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Electricity interconnector policy

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Target audience: Electricity traders, transmission companies, interconnector developers, generators and suppliers, customer representatives and other interested parties

Overview:

The GB electricity market currently has up to 2.5 GW of interconnection to France and Northern Ireland. By 2012, this will increase to about 4 GW, with new links to the Netherlands and Ireland. By 2020, it could increase further to about 8 GW.

The consultation describes proposed models for the allocation of capacity on these interconnectors, including "market coupling", and for regulation of new investment. It seeks views on how Ofgem's policy should develop and will lead to further proposals, most likely in conjunction with National Regulatory Authorities from neighbouring markets.

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Context

The GB electricity market currently has limited interconnection with other markets but this is expected to increase significantly in the decade ahead. In part, this reflects the expectation that increased interconnection will help accommodate the expected huge increase in intermittent wind generation and will contribute to security of supply. Our review of electricity interconnector policy therefore has links with Project Discovery as well as Transmission network regulation, including any changes arising from our RPI-X@20 review of network regulation.

At the European level, attention has focussed recently on developing target models for capacity allocation, particularly through the Project Coordination Group set up by the European Commission's Florence Forum. Work on co-ordination of regional markets is taken forward through the Regional Initiatives established by the European Regulators' Group for Electricity and Gas (ERGEG), including the France-UK-Ireland region which Ofgem chairs. More generally, the legal framework is now established by the Third Package of internal energy markets legislation, which is due to come into effect in March 2011. This consultation considers our electricity interconnector policy in the light of these developments.

Associated Documents

France-UK-Ireland Electricity Regional Initiative Consultation on Priorities, November 2006: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/France-UK-Ireland/Public_consultations/Priorities/CD

BritNed exemption - original decision:
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/TPAccess/Documents1/BritNed%20Decison%20letter%2012%20July.pdf
Amended decision:
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/TPAccess/Documents1/Britned%20amended%20exemption%20order.pdf

Imera exemption – original decision:
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/TPAccess/Documents1/EWC%20exemptions%20decision%20doc.pdf
Amended decision:
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/TPAccess/Documents1/EWC%20amended%20exemption%20orders%20cover%20letter.pdf

Project Coordination Group presentation at the 17th European Electricity Regulatory Forum:
http://ec.europa.eu/energy/gas_electricity/doc/forum_florence_electricity/meeting_17_2_pcg_presentation.pdf

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Summary

With the arrival of the Third Package, construction of new interconnectors connecting to Great Britain in the near future and developments in the European policy regarding allocation of interconnector capacity, Ofgem considers it timely to review the framework for regulated interconnection investment and capacity allocation in Great Britain.

The overall aim of our policy is to maximise the efficient use of existing and planned interconnection by ensuring that users can respond efficiently to price differentials and that the mix of capacity products and levels of firmness provide for competition, market entry and an appropriate allocation of rights and responsibilities between market participants.

The efficient use of interconnectors will lead to clearer investment signals for additional interconnector build, through more accurate exposure of price differentials and the demand for additional investment. A clear and predictable framework for regulated interconnector investment should be in place to bring forward an efficient level of new capacity to meet demand.

Framework for interconnector investment

To date in Great Britain, interconnectors have been developed as stand-alone projects outside the price controlled transmission business. The developer is fully exposed to the market demand for the capacity and the price determined via auctions, both of which can be uncertain at the outset. For this model to work, the developer may seek some protection against regulatory intervention to cap profits or change the basis on which capacity can be sold. This has been provided through exemptions from certain aspects of the licences and European legislation. By contrast, in other Member States, it is more common for interconnection to be developed by national transmission companies with revenues underwritten by consumers.

Recent experiences with the exemption process and implications of the Third Package (such as the development of cross-border codes) have led Ofgem to consider whether the current regulatory arrangements will continue to provide sufficient incentive for developers to invest in interconnection. It may be the case that improvements could be made to facilitate future investment.

This consultation discusses a range of regulated investment models which could address the risks, uncertainties and opportunities facing a potential investor in interconnection. It seeks respondents' views on an appropriate framework for investment in interconnection on a regulated basis. After consultation responses have been considered, Ofgem envisages further work with regulators in neighbouring markets which could lead to joint consultations on proposed models.

Efficient use of interconnection

Efficient use of interconnection means that the maximum capacity is made available to market participants, while maintaining operational security, and that electricity flows in response to market price differentials. Whether existing capacity is used efficiently will depend on the degree to which capacity products and national electricity market design creates barriers to, or facilitates, economic trade between neighbouring electricity markets.

This consultation paper explores options for congestion management on interconnectors connecting to GB. These options are presented in the context of European policy discussions and legal requirements promoting a single European electricity market and the prospect of increased interconnection between Great Britain and neighbouring markets. They build on the new approaches developed on the England-France Interconnector (known as the IFA) through the ERGEG Regional Initiatives and new target models established by the Project Coordination Group under the Florence Forum.

The regional coordination of capacity auction models and products becomes more important with increased levels of interconnection. The BritNed interconnector will connect the British electricity market to the Dutch market. As BritNed's exemption requires it to provide day-ahead implicit auctions, this will result in a degree of market coupling between Great Britain and neighbouring markets. We seek views on how this could best be achieved, on co-ordination of capacity allocation in other timescales and on integration with the Single Electricity Market (SEM) of Ireland and Northern Ireland.

Introducing particular capacity allocation models will have impacts on our immediate neighbours and more broadly as the internal electricity market develops. Equally, developments in other regions may make certain capacity allocation models more attractive as harmonisation with other countries is likely to increase demand for capacity on GB interconnectors and will also mean that the benefits of interconnection are more likely to be realised. The new models may become mandatory through the Third Package mechanisms of Framework Guidelines and Network Codes. This consultation discusses potential options for regional integration at a high level, following which concrete plans will need to be developed in coordination with neighbouring countries through the Regional Initiatives or other fora.

Next steps

We strongly encourage industry participants and others to respond to the questions this document raises and the options proposed. Discussions on new models of capacity allocation are ongoing, and will be informed by the responses to this consultation. Over the coming months, Ofgem will also develop its thinking for regulation of new electricity interconnectors, in discussion with neighbouring regulators and expects to publish proposals later this year.

1. Introduction

Chapter Summary

This chapter provides the background to this consultation, explaining the extent of existing and planned interconnection, outlining the regulatory and legal framework and ongoing work through the France-UK-Ireland regional initiative.

It also explains why we are consulting now on this issue, both in respect of particular projects and general developments.

Question box

Question 1.1: Have we accurately captured the benefits of and demand for new interconnection? Are the projects under consideration all viable? Would they be sufficient? Are there other projects being developed?

Question 1.2: Are there other key aspects of the legal or regulatory framework that we should consider, or should some features be given a different emphasis?

Question 1.3: How can the Regional Initiative best contribute to development or implementation of policy? Do you agree with the priorities and approach outlined?

Current and planned interconnection

1.1. There are two existing interconnectors between GB and other markets – the Interconnexion France-Angleterre (IFA) and the Moyle Interconnector (Moyle) from Scotland to Northern Ireland:

- the IFA, which commenced operation in 1986, is a 2000MW high voltage direct current (HVDC) link between the French and British transmission systems. The interconnector comprises of four 500MW cables between Sellindge in England and Les Mandarins in France. National Grid Interconnector Limited (NGIL)[1] and the French transmission company Réseau de Transport d'Electricité (RTE) jointly own and operate the IFA.

- Moyle started commercial operation in April 2002. The interconnector links Scotland to Northern Ireland and has a contracted capacity of 450MW into Northern Ireland and 80MW into Scotland. In 2003 the company was mutualised and the asset is now owned by Northern Ireland Energy Holdings and operated by the System Operator for Northern Ireland (SONI).

[1] A wholly owned subsidiary of National Grid Plc.

1.2. In addition, there is an interconnector to the Netherlands (BritNed) under construction, due to begin operation by the end of the year and to be commissioned in early 2011. An interconnector to Ireland being developed by Eirgrid is due to commence construction in 2010 and operation in the summer of 2012. Further interconnection projects to Ireland, being developed by Imera, have been granted exemptions – we understand that timing is subject to consents and connection agreements.

1.3. These, together with further projects at an earlier stage of development, where timing has yet to be determined or finalised – but which could be operational by 2020, are set out in Table 1. In the table, "Exempt" refers to exemption from conditions 9, 10 and 11 of the Interconnector Licence and Article6(6) of the Second Package Regulation. "Regulated" means not exempt from these requirements – all the projects are regulated in the sense of requiring a licence.

1.4. Of the projects in Table 1, the ones that are driving the considerations in this paper are primarily BritNed and IFA in terms of capacity allocation and Nemo (a proposed interconnector with Belgium) in terms of the regulation of investment. Ofgem will be asked to approve the allocation of capacity on BritNed in mid 2010, and it may be sensible to consider these alongside arrangements on the IFA and for future interconnectors – this is considered in Chapter 2. National Grid (NG) has asked Ofgem to consider how it would treat Nemo under a regulated model, and we need to respond in 2010 to keep pace with the project's timetable – this is addressed in Chapter 3. All of this also sits within a broader context of developments at the European and regional levels, as explained further below and in each Chapter.

1.5. In addition to the "pure" interconnection projects in Table 1, there has been some interest in offshore windfarm connections to multiple markets (combining a windfarm connection and an interconnector) and – increasingly – in the idea of a North Sea offshore grid. These are important potential developments which raise a number of questions beyond the scope of this consultation, which require further consideration by governments as well as regulators. Some of the issues are discussed in the current CEER consultation on "Regulatory aspects of the integration of wind generation in European electricity markets".[2] We also note the recent formation of "The North Seas Countries' Offshore Grid Initiative"[3] which provides a vehicle to address some of these issues. We recognise the need for consistency between the offshore grid and connection/interconnector combinations with the topics covered by this consultation, which will be facilitated as the same EU legal framework applies throughout. We would welcome views on any particular implications of these developments which should be taken into account in this consultation.

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[2] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/OPEN%20PUBLIC%20CONSULTATIONS/Integration%20of%20Wind%20Generation

[3] http://www.decc.gov.uk/en/content/cms/news/pn146/pn146.aspx

Table 1: Existing, planned and future interconnection

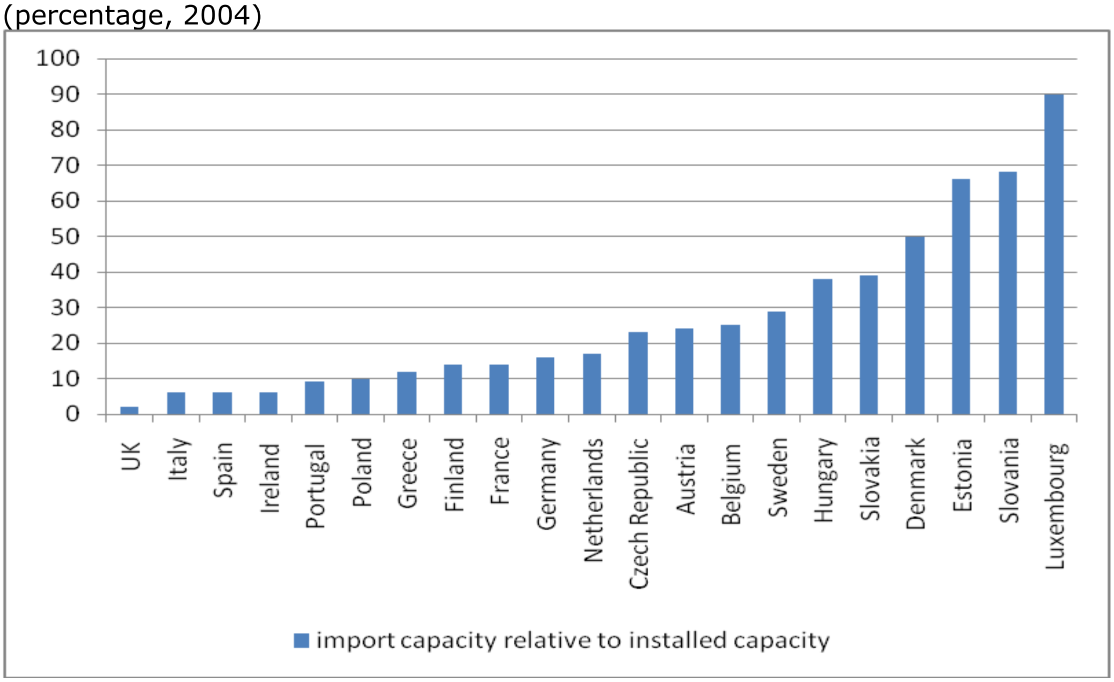
Name	Owner	Connects to	Capacity	Status	Date operational
IFA	NG and RTE[4]	France	2000 MW	Operational Regulated	1986
Moyle	NI Energy Holdings (mutualised)	Northern Ireland	450 MW to NI 80 MW from NI	Operational Within the UK so not an EU law "interconnector"	2002
BritNed	NG and TenneT[5]	Netherlands	1000 MW	Under construction Exemption granted 2007	End 2010 / early 2011
East West Interconnector	Eirgrid[6]	Ireland	500 MW	Construction phase Regulated	2012
East West 1 East West 2	Imera[7]	Ireland	2 x 350 MW	Exemption granted 2009	-
Channel Cable	Imera	France	800MW	Exemption requested in 2009	-
Nemo	NG and Elia[8]	Belgium	1000 MW	Feasibility study complete In discussions with regulators	-
IFA 2	NG and RTE	France	[1000 MW]	Feasibility stage	-
Norwegian interconnector	NG and Statnett[9]	Norway	[1000 MW]	Feasibility study	-
Belbrit	Imera	Belgium	[1000 MW]	Licence granted	-

