Cambridge Judge Business School

EPRG Working Paper EPRG 2611

Cambridge Working Paper in Economics CWPE 2646

Minimising system costs: reforming transmission charges and renewable electricity contracts

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Contact	dmgn@cam.ac.uk
Publication	June 2026

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27 March 2026

Revised 5 July 2026

Abstract

Ambitious European energy plans envisage a large increase in Variable Renewable Electricity (VRE), often located distant from demand and congesting existing transmission. Many countries recognise the importance of better locational signals for investment and operation, and possible changes to VRE support systems to reduce risk and cost. This paper argues that an efficient low-carbon transition requires a suitable portfolio of reforms to transmission and market pricing and VRE support design, with different combinations suitable when some options (like spatial transmission charges or locational wholesale pricing) are ruled out. Forward-looking spatial transmission contracts offer the simplest decentralised solution for least-cost VRE expansion plans, failing which spatial planning may be needed to coordinate transmission delivery with VRE commissioning.

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1. Introduction

Liberalised electricity markets in Europe have ambitious *National Energy and Climate Plans*[2] to increase the share of electricity generated by Variable Renewable Electricity (VRE, on and offshore wind and solar PV). Such ambitions stress existing market and network designs and raise questions about VRE support systems. This article considers the role that locational transmission pricing can play in delivering an efficient transition to a low-carbon electricity market, how best to support VRE under efficient locational transmission pricing, and what alternative support systems and market design options are available if locational transmission pricing is ruled out.

Many countries are contemplating major reforms to the wholesale market and VRE support, although reforms to transmission charging appear to be lagging. The European Commission has issued several documents: EU *Regulation 2024/1747* on improving the Union's electricity market design, and EC (2025) on the design of two-way contracts for difference. The UK Government started its consultation on its *Review of Electricity Market Arrangements* (REMA) in July 2022 (HMG, 2022), concerned to improve locational pricing. European System Operators have also investigated locational pricing (ENTSO-E, 2022), reforming zonal boundaries to improve dispatch with the rapidly changing location of new power sources (ENTSO-E, 2025a), and investing in more transmission to accommodate the

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[2] https://commission.europa.eu/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en

expansion of VRE (ENTSO-E, 2023). Others have argued for more granular pricing to make efficient use of demand side flexibility and notably battery energy storage (Neuhoff et al., 2025 and references therein). Surprisingly little European attention has been paid to improving locational transmission pricing to guide investment decisions.

Other countries are also addressing the numerous challenges of high VRE penetration, and their experience highlights the complex interaction of spatial planning, transmission expansion, transmission access (including queue management) and charging, locational pricing, VRE support design, capacity market design, and other policy instruments such as tax incentives. What emerges is that no single instrument can be designed in isolation as almost all interact, and that there are a variety of design portfolios that may achieve the same or similar results. Inefficiencies that were acceptable at low levels of VRE penetration may become serious as penetration increases and require urgent reform. Desirable reforms may be constrained by institutional design and legacy expectations, making it important to construct a package of feasible reforms that achieve most of the potential gains, rather than proposing ideals that will be litigated, delayed, or under threat from future policy reversals. Market reforms may threaten to move large sums of money around for small efficiency gains and so are successfully resisted. Reform becomes the art of the possible. Nowhere has this been made more evident that Britain's attempt to introduce locational marginal prices, LMPs, to address the need for improved locational guidance for investors in the face of accelerating congestion payments and its subsequent failure.

Further, there are significant differences between fully liberalised electricity markets in which prices, whether market determined, set at auction, or regulated, are the preferred instrument to guide generation (and load) investment and dispatch, and markets in which utilities are directed to plan or authorise generation and transmission investments. There are similarly significant differences between markets with LMPs (most of the US, New Zealand and many countries in Latin America) and those with zonal prices, in many of which the zone is the whole country (as in Great Britain, GB, that includes Scotland, Wales and England).

This article is primarily concerned with European countries that have ruled out LMPs as a way of addressing spatial problems. A later section reviews some of the lessons learned from the rather sparse evidence on the impact of LMPs on investment planning and the richer evidence on other solutions to managing the transition to a high VRE system in an LMP world. The main focus is on the role of transmission pricing in guiding new VRE investment, and how, if that is ruled out for various mainly legacy reasons, other design solutions are available to guide investments to reduce total system cost of the transition to clean power. It is also motivated by the need for acceptable reforms for GB before the increasingly polarised debate threatens the low-carbon transition because of the potentially excessive and unnecessary cost of proposed network investments (NESO, 2024, 2026).

The article is structured as follows. The next section describes the spatial problems to be resolve, section 3 sets out the principles and instruments to guide efficient location, section 4 applies those to find solutions where locational transmission charges have been ruled out. Section 5 looks at countries with locational transmission charges to examine how they can be improved. Section 6 looks at other instruments deployed in countries with LMP, followed by conclusions.

2. The spatial dimension of renewable electricity

The resource (wind, sun) for VRE varies considerably across space within countries. The best resource is often far from demand centres and located very differently from the conventional power stations for which transmission was designed. As VRE reaches high penetration levels, existing transmission will prove inadequate. Congestion and the need to curtail VRE will rise sharply until transmission investment catches up. Planning and other delays often mean that grid expansion may lag years, and perhaps more than a decade (Winser, 2023). There is urgency in providing better location signals to guide new VRE investment to more appropriate locations and for better managing their delivery. Policy reform is needed to better minimise total system cost, including transmission investment and dispatch management, rather than just maximising VRE penetration.

Policy reappraisal is also needed to keep revenue risk low enough for cheap (debt) finance for VRE investment and to prevent windfall gains from energy price spikes while delivering sensible spot market responses to avoid the costly turning-down of conventional generation. This article addresses various solutions to the related problems of efficient dispatch, location choice, and low-risk VRE support design. Some countries (notably Norway, recently Sweden and Italy) have adopted zonal pricing to signal transmission constraints, but others are reluctant to move away from country-wide pricing. The UK, after an extended period of consultation (HMG, 2025) has ruled out both nodal and zonal pricing, and instead announced its intention to reform transmission charging "so that it reflects the true long-term system benefits of new generation (to) ensure that it sends an effective and predictable signal about where new investment should be located" (HMG, 2025). It has also called for advice on how to reform parts of the policy mix that impact location decisions.[3] One response to LMP's failure to address redispatch payments has been to seek subsea HVDC links to circumvent significant onshore congested boundaries (NESO, 2024; 2026). This is argued below to be an unnecessarily costly solution.

