Energy Policy 73 (2014) 298–311

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Electricity transmission arrangements in Great Britain: Time for change?

Goran Strbac [a], Michael Pollitt [b], Christos Vasilakos Konstantinidis [a], Ioannis Konstantelos [a], Rodrigo Moreno [c,a,*], David Newbery [b,a], Richard Green [a]

[a] Imperial College London, London SW7 2AZ, UK
[b] University of Cambridge, Cambridge CB3 9DE, UK
[c] University of Chile, Santiago 8370451, Chile

HIGHLIGHTS

- We identify three key areas of concern with the current transmission arrangements.
- We then propose three options for transmission network planning and delivery.
- Key strengths and weaknesses of each above option are identified and studied.
- We conclude that the most appropriate option for GB would be that of an ISO.

ARTICLE INFO

Article history:
Received 21 February 2014
Received in revised form
11 June 2014
Accepted 17 June 2014
Available online 9 July 2014

Keywords:
Multi-purpose transmission investment
Transmission regulation and pricing
Market design

ABSTRACT

In Great Britain (GB) and across Europe significant investment in electricity transmission is expected over the coming years as decarbonisation and market integration efforts are intensified. However, there is also significant uncertainty with the amount, location and timing of new generation connection, which in turn will drive the transmission investment needs. Given the absence of efficient market design, we identify three key areas of concern with the current transmission investment arrangements: (i) a misaligned incentives framework for transmission investment and operation; (ii) lack of coordination of investment and operation; and (iii) conflicts of interest. We then propose three options for future evolution of transmission regimes, which cover the full spectrum of institutional arrangements with respect to transmission planning and delivery, i.e. how and who plans, owns, builds and operates the transmission system. For each option we present: key characteristics; evolution of the current regimes; the ability of the option to address the concerns; and key strengths and weaknesses. Overall, we conclude in the case of GB (this conclusion could be extended to other European countries) that the most appropriate option would be that of an Independent System Operator (ISO) who would be responsible for planning and operating the transmission system.

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1. Introduction

In Great Britain (GB) it is projected that a very significant amount of transmission investment will be needed in the coming years to support efficient integration of low carbon generation within the EU context (e.g. Ofgem, 2012a). Indicatively, these investments will be the largest transmission network reinforcements since post-World War II expansion. In Table 1 the projected range of onshore, offshore and cross-border investments to 2030 is presented against the estimated asset values.[1]

As Table 1 indicates, not only is there expected to be an exceptionally large transmission investment programme over the next years but there is also significant uncertainty regarding the amount, location and timing of new generation connection. As described in ENTSO-E (2012) similar investment programmes in

* Correspondence to: Avenue Tupper 2007, Energy Centre, Department of Electrical Engineering, Santiago 8370451, Chile. Tel.: +56 2 29784817.
E-mail address: rmorenovieyra@ing.uchile.cl (R. Moreno).

http://dx.doi.org/10.1016/j.enpol.2014.06.014
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[1] The expected investment ranges have been established by considering minimum and maximum investment scenarios from a number of sources including Ofgem (2012a), Imperial College and NERA Consulting (2012) and the National Grid Electricity Ten Year Statement available at ⟨http:/www.nationalgrid.com/uk/electricity/ten-year-statement/⟩.

Table 1
Current and projected transmission Regulatory Asset Value (RAV) (£bn).

	Estimated asset value at 2012 (£bn)	Expected investment to 2030 (£bn)
Onshore	8.4	6.2–12.4[a]
Offshore	2.5	8–20
Interconnection	2	8–20

[a] To 2021.

terms of scale are under way in continental Europe as well as other parts of the world.

This paper reviews whether the current arrangements for system planning and delivery are fit for purpose in meeting the identified investment challenges in a timely and efficient manner and in particular aims to answer the following key questions:

- *Planning*: Will the current arrangements deliver an optimum level of transmission that will maximise social welfare?
- *Delivery*: Will this investment be undertaken in an efficient manner and delivered at minimum cost?
- *Options*: If not, what are the options for improvement of the present regimes?

This paper identifies that the overarching weaknesses of the current transmission arrangements in GB and across Europe stem mainly from the lack of efficient transmission access pricing due to the absence of locational marginal energy prices as proposed in Hogan (2011). However, recognising that a radical market design change is unlikely in the short to medium term, we have identified three key areas of concerns that would need to be addressed if efficient transmission pricing is not implemented. Subsequently, we propose three options for future evolution of transmission regimes, which cover the full spectrum of institutional arrangements with respect to transmission planning and delivery. For each option we present: key characteristics; evolution of the current regimes; the ability of the option to address the concerns; and key strengths and weaknesses.

The analysis presented in this paper was carried out as part of Ofgem's Integration Transmission Planning and Regulation (ITPR[2]) and as a result it is focused on the GB transmission arrangements. However, related issues are faced by the majority of European countries that operate under similar market designs to GB, making the conclusions of this paper relevant for evaluating the efficiency of their national transmission arrangements. In addition, in order to realise the significant benefits of EU energy market integration, as quantified by Booz & Company et al. (2013), efficient transmission operation and investment in both national and cross-border levels will be required. Beyond GB and Europe, this paper aims to inform the ongoing debate, identified by Chawla and Pollitt (2013), on which is the set of transmission arrangements that represents the best practice.

The paper is structured as follows: in Section 2 we present our method of analysis where we compare implemented against theoretically ideal institutional arrangements. As a result of our analysis, in Sections 3 and 4 we identify the key current regime weaknesses and the options for change, respectively. In Section 5 we conclude and discuss policy implications. In order to increase the clarity of the paper for non-GB audiences we have also included an Appendix with a list of abbreviations and definitions of the GB related nomenclature used throughout this paper.

[2] More information available at: ⟨https://www.ofgem.gov.uk/electricity/transmission-networks/integrated-transmission-planning-and-regulation⟩.

2. Method of analysis

In this section we firstly examine (i) the main aspects of the current GB transmission investment arrangements in light of the challenges going forward, and then (ii) the theoretically ideal alternative arrangements for efficient transmission investment. Based on a comparative analysis between implemented and theoretically ideal institutional arrangements that can deliver efficient transmission investment, we aim at identifying the key current regime weaknesses and thus propose alternative regimes for addressing these weaknesses.

2.1. Current transmission arrangements and future challenges

The GB electricity market is a bilateral market with non-location specific energy pricing. Currently there are three distinct transmission arrangements, namely the onshore, offshore and interconnection regime. Next sections give a high level description of the three regimes and their main interactions.

2.1.1. Onshore regime

The onshore system is owned by three companies: National Grid owns the 275 and 400 kV network in England and Wales and two vertically integrated utilities, Scottish Power Transmission Limited (SPTL) and Scottish Hydro-Electric Transmission Limited (SHETL), own the 132, 275 and 400 kV system in Scotland. For simplicity the Scottish Transmission Owners (TOs) will be only referred to as TOs for the remainder of this paper. National Grid is an unbundled transmission utility and also acts as the GB System Operator. Throughout this paper National Grid will be referred to as the NETSO when referring to its role as GB system operator and NGET or TO when referring to its function of transmission owner of the England and Wales transmission system. Theoretically, these two functions of National Grid are internally separated. Transmission planning and delivery is in broad terms reactive, in the sense that firm financial user commitment is required so as to trigger transmission investment, which is subject to regulatory approval through the price control regime. The TOs are mainly responsible for planning and delivering transmission investment in their own jurisdictions, although there is a certain degree of co-ordination between them with regards to planning and delivering wider works (i.e. major transmission infrastructure with nation-wide impact). Moreover, there are certain provisions for anticipatory investment mainly driven by the need for integrating renewable energy, which is predominantly located in Scotland and offshore in the future. Although the price of energy is location non-specific, there are annual transmission tariffs, called Transmission Network Use of System charges (TNUoS), which are paid by the market participants to the NETSO, who then distributes this revenue to the TOs. These charges consist of annually fixed regulated locationally varying tariffs and additional non-location specific flat tariffs (known as the residual) and range from around £20/kW/yr in Northern Scotland to −£5/kW/yr in South West England for generators. Currently, the majority of system costs (c. 75%) are collected through the residual flat charges implying a high level of cost socialisation. The regulated revenue to be collected is split 27/73 between generation (27 price zones) and demand (14 price zones). The locational part of the TNUoS tariffs is computed using the published ICRP methodology (National Grid, 2010), which intends to reflect the long run marginal costs of transmission investment. The current asset value of the onshore network is estimated to be £8.4 bn, whereas transmission investment to 2021 is expected to be between £6.2 bn and £12.4 bn subject to specific triggers, which mainly depend on the level of renewables connecting to the system (National Grid, 2012).

