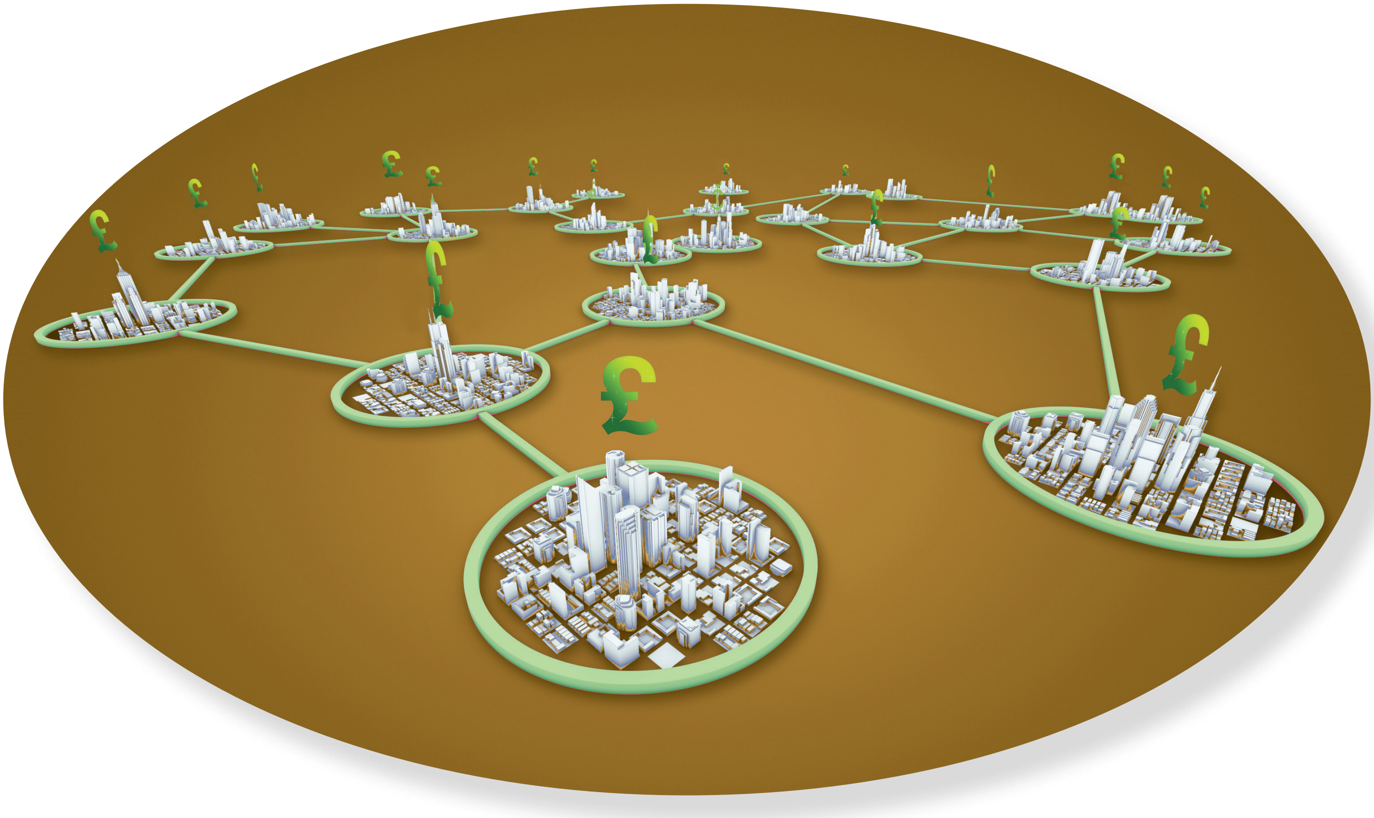
It's All About Grids



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The Importance of Transmission Pricing and Investment Coordination in Integrating Renewables

IN GREAT BRITAIN, IT IS PROJECTED THAT AN unprecedented amount of transmission investment will take place in the next decade and that these investments will be the largest transmission network reinforcements since the post-World War II expansion. In Figure 1, the projected range, to 2030, of onshore, offshore, and cross-border investments is presented against the estimated asset values. The value of the transmission assets is expected to more than double to 2030 with investments projected

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between £20 billion and £50 billion across onshore (main transmission system), offshore (connecting mainly offshore wind farms) and cross-border interconnection transmission projects. The exact level and cost of these transmission investments will depend on a number of factors, including the location of new conventional and renewable energy sources (RES) plants (considering on- and offshore developments); decommissioning of existing ones; demand growth; cross-border trading of energy and ancillary services; and uptake of distributed generation, energy storage, demand-side response, and other smart grid technologies.

Given this uncertainty and to a certain degree flexibility on the potential investment plans, it becomes imperative that these investments are undertaken, as much as possible, in an efficient and timely manner that will largely depend on how transmission investment is undertaken and how costs are allocated. In this context, we analyze two main factors that can significantly impact the level and cost of the transmission investments going forward by drawing on our recent experience of 1) reviewing transmission pricing in Great Britain and 2) examining the benefits of alternative policy approaches associated with different levels of coordination and Great Britain–European Union (EU) market integration among offshore wind generation and interconnector projects in the North Seas, respectively.

Effects of Transmission Pricing Options in Great Britain

In principle, the mechanisms used to allocate short- and long-term transmission network costs could materially affect the value of a generator and its output and hence also affect the generators' locational decisions. For instance, the choice of where to locate a wind farm should involve consideration of the trade-off between regional variation in wind speeds (i.e., load factors) and the costs imposed on the transmission system; similarly the choice of the location of gas-fired generators entails a trade-off between regional variation in gas prices and electricity transmission system costs, along with other factors such as the availability and costs of cooling water. Efficient network charges that recover the costs of infrastructure, congestion/constraints, and losses convey pricing signals to investors and therefore provide a means of ensuring the overall system economic efficiency.

In this context, we will explore this question further by drawing on the recent experience of reviewing transmission charging regime in Great Britain and the analysis carried out (as part of this process) to assess the impact of the alternative network charging options.

Great Britain Transmission Arrangements

The British wholesale market is characterized by a single national wholesale price that reflects the prevailing marginal cost in a system without network congestion/constraints. Although there is no location-specific pricing, infrastructure costs are recovered through network tariffs called transmission network use of system (TNUoS) charges that include a location-specific component. Given the dominant north-to-south power flows, network charges for generators vary from around £25/kW/yr in Northern Scotland to £–5/kW/yr in South West England (Figure 2), while network charges for demand customers, based on their peak demand, vary from £23/kW/yr in North Scotland to £45/kW/yr in South West England.

For 2015/2016, the total revenue collected will be £2,637 million, and it is expected to almost double by 2030. The cost is split 27/73 (the exact split is currently under review with proposals to review it annually or change the split to 15/85) between generation and demand, and currently, the majority of transmission network costs (about 75%) are collected through nonlocation specific flat charges (called residual charge) implying a high level of cost socialization. The locational part of the TNUoS tariffs is computed using a methodology that intends to reflect the long-run marginal costs of transmission investment. This part of the transmission tariff was recently reviewed through a regulatory project called TransmiT.