This article considers reforms that deliver, or at least improve on, the desired aim of minimising the total system cost of decarbonising electricity. Its key point is that there are often a range of solutions that, if carefully coordinated, combine to give a reasonably efficient solution to minimising the transition costs to the low-carbon electricity system. It follows that it is the whole mix of policies, such as grid access priority, curtailment compensation rules and contract design that matter. Choosing single elements that may seem attractive in isolation may be undermined rather than amplified by other policy choices. Conversely, if one option, such as nodal or zonal pricing, is ruled out, other alternative levers, specifically transmission pricing and/or VRE support design, may at least partly compensate for such policy restrictions. These options become increasingly important as the delays in consenting and then building transmission lines appear to grow ever more serious. In the early post WW2 years, the move to higher voltages and country-wide grids delivered power to distant places at lower prices. Consumers applauded the march of pylons as signs of progress. Today they are opposed by those who like the countryside to retain their vision of rural continuity, vague though that may be in an increasingly urbanised society. Transmission expansion

[3] https://questions-statements.parliament.uk/written-questions/detail/2025-12-12/99556

seems stalled without significant planning reform but there would seem to be possible solutions to explore.

3. Principles and instruments to guide efficient location

Countries face two pressing challenges to increasing VRE penetration: developers' preference for high resource locations with inadequate transmission, and resulting long queues for access to such locations. Those charged with designing an approving network expansion (transmission system operators, independent system operators, regulatory bodies or some combination) ideally would like to coordinate network expansion and VRE investment to minimise total system cost and to ensure both are delivered at the same time and with the right capacities. System operation should then deliver security-constrained efficient dispatch (Hogan, 2014). On the principle of working back from the final market this last requirement should be addressed first, then to address permitting problems and queue management, and finally to encourage the efficient expansion plan of VRE and transmission.

3.1. Reforms to ensure efficient dispatch

EU Regulation 2024/1747 mandated that support schemes "should be two-way CfDs (2-w CfDs)" (§35) and that CfDs holders "should participate efficiently in the electricity markets" (§41). The Regulation's argument is compelling. Commercial CfDs specify a fixed volume covered at an agreed strike price for specified hours – e.g. 100 MW base-load for the first half of 2026 at £88/MWh, to take a GB example.[4] If the market price is below the strike price generators receive the excess of the strike price over the market price from the CfD buyer, and conversely, they can choose not to deliver if the market price is above their cost, and instead pay buyers the excess of the strike price over the market price. In both cases, production decisions (whether to generate or not) are determined by the market, not the strike price.

VRE cannot predict output more than a few hours ahead and so cannot commit to a commercial CfD. Instead most 2-w CfDs are paid their strike price on metered delivery. If there is priority access or compensation for constrained-off VRE, their average revenue over a run of years is highly predictable and bankable. They are, however, not responding to market prices, and, worse, may even distort the dispatch order resulting in inefficient system operation. The support design question is how to preserve risk-reduction with low finance costs while participating efficiently in the market.

Variable operating costs of renewables are near zero so they should be chosen in preference to other producers unless the price falls to or below zero. Markets across Europe have been seeing a rising proportion of hours with negative wholesale prices. These are often driven not only by genuinely negative marginal costs (as when coal or nuclear plants incur costs to ramp down and then back up) but by support schemes that incentivise renewable generation even as market prices become negative. Figure 1 shows that by 2025 negative pricing was becoming a material issue in many countries, with all those shown experiencing over 500hr/yr. and Spain over 800 hours per year of negative prices.

[4] https://www.ofgem.gov.uk/news-and-insight/data/data-portal/wholesale-market-indicators

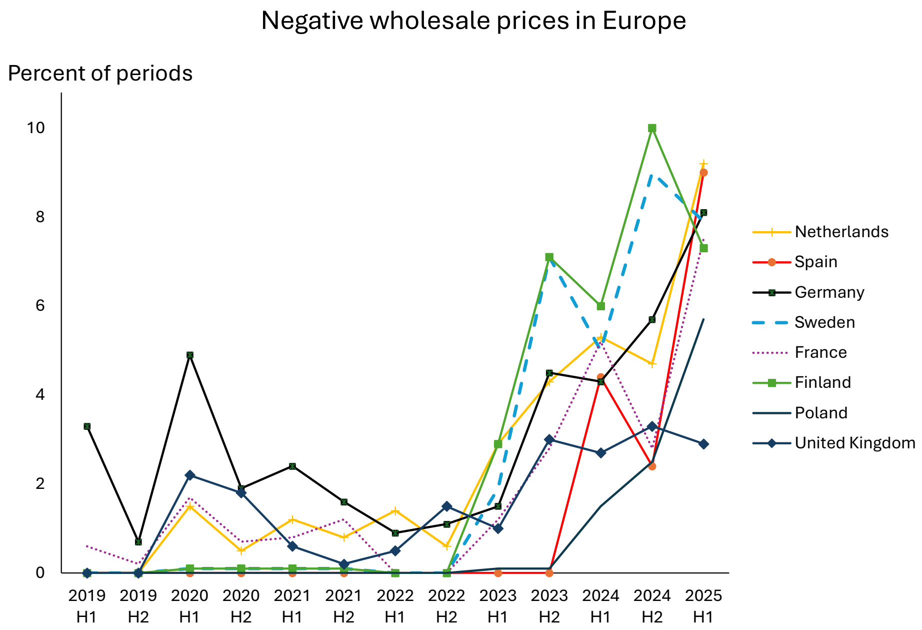

Figure 1 Negative hours as percent of year 2019-25, selected European countries
Sources: https://www.iea.org/data-and-statistics/charts/fraction-of-negative-hourly-wholesale-electricity-prices-in-europe-in-the-first-half-of-the-year-2019-2025 ; https://www.iea.org/data-and-statistics/charts/fraction-of-negative-hourly-wholesale-electricity-prices-in-europe-2019-2024

Until recently VRE curtailment was compensated until the elapse of a certain number of negative price hours e.g. in Italy, Greece and several other EU countries (Eurelectric, 2024), thus compensation was suspended only after six hours in GB[5] and Germany. EC *Guidance* (EC, 2025, p15), clarifying *State Aid Guidelines* (EC, 2022, para 123) argues that efficiency requires offering production at marginal cost, and VRE support should not incentivise offers below marginal cost. "In particular, beneficiaries should not receive any aid for electricity production during periods when the market value of that production is negative.[6] For the purpose of this document, the marginal cost of solar and wind electricity production is assumed to be zero.[7] Consequently, it is crucial that these technologies do not receive support when the market value of produced electricity is negative."