[4] RTE is the French transmission system operator.
[5] TenneT is the Dutch transmission system operator.
[6] Eirgrid is the Irish transmission system operator.
[7] Imera is a private company.
[8] Elia is the Belgian transmission system operator.
[9] Statnett is the Norwegian transmission system operator.

How much interconnection?

1.6. At present, GB has proportionately less interconnection capacity than all the other main European electricity markets (see Figure 1.1 below) and is significantly below the target of 10 per cent of generation capacity agreed by Member States in 2002. However, the costs of interconnection between GB and neighbouring markets are relatively high, due to the need for sub-sea cable connections, so this is perhaps not surprising. Other markets which are geographically peripheral, such as Ireland and the Iberian peninsula, also have relatively limited interconnection.

Figure 1.1: Average total import capacity relative to installed generation capacity (percentage, 2004)



Source: DG Competition Report on Energy Sector Inquiry (2007)

1.7. A recent consultation[10] carried out by National Grid, Elia and RTE concluded that there was significant demand for new interconnection between GB and the continent. Respondents considered interconnection an important means to respond to intermittency and excess power associated with renewable generation[11] and to help meet the challenge of retiring fossil fuel and nuclear plants in GB. Respondents also noted benefits of access to neighbouring wholesale and supply markets and, in the case of DC interconnectors, the provision of balancing and ancillary services.

[10] http://www.nationalgrid.com/uk/Interconnectors/France/consultations/

[11] Under the EU Renewables Directive, the UK is committed to meeting 15 percent of its energy needs from renewable sources by 2020.

1.8. The benefits of interconnection are based on different conditions prevailing in markets either side of the border. For example, wholesale electricity prices in GB may be higher than in France (where there is a high share of nuclear generation), leading to imports into GB. This winter, lower availability of the French nuclear fleet is keeping French prices relatively high, leading to exports from GB to France. Some price differentials may be structural, for example due to the different fuel mix of generation or the different timings of demand variations. As the volume of intermittent wind generation increases, particularly in GB and Ireland, but also on the near continent, varying flows across the interconnectors may help accommodate fluctuations in wind output.

1.9. The DECC consultation on electricity security of supply,[12] the Poyry study on integrating wind,[13] studies by EirGrid[14] and experience in other markets such as Denmark, all show benefits of increased electrical interconnection. Ofgem's consultation on liquidity[15] suggested increased interconnection could be beneficial. The findings of Project Discovery will also be of interest here. However, the real question is not whether there are benefits, but rather whether they outweigh the costs and what is the most efficient solution (timing, location, capacity etc).

1.10. Differences in prices between two markets are difficult to predict with any accuracy, particularly several years in advance. The benefits are best viewed as an option value – that is, the existence of interconnection capacity creates an option to arbitrage between the two markets. This difficulty in forecasting the benefits of interconnection, together with the importance of incentives for innovation and efficiency, imply significant value in retaining commercial decision-making as the key driver for investment decisions.

Current policy

1.11. The IFA was operational prior to privatisation and was initially treated as a merchant project – that is, any increase or reduction in revenues from sale of capacity to users flows straight to NG's profit. It is not closely linked to the rest of NG's business in economic terms. NGIL has an interconnector licence and is now subject to the full legal requirements set out below.

1.12. New investments to date have fallen into one of two categories. Either they have been fully funded by customers at the far end of the link (Moyle and Eirgrid),

[12] DECC, 2009, "Delivering secure low carbon electricity: A call for evidence" http://www.decc.gov.uk/en/content/cms/consultations/electricsecure/electricsecure.aspx

[13] Poyry, 2009, "Impact of Intermittency – How wind variability could change the shape of the British and Irish electricity markets" http://www.poyry.com/linked/group/study

[14] EirGrid, 2008, "Business Case - The Development of an East-West Interconnector" published by CER at http://www.cer.ie/en/electricity-transmission-network-interconnection.aspx?article=06ca8252-a2fc-449e-8312-147b96fa9e37 and EirGrid, 2009, "Interconnector Economic Feasibility Report" http://www.eirgrid.com/media/47693_EG_Interconnect09.pdf

[15] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Liquidity%20in%20the%20GB%20wholesale%20energy%20markets.pdf

and/or they applied for, and were granted, exemptions from the use of revenues and charging methodology approval requirements explained below (Moyle, BritNed and Imera). Appendix 2 sets out in more detail the regulatory arrangements and capacity allocation process in respect of each of these interconnectors.

1.13. Our policy with respect to gas interconnectors has been similar to electricity – for example the BBL pipeline was granted an exemption from third party access in 2005. If our policy in respect of electricity interconnection changes following this consultation, we would need to consider any implications for gas. However, we note that the legal position is different in gas (for example, in respect of use of revenues) and we are not aware of plans for new gas interconnectors.

Aspects of the legal framework

1.14. There are three key aspects of the EU legal framework that are particularly relevant to this consultation. These are summarised briefly here.

Requirements for regulated interconnectors

1.15. The Third Package Electricity Directive[16] and Regulation[17] include provisions requiring a system of regulated third party access to be applied to interconnectors. The Congestion Management Guidelines, annexed to the Electricity Regulation, entered into force in December 2006, under the Second Package. They require market based congestion management and are intended to facilitate more efficient use of interconnection and enhanced regional integration. Provisions relevant to this consultation include:

- Capacity shall be allocated by means of explicit or implicit auctions. Both methods may coexist on the same interconnection.

- TSOs shall define an appropriate structure for the allocation of capacity between different timeframes. This may include reserving capacity for daily or intra-day allocation.

- TSOs shall optimise the degree to which capacity is firm to facilitate effective and efficient competition. Part of the capacity can be offered at a reduced degree of firmness. At the nomination stage, long and medium term capacity shall be subject to the use-it-or-lose-it or use-it-or-sell-it.

[16] Directive 2009/72/EC of the European Parliament and of the Council concerning the common rules for the internal market in electricity and repealing Directive 2003/54/EC
[17] Regulation No. 714/2009 of the European Parliament and of the Council on Conditions for Access to the Network for Cross-Border Exchanges in Electricity and repealing Regulation No. 1228/2003

1.16. In terms of the regulatory framework for investment, a key feature of the Electricity Regulation is the "use of revenues" requirement.[18] In general, interconnectors earn their revenue through a competitive auction of capacity. The requirement is that they use this revenue for one of the following purposes:

- guaranteeing the actual availability of the allocated capacity; and/or
- maintaining or increasing interconnection capacities; or
- if the revenues cannot be efficiently used for the purposes above and so far as the regulators so approve, as an income to be taken into account in the approval of transmission tariffs/methodologies. Any other revenues shall be held in a separate account until they can be used for the first two purposes above.

1.17. The EU requirements for regulated third party access were implemented in Great Britain via the Energy Act 2004[19]. The Energy Act 2004 introduced a licensing regime for electricity interconnectors, through which the requirements concerning third party access, regulatory approval of charging arrangements and use of revenues (and, where appropriate, exemptions from these requirements) were implemented. The Energy Act prohibited the same legal person from holding an interconnector licence and any generation, transmission, distribution or supply licence. The prohibition was intended to provide a level playing field between undertakings investing in interconnection. Key terms of the electricity interconnector licence are summarised in Appendix 3. We are currently working with DECC to assess the extent to which amendments are required to these arrangements in order to transpose the Third Package.

Criteria and process for exemptions

1.18. There are explicit criteria which allow regulators to grant exemptions from particular requirements, including those set out above.[20] They include legal separation from the national TSO and none of the costs being covered by transmission tariffs. They also require the level of risk to be such that the investment would not take place without exemption.

1.19. It is clear from the legislation that the regulated approach is the default position and exemptions should only be granted by exception at the request of the developer. The Commission also has the right to veto or amend the exemption and in both our recent electricity interconnector exemption decisions (BritNed and Imera), it required additional conditions.

[18] Article 16(6) of Regulation 714/2009.
[19] In 2003 Ofgem and the then Department of Trade and Industry (DTI) carried out a consultation on the appropriate regulatory regime and requirements to implement the Second Package: *LNG facilities and interconnectors: EU legislation and regulatory regime DTI/Ofgem initial views*
http://www.ofgem.gov.uk/Europe/Archive/3804_Initial_Views_on_directives_IC_and_LNG_final.pdf
[20] Article 17(1) of Regulation 714/2009

Third Package requirements on TSOs

1.20. The Third Package introduces a range of new requirements and mechanisms. In particular, it requires all TSOs to work together to develop a 10 year plan for network development (including interconnection) and each TSO to provide sufficient information to connected TSOs to ensure the coordinated development (amongst other things) of the interconnected system. It also requires the procedures for allocation of capacity to be approved by regulators, including for exempt interconnectors. More generally, the Third Package establishes a process that will, in time, lead to new legal requirements on how cross-border capacity is allocated and managed (so-called Framework Guidelines and Network Codes).

Is GB different?

1.21. Most interconnectors in Europe are transmission lines joining national transmission systems across land borders, comparable to the assets required to extend the network to connect a new power station and usually with the same network security standards as their national network (typically N-1). A minority of European interconnectors involve much greater assets, such as sub-sea DC cables with converter stations at each end, generally with no redundancy[21] – the key distinction for section 3 of this paper being the much greater cost and for section 2 also being the lower redundancy and greater transparency. All of our interconnectors fall into this second category, as well as some interconnectors involving other countries. It is therefore important that as new arrangements are developed, they accommodate both types of interconnector.

Regional integration

1.22. As noted above, the Congestion Management Guidelines include explicit requirements for co-ordination on a regional basis. This is taken forward through the ERGEG Regional Initiative process – in our case within the France-UK-Ireland (FUI) region which is chaired by Ofgem.

1.23. In practice, the FUI region has focussed on the capacity allocation arrangements for the IFA. This is because the Moyle interconnector is wholly within a member state (the UK) so not subject to the same treatment under EU law and the interconnection between Northern Ireland and the Republic of Ireland is fully subsumed into the all island Single Electricity Market (SEM). The FUI region has already implemented two key new systems for the IFA:

- interim[22] balancing arrangements: a new TSO to TSO process for exchange of balancing energy went live in March 2009. This allows for multiple prices within the day and has led to a significant increase in use of the IFA for balancing purposes; and

[21] In other words, the full capacity is used and none is held as contingency to enable supplies to be maintained in the event of a fault.
[22] Work is ongoing to develop enduring arrangements for implementation in late 2010.