2.1.2. Offshore regime

The offshore transmission regime governs the planning, delivery, ownership and operation of the transmission assets connecting offshore wind farms to the onshore system. Driven by the European Commission unbundling directives, the offshore assets must be owned and operated by independent Offshore Transmission Owners (OFTO's) (excluding generation companies and incumbent onshore transmission owners – at least without sufficient business separation in place). Developers of offshore wind generation plan and build the offshore transmission assets, which then must be divested through auctions to OFTO's, who earn a 20 year regulated return subject to availability incentives. Ultimately, the cost of the offshore assets is paid by the offshore wind plant developers through a local asset charge added to their zonal transmission tariffs. This is in contrast to the onshore regime, where a significant part of the transmission cost is socialised. To date, all the offshore assets (radial lines between individual offshore wind farms and the onshore system) have been planned and built by generating companies albeit there are provisions for future OFTO-built lines. The anticipated investments up to 2030 in the offshore transmission system are even higher than the onshore system and estimated between £8 bn and £20 bn (National Grid, 2012). A key concern (Ofgem/DECC, 2012) has been the lack of an integrated and co-ordinated development of the offshore network, which could potentially yield significant cost savings estimated at £0.5–3.5 bn (Redpoint Energy, 2011). Although in principle benefits of efficient offshore grid co-ordination could be captured by wind farm developers, so far the network connections, and corresponding investments, have been specific to individual projects.

2.1.3. Interconnection

GB has currently around 4 GW of HVDC interconnections to continental Europe and Ireland through sub-sea cables. The interconnection regime is largely governed by European Commission directives, which determine the legal definition of interconnectors[3] as well as their operation and revenue model. Interconnectors earn revenue either through price arbitraging or through forward sales of (physical until now) transmission rights. The European Union (EU) requires that interconnectors are regulated (unless exempted) and that their revenues are used either for funding further interconnection projects or for reducing the national transmission tariffs. Nonetheless, it is possible to develop pure merchant projects by obtaining an exemption from the EU requirements, although this process is considered uncertain as revenues (net of financing costs) must still be allocated to benefit transmission users. As such, Great Britain is currently developing a hybrid regime for interconnectors by establishing revenue cap and floors. Although all current interconnectors are in effect merchant (i.e. their revenues are driven by price differentials), under the cap and floor regime a cross-border project could be either, depending how wide the cap and floors are (Ofgem, 2013b). In addition, under EU rules interconnectors are not classified as either demand or generation and as such have been exempted from paying transmission tariffs and enjoy full firmness with regards to their imports and exports to/from the GB market. This implies that there are no efficient siting signals and no co-ordination of planning, operation and development between the onshore and the interconnection assets. Although EU rules should facilitate the development of cross-border interconnection, one of the key well recognised obstacles for interconnection is the asymmetric benefits that interconnection brings to connected jurisdictions, given the member state centric rather than EU wide approach to energy system development.

2.1.4. Regime interactions and multi-purpose projects

Given the three distinct regimes and the limited amount of offshore and interconnection assets to-date there is currently little interaction between them with respect to co-ordinated transmission planning, delivery and operation. Since the current net effect of radial offshore and interconnection assets to the onshore system is similar to generation and demand, the main co-ordination channel has been through the locational TNUoS tariffs, which aim to incentivise efficient siting, although this is now no longer available for interconnectors. However, multi-purpose projects (MPPs) are likely to be proposed in the future and it may be not clear which of the three regimes would support a particular development. A few examples of such projects include offshore wind farms connecting to interconnectors or planned "on-shore"[4] DC links, meshed offshore grids which might also serve to increase the onshore boundary capacity etc. Another example is a recent proposal to develop wind farms in Ireland that would be connected to the GB system only, and it is not clear if the network connection should be classified as offshore or interconnection. The current arrangements (Ofgem, 2012b) are seen as not fit for delivering multi-purpose projects both from a legal (licencing) as well as market design standpoint. In particular, it is unclear which bodies would be responsible (incumbent TOs, OFTOs or merchant developers) in planning and delivering MPPs. Further unresolved issues include MPP access firmness, charging and the overall business model.

2.2. Efficient transmission investment in an unbundled electricity system

There is no consensus on the optimum institutional arrangement that can deliver efficient transmission investment. In fact, Chawla and Pollitt (2013) recently examined the evolution of transmission system regimes across the world and concluded that no clear winner has emerged yet; the majority of European countries follow the TSO paradigm whereas in the Americas they have developed the ISO concept. Next, we present the theoretical frameworks that can potentially deliver efficient investment.

2.2.1. The alternative theoretical frameworks

As Hogan (2013) elaborates, efficient (user-driven) transmission investment can be supported by a market design, named the Standard Market Design (SMD), based on the following market structures and processes:

- An Independent System Operator (ISO) manages the transmission system and evaluates all proposed transmission investments using social cost benefit methodology – including reliability, economic and public policy elements.
- Efficient short term access pricing is established through Locational Marginal Prices (LMPs) supported by hedging instruments in the form of Financial Transmission Rights (FTRs).
- Individual Transmission Owners (TOs) are responsible for availability of their assets.
- Merchant investments are subject to golden rule, i.e. the net benefits are higher than the costs.
- Mandated (non-merchant) investments are voted on by market participants and go ahead if there is super-majority. The

[3] An interconnector in effect means any transmission line crossing national borders.

[4] The planned DC lines will in effect increase the onshore North to South boundary capacities but will be mainly routed offshore in the West and East of Great Britain.

projects can be delivered through competition or alternatively carried out by incumbent TOs, depending on the project size.
- Investments are paid by the beneficiaries determined through a long term Cost Benefit Analysis exercise.

In contrast, Joskow (2007) argues that an integrated for profit Transmission System Operator (TSO) owning, planning, investing and operating the transmission system can internalise all the associated costs and if subjected to an efficient Performance Based Regulation (PBR) will be able to facilitate efficient transmission investment. Nonetheless, the regulatory framework is not specified. Hogan (2011) presented a PBR scheme for Transmission Owners (TOs), that can be developed only under strict conditions to optimum investment, which presupposes efficient transmission pricing in the form of LMPs, FTRs and beneficiary pays transmission tariffs.

Both market designs exemplify the importance of efficient transmission pricing and in particular optimum short term access prices, defined as the locational price differentials between two system nodes, complemented by a transmission tariff based on beneficiary pays principles as described in Hogan et al. (2010).

Lack of efficient pricing will inherently lead to cross-subsidies among network users thus undermining social welfare maximisation and in the case of extensive cost socialisation, which is currently practiced in the majority of power markets; it will lead to lack of incentives for effective network user engagement in the transmission investment process. As explained in the next section, this in turn can result in significant inefficiencies in transmission investment and operation.