Britain modified its 6-hour rule in 2020 (DESNZ, 2020, p51) "so that difference payments are not paid to CfD generators when the Intermittent Market Reference Price is negative." In countries with zonal or country-wide single prices (as in the UK) this rule would only work properly if the Reference Price were interpreted as the real-time or

[5] https://assets.publishing.service.gov.uk/media/5a7f291040f0b6230268dcdf/Baringa_DECC_CfD_Negative_Pricing_Report.pdf

[6] Footnote 44 of the *Guidance*: "See paragraph 123 of the *Guidelines on State aid for climate, environmental protection and energy* (EC, 2022): "Please note that in certain circumstances, the costs of operating the unit also encompass the costs of ramping up and down, for example for nuclear installations."

[7] Footnote 45 of the *Guidance:* "The marginal cost of production of solar or wind generation assets (i.e. the cost of producing one additional MWh) is considered to be very low, close to EUR 0/MWh."

balancing price needed to balance supply and demand at the places where VRE injects into the grid. It should be easy for System Operators to apply this rule, but might require further Commission, regulatory or Government directives, e.g. in GB through code modifications.[8]

3.2. Efficient self-curtailment

Transmission is expensive, and the value of the small number of peak hours of VRE is low as it is likely producing surplus at the same time as similar technologies and saturating the system. If Transmission Entry Capacity, TEC, is costly (as in GB but few other countries), then VRE would choose an efficient level of TEC, and discard any surplus above that with no compensation. Newbery (2026a) sets out the derivation of the optimal TEC as a function of TEC cost (in £ per kW per year). As few countries levy TEC charges, one imperfect solution is a Flexible Connection Agreement, FCA (ACER, 2025, §5.4) that limit or control injections (and in some countries withdrawals). Such interruptible contracts are fairly common in Europe – ACER (2025, §149) lists 11 countries that offer or require FCAs for injection (AT, BE, CZ, DK, EE, FI, FR, HR, NL, NO, PT). These may specify the percentage of output or time that they can be curtailed without compensation, and if voluntary require some incentive, such as earlier connection. At the distribution level GB offers such FCAs in return for a reduced deep connection charge where this can avoid costly reinforcement.

3.3. Spatial planning and the EU's Renewable Acceleration Areas

A major obstacle in most EU Member States and certainly in the UK is the lengthy administrative permit-granting procedures. Project-by-project environmental impact assessments and public consultations place strains on under-resourced administration resulting in long delays. The EU's solution under the revised Renewable Energy Directive (Directive (EU) 2023/2413[9], RED-3) is to map suitable areas for "favourable" energy as Renewable Acceleration Areas (RAA) differentiated by type of technology, which "will then undergo a "strategic" environmental impact assessment at area-level and further projects will benefit from an exemption of project level environmental impact assessments plus accelerated permitting procedures."[10] This deals with environmental objections but not the economic problem of finding least system cost solutions for locating VRE.

3.4. Queue management

Italy's Law Decree No.1/2026 Article 7[11] is a good model in that it requires the TSO Terna to publish the maximum additional capacity of RES that can be integrated into each part of the network.[12] Article 7 also requires that capacity must be allocated through transparent and non-discriminatory procedures. Britain's NESO has similarly recognised this concept of "virtual congestion" or excess applications in the hope of securing a connection and sought and obtained regulatory approval for queue management.[13]

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[8] https://www.elexon.co.uk/bsc/article/breakthrough-for-flexibility-provision-as-rule-change-goes-live/

[9] https://eur-lex.europa.eu/eli/dir/2023/2413/oj

[10] https://www.solarpowereurope.org/advocacy/position-papers/renewables-mapping-guidance-a-step-by-step-approach

[11] See e.g. https://www.squirepattonboggs.com/insights/publications/latest-updates-on-law-decree/

[12] https://www.terna.it/en/electric-system/gaudi

[13] https://www.neso.energy/industry-information/connections/queue-management

3.5. Location guidance for new connections

ACER's (2025) survey of tariff practices contrasts connection charges from use of system charges:

130 ACER concludes that providing locational signals in connection charges is applied in most countries, particularly in distribution. In use-of-network charges, on the other hand, locational signals are observed in only a few countries (mostly at the transmission level and for injection).

329 Connection charges, if well designed, can provide locational signals to network users to connect at points of the network that are more cost efficient from a system point of view.

330 There are pros and cons for both shallow and deep connection charges. Countries that apply shallow connection charges appear to value their simplicity, higher certainty and visibility to the network users, while deep connection charges can provide stronger locational signals and can be useful to steer investment to the right place in the grid.

331 Need for locational signals and need for increased cost-reflectivity are among the most frequently reported reasons for the application of deep connection charges. This is particularly true in the case of generators, which are not subject to use-of-network charges or are subject to only marginal charges in more than 60% of the countries. However, calculating deep connection charges may be more difficult.

In theory deep connection charges, in which the developer pays the incremental cost of reinforcing the network can be efficient if shared with suitable subsequent entrant capacity (Newbery and Biggar, 2024). Deep connection charges are used in EE (Estonia), HU (partially deep) and ES, while DK differentiates between generation surplus and deficit regions. While the theory stresses the need for forward-looking or incremental cost of reinforcement most countries have an average cost model that we show below has serious limitations. The exceptions are NO and SE which use marginal losses from each connection point (which is not the same as incremental cost), and PO where they are based on peak use. Both NO and SE have zonal pricing, and until recently, both offered renewable certificates that pay in addition to the zonal price, and as such provide some locational guidance away from VRE surplus regions that depress the zonal price. After 2023 under EU pressure, NO replaced green certificates with CfDs but SE instead chose to rely on Power Purchase Agreements, which should deliver similar locational incentives.

