

The Creation of Regional Electricity Markets

An EREG Discussion Paper

for Public Consultation

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Chapter 1: Introduction

- 1.1 This chapter provides background information on the regional markets initiative as a route to the creation of a single European market, considers what, in this context, is meant by a regional market and sets out the rationale for, and scope of, the paper.
- 1.2 Recognising that national arrangements are different between the member states and that market operators, regulators and participants are operating under different legal and commercial conditions, this paper considers what potential barriers might exist to effective trade between markets.
- 1.3 This paper considers the activities of transmission network operators (TSOs) and of wholesale energy trading market arrangements and discusses whether or not obstacles exist within these areas which may need to be overcome in order to establish an effectively functioning competitive regional market. Such obstacles may include regulatory, technical, structural and political ones. This paper also considers the extent to which other issues may arise that may represent obstacles to the effective functioning of a regional market, such as the lack of a coherent regulatory framework, government interaction and the prevailing situation in related markets such as gas. This paper confines attention to wholesale electricity markets, in particular the interactions between them in terms of trade, how trade can be influenced by wholesale market rules, and how market distortions might arise from differences in market design in adjacent markets.

Background to the regional markets initiative

European objective

- 1.4 It is a stated aim of the European Commission, regulators, and others, to work towards the creation of a single, efficient and effectively competitive electricity market.
- 1.5 The European Commission has set out a statement of the vision and process for the creation of a Single Electricity Market in its March 2004 Strategy Paper *Medium term vision for the internal electricity market*. This anticipates the integrated single market being reached via the interim step of the establishment and further development of a number of regional markets. Market arrangements within regions are likely to be relatively strongly harmonized, and reflective of strong underlying physical, institutional, and political links. The Nordic region is a good example of an existing regional electricity market, although there remains scope for further integration. More compatible arrangements can lead to the application of similar rules for all market players and hence tend to promote efficient trade. Regions or markets would in due course become more closely integrated and so approach the single market paradigm.
- 1.6 It should be noted that experience from the case studies presented in the paper suggests that it is not necessary for the establishment of the single electricity market that full harmonisation of national and regional arrangements must occur.

Differences will remain in any event, such as taxation, environmental and social measures which are national issues that may affect the market. The operation of different arrangements (either on a national or regional scale) will not in itself lead to inefficient trade. However some degree of co-ordination and harmonisation in material areas is likely to be required to ensure that national and regional markets do not create any impediments to effective operation of the overall market. For example, some co-ordination of market rules, clear rules for operation within a market and transparency within and between markets will be required to ensure that market participants act upon their commercial incentives to trade.

Current EU regional initiatives

- 1.7 For the management of congestion on electricity interconnectors between Member States, this regional approach has been the subject of direct action following the 11th Florence Forum of September 2004. The Forum called for the establishment of 7 “mini-fora”. Each mini-forum is a grouping of relevant stakeholders from a number of neighbouring Member States. Each is to provide a plan and detailed timetable for the introduction of at least day ahead co-ordinated market based mechanisms for congestion management between territories. The ‘Central Western’ mini-forum for example comprises Belgium, France, Germany, Luxembourg, and the Netherlands. A central idea is that these smaller Regions will be able to introduce feasible and pragmatic congestion management methods that take account of local conditions and markets more easily than methods that attempt to cover the whole EU.
- 1.8 Each mini-forum is expected to report back progress on its regional initiative to the next Florence Forum. Given the nature of the issues, reports may well include wider consideration of issues associated with integrating markets in order to form regional markets.

Independent initiatives within EU

- 1.9 The regional approach to market integration is also being reflected in a number of separate initiatives taken forward by individual member states working in co-operation with others. The Nordic market is a particularly good example of a regional electricity market, where three Member States and Norway have already adopted a large degree of harmonization methods designed to allow seamless and efficient trade of electricity across the four countries. The Spanish and Portuguese governments have committed themselves to creating a single Iberian market for electricity. Similarly, government and regulatory authorities have adopted plans to create an all-island electricity market across the Republic of Ireland and Northern Ireland. A single electricity market across Great Britain came into effect on 1 April 2005 from which point the two separate markets became fully integrated. Steps are also being taken towards establishing a South East European Energy Market (which would include both EU and non EU states). The fact that some EC members, who are neighbours of the South East Europe region assist the countries of the South East Europe region cannot hinder their market development and their regional cooperation outside South Eastern Europe. In relation to Austria and some parts of France and Germany a common wholesale price area has developed as a result of a high degree of interconnection capacity.

1.10 All of these initiatives and processes point to the fact that individual national and regional markets are gradually being welded together, at different times, places and speeds. In order to promote and maintain efficient trade within and between these markets and to foster the emergence of other new regional markets it is necessary to consider the extent to which differences in market arrangements and rules adopted in neighbouring markets have the potential to promote inefficient trade, even where the market rules within any one market are consistent with efficient trade and to identify the main issues that require attention.

Defining a regional market

1.11 A discussion of what is meant by the concept of a 'regional market' is useful because an analysis of the concept can help to illustrate what issues may be important when integrating markets. Such a discussion is also clearly useful because the concept is a key element of the evolution towards a single market for electricity. However, it is not intended that this paper should consider a detailed regional market definition; rather it sets out, at a high level, a roadmap for taking forward greater co-operation and co-ordination within a region.

1.12 We observe significant trade occurring in and between certain markets and not others. This is partly due to market outcomes, and partly due to legislative, regulatory and market rules and network arrangements. Abundance of (or the potential abundance of) trade between markets for either (or more probably a combination) of these reasons suggests that the markets form, or can form, a 'regional market' that spans across borders. From an electrical point of view the borders are TSO borders, although such borders generally coincide with political, member state, borders.

1.13 A regional market will have arrangements in place to minimise barriers to trade within the region and market rules which take account of interactions with, and required compatibility with, other areas within that region. Within a regional market it is expected that market prices will converge. Differences in price may still exist as a result, for example of congestion management (as in the Nordic market) rather than from the existence of incompatible network or market rules.

1.14 Generally, CEER considers that the existence of a regional market will be signalled where the following conditions exist:

- (i). sufficient transmission capacity exists between the markets within the region and is made available to market participants (such capacity may be made available through the use of implicit or explicit auctions)
- (ii). there are no distortions within the local markets which significantly affect the functioning of the regional market
- (iii). an appropriate legal and regulatory framework is in place which allows for action across a regional market

- (iv). national institutions within the regional market co-ordinate and co-operate closely with each other within an appropriate legal framework. In particular :
- TSOs working together in order to ensure that interconnector capacity is optimised and allocated efficiently
 - Regulators working together and freely exchanging information so that proper monitoring and regulation both of national and regional markets can happen.
- 1.15 The above indicators can, of course, only offer a broad view on whether or not two or more individual markets might be said to form a regional market, however, they can provide a useful checklist for regulators in considering what issues may arise in moving towards a regional electricity market.
- 1.16 In considering whether a regional market exists it is also necessary to recognise that evidence may suggest that a regional market exists for some elements of the supply chain but not others. For example it is possible that wholesale markets may be well integrated but for the treatment of retail markets to differ.

Rationale for paper

- 1.17 The CEER consider that the establishment of regional markets represents a practical and achievable way of delivering progress on the move towards a single electricity market. The development of regional electricity markets, alongside the continuation of work to ensure effective liberalisation within national markets is an important step in delivering a competitive and effectively functioning single electricity market. In view of its support for the Commission's thinking in this area for the medium term the CEER began to consider the nature and scope of this issue, and the questions raised, in a working paper presented to the 11th Florence Forum¹. In order to take forward work on the issue of regional energy markets the CEER set up the Regional Energy Markets Task Force with the specific task of defining a 'roadmap' for the establishment of regional energy markets to identify the main obstacles to effective interaction across borders which will need to be addressed in order to establish regional energy markets.
- 1.18 The aim of this paper is to develop further the ideas presented by CEER in its working paper for Florence and so define a 'roadmap' for the development of regional electricity markets as a mechanism for moving to a Single Electricity Market.
- 1.19 This paper sets out a first view of those market design features that have the potential, where treated differently in adjacent markets, to produce the largest distortions to trade across and between markets and hence where potentially the largest impediments to market integration might occur. These market design features are considered, on a theoretical basis, broadly within two groups: network

¹ CEER Working Paper for Florence *Key interactions and potential trade distortions between electricity markets* September 2004

operations and wholesale market arrangements. This paper also analyses and identifies some broader questions that may need to be addressed in order to facilitate market integration and efficient trade and investment across and between markets, for example issues relating to effective regulation of a regional market.

1.20 A wealth of experience and practical application of market integration exists from a number of current regional initiatives. The CEER, in preparing this 'roadmap' paper have considered case studies prepared on various regional initiatives:

- Great Britain
- All-island market for the Republic of Ireland and Northern Ireland
- Iberian peninsula
- Nordic countries
- Australian national market²

1.21 The characteristics of a regional market will of course differ depending on the particular circumstances of the case. However consideration of these case studies can provide a broad view on the important issues that are likely to arise in relation to a regional market and identify lessons to be learnt from those experiences. In light of the consideration of these case studies, which are annexed, this paper sets out the key issues that have emerged from the case studies

1.22 Whilst recognising that the circumstances of individual market conditions will differ, and that any solution will need to take account, flexibly, of these differences, this paper also sets out a proposed broad prioritisation of issues, in light of both the theoretical considerations set out in this paper and the experience gained from existing regional initiatives, such that action is appropriately focused on those areas that are most likely to be inhibiting trade. The paper identifies the key relevant stakeholders or coalitions of stakeholders that might be expected to progress the issues, identifies the importance of the governance issues associated with taking this regional markets initiative forward and sets out a suggested way forward.

² (although noting that this does not include Western Australia or the Northern Territories)

Chapter 2: Obstacles to trade: network operations

- 2.1 The stewardship of TSOs over the transmission network is of crucial importance to the achievement of an efficient and competitive single European market. The creation of an effective regional market requires that interaction takes place between the national markets that comprise that region. The fact that there are numerous TSOs across Europe, each responsible for the operation of their own network (control area), gives rise to the possibility that obstacles may exist to effective interaction across and between these networks, in particular resulting from different approaches adopted by adjacent TSOs. In addition, it may be possible for the operation of each individual network to be made more efficient through greater co-operation between TSOs.

The role of the TSO

- 2.2 TSOs undertake a number of essential core functions, which are typically performed in discharge of obligations owed by those TSOs under legislative or regulatory provisions.

Network capacity and investment: TSOs invest in their networks to ensure that the infrastructure continues to meet technical security standards and to ensure that sufficient capacity is delivered.

Network access: TSOs contract with users to provide access to their respective transmission networks.

Transmission charging: in contracting with users for access to the transmission network, the TSO also levies charges on network users to recover the costs of the network.

Live network operation: TSOs operate the transmission system in real time situations. In doing so TSOs will undertake a number of activities to ensure that the network remains stable. However, the precise way in which TSOs achieve this varies.

Emergency planning and black start: TSOs plan and make arrangements for possible network disturbance situations such as the failure of a major generating station or the more widespread failure of part or all of the network that may lead to a black out or brown out. Each TSO will establish operational plans to recover from these situations and will enter into contracts for the procurement of adequate services needed for recovery, like e.g. black start of generators, reserves etc.

Network maintenance: TSOs undertake the day-to-day maintenance of their transmission network equipment.

- 2.3 In carrying out these activities, TSOs, particularly those who are part of a highly meshed and synchronised network, co-operate with other TSOs in order to ensure

the secure technical operation of their joint networks. Currently the principal mechanism for achieving this on the synchronously connected parts of western and central Europe is through following UCTE rules and recommendations. Other arrangements to facilitate such co-operation may also exist, for example prior to the introduction of BETTA in Great Britain co-operation arrangements across the three British TSOs were set out in the British Grid Systems Agreement, while in the Nordic region the Nordel agreement provides a contractual framework for co-operation between the four TSOs.

- 2.4 The role of the TSO means that typically TSOs have access to a range of information that is important to the operation of market arrangements. How that information is handled by TSOs is therefore important, in particular where a TSO has market related affiliations.
- 2.5 Each of the above areas are discussed in turn below. The analysis examines whether there exist obstacles to effective interaction between TSOs which might distort the competitive market place and whether there is scope for efficiency gains to be achieved through greater co-operation/interaction between TSOs.

Network capacity and investment

- 2.6 On a national level enhancements to transmission capacity, either through the construction of new transmission lines or the upgrading of existing ones, results from a process whereby each TSO undertakes system studies of their network. The studies will examine what changes need to be made to the transmission network in order for it to remain compliant with established technical standards against the background of likely future changes in generation and demand. Changes in the volume or location of generation and demand affect the electrical flows over the network and consequently affect the need for network re-enforcement.
- 2.7 Historically, the obligation on TSOs to build infrastructure stems from domestic regulatory requirements. In return for making investments in the network to meet security standards the TSO expects to receive a reasonable rate of return and the revenues which provide this return are, in most countries, approved by the relevant regulatory authority. This is the fundamental 'regulatory contract' that exists between TSOs and regulators. Within this regulatory contract there is a risk that investments which are not efficient will be disallowed by the relevant regulatory authority who will be concerned that the network does not become gold plated and that a proper balance is struck between the interests of shareholders and consumers. In some instances this risk may be that investment that is not efficient cannot be recovered by users (and thus the cost is borne by the TSO) while in other situations such investment may not be approved for development.
- 2.8 In situations where recovery for investment is allowed, these arrangements mean that the risk associated with any individual investment is underwritten by transmission network users (as they have no choice about the tariffs which cover these costs) which presents a low investment risk to investors. Consequently, TSOs are generally able to obtain low costs of capital. On the whole this arrangement works well for users provided the regulatory framework is robust.

- 2.9 Investment in infrastructure forms the main part of the capital investment of TSOs and the sums of money are clearly material. Care is needed to ensure that such investment is efficient (especially where the costs are passed directly through to users through regulated network tariffs).
- 2.10 The presence of sufficient interconnection across borders is fundamental to the establishment of a successful single electricity market. Improved interconnection allows for greater flows across borders and increases the possibility of TSOs sharing services such as balancing, reserve and other ancillary services and enhances network capacity and reduces congestion. As such appropriate arrangements are required for the identification and delivery of required cross border investment.
- 2.11 Interconnector investments, by definition, span TSO and usually member state boundaries, and therefore extend across regulatory borders. TSOs however are national bodies with national networks and investing to meet security standards is normally limited to investment to meet the needs of their own network in accordance with their national obligations.
- 2.12 As things stand, national obligations on TSOs (as their part of the 'regulatory contract') to maintain and develop their network to achieve technical standards does not extend across national borders or to connections with other networks. Consequently investment in cross border infrastructure is typically driven by factors different to those used for in-country investment, such as local requirements to maintain system security or where TSOs and regulators agree that the construction of a particular line would be beneficial.
- 2.13 In addition to addressing issues associated with the triggering of cross border investment, it is also necessary to consider the issue of funding of that investment. In order for cross border investments by TSOs to occur there needs to be an assured basis for future recovery of the costs of that investment. However, the 'regulatory contract' which forms the basis for 'regulated' investment decisions by the TSO does not, in all instances, apply in respect of cross border investment. In some countries the issue of funding is addressed by Government decision. For example, in Finland, Spain and Austria cross border investment in infrastructure is approved by the Government and the cost is automatically incorporated in the Regulated Asset Base (and recovered through network tariffs). However, in other instances, such as the arrangements in place in Great Britain no such arrangements exist.
- 2.14 The consequence of these difficulties is that 'regulated' investment in new transmission infrastructure across borders typically occurs on an ad-hoc basis. This could be a major impediment to the fulfilment of a competitive single European energy market given the importance of interconnection capacity to effective cross border trade. A major cause would seem to be the lack of an appropriate framework in which to fulfil the "regulatory contract" for TSOs in relation to 'regulated' investment in cross border infrastructure. Regarding the regulator's part of the 'regulatory contract' ie the recovery of investment costs which will also need to be addressed.