- a new Congestion Management System: changing the allocation of capacity to include firm nomination of long-term capacity, with UIOSI into a day-ahead explicit auction and then UIOLI into intra-day auctions.

1.24. As these projects have been delivered, we have been in discussions with our fellow regulators and with the region's stakeholders on the next priorities. Among the topics proposed for consideration are: market coupling, co-ordination of explicit auctions (including Moyle and new interconnectors); devising regional intra-day and balancing mechanisms; firmness of capacity; addressing barriers to efficient use of the interconnectors and co-ordination of new investment. One of the key challenges is that with BritNed and some of the future projects, the key participants and stakeholders are outside the region as defined. The future of the regional initiatives is now under review and it is possible that this might lead to a re-definition of the shape of the regions, so GB could become part of another region. An alternative could be to adopt a flexible approach to the regional model to include the appropriate group in each case. Inter-regional projects are already developing, such as work between Central West Europe and the Nordic region on market coupling.

1.25. We also note that the SEM regulators have recently consulted on their electricity interconnector policy[23] and the French regulator has recently consulted on its approach to exempt interconnection.[24] This consultation will put Ofgem in a similar position and will facilitate further discussions.

[23] http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=0cfb1fb1-0a51-4b7e-a867-6f691387eaf9
[24] http://www.cre.fr/fr/documents/consultations_publiques

2. Efficient use of electricity interconnectors

Chapter Summary

This chapter describes the key issues relating to the allocation of capacity on electricity interconnectors, the different options and emerging thinking that is developing for how capacity is sold and the mix and nature of products. It then relates these ideas back to the GB market. It addresses the general policy rather than the specific arrangements for BritNed, on which BritNed will be consulting soon.

Question box

Question 2.1: Are the target models explained in this chapter appropriate for GB? What are the issues that need to be considered? Are there alternative approaches that would be better? Will the target models effectively accommodate increased intermittency?

Question 2.2: What should be our approach to firmness of interconnector capacity? Should this vary between new and existing interconnectors, or between regulated and exempt? What are the categories of costs and benefits from changing approach, where should they fall and can they be quantified?

Question 2.3: Should we seek regional solutions rather than individual project solutions for access rules, such as through a broader North West European solution for market coupling? What are the priority areas for greater regional co-ordination?

Introduction

2.1. The way in which capacity is sold or “allocated” on an interconnector is of critical interest to both the interconnector owner (as capacity sales are the predominant revenue stream) and interconnector users. It is also key to maximising the efficient use of the interconnector and securing the benefits of trade.

2.2. As noted in Chapter 1, the current EU law (in particular, the Congestion Management Guidelines) sets some general requirements. Following introduction of its new Congestion Management System (CMS) on 1 October 2009, the IFA is now compliant with these and we would expect any new interconnector to achieve the same or higher standards and operate in a co-ordinated way. Under the Third Package, Ofgem will be required to approve capacity allocation mechanisms for each interconnector.

2.3. All capacity on the IFA is sold through explicit auctions. The CMS system involves auctions of a range of products (annual, monthly, etc), which must be nominated the day before real-time (so-called day-ahead stage) or subject to use-it-or-sell-it (UIOSI) where any capacity not nominated is re-sold in the day-ahead auction with the proceeds going to the previous capacity holder. This is then followed by intra-day auctions (when any unused capacity becomes use-it-or-lose-it, UIOLI – i.e. potentially re-sold but with no payment to the previous capacity holder). Any remaining capacity can be used by the TSOs for balancing – a new balancing mechanism for SO-SO trades was introduced in March 2009 and is among the most advanced in Europe.

Key Concepts

Explicit and implicit auctions

2.4. Capacity can be allocated explicitly or implicitly. In **explicit auctions** transmission capacity is auctioned to the market separately and independently from the trading of electricity. Auctions are often held by the transmission system operator or interconnector operator and they allocate capacity based on an order book of price and volume offers submitted by traders. The price for capacity can be set via the marginal price for capacity (the clearing price in the auction) or at the price submitted by each market participant (pay as bid). To secure electricity to transit over the interconnector, participants can purchase electricity via bilateral contracts or the power exchanges in either market, or can use their own generation. The amount of electricity that will be transited over the capacity secured at auction is nominated to the interconnector operator at a pre-determined time, the interconnector operation then determines the volume and direction of flows based on the nominations.

2.5. **Implicit auctions** integrate the capacity allocation and energy trading functions. Implicit auctions are typically used at the day ahead stage. The interconnector operator determines the available capacity and makes this available to the power exchange. The bids and offers submitted to the power exchange by participants in each market are combined to create a net export curve for each market. The two net export curves are then combined, taking account of interconnector capacity, to determine the direction of electricity transit (movement from lower price area to higher price area) and the resulting market price or prices. Long term capacity rights which are either not going to be used or are nominated to flow in the opposite direction will be subject to UIOSI or UIOLI and netting (respectively) to maximise the use of capacity at the day ahead point.

2.6. "Netting" means that any capacity sold in one direction is netted off against capacity sold in the other direction. For example, suppose the technical capacity is 2000 MW in either direction and 500 MW has been sold in the import direction. This leaves available capacity of 1500 MW more import, or potentially 2500 MW export (backing off the 500 MW import sold, plus the full technical capacity to export – the full amount is only available if the 500 MW sold as import is actually used).

Product mix across different timeframes

2.7. Capacity is allocated across a number of different timeframes. For example, yearly products give the owner the right to use a certain amount of capacity for a year. Other products could be seasonal, monthly, weekly or daily, either for baseload or for particular hours or shapes. The amount of capacity set aside for each timeframe is pre-determined, often by the interconnector operator following consultation with users. More capacity set aside for the day ahead stage implies users are more concerned in arbitraging price differentials in two markets as opposed to securing long term capacity as a hedge against a wider generation portfolio or to arbitrage long and short term auction prices.

2.8. Reserving capacity for the day-ahead stage is likely to be required for implicit auctions to work in practice, at least initially. The presence of UIOSI and UIOLI creates an automatic mechanism for the resale or release of unused capacity back to the market.

2.9. Intra-day allocations often use spare capacity which has resulted from UIOLI and capacity in the un-economic direction, as seen at the day-ahead stage. It is therefore particularly important if market conditions change between the day-ahead stage and real time so as to reverse the efficient direction of flow. Intra-day allocation can be through periodic auctions, i.e. auctions are carried out at predetermined times throughout the day and allocate capacity based on economic selection of bids. Alternatively, it could be through a first come first served process, which is a continuous allocation of capacity between users wishing to release or use capacity, often without payment to the interconnector owner given the lack of a pricing mechanism.

2.10. If capacity at the intra-day stage is scarce, it may be that auctions would allocate the capacity more efficiently than first come first served, provided there is sufficient liquidity when the auction is held. Conversely, continuous allocation may be more appropriate when the intra-day mechanism is dealing with relatively small amounts of capacity and where the priority is to make it available as quickly as possible.

2.11. It is not common to reserve capacity for the intra-day auction, however providing more opportunities to optimise positions within day could become more relevant with increasing amounts of wind capacities. The extent to which setting aside capacity for intra-day markets is compatible with implicit auctions needs further consideration.

2.12. Capacity not used after the intra-day stage is then available for balancing.

2.13. Financial transmission rights and secondary trading markets are used in some European markets to varying degrees. For example, Nordpool uses contracts for difference as a product for traders to hedge against expected day ahead positions and available capacity.

Capacity Rights

2.14. The rights conferred with the purchase of cross-border transmission capacity are important to consider as the correct balance of rights and responsibilities between interconnector’s users and interconnector operators should achieve an optimal amount of capacity released and user confidence that they will be able to use the capacity as expected.

2.15. The products sold are often options, in that the capacity holder has the right but not the obligation to use the capacity until it is nominated (when the user commits to exercise the right, unless it then resells at the intra-day stage or purchases capacity in the opposite direction).

2.16. A key question is what happens if the interconnector operator is unable to provide the capacity, for example because of an equipment failure. In meshed networks, the amount of capacity offered will typically be set so that the system operator can still provide the capacity on first failure (so called N-1), but on DC cables the full capacity may be offered. The options then include:

- physical firmness: where the interconnector operator purchases energy in one market and sells in the other, to leave the holder of capacity in the same position as if the interconnector was operational;
- full financial firmness: where the interconnector operator compensates the capacity holder to leave it financially indifferent to the loss of capacity – generally based on the spread of wholesale prices between the two markets which can sometimes be very large; or
- other mechanisms such as reimbursement of the price initially paid for the capacity – which may be higher or lower than the full market spread but is less risky for the interconnector operator and conversely more risky for the capacity holder.

2.17. The degree of firmness may vary before and after nomination of the capacity. In 2008, ERGEG published a position paper on Guidelines on Firmness of Nominated Transmission Capacity[25]. The ERGEG Guidelines state that *"as a minimum requirement transmission rights shall be firm after they have been nominated by market participants. Even though physical firmness is the preferred approach for nominated capacity, financial firmness is also an acceptable solution in the context of explicit auctions".*

2.18. To the extent that physically or financially firm products are more valuable to capacity holders, they may increase the value paid in auctions and could also improve the attractiveness of trade, to the benefit of liquidity and competition. However, to the extent they are more risky to the TSO, they could encourage reductions in capacity made available. This is more likely to be an issue on AC networks where the calculations are more opaque, but this would then lead to a different risk-return balance between AC and DC interconnectors. An alternative may be to make part of the capacity financially firm and part interruptible, as envisaged by the Congestion Management Guidelines.

[25] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_ERGEG_PAPERS/Electricity/2008/E08-EFG-29-05_FirmnessTransmissionCapacity_2008-07-15.pdf

2.19. In some markets, the costs of providing financial or physical firmness are not born by the TSO but passed-through in full to transmission customers (also known as "socialised"). This may make the TSO more willing to offer more capacity and firmness, but moves the risk to customers and removes the incentive on the TSO to maximise availability of the capacity sold. Alternative hybrid models could be envisaged where the risks are shared between traders, TSOs and customers.

2.20. It should be noted that implicit auctions require capacity to be physically firm because the capacity owner is not explicitly identified – the implicit allocation process rather establishes an overall price-volume outcome. This then means that interconnector operators have to bear imbalance costs, or take actions themselves, to ensure the firmness.

European Target model

2.21. The Florence Forum established in 2008 the Project Coordination Group of Experts chaired by ERGEG and with participants from the European Commission, ETSO, Europex, Eurelectric and EFET. The PCG's task was to develop a practical and achievable model to harmonise interregional and then EU wide coordinated congestion management and to propose a roadmap with concrete measures and a detailed timetable, taking into account progress achieved with ERGEG's Electricity Regional Initiative.

2.22. Over the past year, there have been extensive discussions in the PCG to establish a "target model" for capacity allocation that could be adopted by 2015. This was presented in December 2009.[26] It is a conceptual model, with practical details yet to be resolved, and it is not legally binding - but it is influential in informing regional developments. It will be a key input into work to be taken forward by the regulators in 2010 towards the adoption of a Framework Guideline on capacity allocation, which is then expected to lead to a legally binding network code. In brief, the arrangements foreseen include:

- explicit longer-term auctions of capacity on interconnectors (timeframes such as monthly, annual and potentially multi-year), for either physical or financial transmission rights with secondary markets to trade between capacity holders; physical transmission rights, if used, would be complemented by a UIOSI mechanism;

- at the day-ahead stage, implicit allocation of all (remaining) capacity through price coupling between power exchanges, growing from the initial regional models to a Single Price Coupling with one matching algorithm encompassing the entire EU;

26 http://ec.europa.eu/energy/gas_electricity/doc/forum_florence_electricity/meeting_17_2_pcg_presentation.pdf

- intra-day adjustments, for bundled energy and capacity products, based on a two-layer approach; with continuous implicit allocation (matching bids and offers on a first-come-first-served basis) at least for the inter-regional layer but with the possibility of other approaches within regions; and

- balancing between TSOs using any remaining available capacity, through a multilateral TSO-TSO concept with a common merit order following pilot projects and including harmonisation of gate closures and technical characteristics as well as roles and responsibilities of all major parties.