The remaining two cases that have any form of locational guidance both use locational Generation Transmission Use of System (G-TNUoS) charges: GB and the Single Electricity Market (SEM) of the Island of Ireland. The GB case is taken as a case study in section 5, which also mentions the SEM case. ENTSO-E (2025b) provides greater detail at the country level for the other countries.

4. CfD reform without spatial transmission pricing

With the few exceptions that attempt to guide new generators to least system cost locations with deep connection charges (and most of these do so imperfectly), almost all EU countries have spatially uniform transmission use-of-system charges. These are often set at zero with all revenue collected from demand. Unless supplemented by other policies, these transmission tariffs give very poor location guidance to new renewable investments.

4.1 Guiding spatial investment choices without locational transmission charges

The first, and EU-mandated step is to draw up Renewable Acceleration Areas that simplify environmental permitting. The second is to incentivise efficient queue management in the inevitably over-subscribed high resource areas that have inadequate transmission capacity, supplemented by Flexible Connection Agreements that offer only a guaranteed proportion of compensated access hours. In parallel, spatial transmission expansion planning should determine the more socially profitable routes to develop, balancing cost and distance against the potentially delivered VRE. Calculations in the next section show how relatively long on-shore overhead lines can be justified if they access resources with 2-3% higher potential capacity factors. These steps might suffice if transmission access is only granted when and to the extent to which transmission capacity is adequate, but they do not eliminate costly (to consumers) excess rent in high resource areas in the absence of locational transmission charges.

4.2 Designing CfDs for renewable electricity to reduce excessive rent

There is a simple change to reduce incentives (and windfall gains) to locate in high wind or sunny places. If the EU-required two-way CfD contracts were set for a fixed number of delivered MWh per MW of transmission-connected capacity instead of a fixed number of years, a wind farm or PV array in a windy or sunny location would receive the same revenue over the life of the CfD as one in a less favoured location with adequate transmission access.

A defence of this radical move is that the costs of VRE are moderately site-independent, so that it is unnecessary to over-reward locations with high potential capacity factors. Combined with the zero-price rule in the balancing market it would also discourage locating in constrained places with inadequate transmission. There would still be an advantage in higher resource areas, as payment would arrive faster (if not delayed by curtailment), and after the contract expired would provide more revenue per year, but the distortion to system costs would be lower. In addition, the apparent expropriation of not paying for periods of zero or negative prices would merely be a deferred payment, not a pure loss. Spain appears to have adopted such a model. 12-year CfDs were auctioned in Jan 2021. “Awarded projects must sell a defined amount of electricity to the market under the CfD contract, but once the threshold is reached, they can either opt to continue selling their electricity under the CfD or, for example, sign corporate renewable power purchase agreements (PPAs) with industrial customers.”[14] Combined with Spain’s deep connection charging regime and the likelihood that future contracts might be at lower prices this would seem to provide strong locational signals.

Some countries, Germany is a leading example, differentiate CfD strike prices or Feed-in Tariffs (FiTs) by resource quality (Kröger and Newbery, 2024, Table 4). Although not addressing transmission congestion, it can partly mitigate the incentive to choose high resource distant locations. Combined with other requirements set out above the result may be acceptable.

[14] https://balkangreenenergynews.com/spain-gets-europes-lowest-wind-energy-price-with-cfd-auction-model/

5. Improving spatial transmission pricing: the British example

The UK[15] and Ireland are unusual in Europe in charging transmission-connected generators an annual fee that varies quite strongly with location - the Generation Transmission Network Use of System (G-TNUoS)[16] charge. The purpose of these locational charges is to signal to developers the cost of choosing different locations, ideally so that they choose the least system (generation and transmission) cost solution. In GB the G-TNUoS charges are high in Scotland and low in the South-West. Table 1 shows selected G-TNUoS charges for 2023-24. Charges depend on the type of generation and the demands it makes on the system and so four cases are shown for different generation types and capacity factors (CF).

Table 1 Selected G-NUoS charges for 2023-24 £/kWyr.

Zone	Zone name	100% CF	baseload 90% CF	wind 34% CF	wind 60% CF
1	North Scotland	£40.26	£38.21	£23.71	£29.05
2	East Aberdeenshire	£32.63	£31.45	£20.72	£23.79
7	Argyll	£36.17	£34.76	£23.71	£27.38
10	South West Scotland	£25.93	£24.59	£14.40	£17.87
15	South Lancs and Yorkshire	£5.05	£4.84	-£0.49	£0.04
16	North Midlands, N. Wales	£1.94	£1.89	-£1.37	-£1.25
18	Midlands & East Anglia	£3.97	£3.55	-£0.10	£1.00
23	Central London	-£4.21	-£4.63	-£3.62	-£2.51
27	West Devon and Cornwall	-£11.74	-£10.76	-£4.85	-£7.40
	range 1-27	£52.00	£48.97	£28.56	£36.44
	Western bootstrap Z10-Z16	£23.99	£22.70	£15.77	£19.12
	Z11-Z13 (for SEGL 1)	£7.82	£7.09	£3.93	£5.82
	Z2-Z15 (for SEGL 2)	£27.58	£26.61	£21.22	£23.75

Source: NESO (2023)

The range (in 2024/25) for a baseload generator with a 90% capacity factor, CF, is £48.97/kWyr. or £48,970/MW of Transmission Entry Capacity per year. This can be compared with the latest GB capacity auction result of £60/kWyr. for flexible new build needed to maintain capacity adequacy.[17] For a 34% CF windfarm the charges are on average about 53% of the baseload charge, but with considerable spatial variation. Thus a windfarm connected in Argyll in Scotland (a windy location) would pay £23.71/kWyr. (66% of the full amount) while one connected in the Midlands and E Anglia would be paid £0.10/kWyr (on average delivery in winter peak hours). At the assumed 34% load or capacity factor (CF) the difference between the two translates to £7.96/MWh, a substantial incentive to locate wind farms in low charge zones instead of zones distant from demand. To put this figure into

[15] The UK includes Northern Ireland, part of the Single Electricity Market with Ireland, but the SEM decides its own TNUoS charges.
[16] E.g. for 2025/26 at https://www.neso.energy/document/374811/download
[17] https://www.rwe.com/en/press/rwe-generation/2025-03-11-uk-t-4-capacity-auction-for-delivery-in-2028-29-finished/

context, the Feb 2026 Auction Round 7a cleared at £72.24/MWh for onshore wind.[18] A wind farm in Argyll would earn a gross profit of £63.28/MWh at 34% CF, compared to the full £72.24/MWh in East Anglia. The Argyll windfarm would need to have a 38.2% capacity factor to earn the same gross profits as a 34% CF East Anglian wind farm, which, given its higher wind resource, looks attractive. The 4% difference in CFs needed to overcome a lengthy overhead transmission reinforcement puts many high resource areas within economic reach.