- 2.15 The development of a framework to allow the concept of a 'regulatory contract' to fully extend to cross-border investment would provide a solid basis for future development of cross border infrastructure on a multilateral, as well as bilateral, basis. The development of such a framework requires consideration of new issues such as how the costs and benefits of particular investment should be split between the adjacent markets. Such a framework could be prescribed at an EU level prescribed framework but could alternatively be developed through co-operation between relevant member states. Regulation 1228/2003 provides a legal basis for the establishment of a compensation mechanism for the costs of cross border flows. These arrangements are likely to help address some of these issues. Another factor that may provide a further driver for investment is the presence of effective arrangements for congestion management. If the price of such congestion is revealed it should provide clearer signals for investment by TSOs.
- 2.16 The position paper and guidelines issued by CEER in May 2004 '*Regulatory control and financial reward for electricity cross-border transmission infrastructure*' provides a useful tool for regulators in considering cross border investment issues. The guidelines state that the initiative to pursue new cross border investments will mostly be placed with the TSOs (who will consider market signals and requests from market agents) since the TSOs have the technical knowledge as well as the expertise, to evaluate cross border transmission investments, although noting that authorization by the relevant national authorities will continue to take place as normal. The guidelines seek to address issues relating to TSO uncertainty on obtaining adequate remuneration for such investment, by providing that the involved regulators reach a common position on an adequate remuneration for the cross border facilities and set an appropriate remuneration scheme. However these guidelines do not include consideration of some of the complex issues surrounding the allocation of costs of regulated cross border investment as between users of the respective networks nor do they consider the extent to which clear cross border investment obligations may need to be introduced within defined regions, relating both to the delivery of cross border infrastructure and other infrastructure required for cross border purposes. The guidelines are also constrained by the current supporting regulatory framework.
- 2.17 It is likely that, in the absence of further EU wide measures, the appropriate focus in this area should be on ensuring effective co-operation between the relevant member states and regulatory authorities, perhaps within a clear governance framework setting out common principles for dealing with issues of cross-border investment, both in terms of triggers for such investment and the recovery of investment costs.
- 2.18 In some instances merchant investment in network infrastructure occurs. In such cases private capital is invested and a market based rate of return may be allowed. Provided there is adequate competition the charges that merchant investors may make will be limited by the forces of competition and investors will be exposed fully to the risks of failure, as is the case in other sectors of the economy. In such cases investors are fully exposed to downside risks and therefore are able to benefit from any upside return on investment. Such investments would continue to be possible under the enhanced regulated arrangements described above.

Network access

- 2.19 In terms of network access, network users pay a regulated tariff for access to the transmission network and in return receive a defined level of transmission access rights from the TSO.
- 2.20 The allocation of transmission access rights may differ from network to network. Some transmission networks (such as Great Britain, Austria and Finland) provide financially firm transmission access rights. In such cases a market participant that has their physical access rights reduced as a result of constraints or a transmission disturbance, receives financial compensation for lost output or consumption. The effect of these arrangements is to make individual market participants less sensitive to the commercial risks associated with their particular location on the transmission network or to changes in the physical availability of transmission capacity. This reduces commercial uncertainty for market participants.
- 2.21 In other member states access rights are financially non firm. In such cases market participants are not compensated for the withdrawal of access rights and bear the commercial risks associated with lost output and consumption.
- 2.22 Transmission access rights are likely to be most scarce at times of system stress, when such access rights may be withdrawn to address system issues. The price risks at these times may be significant and a system of financially non-firm access rights places risks on market participants which small and new entrant participants will find difficult to bear or hedge. The inability of market participants to fulfil their commercial contract may be a double blow as they will be unable to capture the rents of higher electricity prices in such periods and may also face penalties for failure to deliver. Within a single market this works to the advantage of incumbent participants and in the context of regional markets it works to the further benefit of those with firm rights.
- 2.23 In respect of cross border trade, the manner in which access rights to the interconnection are allocated, both in terms of the method of allocation and whether that access is financially firm or not can have a significant effect on the regional market.
- 2.24 While investment in sufficient capacity is fundamental it is also necessary to ensure that market participants are able to access that capacity otherwise opportunities for cross border trade will be limited. Appropriate arrangements should be put in place to deal both with the initial allocation of cross border capacity and any short term re-allocation where reserved capacity is not being utilised. TSOs should also be subject to incentives to maximise the availability of capacity to market participants.
- 2.25 It should be noted that in some markets a proportion of capacity may be reserved, under long term contracts or by the TSO for reasons of system security. Such arrangements may limit the availability of capacity at borders and thus limit opportunities for cross border trade. In such instances steps should be taken to maximise the availability of capacity to the market.

- 2.26 If access rights to interconnector capacity are non-firm then interconnector users may be at a disadvantage regardless of the access rights regime in the adjacent network, as they will face not only the risk associated with the use of that network (as would an indigenous competitor) but also the risks associated with the use of the non-firm interconnector. The option for users of choosing financially firm access rights must be available with regard to such key infrastructure. Issues relating to the financial firmness of access rights are also considered further in the later discussion on system balancing and constraint management.
- 2.27 Regulation 1228/2003 now provides a legal basis for the allocation of capacity relating to congestion management. The Commission is empowered to set binding guidelines on congestion management mechanisms. Present drafts of the Guidelines require TSOs to offer capacity as firm as possible.

Transmission charging

- 2.28 For TSOs, tariffs essentially serve two principal functions: they allow TSOs to recover revenues for their business; offer the possibility of imposing locational charges to improve efficiency in the way users locate and manage plant connected to the transmission system.
- 2.29 Regulated tariffs in Europe are required to be cost reflective and within this broad parameter tariffs reflect the costs of the specific network to which the user is connected, together with any adjustment that is imposed by the ITC mechanism. Different countries have in place different methods and different charging arrangements for dealing with transmission charging, with some including a locational element.
- 2.30 The issues of charging for the horizontal network and locational pricing have been much debated in European fora. The use of locational tariffs, can have a material effect on the operational arrangements for networks by affecting the location of new investment by users as well as exit decisions which will influence the need for, and location of, new investment by TSOs. Locational tariffs may also affect the merit order of generating plants which can materially affect congestion on the network. In those member states where no locational element is superimposed upon the tariff, charges are uniform or “postage stamp” across the network.
- 2.31 Differences in tariffs due to location can have a material impact on the relative competitive positions of market participants. Whilst all tariffs may be cost reflective there can be interactions between adjacent networks which charge on different basis which affect the operation of a regional market. In particular, if locational charges in one network are based on the supply and demand patterns within that network the incentives on plant to generate could, potentially, be perverse at the borders and could operate to the competitive advantage (or disadvantage) of market participants in the adjacent network.
- 2.32 The proportion of the total charge placed on generators and users by each TSO may also create obstacles for a regional market. In some TSO areas generators pay an average of zero, while in others generators may pay up to forty per cent of the total

cost. Such differences can be a disadvantage to generators in one TSO area compared to another in competition for the same customer. The Commission is empowered³ to set binding guidelines on all members states which require that average charges to generators for use of the transmission system does not exceed a particular level (excluding charges for connection, losses etc). Present drafts of the Guidelines set this level at 0 euros for most parts of Europe with higher levels being set for Great Britain, Ireland and the Nordic region.

- 2.33 Economically the most efficient solution would be to charge all users a cost reflective amount for the use of the transmission network in their market area in a way which reflected back the costs they imposed on the network and for there to be a common standard for the division of charges between generation and load.
- 2.34 For users tariffs represent a cost to their business. To the extent tariffs do not distinguish between users, then users should be reasonably neutral to the absolute size of the tariff charges. Differences in charges between users will, however, affect the relative competitive position of one user compared to another. In this context differences in tariffs between adjacent networks will be significant, as will the structure of tariffs – such as locational charges. For example, a 1MW generator with a 70% load factor obtaining a wholesale price of €50 would receive an annual income of €306,600. If a charge of €20/kWh were incurred by the generator in excess of its competitors then the additional annual transmission charge would amount to €20,000 or 6.5% of total revenue. As can be seen from these indicative figures, the potential impact of different tariffs on network users can be significant. However, this is the extreme difference. In reality tariff differences in regions are unlikely to be so wide. Therefore, whilst there may be some obstacles resulting from such tariff differences they are unlikely to form a systematic barrier to European trade.

Live network operation

- 2.35 The live operation of transmission networks requires TSOs to ensure a constant balance between supply and demand through undertaking balancing actions, as well as ensuring the local stability of the network through the provision of reactive power. Reactive power is a service which is location specific and therefore is likely to have little effect on the competitive market place or on interactions between TSOs, as such it is not considered here. The more significant activity in these terms is therefore system balancing.
- 2.36 TSOs have different approaches to system balancing and may be incentivised to reduce balancing costs and in order to achieve this may be able to access balancing markets or enter into balancing contracts. All will procure automatic frequency response as a service provided by generators automatically whereby mechanical governors will raise or reduce the output of their plant within certain tolerances in response to system frequency. This has the effect of keeping the system in balance on a second by second basis. However, it does not deal with major disturbances in the network and for these the TSO needs to take explicit actions normally involving

³ Regulation 1228/2003 provides a legal basis for the co-ordination of generation charges for transmission.

- constraining one or more users (a user in this context may be a generator, a supplier or a customer connected to the transmission network) on or off the network and reducing the amount of energy available in the market place.
- 2.37 The approaches used by TSOs in taking significant balancing actions of this kind vary. Some enter into balancing contracts with system users, in some markets there are balancing markets where users can bid prices at which they would be willing to be constrained on or off (such as the arrangements in place in Great Britain), and in other areas balancing actions are a regulated activity.
- 2.38 In Great Britain, NGC as the system operator tenders in a transparent manner for the procurement of these services from market players and is also subject to incentives regimes designed to minimise costs associated with these actions.
- 2.39 The cost of balancing may be significant in certain countries, while in others it may represent a relatively small proportion of overall costs. For example, in GB the cost of balancing is around 30 per cent of the total annual cost of operating the transmission network, in the Nord Pool area they range from 2% to 5%⁴, while in Spain they are 27% and in Germany they are around 10%. The way in which the costs of balancing are handled (including the way in which imbalance charges are passed back to users) may vary between areas. Issues regarding imbalance charges and the way in which they are passed through to users are considered further later in this chapter on the discussion of issues of market compatibility.
- 2.40 Balancing of the network, while affected by the particular design of the network is not a particularly locational activity, in that absent any local congestions a TSO may take a balancing action in any part of the network to ensure system balance. In principle, TSOs should be able to collaborate across borders to achieve the most efficient outcome in balancing their respective networks given that the balancing of the network, while affected by the particular design of the network, is not a particularly locational activity. Consequently, there is likely to be scope for greater co-operation between TSOs on balancing actions with the aim of reducing balancing costs overall. On a meshed network it may also be the case that a balancing action taken by one TSO could result in the need for a balancing action by one or more adjacent TSOs. Such co-operation occurs to some extent today in current regional market initiatives, leading overall to a more efficient outcome within the region.
- 2.41 Recognition of the benefits, in terms of efficiency, of seeking to establish common principles and arrangements for balancing on the synchronised network has led to work being undertaken by CEER in 2005 to develop principles for the co-ordination of balancing market rules in the synchronised area, including the possible need for a more formal legal framework for balancing markets. While it is not considered that an absence of harmonised balancing arrangements (note that imbalance is dealt with separately in chapter 3) would be a significant obstacle to the establishment of an effectively functioning regional market it is recognised that the presence of compatible arrangements may add to the overall efficiency of that regional market and may, in the context of the synchronised system, where the actions of one TSO

⁴ Note that the definition of balancing costs can vary between countries and regions.

- may require another TSO to take a balancing action, provide greater benefits. Work on the development of increased harmonisation and co-ordination within the Nordic market in this area is currently being taken forward.
- 2.42 Users may be affected by balancing arrangements in a number of ways. Where competitive balancing markets exist users may get financial benefit by offering balancing services to the TSO. In these arrangements both generators and the demand side may be able to participate and the value to the TSO of balancing services bought at short notice (i.e. flexible response) may be revealed thus providing incentives for plant to be made available to provide these services. Users may also be affected by the way that imbalance costs are passed on by TSOs to users through imbalance charges, although this is discussed later in this chapter.
- 2.43 A further important area of managing a live network is in managing congestion. Approaches to the management of congestion by TSOs vary. Implicit auctions are the primary means used by TSOs in the Nord Pool area for managing congestion between balancing zones and have been a focus of discussion at the mini-fora established through the Florence process. Most other TSOs tend to constrain on or off network users in order to manage congestion around their network and to provide for scheduled flows across interconnectors. The approach to constraining on or off users could be through the use of bilateral contracts, balancing mechanisms or administered means.
- 2.44 The management of congestion within networks as a material costs to TSOs varies across Europe. In GB in 2004 the cost of congestion management was £50 million, or 0.2% of the total annual cost of the network, whereas in Austria the costs of congestion management in 2005 are expected to be about 7.5%. For users, however, the management of congestion is very important for a number of reasons. The ability of a user to trade depends on their access to the transmission network as it is essential for the delivery of their trade. A congestion management process which may result in a user being constrained off of the network could affect their ability to trade in those periods and results in significant risk for that user. In some areas this issue is addressed through the provision of financially firm access rights.
- 2.45 In such cases users who are constrained off of the system receive compensating payments such that they are left financially neutral when they are constrained off. (Similar payments occur when users are constrained on to the system). The provision of financially firm or non-firm rights can therefore significantly affect the competitive position of users on adjacent networks.
- 2.46 In other areas, such as Nord Pool, TSOs may act within the power exchange as a means of managing congestion and balancing the system rather than constraining off particular users. While such actions are not inappropriate, such action by TSOs within the power exchange can affect electricity prices within the market and as such should be regulated closely in instances where a TSO has market related affiliations.
- 2.47 The management of congestion is also important in relation to interconnectors. As noted earlier in this paper the Commission is in the process of putting in place binding guidelines on congestion managements.

- 2.48 If capacity rights in respect of interconnector users is not financially firm, then potential cross border market participants may be disadvantaged when competing with other users based within the adjacent market. As mentioned earlier, this will be the case whether the network they are supplying offers financially firm rights or not as such users will be equally exposed to the congestion arrangements on the supplied network as indigenous users, as well as to the interconnector risk. Current developments in the guidelines concerning congestion management does not fully address the issue of financial firmness of access rights and as such will require further consideration in the context of a regional market.
- 2.49 TSOs, in handling issues related to congestion management on their respective networks tend, where possible, to try to deal with congestion by making adjustments to 'Net Transfer Capacity' to reduce import capability. If this results in 'pushing' congestion' out to national borders it creates a potential obstacle to the effective operation of a regional electricity market by reducing the scope for cross border trade.

Emergency planning and black start

- 2.50 TSOs undertake emergency planning, usually based on scenarios of possible emergency situations. Such work is usually unseen by market participants unless a real emergency arises. In such rare situations the planning work of the TSO is essential to the resolution or management of the emergency. This work has a low impact until called into use. Depending on the nature of the emergency there may be a significant impact on market users. For serious incidents involving loss of supply, there is a premium on restoring supplies as quickly as possible.
- 2.51 Within their own network TSOs have the information and resources to undertake this work and are considered to be positively obliged to plan for such emergencies in relation to their respective networks. However, as we move towards a more integrated single European energy market there is likely to be growing interdependence between TSOs in preventing and resolving emergency situations across increasingly highly meshed networks. The black outs in Italy on 28 September 2003 demonstrate the problem.
- 2.52 It is unlikely that significant barriers exist to increased co-operation between TSOs in planning for such emergencies, although there may be concerns about the sharing of information which could be commercially sensitive. In fact in the case of the fully synchronous network (the 'supergrid') such co-operation does take place through UCTE (this co-operation is considered in more detail in the general discussion of TSO co-ordination later in this chapter). More likely is the existence of barriers, or a lack of positive obligations on the TSOs, in relation to actual co-operation and co-ordination taking place in the event that such an emergency arises. For example, insufficient arrangements may be in place within a national market to allow a TSO in country A, in response to an emergency in country B, to take a deliberate action on its own network to assist in instances when such an action may not, based purely on national considerations, be efficient. Action may be required in order to address the 'regulatory gap' that may exist here, both in terms of removing any barriers to co-

ordinated action in emergency situations and perhaps to require such action in certain circumstances.

- 2.53 For users, emergency planning and black start arrangements are almost unseen. Users may enter into black start contracts with the TSO, but they are not significant to the operation of the market place day to day.

