of renewable generation resources to meet government decarbonisation targets and the costs of transmission needed to incorporate them into the grid. We see this in the ENTSO-E "Ten-Year Network Development Plans" (TYNDP), scenarios in which higher energy consumption is associated with higher investment in renewables and higher renewable penetration, as illustrated in Figure 2.[18] Hence, while growth in peak load growth increases transmission infrastructure costs, higher energy consumption can also increase the transmission costs incurred to accommodate renewables.

Figure 2. **Comparison of Renewable Penetration and Total Energy Consumption Across TYNDP Future Scenarios 2024**



Source: ENTSO-E.[19]

Accordingly, it would not be cost-reflective to charge for the transmission needed to integrate renewables into the power system based on consumers' usage of the grid at time of peak demand. In fact, demand in any hour may coincide with peak loading on the transmission assets provided to integrate renewables. And demand at any time of the year may increase the need for more renewable generation resources, in turn requiring larger transmission infrastructure to integrate them into the power system.

To the extent that renewable generators are not charged directly for the costs of transmission to enable their integration into the grid, it can therefore be cost-reflective to recover costs of integrating renewable generation through charges on consumers' energy demands across the year, not just peak demand or connection capacity, because demand in any hour could drive the costs of renewables integration.

Charging for some transmission costs through an energy charge can therefore be cost-reflective, sending price signals that encourage efficient use and development of the grid to users. By contrast, if all transmission infrastructure costs were recovered through peak demand charges, customers would be encouraged to consume when wholesale market prices are lower because of high renewable generation and with a usage pattern that avoids peak time to minimise their contribution toward transmission infrastructure costs. Such consumption patterns could be inefficient, because (i) users do not consider the costs of transmission needed to integrate the renewables serving their energy demand and (ii) recovering the full costs of transmission through peak demand charges sends a cost signal to customers that exaggerates the transmission infrastructure cost savings from reducing peak load.

An energy charge may also meet "beneficiary pays" principles of tariff design, which can correspond to principles of fairness or equity set out by Bonbright. Customers consuming more energy when renewables are producing would pay higher energy-based transmission charges but may also benefit from cheaper wholesale prices due to the renewable production serving their off-peak demand. If costs associated with integrating renewables were instead recovered using a peak demand charge, customers consuming renewable energy at off-peak times would benefit from the integration of renewables but would not pay toward the transmission costs incurred to integrate them.

EXAMPLE: RISING TRANSMISSION COSTS IN GREAT BRITAIN ARE RECOVERED THROUGH CHARGES THAT DO NOT SIGNAL HOW HIGHER CUSTOMER DEMAND DRIVES THE TRANSMISSION COSTS TO INTEGRATE RENEWABLE ENERGY

In the context of the ongoing Review of Electricity Market Arrangements (REMA) in Great Britain, Ofgem recently highlighted the challenges created by "unprecedented levels of transmission network build (and associated costs) in the next decade" for the design of transmission tariffs, emphasising such charges "should send efficient locational, long-run investment signals."[20]

Currently, transmission costs in Great Britian are recovered through Transmission Network Use of System (TNUoS) charges. The total costs recovered through TNUoS charges are forecast to grow over time due to the investment required to integrate new renewable generation.[21]

- TNUoS charges are paid by generators and demand, with demand paying c. 75% of total transmission charges. TNUoS charges levied on demand include locational elements intended to signal differences in the Long-Run Marginal Cost (LRMC) of transmission that usage at different locations imposes on the network.[22] Locational tariffs for demand are based on consumption during peak periods (three "triad" half-hours with the highest demand each year between November and February, separated by at least 10 days) or consumption during peak time (energy consumption from 4:00 to 7:00 pm each day) if customers are not half-hourly settled.[23]

- The remaining costs are covered through a residual charge levied as a fixed charge irrespective of customer usage:[24]
  - Residual tariffs recover c. 97% of costs allocated to demand and c. 73% of total costs and are levied through a fixed charge on each final customer site. The proportion of revenue recovered through residual charges is particularly high when compared to the locational elements that aim to signal LRMC because the method used to set locational charges does not aim to reflect the level of transmission costs caused by marginal changes in demand but instead differences in LRMC across locations of the network.
  - Site charges are determined by allocating similar sites into bands based on their characteristics (such as their connection voltage) and smearing the costs to be recovered through residual tariffs across bands based on proportions of consumption. Under this approach, a customer site faces the same residual tariff irrespective of its energy consumption. Customers do not face a signal of how higher energy usage will tend to drive the need for more transmission to integrate renewable generation into the grid.