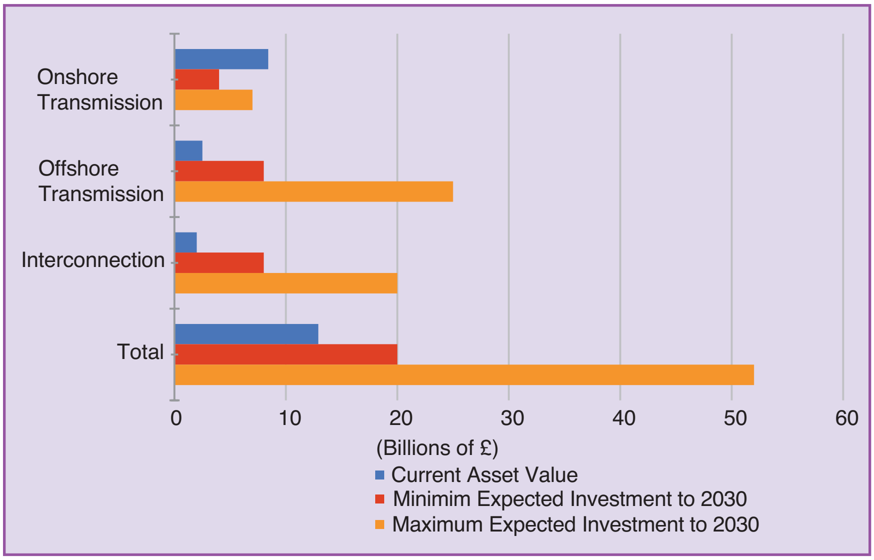

figure 1. Great Britain's current and future transmission asset value.

Project Transmit Overview

The TNUoS charging methodology called investment cost related pricing (ICRP) aims at setting network charges that proxy the network investment costs needed to accommodate a "marginal" megawatt of generation capacity or demand. Since historically

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the transmission system was planned and built to provide the capacity required during peak demand conditions, the current ICRP methodology reflects the network investment costs needed to meet this requirement.

However, the need to accommodate peak demand conditions is no longer the sole driver of transmission capacity requirements. Increasingly, investments to expand the transmission system are required to integrate renewable generators into the transmission system, particularly wind farms. Wind generators typically produce less during extreme winter conditions when demand is highest. Instead, their production is highest on windy days when overall electricity demand is typically lower than peak levels. These dual drivers of transmission investment are now reflected in the network planning standards, which specifies the criteria that transmission owners must apply when deciding how much transmission capacity to provide. As a result, transmission system operators (TSOs) are obliged to provide sufficient boundary capacity to fulfil two criteria:

- ✔ a demand security criterion that requires sufficient boundary capacity to ensure continued system operation in peak demand conditions, on the assumption that intermittent generation and interconnectors are unavailable and with all other generation variably scaled uniformly to match generation to demand
- ✔ an economic criterion that requires sufficient boundary capacity to ensure economic operation of the system (balanced network investment and congestion/constraints), on the assumption that output from different low-carbon generation technologies (intermittent, nuclear, and carbon capture and storage), conventional generation, pumped storage, and interconnectors are scaled by specific factors to meet demand.

For this reason, in 2010, the Great Britain energy market regulator, Ofgem, announced a fundamental review of current electricity charging arrangements, called Project TransmiT, which aimed to improve the charging methodology. Through this process, Ofgem originally proposed to consider three possible scenarios for network charging going forward:

- ✔ the status quo, whereby the current model would continue with minor modifications
- ✔ a socialized or uniform charging model, whereby generation TNUoS charges would be paid through a uniform charge per megawatthour of energy output
- ✔ an improved ICRP charging model, which seeks to alter the existing charging model to reflect the fact that different types of generation may impose different costs on the transmission system.

The way the uniform charges are calculated is straightforward; the total amount of revenue that needs to be recovered from generators [27% of the annual regulatory asset value (RAV)] is just split by the total generation capacity resulting to a fixed uniform charge on a £/kW/yr basis. To calculate the status quo and improved ICRP charges, a transport model is used that calculates the marginal cost of investment in the transmission system, required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, by analyzing the system power flows during peak demand conditions. The key difference between the two charging methodologies is how generation is scaled so as to meet this peak demand condition. In the status quo, all generation capacity is scaled down uniformly. In the case of improved ICRP, the transport model runs twice with different scaling factors for different technologies. The first run, called peak scenario (accounting for the demand security criterion), assumes that interconnection and RES load factor is zero and all other generators are scaled uniformly. The second scenario, called year-round (that accounts for the economic criterion), sets different scaling factors for different types of plant (Table 1).

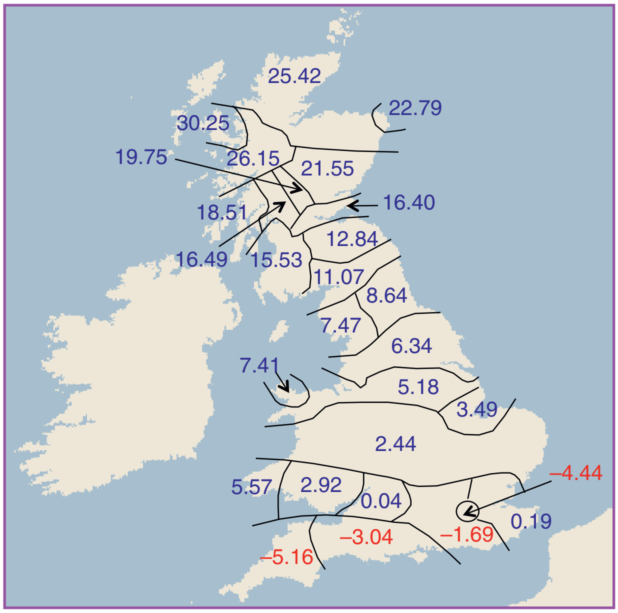

figure 2. Great Britain generation transmission tariffs £/kW/yr.

table 1. Scaling factors per generation technology for improved ICRP transport model.

Technology	Demand Security Criterion	Economic Criterion
Peaking plant (e.g., OCGTs)	Variably scaled	0%
Wind, wave, and tidal	0%	70%
Nuclear and CCS	Variably scaled	85%
Pumped storage	Variably scaled	50%
Interconnectors	0%	100%
Other	Variably scaled	Variably scaled

For each network circuit, the power flow in the peak and year-round scenarios is compared, and the costs of each circuit are attributed to the scenario with the highest power flow. This ensures that the marginal costs of each transmission circuit are reflected in only one of the two scenarios resultant charges. In this way two tariffs are obtained: the peak security tariff and the year-round tariff. An intermittent plant would not be exposed to the peak security tariff. All generators will be charged the year-round tariff in relation to their average annual load factors while applying a series of heuristic rules and approximations.

Modeling Framework

The modeling framework developed for analyzing transmission charging options consists of two stages, impact assessment and cost reflectivity assessment.

Stage 1: Impact Assessment

This first stage determines the whole system evolution and its associated cost and consumers' bill when different network charging options are modeled. The modeling horizon for this analysis was 2030, and the modeling exercise involved iterating among a power market model, a transmission investment model, and transmission charging model until all three converged (see Figure 3). To model the evolution of the wholesale power market, the AURORAxmp market model (referred to hereafter as Aurora) was used. A separate model to optimize investment in renewable generation capacity was created that works in tandem with Aurora. Both of these models use assumptions on a range of fundamental market drivers, such as the volume and characteristics of existing generation capacity, commodity prices, the costs of new generation capacity, and electricity demand growth, as well as TNUoS charges. To model optimal operation and investment in the transmission system our dynamic transmission investment model (DTIM) was used (implemented in FICO Xpress), which takes locational generation and demand data as an input. Using the forecast of transmission investment from the DTIM, TNUoS charges for the period to 2030 were computed for proposed network charging methodologies, which were then fed to the power market modeling.