3. Current regime weaknesses

3.1. GB market design inefficiencies

In contrast to the notion of “beneficiary pays” as developed in SMD, given the current on-shore transmission tariffs with the majority of network investment costs socialised, and the fact that all balancing costs are also socialised, market design and network pricing in GB are inherently inefficient. The situation is further exacerbated by EU tariff harmonisation legislation that postulates average generation charges should not exceed 2.5 €/MWh, thus preventing changes in the charging arrangement that would result to sharper and more cost reflective transmission and balancing pricing. This in turn results in inefficient generation dispatch[5] and siting and eliminates network users' incentives to actively engage with the transmission investment process. Furthermore, this is aligned with the commercial interest of incumbent TOs as increased and potentially inefficient investment in network reinforcement is an inherent objective, given the regulatory framework (mainly RAV based) within which these companies operate.

In addition, the co-existence of merchant and regulated investment can only be effectively facilitated with efficient transmission pricing. This is due to the fact that for regulated investments beneficiaries would ultimately pay for these projects, thus creating a level playing field when network users are faced with the choice of funding merchant or regulated investment. As a result, the only difference between these two types would be the process followed to reach the investment decision. Otherwise, merchant investments would be viewed as too risky given that their revenues could be eroded if a mandated project (regulated investment) whose costs are to a large degree socialised, is built. As such, there is a very high option value in waiting for regulated investments to take place (and only pay a fraction of the costs) rather than sponsor merchant projects.

Furthermore, with efficient transmission pricing the differences across the three regimes would be automatically eliminated, which would also imply that there would be an effective framework for the development of MPPs.

Finally, in order to mitigate the consequences of the absence of cost-reflective long and short-term locational signal, the regulator as the buyer of network services on behalf of all users and consumers, should ensure that the planning and delivery of network investment is efficient. This in turn requires in-depth scrutiny of investment plans that necessitates full understanding of the technical and economic aspects of transmission network planning and operation that is clearly beyond the remit of a regulator's setup. Given the absence of efficient market design, we identify three key areas of concern with the current transmission investment arrangements:

- A mis-aligned incentives framework for transmission investment and operation.
- Lack of coordination of investment and operation.
- Conflicts of interest.

3.2. A mis-aligned incentives framework for transmission investment and operation

The onshore system planning process in GB is largely based on the following key principles:

- TOs develop investment plans based on generators'/grid users' commitments (indicating proposed connection requirements).
- Anticipatory onshore network investment during the price control period may be permitted through the Strategic Wider Works scheme which allows cost recovery of further investment through TOs’ revenue adjustment.

Offshore network assets are developer-led, and as such to a large extent they are incentivised to plan, design, and deliver their assets efficiently. Similarly, new interconnection assets are market-driven (whether merchant or regulated) and interconnection developers are incentivised to ensure that design, delivery and operation are efficient, although their location is subject to distortions, given that TNUoS charges do not apply to interconnectors.

In the case of the onshore network the efficiency of the transmission planning and delivery process in GB, given the lack of motivation for effective user engagement, largely depends on the TOs' and NETSO's regulatory incentives and the ability of Ofgem/government to scrutinise the proposed investment plans.

3.2.1. Transmission Owner (TO) incentives

NGET and Scottish TOs' revenue is RAV-based. As recognised by Pollitt (2012) historically there has been a tendency (supported by the RAV-based approach) to favour capital investment to other asset-light alternatives. Despite improvements to the regulatory approach in recent times, the RAV based approach may continue to encourage capital expenditure. Thus, although the new GB regulatory regime, named RIIO[6], does incentivise efficient building once investment programmes have been agreed, the efficiency of asset planning will largely depend on the ability of the regulator, as the service buyer, to ex-ante evaluate and benchmark investment costs prior to the price control period. It is unclear

[5] See Ofgem (2009) and Green (2004).

[6] For more information on RIIO see Ofgem (2010).

what ex-ante incentive TOs have to propose non-asset heavy solutions where these are likely to receive regulatory approval.

If RIIO works well, the main impact of any remaining incentive problems will be for informational rent transfer to the TOs, and not necessarily inefficient delivery, which is some consolation. However, RIIO has just been implemented and it will be some time before its full effect can be assessed.

3.2.2. System Operator (SO) incentives

On an operational level, the SO incentives scheme[7] in GB is a target-based incentive scheme which provides strong incentives to NETSO to reduce congestion costs in the short term.

However, the extent to which National Grid Company will co-optimise transmission investment and operation will depend on the weight that the NGET and NETSO incentives have on its total revenues/profits. Indicatively, National Grid's RAV-linked profit from electricity transmission was £849 mn against £9 mn from the NETSO operations in 2011/12.

Given the very low contribution of the NETSO activities to its overall revenue and profits, the impact of its incentives may be on maximising benefits to the NGET business rather than on co-optimising transmission planning and operation.

3.2.3. Absence of incentives for implementation of efficient operational measures

Given that beneficiaries of wider network reinforcements are not directly exposed to the cost of these reinforcements and their access to the energy market is partially subsidised by other network users, there are no strong incentives among market participants to scrutinise the TSO plans and propose potentially more efficient alternative operational measures to network reinforcements (since consumers through demand charges pay for the majority of those investment).

A key requirement for delivering the efficient transmission investment plans cost effectively is to enhance the utilisation of primary network assets and make full use of operational measures and various corrective control techniques as demonstrated by Moreno et al. (2012, 2013). These operational measures directly compete with asset-based solutions, but at present there are no clear commercial incentives for their full implementation.

Very significant advances[8], at the international level, have been made in developing and implementing a range of new effective operation and control techniques and technologies, and it is critically important that these are fully considered, as an alternative to network reinforcement, in order to ensure efficiency of the unprecedented network investment that GB is facing.

Given the absence of the market that would facilitate this, specific mitigation measures are needed to remove the bias towards investment over operational alternatives. Furthermore, the present network regulation does not consider and is unable to deal with the fundamental question of whether the level of network capacity released to network users at the operational timescale is delivering good value for money and that an appropriate balance is being struck between costs and benefits in the decision making process. Strbac et al. (2011) demonstrate that the present network standards, developed in the early 1950s are inefficient and should not form the basis for the development of 21st century transmission networks.

This is in contrast with the clear trends, observed in a number of jurisdictions (particularly in South America, Australia and New Zealand), of modernising network operation and design standards[9] accompanied by rapidly growing use of advances in various technologies that can release latent network capacity through more sophisticated system operation. These include the application of coordinated special protection schemes, coordinated corrective power flow and voltage control techniques supported by wide area monitoring, advanced protection and control systems, and advanced decision making tools.

3.2.4. The regulator's role

Under the current incentives scheme, Ofgem has evolved into a sole 'buyer' of transmission service, both on and offshore. Regarding the on-shore transmission network operation, Ofgem has recognised the difficulty (Ofgem, 2013a) in defining an efficient enduring NETSO incentive scheme, as this requires an in-depth understanding of transmission operation and options for managing the corresponding costs. Furthermore, this would require that Ofgem closely monitors and scrutinises planning and delivery as well as the operation of the transmission system. Again, 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 investment in primary network infrastructure (e.g. new lines, transformers etc.).

Going forward, given the absence of efficient market framework and transmission pricing, it is questionable whether the regulator or the relevant GB government department possess the needed expertise to increasingly act as the single buyer of onshore and offshore network services, as the complexity and interactions between these will significantly increase. 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. It should be noted that this is the case for other jurisdictions, where the regulator also assumes the role of the network service buyer.