Despite the majority of transmission costs being paid for through customers' residual charges, which ultimately feed through into customers' standing charges, rising transmission costs are being driven by the costs of integrating renewable energy resources into the power system.

Ofgem has explained that unprecedented levels of investment in expanding the transmission network are required, largely to "increase the capacity for transporting renewable power from the North to demand centres in the South."[25] Peak flows from the North to South are driven by times of peak renewable output and not necessarily customer peak demand during cold winter evenings. For instance, in 2023, the highest half-hourly wind generation of 22.0 GW occurred on 10 January between 6:30 and 7:00 pm, when demand was 22.5 GW, materially lower than the overall peak demand of 44.1 GW in the same year, which coincided with only 5.4 GW of wind generation. And across 2023, Figure 3 shows:[26]

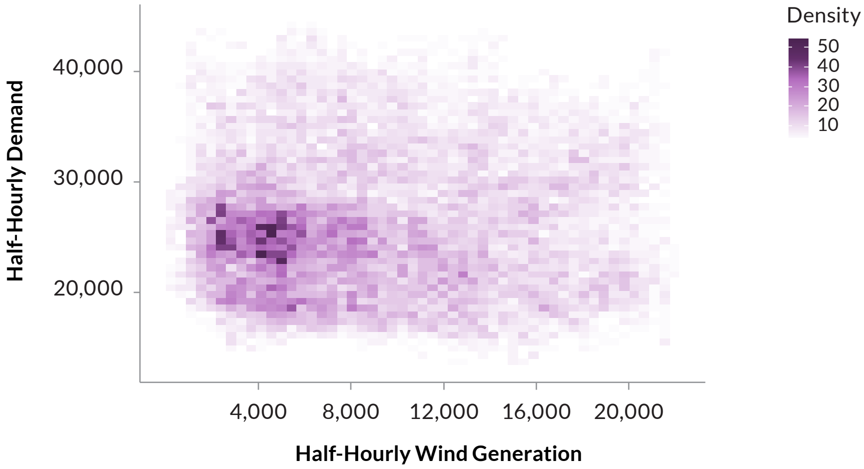
- Half-hourly, national demand is unrelated to half-hourly wind generation (the correlation coefficient between these two variables in 2023 was just 0.01);

- Half-hourly, national demand is unrelated to half-hourly flows from Scotland to England and Wales (a correlation coefficient of just 0.09), which are driving considerable transmission expansions; but

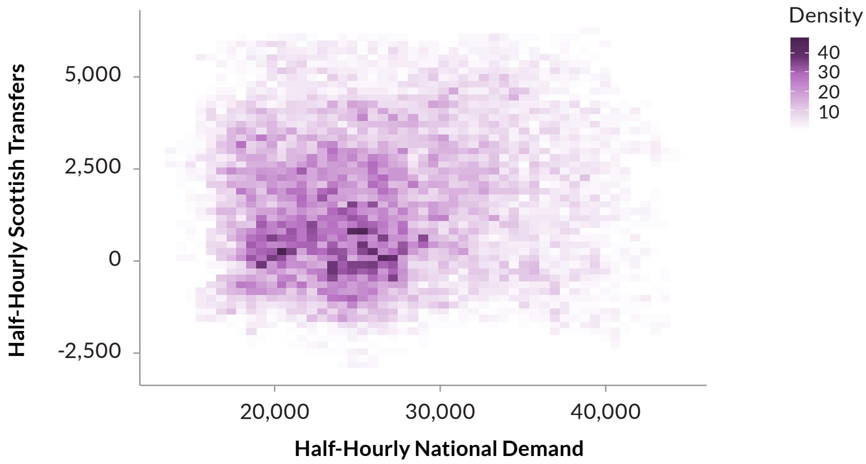
- Half-hourly wind generation is much more closely related to half-hourly flows from Scotland to England and Wales (a correlation coefficient of 0.60).