Stage 2: Cost Reflectivity Assessment

Tariff philosophy in Great Britain establishes that locational network charges should reflect the long-run marginal cost (LRMC) of the network infrastructure. Hence, DTIM was used to estimate the LRMC of transmission infrastructure associated with particular types of generation at different points in the network. The methodology of calculating the LRMCs is similar to the improved ICRP, but instead of considering only peak demand and two generation scenarios, all year-round demand and generation conditions (of which many may present network congestion) are analyzed and used to calculate annuitized transmission charges for every plant in the system.

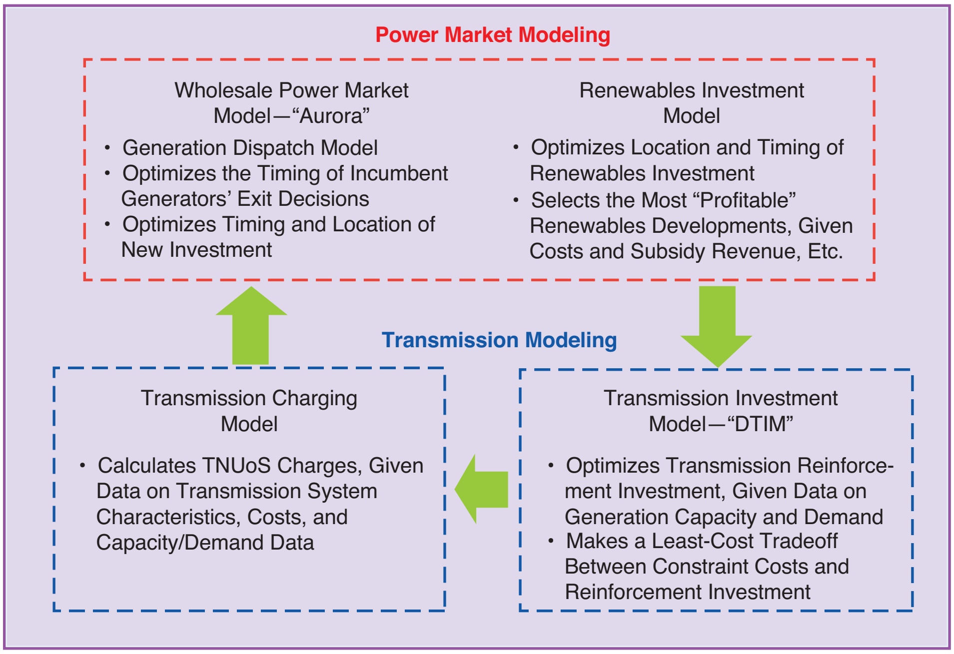

figure 3. An overview of the impact assessment modeling framework.

Modeling Results

Generation Investment Patterns

Our analysis suggests that although the capacity mix is broadly similar across

> Investments to expand the transmission system are required to integrate renewable generators into the transmission system, particularly wind farms.

different charging methodologies, there were some marked differences. As expected, under less location-specific network charging regimes, both RES and new conventional plants tend to locate further in the north of Great Britain where wind resources are better and gas charges lower. Similarly, more wind capacity is located offshore and less onshore, while offshore wind generation development is concentrated in more remote sites, as illustrated in Figure 4, which contrasts wind generation investment patters under location specific (i.e., status quo) and uniform pricing. Interestingly, improved ICRP also results in (slightly) more renewable generation capacity that is located further north of Great Britain.

Transmission Costs

As expected, given the significantly different generation investment patterns, and as Figure 5 shows transmission investment costs, congestion/constraints costs and losses are substantially higher under uniform network charges. Because improved ICRP results in slightly more renewable generation capacity that is also located further north, it tends to increase transmission system costs, as well as transmission losses due to increased north-to-south power flows.

The Impact on Wholesale Power Prices

Uniform TNUoS charging removes the possibility for new entrant combined-cycle gas turbines (OCGTs) and open-cycle gas turbines to locate in zones with negative TNUoS charges where plants would receive a remuneration rather than be charged, which increases the costs needed to be recovered through power market prices and hence create welfare transfer from consumers to producers (Figure 6). Likewise, the improved ICRP charging model also changes the fixed costs of new entrant plants and, in particular, in the period to 2020, the long-run marginal cost of new entry is around £1/MWh higher than the status quo.

The Impact on Consumers

As a result of higher power prices and transmission system costs, this modeling estimated that uniform network charges would increase costs to consumers by £19.8 billion in net present value (NPV) terms between 2011 and 2030 compared to the status quo. This equates to £3.56 per megawatthour of energy demand, or around 2.2% of the energy component of 2020 consumer bills. Introducing the improved ICRP methodology would also increase consumer bills by around £3.4 billion in NPV terms over the period to 2030 (see Table 2 where the NPV base year for the comparison of status quo with uniform and improved ICRP charges is different because the analysis was undertaken for different periods).

Cost Reflectivity Analysis

The impact assessment analysis quite clearly suggests that the status quo charging methodology results in lower consumer bills and system costs compared to both of the alternative charging methodologies. Whereas the inefficiencies associated with uniform charging were somewhat expected, this is not the case with improved ICRP, which is a more advanced charging methodology. As a result, the two charging methodologies were further compared using the cost-reflectivity modelling frame work presented earlier.

As Figure 7 shows, both the improved ICRP (red lines) and status quo (blue lines) methodologies send locational signals to wind farms that understate the LRMC (black line) of transmission. However, because improved ICRP compresses the locational spread between tariffs in the north and in the south compared to the status quo, this analysis suggests that improved ICRP is less cost reflective for Scottish wind farms than the status quo. This finding implies that the cost of network reinforcement caused by connecting wind farms will be subsidized by other market participants.

On the other hand, as Figure 8 shows, both improved ICRP and the status quo methodologies set locational tariffs to peaking plants in Scotland in excess of the LRMC of transmission that their presence imposes on the system relative to the LRMC of connecting in other parts of the country.

Because improved ICRP compresses the spread between tariffs in the north and in the south more than the status quo, this suggests that improved ICRP is more cost reflective for this category of generation. However, under both improved ICRP and status quo methodologies, TNUoS charges are lower for peaking plants in England and Wales than in Scotland. In summary, while the improved ICRP charging methodology does make changes to TNUoS charges that (on the face of it) recognize the dual drivers of transmission reinforcement (peak security and "year-round" investment requirements), these changes are calculated through a series of heuristic rules and approximations. The analysis presented shows that the combination of these approximations used in the improved ICRP methodology produces locational charging signals that reflect the LRMC of transmission less (or no more) accurately than the status quo, which