3.3. Lack of co-ordination

Regarding the co-ordination in transmission activities, we have identified a number of concerns:

- *TO/NETSO co-ordination*: the lack of co-ordination between TOs leading to an increase in network constraint costs in the short term and inefficient investment in long term.
- *Coordination in meeting existing and future users' needs*: limited scope for anticipatory investment and absence of a formal framework to meet existing and future users' needs.
- *Co-ordination across regimes*: concerns regarding the ability of multiple parties (onshore and offshore TOs, interconnectors, developers of offshore generation and multiple purpose project developers) to coordinate and deliver efficient investment for GB.
- *Regional coordination of network investment*: concerns that parties delivering cross-border investment do not take into account regional network needs.

3.3.1. TO/NETSO co-ordination

As explained, National Grid Company owns the transmission assets in England and Wales and is the NETSO for the two Scottish grids (and the offshore grid). Given that the NETSO is incentivised to minimise congestion costs, there is an incentive to cooperate with

[7] See Ofgem (2013a).

[8] See Huang et al. (2004), Breidablik et al. (2003), Ingelsson et al. (1996), Correa Da Silva et al. (2006), Kirby et al. (2012) and Pipelzadeh et al. (2012).

[9] See Matus et al. (2012) and Carlini et al. (2006).

the Scottish TOs and coordinate maintenance. On the other hand, Scottish TOs are not strongly incentivised to cooperate (while NETSO is not incentivised to try out solutions which would undermine NGET's business model in England and Wales). It is important to note that generators in Scotland benefit from firm access to the GB-wide market and are not affected by these inefficiencies.

On the other hand, if the network access regime were location specific (for example in the case that the GB market was split into 2 zones; England and Wales, and Scotland), the export constraint would lead to a fall in electricity prices in Scotland below those in England, which would clearly affect the revenues of generators in Scotland. This would create pressure on all TOs to coordinate their maintenance and construction outages and consider alternative operational measures to minimise the impact of constraints. In the absence of these market signals, additional mitigation measures would need to be considered in order to achieve coordination in the short-term and long-term.

3.3.2. Coordination in meeting existing and future users' needs

In order to facilitate transmission investment co-ordination across regimes and/or take into account future investment needs, it might be necessary that TOs engage in anticipatory investments. Anticipatory investments refer to network developments for which full firm user commitment is not obtained at a particular point in time. However, anticipatory transmission investment may be efficient when there are material economies of scale in transmission investment, constraints associated with establishing new transmission corridors or developing new rights-of-way, or environmental constraints associated with the number of shore landing points that may be needed to connect offshore and onshore network assets.

On the other hand, as recognised by Ofgem (2013a), given the significant uncertainty and the difficulties in predicting the time, location and volumes of new generation, the risk of investing in stranded assets could be high. The increasing uncertainty about future transmission needs coupled with the irreversible nature of transmission investment, indicates that attractive opportunities should not be identified solely on the basis of net benefit but also on the option value that they provide. However, option value is often ignored due to the inability to charge potential users who value the option of use in the future, foregoing potentially valuable synergy opportunities due to lack of a flexible planning framework.

3.3.3. Co-ordination across regimes

Given the three distinct regimes and the limited amount of offshore and interconnection assets at present, there is currently little interaction between the regimes with respect to co-ordinated transmission planning, delivery and operation. Since the current net effect of radial offshore and interconnection assets on the onshore system is similar to generation and demand, the main co-ordination channel is through the transmission tariffs. In the particular case of interconnection planning, the lack of TNUoS charges and the ad-hoc process for planning and connections offers is likely to lead to inefficiencies.

Furthermore, there has been a significant interest in transmission projects that span across regimes (MPPs). Examples include offshore wind farms connecting to interconnectors and the development of meshed offshore grids that would also potentially increase onshore boundary capacities. It is expected (Ofgem, 2012b) that the volume of MPPs will significantly grow. Given the absence of efficient pricing signals, the current arrangements are likely to lead to inefficient design of MPPs, even if the considerable legal and licencing issues are resolved.

It is worth noting that the boundaries and the definitions of the three regimes (onshore, offshore and cross-border) are in principle artificial, given that the role of underlying assets used in each regime and across the regime is essentially the same. However, the differences and inconsistencies have significant implications for both the asset owners and network users and will significantly affect the incentives of different parties to propose and undertake MPPs. For example, NGET might not have incentives to consider MPPs that might alleviate the need for onshore investments if these are not included in its RAV. Similarly, an interconnector might discourage an offshore generator from connecting if this means that it would need to operate under the OFTO regime and potentially earn a lower rate of return. If efficient co-ordination across regimes is to be realised then these issues would need to be effectively resolved.

We stress that the inconsistencies among the regimes are driven by the differences in the setups of these regimes, although the underlying assets perform the same function. This means that these will not be effectively resolved unless there is a radical re-definition of the regimes or efficient transmission pricing is implemented. We also note that inconsistencies in network access between national and cross-border regimes are embedded within the EU target model. Within GB, some mitigation measures may be established, such as re-instating some form of interconnection TNUoS, but it will fall short of addressing the inconsistencies with respect to capacity allocation and firmness of access. As mentioned, efficient network pricing, would resolve these issues by facilitating the co-existence of merchant and regulatory investments.

3.3.4. Regional coordination of network investment

Cross-border transmission investment is essential in facilitating regional co-ordination and the aspirations of the EU Target Model and climate change policy (Booz & Company et al. (2013)). In particular, cross-border investment will need to be done in a co-ordinated market with regional partners so as to

- promote integration of EU energy and balancing markets;
- enable generation outside GB to participate in the GB capacity market so as to minimise the cost of security of supply; and
- facilitate efficient implementation of EU Renewables directive.

Under the current interconnection regime, multiple parties are capable of planning and delivering cross-border assets on a merchant basis, with limited scope for taking into account the regional needs.

3.4. Conflicts of interest

Conflicts of interest are more likely to be a problem when the incentives on the party to act in its own interest in a manner that diverges from the public interest, are high and the probability of detection is low. If both of these are true, then mitigation can take the form of aligning incentives so that private and public interest coincide, and/or taking steps to raise the probability of detection. It is also important to note that even perceived conflicts of interest can be self-fulfilling and have detrimental effects. There are two potential sources of conflicts of interest in transmission planning and delivery across the regimes:

- Conflicts involving businesses with competitive interest and transmission planning roles.
- Conflicts arising from preferential access to information for some parties.

3.4.1. Competitive businesses

National Grid Company has interests in two current interconnectors (IFA and BritNed), at least one proposed interconnector

(NEMO), and a possible future link to Norway.[10] As such it is in competition with other proposed and competitive interconnectors. Also, National Grid Company has an interest in the Energy Bridge MPP project looking to connect wind farms in Ireland to the GB system.

The potential conflicts arise in that NGET as the incumbent planner could favour investments that facilitate transmission connections to the on-shore landing point of either interconnectors or offshore wind farm connections, and disfavour (by delays, higher connection charges, etc.) competitive rivals. In the case of quasi-merchant interconnectors, other competitors might reduce the arbitrage profits of National Grid Company's subsidiaries. In the case of offshore wind, NGET could potentially offer a connection point that would require more costly onshore network reinforcement (in order to increase their RAV) as opposed to a potentially more efficient solution, which might require less costly reinforcement of onshore assets.

There must therefore be some concerns that the same owner should both be designing and building the transmission assets and benefitting from interconnections facilitated by such transmission investment, and also concern that potential entrants might be deterred by the perception that they would be relatively disadvantaged. That would continue after connection, as timely maintenance to ensure access to the GB market from the onshore connection point might be less assured.