2.23. **The central proposal is price coupling** (also known as market coupling or more generally as implicit allocation) at the day ahead stage. The basic idea is to move away from relying on explicit auctions of capacity and then for capacity holders to decide to flow energy, which has, on many borders, led to apparently sub-optimal usage of the capacity – i.e. in many cases interconnector capacity is not fully utilised even where there is a material price difference across the border and sometimes the flow goes from high price to low price markets.

2.24. The model proposed is to use power exchanges to schedule the interconnector flows so that power flows from low price to high. This is achieved by combining all the bids and offers on both power exchanges to find the joint market clearing position, taking account of interconnector capacity. Where the interconnector capacity is "large", this may result in prices equalising in the connected markets, explaining the label "market coupling" or "price coupling". Where the capacity is relatively low, prices would not equalise but flows should still be efficient. The term "implicit allocation" may be more intuitive in this situation. One of the characteristics of this model is that the holder of the capacity on the interconnector is not separately identified. There has not been agreement on how much capacity would be held back from longer-term auctions for this day-ahead stage but an illustrative example could be 20 per cent. However, because of use-it-or-lose-it and netting arrangements, the day ahead market coupling will end up being the key determinant of interconnector flows.

2.25. A key component of this approach is a robust day-ahead power exchange. This has not been a central element of the GB market design, but there is a power exchange operated by APX (a power exchange owned by the Dutch transmission company) and another has just been launched (N2Ex, an exchange developed by NASDAQ OMX Commodities and Nord Pool Spot). It remains to be seen how these exchanges will develop but, in principle, either power exchange could operate a market coupling arrangement. Indeed, if a wider market coupling solution is developed, it may be possible for more than one power exchange in GB to participate. Of course, it may be that market participants will prefer one solution over another and liquidity will tend to move to a single location.

2.26. For the intra-day and balancing timeframes, the target models are less fully developed but also rather complex. However, the initial steps towards these models appear to be broadly in line with the approaches recently adopted on the IFA, which also complies with one of the target models for forward contracts. The exception to this could be the use of explicit auctions for intra-day on the IFA rather than implicit matching, but this could be partly explained by the greater liquidity of the GB intra-day market and, in any event, needs careful consideration given the importance of intra-day for intermittency. We understand that NGIL and RTE intend to consult on the way forward for intra-day on IFA and it will also be part of BritNed's consultation on its access rules.

Experience of market coupling

2.27. Day-ahead market coupling is already in place between the French, Dutch and Belgian[27] markets (referred to as the Tri-Lateral Coupling or TLC) and has been seen as successful. Extension to include Germany (to encompass what is known as the Central West Europe or CWE region) is planned for spring 2010.

2.28. A different approach, known as market splitting, has long been applied in the Nordic market. The main difference is that market splitting involves participants from several areas bidding into a single exchange rather than (as with market coupling) to several national exchanges which then combine bids. In both cases, there will be one price if interconnection capacity is sufficient to accommodate unconstrained flows and multiple prices if not – in economic terms the two models should give the same results. However, institutionally, coupling national markets is likely to be easier to achieve than merging to a single market with national or regional zones, so market coupling is seen as a more pragmatic way forward.

2.29. Discussions are underway about a price coupling encompassing wider areas, including the CWE and Nordic regions, plus potentially the Iberian regional and then on to central Europe. Further details of experience to date and plans for the future are set out in Appendix 5.

2.30. Any new interconnection between GB and the continent will likely be into a price coupled market and the model is becoming established.

Considerations for GB

2.31. In general, the target model is a welcome step towards more efficient allocation of interconnector capacity. However the details are still to be resolved and could be critical to its effectiveness. For example, the emphasis on the day-ahead stage must not detract from the need to ensure that flows are still efficient at real-time. This is particularly important to reflect the challenges of intermittency likely with huge increases in wind generation and requires an effective intra-day mechanism.

2.32. There are also some practical issues involved in linking the GB market with the continent. For example, the CWE markets all trade in Euros – currency conversion

[27] In view of the limited role of power exchanges in the GB model, it is worth noting that Belgium did not have a power exchange prior to the introduction of TLC.

would be a new issue (albeit one for the Nordic area as well). We also have a different treatment of losses – of course, losses on the interconnector itself are more of an issue for long sub-sea cables than for land borders. These are technical issues which should not be a major obstacle.

2.33. The price coupling arrangement would also require interconnector capacity to be provided on a firm basis – this has been subject to ongoing discussion with respect to the IFA. At present, if the IFA is unavailable due to an equipment outage, capacity holders are repaid at their initial purchase price. Under financial firmness, they would instead be compensated at the spread in prices between the two markets (although it may not be clear which price should be used, which may vary depending on the time the interruption is notified). Under a model of physical firmness, the interconnector owner would deliver, through local purchases, additional energy in the importing market and reductions in the exporting market to deliver the same position as if the interconnector flow had occurred – which is likely to cost the same as the market spread.

2.34. NGIL argues that to offer full firmness on the IFA (financial or physical) would potentially be very expensive and that it is not obliged to do so by any aspect of EU legislation. Analysis suggests that the costs in 2008 could have been of the order of £10 million. We understand this may be much higher than for other borders, on the continent, where the interconnection is part of a meshed network which may be secure against the first fault (because this is taken into account in determining how much capacity is made available) and may also offer possibilities to reconfigure to provide power flows in a different way. The regulatory approach may also differ - on the French side, these costs would be passed-through to customers whereas on the GB side, under the current regulatory model, they would be borne by NG shareholders. The risks may reduce once the present refurbishment is completed,[28] assuming reliability then improves as expected, but there would still be the chance of very expensive outages.

2.35. The French regulator, CRE, and market participants, including EFET, have argued that full firmness is important to encourage efficient trade. If a trader cannot rely on interconnector capacity as a hedge against a price differential, the capacity may have less value and the competitive position of the trader weakened against an in-market participant (assuming the risk is material compared to the risk of, for example, power station outages, which seems likely in respect of IFA). Not offering full firmness could therefore reduce the competitive pressure provided by cross-border trade. In principle, firm capacity should be valued more highly which may offset the risk of higher payments for unavailability.

2.36. There are a number of important issues here, including how the firmness required for implicit allocations can be delivered and whether interconnectors should be required to provide full financial firmness for capacity that is sold through explicit auction (both for new interconnectors and for those already developed). We would welcome views on this issue.

[28] See Joint National Grid-RTE press release 2 July 2008.

2.37. Market participants have also argued that there is a practical issue with Triad charges (transmission network charges to demand customers), which they consider act as a barrier to trade and to be incompatible with price coupling. We are currently considering these issues outside this consultation process. However, we flag this here given the suggestion that a change to these charging arrangements would be a pre-condition to implicit allocation being implemented on GB interconnectors.

2.38. In September 2009, the SEM regulators issued a consultation on future interconnection.[29] This explained that the target models would be particularly difficult for them as their Single Electricity Market (combining Republic of Ireland and Northern Ireland) is based on a compulsory pool with capacity payments and does not have a day-ahead power exchange or intra-day trading. However, it may be possible to find solutions which do not require radical changes to the SEM.

A regional solution day-ahead

2.39. BritNed's exemption was granted on the basis that it allocates capacity using a mix of short-term explicit auctions and day-ahead implicit allocation. BritNed is expected to begin operations in late 2010 and to commission in early 2011, so the need to develop the implicit allocation method is now pressing. BritNed are working with APX on this and, following discussion with Ofgem and the Dutch regulator, have held initial seminars with market participants and announced a timetable for consultation on their arrangements. It is not the purpose of this document to consult on the arrangements specific to BritNed, but we do consider here the wider implications.

2.40. In particular, it was suggested at the FUI regional initiative Stakeholder Group meeting on 4 November 2009 that it would be preferable to adopt a price coupling solution which applied to all interconnectors between GB and the CWE region, rather than to focus on BritNed alone. In the first instance, this would include the IFA.

2.41. We understand that the CWE region is currently focussed on extension of the TLC to Germany. There are proposals to couple the CWE region with the Nordic market and with the Iberian market at the start of 2011. While it may be possible for all these markets to couple at once, there must also be a risk of delay.

2.42. BritNed and APX have therefore developed a "spur" solution, whereby the APX exchange in GB, through BritNed, can be treated as part of the Dutch market. This should allow BritNed to meet its commitment to have implicit allocation while minimising the interaction with the rest of the CWE region. One of the issues with this approach is that it may make it less rather than more likely that GB could join the CWE model soon thereafter as incorporation of GB through a general solution may be seen as a lower priority if a form of coupling has already been achieved. It may therefore be preferable to move straight to a regional solution, provided this can be agreed quickly by all relevant parties and implemented by early 2011.

[29] http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=0cfb1fb1-0a51-4b7e-a867-6f691387eaf9

Regional coordination at other timescales

2.43. The current and proposed arrangements and policy considerations must be considered in the context of European developments. Coordination with neighbours is likely to maximise efficiencies and to provide the best chance that solutions are future proof.

2.44. The priority here is to meet our obligation under the Third Package to have a co-ordinated approach to cross-border capacity in the region (for this purpose, France-UK-Ireland). Even though Moyle is not an interconnector as defined in EU legislation, it is likely to be beneficial to include Moyle in such co-ordination as far as possible.

2.45. It is for consideration where our priorities should lie in respect of looking at increased co-ordination, for example between harmonising arrangements of longer or medium-term explicit auctions, moving to a common platform or aligning intra-day allocations. For intra-day, there may be advantage in early discussions before new approaches are implemented on Moyle and BritNed but it has also been suggested that arrangements on IFA should be reviewed first. It should be noted that intra-day is likely to be particularly important if interconnectors are to assist in accommodating intermittent generation. We would welcome views.

2.46. In respect of balancing, work is underway to develop an enduring solution for IFA which is aligned with other French borders, building on the successful implementation of the interim solution. This could also be co-ordinated with other GB borders, but this may be seen as a lower priority for market participants than co-ordinating longer-term and intra-day markets.

Proposed way forward

2.47. In discussions with stakeholders from the France-UK-Ireland region at a meeting on 4 November 2009, there was general support for proposing to integrate the whole France-UK-Ireland region into a price coupling arrangement with the CWE model. In particular, National Grid, as co-owner of both BritNed and IFA, strongly supported this approach as did the Irish regulator, although recognising that integration of the SEM may follow later than for GB.

2.48. We are already committed to price coupling on BritNed by the exemption decision – the key question is whether this can be part of a larger initiative, including IFA as well. We would welcome views on the best way forward, noting that the requirement in the exemption for implicit allocations in early 2011 is binding.

2.49. We would also welcome views on the other issues raised here and in particular on the firmness of interconnector capacity, the appropriate model for intra-day re-allocation and the priorities for regional co-ordination.

2.50. We expect this work to be taken forward in parallel through the process for approval of the BritNed access rules, on which BritNed intends to consult in February 2010, and through the broader work programme for the France-UK-Ireland regional initiative or such other grouping as includes the relevant parties for each topic.

3. Regulating new interconnector investment

Chapter Summary

There is significant interest in new interconnector capacity, which will require investment decisions in the next couple of years if it is to be available in the latter part of this decade. Some of the projects may be suitable for exemption, but others may not. We have been asked to set out how we would implement a regulated approach.

This chapter considers the key issues in regulating new interconnectors, drawing on our experience with recent projects. We recall the legal requirements and explore a range of options for how a regulated approach could work.

Question box

Question 3.1: Does this chapter capture the key issues in regulation of new electricity interconnectors? Should we assume that all new interconnectors will seek exemptions?

Question 3.2: Of the options set out, which are preferable and why? What are the key considerations in taking forward any of the options?

Question 3.3: Is it feasible to have a mixture of different approaches for different interconnectors – such as some exempt and others regulated? If not, why and how should this be resolved?

Introduction

3.1. In September 2008, National Grid, in conjunction with the French and Belgian TSOs (RTE and Elia) consulted market participants on their interest in new interconnection capacity between GB and the continent. This confirmed strong interest in purchasing capacity over multi-annual to short-term periods. As explained in Chapter 1, National Grid has been developing a number of potential projects in partnership with the transmission company at the other end of the link. In parallel, we have seen plans from Imera to develop merchant interconnections. At present we cannot be sure which of these projects will proceed or when.