TNUoS charges are set according to the Investment Cost Related Pricing (ICRP) methodology explained in the *Connection and Use of System Code* (CUSC: at NESO, 2025, p31 et seq.). ICRP is roughly equivalent to the Long-run Marginal Cost (LRMC) of investing in transmission to transport power assuming access to the same options as existing wires. The charges are then shifted down so that the average does not exceed €2.50/MWh to ensure compatible trading with neighbours.[19] This average requires some charges to be negative to preserve the range of prices required by ICRP. The detailed explanation in NESO (2025) is extremely complex, as it has to account for the laws of physics governing load flows in meshed circuits and the different demands made by different output patterns, summarised by their type and load (or capacity) factors.

While G-TNUoS charges should measure the annuitized value of the investment needed to deliver an extra unit of power from each zone, they assume that each existing line can be immediately expanded by 1 MW. In practice it takes on average 14 years to build new overhead lines (Winser, 2023), and it has been claimed that it is almost impossible to strengthen on-shore overhead lines (OHLs) from Scotland to England. One exception is the Cross Border Connection currently under lengthy consultation (National Grid, 2025) discussed below while others are described in NESO (2026).

Instead the Transmission Owners (National Grid, SSEN and SPEN) are building subsea HVDC (High Voltage Direct Current) links. The National Energy System Operator, NESO, is responsible for planning this expansion. Its *Beyond 2030 report* recommends around £58 billion in direct investment for offshore and onshore network upgrades as indicated in Figure 1. The *Report* includes the Western Bootstrap,[20] WB, which was commissioned in 2017 at a cost (then) of £1.2 billion (£1.55 billion, 2024 prices) and two Scotland England Green Links, both 2 GW, SEGL 1[21] and SEGL 2.[22] These have been approved for a cost for SEGL 1 of £2.0 billion[23] and for SEGL 2 of £4.3 billion (2024 prices).[24] Two further Eastern Green Links shown in Figure 1 have been approved to

[18] https://assets.publishing.service.gov.uk/media/698a0dc06da2dee8230a9c3a/contracts-for-difference-AR7a.pdf
[19] https://www.neso.energy/industry-information/codes/cusc/modifications/cmp261-ensuring-tnuos-paid-generators-gb-charging-year-201516-compliance-eu25mwh-annual-average-limit-set-eu-regulation-8382010-part-b-3
[20] https://www.spenergynetworks.co.uk/pages/western_hvdc_link.aspx
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[23] https://www.ofgem.gov.uk/sites/default/files/2024-11/EGL1%20Project%20Assessment%20Decision%20Final.pdf
[24] https://www.ssen-transmission.co.uk/news/news--views/2024/8/go-ahead-for-uks-biggest-subsea-connection-

proceed[25] but cost data are not readily available. If transmission charges are to give good locational guidance for new connections, they should reflect the cost of expanding capacity given the options available. It is, however, difficult to gain a clear sense of what these might be and to relate either the published charges or the underlying construction costs to the current cost of building specific new lines. It is also not clear whether they should be approved, as discussed below. Since then NESO has updated its report (NESO, 2026, p20) and added two additional subsea links from Scotland (EGL 5 and 6), the longer one from Scotland right down the North Sea to the South East of England. The revised cost has increased from £58 billion to £89 billion, partly due to inflation, partly from increased forecast demand with the need for more capacity.[26]

Table 2 is an attempt to gain some sense of the relative costs or charges for three specific routes from Scotland to England, and draws on Mott MacDonald (2025) for the costs of generic links of HVAC and HVDC overhead lines and HVDC subsea connections comparable to WB and the two SEGLs. The figures are not directly comparable, as TNUoS charge differences reflect the cost difference between the entry/exit zones of the subsea

project/#:~:text=*%20Ofgem%20has%20calculated%20a%20total%20expected,for%20inflation%20this%20equates%20to%20around%20%C2%A34.3bn.

[25] https://www.ofgem.gov.uk/consultation/accelerated-strategic-transmission-investment-material-scope-change-and-early-construction-funding-egl3-egl4-and-gwnc

[26] https://www.theguardian.com/business/2026/jun/30/great-britain-electricity-network-90bn-pounds-2030s