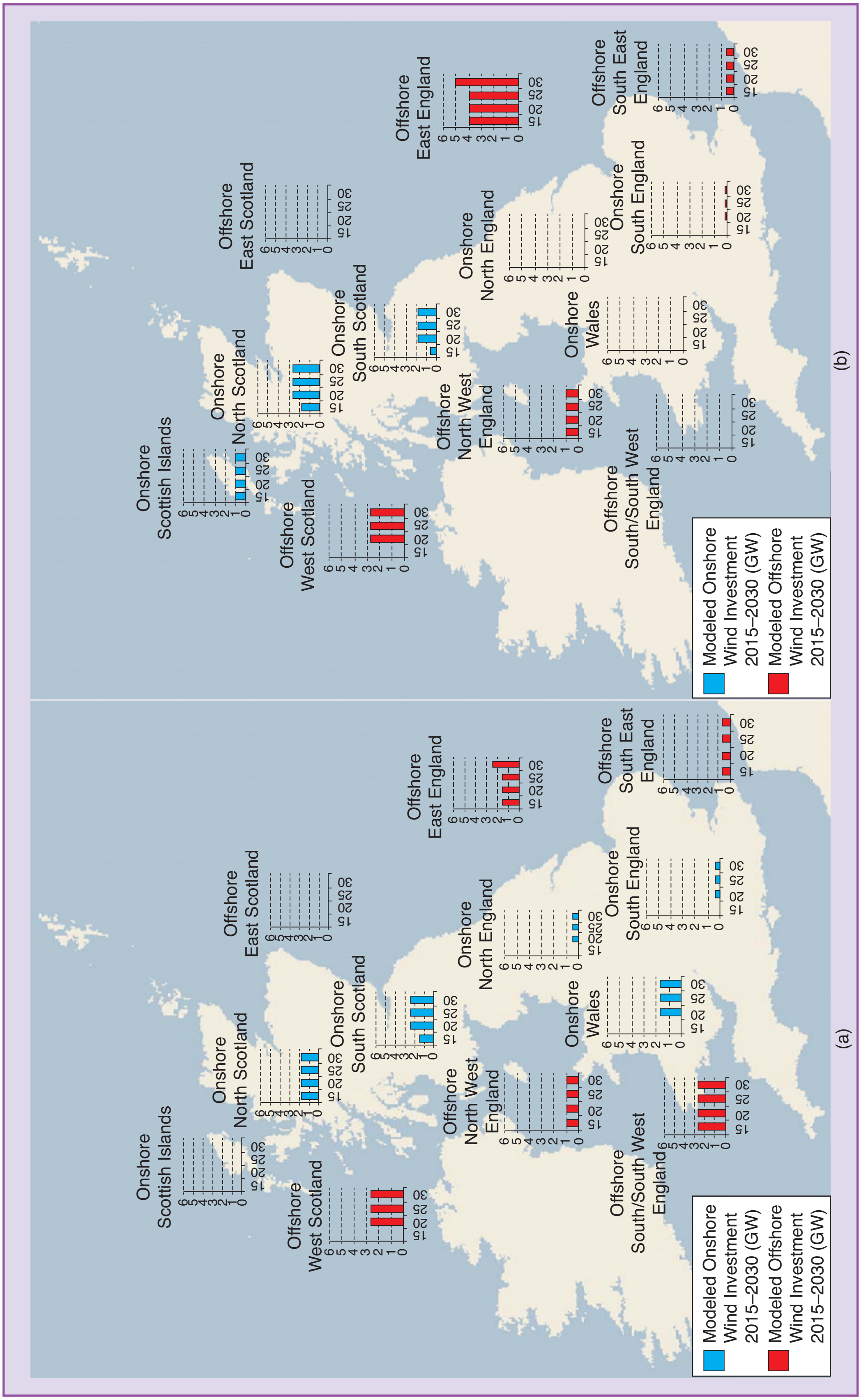

figure 4. Wind generation investment patterns under (a) locational (i.e., status quo) and (b) uniform pricing (GW).

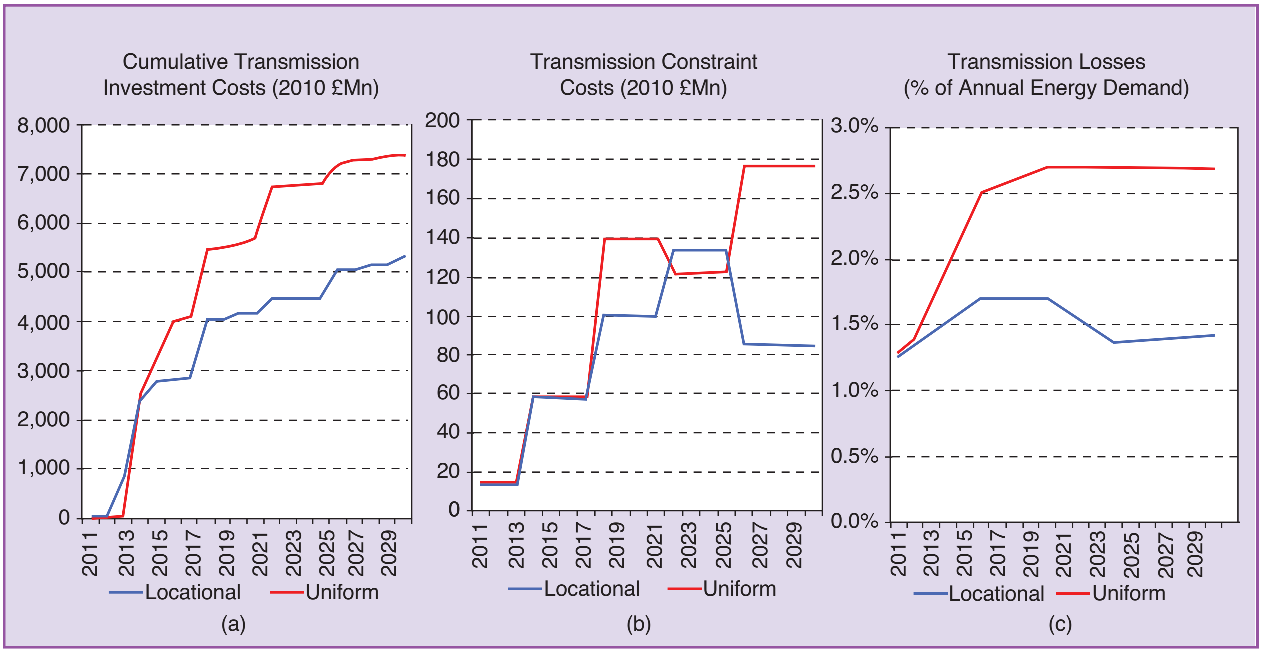

figure 5. Transmission system costs.

is also supported by the results obtained through the impact assessment analysis.

Effects of Coordination Policies Across Transmission Regimes in the North Seas

Offshore wind power is expected to make a significant contribution toward decarbonizing the Great Britain and European energy system. It is envisaged that today's installed capacity levels of about 5 GW of offshore wind generation may reach 150 GW by 2030, with approximately half of this capacity located in the North Seas. Given Europe's goal of increased integration of the power markets by expanding cross-border interconnectors, there is a significant opportunity to integrate offshore wind generation and interconnector projects in the North Seas to take advantage of potentially significant economies of scale and thus reduce network costs.

In this context, this section examines the benefits of different policy approaches associated with different levels of coordination and Great Britain–EU market integration among offshore wind generation and interconnector projects in the North Seas, as summarized in Table 3. These policy approaches range from a radial incremental approach, to more strategic approaches to integrating offshore wind generation and increasing levels of market integration, ranging from limited (energy neutral and self-secure) to a fully integrated EU electricity market.

As the radial approach most closely resembles today's connection practices, it is chosen as the counterfactual, and costs associated with other policy choices are presented in relation to this approach. Furthermore, consideration of the extreme case of energy neutrality in the counterfactual—member-state centric rather than EU-wide energy system development—is used to assess the benefits of full integration of the EU electricity market. Thus it is something of a caricature in that countries are not exactly energy neutral, but deviations from energy neutrality are relatively small. Recent analysis conducted by the EU commission demonstrates that, although the market coupling is enhancing the energy exchange between North Seas member states, larger countries are still broadly energy neutral. In other words, the total energy imports/exports are relatively small as a proportion of the total energy consumption.

table 2. Savings associated with system development under status quo.

	Uniform Charging Versus Status Quo £mn (NPV 2011–2030)	Improved ICRP Charging Versus Status Quo £mn (NPV 2014–2030)
Power purchase costs	13,899	1,717
Renewable subsidies	262	269
Losses	4,082	687
Congestion/constraints	344	116
Demand transmission investment charges	1,182	769
Total	**19,768**	**3,379**

In this article, we demonstrate that effects of transmission arrangements on consumer bills are significant, when a large amount of RES is expected to connect.