3.2. Under EU legislation, it is clear that the default approach to interconnection is as a regulated investment, offering full third party access in line with the requirements of the Congestion Management Guidelines, for example. Exemptions, although permitted in certain circumstances, are the exception to this rule and may become more difficult to apply in practice.[30] Elsewhere in Europe, the regulated approach

[30] We note, for example, the new requirement in Article 17(4) of the Electricity Regulation 714/2009 that, in assessing the criteria in Article 17(1), the results of the capacity allocation

often involves a mandate for the national TSO to build interconnection underwritten by national transmission customers. Under the Third Package, there is a requirement for electricity TSOs to co-ordinate on a regional basis but in electricity, unlike in gas, there is no explicit requirement on TSOs to develop cross-border capacity.[31]

3.3. By contrast, our recent experience has been of projects seeking exemption from some of these requirements, and of exemptions being granted subject to certain conditions. This may still involve full third party access, but the interconnector operator bears the risk of returns being higher or lower than expected and may have some protection against changes to the access rules being imposed. One of the strengths of this "merchant" approach[32] is that it leaves this decision of whether, when and how to invest in the hands of developers, with strong commercial incentives, rather than a central planner.

3.4. The approach to regulation of any cross-border infrastructure will of course involve the regulators on either side of the border. There is a clear need for a co-ordinated approach, which may not be identical in each case but must be consistent and coherent. The new Agency for Co-operation of Energy Regulators (ACER) may have a role when it is operational in cases where the two regulators cannot agree, but it seems preferable for the two national regulators to reach a common position and to set out, at the outset, a clear and predictable framework within which the investment can be made.

Challenges with the merchant approach

3.5. The typical route to the merchant approach has been to secure an exemption from the use of revenues, third party access and methodology approval requirements. However, this seems increasing difficult. In each of our two electricity interconnector exemption decisions, the Commission have required additional conditions on the exemption. In the BritNed case,[33] this involves a cap on returns. We understand that one of the main concerns is that merchant interconnectors will be under-sized as the incentives on the developer do not include wider benefits. For example, if the interconnection capacity is large relative to the size of the markets, wholesale prices may converge and the scope for competition between the two areas increases but interconnector revenues fall towards zero which is a strong disincentive for a merchant operator.

3.6. One of the difficulties is that the Commission decision whether to veto or require additional conditions on an exemption decision comes at the end of a significant

procedure shall be taken into account. To date, interconnectors have typically sought the certainty of an exemption prior to allocating capacity.

[31] The provision in gas is in Article 13 (2) of the Gas Directive 2009/73/EC – this provision is not included in the electricity Directive.

[32] By "merchant" approach, we mean that the project developed has gone ahead on a voluntary basis rather than due to a legal obligation and that the revenues of the project are those earned from the sale of capacity and ancillary services – they are not capped or collared or linked to transmission tariffs or required to be held back for another use.

[33] See Appendix 2 for further detail.

process. The uncertainty of the outcome may be unattractive to developers at the outset of their project.

3.7. If the exemption is granted, the developer still faces a risk of a subsequent interconnector being built on a regulated or subsidised basis which could damage their returns.

3.8. In addition for some potential partners, their corporate structure may make it difficult to meet the exemption criteria, such as the requirement for the exempt interconnector not to be part of the TSO. All of these may lead some parties to be unwilling to pursue the exempt approach.

3.9. None of this suggests to us that we should not be open to exemption applications both now and in the future. This consultation does not signal any change to our approach to exemption requests.

3.10. But it does suggest that we should consider further how we would address a proposal to build a regulated interconnector. We have met with National Grid, Elia and the Belgian regulator, CREG, to discuss these issues and this consultation is intended to canvass views from a broader range of market participants before we reach any firm views.

Core requirements of a regulated approach

3.11. As noted above, the regulated approach implies full compliance with the Electricity Regulation 714/2009. This includes both the Congestion Management Guidelines which are currently annexed to the Regulation and, going forward, any new network codes and guidelines which are approved through the Comitology procedure as set out in the Third Package.

3.12. Arguably the key requirement from which exemptions have been sought is the "use of revenues" requirement.[34] In general, interconnectors earn their revenue through a competitive auction of capacity. The requirement is that they use this revenue for one of the following purposes:

- guaranteeing the actual availability of the allocated capacity; and/or
- maintaining or increasing interconnection capacities; or
- if the revenues cannot be efficiently used for the purposes above and so far as the regulators so approve, as an income to be taken into account in the approval of transmission tariffs/methodologies. Any

[34] Article 16(6) of Electricity Regulation 714/2009. Regulation 714/2009 is worded differently from the similar article in the Second Package - Regulation 1228/2003 - in that it is more explicit that expenditures for the first two purposes do not need to be made in the year the revenue is received. Regulation 714/2009 is also clearer on the regulators' role should revenues be offset against tariffs.

other revenues shall be held in a separate account until they can be used for the first two purposes above.

3.13. The meaning of these categories may not be completely self-evident. However for the purposes of this consultation, we assume that the first two categories cover, between them, the costs of operating the interconnector, or maintenance and refurbishment and potentially any costs of providing compensation for unavailability (firmness) as discussed in Chapter 2. For example, the current €70m investment in mid-life refurbishment on IFA would fall in the second category. We also assume that they allow for a return on investment made to date as well as (or more logically, instead of) capital expenditure on capacity increases. They do not appear to be prescriptive on the level of returns and appear to provide scope for incentives, for example to maximise available capacity, which could alter returns.

3.14. Beyond the first two categories, there is the potential for capacity revenues to be offset against transmission tariffs. Under the GB arrangements this may be complicated by the separation between the interconnector licensee and the transmission licensee, but could be seen as analogous to arrangements between the GBSO and TOs (and OFTOs). The requirement to "take into account" does not appear to require a mechanistic link. Full offsetting, so any revenues from capacity sales above or below a pre-determined level are return to or sourced from transmission tariffs, would amount to a revenue control on the interconnector of the same general category as we apply to transmission owners in GB. As with the TO controls, it may be subject to a number of incentives and revenue drivers.

3.15. The Electricity Act 1989 (as amended) requires that interconnector licensees are a distinct legal entity from transmission licensees. In a situation where we could have both exempt interconnectors operating on a merchant basis and regulated interconnectors (such as IFA), this may be seen as necessary to achieve at least a minimum degree of independence from the GBSO, and hence a level playing field. However there may be questions whether this is sufficient, or whether allowing new regulated interconnectors to be part of the NG group would raise concerns for independent developers. On the other hand, the separation between interconnector and transmission licensees is a point of difference with other European markets which may be unhelpful. While this provision sits in primary legislation and is therefore a matter for Government rather than Ofgem, we would welcome views as to whether change is required. The remainder of this chapter assumes that the current legal position in GB stays as at present, so that interconnection remains a separate licensable activity which needs to be a different legal entity from a transmission licensee.

3.16. It should however be noted that the position regarding revenue flows and offsetting against transmission tariffs is more complicated in GB, due to the different entities and licences, than it would be in a market where a regulated interconnector is part of the national TSO. Further legal analysis would therefore be required if we were to pursue options which involved any offsetting or supplementing of interconnector revenues with transmission tariffs.

Options for regulating new interconnectors

3.17. The spectrum between a fully merchant and fully revenue-controlled approach (including the BritNed outcome on the way) can be presented as four options:

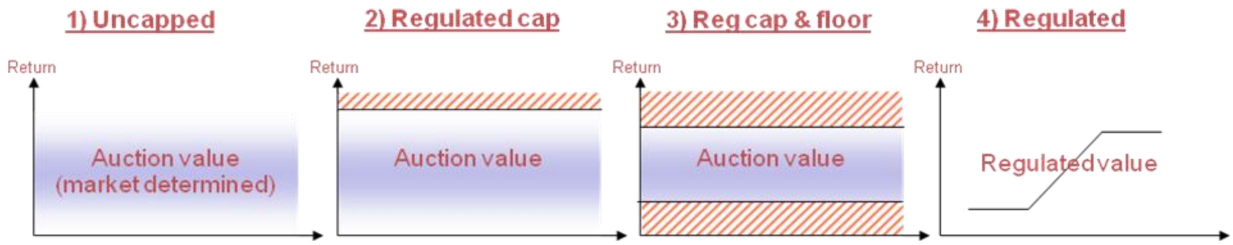
1. Uncapped: returns depend entirely on auction revenues;

2. Regulated cap (BritNed): returns depend on auction revenues, but with a cap above which excess returns must be invested in increased capacity or returned to transmission customers;

3. Regulated cap and floor: returns within a range depend on auction revenues; above or below the range they are returned to or supplemented from customers (taken into account in approving transmission tariffs).

4. Regulated revenues: an assessment is made of required revenues (potentially including incentive mechanisms) and any auction revenue above or below this amount is returned to or supplemented from customers in general. This is equivalent to including the interconnector in the normal transmission tariff mechanism.

They can be depicted pictorially as:



3.18. **Option 1** is a merchant approach, in that revenues are determined by auction proceeds. It is seen as requiring an exemption to protect against the risk of subsequent changes to market rules damaging the business case of the project. Experience on BritNed suggests that one of the conditions of the exemption could be a cap on returns, which would be a move into option 2.

3.19. **Option 2** puts a cap on returns or revenues. The developer still has all the downside risk but a capped upside, so lower expected returns. The cap could either apply each year or only over the entire duration of the project (as in BritNed's exemption, where the cap is calculated over the 25 year life of the exemption and any excess may be paid to national TSOs).

3.20. **Option 3 can** be seen as a development of option 2 or as a variant of option 4. It may be easier to understand if option 4 is described first – so the description follows further below.

3.21. **Option 4** is a regulated approach. It involves setting the revenue entitlement of the interconnector project independently of the revenues received from auctioning capacity on the interconnectors. There is therefore a need first to set the allowed revenue level (or formula) and then for a true-up mechanism of some sort. This would require the regulator effectively to approve the project and to use customers' money to underwrite the costs. The major downside is the risk of stranding (i.e. values recovered from capacity sales not being sufficient to cover costs, leaving customers to pick up the difference) – although there is also an upside where customers could profit. This would be a substantial departure from our approach to date. If we were to adopt this approach, the methods used to set revenues would need to be compatible with our approaches for transmission price controls, as developed in the light of the RPI-X@20 project.[35]

3.22. A variant on this approach (option 4A) could be, rather than undertaking a cost-based assessment of required revenues, to tender the project as a build, own, operate scheme to determine the revenue requirement through a competitive tender. This could, for example, be a reverse auction where competing interconnector developers bid for a revenue stream.

3.23. For such a tendering process, the location, timing and capacity of the interconnector would need to be specified (at least in broad terms, to have some common basis on which to compare bids) and the auction would need to be for the project as a whole. The comparison with offshore transmission may appear to make this attractive – however, unlike offshore transmission, none of these conditions are necessarily fulfilled for an interconnector project. The choice of location, timing and capacity are key variables which may be better determined through competitive entry decisions by developers with incentives to make the best choices, rather than centrally specified for a competition. The investment and intellectual capital in pre-constructions studies to make these decisions is a key issue. In addition, it does not seem likely that this approach would work for a joint venture which causes difficulties for many of the projects being developed.

3.24. However the revenue allowance is set – whether competitively or through a price control as for onshore transmission, option 4 requires a mechanism for all customers or transmission users to pay to make up any shortfall in capacity auction revenues (and for any surplus to flow to customers or, if required, to be held in an account to subsidise future interconnector investment decisions). The offshore (and indeed Scottish onshore) transmission owner model provides a precedent mechanism demonstrating how any such flow of funds to or from customers could work – they involve payments via the GB system operator.