Network maintenance

- 2.54 TSOs undertake maintenance to their network, which represents a material cost to the TSO. Poor maintenance would lead to greater risk of failure but technical standards exist to which networks must be maintained, and in any case it is in the interests of TSOs to maintain their assets and prolong asset life.
- 2.55 The impact on users of network maintenance by TSOs is mainly through the scheduling of circuit outages by the TSO to allow maintenance operations to take place. Usually the TSO will try to manage its maintenance outages of the transmission network with planned outages of generators, and commonly will have specific obligations to do so, such as Grid Code obligations in Great Britain. Such outages may give rise to constraints or a greater risk of transmission network failure until the relevant circuit returns to service. As such arrangements for maintenance may impact on cross border flows and as such have an impact on the regional market.
- 2.56 In terms of the co-ordination of maintenance on infrastructure that might affect cross border flows it is unlikely that significant barriers exist to increased co-operation between TSOs in such matters.

Co-operation between TSOs

- 2.57 Although the drive towards a single European energy market is well established, there remains surprisingly little regulatory oversight of the technical interaction between TSOs. As mentioned above, there is no regulatory framework for investment by TSOs in interconnector capacity, or in many other areas, such as emergency planning and prevention. Co-operation between TSOs does however take place today, both on an ad hoc basis (for example in relation to the development of new infrastructure), and on a more organised basis.
- 2.58 The TSOs in mainland Europe have established a fully synchronous network (the 'supergrid') and those TSOs who are part of it have established UCTE and through that body have agreed to voluntary guidelines for the co-ordinated operation of the supergrid. These existing arrangements are currently under review and it is intended by UCTE that they will be migrated from the voluntary mechanisms that have been used over the past decades, towards a new UCTE Operational Handbook which will have contractual force as between the parties. It is not clear at this stage how developments in this area will progress, although it is noted that the co-operation delivered on the synchronised network by UCTE (either in its current form or in any revised form) is a welcome example of co-operation by TSOs.

- 2.59 The UCTE guidelines are important for the establishment of the single European energy market, as are other forms of co-operation between TSOs, such as the Nordel Agreement between the TSOs in the Nordic market. However, any guidelines of this kind can have potential impacts on the development and operation of the market and as such consideration should be given to the regulatory rules governing co-operation between TSOs and their oversight. In particular consideration is required as to whether a clear and coherent regulatory framework is needed for co-operation across a particular regional market and for the oversight of such TSO interactions. Such a framework on a regional basis could be delivered through member state co-operation within that particular region and does not necessarily require EU level action. However, EU-wide co-operation is more likely to require Commission action if it is to be delivered.
- 2.60 In addition to ensuring that arrangements for effective co-operation and co-ordination between TSOs on key issues are in place, it is also necessary to consider the extent to which existing national arrangements and regulatory rules may operate as a barrier to such interaction, such as is described above in the consideration of emergency planning. The presence of national rules and arrangements which prevent the cross border co-operation by TSOs should be avoided, although noting of course that such co-operation should not in any way detract from the national obligations owed by the TSO in relation to its own control area.
- 2.61 To the extent that different national technical and operational standards may impact on the ability of TSOs to co-operate, Regulation 1228/2003 empowers the Commission to set binding EU wide guidelines on technical and operational standards for transmission system planning and operation and may have a role to play as development of these guidelines is taken forward by the Commission, with the advice and support of ERGEG.

Information provision by TSOs

- 2.62 As a result of their position as operators of the networks, TSOs are in a unique position as they are in possession of information about the state of the network. For example, information on the overall balance of supply and demand, the location of constraints, the location of generation and demand sites and the future timing of generator outages are examples of information held by TSOs which could affect the position of individual market participants or even the electricity price in the market. Typical information held by a TSO includes:
- system load information (both ex post and ex ante forecasts such as day ahead, week ahead)
 - generator information such as installed capacity (and forward projections on such capacity), generation outages and adjustments to available capacity and ex post information, on unpredicted unavailability
 - data on the balancing mechanism in countries where such a mechanism is actually in place .
 - ex post information on average physical flows and line
 - forecast investments on the high voltage grid of each member state and impact of such investments on the availability of the transmission capacity available, for each of the five coming years or more

- 'Net Transfer Capacity' forecasts which take into account all information available to the TSO at the time of the forecast's calculation, for example with regard to the maintenance works on the grid and of the production units*.
 - ex post information on total requested capacity and capacity given out by TSOs for a given allocation period. In case of auctions, market clearing prices and volumes should be published.
 - total nominated capacity per market time unit immediately after the moment of nomination.
- 2.63 Such information is important to the effective operation of competitive wholesale market arrangements and thus to the liberalisation process. Differences in the availability of such information between national markets may also create obstacles to a regional market, which are considered further in chapter 3 of this paper in considering possible obstacles to regional wholesale market arrangements.
- 2.64 It is therefore of fundamental importance that TSOs, within a regional market, where possible, place the information that they hold in the public domain without delay. Where it is not possible for such information to be placed in the public domain either at all or only with delay it is important that TSOs guard that information carefully until such time as it can be released. This is of particular importance where a TSO is vertically integrated and has interests in the competitive part of the market place. The effect of a less than transparent approach to information management, or one where the management of information by the TSO, is insufficiently robustly monitored will be to undermine confidence of other players in the market regardless of whether the TSO actually abuses its position in relation to this information. In the context of a regional market inadequate management of information by some TSOs may create an obstacle to effective operation of the regional market.
- 2.65 For example, in putting in place the BETTA arrangements in GB it was considered to be of utmost importance that the GB system operator, as the party responsible for providing access to, and operating, the GB system should be free of all market affiliations, not because of expected abuse in such areas but of the damage that possible opportunities for abuse could cause to market confidence and market activity.

Chapter 3: Obstacles to trade: wholesale market arrangements

- 3.1 In order for trade to occur in electricity, as in any other market for a commodity, what is required is the existence of a fungible product, ie one that is capable of being traded on a like-for-like basis, and the presence of a market where market participants can come together to trade. The mechanism through which such trade occurs could take one of various forms. There is no one view as to what market type may be appropriate in any given situation. Many factors, including the size of the overall market, may be a factor in the market design decision. For example a series of small national markets in close proximity may see benefits that could be realised by converging into a single market (which in these terms may be considered to form a regional market)
- 3.2 A market could be a mandatory market (such as a Pool arrangement) through which trades must occur or could be through the existence of an 'over the counter' bilateral market where market participants enter voluntarily into bilateral contracts. In some instances, it may be common for both types of market to be in existence in any given area. The market mechanisms required for trade to occur do not need to be mandated they can, and subject to appropriate commercial drivers being in place, will emerge naturally within a given market.
- 3.3 An example of a wholly organised (and mandatory) market is the proposed arrangements for the establishment of a gross Pool for the all-island market for Ireland and Northern Ireland. Market participants wishing to trade within this area must conduct all trade through the Pool arrangements. An example of a voluntary market is the trading arrangements established in Great Britain where all contracts for the sale and purchase of electricity are bilateral contracts entered into on OTC markets or through a power exchange. Other market arrangements may provide for a combination of such mechanisms, such as the Spanish Pool arrangements where the majority of electricity is traded through the Pool but trade is also a feature.

Market types

- 3.4 As mentioned above there are various different market designs in existence. This section considers the key characteristics of those various market types.

Pool systems:

- 3.5 Under a Pool system generators make offers to supply electricity for a given period (at a particular quantity and for a particular price). The demand side puts forward its estimated demand requirements for that period and algorithms determine the appropriate levels of required supply (creating a merit order starting with the cheapest offered generation until supply and demand requirements are balanced) with the price for all generators and purchasers being set by the marginal generator's price. The periods to which Pool markets relate are typically day ahead. The Spanish Pool arrangements provide for day ahead but there are also intra day and balancing markets in operation. This may not prevent contractual arrangements being struck between market participants for longer term supply arrangements, although the price of such contract is usually governed by the Pool price for the

period (with contracts for difference often being put in place to deal with differences between the contracted price and the price given by the Pool).

Bilateral markets

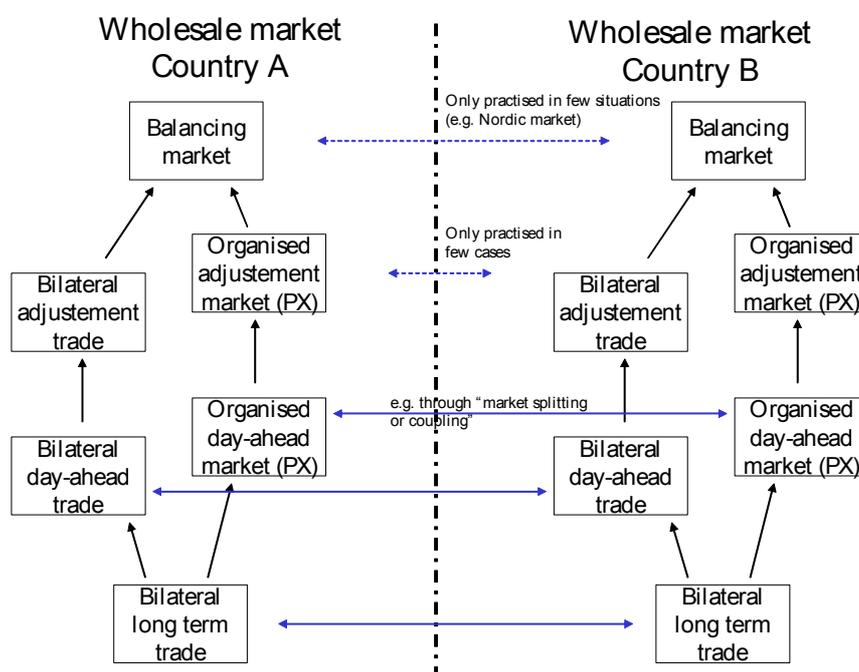
- 3.6 OTC unorganized bilateral markets are the basis of liquidity for most non pool systems. Under such systems participants in the market (generators, suppliers and 'pure' traders) directly strike private bilateral contracts for the sale and purchase of electricity. Such contracts can be struck significantly in advance of real time and the same electricity is capable to being the subject of multiple bilateral contracts, being bought and re-sold by various participants. Estimates of OTC trade suggest that the volume of electricity traded is about 4 times physical consumption in continental Europe.
- 3.7 Such contracts are then notified to the market operator at 'gate-closure' so that they are aware, in operating the system, of all contracted positions. Contracts in place at that time will need to be physically performed or the market participants will be in imbalance. Such 'gate closure' is the point by which all such notifications need to be made may occur at various times, for example half hour before real-time or a day in advance of real-time. Given that a participants prediction of its likely physical position at a particular time is likely to become clearer the closer you are to that time (for example prevailing weather conditions, system constraints or unplanned generator constraints) the closer gate closure is to real time the greater opportunity market participants have to seek to adjust their contractual position to match their expected physical position thereby reducing imbalance.
- 3.8 Transparency in such markets comes from the publication of reported prices, for example such as price reporting by Platts, or other price reporters, therefore the reliability of such reported prices is important.

Power exchanges

- 3.9 A power exchange is a market mechanism through which market participants can buy or sell electricity within various timescales, from periods close to gate closure as well as forward markets relating to 'periods' many months or years ahead. Participants in such markets are not necessarily intending to take a 'physical' position to actually deliver that electricity.
- 3.10 The presence of different market arrangements while not necessarily representing a barrier to trade between those markets may however, operate so as to make such trade more difficult.
- 3.11 For example, wholesale markets may be mandatory day-ahead pools, or could be bilateral markets underpinned by balancing mechanisms. Figure 1 illustrates the possible elements of the wholesale markets in two adjacent markets. The more that designs and rules for these elements differ, the more likely it is that trade is impeded or distorted between the markets, and the less likely it is that the two markets together can be considered a region. For example, wholesale market players' are likely to find it more difficult or relatively expensive to trade between markets if one is

a mandatory day ahead market and the other is based on bilateral trading with a residual balancing market. In such situations, all things being equal, market players will tend to transact with players in the same national market rather than expose themselves to risks and difficulties of dealing with the other market which may tend to discourage trades that might otherwise have been efficient.

Figure 1 : Potential wholesale market interactions



Key market characteristics

3.12 Electricity markets invariably have their own particular designs and sets of accompanying rules. These set the parameters within which market participants will take a decision on whether they wish to act (and if already present whether they wish to remain) within that market. The complexity of those rules, market structure and the opportunities that the market represents for the participant (in terms of trading activity) are all factors that may affect a decision to enter (or remain within a market).

3.13 There is no one view as to what market type may be appropriate in any given situation and each has their respective strengths and weaknesses. However there are certain key characteristics that each competitive market should have.

Efficient price discovery

3.14 The price of electricity traded within the market should be a non-distorted price drawn from the interactions of supply and demand and not from market

imperfections, such as the exercise of market power to increase price above equilibrium levels (for example by withholding generation capacity such that prices are inflated). The existence of cross subsidies can also serve to distort price. Transparent market prices should reflect the value of used power at every moment of time and at any specific physical location in the system.

Imbalance arrangements

- 3.15 Electricity cannot be stored and therefore where there is a discrepancy for a given period between the actual physical position of a market participant and their contracted position then that participant is out of balance for that period (except possibly in relation to gross pool arrangements where imbalance may be aggregated over a longer period of time). For example, a participant may have contracted with a customer to supply 500MW of electricity but given an unexpected problem at the generating plant is not able to deliver in accordance with that contract (and is for the relevant half hour period exporting 0 MW). Similarly a supplier may have contracted to receive 100MW in the same period but due to a fall in its demand requirements has no customers to provide that electricity to. In such cases the TSO will act to make up the shortfall by constraining on or off other generators and users. Such actions have a cost.
- 3.16 The cost of such imbalance may be dealt with by smearing the costs of such imbalance across all users or by allocating the costs to the market participant that is out of balance. In either situation, it is important for market participants to be able to make short-term adjustments to their contracted position, close to real-time, such that they are better able to manage changes in their physical position and thus fine tune their commercial position. OTC markets are less suited to trades very close to gate closure given the practicalities of a buyer and seller coming together in such timeframes with matching (but opposite) requirements. As in such it is likely to be necessary to establish a short-term spot market, as a trading place, to complement the bilateral contracts market through which market participants wishing to make adjustments to their contractual position in advance of gate-closure are able to trade. Such exchanges may be delivered by the market although in the absence of such a development may need to be mandated by the appropriate authority.
- 3.17 Differences in national arrangements for dealing with the costs of imbalance may impact upon the regional market by affecting the competitive position of market participants within a part of the regional market as opposed to other participants. For example, if in system A the imbalance costs imposed by a user are reflected back on to them fully (as in Great Britain) this results in sharp price signals that incentivise users to stay in balance and exposes them to risk if they fall into imbalance. The risk of a user connected to an adjacent network where balancing costs are smeared across all users means that the risk profile of a user on that network is different and the consequence of arriving at an imbalance position may be much less severe for any individual. This may have the effect that a generator in system B has an advantage over one in system A who will face the cost of imbalance directly whilst the other will not.

Information and transparency

- 3.18 In chapter 2 of this paper it is recognized that TSOs hold a significant amount of information regarding their respective networks. This includes information on the overall balance of supply and demand, the location of constraints, the location of generation and demand sites and the future timing of generator outages are examples of information which could affect the position of individual market participants or even the electricity price in the market. Key information may also be held by other parties such as market participants, power exchanges etc. For example, generators hold key information including schedules, operating points, planned and unplanned outages and maintenance. Reliable information on the operation of bilateral markets is particularly important to the effective operation of the wholesale market arrangements, for example clear, reliable and prompt information on prices and volume.
- 3.19 The placing of such information in the public domain where possible (and the safeguarding of the confidentiality of that information prior to any public release) is vital both for providing market participants with all possible information that might assist them in managing their market position (unless there is a clear reason why that information should not be provided to them) and in terms of reinforcing market confidence.
- 3.20 The extent to which such information is made available to market participants may vary across networks, both in terms of what information is made available and the timescales for making such information available. Transparency of certain information is already prescribed, at the EU level by the Directive and Regulations while in other circumstances information is voluntarily provided by TSOs, market participants etc⁵.
- 3.21 In addition however, it is likely that there are other key pieces of information which are required to be transparent for market purposes, much of which will be held by the TSO. The CEER is currently developing guidelines for good practice in transparency which will identify information which should be made publicly available. The focus of these guidelines will be information relating to the wholesale market, and in particular information held by TSOs. While the main driver for such transparency is clearly the liberalisation process it is recognised that differences in information provision across a region may create obstacles to effective interaction within that region.

Assessment of possible obstacles to effective trade between markets

- 3.22 The fact that there are numerous market systems in operation across Europe, each having different characteristics and market rules gives rise to the possibility that obstacles may exist to effective interaction across and between these markets, in particular resulting from different approaches adopted by adjacent energy markets.