Figure 3. Relationships Between Half-Hourly Demand, Wind Generation, and Flows from Scotland to England and Wales in 2023 (MW)

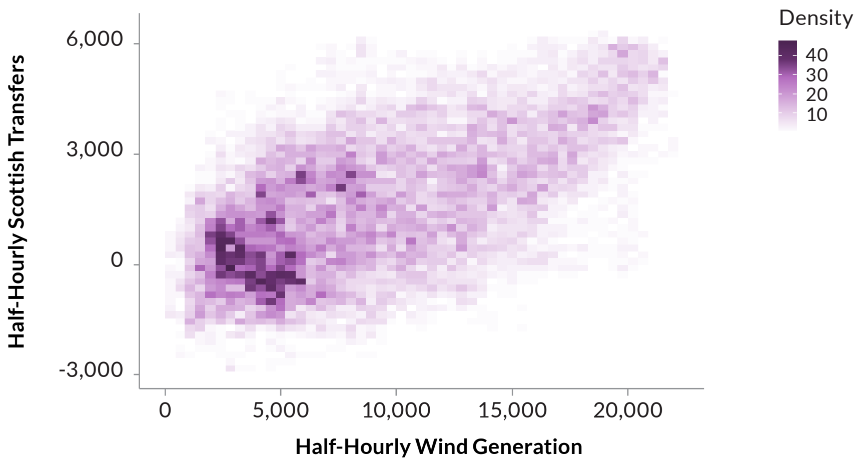
There is a weak correlation between half-hourly demand and wind generation.



There is a weak correlation between half-hourly demand and flows from Scotland to England and Wales.



Half-hourly wind generation is much more closely related to flows from Scotland to England and Wales.

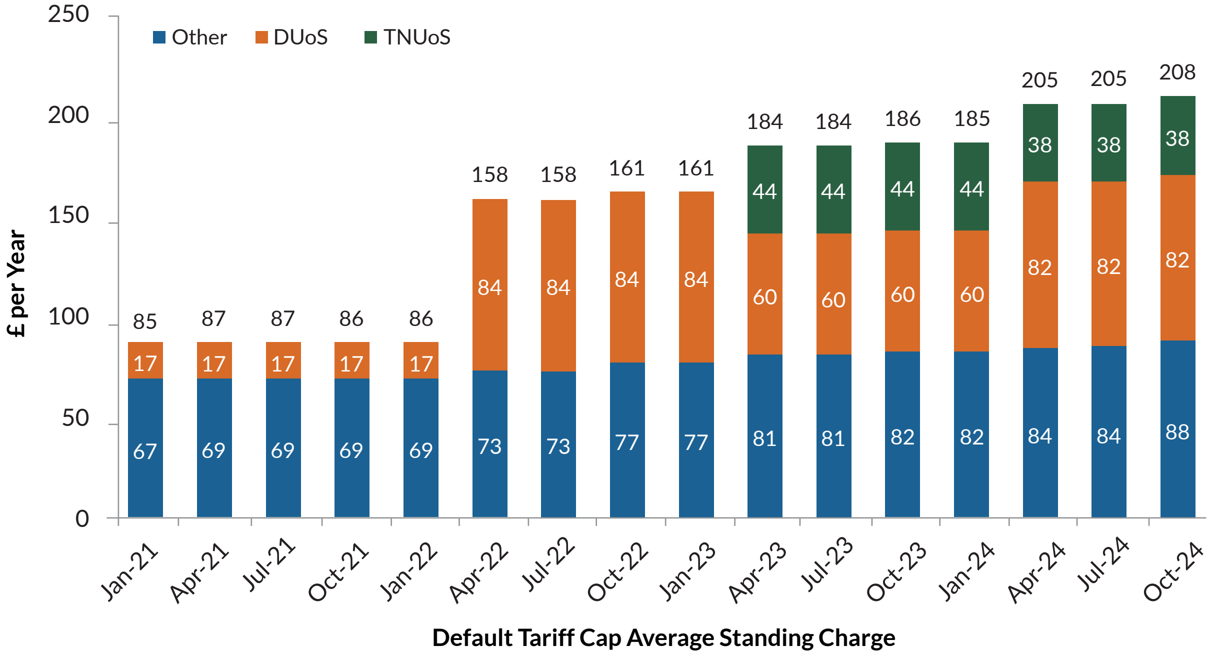


Source: NERA analysis of data from the National Electricity System Operator.

Therefore, while investments to incorporate renewables are important for enabling the UK's net zero transition, it is not cost-reflective to recover them as if the investments are driven by customers' peak demand requirements or through charges independent of customers' energy usage (e.g., through residual tariffs). Instead, the principle of cost-reflectivity requires that TNUoS charges levied on demand should identify the costs associated with renewable integration not already charged to generators and recover them through volumetric tariffs.