3.25. **Option 3** can be seen as a generalisation of the other options.[36] If the range between the cap and floor is very wide, option 3 looks like option 1. If the range is

[35] See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=36&refer=Networks/rpix20/publications/CD

[36] Option 4 could also be turned into option 3 by adding an incentive mechanism based on capacity sales with a cap and collar. As noted at the outset of this section, the options are variants along a spectrum rather than completely different concepts.

very narrow, option 3 looks like option 4. The cap and floor could be set as levels of revenue or as returns, and in either case could be calculated annually or over a much longer period. The purpose of the floor would be to offset the regulatory risks associated with (a) the cap, (b) the risk of future regulated or subsidised interconnection damaging the returns and (c) changes to legal requirements as to how they can sell capacity. Of these, only (b) is a risk for exempt interconnectors under option 1.

3.26. Just as the value in option 4 could be determined through a competitive tendering process (option 4A mentioned above), so could the floor in option 3 (option 3A). As explained above, this does not seem feasible for part of a joint venture.

3.27. Under option 3, there would be a difficult decision in setting the cap and floor. In particular, the floor is critical for the extent to which customers in general bear a risk of stranding (see above). Even with a relatively low floor, we would need to assess the risks to customers, which implies understanding the investment case for the project. This requires similar information to that we already require for decisions on exemptions. If the floor was higher – for example at or close to the cost of debt – then it would raise concerns about incentives for efficiency. Option 3 may therefore depend on the floor being set much lower (for example, at or close to a return on capital of zero).

3.28. We have also considered hybrid models where different approaches are adopted either side of the interconnector. For example, if one regulator preferred option 4, could this be combined with options 1 or 2? It is not clear that such approaches are workable – at a minimum there would appear to be significant risk of conflicting incentives between the joint venture partners. This does not necessarily mean that the arrangements need to be identical, but it will be important to be sure that they can work well together and give consistent incentives to the interconnector operators.

Proposed way forward

3.29. It is clear from discussions to date that most of the counterparts for interconnectors from GB to the continent prefer option 4. However, there appears to be a willingness to consider something akin to option 3 above, under a regulated (not exempt) approach.

3.30. Importantly, under any of these options we could still retain contestability – any party could propose to build, either under a regulated or exempt approach. In the options with a fixed level or floor, we would envisage this being set on a case-by-case basis. Under option 3, as noted above, the presumption would need to be that the floor would be low.

3.31. If for example, there were multiple developers wanting to build very similar projects on a regulated basis but it is seen that it would not be economic for all to proceed, this could be addressed through the way the revenue entitlement (option 4), cap (options 2 and 3) or floor (option 3) are set. For example, in this circumstance, the projects could compete on the level of the cap or it may be appropriate to proceed without a floor.

3.32. We would not expect any decisions on our approach to new interconnectors necessarily to apply retrospectively to existing interconnectors (and given BritNed's exemption, this would only be possible for IFA). However, any implications for these or other projects or related workstreams would need to be considered in due course.

4. Next steps

4.1. The main purpose of this consultation, as set out on the front cover, is to describe the proposed models for interconnector capacity allocation and for regulation of new investment, and then to seek views on how Ofgem's policy should develop. Discussions on these issues are continuing in European fora, on a regional basis and bilaterally between regulators. We would therefore welcome input from stakeholders on any of these issues, but specifically on the questions raised in this consultation.

4.2. As part of this consultation process, Ofgem is considering holding a workshop on these issues, to prompt debate between stakeholders in advance of formal consultation responses. This would likely be in London in the first half of March. If you are interested in attending such a workshop, please notify Emmanouela Angelidaki, at Emmanouela.Angelidaki@ofgem.gov.uk by 5 February 2010.

4.3. In addition, we would be interested to meet stakeholders bilaterally to

4.4. Following closure of this consultation on 30 March 2010, Ofgem will consider how best to take forward the issues raised. We are conscious that the process for individual projects will move forward in the meantime – in particular in relation to the consultation on and approval of BritNed access rules, potential announcements on the France-UK-Ireland regional initiative priorities and work plan (and the European Commission's proposed communication on the future of the regional initiatives more generally) potential further deliberations or consultations with neighbouring regulators on the regulatory framework for individual projects.

4.5. We will therefore assess the responses to the consultation and provide an update on our proposed next steps by early Summer 2010.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 30 March 2010 and should be sent to:

- Emmanouela Angelidaki
- European Strategy
- 9 Millbank
- London SW1P 3GE
- 020 7901 7037
- Emmanouela.Angelidaki@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Any questions on this document should, in the first instance, be directed to:

- Emmanouela Angelidaki
- European Strategy
- 9 Millbank
- London SW1P 3GE
- 020 7901 7037
- Emmanouela.Angelidaki@ofgem.gov.uk

CHAPTER: One

Question 1.1: Have we accurately captured the benefits of and demand for new interconnection? Are the projects under consideration all viable? Would they be sufficient? Are there other projects being developed?

Question 1.2: Are there other key aspects of the legal or regulatory framework that we should consider, or should some features be given a different emphasis?

Question 1.3: How can the Regional Initiative best contribute to development or implementation of policy? Do you agree with the priorities and approach outlined?

CHAPTER: Two

Question 2.1: Are the target models explained in this chapter appropriate for GB? What are the issues that need to be considered? Are there alternative approaches that would be better? Will the target models effectively accommodate increased intermittency?

Question 2.2: What should be our approach to firmness of interconnector capacity? Should this vary between new and existing interconnectors, or between regulated and exempt? What are the categories of costs and benefits from changing approach, where should they fall and can they be quantified?

Question 2.3: Should we seek regional solutions rather than individual project solutions for access rules, such as through a broader North West European solution for market coupling? What are the priority areas for greater regional co-ordination?

CHAPTER: Three

Question 3.1: Does this chapter capture the key issues in regulation of new electricity interconnectors? Should we assume that all new interconnectors will seek exemptions?

Question 3.2: Of the options set out, which are preferable and why? What are the key considerations in taking forward any of the options?

Question 3.3: Is it feasible to have a mixture of different approaches for different interconnectors – such as some exempt and others regulated? If not, why and how should this be resolved?

Appendix 2 – Existing and future interconnection

France-England Interconnector

Background

1.1. The Interconnexion France Angleterre (IFA), which commenced operation in 1986, is a 2000MW high voltage direct current (HVDC) link between the French and British transmission systems. The interconnector comprises of four 500MW lines between Sellindge in England and Les Mandarins in France. National Grid Interconnector Limited (NGIL)[37] and Réseau de Transport d'Electricité (RTE) (the French TSO) jointly own and operate the IFA.

Regulatory framework

1.2. In August 2006 National Grid Plc transferred its part of the ownership of and operational responsibility for the IFA to NGIL. This was to ensure compliance with the provisions of the Electricity Act 1989 (as amended), which prohibits a transmission licence holder from also holding an interconnector licence.

1.3. NGIL was granted an interconnector licence in August 2006. All standard conditions of the interconnector licence have been switched on.

Capacity allocation

1.4. In April 2001 National Grid Company plc and RTE introduced joint arrangements for the allocation, through a mix of tenders and auctions, and use of capacity on IFA. In October 2009, NGIL and RTE launched a new capacity management system (CMS) to ensure compliance with the CMGs[38]. The new CMS is explained in more detail below.

1.5. A mix of long and short term capacity products are auctioned via a platform jointly run by NGIL and RTE. Long-term auctions are explicit auctions of transmission capacities. Capacity is offered for certain time periods (yearly, seasonal, quarterly, monthly and weekly) and for different auction products, such as, base, peak and off-peak capacities.

1.6. Long term capacities are subject to UIOSI. This means that at the D-2 stage any non-nominated capacity is automatically resold as day ahead capacity. Long term capacity holders receive the auction price paid in the day ahead capacity auction. The capacity released via UIOSI is combined with capacity reserved for the day ahead auction. In the day ahead auction capacity is offered in blocks and as individual hours auctioned separately. The day ahead takes place at 0830hrs on D-1 and

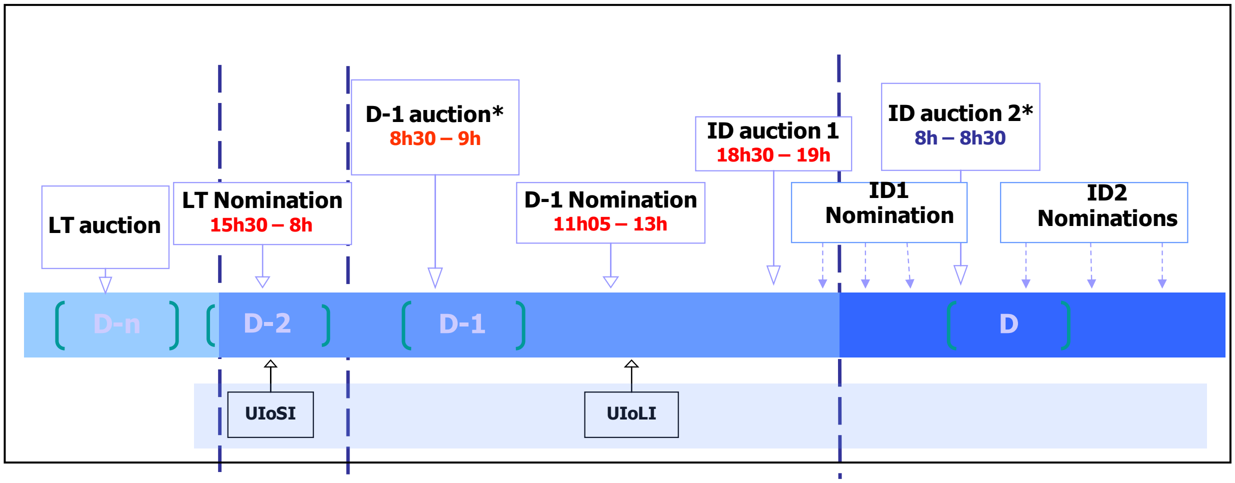
[37] A wholly owned subsidiary of National Grid Plc.
[38] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2006:312:0059:0065:EN:PDF

nominations take place at 1100hrs. Day ahead capacity which is not nominated at 1100hrs is subject to UIOLI.

1.7. Two intra-day auctions, at 1900hrs on D-1 and 0800hrs within day, allow capacity traders to optimise their positions and react to unexpected events during the day. Unsold day ahead capacity, UIOLI capacity and any capacity made available through netting, is offered in two intra-day auctions. Capacity bought on intra-day auctions is secured for half a day and is not subject to netting. There are six opportunities for capacity holders to refine their nominations within day.

1.8. An interim solution for TSO-TSO balancing was implemented on 3 March 2009, allowing TSOs to exchange six prices a day for four hour segments, prior to this one price per day was exchanged. TSO-TSO balancing uses capacity which has not been nominated in the long term, day ahead and intra-day auctions. Both TSOs are working on developing an enduring solution which is likely to lead to more prices per day being exchanged.

1.9. The diagram below sets out the timing for each auction and nomination point on the Capacity Management System for the IFA.



1.10. In agreeing the access rules for the new CMS, regulators discussed the application of capacity rights for nominated capacity. As set out above, the CMGs require that TSOs optimise the degree to which capacity is firm, taking into account the obligations and rights of the TSOs involved and the obligations and rights of market participants. The CMGs do not specify whether, in the event of curtailment, the capacity holder should receive compensation equivalent to the unit price paid for the capacity or to the lost trading opportunity (the price difference between the interconnected markets).

1.11. In the event of curtailment, capacity rights are curtailed pro-rata for all users in the following order (i) intra-day nomination (ii) day ahead nominations (iii) nominations at long term nominations gate closure. Where capacity has been curtailed the capacity holder will received the unit price paid for the capacity curtailed.

Moyle Interconnector

Background

1.12. In 1999, Moyle Interconnector Limited was established as a wholly owned subsidiary of Viridian Group Plc to construct the link. Construction of the Moyle Interconnector ("Moyle") took place in 2000 and commercial operation started in April 2002. The interconnector links Scotland to Northern Ireland and has a physical capacity of 500MW in either direction. Moyle's connection agreements limit the trading of capacity to 450MW into Northern Ireland and 80MW into Scotland.