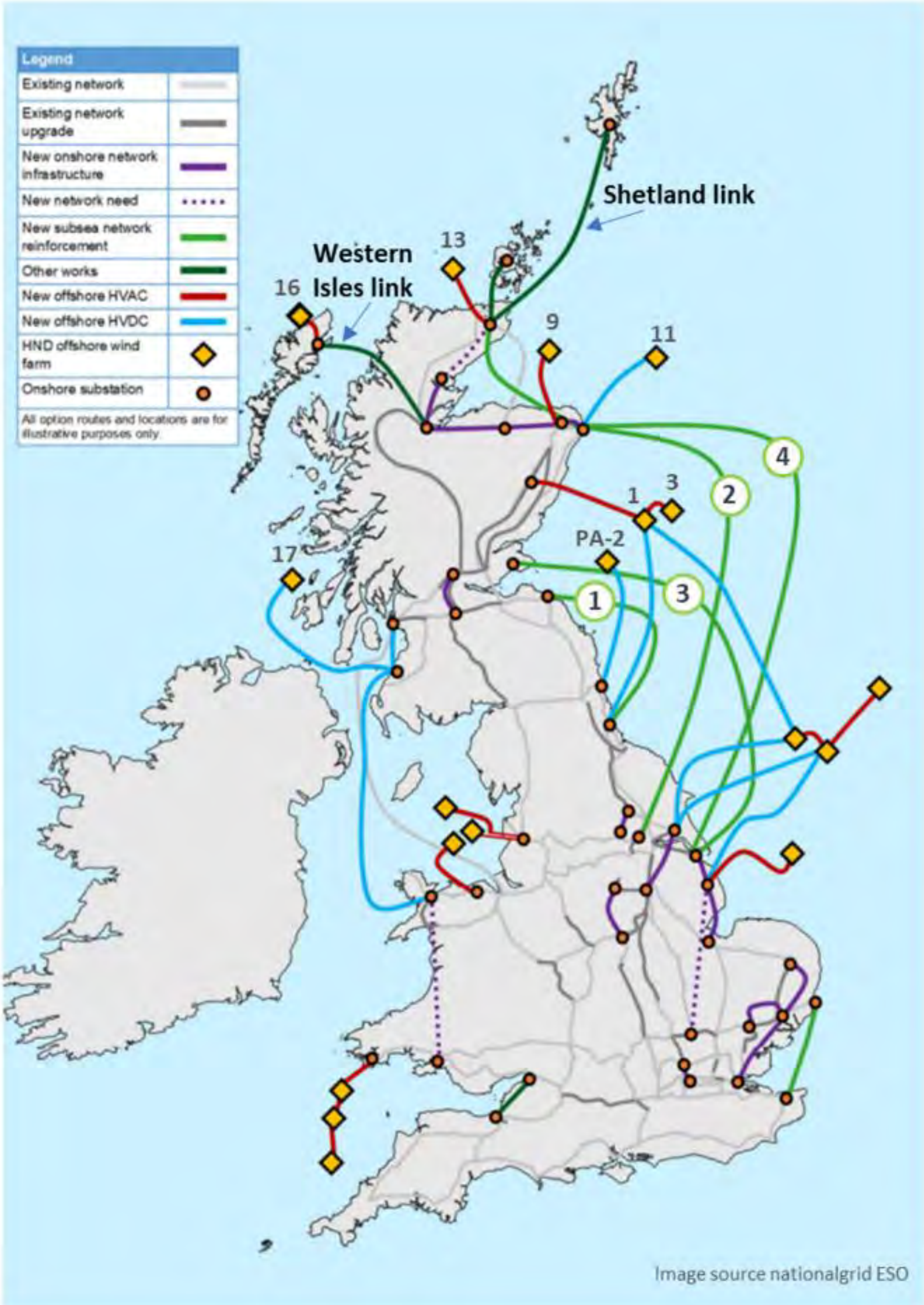

Figure 1 Beyond 2030 Network plans
Source NESO (2024)

cables, and include a variety of system-wide adjustments The Mott MacDonald costs are lifetime costs from which power losses have been subtracted, but include converter stations for DC lines, on-shore buried cables and O&M costs.

Table 2 Various cost estimates for expanding transmission lines

Item	WB	SEGL 1	SEGL 2
Length km	420	190	440
capital cost £/kW	£1,032	£647	£2,150
annuitized cost £/kWyr.	£41.75	£75.75	£130.29
TNUoS	£23.99	£7.82	£27.58
Cross border HVAC 4GW	£29.66	£13.42	£31.07
ratio subsea/TNUoS	1.74	9.68	4.72
MM 2 GW subsea HVDC	£166.28	£111.45	£174.20
MM 2.5 GW HVAC OHL 113km	£20.29	£9.18	£21.25
MM 7.5 GW HVAC OHL 113km	£9.28	£4.20	£9.72

Notes: HV: High voltage; OHL: overhead lines; MM: Mott MacDonald (2025).
Sources: For WB, SEGL 1 and 2 see links above. Costs are augmented by 20%% to cover O&M, as in Mott MacDonald (2025). TNUoS charges are for the difference in charge in the entry and exit zones for 100% CF (from Table 1). Cross Border Connection is the National Grid proposed 58km link south to Carlisle (National Grid, 2025). The MM figures are derived for specific line lengths, converted to costs per MWkm and then multiplied by link lengths at top. The MM subsea HVDC lines are either for 180km (for SEGL 1) or 275km for the others, long lines are cheaper per MWkm. The annuitizing factor is 5.05% (as in MM), also applied to the Mott MacDonald capital costs, which have been adjusted to exclude power losses. Underlying data in Newbery (2026b, Appendix).

The G-TNUoS charges are reasonably close to the estimates based on costs per MWkm of the OHL HVAC lines reported by Mott MacDonald (2023, p46). What is striking are the comparisons for HVDC lines on and offshore. The first point to note is that, with the exception of the WB, the proposed offshore HVDC cables are 5 -10 times as costly as current TNUoS charges (and the similar MM's estimated onshore OHL HVAC lines). Mott MacDonald's estimate (p109) for long distance (700km) high capacity (8GW) HVDC onshore lines are only 16% per MWkm of the 2GW shorter (275km) lines and considerably cheaper than current G-TNUoS long distance charge differences (from Table 1). Power losses are considerably lower on DC lines, and this offsets the higher cost compared to AC lines over distances of more than 500-600 km.

The current TNUoS charges assume that transmission can be instantly expanded to deal with all new entrants. Most of NESO's network plans in Figure 1 were drawn up when National Grid was in charge of design, operation as well as ownership of the grid. As a regulated monopoly National Grid had an incentive to pursue asset-heavy solutions on which it can earn a sufficiently high rate of return to attract finance. The asymmetry of information leads to situations in which the realised rate of return usually exceeds the cost of finance, as shown by market to asset value ratios normally exceeding one. The creation of NESO in 2024 as a publicly owned company acting to minimise system costs should remove the incentive National Grid had to argue for asset-heavy solutions. (The SO function was legally separated within National Grid in 2019 to mitigate this temptation.) One concern is that NESO is likely staffed by many former employees of National Grid, with the company culture of gold-plating, and in any case engineers are likely to prefer the more speedy subsea solutions.

There would seem to be two solutions worth exploring. The first is to run an additional double circuit set of pylons along the way-leaves of the current North-South main transmission lines. The nuclear power station at Sizewell has two parallel circuits to accommodate the addition of Sizewell B to Sizewell A. Indeed, the methodology for setting TNUoS charges assumes that existing lines can be incrementally expanded each year. That is demonstrably not happening at present but is clearly worth considering. The visual intrusion of adding a line to one already there would seem to be minimal, and there is little evidence of strong protests against the existing lines. One might argue in the spirit of the Renewable Acceleration Areas of REF-3 that all the necessary consents are in place and no further consultation is needed.