Similar concerns would also apply if it was decided that competitive delivery should extend to onshore assets. An important aspect to note with these sorts of conflicts of interest is that they do not depend on any explicit communication between the businesses of incumbent TOs, but simply recognition that at the board level the company objective and fiduciary duty to its shareholders is to jointly maximise total profits from all its interrelated businesses.

3.4.2. *Conflicts arising from informational advantages*

National Grid Company as both the delivery agent of the GB Electricity Market Reform (EMR), the transmission planner and NETSO would benefit from the information supplied for connection agreements and future contracting plans for additional generation, and would thus be in a better position to plan its own commercial activities.[11] As transmission system designer and deliverer, it would be better placed to assess the attractiveness (cost, speed and future TNUoS charges) of different future connection points. Other merchant interconnectors and OFTOs would lack access to (some of) this transmission planning information and the cost implication of different choices associated with connection to the onshore grid. This could undermine new entry of independent transmission owners, who could bring innovations in the transmission investment process.

Even if ‘Chinese walls’ within the company are effective, these might not remove the perception of conflicts of interest in the existence of such information. There is also a concern that Chinese walls could lead to information, which would and should have been made public, being withheld for fear of giving unfair advantage to other businesses, e.g. the current connection costs at every node.

Another concern is the fact that National Grid Company is the primary organisation that engages with transmission planning on the EU level through its engagement with ENTSO-E. This implies that it potentially has access to information that other TOs do not have. This is important given the role that European institutions are expected to play in the development of the future transmission system through the inclusion of projects (and the associated funding) in the EU ten year development plans.

The following section describes a range of transmission investment arrangement options aiming at mitigating these identified concerns.

4. Options for change

In order to mitigate the aforementioned key concerns of the current regime, three options for change have been identified. These cover both ends of the spectrum of theoretical routes that can be taken, with an asset-owning TSO and an ISO that (only) plans and operates all the transmission assets built and owned by other companies.

4.1. *Improved Status Quo option*

The Improved Status Quo (SQ+) option maintains the current regime setup and aims to address the identified inefficiencies. The SQ+ option's main feature is to introduce a shadow Independent Design Authority[12] (IDA) to support the decision-making process of the regulator. Given that under this option the regulator would effectively remain a buyer of network services, it is important that the regulator strengthens its capability for in-depth scrutiny and analysis of network investment and provides stronger input to coordination of investment. Currently, the core technical experience and expertise lies with NETSO and the incumbent TOs, aggravating the gap between ‘buyer’ and ‘seller’. The shadow IDA would undertake Cost Benefit Analyses (CBA) of a range of future GB development scenarios across all regimes. This would provide support to Ofgem in exerting regulatory oversight, ensuring that social welfare is maximised and the needs of future consumers are taken into account.

More specifically, as displayed in Fig. 1, the remit of the shadow IDA would span all three regimes, which would enable it to develop and maintain a holistic view of the system, coordinate connection applications and administer MPP planning.

NETSO would remain the main system operator, while onshore planning activities would remain with the three incumbent TOs. Interconnector and offshore planning would remain largely developer-led, following the current ownership structures. No asset divestment would be necessary under SQ+, meaning that the option could be implemented with a minimal amount of legislative change.

The current TNUoS charging scheme would remain largely unchanged, with the inclusion of interconnectors to facilitate cost-reflective interfaces between the onshore and interconnector regimes and facilitate coordination.

As elaborated in Section 5, the fundamental inefficiencies associated with the present single-price market remain, but their impact would be marginally reduced through strengthening of the regulator's capability as the principal buyer of network services. The shadow IDA would be strictly governed by rules that fully specify the processes and methodologies to be followed. In this light, the shadow IDA would not take a view on the future system

[10] For more information refer to the National Grid Annual report available at: ⟨http://www.nationalgrid.com/NR/rdonlyres/763A93AA-4982-45D1-94EF-8A8D90-522D7A/61001/National_Grid_Interactive_FINAL.pdf⟩.

[11] See KPMG (2013).

[12] IDAs as opposed to TSOs and ISOs only plan the transmission system without controlling its operation. Within the context of the Status Quo+ we refer to a shadow IDA since system planning would continue to be carried out by the TO's and as such the shadow IDA would have primarily a technical oversight and co-ordinating role. In this respect the shadow IDA could potentially be a part of the regulator or an independent full time body that has significant technical expertise in assessment of transmission investment and operation.

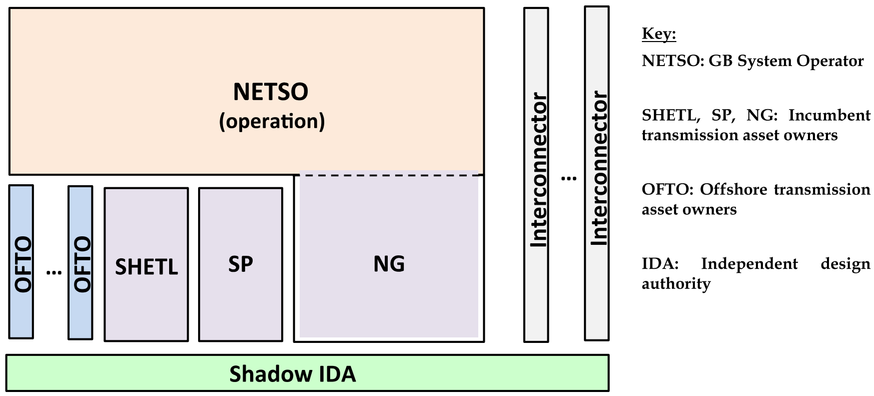

Fig. 1. Improved Status Quo option.

evolution, but would provide the necessary expertise to carry out the required tasks.

4.2. TSO option

Under a transmission system operator (TSO) framework, one single party owns the transmission network as well as operates it. Such a party is accountable for providing access to new users, operating, planning and delivering network infrastructure. There are two main options associated with this framework for GB. The first option bundles the above activities only over the current onshore transmission network (onshore TSO) while a second one bundles them across the three transmission regimes, i.e. onshore, offshore, and interconnector (GB TSO). Both would require horizontal integration of transmission facilities under the main incumbent transmission owner, i.e. National Grid as displayed in Fig. 2.

Under the above options, the governance of the TSO would not be fundamentally different from that of the current TSO of England and Wales (i.e. National Grid) and therefore it would remain the case that it will not to be allowed to own generation or retail businesses or be dependent on affiliated market participants, in order to eliminate conflicts of interest. Likewise, in the case of the onshore TSO, a clear functional separation for the unregulated lines of business like interconnectors would need to be imposed, potentially going even further then at present and requiring complete independence. Furthermore, because a TSO is fundamentally a for-profit entity, it would need to be exposed to a tailor-made and adequate system of performance based regulation (PBR) and ruled according to an array of network codes that promote transparency in all network activities (operation, planning and delivery), in order to align its economic incentives and actions with those that increase social welfare. This is further developed next.

Under the TSO options, it is envisaged that the current onshore regime in England and Wales will be expanded to the entire onshore network (onshore TSO option) or all three transmission regimes (GB TSO option). Thus, the TSO would be responsible for network operation, facilitating access as well as co-ordinating planning and delivery across regimes, timescales and on a regional basis through engagement with industry stakeholders, the regulator, the Department of Energy and Climate Change (DECC) and EU counterparties.