⁵ For example, publication by FINGRID of the generation information referred to in chapter 2.

Compatibility of national market arrangements

- 3.23 The presence of different market arrangements while not necessarily representing a barrier to trade between those markets may however, operate so as to make such trade more difficult.
- 3.24 For example, all markets will have a point of 'gate closure' where physical notifications become fixed. After that point to the extent that a market participant's physical position within the given trading period does not match its contracted position the participant will be considered to be out of balance. Up until this point market participants will be able to trade to try and provide that their contracted position reflects their expected physical position. To the extent that there are differences in the timing of gate closure across a border, ie where country A is ½ hour and country B is 1 day, there will be little or no opportunity for short term trade to occur from country A to country B although opportunities will exist from country B to country A.
- 3.25 Similarly, the way that balancing costs are passed on to users through imbalance charges can affect their competitive position and as such the extent of compatibility between national imbalance arrangements within a regional market may have a material impact on that regional market.
- 3.26 Compatibility between key market rules such as the timing of gate-closure may also be important so that opportunities for trade can be fully realized (against the backdrop of the required network issues such as investment in capacity and access being addressed). However this does not mean that full harmonization of all trading rules and arrangements is required for effective interaction between markets to occur.
- 3.27 Another factor that may need to be considered is the extent to which national measures for ensuring security of supply may need to be compatible. The presence of differing national approaches may impact upon cross border trade. Governments in considering security of supply solutions within their respective markets will need to be aware of the potential impact on cross border trade that could result. For example, a market with capacity payments may need to address how these payments would work in relation to energy imported from an adjacent market.

Market information

- 3.28 As explained above the provision of relevant market information to all participants and within appropriate timescales is a key factor in an effective market. Such information provides participants with key information which may be relevant to their market decisions. Without access to key information market participants are exposed to greater risk regarding possible events or externalities which may affect their market position and as such their decision to act across a regional market. Also a lack of ex post information with regard to actual action may affect market confidence and limits appropriate scrutiny of such actions which again could impact on the effectiveness of that market. Similarly, significant differences between adjacent markets as to the transparency of market related information may affect cross border activity with market participants preferring to act with the more 'open'

market where it may be more possible for the participant to predict market conditions and thus manage their potential exposure.

Impact of national market structure

- 3.29 Market structures will also affect decisions with regard to market participation and as such influence the degree of interaction between markets. For example, a lack of retail liberalization is likely to lead to a lack of opportunities for trade by limiting the portion of the market that is open to trade (limiting potential buyers largely to the incumbent) and result in one-way trade flow, while the presence of significant market power in both generation and supply is also likely to lead to a lack of opportunities to trade.
- 3.30 A decision to participate within a wider regional market may also be affected less visibly by the level of confidence that a market participant may have in the robustness of those market arrangements. For example, the presence of a TSO with market affiliations may reduce market participants confidence that the market will be allowed to operate in such a way that unfairly favours those affiliates. Of course, the presence (and enforcement) of effective market rules regarding conduct, discrimination and information transparency and ringfencing can assist in securing market confidence in such arrangements and thus in the regional market. For example, while TSO activity within the bilateral market (in order to purchase energy to balance the system) may not per se be detrimental, in instances where TSOs are also a participant in the potentially competitive areas of the market there could be a negative effect on cross border trade unless there is sufficient separation and transparency of the TSOs activities. This area is again a demonstration of the close links between the regional markets initiative and the liberalization process, whereby delivery of effective functioning regional markets is linked closely to the completion of the liberalization process.

Chapter 4: Obstacles to trade: regulation across a regional market

- 4.1 If a regional market is to be established a key question that needs to be addressed is how activity within that market is to be regulated on an ongoing basis.
- 4.2 Within the existing national markets, each regulatory authority has national responsibilities and duties with regard to the market that it must discharge. In order to fulfil its role within the national market the regulator is provided with the necessary powers and jurisdiction such that it is able, where required, to act. The nature of the regulator's actions within its national market may vary, for example in relation to liberalized areas the role of the regulator may largely be one of monitoring behaviour whereas in the monopoly network businesses the level of regulatory control is likely to be much greater.
- 4.3 The regulatory framework in EU member states provides for standards for supply to customers and safety standards for the operation of networks. However, in relation to the competitive market place the principal purpose of the regulatory framework is to provide the basis for a level playing field in order that market participants can compete fairly one with another. In order to achieve this regulations often address the rules associated with trade and wholesale markets, although in many countries bilateral trades are subject only to the normal commercial rules applying to commodity contracts. The main focus of regulation in electricity in seeking to provide for a level playing field is in the provision of equal access to the monopoly transmission network. If one player is provided with favourable terms for access to the transmission network compared to another player then they will be at an advantage because, even if the production of raw energy has identical costs and risks, the transport of that energy to market will not. It is these differences that the regulatory framework seeks to address and equalize, whilst often seeking economic efficiency in the process.
- 4.4 A regulatory framework provides a level playing field for transmission access in a number of ways. For users, tariffs are set which provide users with a defined level of access to the transmission network. For TSOs the regulatory framework provides them with a reasonable expectation of a return on the capital that they invest in the provision of capacity of the network. This fundamental "regulatory contract" exists in all member states. However, the way it is given effect may vary from market to market and further examination is required of the way this regulatory contract operates between markets.
- 4.5 There will, within a regional market, be a strong need for co-operation between regulatory authorities in ensuring the ongoing compatibility of arrangements within the regional market and ensuring that the required rules, arrangements and incentives are in place such that the aims of the regional market are realised as well as the aims of the national market. This is likely to include ensuring that the 'regulatory contract' between regulators and TSOs and market participants is fulfilled both from a national perspective and a regional perspective.

- 4.6 Under the regional markets model, companies (including TSOs) will be active on regional markets. Regulators however have limited jurisdiction and authority. For example, without such a framework a market participant may be able to take action in market A which has an adverse impact and effect on market B but in relation to which the regulatory authorities in Market B will have no remit to act. In such instances they will be reliant on the regulatory authorities in Market A taking action who may not consider such action to be a priority if there is effect has little or no effect within their own national market. A lack of effective arrangements for the interaction between regulators across a regional market may create real difficulties and serve to undermine the effectiveness of the market.

Chapter 5 – Interactions between markets - key themes from the case studies

- 5.1 In developing its thinking on a 'roadmap' for the establishment of regional electricity markets the CEER has been able to draw upon the real practical experience provided by existing regional initiatives both within Europe and overseas. These case studies provide valuable insight as to the key issues faced in moving towards regional electricity markets, both in terms of practical design considerations and delivery.
- 5.2 Annexed to this paper are the case studies prepared by the CEER in taking forward this work. These case studies cover the following regional initiatives:
- Great Britain
 - All-island market for the Republic of Ireland and Northern Ireland
 - Iberian peninsula
 - Nordic countries
 - Australian national market⁶
- 5.3 It is important to note that of the five case studies undertaken only three regional initiatives are currently in operation. Furthermore, the history of each particular regional initiative is different. Some regional initiatives, such as the Nordic arrangements have evolved over considerable time (and continue to evolve), while others such as the BETTA arrangements in Great Britain were introduced in a single set of reforms. Regional initiatives may also have been driven by different considerations and/or parties, for example in the Nordic region initial moves towards a regional approach were taken by the TSOs whereas in Great Britain the moves for a regional approach came from the regulators and government.
- 5.4 Consideration of the case studies does however suggest a number of common themes emerging in terms of key issues for regional electricity markets both in terms of market design and practical delivery.
- 5.5 It should also be noted that work is progressing towards the establishment of a regional electricity market in South East Europe (SEE) which will include both EU and non EU member states. The initiative has progressed in a way that a legally binding Treaty is in its final stages of conclusion between the European Community and the countries of SEE. The most important provisions of this Treaty include the expansion of the Aquis Communautaire on energy, environment and competition to the SEE region, provisions for mutual assistance in the case of energy disruption, common external energy policy and provisions for future measures which go beyond the EU legislation regarding the transmission of energy. It also provides for the establishment, among other Institutions, of a SEE Regional Regulatory Board, consisting of the Regulatory Authorities of SEE, which will have mainly an advisory

⁶ (although noting that this does not include Western Australia or the Northern Territories)

role but also may be empowered with executive powers for the implementation of measures related to the regional trading and settlement of disputes. A lengthy discussion on the appropriate regional market design is currently taking place, under the auspices of the European Commission, with the participation of regional stakeholders, which include, among others, International Agencies and Financial Institutions (e.g. EBRD and the World Bank). CEER is deeply involved in the process. Details of the proposed regional arrangements and progress in taking forward the development of this important initiative can be found at: <http://www.seerecon.org>, at: <http://www.seenergy.org> and also at the CEER website at: <http://www.ceer-eu.org>.

Key market design features

- 5.6 There is great variety in market design across the various regional initiatives considered. In a number of cases, such as the all-island project and the BETTA project in Great Britain, market convergence rather than market compatibility has been opted for, although in many instances it is recognized that compatibility between national markets could also have delivered a regional market. The reasons for opting for a particular market design will depend very much on the circumstances of the particular case and it is unlikely that there will be one market design solution that will apply for every region. For example the size of the various national markets may be a key factor in some instances, such as in the case of the all-island proposal and BETTA as may concerns about generation concentration and the market affiliations of TSOs. In other instances regional initiatives may be the result of a gradual process, such as with the development of the Nordic arrangements.
- 5.7 There does however appear to be a number of key factors which emerge from the case studies as particularly important in terms of market design.
- key market arrangements within the various national markets must be compatible if effective interaction is to be achieved. However, full harmonization is not necessary and different arrangements can operate well together provided attention is given to making them compatible. Particular attention to network issues is essential as incompatible arrangements in areas such as transmission investment, the allocation of transmission access rights and arrangements for connection to the transmission system may have a significant impact upon the level of interaction within a regional market with market participants either unable, or unwilling to act on a regional basis. Other key areas also require consideration, such as imbalance charges and wholesale market rules. The experience of the Nordic and all island market in Ireland demonstrate that it is possible (and perhaps preferable) to make initial moves towards forming a regional market rather than developing a fully developed 'ideal' solution, as further development can be undertaken through evolution.
 - clear and compatible transparency arrangements at both the regional and the national level, such as those in place in the Nordic region, are clearly important. This includes both information relating to key cross border infrastructure, such

as capacity information and also national market information, the absence of which may limit opportunities or willingness to engage in cross border trade within the region.

- in all of the case studies it is recognized that an important element of a regional market is effective interaction between the TSOs within the region. TSOs need to work together both in respect of ensuring that national arrangements and actions (including matters such as system development and system operation in emergency situations) does not impact adversely on other TSOs within the region and also to ensure that an appropriate 'regional' perspective is achieved with attention paid to the requirements of the region overall as well as to national markets.
- The level of liberalisation within each national market is also recognized by those taking forward regional initiatives as being an important factor, noting that where liberalization is at different stages within the regional market effective trade and interaction across national markets within the region may be inhibited.

A regulatory framework for the region

- 5.8 Some form of overarching regional regulatory framework is likely to be required to ensure that TSO interaction take place in an appropriate manner. Such a framework is also required to ensure that effective regulatory scrutiny is applied at the regional level, creating a 'regional' environment where the appropriate cross border obligations, duties, incentives etc are placed upon actors and to ensure that interaction across borders take place in a manner which is appropriate from a regulatory perspective.
- 5.9 The presence of an appropriate framework is important in terms of ensuring consistency across the region and would seem to be required even in instances where there is strong industry support for regional co-operation or where industry initiatives are already in place. One example where it may be considered that the absence of an overarching regional framework has caused difficulties is in the area of cross border investment where plans in respect of new cross border interconnection are not developed as a result of clear 'regional' obligations and where significant government and regulatory involvement is required before investment occurs. This can be considered to have resulted in less cross border investment being provided than would have been the case were a regional framework in place.
- 5.10 It may not be essential that the framework for such matters be prescribed at the Commission level. Previous initiatives have demonstrated that member state governments and regulatory authorities working together can deliver the regional markets model. To the extent that such co-operative and freely evolving arrangements develop, member state authorities should be able to assume responsibilities for driving forward these developments.

5.11 Such a framework could be underpinned by international agreements such as treaties (like the all-island and the South Eastern Europe proposals) and may or may not lead to the establishment of a single regulatory body for the region. Alternatively, such a framework could be delivered through co-operation between the national regulators, working closely to deliver a consistent framework across all parts of the region. Experiences in the Nordic region demonstrate that much progress can be made without the need for a formal overarching regulatory framework (for example through regional regulatory co-operation and Memorandums of Understanding). However, it remains open to the Commission to propose further measures should initiatives from member states fail to make sufficient and timely progress.

Delivering a regional market

5.12 The evidence presented by the case studies suggests very strongly that in order to take forward a regional initiative the involvement of key groups from each of the national markets is vital. In all of the case studies considered in this paper collaborative working at the local level, between regulators, governments and TSOs has been a common feature, with parties working together closely to deliver the required arrangements.

5.13 The importance of securing governmental support for a regional initiative is particularly important, both in terms of delivery of any required legislative changes and also in terms of providing sufficient impetus for the initiative amongst those elements of the industry that may be reluctant to see such regional development. Strong governmental support is evident in all of the case studies considered and it is difficult to imagine successful delivery of these complex and large scale projects without such support. It is noted that such support could, if required, be mandated at the EU level through further legislative measures.

5.14 Consideration of the case studies also suggests that it is important to recognise that regional market arrangements are unlikely to be perfect. It is likely that national arrangements, such the treatment of renewable energy sources, taxation, currency and the liberalisation process may all operate at a national level so as to affect the operation of the regional market. However, even against this background the benefits of a regional market can still be realised and should be positively pursued by those involved.

Chapter 6: Priority areas for further action

- 6.1 Chapters 2, 3 and 4 of this paper considers what matters may, in principle, inhibit trade between markets. Chapter 5 considers the actual experience of a number of regional initiatives. The discussion within these chapters highlights a number of key issues which, in CEER's view, need to be addressed if the Commission's vision of regional markets (and ultimately a single EU-wide market) is to be realized. A key lesson from real world experience is that different approaches between markets is acceptable provided that attention is paid to making these arrangements compatible with one another. Further, full implementation of a completed market solution may be unnecessary at the initial stages – an evolutionary approach can work well.
- 6.2 In terms of identifying area where further action may be required for delivery of a regional market, four broad categories of issues have emerged:
- ◆ availability of transmission capacity
 - ◆ availability and control of information
 - ◆ co-operation between network operators
 - ◆ compatibility of wholesale market arrangements
- 6.3 In addition to consideration of these specific issues it is important to consider the impact that regulatory and political considerations and levels of involvement can have on the delivery of regional electricity markets.

Availability of Transmission Capacity

- 6.4 The presence of effective arrangements for investing in cross border infrastructure, managing congestion across borders, allocating access rights and the nature of those access rights are all clearly vital in ensuring the establishment of an effective regional market.
- 6.5 Investment decisions are clearly significant (and material) decisions for TSOs to take and as such TSOs must, if a regional perspective is to be achieved, have clear obligations and incentives to invest efficiently in the provision of cross-border transmission capacity. In return they should be able to expect to receive a reasonable rate of return on their investment. At the national level a regulatory framework exists for the investment decisions of TSOs. Such investment is identified by TSOs in terms of planning to meet security standards who will, subject to such investment being considered to be efficient, will be recompensed for its investment. In relation to cross border investment no such regulatory framework exists (although the CEER have published guidelines for regulators on incentivising cross border investment) and as such investment is unlikely to be delivered without significant input and assurance from the member state and national regulators. In some member states investment in cross border infrastructure is approved by the government which provides the necessary certainty to the TSO of forward revenue recovery (although these arrangements do not always deal with cost allocation or efficiency issues). However, in other areas no arrangements exist to provide such certainty of revenue recovery for cross border investments. No clear criteria exist to

trigger investment in new cross border transmission capacity and this is often left to the discretion of TSOs.