Modeling Approach

We have applied our DTIM that has been enhanced to facilitate optimal transmission network investment decision-making process under different levels of coordination in integrating offshore wind generation and different levels of EU market integration. Furthermore, the capability of dealing with uncertainty in future generation deployment has been included in the model. Within a holistic optimization process, DTIM balances costs of multiple transmission investment propositions against the associated costs of system operation such as cost of congestion/constraints, cost of wind curtailments, cost of network losses, and reliability across multiyear time horizons. The DTIM explicitly optimizes offshore grid topology, and for this purpose we have identified a large number of candidate corridors to be potentially constructed (and shown in Figure 9) and have used advanced optimization techniques to identify network sections that should be built. All network asset investments are structured on the basis of fixed and variable costs, enabling the model to explicitly consider the effects of economies of scale and hence to more accurately capture the fundamental differences between incremental and strategic network investment philosophies. Uncertainty in offshore generation deployment in terms of time, location, and amount is considered explicitly in this study through a min-max regret approach. This is an important contribution given that all existing North Seas grid studies have been based on deterministic analysis frameworks and have not explicitly considered the time dimension associated with offshore wind deployment decisions.

The study considered four offshore wind development scenarios covering the period 2015–2040. We have adopted a scenario tree approach, where a consistent set of possible future developments is compiled and analyzed to identify optimal investment commitments that would lead to optimally robust performance across all envisaged futures (considering that investment decision in the first stage is made before uncertainty is resolved). The amount of offshore wind generation across the different scenarios and time scales considered in this study is presented in Figure 10.

Key Findings

From Figure 11, we observe that, in the case of large-scale deployment of offshore generation resources, coordination through offshore hubs could deliver significant economic benefits when compared to incremental point-to-point connections. As expected, benefits will depend on the scenario, i.e., the amount of offshore wind generation deployed. For a large penetration of offshore wind, savings in network investment from coordinating connection of offshore wind clusters are about €40 billion, while for small-scale deployment, benefits are about €8 billion. This is significant given that the total asset value of the present onshore, offshore, and interconnection infrawstructure associated with the regions of the North Seas countries is estimated to be below €60 billion.

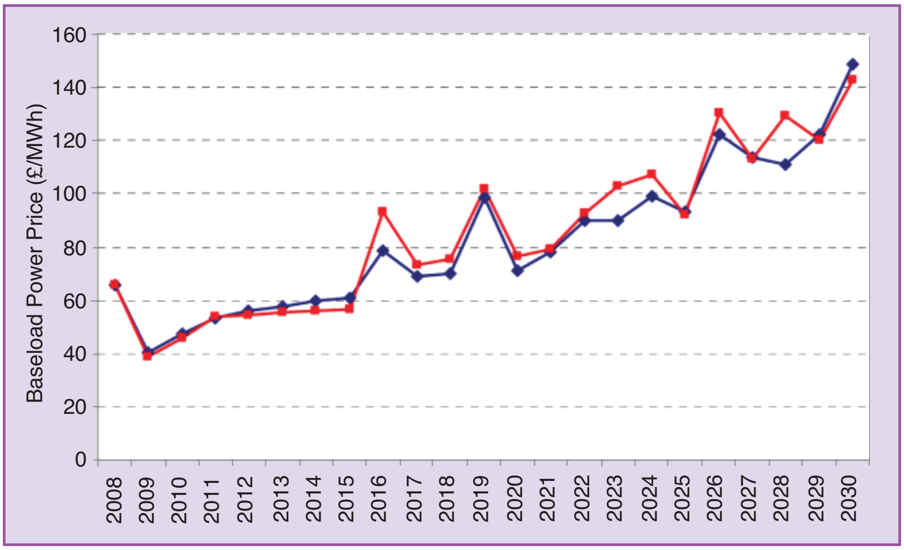

figure 6. The impact on power prices of uniform charging versus status quo (£ nominal).

Assessing the benefits of establishing an offshore grid through developing offshore-to-offshore links, and the interaction between offshore grid and interconnection, is one of the key objectives of this study. We observe that the benefits of connecting offshore clusters via a grid would be relatively modest in the energy neutral case (a small increase in network

figure 7. A comparison of LRMC, improved ICRP, and status quo TNUoS for wind and nuclear across system zones (£/kW/yr). Zones 1–6 are located in Scotland, and zones 7–16 are located in England and Wales.

investment costs savings comes from relaxing the constraints of connecting wind farms to single country of origin but sharing the connection between member states). Additional savings in system operation costs achieved through an offshore network are relatively modest due to limited energy exchanges between member states.

On the other hand, the benefits of full EU market integration are very significant. In addition to savings associated

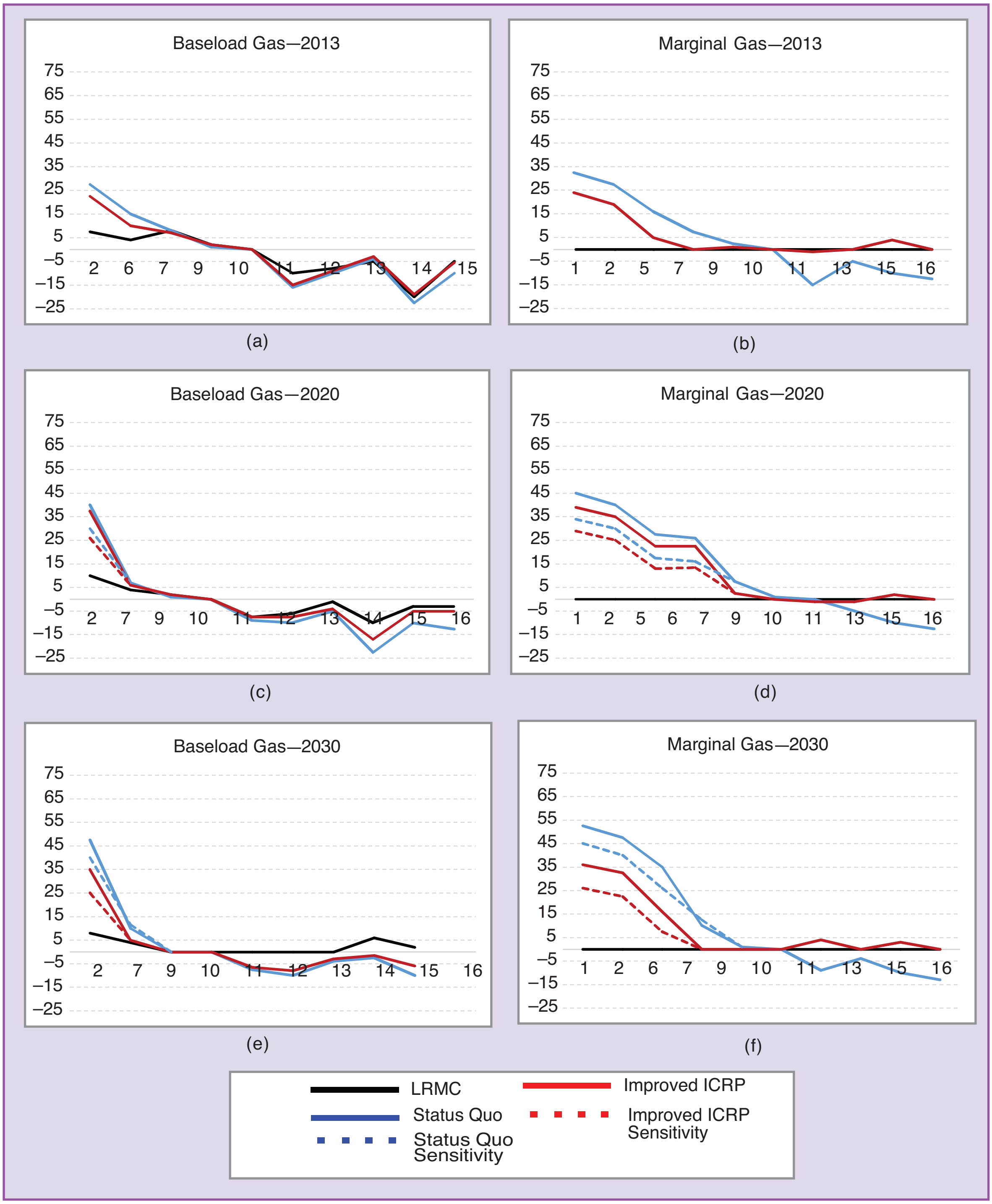

figure 8. A comparison of LRMC, improved ICRP, and status quo TNUoS for baseload and marginal gas across system zones (£/kW/yr). Zones 1–6 are located in Scotland, and zones 7–16 are located in England and Wales.

