Regulation of access, fees, and investment planning of transmission in Great Britain

EPRG Working Paper 2307

Cambridge Working Paper in Economics 2335

David Newbery

Before liberalization in the 1990s, most electricity utilities vertically integrated generation and transmission. Planning could locate generation and build the network to minimize total system cost. Pricing was mainly concerned to set wholesale prices to distribution networks that set consumer tariffs. Liberalization separated potentially competitive generation from natural monopoly networks that required regulation. Generators sold to the wholesale market, which had to be designed to ensure reliable operation. The transmission system operator had to devise suitable rules, tariffs or charges to decentralize investment location and real-time dispatch decisions. Previous transmission lines were located to serve large fossil generation. The network that had been adequate for fossil generation now had to contend with quite differently located variable renewable electricity (VRE, wind and solar PV). From 2014, VRE accelerated to become the dominant form of new GB generation.

Great Britain provides an interesting case study of these various transitions: from integrated state-ownership under the Central Electricity Generating Board (CEGB) to unbundled transmission and system operation, from a fossil-dominated system to one facing massive entry of VRE, and the challenges they set for devising efficient market designs and transmission charging. The original 1990 market design enjoyed central dispatch with capacity payments, serving just England and Wales (E&W), leaving Scotland with two vertically integrated incumbents. In 2001 this market design was replaced by an energy-only market with self-dispatch. In 2004 the two nations were integrated into a single price zone - the British Electricity Trading and Transmission Arrangements (BETTA), which increased constraint costs between Scotland and England. Before BETTA, constraint costs in were less than £50 million/yr. but jumped to £250 m./yr. by 2008/9. The increase in constraint costs was exacerbated by “connect and manage” - designed to accelerate entry of wind generation in windier Scotland.

Transmission charging and connection arrangements should encourage the least system cost of delivering reliable electricity to end consumers while meeting the Government’s climate change targets. Critically, this requires correct signals for locating investment, as once made that cannot be changed. The charges should signal when, where and what type of generation should connect, and guide the least-cost evolution of the networks. Transmission charging is only one part of least-cost system design, which also requires efficient wholesale pricing and well-designed VRE contracts.

Before 1990, the CEGB had a long history of setting tariffs to reflect the costs of delivering power to different destinations; relatively unusual in the Europe apart from Norway and Sweden. After privatization National Grid (NG) evolved principles for setting the Transmission Network Use of System (TNUoS) tariffs: “Generators pay to use the network to transport their electricity supply to where it’s needed, and directly connected consumers and suppliers pay to use the network to meet their electricity demand.” The tariffs are based on Investment Cost Related Pricing (ICRP, approximating long-run marginal cost), but assume (incorrectly) that transmission lines can be instantly increased 1 MW at a time. NG makes only gradual adjustments to tariffs to avoid destabilizing investment decisions. Tariffs at best give only long-run signals that may conceal short-run congestion problems, unsuited to guiding high volumes of quick-build differently located VRE entry.

Generation or G-TNUoS charges are paid on Transmission Entry Capacity (TEC, kW), regionally differentiated to reflect the notional costs of transport from each zone to demand. The range across GB is £$_{2022}$45/kWyear or £7.50/MWh for baseload generation, compared to a pre-pandemic wholesale price of around £50/MWh and comparable to the clean spark spread. Load or L-TNUoS charges are similarly regionally differentiated to reflect the cost of delivery. The sum of each zonal L and G charge is roughly constant across the country: the average wedge between the cost of injecting and withdrawing electricity is roughly independent of location and primarily set to recover the total allowed transmission revenue.

Transmission tariff setting and investment planning have been and continue to be reformed to deal with expediting VRE connection without large consequential congestion costs. In the face of an investment drought (caused in part by policy uncertainty) capacity auctions were introduced in 2014. The first auction cleared at £20/kWyr. However, transmission-connected entrants (usually gas-fired) were faced with G-TNUoS charges while distribution-connected small (often diesel) entrants were credited with saving the L-TNUoS charge paid by the distribution network, benefiting from the total TNUoS (the wedge, largely residual charge) of around £60/kWyr. This distortion remained until the 2019 *Targeted Charging Review*.

The next sequence of reforms (still on-going) addressed problems with transmission investment planning. To address the temptation for asset-heavy solutions responding to in effect rate-of-return regulation, System Operation was separated (to NGESO) from Transmission Ownership (NGET). NGESO is expected to revert to public ownership with responsibility for more forward-looking planning.

Meanwhile Britain has been remarkably successful at developing offshore wind farms (OWFs). The first commercial-scale OWF was installed in 2003 and by 2022 Britain had 11 GW operational. The 2022 *British Energy Security Strategy* target is 50 GW of offshore wind by 2030. The ownership structure of off-shore wind is quite complex. The Crown Estate owns the rights to the seabed. As a statutory corporation independent of government its function is to "invest in and manage certain property assets belonging to the monarch; and remit its revenue surplus each year to the Exchequer." The Crown Estate identifies a number of zones and periodically auctions off options to develop within these zones. Developers build the transmission link to connect OFWs to the grid, but this must be unbundled and so is auctioned off to an Offshore Transmission Owner (OFTO), recovering the developer's investment cost in exchange for a 20-yr. contract payment in £/MWh.

The total cost of paying the licence option and rental fees to the Crown Estate, plus the OFTO charge and the G-TNUoS charge can collectively be high. The option fee in Round 4 (for the minimum three years) is $£_{2012}$284/kW, raising the 2025 projected cost of an OWF (excluding the OFTO) of $£_{2012}$1,480/kW by 17%. The OFTO charge might be (for a recent Scottish OWF) $£_{2012}$33.8)/kWyr, which, added to the G-TNUoS could be $£_{2012}$52.92/kWyr. or $£_{2012}$11.45/MWh. The recent strike price in the renewables auction for OWF in 2019 cleared at $£_{2012}$39.65/MWh, which, after paying the Crown Estate rent of $£_{2012}$3.30/kWyr., leaves just £24.90/MWh for the (option cost-inflated) OWF.

Conclusions

Britain provides useful lessons on regulating transmission charges and setting transmission tariffs to provide investment location signals. As the leader in offshore wind it provides lessons for allocating sites, efficiently pricing the offshore transmission and even proposing to coordinate OWFs with multi-link transmission investments. TNUoS charges give powerful location signals but overgenerous VRE support works against these TNUoS signals, leading to excessive congestion.

Thus both renewables support systems and transmission charges need to give efficient entry location signals. This is most simply achieved by offering long-term forward-looking transmission contracts at connection, while grandfathering charges on existing immobile generators. There are simple changes to renewables support to improve their location choices, by limiting the contract to a fixed number of efficient hours (MWh/MW), not years, as the aim of support is to finance the initial investment with cheap debt and not to amplify the benefits of distant resources.

Finally, Britain has unbundled the transmission ownership and system operation functions. If, as planned, the SO function is taken into separate public ownership and combined with anticipatory and perhaps even proactive integrated network planning, the bias towards asset-heavy solutions may be overcome.