- 6.6 The establishment of a clear regulatory framework for efficient TSO investment in relation to cross border activity to operate in a similar manner to its operation at the national level would provide a stable background against which essential cross border investment could take place. Within this framework TSOs and regulators would be able to work together (as they do on a national basis already) to ensure necessary, efficient investments take place. The establishment of such a framework can (in the absence of EU legislation) be facilitated by member state governments within the region, as can be demonstrated by the case studies. Merchant investment should continue to be available in appropriate circumstances.
- 6.7 Adequate arrangements will also need to be put in place across the regional market such that TSOs co-operate to ensure network investment anticipates the demands of cross-border transit and loop flows. The ITC mechanism should continue to be developed so that the cost of dealing with these flows is properly compensated and that the costs are properly allocated to those that cause these flows.
- 6.8 While initial investment is important, equally important is the subsequent availability of that capacity to market participants in order to enable them to access the wider regional market. As such appropriate arrangements for allocation of capacity are required and TSOs should be subject to incentives to maximise the availability of capacity, in varying timescales, at interconnection points.
- 6.9 Rules, obligations and incentives need to be put in place such that TSOs are incentivised to make capacity available, to allocate that capacity fairly and efficiently and to operate their respective networks within the context of the overall regional market efficiently. The EU guidelines on congestion manager, when introduced, will begin this process but further work is required, for example in considering the financial firmness of access rights.

Availability and control of information

- 6.10 The provision of relevant market information to all participants and within appropriate timescales is a key factor in an effective market. Such information is held by market operators, power exchanges and TSOs.
- 6.11 TSOs, as a result of their position as operators of the networks, are in a unique position as they are in possession of information about the state of the network. This information is important to the operation of a competitive market place for electricity and as such is important to the effective functioning of a regional market. Differences in such information provision across a regional market and the lack of key 'cross border' information being made available to parties in a transparent and non-discriminatory way is also likely to impact on the operation of a regional market. Key information which might provide benefits to market participants includes information on the overall balance of supply and demand, the location of constraints, the location of generation and demand sites and the future timing of generator

outages. Such information could affect the position of individual market participants or electricity prices in the market and as such is clearly important.

- 6.12 Such information should be placed in the public domain where possible. Such public release is vital both for providing market participants with all possible information that might assist them in managing their market position and in terms of reinforcing market confidence. Therefore, unless there is a clear reason (which may include economic efficiency as well as sensitivity) why particular information should not be provided, it should generally be placed in the public domain.
- 6.13 Where information is not placed in the public domain (or is placed there with delay) appropriate arrangements need to be in place to ensure the confidentiality of that information to ensure that it is not used to advantage some market participants at the expense of others. While the need for such safeguards exists both in instances where a TSO is vertically integrated and where a TSO is fully independent the issue is clearly more critical where a TSO has market related affiliations. Given the quantity of information held by TSOs and the potential significance of that information for market participants in terms of their ability to take accurate market decisions in all instances where such information is held (and not released) by a TSO that has market affiliations that information must be the subject of information ringfencing requirements, which must be subject to regulatory oversight. The absence of such arrangements in these instances is likely to have a material impact on market confidence within that national market and as such impact upon the regional market.

Co-operation between network operators

- 6.14 The emergence of regional markets provides greater scope for interaction and co-operation between TSOs in network operations. Such increased co-operation and interaction may provide possibilities for improvement to overall efficiency and quality of service to customers within the region. Opportunities for such co-operation are varied and include co-operation in investment analysis and decisions, emergency planning and maintenance arrangements as well as balancing activity. Existing initiatives and arrangements for co-operation across borders, such as the UCTE and Nordic arrangements demonstrate the benefits of increased interaction between TSOs.
- 6.15 Given the possible benefits that such co-operation can bring it is important that potential barriers to such increased co-operation are removed in moving towards a regional market. To the extent that such barriers exist national authorities should work to address these issues such that regional co-operation is achievable. However in light of such co-operation and increased interaction at the TSO level it is also necessary to consider whether existing national regulatory arrangements are sufficient to deal with this broader context both to enhance proper functioning of the market and to ensure proper preparations for system disruptions. For example such that interaction in emergency situations is properly planned in emergency conditions and that emergency incidents are managed efficiently. While existing national arrangements could be adapted, where required, to reflect a broader regional perspective, it may be necessary to consider whether there is a need to establish a

'regional' regulatory framework under which co-operation and co-ordination takes place, both in terms of ensuring that such co-operation does indeed take place and in terms of ensuring that it takes place in an appropriate manner. A possible example of such a 'regional' framework is the Memorandum of Understanding in place between the Nordic countries

- 6.16 Again co-operation between the relevant member state governments can help to address all of these issues in relation to each 'region'.

Compatibility of wholesale market arrangements

- 6.17 In terms of effective market interactions within a regional market, key factors appear to be the extent to which different rules are applied within national wholesale markets which may impact upon the regional market and the extent to which industry structure and market oversight arrangements may affect market confidence (and thus participation in the regional market). These issues are considered below.

- 6.18 The compatibility of national market rules within a regional market requires consideration. While convergence of market arrangements may be opted for as a market design model for the region (as demonstrated by a number of the case studies, such as the all-island proposals) it is unlikely that harmonisation is ultimately required to achieve a regional market but there is a need to ensure that national arrangements within the region are compatible. Compatibility in key areas, where differing arrangements are likely to affect the operation of the regional market, is however, particularly important. For example, the allocation of imbalance costs within national markets and the effect of transmission capacity allocation rules on participants in adjacent markets need to be carefully considered given their potential to impact upon regional arrangements. Consideration may also need to be given to the timing of gate closure across borders given the impact that such differences may have a significant impact on the likelihood of such short term trade occurring across borders.

- 6.19 It is also necessary to ensure that appropriate regulatory scrutiny is applied to national wholesale markets so that the effectiveness of the regional market as a whole is not distorted by activity within a national market. One example, would be where vertically integrated TSOs act within the power exchanges for the purposes of balancing or congestion management. Such activities may act to undermine market confidence and the absence of sufficient arrangements for regulatory oversight may undermine the operation of the overall regional market.

- 6.20 Effective regulatory mechanisms must be put in place to ensure that activity across the whole regional market can be effectively regulated.

The role of governments and regulators

- 6.21 While much can be achieved on the basis of collaborative working by the TSOs and other interested parties, as can be demonstrated by consideration of the Nordic arrangements it is also clearly evident from consideration of the existing regional

initiatives that the support of the national regulatory and government authorities is very important for effective delivery.

- 6.22 Typically national arrangements are different between member states, with market operators and participants doing their business under different legal and commercial conditions. As can be evidenced from the discussion in the paper the presence of such different arrangements can present obstacles to establishing and operating a regional market and as such action may be required to make these arrangements compatible (this does not mean that full harmonization or the creation of a single set of arrangements across the region will be necessary but it does suggest that some action will be required).
- 6.23 In some instances it is possible that some elements of a regional market can be delivered by market participants or TSOs acting together to establish co-operation. For example through the establishment of greater cross border TSO co-ordination of network operations. In other circumstances it may be possible for regulators (working with TSOs) to deliver elements of a regional market, exercising their national powers in order to remove any obstacles to regional interaction, providing regulatory input to considerations of cross border investments etc.
- 6.24 However, TSOs, market participants and regulators can only take developments so far. It is likely, and indeed is evidenced by the case studies, that government action and support will most likely be required to deliver changes to the existing national arrangements in order to provide the required environment, both in terms of removing national rules and laws that may be incompatible with the requirements of the regional market or in terms of ensuring that the regulatory framework appropriately reflects the requirements of the regional market. In developing the regional arrangements for Great Britain the support of the Government was required in terms of making the required legislative changes and also in terms of delivering the large scale amendments to electricity licences and regulated codes that was required to ensure introduction of BETTA. The delivery of these arrangements and the chosen market design would not have been possible without this government involvement.
- 6.25 In some instances, such as the Iberian market, formal treaties have been established to provide the legal basis for the regional market while in other cases reliance has been placed upon co-operation between the various nations. Further development of regional markets could come through continued and increased co-operation between the national governments concerned or from action by the European Commission and other EU institutions or a combination of both. Treaties (as for the Iberian and Southern European markets) or further EU requirements might be a useful legal basis for governance of regional markets.
- 6.26 A key factor emerging from the considerations in this paper is the need for some kind of clear regulatory framework at the regional level in order to address some of the obstacles highlighted above. It is necessary to recognise that each individual regulator has limited jurisdiction and authority (ie limited to its own national market area) and that it may be necessary to put in place clear and effective regulatory mechanisms to ensure that activity across the regional market can be effectively

regulated. Important factors that needs to be considered here by the regulators is the need to address any critical 'regulatory gaps' that may exist within the regional market, for example in terms of investment but also in terms of the monitoring of market activity at a regional, as well as national, level.

Possible external distortions

- 6.28 External distortions may have an impact on a regional market which may limit the effectiveness of that market. Differing national arrangements for taxation, currency and environmental policy may impact on trading opportunities between markets, distorting the relative competitive positions of individual market participants. Such action by national governments is legitimate and it is not proposed that any action be taken to address this form of distortion. However, it is important to recognise that this form of distortion is likely to exist for the foreseeable future and that other forms of distortion in the energy market should be seen against this background.
- 6.29 Similarly, the establishment of a regional market in electricity which does not correspond with a regional market for gas has the potential to create distortions or affect the operation of that regional electricity market in those markets where gas is a significant fuel source for power generation and could distort the signals for the location of new generation plant.
- 6.30 Such external distortions are likely to persist. Against this background the commencement of the practical delivery of the regional market concept is more important than focusing on developing the 'ideal' regional market design. Such a view is also borne out by the case studies for all-island in Ireland and the Nordic market.

Chapter 7 - Recommendations for next steps

- 7.1 The development of regional markets as an interim step towards the establishment of a single European energy market is, in the view of CEER, a sensible and achievable objective. The evidence of the case studies and the analysis of network and market interactions in this paper support this view.
- 7.2 The discussion within this paper highlights the types of detailed issues that are likely to arise in considering a regional electricity market. How those issues will need to be addressed for a particular regional market, including fundamental questions of market design, is likely to be dependent on a number of technical, political, geographical, economic and regulatory factors which may be specific to that collection of national markets. As such it is unlikely that there is one single design solution for creating regional electricity markets. However it is possible to identify the key obstacles to the establishment and operation of a regional market and so provide a checklist for further consideration of regional electricity markets in specific instances.
- 7.3 It is proposed that in taking forward work on the creation of a “Road Map” the following actions are given priority.
- 7.4 As a first step an assessment of the issues to be addressed to establish regional electricity markets should be undertaken. These assessments should be undertaken on a regional basis as the obstacles existing within a particular region are likely to vary depending on the national markets existing within that region. The case studies undertaken by these regional groups should give consideration to the practical issues that would arise in developing a regional market on the ground in that area, drawing upon the issues highlighted in this paper which is intended to provide a checklist to be applied in each instance.
- 7.5 Initially further case studies of potential regional markets should be undertaken by regulators in co-operation with TSOs and governments focused on the 7 mini-fora areas.
- 7.6 Further case studies should be developed in other areas of the EU where the countries concerned are willing to participate.
- 7.7 Those member states where regional market initiatives are already underway should apply the checklist of issues identified in this paper in their current regional initiative in order to identify any areas of potential improvement, and also to offer further insights from their own experience for the benefit of others.
- 7.8 In addition, CEER proposes to give its consideration to the governance arrangements that should apply to the development of these case studies, noting that issues may arise as a result of the numerous parties who should be involved in such case study development within a region, for example: member state governments, regulatory authorities, TSOs, market operators, market participants.

Chapter 8 - Invitation for Interested Parties to Comment

8.1 ERGEG would welcome comments from any interested parties on all aspects of this ERGEG Discussion Paper. In particular comments on the following elements of the paper would be welcome:

- the key market design features that may need to be addressed in creating a regional market (including any additional features not discussed within this paper)
- the possible need for an overarching regional framework through which interaction across a regional market would be organised and regulated
- the role of regulators and governments in delivering regional electricity markets
- the proposed process for taking forward work on the creation of regional markets, in particular:
 - the use of practical case studies through which the detailed issues for delivery of particular regional markets can be assessed, noting that the issues faced may vary depending on the national markets included within a region
 - the use of the existing mini-fora regions as a basis for these case studies (with other 'regional groupings' being taken forward where countries agree) and the proposed involvement of member state governments, the Commission, regulators, TSOs, market operators and market participants in taking this work forward

8.2 Any comments should be received by **31 August 2005** and should be sent to:

Mrs. Una Shortall
Email: una.shortall@ceer-eu.org
Fax: +32 2788 73 50
Telephone: +32 2 788 73 30

8.3 Unless marked confidential, all responses will be published by placing them on the ERGEG website (<http://www.ergeg.org>). Any questions on this document should, in the first instance, be directed to Mrs. Una Shortall.

8.4 Following consultation ERGEG intend to publish its conclusions on the key matters that need to be addressed in the creation of regional electricity markets and the process for taking further work forward in this area.

Annex 1 – Case study – wholesale electricity markets (Australia)

Introduction

This case study focus on the integration of the previously separate electricity markets in Queensland, New South Wales, South Australia, Victoria and the Australian Capital Territory, which has been operating as a single market from 1998.

Background

Prior to the introduction of the integrated arrangements, the electricity markets in all five states could be considered to be quite mature. The competition reform of the 1990s transformed Australia's electricity and gas sectors. They included the separation of the previously vertically integrated supply chain, introduced competition between generators and retailers, brought the network element under access and price regulation, and saw the creation of a National Electricity Market (NEM).

The NEM is a wholesale market for the supply and purchase of electricity. It allows access to the transmission and distribution networks across New South Wales, South Australia, Victoria, Queensland and the Australian Capital Territory. Tasmania is due to join the NEM in 2005 with a physical connection to the Australian mainland via a 300MW interconnector known as Basslink. The remaining Australian states of Western Australia and the Northern Territory are unlikely to join the NEM because of the extremely long distances involved. The NEM operates on the world's longest interconnected power system – a distance more than 4000 kilometres. Up to \$7 billion of electricity is traded annually in the NEM to meet the demand of the almost eight million end-use consumers.

Since the commencement of the NEM, electricity consumers have progressively gained the right to choose their own suppliers. By May 2004 more than 700,000 contestable customers from a possible 5,5 million had changed their retailer, and the rate of change is steadily growing.

The objectives of the NEM are that:

- The market should be competitive
- Customers should be able to choose which supplier they will trade with
- Provide open access to transmission and distribution networks
- No favouring of existing markets participants over potential market participants
- No favouring of one fuel type or technology over any other fuel type or technology
- No favouring of intrastate over interstate trading

Regulatory and monitoring arrangements

One of the distinctive features of the Australian regulatory model is that the Australian Competition and Consumer Commission (ACCC) are both the national electricity regulator and the competition authority. ACCC monitors market behaviour and may authorise

changes in the National Electricity Code (NEC). ACCC sets a regulatory test to determine whether a proposed network investment project can be classified as a regulated asset⁷.

The primary responsibility for market monitoring and surveillance lies with the National Electricity Code Administrator, which is also responsible for administration of NEC⁸ provisions. The NECA prepare weekly market analyses and quarterly statistical digest that monitor the performance of market. These reports include:

- Monitoring and responding to potential Code breaches through continuous and targeted monitoring of market participants and systems
- Investigations (market events and practices, allegation made by other parties)

The quarterly statistical digest brings together key information about the performance of the national electricity market, which includes: market trends, variation between forecast and actual prices, rebidding, reserve, and ancillary services.

The National Electricity Market Management Company Limited (NEMMCO) was established to administer and manage the NEM to develop and continually improve its efficiency. The NEMMCO is responsible for the day-to-day operation and administration of both the power system and electricity wholesale spot market in the NEM. It has also a role in the monitoring process by being required to conduct reviews of significant operating incidents to assess the adequacy and response of facilities or services. The NEMMCO has to provide data to the NECA, which includes:

- Re-bidding activity and reasons
- Dispatch compliance
- Routine report and data requirements

Legislative aspects of NEM:

- All transmission service providers, distribution service providers and must register with the NEMMCO and abide by the National Electricity Code regarding open access to their networks.
- Generation companies must register with the NEMMCO.
- The NEMMCO is the only operator of the wholesale electricity market.
- Electricity suppliers may only purchase electricity from the NEMMCO

At the outset of the NEM there were a number of independent power producers with power purchase agreements in place. These contracts run for up to 20 years and they were carried forward into the NEM. An agent manages these contracts within the rules of NEM and bids the contracts into the wholesale market.

⁷ Regulated interconnectors – interconnector that has passed the ACCC-devised regulatory test. It receives a fixed annual revenue based on the value of the asset and set by the ACCC regardless of actual usage. At present regulated interconnectors exist between all adjacent regions.