In Great Britain, the current practice of recovering transmission costs through site-specific charges is increasing customers' standing charges, as Figure 4 illustrates. This practice is not cost-reflective, as the main driver of rising transmission costs is the costs of integrating low carbon energy resources.

Figure 4. **Average Standing Charge in the Default Tariff Cap (£ per Year)**



Notes: We show average DUoS and total standing charges across regions rounded to the nearest pound. Source: Ofgem.[27]

SEVERAL DESIGN CHOICES WOULD BE NEEDED TO DEVELOP ENERGY-BASED TRANSMISSION INFRASTRUCTURE CHARGES, IN PARTICULAR WHETHER TO USE TIME-OF-USE TARIFFS

The question of whether an energy charge is always a cost-reflective way to recover transmission infrastructure costs and the detailed choice of implementation method will vary by jurisdiction due to factors such as the regulatory and legal constraints on tariff design, the transmission planning process, the existing grid topography and patterns of usage, and practical considerations such as data availability and implementation processes.

Where energy-based transmission charges are used, a particularly important methodological choice is whether and how to use *time-of-use* energy charges to recover the transmission costs associated with renewables integration. A time-of-use energy charge would tend to be cost-reflective when the size of the transmission network is systematically related to supply-demand patterns at particular times. In wind-dominated systems, this is less likely, as wind output can be highest at any point of the year or day. However, it may be cost reflective to incorporate a time-of-use energy charge in systems in which demand is served by more predictable technologies like solar generation to reflect that daytime energy consumption likely causes (and benefits from) transmission investment to integrate solar than consumption at night.

THE FIXED COST, FIXED CHARGE FALLACY

A possible retort to the suggestion that energy charges should be used to recover transmission costs is the notion that "all 'fixed' costs must be recovered through fixed charges."[28] Such a position stems from a simple—and ultimately irrelevant—observation that transmission costs are largely fixed, in the sense they are incurred to construct and maintain the asset and do not vary materially with its use once in operation. Therefore, the misleading "fixed cost, fixed charge" argument posits it is cost-reflective to recover "fixed" transmission costs through fixed charges levied on users' peak demand, not charges that vary with consumption.

This reasoning is flawed because it conflates the objective of ensuring transmission tariff structures reflect the drivers of those costs ("cost reflectivity") with the notion that the cost structure of transmission investments should dictate tariff structures. Rather, tariffs that meet the principle of cost-reflectivity should charge based on what usage patterns cause transmission costs to be incurred, which could be peak demand-based or use other metrics like energy consumption.

Transmission infrastructure investments inevitably involve large upfront capital investments, the costs of which are "fixed" once incurred, and relatively low variable costs of using the asset once constructed. Assets built to integrate renewable generation and assets built to serve peak demand share this cost structure. However, the cost structure of the transmission assets says nothing about what caused the assets to be built. The principle of cost-reflectivity requires tariff structures be based on the drivers of cost.

CONCLUSION

The large-scale integration of renewable generation resources into the power system requires enormous transmission investment. Rather than meeting peak demand, new transmission capacity is needed to integrate generation projects that will serve customers' year-round energy requirements. Reform of traditional transmission tariff designs may therefore be needed to avoid the inefficiencies caused by recovering transmission costs incurred to integrate renewables from charges levied on peak demand or via standing charges. Energy-based transmission infrastructure charges may play a role in promoting the efficient use and development of transmission systems.

NOTES

1 "TYNDP 2024 European Offshore Network Transmission Infrastructure Needs Pan-European Summary," ENTSO-E, January 2024, p. 7–8.

2 "Report on Electricity Transmission and Distribution Tariff Methodologies in Europe," ACER, January 2023, p. 16.

3 Order No. 888, FERC, 24 April 1996, p. 296. We also note that FERC is continuing to investigate issues related to transmission planning, cost allocation, and the need to integrate renewables or "grid enhancing technologies," recently publishing Order No. 1920 on related matters in May 2024.

4 "Five-Year View of TNUoS Tariffs for 2025/26 to 2029/30," National Electricity System Operator, April 2024.

5 "Electricity Network Tariff Report," ACER, January 2023, Table 33.

6 "Tariff Rates, Section II Open Access Transmission Tariff (OATT) Rates," ISO-NE, 9 August, 2024, available at https://www.iso-ne.com/markets-operations/settlements/tariff-rates; "Zonal Rates and Determinants 2024," MISO, 8 October 2024, accessed 29 October 2024, available at https://www.misoenergy.org/markets-and-operations/settlements/ts-pricing/; and "ISO Tariff – Current and Archive, ISO Tariff – Rate DTS," AESO, 1 January 2024, p. 1.