As a result, the role of Ofgem/government would shift from a buyer of transmission service to only the designer of the incentive schemes and facilitator of Constructive Engagement (CE) among the market participants. A prerequisite for a successful application of CE is a fully efficient location-specific network pricing regime (Locational Marginal Pricing) in the short term, combined with the

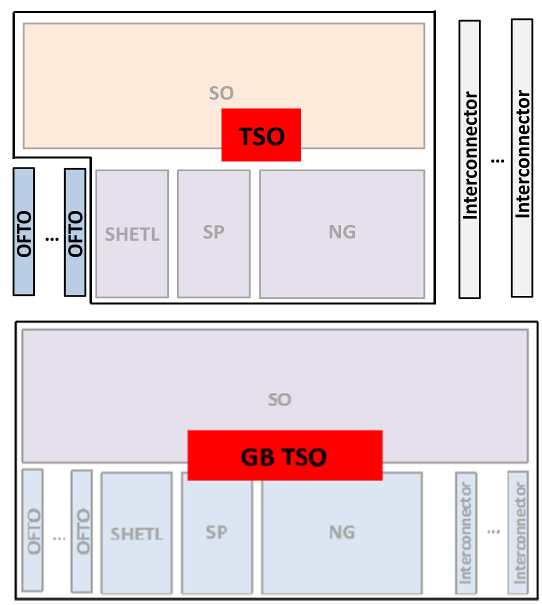

Fig. 2. TSO options that bundle operation planning and delivery over the onshore network (upper) and across the three regimes (lower).

allocation of fixed transmission costs based on a “beneficiary pays” principles, similar to those established in Argentina and Chile.[13]

Under these conditions, network planning would be carried out through a transparent and established process, with potentially the regulator and government providing input on behalf of consumers (in case of absence of strong consumer advocate groups) and future users' needs.

A necessary condition for the TSO option is that regulation will provide the necessary incentives to align benefits to the TSO and to society. In fact, if an adequate performance based regulation (PBR) were in place, bundling network ownership and operation would lead to optimum operation, planning and delivery by taking advantage of the synergies from combining SO and TO functions, particularly in asset operability and flexibility assessment. Furthermore, the TSO could be allowed to undertake a holistic balance of short and long-term network operation and investment by internalising the associated costs through the incentives schemes and the response of network users through the constructive engagement process. This would minimise the need for the regulator to scrutinise system operation, planning and delivery activities.

[13] See Littlechild and Ponzano (2008), Littlechild and Skerk (2008a, 2008b, 2008c, 2008d, 2008e) and Araneda and Rios (2005). It should be noted that in Argentina and Chile this principle is implemented by an ISO.

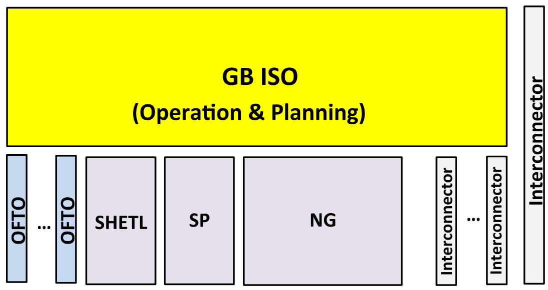

Fig. 3. ISO option.

Nonetheless, as opposed to other sectors where the regulated output can be clearly defined in electricity transmission, defining the output and the associated cost function is much more challenging. As elaborated in Hogan et al. (2010)[14] the transmission cost function displays non-convexities and as such it is still an open question whether an efficient regulatory formula could be established, even in the presence of efficient pricing.

Finally, in order for the TSO option to function, restructuring of current asset ownership will be needed (i.e. asset divestment of TOs in Scotland, and perhaps OFTOs and interconnectors in GB TSO option).

4.3. ISO option

Under this option, an Independent System Operator (ISO) would be established, with key responsibilities for system operation, transmission planning and for administering system delivery.

As displayed in Fig. 3, the GB ISO would replace NETSO as the system operator and would be responsible for overall co-ordination across regimes. However, the ISO would not own any transmission assets and its structure and scope would be broadly based on the ISOs found in the US and Latin America.[15]

A key distinction to the current NETSO structure would be that instead of relying on profit maximisation incentives the majority of the ISO functions would be dictated through grid codes and rules and a broad mandate to maximise social welfare. This equates to minimising transmission investment, congestion costs and un-served demand, given demand and generation power injection/withdrawals and entry/exit decisions. As a result, the ISO would internalise these costs and operate and plan the system accordingly. In order to ensure this is done efficiently, the most important characteristic of the ISO is its independence from any market participants.

Overall, the responsibilities and actions of the ISO would broadly match those of the NETSO, implying that this option would not require substantial market code changes.

In line with the international experience, elaborated in Pollitt (2012), the ISO would be a public, not-for-profit entity, managed by a board of directors and could be supported by an advisory board representing the interests and expertise of all market participants and TOs.

Grid codes, well defined process and rules, supporting decision making through transparent social welfare maximisation CBA (all of which would be reviewed regularly against the best international practice), will ensure that ISO maximises efficiency of system operation. These will be the key for dealing with criticisms of the ISO option involving (a) risk-aversion and thus conservative system operation and planning, (b) ever-expanding area of influence and undertaking activities for which others pay and (c) a lack of internal cost control.

With respect to ISO funding, the current cost recovery mechanism through Balancing Services Use of System charges (BSUoS) would be appropriate. Since the ISO would not invest in any assets, the level of annual costs is expected to be similar to the current NETSO costs. In order for the ISO to be able to strike contracts cost-effectively, the government, through guarantees for cost recovery, will ultimately provide its credit.

The ISO could be established through divestment of the current NETSO from NGET. The fact that the NETSO does not have any significant asset should minimise the complexity of this process.

Similar to the Improved Status Quo, the ISO option does not require fundamental changes to the current market design and network charging arrangements but a rationalisation so as to resolve the inconsistencies across the different regimes. It is important to note, that going forward the value of assets offshore, cross-border and the Scottish TOs is expected to surpass that of NGET, implying that the majority of the transmission system will be operating under arrangements similar to the ISO option.

The evolution of current regimes and how they address current regime concerns are summarised in Tables 2 and 3.

5. Conclusions and policy implications

A summary of the key strengths and weaknesses of each of the proposed options is presented in Table 4. The Status Quo+ option has the obvious advantage of requiring the minimum amount of change and possibly has the lowest implementation costs. Moreover, it would provide time to evaluate how effective coordination and delivery of networks across different regimes is, as well as to consider further evidence for or against change as this becomes available. On the other hand, as explained in Section 4 a number of the current concerns would not be addressed and the challenge of the regulatory task of Ofgem would continue to grow, as investment levels and asset complexity escalate.

The GB TSO options have a number of benefits, the most important being that a single entity could internalise the costs of investment and operation efficiently and deliver an optimum transmission system. This can lead to significant synergies both with respect to operation and ownership as well as planning, designing and delivering the transmission system, which in turn leads to low transaction costs. Moreover, this option is the dominant one in Europe. However, there are a number of prerequisites for this option to deliver efficient network operation and investment including:

- Efficient location specific energy pricing with beneficiary pays concept is established.
- A Performance Based Regulatory regime can be established with appropriate outputs defined.
- The constructive engagement process is effective.

In addition, this option would require existing TOs to divest all their transmission assets to the GB TSO.

As explained in Section 4, the ISO option can potentially resolve the majority of the weaknesses identified with the current regimes as well as promote innovation and increased stakeholder engagement through an advanced transmission planning and delivery process. Because of the non-profit nature of the ISO, the key

[14] This study identifies a transmission investment regulatory framework which exposes the TSO to both regulated and congestion surplus revenue with different weights, showing that the TSO would invest optimally. However, this in only ensured if the transmission investment cost function is well defined and convex (which is not necessarily the case in practice).

[15] For more details on the transmission planning and delivery experience in markets with an ISO see Pollitt (2012).