The second solution is to install HVDC cables from a suitable site in Scotland down to the Midlands. The total cost of long distance HVDC is lower than conventional AC lines above distances of 500-700 km because of much reduced power losses (Mott MacDonald, 2024, p109 and App G.2). Thus the lifetime cost of a 700km 8GW HVDC cable is 53% of the conventional HVAC overhead line, a dramatic saving. HVDC lines can be carried on lower pylons so if following existing way-leaves would be even less intrusive. According to Mott MacDonald (2025, p267) HVDC onshore is "Not currently used in GB but common-place in other countries. Multiple such links are currently under construction in Germany to provide a link between the North of the country which has significant renewable generation, and the South which has high demand."

One might hope that Ofgem would challenge NESO to demonstrate that its expansion plans were least cost, following the 2026 example of the US Federal Energy Regulatory Commission's cause orders under Section 206 of the Federal Power Act. This requires TSO's to consider "alternative transmission technologies; (P)reventing cost shifting and requiring transparency into transmission costs."[27]

5.1. Using reformed TNUoS charges for locational guidance

Now that all wholesale locational price signals have been ruled out in GB, the problem of guiding efficient location needs an alternative solution. The simplest to introduce is to grandfather all existing G-TNUoS charges, and to offer carefully designed forward-looking long term (e.g. 20 year) contracts for new connections. Grandfathering (i.e. allowing existing generators to enjoy the current methodology of setting G-TNUoS charges) might seem to commit the regulator to an inflexible regime, but it does not change the existing rules of the game. All residual required revenue not collected by G-TNUoS is in any case collected from load providing all the regulatory flexibility needed. Incumbents have no cause to oppose the proposed reform and the new contracts can give very powerful locational guidance.

Similar models of deep connection charging already apply to new connections to the distribution networks,[28] while off-shore wind farms are offered 20-year offshore transmission

[27] https://www.ferc.gov/news-events/news/fact-sheet-ferc-takes-action-supercharge-americas-grid-efficiency-reliability-and

[28] Ofgem financed the *Flexible Plug and Play* project – see https://www.ofgem.gov.uk/sites/default/files/docs/2015/02/fpp_progress_report_dec_2014_v1.0_pxm_151214_with_signature.pdf

contracts, whose charges are set in OFTO auctions.[29] As noted above they are in use in a few EU Member States. Further, as the regulator, Ofgem, has to ensure that charging is efficient as well as revenue-adequate, the new methodology could be introduced in the next annual round to apply to all developers who have not yet made their final investment decision and/or not yet secured a connection agreement.

Provided new entrants pay the efficient (incremental) cost of transmission and are not over-compensated in the Balancing Market for curtailment, location decisions should be efficient with the now-revised CfDs (zero compensation for system-wide curtailment that leads to zero prices) and without any additional changes to the CfD contracts (i.e. they can continue to be for a fixed number of years). If we cannot avoid (at least in the short run) going offshore to connect Scotland to England, then the forward-looking G-TNUoS charges in Scotland based on the costliest (and therefore marginal) proposed SEGL2 would be £100/kWyr. (assuming the same 77% ratio of 34% CFs to 100% CF in the bottom line of Table 1 - £21.22/27.58). This translates to £33.58/MWh for a 34% CF wind farm (once the line is commissioned). This would raise the required capacity factor for an equivalent gross profit by £33.58/£72.24 or 46% (e.g. from say a CF in E Anglia of 34% to 49.8%, very high for an onshore wind farm. The TNUoS charge would also increase with the higher CF to perhaps £106/kWyr, raising the required CF to 50.7%. By contrast, the existing Western Bootstrap only costs £53/kWyr., less than half as much.

Confronted with this G-TNUoS charge, Scottish developers would need to bid a considerably higher price and would be likely outbid by wind farms south of the border, avoiding the need for the subsea links (provided, as is surely sensible, all wind competes in the single market for which these incremental G-TNUoS charges are designed).

If only a limited export capacity at any node is currently available, only that amount would be offered firm (as under ACER's Flexible Connection Agreements), with no compensation if curtailed more than some specified amount. This has been proposed for the island of Ireland by Eirgrid (2022), which offers a non-firm connection until the link is reinforced or after five years, whichever is sooner. Logically this would be combined with priority curtailment – last connected first curtailed.

3.2 Strategic Spatial Planning and Location

The other alternative to delivering efficient location decisions is for NESO in its Strategic Spatial Energy Plans[30] to decide what can be connected where and when. If NESO properly calculates the cost of delivered power allowing for curtailment in different locations, and balances strong wind or sun against a possibly higher cost and slower delivery, the SSEPs should deliver a least-cost transition plan and hence avoid unnecessarily high consumer bills.

If VRE developers are not to enjoy windfall profits in favoured locations, there is still a strong case for appropriate G-TNUoS charges based on a proper calculation of the incremental cost of any transmission reinforcement. The alternative is to auction off the (already consented and connected) sites. Developers could also choose how much

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[29] https://www.ofgem.gov.uk/energy-regulation/electricity/offshore-electricity-transmission/ofto-tender-rounds

[30] https://www.neso.energy/what-we-do/strategic-planning/strategic-spatial-energy-planning-ssep

Transmission Entry Capacity, TEC, to buy, balancing the benefit of avoiding curtailment in a small number of hours per year against the cost of the extra TEC needed.

6. Expansion planning with LMPs

The US and various other countries have adopted LMP and this could in theory give locational guidance to new connections, provided future LMP differentials (from some hub price) were reasonably predictable, and could be suitably hedged. There is very little empirical evidence on the actual (as compared to modelled) impact of LMPs on spatial location, with the exception of a recent paper by Adamson (2026). Using hourly say-ahead data from PJM for the past 20 years Adamson finds that LMPs and locational capacity prices have been statistically significant in guiding the location of solar and gas-fired generation across PJM, but not for wind generation. LMP spatial differences of baseload and solar prices from their counterpart hub prices are reasonably stable giving predictable spatial price differences. Wind output is poorly correlated with any systematic price index, and is in any case geographically concentrated in areas where capacity factors outweigh LMP differentials.