7 See potential reasons for this here: "Paris Agreement Compatible Scenarios for Energy Infrastructure," accessed 29 October 2024, available at https://www.pac-scenarios.eu/project-old/background.html.

8 "The North Sea: A Clean Energy Powerhouse of the Future," National Grid, accessed 29 October 2024, available at https://www.nationalgrid.com/stories/energy-explained/north-sea-future-clean-energy-powerhouse.

9 "Wind Explained, Where Wind Power Is Harnessed," EIA, accessed 29 October 2024, available at https://www.eia.gov/energyexplained/wind/where-wind-power-is-harnessed.php.

10 "TYNDP 2024 European Offshore Network Transmission Infrastructure Needs Pan-European Summary," p. 7–8.

11 Excluding some investment in Great Britain and Norway. See "TYNDP 2024 · Sea-Basin ONDP Report · Northern Seas Offshore Grids," ENTSO-E, January 2024, p. 9.

12 Id., p. 9.

13 James Bonbright, "Principles of Public Utility Rates," *Columbia University Press*, 1961, p. 291.

14 "Open Letter: Seeking Industry Action to Develop a Temporary Intervention to Protect the Interests of Consumers by Reducing the Uncertainty Associated with Projected Future TNUoS Charges," Ofgem, 30 September 2024.

15 For example, the system operator in Great Britain plans to meet peak demand conditions on cold winter nights. "Winter Outlook 2024/25: Early View," NESO, June 2024.

16 Transmission networks have always been built to accommodate flows of in-merit energy from thermal generation. However, unlike thermal generation, the peaks from renewable generation in in-merit energy generally occur at times other than peak demand because flows are partly dependent on climatic factors that determine when renewable generation output is highest.

17 Costs can also be recovered through congestion income across zones of the market or locations on the network. For instance, the introduction of zonal pricing is being considered under the Review of Electricity Market Arrangements (REMA) in Great Britain. "Review of Electricity Market Arrangements (REMA): Second Consultation," DESNZ, 12 March 2024, accessed 29 October 2024, available at https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements-rema-second-consultation.

18 "TYNDP 2024 Draft Scenarios Report," ENTSO, May 2024, accessed 29 October 2024, available at https://2024.entsos-tyndp-scenarios.eu/.

19 Notes: Final demand shown as final demand (including T&D losses and excluding pump storage) of EU27 (TWh). Renewable penetration as percentage of total generation calculated as the sum of offshore and onshore wind and solar generation (TWh) divided by total generation across power generation mix of EU27 (TWh). Id.

20 "Open Letter: Seeking Industry Action to Develop a Temporary Intervention to Protect the Interests of Consumers by Reducing the Uncertainty Associated with Projected Future TNUoS Charges," Ofgem, 30 September 2024, p. 1.

21 See for example, "Five-Year View of TNUoS Tariffs for 2025/26 to 2029/30," National Electricity System Operator, April 2024, p. 5 and Tables 14 and 15.

22 "TNUoS in 10 Minutes," National Electricity System Operator, January 2024, p. 3.

23 Id., p. 3–4.

24 Id., p. 5–6. Proportions estimated from "2024–25 TNUoS Tariff Report Tables," National Electricity System Operator, Table 22.

25 "Open Letter: Seeking Industry Action to Develop a Temporary Intervention to Protect the Interests of Consumers by Reducing the Uncertainty Associated with Projected Future TNUoS Charges," Ofgem, 30 September 2024, p. 2.

26 NERA analysis of data from "Historic Demand Data 2023," National Electricity System Operator, accessed 29 October 2024, available at https://www.neso.energy/data-portal/historic-demand-data and "Historic Generation Mix and Carbon Intensity," National Electricity System Operator, accessed 29 October 2024, available at https://www.neso.energy/data-portal/historic-generation-mix.

27 "Default Tariff Cap – Pre-Levelised Rates Model and Annex 3 – Network Cost Allowance," Ofgem, 23 August 2024, accessed 29 October 2024, available at https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/energy-price-cap-default-tariff-policy/energy-price-cap-default-tariff-levels.

28 This logic and its corresponding problems are outlined in more detail in "Electric Cost Allocation for a New Era: A Manual," Regulatory Assistance Project, January 2020, p. 78.

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