with network development, we observe significant benefits from a reduction in generation operating costs. This is driven by making use of North Seas grid infrastructure and interconnection to fully integrate operation of the EU electricity generation system. In the high offshore wind scenario, total savings are about €75 billion, while for small-scale deployment, benefits are about €24 billion. In addition, a fully integrated EU market will also generate security of supply savings that will exceed €25 billion (not presented in figure). As expected, the proactive policy choice will bring further benefits in both network investment and operation. Most of the savings, when compared with the fully integrated approach, are associated with a reduction in network investment cost achieved through integrated optimization of offshore wind

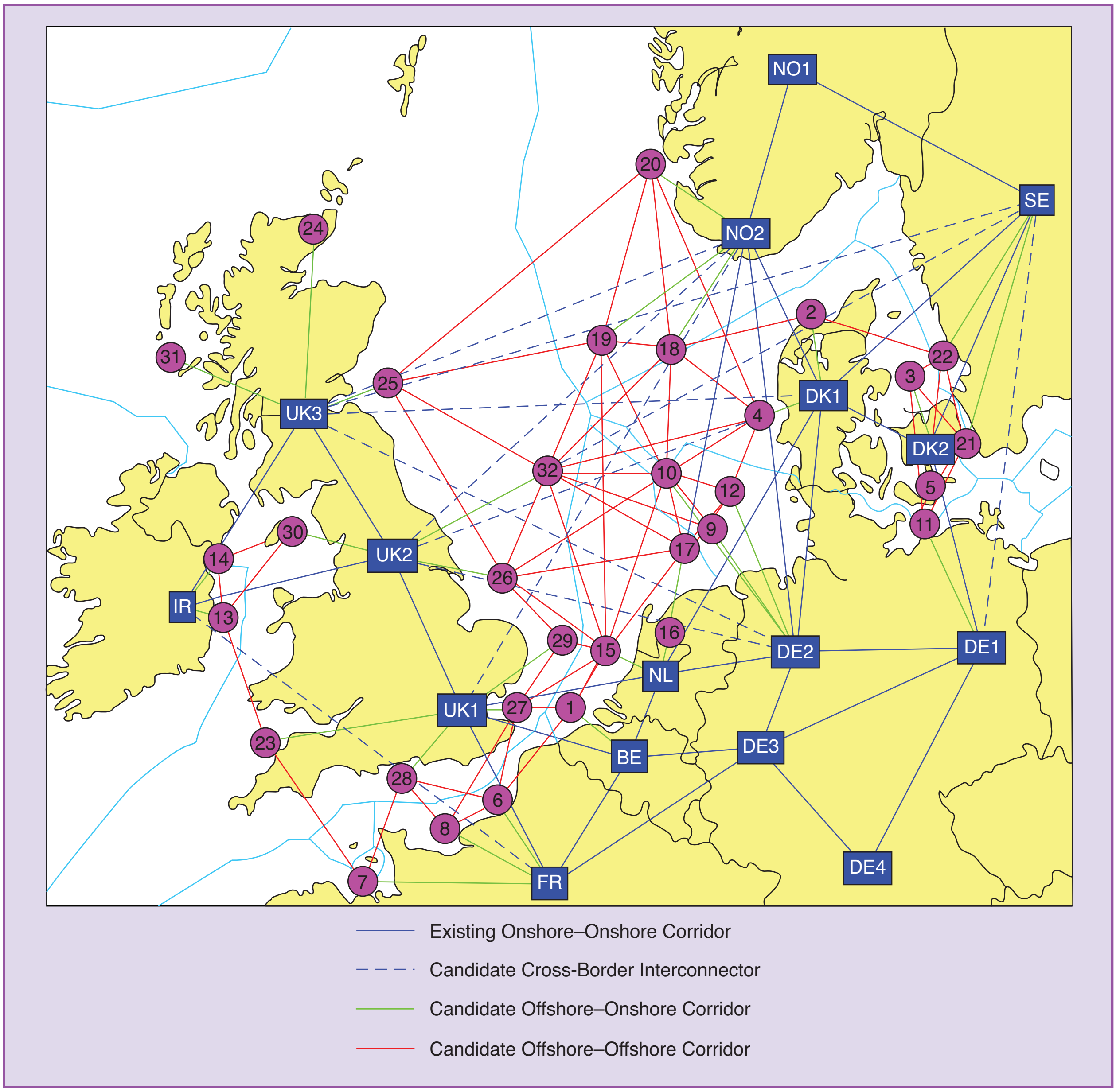

figure 9. A set of corridors in the North Seas.

generation that will be connected and the corresponding network investment.

In the context of uncertainty, this study investigated a min-max regret approach to the development of an offshore grid network and examined the extent to which strategic infrastructure investment decisions could deliver the flexibility to accommodate various future wind development scenarios through facilitating multiple network designs that are not overly constrained by the design choices in earlier years. To that effect, the min-max planners have to find the optimal compromise between all possible choices that will enable them to both operate the system efficiently in the short term (the planners will have to live with their initial commitments until further reinvestment can be undertaken) but also render them well positioned to adjust to actual developments at minimum cost. Of course, first-stage commitments can pose substantial limits to how optimally the system can adjust to the eventual realization.

Our analysis demonstrates that it is more cost-effective to marginally over invest and run the risk of stranded assets than under invest and considerably constrain the available wind energy output. In other words, the potential regret associated with overbuilding the grid in expectation of high levels of deployment is much lower than the regret associated with underbuilding the grid on the basis of overly conservative deployment expectations. In addition, our analysis illustrates how the min-max approach,