Unregulated interconnectors – not required undergoing regulatory test evaluation. These assets derive revenue by trading in the spot market. At present, an unregulated interconnector operates between the Queensland and NSW region.

⁸ National Electricity Code (NEC) – sets out the market rules, which apply to market operations, power system security, network connection and access, and pricing for network services

Trading arrangements

The NEMMCO is responsible for operating this wholesale spot market and continually balancing electricity supply and demand. Generators submit dispatch bids every day, with each bid offer consisting of up to 10 different price bands. The NEMMCO prepare network constraints values and identify any Ancillary Services requirements before preparing to dispatch generators. Generation in each zone is referenced to a single point (the largest demand point) and all generators in this zone are paid for the electricity notionally generated at this node. The spot market price varies from zone to zone. The five interconnected electrical regions that comprise the NEM basically follow state boundaries.

A spot market price is calculated every five minutes and the clearing/settlement price to match demand is set every half hour (an average of each five minute period) by the average marginal generator. Generators and suppliers are allowed to hedge the spot price. Prices have lower and upper ceilings of negative \$1000/MWh to \$10,000MWh respectively.

Ancillary service requirements are incorporated into market schedules. The energy settlement process does not take into account constraints on/off and generating units are paid for their energy at the appropriate market price. The NEMMCO has an obligation to compensate a participant where the despatch leads to the demonstrable loss of market opportunity.

The Australian NEM is one of the few markets that follows a data release policy of full disclosure the next trading day of all bids, schedules and output levels.

Reasons for integration

Reasons for integration of the electricity supply utilities in Australian jurisdictions (see above) are as follows:

- prior to 1990 all states had single vertically integrated electricity supply utilities,
- there was no pooling between states,
- interconnection was only used as a means of extra capacity during times of high demand.

Means of delivery and scope of reforms

The processes that lead to the NEM were set underway in 1990 when the Australian federal government commissioned a report titled “Energy Distribution and Generation”. In 1991 the report, which was written by the Australian Industry Commission, recommended total dis-aggregation of the electricity supply utilities. Following the Industry Commission report, the National Grid Management Council (NGMC) was set-up to “encourage and coordinate the most efficient, economic and environmentally sound development of the electricity industry in eastern and southern Australia having regard for key national and State policy objectives”, and advise the federal and state governments on what was later to become the NEM.

The Australian Heads of Government established the Council of Australian Governments (COAG) in 1992. COAG was intended to act as an intergovernmental body through which reforms of national significance could be pursued. The role of COAG was to initiate, develop and monitor the implementation of policy reforms that were of national significance and required the cooperative action of Australian governments.

In 1994, the COAG agreed to develop a Code of Conduct for the operation of the National Grid, where the National Grid was defined as “the sum of all connected transmission systems and distribution systems within the participating jurisdictions”.⁹ The participating jurisdictions were Queensland, NSW, SA, and the Australian Capital Territory.

In 1996, the participating jurisdictions agreed to pass the National Electricity Market Legislation. This provided the legal basis for the restructured industry, including the National Electricity Code and the key institution. The NGMC released the NEM Code of Conduct in February. It has since evolved into the National Electricity Code (NEC), which is now maintained by the National Electricity Code Administrator (NECA) company owned by the participating jurisdictions that was created by the National Electricity law, which also created the National Electricity Market Management Company (NEMMCO) to operate the NEM.

Prior to restructuring, each jurisdiction owned the electricity supply industry within its borders. As a result, each jurisdiction determined the extent of dis-aggregation and privatisation of its industry. Victoria has proceeded furthest; South Australia has leased its supply industry assets on long-term lease while the electricity supply industries in New South Wales and Queensland remain in government ownership.

Each jurisdiction also decided the extent of the introduction of competition for retail electricity customers.

The rules of the NEM still applied to the system and it was treated as a zone with zero interconnection capacity.

The scope of the reform included:

- To introduce retail competition.
- To ensure that there were no regulatory barriers to the entry of new competitors to electricity generation or supply.
- To prevent any barriers to interstate trade.
- To ensure that there was open access to transmission and distribution networks.

Description of approach to further market merger

COAG established the Ministerial council on Energy (MCE) in June 2001. The MCE has the responsibility for the national energy framework, future strategic directions for the Australian energy market and governance and institutional arrangement for the Australian energy market.

After some years of functioning of the NEM, the COAG decided to evolve study, which will detect the remaining deficiencies in electricity industry restructuring in Australia.

⁹ National Electricity Code Version 1, NECA, as amended 1998-2003, Glossary

The Study (known as the Parer Review) has found that substantial progress on energy market reform has been made and that significant benefits have arisen from that reform. Competitive pressures have seen increased generator efficiency and availability, additional generation investment has occurred that seem market related, there have been new gas fields discovered and utilised, new pipelines have been constructed to transport gas interstate, and there have been substantial improvement in the participation of consumers in the energy market through choice of retailer.

But it also concurred with the Study that substantial policy issues remain to be resolved if the full benefits of market reform are to be realised. The MCE considered that a second phase of market reform is required to capture those benefits.

The deficiencies were:

- energy sector governance arrangements are confused and there is excessive regulation
- insufficient generator competition
- electricity transmission investment and operation is flawed
- financial contracts market is extremely illiquid
- many impediment to the demand side
- NEM was currently disadvantaging some regional areas

Without these deficiencies being addressed, Australia's energy market will not only fall short of reaching its full potential, but risks losing the valuable benefits gained over the past years. Therefore, the MCE prepared reform package for COAG.

The legislative underpinning for this second package market reform was an extension of the legislation that was used to implement the National Energy Market in Australia in 1990. The Australian Energy Market Agreement (30. June 2004) establishes two new statutory bodies.

The Australian Energy Market Commission (AEMC), which has responsibility for rulemaking and market development and the Australian Energy Regulator (AER), which has responsibility for economic regulation, market monitoring and enforcement. Until this new structures is in place, the NECA will continue to administer and enforce the provisions of national Electricity Code (NEC) as it has done since market-start.

The ACCC should continue to approve changes to the Code and set pricing levels for transmission services until the new regulatory arrangements are in place.

The AER will be responsible for the regulation of electricity transmission, and from 2005 will be responsible for gas transmission. From 2006, the AER will also be responsible for electricity and gas distribution and retail regulation (except retail pricing).

A memorandum of Understanding between the ACCC, the AER and the AEMC will guide interaction between the three bodies and their function in the Australian energy industry. Individual state energy regulators are being phased out and their functions are being passed to the three federal energy regulatory bodies.

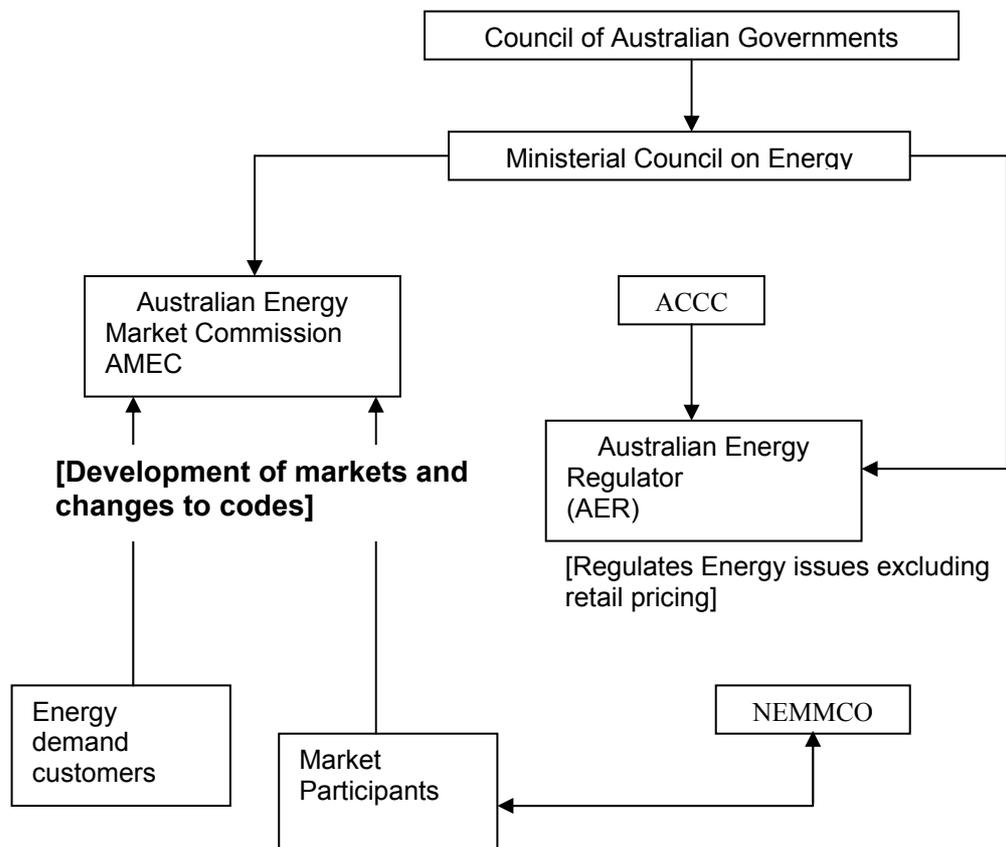
Created under the auspices of the Ministerial Council on Energy, the new regulatory bodies will take over many of the electricity arrangements that are currently the responsibility of state government authorities.

These include:

- Regulating pricing for distribution network access
- Preventing abuse of monopoly power
- Enforcing safety and environmental standards
- Setting distribution and licence conditions
- Regulating retail prices

The MCE also suggested, in its study, to develop new NEM transmission planning function, including an Annual national Transmission Statement, and a last resort power to direct that a project be subjected to the regulatory test. In addition to this it was proposed to develop a new model for assessing wholesale market regional boundaries, while maintaining jurisdictional boundaries for retail customers and improving inter-regional financial trading arrangements, which will be evaluated in conjunction with future arrangements for regional boundaries.

Jurisdictions are sharing responsibilities for further developing and implementing of reform initiatives. Legislation establishing the AER was passed through the Australian Parliament in June 2004. Legislation to establish the AEMC was passed through the SA Parliament in June 2004 but has yet to be applied in other jurisdictions.



Lessons learned

Regulatory arrangement cannot be seen in isolation from general governance questions. The operation and effectiveness of market regulators is as central to the question of governance as the operation and effectiveness of bodies such as the NEMMCO and the NECA.

Experience from the case study, is that in order for any reform project to be credible it is necessary for those affected by it to be assured that both the political will and the appropriate powers are available. In case of Australia, the driving force behind the establishment of a wholesale electricity market was the federal Australian government. The federal government had the power to create the necessary institutions (such as the Ministerial Council for Energy) to carry out the development of a new market.

The creation of a new market was aided by the fact that the trade unions did not oppose the dis-aggregation of vertically integrated utilities.

Experience of the case study is that it is important to have a central independent body with decision making powers in order to solve disputes, make daily decisions, improve accountability and remove the duplication of regulatory process.

In the case of Australia it was suggested to maintain the jurisdictional boundaries for retail customer pricing. However, a new and more transparent process is required to enable assessment of regional boundary changes for the wholesale market to facilitate investments and more efficient operation for the NEM.

The complexity and workload associated with any reform should not be underestimated. Despite the fact that the case of Australia relied very essentially on the pre-existing arrangements for wholesale trading, transmission access etc. (which already took one decade of electricity restructuring in Australia). The implementation of a fully integrated set of market arrangements is still work in progress that may require another decade to complete. The end-point of the reform is to contain a mix of competitive and cooperative decision-making frameworks that are more refined than the current national Electricity Market design.

Annex 2 – Case study – wholesale electricity markets (Great Britain)

Introduction

The Regional Energy Market Task Force's anticipated 'Road Map' paper is intended to include a number of case studies, where each study looks at an initiative to integrate two or more national markets into a 'Regional' market. The purpose of this is to try to draw lessons for general integration questions from real life initiatives.

This case study looks at the integration of the separate electricity markets in Scotland and in England and Wales (E&W) which have operated as a single market from 1st April 2005.

Background

Brief overview of arrangements prior to integration

This section provides a brief overview of the arrangements in place in each of the separate markets prior to integration.

Prior to the introduction of the integrated arrangements, the electricity markets in both E&W and Scotland could be considered to be a relatively mature and, particularly in the case of E&W, reasonably competitive markets. Market based arrangements for wholesale competition in both E&W and Scotland was introduced into both of the markets in 1989/90. Ofgem (previously Offer) is the organisation responsible for regulation of both the separate markets in E&W and in Scotland.

The main features of the arrangements in E&W were:

- Full retail competition
- Substantial new investment in generation, principally gas, and more latterly a "dash for wind" (driven principally by governmental financial support for such schemes)
- Reasonably mature wholesale electricity market, initially a single wholesale pool, more latterly an imbalance clearing mechanism.
- Substantial activity in corporate restructuring over time (vertical and horizontal take-overs and mergers etc.)
- Fully independent transmission sector, transmission system operation and ownership within a single company.
- Distribution ring-fenced from G and S.
- Activities of generation, transmission, distribution and supply regulated by an independent regulator through the use of a licensing scheme

The main features of the arrangements in Scotland were:

- Full retail competition
- Very limited new investment in new generation, although more latterly there has been a "dash for wind" (again driven principally by governmental financial support for such schemes).
- Wholesale electricity market characterised as contracts market with top-up and spill being provided by two dominant incumbent generating companies.
- Limited corporate restructuring

- Transmission ring-fenced from G and S, but nevertheless owned and operated by two dominant market participants.
- Activities of generation, transmission, distribution and supply regulated by an independent regulator through the use of a licensing scheme.

Reasons for integration

The reasons for the integration of the electricity markets in England and Wales and in Scotland included:

- A desire to have more competitive wholesale market arrangements in place in Scotland and to deal with issues raised by arrangements for access and use of transmission networks being the responsibility of persons who have market related affiliations
- Providing a level playing field for all participants and ultimately a better deal for consumers with a single set of market arrangements, a single set of transmission arrangements (with a single GB transmission system) and a single system operator free of market related affiliations
- A recognition that in order to accommodate substantial new investment in wind generation in Scotland, it would be necessary for the relatively small market in Scotland to be merged with the E&W market.
- A desire by the GB Government to ensure the roll-out of deregulation in GB in order that they may more legitimately push for further deregulation elsewhere in Europe.

Means of delivery and scope of reforms

The impetus for the delivery of the integrated arrangements came from central government and from Ofgem (the regulator for both of the two separate markets that were being merged). The government brought forward the requisite legislative change needed to implement the reforms whilst Ofgem (working with the industry, most notably the three transmission companies) developed the required changes to licences, contracts and industry structure needed to deliver the integration. Over time, the responsibility for delivery of change moved from Ofgem to the transmission licensees as the project progressed, moving from delivery of changes to licences and contracts to the delivery of more detailed practical operational changes.

It is noted that because the separate market arrangements in E&W and Scotland are subject to the jurisdiction of the same governmental body (the GB Parliament) and the same regulatory authority (Ofgem), no inter-governmental or inter-regulatory agreements were needed to deliver the BETTA reforms.

The scope of the reforms included:

- Extending (with some changes) the prior arrangements for wholesale energy trading in E&W to apply to the integrated GB market
- Extending (with some changes) the prior arrangements for transmission access and transmission charging in E&W to apply to the integrated GB market

- Appointing a single independent system operator free from market related affiliations for the entire GB transmission system responsible for key 'market facing' activities (such as being responsible for operation, contractual access, outage planning with investment planning being co-ordinated with the separate transmission owners)
- Creating a single GB transmission system in place of three separate transmission systems
- Developing a new regulatory and contractual relationship between the single system operator and those owning the transmission system.

In terms of market design consideration was given to making the existing trading and transmission arrangements in GB compatible rather than creating a single GB transmission system and a GB wholesale market but ultimately the decision was taken that a single set of arrangements would be more appropriate in this instance.

Summary of changes

The following table summarises certain elements of the arrangements prior to and subsequent to integration.