1.13. In 2003 the company was mutualised. This entailed buying out the previous shareholder, Viridian Group Plc, and transferring the asset into a not-for-profit company, Moyle Energy Holdings. The company's investment was debt financed through a 30 year bond issued by financing. The asset was subsequently transferred to Northern Ireland Energy Holdings, a company limited by guarantee. Having no shareholders, the Group's principle stakeholders are the energy consumers of Northern Ireland and its financiers. As part of this arrangement, any revenue shortfall can be recovered through use of system charges and any operating surplus is returned to consumers via a reduced electricity tariffs. This relationship is managed through Moyle's Collection Agency Agreement with the System Operator for Northern Ireland (SONI).

Regulatory framework

1.14. As Moyle connects two regions with a Member State it is not classified as an interconnector under EU legislation. However, some of the requirements of EU legislation have been implemented through, for example, the non-discriminatory provision of third party access through the auctioning of capacity rights.

1.15. Responsibility for energy policy has been devolved to Northern Ireland. The Northern Ireland Authority for Utility Regulation (NIAUR) issued Moyle Interconnector Ltd with its transmission licence in 2003[39]. Moyle Interconnector Ltd was also issued with a GB interconnector licence with standard conditions 9, 10 and 11 switched off. Moyle makes capacity available to the market in accordance with access arrangements[40] which are subject to approval by NAIUR.

1.16. SONI has been contracted to act as system operator and operational agent for the Moyle interconnector. This entails managing all aspects of the Moyle

[39] http://www.niaur.gov.uk/uploads/publications/Electricity_Participation_in_Transmission_Licence_-_Moyle_Interconnector-_Consolidated_Working_Copy_Fin_Granted_28_Feb_03.pdf
[40] http://www.nienergyholdings.com/Download/Moyle%20Access%20Arrangements%20from%20October%202009.pdf

interconnector operation including capacity auctioning, scheduling and real-time operation.

Capacity allocation

1.17. Moyle offers capacity to the market in long term (1-3 years) and short term (monthly) capacity auctions. Capacity is sold in 5MW blocks with a reserve price. A non-standard product was recently introduced which reserves a minimum amount of MWh per month, with any additional usage charged per MWh on a pay as you go basis.

1.18. Moyle is considering the introduction of weekly, daily or even intra-day capacity products. To facilitate this Moyle has submitted a request to NIAUR for the same IT system as has been procured for use on the IFA. Moyle intends to follow a similar path to IFA to facilitate short term capacity sales and to align capacity allocation and management with other European interconnectors. NAIUR and CER have committed to ensure that a common co-ordinated means of allocation capacity up to the day-ahead stage is put in place.

1.19. Unused capacity after market gate closure may be used by the transmission system operator.

BritNed

Background

1.20. BritNed, a joint venture between NGIL and Nlink International B.V (Nlink)[41], is currently building a high voltage DC electricity cable between the Isle of Grain in GB and Maasvlakte in the Netherlands. The cable is expected to have a capacity of 1000 MW. It will be commercially operational in the first quarter of 2011.

Regulatory Framework

1.21. In 2006, BritNed requested an exemption from the SLCs 9, 10 and 11 of the interconnector license and Article 6(6) of Regulation No 1228/2003. In its application, BritNed stated that it‟s motivation for seeking an exemption is "solely to ensure that the risk/reward balance remains aligned over the duration of the exemption‟. Following consultation, in July 2007, Ofgem issued an exemption order for a period of 25 years from the date which the BritNed interconnector commences commercial operation.

1.22. In accordance with article 7(5) of Regulation (EC) 1228/2003, which gives the Commission the power to veto or amend the regulatory authority's decision, the European Commission requested the Ofgem to amend the exemption order and include the following conditions:

[41] NGIL is 100% subsidiary of National Grid plc and NLink is 100% subsidiary of TenneT Holding B.V (TenneT).

a) BritNed has to present to the national regulators within ten years after the start of operations (as defined in the exemption decisions) a report that contains all the details necessary to scrutinise the total costs and revenues of the project and the rate of return on the investment with 2007 as the base year, allowing for comparison with the data provided for the exemption request.

b) If, calculated over 25 years, the estimated internal rate of return for the entire project is more than one percentage point above the internal rate of return estimated when filing the exemption request, BritNed shall either use the excess to fund additional capacity or shall pay it to the national TSOs to finance their regulated investments (for the benefit of national transmission customers).

Capacity allocation and management

1.23. BritNed has indicated that its business rules and auctions systems that are currently being developed, will be compliant with the CMGs. BritNed will operate purely as the infrastructure company and will not buy or sell power itself. The project will be financed through the sale of capacity. Therefore, none of BritNed's costs will be underwritten through regulated transmission charges.

1.24. Capacity will be made available through a blend of implicit and explicit auctions with duration of no more than 1 year. BritNed will not enter into long term capacity contracts. Its revenues will be determined by congestion rents from the implicit and explicit auctions. BritNed has indicated that it will hold medium term[42] and intra-day explicit auctions and day-ahead implicit auctions. The implicit auction day ahead system will also be used to implement UIOLI. Furthermore, BritNed has stated that it will comply with other provisions of the CMGs such as the application of firmness or with any future guidelines on UIOLI/UIOSI arrangements.

1.25. At regional level, BritNed will connect the GB electricity market to the Trilateral Market Coupling (TLC) area of Belgium, Netherlands and France – or rather to the Central West Region, as the TLC will is expected to expand to include Germany and Luxembourg in April 2010. The provision of day-ahead implicit auctions will result in a degree of market coupling between GB and the above-mentioned region.

1.26. Building on the experience of the IFA, BritNed will provide cross border balancing and ancillary services and is currently working on the range and structure of services that will be offered. The specific services that are currently under discussion between TenneT, NGET and BritNed are: frequency response, operational tripping schemes to accommodate congestion management and SO-SO trades.

1.27. BritNed has agreed to consult widely on the access arrangements, including the appropriate split between implicit and explicit auctions. Following the approval of access arrangements by the two NRAs (Ofgem and EnergieKamer), which the Third

[42] BritNed is planning to hold annual, seasonal, quarterly and monthly explicit auctions

Package will make a formal requirement[43], BritNed aims to go live with its access rules by mid-2010.

EirGrid East West Interconnector

Background

1.28. In 2004 the Irish Government requested CER to canvas the degree of interest among potential investors to build a 500MW DC interconnector between the Republic of Ireland and GB. Following consultation, CER received no indication of practical commitment to a merchant project and concluded in June 2004 that the only realistic way to ensure delivery was through a regulated model. In this case regulated means some form of commitment of financial support from regulated transmission use of system charges to underpin the necessary investment.

1.29. In September 2006 the Irish Government requested CER to arrange for the design of tender for the construction of a 500MW DC interconnector between Ireland and GB to be owned by EirGrid[44]. The CER approved the project based on EirGrid's "Approval to Proceed" submission in February 2009 Final investment approval was given by the Irish Government in March 2009. The interconnector is due to be operational in July 2012.

1.30. Ofgem issued an interconnector licence for EirGrid Plc in on the 20 November 2007. As an interconnector linking two Member States, and as EirGrid has not sought an exemption, it will be subject to EU legislation on use of revenues, third party access and capacity allocation and management. The details of the auctioning of capacity on the East West Interconnector have yet to be determined.

East West Cable One Limited

Background

1.31. East West Cable One Limited (EWC)[45], formerly Imera Power Limited, is planning to build and operate two 350 MW HVDC sub-sea cables linking the Irish SEM and British electricity markets. In its exemption application EWC stated that, subject to the necessary consents, it envisaged the first cable (EW1) would become operational in 2010 and the second cable (EW2) operational in 2011.

Regulatory framework

1.32. Ofgem granted EWC licences for two interconnectors between Wales and the Republic of Ireland on the 20 November 2007. As part of its licence application EWC

[43] Article 37 Directive (EC) 2009/72/EC
[44] EirGrid plc is the independent electricity transmission system operator (TSO) in the Republic of Ireland and the Market Operator in the wholesale electricity trading system.
[45] EWC is a limited company incorporated in the Republic of Ireland. EWC is owned by Imera Ltd (35%) and Imera Holdings (65%).

submitted an application for exemption from SLCs 9, 10 and 11 of the electricity interconnection licence and Article 6(6) of Regulation No 1228/2003.

1.33. In its exemption application EWC stated that its motivation for seeking an exemption is "related to the commercial and regulatory risk of the project". EWC commented that an exemption from the regulated TPA regime was necessary to eliminate the risk that the regime changed during the period of exemption. In addition, EWC stated that exemption from the use of revenue requirements removed the risk that investor returns would be capped or removed, while there was no equivalent mechanism to compensate investors if the project failed. EWC stated that removing this kind of regulatory risk is crucial for the success of the project.

1.34. EWC also highlighted additional risks associated with the nature of trading arrangements in the SEM. EWC considered changes likely as the SEM is a relatively young market launched at the end of 2007 with a gross mandatory pool and ex-post pricing mechanism.

1.35. Following consultation, on the 26 September 2008, Ofgem issued an exemption order for a period of 25 years for EW1 and 20 years for EW2. Subsequently, the European Commission requested the Ofgem to amend the exemption order and include the following conditions:

c) A capacity cap of 40% applied to any dominant party, in either generation or supply (as defined by the directive) in either system or market to which the interconnector is connected.

d) Before the first Imera Interconnector is made available to system users, effective congestion management can be fully implemented, in accordance with Congestion Management Guidelines, allowing intra-day trading on interconnectors by individual market participants.

e) CER and Ofgem will assess the effectiveness of the secondary trading and UIOLI provisions ensuring access for all potentially interested parties within six months of the first twelve months the first Imera interconnector is made available to system users.

1.36. EWC provided its consent to the amendment of the exemption orders which were re-issued on 10 February 2009.

Capacity allocation mechanism

1.37. In its exemption application EWC indicated that it does not intend to buy or sell power itself, but intends to own and operate both interconnectors. The project will be financed through the sale of capacity. Therefore, none of EWC's costs will be underwritten through regulated transmission charges.

1.38. EWC considered that, in order to ensure financing, long-term contracts were necessary to underwrite the project. Therefore, EWC proposed to allocate all interconnector capacity on the basis of long-term contracts (i.e. with minimum term bids of 10 years) and establish a reserve price for capacity. The rights are intended to be allocated at the beginning of the project via an open season type auction process.

1.39. In order to ensure efficient use of existing capacity and minimise capacity hoarding EWC proposed that all contracted capacity be subject to UIOLI provisions and to facilitate secondary market trading by establishing an electronic bulletin board. EWC also propose to introduce the same information transparency rules as those in place on IFA.

1.40. EWC commented that while the proposed access regime met the existing regulated TPA and CMG requirements an exemption eliminated risk of potential delays associated with approval and risk that the regime may change during the life of the asset.

Appendix 3 – Electricity interconnector licence

1.1. The Electricity Interconnector Licence contains 18 standard conditions[46]. Standard conditions 9, 10, 11, 12 and 13 are important to note for the purposes of this consultation and are explained in more detail below. References in this Appendix to the Electricity Directive and Regulation are to articles in the Second Package as that was the basis on which the Interconnector Licence was developed. DECC and Ofgem are currently considering whether changes to the Licence will be required to transpose the Third Package.

1.2. Standard condition 9 requires the licensee to allocate revenues it has received to one or more of the purposes specified in Article 6(6) of the Electricity Regulation. These include guaranteeing the availability of allocated capacity, maintaining or increasing existing capacity, as a subsidy to reduce network tariffs or as income to be taken into account in the approval of the charging methodology. To monitor compliance the licensee is required to submit an annual use of revenues statement.

1.3. Standard conditions 10 and 11 require regulatory approval of the charging methodology for interconnector use and for the licensee to offer terms of access to the interconnector. The standard conditions transpose Article 20 and Article 23 of the Electricity Directive. The standard conditions set high level objectives that the charging methodology and non-price terms and conditions for access are objective, transparent and non-discriminatory.

1.4. Standard condition 13 reflects Article 6(3) of the Electricity Regulation and requires licensees to make the maximum interconnector capacity available, to establish an effective UIOLI mechanism and to entitle users to re-sell capacity on secondary markets. Minimum transparency requirements are also established.