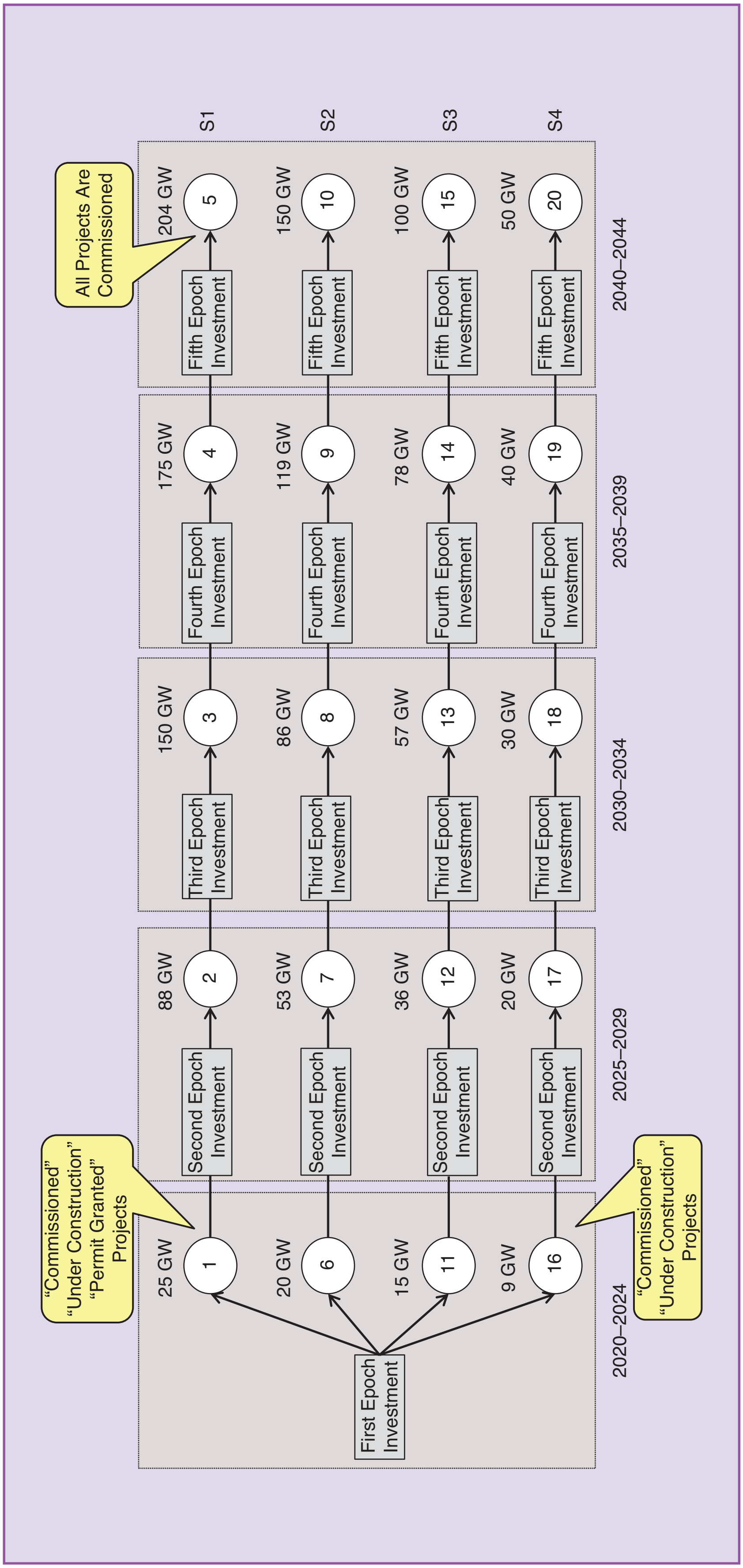

figure 10. A scenario tree capturing possible paths of future offshore wind deployment in the North Seas. The yellow balloons indicate development status of offshore wind projects used to build each scenario (e.g., in scenario 1, it is assumed that all wind projects currently classified as commissioned, under construction, and permit granted are deployed by 2020).

that optimizes investment in the first stage under four potential future scenarios, would involve the development of assets that create future options and are *not built* under any single scenario optimization (that does not consider occurrence of alternative scenarios). In other words, this min-max model can identify the optimal investment strategy that is not based on investment schedules determined by individual (deterministic) scenario models. We demonstrate that the benefits of endogenously optimizing min-max regret based investment would deliver *additional* savings between €1 billion and €5 billion per decision-making period (in this study five years) even if significant volumes of offshore wind fail to materialize. Interestingly, we observe that these additional cost savings are achieved through the construction of offshore-to-offshore links aimed at providing flexibility to deal with uncertainty, through integrating offshore wind clusters while enabling further cross-border transfers between North Seas countries as shown in Figure 12.

Other Aspects of Transmission Arrangements on Future System Costs

TSO Incentives

The majority of the Great Britain TSOs revenue is based on their RAV. As has been widely reported in literature, historically there has been a tendency (supported by the RAV-based

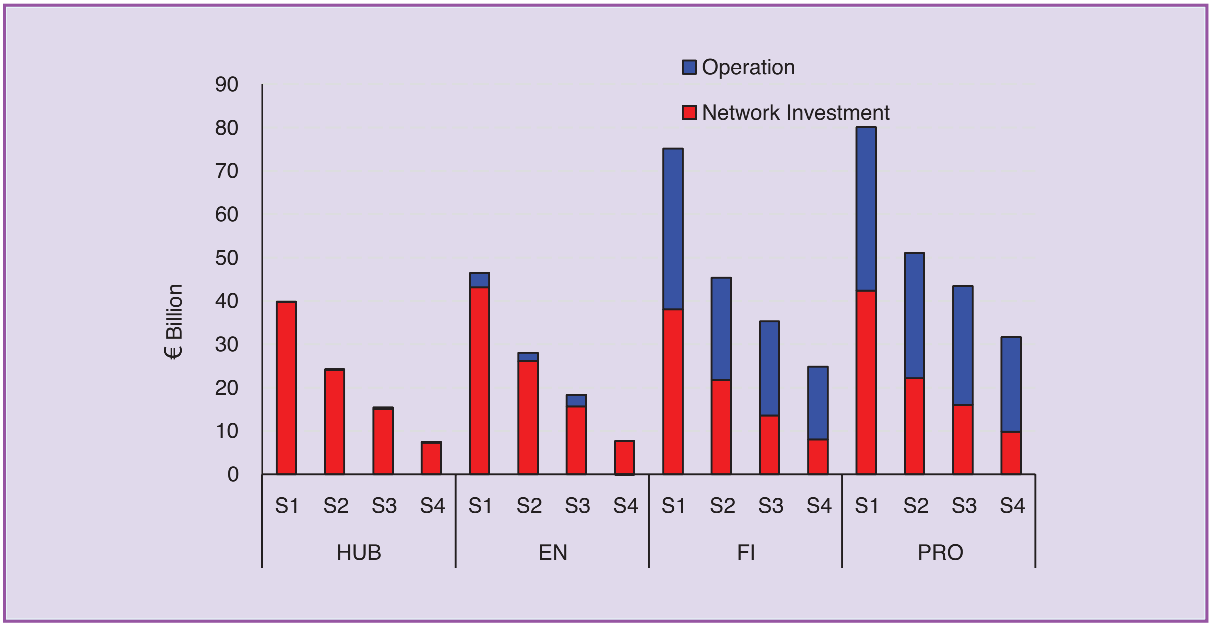

figure 11. Savings in operation and network investment costs of different policy approaches when compared to the radial solution.

approach) to favor capital investment to other smart asset-light alternatives. It would be important to recognize the benefits that may be associated with the early adoption of new smart operation practices (e.g., value of learning by doing) as well as the increased exposure to technical and commercial risks and that the corresponding benefit and risk premiums are included in the rate of return applicable to smart solutions. These policy measures would level the playing field (between traditional asset-heavy and less costly smart solutions), remove commercial distortions that may be hindering direct comparison between competing technologies and encourage TSOs to adopt cost-efficient advanced operational measures where appropriate. To achieve this, it may appropriate to consider increasing the rate of return associated with projects that deliver lower-cost solutions (e.g., cost-efficient smart measures) compared to more costly upgrade projects and ensure that such measures are pursued proactively by TSOs.