Attribute	E&W arrangement prior to integration	Scottish arrangement prior to integration	GB integrated arrangement
Approx Market size (2004/05)	Installed capacity 65GW Transmission peak demand 56GW Units supplied 320TWh	Installed capacity 10GW Transmission peak demand 6GW Units supplied 50TWh	Installed capacity 75GW Transmission peak demand 62GW Units supplied 370TWh]
Bulk electricity trading model	Bilateral contracts markets, power exchanges	Bilateral contracts	Bilateral contracts markets, power exchanges
Pooling arrangements	Residual imbalance pool with ex-ante bilateral contract notification	Top-up and spill for non-host parties provided by 2 host Generation business in each of 2 Scottish sub-regions. Regulated top-up and spill pricing Ex-post bilateral contract notification	Residual imbalance pool with ex-ante bilateral contract notification
Power Exchange (if any)	Reasonably liquid bilateral contracts markets and power exchanges	Bilateral contracts market	Expectation is that it will be as per E&W prior to integration.

Attribute	E&W arrangement prior to integration	Scottish arrangement prior to integration	GB integrated arrangement
Transmission Charging	Very shallow asset based connection charge and Infrastructure charged on zonal basis reflecting marginal cost of new transmission investment required for each zone.	Northern Scotland: Connection charges and Postage stamp infrastructure charges for G and S (with additional G charges applying to new generators) Southern Scotland: Connection charges and postage stamp infrastructure charges.	Very shallow asset based connection charge Infrastructure charged on zonal basis reflecting marginal cost of new transmission investment required for each zone.
Interconnection Capacity	2GW DC to France, 2.2GW AC to Scotland	2.2 GW to E&W, 500MW DC to Northern Ireland	2GW DC to France, 500MW DC to Northern Ireland
Generation and Supply market structure	Reasonably diverse mix of market participants who tend to be vertically integrated from a generation/supply perspective. Principal market participants include Innogy (RWE), Powergen(E.ON), British Energy, British Gas, Scottish Power, EdeF, Scottish and Southern	Two dominant market participants, Scottish Power and Scottish and Southern, although British Energy and British Gas also participate to a reasonably degree.	Mix of two local positions
Fuel mix (2004/05 based on installed capacity)	Principally CCGT (35%), coal (33%), nuclear (15%), other - oil, pumped storage, OCGT, interconnector - (18%).	Principally coal (32%) and nuclear (25%) with gas (17%), hydro (14%) and other - wind, pumped storage OCGT, etc (11%). Onshore and offshore wind generation sector growing.	Gas (33%), Coal (33%), Nuclear (16%), other (18%).
Transmission	Fully independent, private	2 separate private transmission	Single fully independent system operator which

Attribute	E&W arrangement prior to integration	Scottish arrangement prior to integration	GB integrated arrangement
sector structure	transmission company which both owns and operates the E&W transmission system (NGC)	companies which both own and operate their respective transmission systems (SP Transmission Limited, and SHETL). These are owned by ring-fenced companies which are part of a larger corporate group which also owns generation and supply.	<p>also owns the E&W transmission system (NGC).</p> <p>The Scottish transmission companies will continue to own their own transmission systems.</p> <p>SO responsible for contracting with users for connection to and use of the transmission system, transmission despatch, system operation (G and D despatch), outage planning, reserve, response, reactive contracting and despatch.</p> <p>TOs responsible for maintenance, construction and for investment planning (including being required to co-ordinate investment planning with other TOs and the SO).</p>
Licensing arrangements	Separately licensed Generation, Supply, Distribution and Transmission	Separately licensed Generation, Supply, Distribution and Transmission	Separately licensed Generation, Supply, Distribution and Transmission. Transmission licences split into conditions applying to system operation and to transmission ownership.

Attribute	E&W arrangement prior to integration	Scottish arrangement prior to integration	GB integrated arrangement
General comments	Reasonably mature and competitive wholesale and retail market. Generally moving towards treating electricity as a commodity. Relatively recent dash for Gas and more recently for wind (both on and offshore) – this (taken with the additional wind connecting in Scotland) has triggered the need for new transmission infrastructure.	Whilst there is some development of competition, the local vertically integrated companies remain strong and the top-up and spill and administered pricing arrangements are not considered ideal. Recently substantial wind power growth (actual and potential) triggering the need for substantial new transmission infrastructure.	It is intended that the benefits of a competitive market in E&W will be brought to bear across the whole of GB with the implementation of the integrated market. Some constraints on the interconnecting circuits between Scotland and England and Wales may exist,

Discussion

Description of approach to (further) market merger

The legislative underpinning for the merged market is an extension of the legislation that was used to implement, and subsequently reform the deregulated arrangements in the first place. The legislative arrangements provide for the licensing of the various market activities (generation, transmission, distribution, supply). The detailed market arrangements are implemented through the imposition of licence conditions (for example requiring licensees to comply with and/or contractually accede to certain industry documents – see table above). This provides both a regulatory and contractual framework for the arrangements.

Whilst provisions typically exist within the framework for changes to be made to the market arrangements, very substantial change (for example the replacement of the compulsory wholesale pool originally introduced in E&W, or the merger of the two markets) is generally considered to require primary legislative change in order to ensure implementation in an appropriate timescale and to deal with matters such as changes in property rights etc. In the case of the merged market which is the subject of this case study, the principal power delivered through revised legislation was the ability to change licence conditions for G, S, T and D for the purposes of implementing the merged market arrangements without the need to follow the normal change processes (and bypassing the normal appeal routes). The legislation also delivered a revised framework for licensing transmission in light of the decision to have a single separate system operator and to permit this activity to be carried out separately from transmission ownership (without this amendment to the licensing structure it would not have been possible to have more than one transmission licensee carrying out transmission tasks in a given geographical area).

Whilst the merging of the market arrangements was a substantial task, not least given the required restructuring of the transmission sector, given the fact that the UK Parliament had jurisdiction over both of the market areas being merged and given the fact that a single regulatory body existed for both markets, it was not necessary to address some of the issues that would emerge had this not been the case. Furthermore, the trading rules and transmission access rules used for the BETTA arrangements were very substantially based upon those previously existing in the E&W market, which were used as the basis for consultation on the new arrangements which would apply across GB.

The reforms have had the full support of the electricity regulator (Ofgem) who developed the necessary changes to licences and contracts required to underpin the new arrangements. Generally, the introduction of BETTA had the support of the industry, although some opposition was experienced, although such opposition was generally targeted at specifics of the detailed proposals rather than the overall idea itself.

Given the nature of the merger, much of the work involved has been the establishment of a single system operator and the definition and contractualisation of the boundary of responsibility between the system operator and the transmission owners. As this is the case, much of the detailed implementation work has fallen to the three incumbent transmission companies (one of which was appointed as system operator). The views of the transmission companies towards the integration of the markets has been mixed. Along

the road to implementation it will inevitably be necessary to face reluctance at some levels and on some issues from key parties involved. Two of the transmission licensees are giving up their system operation role to the third which has inevitably caused some tension as has the fact that two of the transmission licensees contain within their corporate group significant market interests. Some reluctance has also been experienced from all parties (at times) in terms of the large efforts involved in delivery and what may be seen as little tangible benefits being represented by the reforms for the transmission sector participants.

Scope of market activities being integrated

The scope of the market activities that are being integrated are:

- Compulsory imbalance settlement mechanism (and consequently the wholesale market)
- Balancing arrangements
- System operation
- Transmission investment planning
- Certain elements related to the treatment of interconnectors
- Regulatory oversight

These matters are discussed in turn below.

Compulsory imbalance settlement mechanism

The integrated market arrangements require generators and suppliers to comply with a compulsory set of rules for the settlement of half-hourly imbalances between the physical (metered) quantities of production and consumption and the contracted quantities of energy bought and sold by the parties. In determining the imbalance quantities, physical production and consumption may be aggregated from anywhere in the newly integrated market place. These aggregated quantities are compared to the contract purchases and sales which must be notified on an *ex-ante* basis.

Whilst no central provision is made for how the bilateral energy market should operate, the industry itself has established standardised bilateral products for trading energy, and a number of exchanges have developed. These developed in the E&W market which is essentially being extended to cover the integrated GB region (and consequently the reforms that are the subject of this case study were not concerned in any great detail with the development of such arrangements). It was expected that given that under the integrated arrangements, physical production and consumption across the entire region would be used to determine imbalance quantities, the associated wholesale energy markets would simply move to trading at the new notional balancing point of the expanded region – i.e. the implementation of regional imbalance rules would drive the change to the trading of regional wholesale energy products in bilateral contracts and on power exchanges.

Balancing arrangements

The new single system operator is to be responsible for second to second matching of generation and demand and for frequency/voltage control, constraint management etc.

Under the regional market arrangements, generation and demand are permitted to “self-despatch” to meet their contractual position (although deliberately taking a long or short position is not prohibited). A central “balancing mechanism” exists which is used by the system operator to change the notified self-despatched levels of generation or demand in order to meet system needs. This mechanism is supplemented by a variety of bilateral contracts between the system operator and users for services such as frequency response, reactive power production/absorption, reserve, black start etc.

Under the integrated basis, the single system operator is responsible for procurement and call-off of such services on a regional basis.

System operation

The scope of the responsibilities of the single regional system operator include:

- Meeting operational standards
- Generation and demand despatch in real time (i.e. calling off balancing services)
- Transmission despatch (transmission owners actually carry out switching under the direction of the system operator)
- Transmission outage planning
- Co-ordination of transmission investment planning (in conjunction with the transmission owners)
- Contracting for connection to/use of the regional transmission system – i.e. providing and charging for transmission access

The introduction of the regional market required all these activities to be changed to be carried out on a regional basis. This required substantial change to the licensing and contractual arrangements applying to the transmission sector. It also required a process to appoint the new regional system operator.

In 2002 the DTI undertook a process to select a party to act as the GB system operator under BETTA. One of the criteria that applied during that selection process was that, other than for balancing services under BETTA, the party should not itself, nor should it have affiliates who will be undertaking the activity of generation or supply in GB, or be trading GB electricity, or be carrying out any other relevant activity which might conflict with that party being able to carry out the activities of the GB system operator in an independent and non-discriminatory manner. Such independence being considered important in ensuring the presence of a level playing field for all market participants.

Transmission investment planning

Under the regional arrangements, the local transmission owners are responsible for meeting planning standards on their own transmission systems. However, transmission investment planning is carried out on a regional basis under the integrated market. This has led to the need to upgrade the circuits connecting the previously separate market places which were previously treated as interconnectors and across which physical power flows were limited through separate contractual arrangements.

Hence, under the regional arrangements, transmission investment planning is carried out regionally, but implemented locally. There are statutory, regulatory and contractual

obligations on the relevant transmission companies to co-operate to ensure that the appropriate regional solution is reached.

Treatment of interconnectors

Under the market arrangements being introduced, interconnectors are treated just like generation or demand at the point of connection to the regional transmission system. In some ways therefore, the reforms standardise the treatment of interconnectors.

However, the arrangements do not prescribe (nor do they require standardisation of) the arrangements that are in place for use of the interconnector circuits themselves – i.e. they simply standardise the treatment of the interface between each interconnector and the regional market.

Regulatory oversight

As has been identified above, the separate markets which have been harmonised were previously regulated by the same regulator. Hence, no merging of different regulatory bodies has been required. However, implicitly the single regulator will now take a single view of the new regional market – separate regulatory departments for the separate markets are no longer needed, and consequently this element of harmonisation has taken place implicitly within the organisational structure of the regulatory body.

Lessons learned

Given that the merging of two markets will inevitably mean that there are winners and losers, it is suggested that both Government and the regulatory authorities concerned have a strong commitment to the delivery of the reforms.

Furthermore, experience from the case in study is that in order for any reform project to be credible, it is necessary for those affected by it to be assured that both the political will and appropriate powers are available to deliver the reforms. It is highly likely that any differences of opinion between governmental and/or regulatory bodies will be exploited by industry participants in order to optimise their position in the market place.

It is therefore suggested that a relatively united, committed and empowered approach is needed to any merger from the governmental and regulatory bodies associated with the change.

Experience on the case in study is that it is also important for the regulatory bodies to have a strong input into the design phase of the arrangements. Whilst such a role could be carried out by Government, the matters to be dealt with are likely to be of a more specialised and/or detailed nature and consequently are probably best dealt with by the regulatory body. However, the principal point is that it is necessary to have a central independent body with decision making powers in order to (i) resolve disputes, (ii) make day-to-day decisions on matters that may not be vital, but nevertheless need to be resolved in a timely manner and (iii) to ensure that the design is progressed in the interests of the market, not in the interests of market participants.

Depending upon the nature and scope of the changes, it is also considered essential that a reasonable degree of co-operation is received from those principally affected.

Insofar as what pre-requisites there are in order to be able to make the necessary reforms (e.g. physical infrastructure, degree of pro-competitive structures etc.), is concerned, it is suggested that these really depend upon the nature of the reforms being undertaken. It is suggested however that it is important to have a very good understanding of the purpose of the reforms so that when deciding what needs to be done to implement them, a balanced view of the practicalities and requirements can be made. For example, under the case in study, it was decided that in order to expedite implementation, initially at least, the transmission owners could continue to physically switch their transmission systems under direction from the system operator, rather than for example requiring a substantial transfer of property from them to the system operator, or the need for substantial building of new control facilities which direct switching by the system operator would require. Whilst practically this brought substantial benefits, this was at the cost of additional legal complexities and at the expense of making certain market information available to transmission owners that they would not otherwise been given access to under BETTA given their generation and supply affiliations . The underlying purposes of the reforms must be well understood in order that these balanced judgements can be taken.

It is also considered essential that the regulator(s) or appropriate independent body retain control for the development of the high-level legal framework associated with the reforms. Again, this is principally to ensure that this is not inappropriately influenced by those with vested interests and so that an appropriate framework for timely decisions exists.

The complexity and workload associated with any reform should not be underestimated. Despite the fact that the case in study relied very substantially on the pre-existing arrangements for wholesale energy trading, imbalance settlement, licensing, transmission access etc. and despite the fact that the project took place in a region with a single legislative authority, law, language and regulator, the implementation of a fully integrated set of market arrangements was a substantial project, taking over 3 years to implement.

Annex 3 – Case study – wholesale electricity markets (Ireland and Northern Ireland)

INTRODUCTION

This document outlines how the present markets in Ireland and Northern Ireland operate. It also describes in as much detail as is presently available the new proposed single market, which shall apply in both jurisdictions and how it shall be implemented. At this point in time it should be noted that many of the detailed issues relating to legislative frameworks and governance of the market have not been fully developed or agreed. Nonetheless the paper attempts to shed some light on what the likely future constructs will be.

From Cooperation to proactive development

Over the past decade there has been a significant increase in commercial and regulatory activity between the markets of Ireland and Northern Ireland. In 1996 the North-South interconnector was established, allowing flows of electricity between both parts of the island. In the initial four-year period electricity flows between the two markets were limited to those arranged by the two transmission system operators for system stability reasons or to provide some marginal trading in response to emergencies or rescue flows.

Since the establishment of a liberalised market in Ireland on 19 February 2000 significant growth in trade has been achieved. Last year 1.4 terawatt-hours (TWh) flowed across the interconnector, this year the figure is expected to be 1.65 TWh. In 2005/6 it is expected to be 2.63 TWh. This will mean that approximately 10% of all the electricity consumed in Ireland will have been imported from or through Northern Ireland.

The amount of electricity that flows across the border is now at the maximum allowed by the physical limits of the system that carries it. Thanks to a trading mechanism known as super-position, the amount traded across the border exceeds the amount carried. This in effect allows market participants to match imports and exports to ensure that both trades are permitted. Customers in both jurisdictions now enjoy electricity at lower costs than they otherwise would and other benefits that accrue include lower reserve costs.

The Commission for Energy Regulation (CER) in Ireland and the Northern Ireland Authority for Energy Regulation (NIAER) in Northern Ireland have worked in close cooperation since 19 February 2000 to foster and develop greater cross border trade in electricity upon the island. The main focus of their attentions in recent years has included initiating auctions for interconnector capacity and undertaking studies on the practicalities of integrating the electricity and gas markets on the island.

On June 21st 2004 the Department of Communications, Marine and Natural Resources ('DCMNR') in Ireland and the Department of Enterprise, Trade and Investment ('DETI') in Northern Ireland published a draft consultation on an all-island energy market framework.¹⁰ Following consultation with industry and discussions with the Regulatory Authorities, the final document was published on 23 November 2004. This document

¹⁰ All-Island Energy Market Development Framework Draft for Consultation, 21 June 2004 (See www.dcmnr.gov.ie or www.detini.gov.uk)

states that while it is recognised that a cross border energy market already exists in an embryonic form, there is a need to ensure that *'policy developments in both jurisdictions are progressed in ways which advance the goal of improved economic and energy supply benefits for both parts of the island'*. This document defines an all-island market as follows:

An all-island energy market should provide for competitive, sustainable and reliable markets in electricity and natural gas on the island of Ireland at the minimum cost necessary. It should operate in the context of the EU internal energy market and should deliver long-term economic and social benefits that are mutually advantageous to Northern Ireland and Ireland. Customers, irrespective of where they live, should be free to source their energy needs from suppliers and service providers anywhere on the island and generators will be able to participate freely regardless of the jurisdiction.