Table 2
Evolution of current regimes.

	Status Quo+	GB ISO	GB TSO
Onshore regime	• Onshore investment (planning and delivery) driven by incumbent TO's • Shadow IDA would challenge TOs' plans and require evidence that alternative solutions have been considered, including the use of advanced operational measures • Shadow IDA would co-ordinate strategic wider works through public CBA process considering all possible solutions (including non-network ones) both from incumbent TOs and other participants	• Onshore transmission investment driven by GB ISO through a process defined public CBA subject to security standards, policy targets, investment and congestion costs and considering a number of competing technologies such as advanced operational measures, non-network solutions (demand, generation, storage) as well as investment in primary assets • The GB ISO would identify boundary enhancements as well as reserve investment options and invite market participants to submit detailed proposals for each project (or bundles of projects). Subsequently it would carry out CBA determining the cost/benefit ratio for each proposal against the reserve solution. If the ratio is favourable, then this solution would be implemented by the proposing party earning him a regulated revenue, otherwise the ISO would mandate or auction the delivery of reserve solutions	• TSO is exclusively responsible for onshore transmission investment subject to incentive regulation and through a constructive engagement process with network users and consumers
Offshore regime	• Offshore planning would remain a developer-led activity • Shadow IDA would facilitate coordination by reducing the perceived conflicts of interest and perverse incentives through open seasons when the need arises, to reduce barriers to entry	• **Option 1:** In case of deep ISO, OFTO regime would be overturned and offshore transmission planning would be undertaken by the ISO and the delivery competitively tendered • **Option 2:** Similar arrangements to Status Quo+ with ISO facilitating co-ordination and carrying out OFTO auctions	• Offshore regime would fall under the remit of the TSO
Cross-border regime	• Depending on the cap and floor levels, cross-border transmission could evolve either as a merchant or regulated activity • In the merchant case the status quo would be retained • In the case of regulated interconnectors the shadow IDA as part of its regional co-ordination mandate would facilitate a cross-border planning process, which would involve identifying eligible interconnection projects potentially through a centralised CBA process or as suggested by developers. The delivery of these projects could be tendered	• **Option 1:** In case of deep ISO, similar to OFTO with GB ISO planning and tendering interconnectors • **Option 2:** Similar arrangements to Status Quo+	• Cross-border regime would fall under the remit of the TSO
Multi- Purpose Projects	• A new MPP regime would need to be instituted, and Shadow IDA made responsible for planning such projects • The Shadow IDA would perform periodic analysis to indicate MPPs leading to wider benefits, while also allowing proposals from stakeholders. Market solutions would then be solicited through an auction process, where participants would propose solutions and bid for a regulated return on their investment decoupled from asset utilisation	• Under a deep ISO, MPPs would be planned through the CBA by the ISO and delivery competitively tendered • Alternatively a more competitive planning and delivery process could be facilitated as part of the market led CBA for onshore transmission investment	• MPPs would be co-ordinated by the TSO as part of the general transmission investment mandate

concern is that the ISO is likely to be very risk-averse and tend to favour conservative system planning and operational measures. However, the ISO would need to follow grid codes and rules in operating the network which would be supported by established Cost Benefit Analysis (CBA) aimed at maximising social welfare, rather than by commercial incentives. Reviewing the list with the key ISO responsibilities, for the majority of the items it is evident that the actions are a matter of applying market codes and following processes. These rules and CBA would be reviewed periodically against the best international practices. In order to benefit from optimising trade-offs between short-term operation and investment costs, the GB ISO would be able to contract with

Table 3
Addressing current regime concerns.

	Status Quo+	GB ISO	GB TSO
Incentives framework for transmission investment and operation	• Whereas the shadow IDA would scrutinise and challenge the TOs investment plans it is unlikely that the identified issues would be totally resolved. This is because the shadow IDA would not have an informed view of the operational implications of investment decisions	• Under the ISO option this concern would be resolved to a large extent since the mandate of the ISO would be to maximise GB social welfare through the co-optimization of transmission planning and operation and the use of competitive tendering • The overall efficiency of transmission investment would depend on the scope of the ISO as well as the following: – ISO governance and Ofgem's ability to regulate the ISO costs; – the effectiveness of the grid codes and transmission planning and delivery rules and processes • Concerns that would largely remain are – the ability of dealing with uncertainty, and; – the inefficient generation siting due to lack of cost-reflective transmission pricing Hence, a certain degree of overinvestment is still likely but this would be driven by generation and demand siting decisions rather than perverse investment incentives due to the commercial considerations of the ISO • In order to increase stakeholder engagement as well as promote innovation, advanced planning processes such as the one presented in Section 3 and ISO administering Network Innovation Competition could be adopted	• The TSO options would in principle be able to deliver optimal level of network capacity to consumers and could reverse the bias towards asset heavy solutions and use advanced operational measures as alternative non-network solutions since these would increase profitability (together with social welfare). However this would depend on the following strong assumptions: – efficient pricing is established; – PBR can be designed and an appropriate output defined; and – constructive engagement process is effective
Lack of co-ordination	• Facilitating co-ordination will be one of the primary mandates of the shadow IDA and as such it is expected that to a certain degree the lack of co-ordination concern would be addressed • Cross-border transmission investment will be primarily undertaken by independent developers. This implies that efficient regional co-ordination might be difficult to achieve given the large number of parties involved	• This would be resolved as the co-ordination at all levels (operation, across regimes, current and future users and regionally) would be achieved through ISO planning process	• Multiple coordination problems between TOs and NETSO, existing and future users' needs, different transmission regimes, and network investment at regional level (i.e. EU) would be clearly resolved through having a single GB TSO that mandates (subject to Ofgem approval on major investments and subject to a dispute process for connections) all network investment and operation
Conflicts of interest	• The introduction of the shadow IDA as the coordinating hub for connections and the increased information transparency will largely address the concerns related to information asymmetry • Other important concerns such as the conflicts among TOs and between incumbents and competitive businesses will remain largely unresolved. The resolution of these would entail more extended changes, such as the unbundling of network ownership and planning	• Since the ISO will be independent and not for profit, under this option all the existing conflicts of interest would be resolved • However, an entity like the ISO may suffer from conflicts of interest originating in the bureaucracy of the organisation. Consequently, the core ISO functions would be carried out in line with well-defined and transparent market codes, rules and implementation of processes that will be regularly reviewed against best international practices • The remaining concern would be associated with managing ISO operational costs, which in any case are expected to be modest and mitigated through strong regulatory oversight	• The existence of a single party will resolve conflicts between multiple onshore TOs and those between TOs and generation, especially in Scotland since a single TSO will govern the overall onshore grid • Conflicts involving competitive versus incumbent businesses (where the TSO could develop competitive offshore networks and interconnectors) will be also removed under the GB TSO option due to the presence of a single party that will control all network investments, albeit such conflicts will be maintained under the onshore TSO option. In the latter full divestiture of competitive activities of the onshore TSO would be required

Table 4
Key strengths and weaknesses of proposed options.

	Status Quo+	GB TSO	GB ISO
Key strengths	• Minimum change focused on improving current regimes • Optionality to reconsider as more evidence emerges	• Theoretically optimum option • Synergies from combining SO and TO functions, particularly in asset operability and flexibility assessment • Integrated design delivery and operation • Low transaction costs • Preferred practice in Europe	• Resolves most current concerns: implements efficient system operation, removes conflicts of interest, provides effective coordination across regimes and within the region • ISO can promote future market design improvements • ISO option with advanced planning and delivery process can potentially lead to more active stakeholder engagement
Key weaknesses	• Regulation heavy • Key concerns unresolved	• Concerns about the development of PBR • Asset divestments required • Efficient transmission pricing is a pre-requisite • Over-reliance on a single entity	• In the case of a deep ISO, single worldview • Effective governance, grid codes and rules need to guide ISO • SO to TO contracts potentially difficult to define

Table 5
CBA for Status Quo+ and ISO options.