The Regulator's Role

Under the current incentives scheme, the Great Britain regulator Ofgem has evolved into a sole buyer of transmission services. However, this necessitates a progressively in-depth understanding of transmission planning, extensive cost benchmarking, and importantly, but increasingly more difficult to achieve, full appreciation of the investment trade-offs between operational measures, smart grid technologies, and various asset types. Given the unprecedented level of transmission investment that is expected to take place, the risks associated with the decision-making process will also increase, particularly as uncertainty in timing, location, and volume of this investment will be significant. In this context, there is consensus developing that regulators' efforts may be better placed in the design and oversight of the investment framework itself to ensure that the proper incentives are given to network operators and users so that the most cost-efficient solutions emerge endogenously without

table 3. Range of policy approaches and their key characteristics.

Approach	Key Characteristics
Radial	• Incremental connection of offshore wind projects to shore • Offshore-to-offshore connections not considered • Member states are net energy neutral and self secure
Hub	• Strategic connection of offshore wind clusters to shore • Offshore-to-offshore connections not considered • Member states are net energy neutral and self secure
Integrated energy neutral	• Offshore-to-offshore connections considered • Member states are net energy neutral and self secure
Fully integrated	• Offshore-to-offshore connections considered • Unconstrained cross-border electricity trade • EU wide security
Fully integrated proactive	• Offshore-to-offshore connections considered • Co-optimization of network and generation investment • Unconstrained cross-border electricity trade • EU wide security

> The need to accommodate peak demand conditions is no longer the sole driver of transmission capacity requirements.

the need for extensive scrutiny on an individual basis. With such a framework in place, the regulator's role can shift from detailed investment evaluation to ensuring that commercial incentives, market design, and planning process are fit for purpose in view of technological advancements.

From TSO to ISO Paradigm

As a result of the aforementioned concerns, Great Britain is moving toward the introduction of an independent system operator (ISO), which will plan and operate but not own the transmission network infrastructure. The ISO would not have the conflicts of interest that the current TSO as an entity combining transmission ownership and operation potentially has, and at the same time it would be in a better position to evaluate the efficiency of transmission investment than the regulator. If this institutional setup is accompanied by a transparent and efficient process for transmission planning then there is scope for

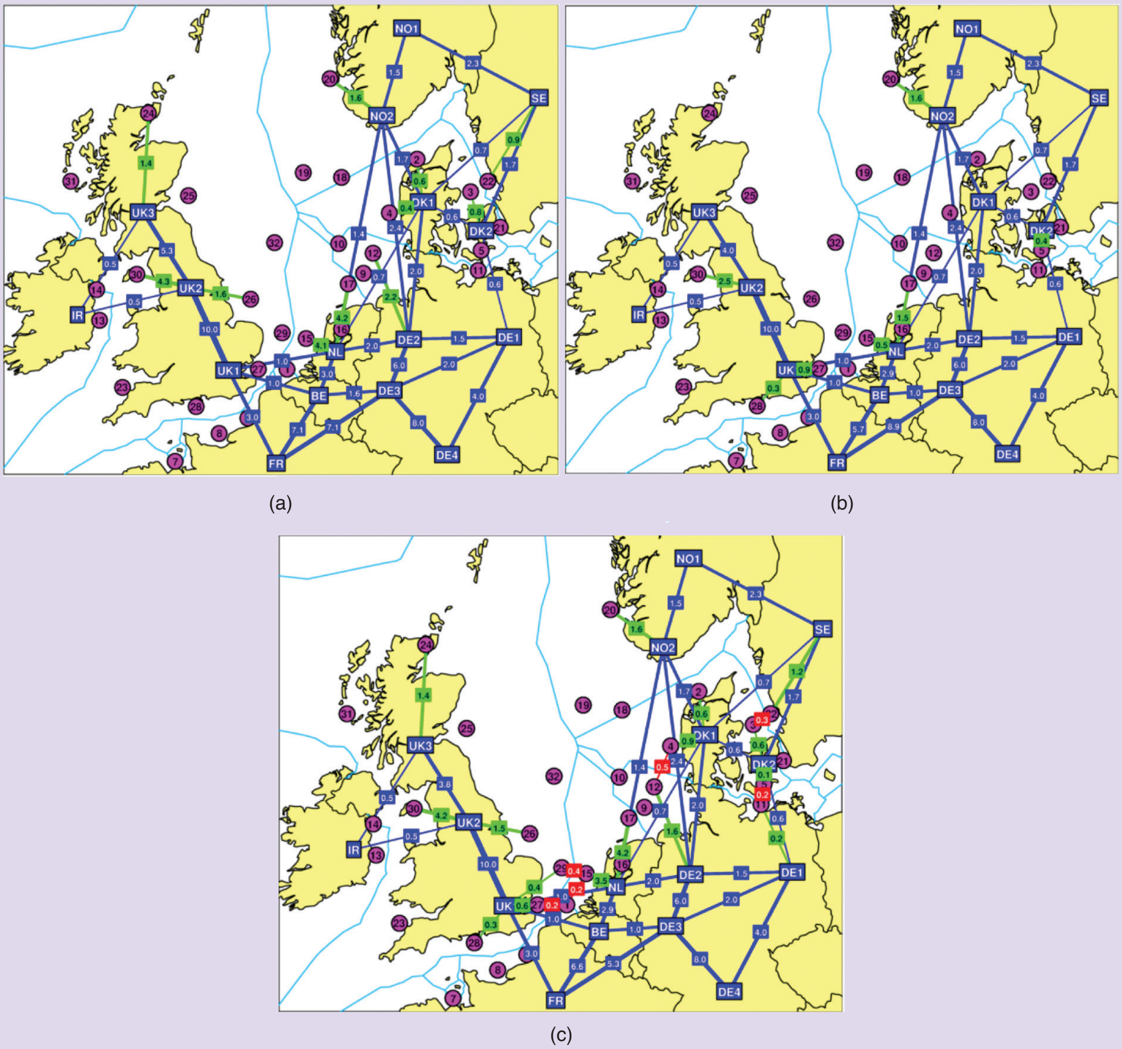

figure 12. An optimal first-stage network design under proactive for (a) scenario 1, (b) scenario 4, and (c) min-max proactive. The color code is the same as in Figure 9.

> Our analysis demonstrates that it is more cost-effective to marginally over invest and run the risk of stranded assets than under invest.

significant cost savings in network related costs and in turn consumers' bills.

Conclusions

In this article, we demonstrate that effects of transmission arrangements on consumer bills are significant, when a large amount of RES is expected to connect, which inadvertently leads to fundamental changes in the way the system is planned and operated. Our analysis and the experience from the transmission charging review recently concluded in Great Britain suggests that transmission pricing inefficiencies can lead to significant increases in consumer bills both due to elevated transmission related costs but also due to significant welfare transfer from consumers to producers.

Of equal importance are the potentially missed opportunities of adopting innovative nonnetwork (or nonwires) solutions due to lack of efficient transmission pricing. This is because the incentives for active market participant engagement in the transmission planning process are muted since they do not face the system costs that they create and therefore cannot reap the benefits of system savings that they may introduce. For new technologies such as demand-side management, storage, special protection schemes, and other smart grid solutions, these potential revenue streams can be very significant.

Our analysis of different policy approaches associated with different levels of coordination and Great Britain–EU market integration between offshore grid (to connect offshore wind generation) and interconnection projects in the North Seas suggests that benefits from regimes coordination, regional integration and explicit consideration of uncertainty in the planning process are significant. This will require the development of new regulatory and market approaches that would facilitate strategic and coordinated network planning and investment under uncertainty associated with low carbon technology deployment necessary for achieving European decarbonization targets.

Moving toward 1) cost-reflective network pricing, 2) strategic, coordinated, and integrated planning and operation of transmission beyond countries' jurisdictions, and 3) improved incentive regulatory framework for network activities (including separation of ownership and operation), presents the opportunity to robustly deliver policy objectives at significantly reduced cost.

Acknowledgments

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For Further Reading

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