Exemption from third party access

1.5. Standard condition 12 reflects Article 7 of the Electricity Regulation, which provides for an exemption to be granted from various requirements of the Electricity Directive and Regulation where specific conditions are met. Exemption may be granted from any or all of standard conditions 9, 10 and 11. Any exemption decision taken by Ofgem grants exemption from the application of the standard conditions and the equivalent articles in EU legislation.

1.6. The exemption test includes requirements that the investment enhances competition in electricity supply, that investment would not take place without an exemption and that the exemption is not detrimental to competition or effective functioning of the internal electricity market. The exemption test also requires that

[46] In April 2005 Ofgem issued guidance to help network users better understand the requirements of the interconnector licence.

the interconnector is owned by a separate legal person from the TSOs to whose system the infrastructure is connected.

1.7. Any decision by Ofgem to grant an exemption must be notified to the European Commission. The European Commission then has two months in which it may request Ofgem to amend or withdraw the decision to grant an exemption.

Appendix 4 – Summary of the Irish and French markets

SEM

1.1. The SEM is the all-island electricity market for the Republic of Ireland and Northern Ireland with average generation of 38 TWh a year. The SEM is a gross mandatory pool with day ahead gate closure into which bids are optimised over the whole day with an ex-post single market clearing price (SMP). Generators, including interconnector users, submit bids into the SEM by 10 am on the day before trading. The SEM is an ex-post market, with a significant time lag between the submission of offers and real time dispatch and the publication of market prices and quantities (though IC users are notified of their firm dispatch quantities two hours after gate closure). It is the scheduling and pricing software, in combination with bids by interconnector users that determines interconnector flows.

1.2. The SEM does not currently have a day-ahead market, one of the consequences of which is that users of interconnectors in the SEM have no indication of the SMP when it comes to settling their position in neighbouring markets. The lack of a day-ahead physical market is considered to be a significant impediment to price coupling the SEM with neighbouring markets. Furthermore the SEM does not currently allow for trading after gate closure. Unless changes are made to market rules, unused interconnector capacity at the day ahead stage (i.e., at gate closure) is lost to the market. The latter is significant in terms of compliance with the CMG.

French Wholesale Market

1.3. France has the second largest electricity market in the EU, in terms of both generation and consumption, with volumes on the wholesale market, including cross border imports, amounting to 450 TWh a year in 2007. The majority of power (some 80%) is generated by nuclear power stations. The state-owned utility, Electricité de France (EdF), dominates the French market in both generation and supply sectors. Most wholesale activity takes place over the counter through bilateral contracts or through intermediaries, with the Powernext exchange facilitating day ahead (spot), intra-day and futures trading. After gate closure, RTE operates the balancing mechanism.

1.4. The French market has significant interconnection, with total cross border flows in 2007 equivalent to 16 per cent of domestic consumption. Nuclear plants typically generate at low marginal cost thus making France a significant exporter of power to its neighbours. In 2007, France exported 65.5 TWh and imported 10.4 TWh. Nonetheless liquidity levels in the French market are relatively low.

1.5. France is market price coupled with Belgium and the Netherlands. Powernext began operating intra-day markets in 2007 and in April 2009 Powernext and the German EEX power exchange merged their entire spot trading activities.

Appendix 5 – Experience with market coupling

The Trilateral Market Coupling and CWE

1.1. The Trilateral Market Coupling between Belgium, Netherlands and France is the first example of decentralised market coupling, launched in November 2006. It is an example of price based market coupling, under which the market coupling determines both the prices and the flows across interconnectors for each market. It was adopted to allocate daily capacities on the NL-BE and BE-FR interconnectors, replacing the previous system of explicit auctions, still used for monthly and annual capacity allocation. The Trilateral Market Coupling which involves the three Power Exchanges (Belpex, Powernext and APX) and the three TSOs (RTE, Elia and TenneT), establishes a single price for power across the region which only differs if there is insufficient capacity available on the interconnectors.

1.2. It is important to note that while all day-ahead capacity is implicitly auctioned, only 10% of flows between the three countries are in practice implicitly auctioned and the rest is still allocated using explicit auctions[47].

1.3. The TLC initiative is considered a success story of market coupling in Europe. After two years of operation, electricity prices in the three Power exchanges were identical for more than 65% of time. TLC has helped to boost liquidity on the exchanges, contributing to the development of the now liquid Belgian spot market and increased market convergence. There are plans to extend the TLC to Germany and Luxembourg and couple all markets in the Central West Region (CWE market Coupling) by April 2010.

NordPool: Market Splitting design

1.4. The Nordic market splitting model was the first initiative of market integration, launched in 1996, which served today Finland, Sweden, Norway, Denmark and Germany. In 2002, the financial and physical markets (day ahead +intra-day) were separated in 2002. Nord Pool Spot power exchange organises the physical trade of electricity and operates the day ahead market (Elspot) and the intra-day market (Elbas). Nord Pool ASA operated the financial market (offering forward and future contracts).

1.5. Nordic Exchange area is divided into several bidding areas and participants make their bids/offers according to where consumption/production is physically located. If there is no congestion, market splitting will result in one price across the region, if there is congestion, price difference will reflect the cost of congestion.

1.6. Today, 333 participants trade in Nord Pool Spot market daily. Trade volumes equal more than 70% of the total consumption of electricity in Nordic Countries.

[47] "SEM Regional Integration, A consultation paper", CER-Commission for Energy Regulation, page 17

1.7. Nord Pool is considered another positive example of market integration, which has led to improve exchanges and liquidity and improved price transparency in the Nordic Power Market.

MIBEL

1.8. The single Iberian Electricity Market (MIBEL), integrating the Spanish and Portuguese markets, was established in July 2007. Interconnection capacity is allocated solely through a market splitting mechanism implemented in MIBEL day-ahead and intra-day markets. The power exchange OMEL underpins the joint management for the Portugal-Spain Interconnection and has the responsibility for the daily and intra-day markets.

1.9. Capacities are fully implicitly allocated at day-ahead by means of market splitting: Portugal and Spain are the two prices areas into which MIBEL is split if congestion arises.

1.10. As of July 2009, a medium and long term capacity allocation scheme has been introduced, based on the auction of financial hedging products. These financial products are export/import contracts for differences (both forwards and options), valued in accordance with observed hourly day-ahead market spread between Portuguese and Spanish Zones. The first auction took place in June 2008.

1.11. Most transactions are carried out in the daily (day-ahead) market with the intra-day market working more as an adjustment market. Intra-day auction markets have been in operation in Spain for more than nine years. Today, OMEL facilitates six intra-day implicit auctions over 24 hours in MIBEL. The Iberian intra-day markets are among the most liquid markets in Europe.

Further market integration

1.12. The EMCC[48] volume coupling initiative between Denmark and Germany is the only example of volume coupling initiative in Europe. Under volume coupling, market coupling determines the net interconnector flow positions but prices are determined locally by each PX in subsequent process. However, the complexity of the approach has proved difficult in practice and is not seen as a preferred model.

1.13. Other coupling initiatives have been proposed. The TSOs (TenneT and Statnett) and Power Exchanges (Nord Pool Spot and APX) involved in the NordNed Interconnector (700MW interconnector between Norway and Netherlands) have been working to develop an appropriate market coupling design. Power exchanges involved in the CWE, Nordic and Iberian markets (EEX, NordPool and OMEL) are working on a single coupling solution covering all these markets.

[48] European Market Coupling Company

Appendix 6 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[49]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[50].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[51];
- the need to contribute to the achievement of sustainable development; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[52]

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

[49] Entitled "Gas Supply" and "Electricity Supply" respectively.
[50] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[51] Under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[52] The Authority may have regard to other descriptions of consumers.

- promote efficiency and economy on the part of those licensed[53] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- the effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[54] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[53] Or persons authorised by exemptions to carry on any activity.
[54] Council Regulation (EC) 1/2003

Appendix 7 - Glossary

A

APX

Amsterdam Power Exchange, Anglo-Dutch Power Exchange operating markets for electricity and natural gas in the Netherlands, the United Kingdom and Belgium.

B

Belpex

Belgian Power Exchange for anonymous, cleared trading in day-ahead electricity, providing the market with a transparent reference price.

BritNed

Electricity interconnector between Great Britain and the Netherlands, currently under construction.

C

CER

Commission for Energy Regulation, the Irish energy regulator.

CMS

Congestion Management System on the England-France Interconnector (IFA).

CRE

Commission de Regulation de l'Energie, French Energy Regulator.

CREG

Commission de Regulation de l'Electricite et du Gaz, Belgian Energy Regulator.

CWE

Central West Europe Region, the electricity region encompassing Belgium, France, Germany, Luxemburg, and the Netherlands.

D

Day ahead

A form of a spot market, typically around the middle of the day prior to real time (e.g. 12 noon on Monday for electricity to be generated and used on Tuesday), where bids and offers are made and prices set. The timing allows for decisions to start or stop additional generators (unit commitment).

DC

Direct Current, unidirectional flow of electric charge.

E

EEX

European Energy Exchange. An energy exchange based in Leipzig, Germany. EEX operates Spot and Derivatives Markets for energy and related products.

EirGrid

Irish Transmission System Operator.

Elia

Belgian Transmission System Operator.

EMCC

European Market Coupling Company, operates the volume coupling arrangements to allocate interconnector capacity between Germany and Denmark.

ERGEG

European Regulators Group for Electricity and Gas.

EWC

East West Cable One Ltd, formerly Imera Power Ltd, energy infrastructure company incorporated in the Republic of Ireland.

Explicit allocation/auctions

Allocation/auction in which transmission capacity is allocated separately from the trading of electricity.

F

FUI

France-UK-Ireland region of ERGEG's Electricity Regional Initiative.

H

HVDC

High Voltage Direct Current.

I

IFA

Interconnector France-Angleterre, 2000 MW electricity interconnector between France and UK.

Imera

Imera Power Group, an independent developer of offshore power transmission projects.

Implicit allocation

Allocation in which both transmission capacity and electric energy are allocated together, typically used at the day-ahead stage and potentially intra-day.

Interconnector

Equipment used to link electricity systems, in particular between two Member States.

Intra-day

Purchase and sale of a product within a given trading day (any time after the day-ahead stage).

M

Market coupling

Method of organising implicit auctions, where different power exchanges in each market area and a (shared) coupling system manages the capacity between them.

Market splitting

Method of organising implicit auctions, where a single power exchange operates across the connected areas and manages the capacity between them.

MW

Mega Watt.

N

Netting

Process in which any capacity sold in one direction is netted off against capacity sold in the other direction.

NG

National Grid plc, international electricity and gas company which owns the transmission system operator in GB and NGIL.

NGIL

National Grid Interconnector Limited, wholly owned subsidiary of NG and holder of an interconnector licence. NGIL jointly own and operate the IFA with RTE.

NIAUR

Northern Ireland Authority for Utility Regulation, the Northern Irish energy regulator.

NRA

National Regulatory Authority.

P

PCG

Project Coordination Group. It was established by the November 2008 Florence Forum to develop a practical and achievable model to harmonise interregional and then EU wide coordinated congestion management and to propose a roadmap with concrete measures and timetable, taking into account progress achieved within ERGEG's regional initiatives.

R

RTE

Gestionnaire du Reseau de Transport d'Electricite. Transmission System Operator in France.

S

SLC

Standard Licence Condition.

SONI

System Operator for Northern Ireland, owned by EirGrid plc.

T

TenneT

Dutch Transmission System Operator.

TLC

Trilateral Market Coupling, decentralised market coupling between Belgium, the Netherlands and France.

TSO

Transmission System Operator, entity in charge of operating transmission facilities either for electricity or gas.

U

UIOLI

Use-It-Or-Lose-It, a contractual term referring to a capacity or rights holder who has the choice to use their capacity/rights or to give them up (without compensation) to be resold on the open market.

UIOSI

Use-it-or-sell-it, a contractual term referring to a capacity or rights holder who has the choice to use their capacity/rights or to give them up to be resold, and to receive the price at which they are resold (also known as UIOGPFI: use-it-or-get-paid-for-it).

Appendix 8 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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