Status Quo+	GB ISO
Costs	
Costs of establishing shadow IDA	Loss of TO/SO synergies in England and Wales
On-going operating costs of shadow IDA	Increased ISO/TO transaction costs in England and Wales
Costs and barriers to implementing information transparency	One-off set up costs of ISO
Costs of reviewing network operation and design standards to promote advanced operational measures	Consultations and code review costs
	Potential ISO operational cost inefficiencies
Benefits[a]	
Benefits of increased co-ordination	
Benefits of increased transmission planning and delivery efficiency	
Reduction in Ofgem/DECC costs by carrying out transmission investment CBA in-house (shadow IDA) rather than outsourcing to consultants	Reduction in regulatory costs due to reduced regulatory burden
	Benefits of adopting advanced operational levels

[a] Given the two options' characteristics, it naturally follows that these benefits will be higher under the ISO option and this should be reflected in the impact assessment methodology.

incumbent TOs and with demand and generation parties for the provision of network services that would reduce network constraint costs and enhance utilisation of existing assets. It is also noted that going forward the asset value of offshore, cross-border and the Scottish TOs is expected to surpass that of NGET, implying that the majority of the transmission system will effectively be operating under arrangements similar to the ISO option.

Given the very strong assumptions under which the GB TSO option would work in practice as well as the fact that it requires significant asset divestments and the establishment of efficient transmission pricing, we consider that this option could not be implemented in the short to medium term.[16]

On the other hand, the ISO option resolves effectively the majority of the current regime concerns. Most of the criticisms of the ISO structure can be addressed with appropriate grid codes, rules and processes. Establishing legally the ISO entity may require changes in primary legislation with associated consequences on the timetable for implementation. Although under the Status Quo+ a number of the identified concerns would remain largely unresolved, the timetable for implementation may be attractive and it could be considered to be a viable interim solution for the ISO option, given that the ISO would most likely be established through the merging of the Shadow IDA and NETSO. Deciding between the Status Quo+ and ISO options would require a detailed impact assessment, which is beyond the scope of this paper. Some of the potential elements of the impact assessment are presented in Table 5.

However, if the estimated benefits of the Status Quo+ option are found to be marginal whereas those of the ISO are significant, then the preparations for the ISO option could begin immediately, without implementing the interim solution. If, on the other hand, the Status Quo+ option benefits are also found to be significant then at the very least the Shadow IDA should be established and this would serve as an interim solution and a detailed action plan should be devised for implementing the ISO option (or potentially the TSO if efficient pricing is on the agenda).

Acknowledgments

The authors are grateful for all contributions received at the 2 workshops, which were essential for gathering international experiences on infrastructure planning and delivery practices in both electricity and other relevant sectors. We would like to thank especially Ofgem and the colleagues that presented at the two workshops:

(1) *Lessons from other sectors*: Cathryn Ross (ORR), Chris Bolt, Emma Gilthorpe (Heathrow), Ian Alexander (CEPA), Martin Cave (Imperial College Business School), Stephen Littlechild (Judge Business School).

[16] Moreover given the uncertainty regarding Scottish independence, it will be very difficult to promote asset divestments of the Scottish TOs' assets until this issue is settled.

(2) *Electricity transmission planning and delivery – International experiences*: William Hogan (Harvard University), Richard O'Neill (FERC), Dan Woodfin (ERCOT), Paul Sotkiewicz (PJM Interconnection), Julia Frayer (London Economics International), Hugh Rudnick (Universidad Catolica de Chile), Juan Carlos Araneda (Transelec), Lewis Dale (National Grid), Fiona Woolf (CMS Cameron McKenna).

The views expressed in this paper are solely those of the authors.

Dr. Moreno gratefully acknowledges the financial support of Conicyt, Chile (through Conicyt/Fondecyt/Iniciacion/11130612 and Conicyt/Fondap/15110019).

Appendix: Abbreviations

BSUoS: Balancing Services Use of System charges, are the charges levied on energy injected in the transmission system which cover the NETSO operating costs including ancillary services procurement. On average these are around £1.5/MWh.

GB: Great Britain (England, Wales and Scotland).

IDA: Independent Design Authority, as opposed to TSOs and ISOs, only plans the transmission system without controlling its operation. Within the context of the Status Quo+ option presented in Section 4.1, we refer to a shadow IDA since system planning would continue to be carried out by the TOs and as such the shadow IDA would have primarily a technical oversight and co-ordinating role. The shadow IDA could potentially be a part of the regulator or an independent full time body that has significant technical expertise in assessment of transmission investment and operation.

Interconnectors: Interconnectors are transmission lines crossing national borders. In GB, interconnectors can be owned only by independent transmission companies, with no generating assets. National Grid Company owns two of the GB interconnectors through a subsidiary, National Grid Interconnector Limited, which is legally separated from National Grid Company. The TOs cannot own interconnectors because of their generating assets. Third parties theoretically can and have tried to build interconnectors but to date no such investment has taken place yet.

ISO: Independent System Operator, refers to a usually not for profit organisation that is only responsible for planning and operating the transmission system but not owning it.

MPP: Multi-Purpose Projects, refers to transmission project that might span more than one of the current three regimes (onshore, offshore and cross-border). A few examples of such projects include offshore wind farms connecting to interconnectors or planned “on-shore” DC links (i.e. HVDC undersea cables aiming at enhancing transfer capability between Scotland and England), meshed offshore grids which might also serve to increase the onshore boundary capacity etc.

National Grid Company: Refers to the corporate entity that owns NGET and NETSO as well as National Grid Interconnection Limited.

NETSO: National Electricity Transmission System Operator, is the system operator function carried out by National Grid Company. National Grid Company also owns the transmission system in England and Wales but in theory the two functions, asset ownership and system operation, are legally separated. In this respect, NETSO can be viewed as equivalent to ISO but its operations are driven by incentive regulation rather than being not for profit.

NGET: National Grid Electricity Transmission, refers to the transmission owner function of National Grid Company.

Ofgem: Office of Gas and Electricity Markets, is the government regulator for the electricity and downstream natural gas markets in Great Britain. Within the context of this paper Ofgem is responsible for scrutinising the transmission investment plans of the transmission companies as well as setting incentives for transmission investment and operation. It is also responsible for regulating transmission charging (onshore, offshore and cross-border) as well as administering the investment process in offshore and cross-border transmission.

OFTO: Offshore Transmission Owners, are companies that own and maintain the offshore transmission grids, connecting offshore wind farms to the onshore grid. OFTOs cannot be generating companies nor can they be any of the TOs or NGET. To date the majority of OFTOs are financial investors.

TNUoS: Transmission Network Use of System charges, are annual capacity based transmission charges paid by the users of the transmission system (demand and generation). They are locationally varying from around £20/kW/year in Northern Scotland to −£5/kW/year in South West England.

TO: Transmission Owner, refers to the two Scottish transmission companies Scottish Power Transmission Limited (SPTL) and Scottish Hydro-Electric Transmission Limited (SHETL), and NGET that is the transmission owner function of National Grid Company. Operation is delegated to NETSO that is the system operator function carried out by National Grid Company.

TSO: Transmission System Operator, refers to an unbundled utility that designs, delivers, owns and operates all of the transmission system. In the case of the England and Wales onshore transmission system, National Grid Company would qualify as a TSO.

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