LMP markets invariable require central dispatch and in the US emerged from a long history of regulated integrated utilities. That perhaps explains why it may be easier for states or utility commissions to require integrated planning of generation and transmission, at least once the pressures of accelerating VRE deployment puts pressure on the more laissez faire early period of liberalisation. Thus California's Clean Energy Plan has adopted an "Integrated Resource Planning (IRP) process, which identifies the optimal mix of new electric resources needed to meet the state's clean electricity goals." California "is also investing in connecting and delivering these clean energy resources to California consumers."[31]

Texas in contrast seems to have followed Australia's Renewable Energy Zone approach, where VRE developers collectively pay for the transmission to the main grid (Simshauser, 2021). Under the Texas Competitive Renewable Energy Zone (CREZ) initiative, huge investments in transmission lines have been financed to connect remote, windy areas of West Texas to the main load centres. Support as in many LMP areas is provided by PPAs made more favourable by tax credits. As VRE penetration increases cannibalisation reduces the VRE output-weighted price and although PPA strike prices have fallen, they remain attractive (Woo et al., 2023). Designing suitable long-term hedges in such markets is challenging but not impossible, and any case PPAs with utilities needing to source a share of VREs would likely encourage those utilities to take account of spatial price differences and hence choose suitably located VREs (Wiser et al., 2020, 2021).

7. Conclusions

Renewables support has evolved over time to require competition for the market through auctions for two-sided CfDs in Europe. Other jurisdictions that have renewable targets have offered state-back and private PPAs, which may better address LMPs and zonal price. Two-side CfDs are a significant improvement on premium Feed-in-Tariffs or one-sided CfDs that give all the upside to producers and politically unattractive windfall gains in high-price periods. A CfD also forces the generator to sell in the market, but normally compensates for any curtailment unless otherwise specified (e.g. by negative prices). By itself, even a

[31] https://www.gov.ca.gov/wp-content/uploads/2023/05/CAEnergyTransitionPlan.pdf

competitive CfD auction for firm connection contracts gives poor location signals, and fails to direct VRE investment to the right place at the right time. If locational grid charges are ruled out, some of the incentive to locate in high resource areas that are costly to connect or highly congested can be addressed by limiting the CfD to a limited number of compensated hours rather than a limited number of years and defining discounts on the strike price for resource-intensive regions. Flexible Connection Agreements help manage queues and discourage premature VRE development ahead of transmission, but none of these additional policies ensures least-cost system expansion.

For countries like Britain with locational transmission charges, forward-looking long-term grid contracts that reflect deep connection costs deal with part of the problem but need further adjustment to discourage early investment in areas experiencing high marginal curtailment. Flexible Connection Agreements offer non-firm connections until reinforcement allows the required Transmission Entry Capacity to be provided, with priority dispatch – last-in first curtailed without compensation. CfDs can then continue to be for a fixed number of years. While this increases developer risk raising revenue requirements it only does so where transmission is not available, and is the spur to more efficient location choices. In both cases it remains to ensure that CfD offers in the balancing market cannot be negative, which, with no compensation for negative country-wide wholesale prices, should finally deliver an efficient dispatch and discourage connecting behind congestion constraints.

Finally, many authors (e.g. Woo et al., 2023) have argued that VRE does not pay the various costs it imposes on the system as a whole, such as the need for higher capacity payments to dispatchable power, and the cost of extra flexibility services. If VRE pays its incremental transmission costs, and only receives properly calculated capacity payments (bearing in mind that unlike conventional generators, it experiences highly correlated outputs and so acts more as a single large generator) provided ancillary services are properly remunerated, the market should still deliver efficient signals for the desired level portfolio of generation. The extent of and cost of VRE expansion then remains as a political choice, made with the transparent accounting of all costs these reforms deliver.

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Appendix: Data sourced from Mott MacDonald (2025)

Onshore HVAC Overhead Line – 75 km – Low Rating (2,494 MW) p46
Build cost £144.70m, O&M cost £12.04m
Total cost £156.74m: Cost per MWkm: £838/MWkm = £55.30/MWkmyr
Cost per 100km: £5.53/kWyr
Cost per 100km for line of length 112.5 km = £4.83/kWyr
[Energy loss £69.62m= £2.46/kWyr for 100km]

Onshore HVAC Overhead Line – 75 km – **Medium Rating** (**4,988 MW**) p47
Build cost £221.17m, O&M cost £18.39m
Total cost £239.56m: Cost per MWkm: £640/MWkm = £42.25/MWkmyr
Cost per 100km: £4.23/kWyr
Cost per 100km for line of length 37.5 km = £6.65/kWyr
[Energy loss £199.24 = £3.51/kWyr for 100km]

Onshore HVAC Overhead Line – 75 km – **High Rating (7,482 MW)** p48
Build cost £221.17m, O&M cost £18.39m
Total cost £239.56m: Cost per MWkm: £427/MWkm = £28.18/MWkmyr
Cost per 100km: £2.82/kWyr
Cost per 100 km for line of 112.5 km = £2.21/kWyr
[Energy loss £362.84m = £4.27/kWyr for 100km]

Offshore HVDC Submarine Cable – 180 km – High Rating (2,000 MW) p121
Total cost including energy loss = £9,887/MWkm = £652.54/MWkmyr.
Total cost per 100km: £65.25/kWyr.
If energy cost per 100km is £6.59/kWyr
Comparable cost excluding energy 100km line is £58.66/kWyr.

Onshore HVDC VSC "embedded link" – 275 km – (2,000 MW) p95
This scenario uses the same converter station infrastructure as an embedded link, but different costs for HVDC cable as a result of the route being onshore and thus using underground cable as opposed to submarine cable to connect offshore to inland sites.
Build cost £1,102m, O&M cost £458m
Total cost £1,560m: Cost per MWkm: £2,836/MWkm = £187.18/MWkmyr.
Cost per 100km: £18.72/kWyr.
[Energy loss £549m = £6.59/kWyr for 100km]

Offshore HVDC Submarine Cable – 275 km – High Rating (2,000 MW) p122
Total cost including energy loss = £6,997/MWkm = £461.80/MWkmyr.
Total cost per 100km: £46.18/kWyr.
If energy cost per 100km is £6.59/kWyr
Comparable cost excluding energy 100km is £39.59/kWyr. 67% of the shorter cable

Onshore HVDC LCC – 700 km – Rating 8,000 MW p109
The HVDC scenario considers an overhead line with two phase conductors and a metallic return, providing the functionality for operation at half capacity under certain situations.
Build cost £4,059m, O&M cost £1,266m
Total cost £5,325m: Cost per MWkm: £951/MWkm = £62.77/MWkmyr.
Cost per 100km: £6.28/kWyr.
[Energy loss £4,075m = £4.80/kWyr for 100km]