In parallel with the development of the framework document, the Regulatory Authorities agreed and issued a Memorandum of Understanding ('MoU') in August 2004 in relation to the development of an all-island electricity market.

The Regulatory Authorities view the development and implementation of the Single Electricity Market (SEM) as the critical element of a successful all-island energy market and have identified a number of other issues that must be addressed in tandem with the new all-island electricity trading arrangements in order to facilitate delivery of the full potential benefits of such arrangements to customers on the island. This is reflected in the All-Island Energy Market Development Framework document, which identifies the development of common trading arrangements and certain other areas of work for progression as a priority as follows:

- Infrastructure
- Trading arrangements & investment
- Dominance & market power
- Sustainable development
- Legislative & administrative and
- Retail market design

It is planned to have the SEM established by July 2007 and the initial steps in developing a single market have already been undertaken. The approach to developing a single market is to design a totally new market, which will apply throughout the island. The Regulatory Authorities have published a draft decision on the proposed design on 31 March 2005 with a view to finalising the high-level market design by the end of June 2005. This should see the commencement of the detailed design and implementation later this year.

The outcome of this process undertaken by the regulatory authorities to date has resulted in the following high-level preferred design features of the future all-island wholesale market.

- The SEM shall be a mandatory gross pool which shall have a single pricing structure in the island.

- The price shall be set ex post based on an unconstrained simple single stack price optimised over 24 hours.
- The market operator will take account of the locational benefits or otherwise of generators by adjusting production volumes by locational loss factors.
- Generators will interact with the market operator by submitting detailed offer schedules and will thereby be centrally committed.
- The market shall be a day ahead gate closure and there is likely to be an administered price cap.
- There shall be dynamic use of the North-South interconnector(s), i.e. the interconnectors shall be treated as an integral part of the transmission system.
- The trading and dispatch period shall be half an hour in duration. Market data shall be published *ex post*, with the exception of indicative dispatch and price schedules which shall be published *ex-ante*.
- There shall be a single market operator and two system operators, one in each jurisdiction.
- Outage planning on the transmission system will to a large degree continue as per current practice, which is by mutual agreement with system operators and generators but with added emphasis on transparency of outage scheduling.

Generators producing electricity from renewable sources shall be accommodate by having priority dispatch. Ancillary services shall be purchased via competitive contracts and operating reserves shall be accommodated through dispatch and Connection policy shall be amended so that the same policy is deployed in each jurisdiction.

INSTITUTIONAL AND STRUCTURAL ISSUES

The following section presents a summary of the market structure and proceeds to discuss some of the institutional issues faced in developing a unified market.

Market Size and structure

The following tables illustrate the size and makeup of the electricity markets in Ireland and Northern Ireland.

Table 1: Summary Information on Market Size

	Republic of Ireland	Northern Ireland	Total: All-island
Population	3.8 million	1.5 million	5.3 million
Electricity Customers	1.8 million	0.7 million	2.5 million
Peak Demand (MW)	4,500 MW	1,630 MW	6,130 MW
Total Annual Consumption (GW)	23,000 GWh	8,200 GWh	31,200 GWh
No. of Generating Plant	21	3	24
Capacity of Power Stations (MW)	5,382 MW	2,060 MW	7,442 MW
Capacity of Wind connected to System (MW)	233 MW	75 MW	308 MW
Total Generation Capacity (MW)	5,615 MW	2,135 MW	7,750 MW

Table 2: Market Structure – Generation

Generator	ROI	NI 2003/04	All island market
ESB	68.7%		50%
Dublin Bay*	7.2%		5%
Viridian	6%		4%
Edenderry Power*	2.2%		2%
Airtricity	2%		1%
Coolkeeragh*		8.12%	2%
Other	13.9%	3.79%	11%
AES*		26.38%	7%

Ballylumford*		41.17%	11%
Moyle		20.54%	6%

NI Notes:

Other: Refers to renewable generation

* Dublin Bay is 70% owned by ESB

* Edenderry Power is independently owned but contracted to ESB Customer Services (ESB retail business)

* Coolkeeragh is owned by ESB

* AES and Ballylumford are independently owned but are contracted to NIE a subsidiary of Viridian

Interconnection

Ireland and Northern Ireland are joined electrically by three transmission lines.

- Louth/Tandragee, 220/275kV with a maximum capacity on 600MVA
- Corraclassy/Enniskellen, 110kV
- Letterkenny/Strabane, 110kV

The main interconnector is the Louth/Tandragee line. The 110kV lines are predominantly used for system security and operational reasons. In the event of the main interconnector failing, the 110kV lines are not in a position to maintain interconnection between jurisdictions. While the nominal capacity of the interconnector is 600MVA, the actual capacity is often less than its nominal rating due to operational constraints on the systems particularly in recent years in Ireland.

Further interconnection is being considered at present and has broad support including government support in both jurisdictions, although no definite date has been set for the construction of a second interconnector as yet.

The Moyle DC Interconnector joins the Scottish electrical grid to Northern Ireland has a capacity to supply 500 MW of power to Northern Ireland. Ireland is presently planning to construct its first electrical interconnector with Wales and the Irish government have already committed to proposals to build two such interconnectors, which are expected to have a capacity of 500MVA each.

Dominance

There is no question that ESB is a large presence in the Irish electricity market. ESB and its related undertakings hold a share of generating capacity that currently exceeds 50% of the total island capacity. This dominant position in the market, particularly in the generation sector, leads to concerns about the ability of any market to function effectively. There is ample evidence that dominant market participants have the potential to undermine the working of electricity markets. The concerns range from the potential for a large participant to raise spot or contract market prices to a high level to the potential to selectively select prices that are sufficiently low as to prevent profitable entry.

Competition laws may act to prevent illegal activity in this regard. However, these laws operate in a manner that might result in judgments at some point after a proven infraction,

but would not be to likely act to restrain future activity. New entrants are hardly likely to take much comfort in competition laws as a measure to restrain a very dominant market participant.

New entrants may see the issue of ESB market dominance as one that places too much risk on a new investment, even if the economic evaluation of an investment were otherwise favourable.

Market power exists in a spot market where bidders have the ability to raise prices or withhold capacity in order to increase profits. In a perfectly competitive market, a bidder would be unsuccessful at increasing its payoff by either of these strategies through the normal functioning of the market - i.e. the lost profit from using the strategy would outweigh the additional profits from higher prices on the remaining production. The most obvious place where market power might be exercised is in a spot market, but the potential for market power exercise is also present in bi-lateral contract markets and in hedge contract markets.

Some of the options to mitigate dominance include (among others): (a) atomistic privatisation, (b) disaggregated government entities, (c) vesting contracts; (d) regulation of existing companies. Additional mitigation through regulation or vesting contracts due to the large size of some ESB stations is likely to be required for options (a) and (b), in addition our current understanding is that either option is not likely to be pursued by the Irish government in the near term.

Note that long-term contracts may present some unique issues, as the NI power procurer may be a holder of significant market power as a result of legacy contracts, which make up almost 15% of the market on the island.

Market Operator & System Operator

For historical and jurisdictional reasons, the Republic of Ireland and Northern Ireland have managed their own electricity power systems and electricity markets, albeit co-operating when appropriate with reserve sharing and trading energy across the interconnector where it is economically advantageous to both parties.

As outlined in the Development Framework published by DCMNR and DETI, there will be a single market operator for the SEM, whilst recognising that in the short to medium term, the operation of the system of each jurisdiction will remain with the existing system operators, EirGrid and SONI, the possibility of a single operator in the future is not ruled out and is, in fact identified as a preferred model for future development.

Connection Policy

A consistent connection policy is something that is needed in the new market. In a market with a single marginal price, there is a concern that generators will locate in areas with low generator construction and operating costs that are far from the locations that need more generating capacity. The overall system will have sufficient capacity, but the transmission system may not be able to accommodate the internal transfers.

One possible approach is to require any generator to obtain regulatory approval prior to connecting, allowing a regulator to apply some locational decisions. Yet another approach

is to deny the rights to “constrained on/off” payments to generators that locate in areas that are not approved.

Presently the policies diverge significantly, where transmission connected generators in the Ireland pay shallow connection charges and are entitled to firm financial access after a finite time where the transmission operator is expected to provide the full deep reinforcements, after which generators are entitled to constrained-off payments. In Northern Ireland generators pay deep connection charges and are not entitled to constrained-off payments.

The regulatory authorities consider that deep connection charges are: Difficult and arbitrary to apply in practice; Discriminatory, notably between existing generators and new entrants; and Not cost-reflective (remote reinforcement can be argued to be of benefit to a great number of users of the transmission system, since it results in a more secure and reliable system).

However, strong locational signals are given whereas a shallow connection policy is: Non-discriminatory

- Cost reflective
- Promotes competition in generation and supply
- Clear and transparent

However, a shallow connection policy provides little or no locational signals, but this can be achieved through locational capacity charges and loss factors. Such an approach is likely to increase the level of transmission system tariffs in the long term.

The regulatory authorities propose to move to a shallow connection policy for the whole island. Given that such a policy provides no locational signal it is proposed to provide locational signals through the use of locational loss factors to be applied to each generators energy production and similarly to apply a locational transmission use of system charge, which will adequately reflect the locational benefit of certain locations.

Governance Structure & legal requirements

The Agreement reached in the Multi-Party Negotiations on Friday 10th April 1998 (the Multi-Party Agreement, better known as the Belfast or Good Friday Agreement) along with the Agreement between the Government of the United Kingdom of Great Britain and Northern Ireland and the Government of Ireland, agreed on the same day (known as the British-Irish Agreement), which constitutes Annex 1 to the Multi-Party Agreement, established a set of institutions, the objective of which was the provision of a lasting constitutional settlement in Northern Ireland.

These Agreements were implemented through domestic legislation in each jurisdiction. In the case of Northern Ireland, this was done by means of the Northern Ireland Act, 1998 and the North/South Co-operation (Implementation Bodies) (Northern Ireland) Order 1999. In the South, this was done by means of the British-Irish Agreement Act, 1999 and the British-Irish Agreement (Amendment) Act, 1999. In addition, the Constitution of Ireland, *Bunreacht na hEireann*, was amended to provide, inter alia, that any institution established by or under the Multi-Party Agreement may exercise the powers and functions conferred on it in respect of all or any part of the island of Ireland.

Within the UK constitutional programme of reform, Stand One of the Agreement concluded the devolution of certain powers from Westminster to the Northern Ireland Assembly and Executive. However, for the purposes of this paper on an all-island energy market and potentially extending this to a regional all-islands energy market, it is confined to highlighting the new institutional context created by Strand Two and Strand Three of the Multi-Party Agreement i.e. the North/South Ministerial Council and the British-Irish Council and British-Irish Intergovernmental Conference.

North/South Ministerial Council

The North South Ministerial Council (NSMC) was formally established on 2nd December 1999 and had its first Plenary Council Meeting on 13th December 1999. Under the Framework Document (1995), which was the precursor to the Multi-Party Agreement, over 40 policy areas, including energy policy and eight implementation bodies were listed as possible areas for co-operation under the remit of the proposed North/ South institutions. During the negotiations on the text of the Framework Agreement, this list was reduced to 12 areas. It was acknowledged during the negotiation process, that although the proposed North/ South body offered the potential for co-operation practically across any sector North and South, no agreement would have been possible at the Multi-Party talks on an explicitly comprehensive or open-ended basis. Thus, on 18th December 1998, the First Minister (Designate) and the Deputy First Minister (Designate) issued a statement, which listed the final six implementation bodies and the six areas for co-operation.

Currently, cross-border cooperation in the energy sector does not fall under the remit of the NSMC.

Despite the suspension of the Northern Ireland Assembly since October 2002, the Irish and British Governments have agreed, by exchange of letters that the North/South Bodies would continue to operate. Both Governments agreed to protect and maintain the achievements of the British-Irish Agreement and the Multi-Party Agreement, and to ensure the continuation of the necessary public functions performed by the Implementation Bodies during the period of temporary suspension of the Assembly.

Both Governments subsequently issued a joint Statement of Clarification on 18th December 2002. This stated that they will only take those decisions necessary to ensure proper care and maintenance of the Bodies in the performance of their necessary public functions (later this was extended to the six areas of co-operation). They also intended only to pursue policies and actions already agreed in the NSMC and not to introduce any new policies. In addition, the new arrangement would cease on the restoration of the Northern Ireland Assembly. The detail of this correspondence is relevant as it clarifies beyond doubt that for the remit of the NSMC to be extended further, the Northern Ireland Assembly needs to be properly functioning.

British-Irish Council and the British-Irish IGC

The establishment of the British-Irish Council (BIC) under Strand Three of the Multi-Party Agreement is relevant to this paper, in terms of considering the creation of an all-islands regional energy market. It is interesting to note that the legal basis of the BIC provides for two or more members to develop bilateral or multilateral arrangements between them. Such arrangements will not require the prior approval of the BIC as a whole and will operate independently of it. In this way, the BIC could emerge as a forum for the

development of new territorial coalitions, with devolved entities seeking to form bilateral alliances with other members of the Council and in particular with the Irish Government.

The purpose of the BIC is to institutionalise the new settlement between the different nations forming the United Kingdom, and between the United Kingdom and the Irish Republic. The legal basis for the East-West dimension rests on bilateral agreements between Ireland and the United Kingdom. It is comprised of Britain and Ireland, the devolved bodies in Northern Ireland, Scotland and Wales, and, when established, and if appropriate, elsewhere in the United Kingdom.. In this regard, the regional organisation is distinguished from most other regional organisations, as it is comprised of a mix of sovereign states, Crown dependencies and areas with varying degrees of devolved power. It is therefore, broadly comparable to the Nordic Council of Ministers, which is comprised of Denmark, Finland, Iceland and Sweden, together with the three autonomous regions.

It has been suggested that Northern Ireland, could in principle, even go into Economic and Monetary Union with the Republic, if Britain itself remained outside, providing there was agreement in the Northern Ireland Assembly and the Secretary of State and the Westminster Parliament assented.

In relation to the creation of an all-island's regional energy market this might facilitate the harmonisation of cross-border regulatory issues, between Wales and the Republic of Ireland, which may arise after the construction of an East-West electricity interconnector, which has been proposed by the Minister for Communications, Marine and Natural Resources in the Republic of Ireland. Although progress in this area would necessarily be limited by the primary legislative powers afforded to Northern Ireland in comparison to the restricted legislative powers devolved to the Welsh Assembly. It is also worth noting, that the British-Irish Intergovernmental Conference, which was also established under Strand Three provides for regular meetings of the Conference, at which the Irish Government may put forward views and proposals on non devolved Northern Ireland matters. Such meetings would also deal with all-island and cross border co-operation on non-devolved issues and would be co-chaired by the Minister for Foreign Affairs and the Secretary of State for Northern Ireland. Here again energy policy could be considered as a possible topic for discussion.

As a consequence of devolution, Northern Ireland is now part of a complex web of legal relations. This new institutional model is deliberately multi-layered. Although the NSMC and the BIC accord a very significant role to governments and are essentially intergovernmental in nature, they also allow for the development of institutional networks on the Irish border and in an all-island context.

Until recently, the creation of an all-island energy market has not gone much beyond the status of a jointly stated objective which falls somewhat short of an explicit policy statement. However in the coming months much work and formative thinking must be done separately by each jurisdiction to meet the stated objectives and deadlines in implementing a single market by June 2007.

There are essentially three administrative/institutional options available for consideration, in terms of designing legal framework for an all-island (and a regional all-islands) energy market.

Firstly, the continuation of the status quo, i.e. intergovernmental co-operation between the Government of Ireland and the Northern Ireland Assembly on energy matters. Such an approach would essentially be driven by political impetus, in a manner, which perhaps offers greater flexibility to both administrations, than otherwise might be the case, in a more formalised institutional setting. However it has already been decided at government level that it is preferable to develop a deeper level of integration than this would permit.

Secondly, the extension of the remit of the NSMC, by agreement, to cover energy policy and/or oversee the creation of an all-island energy market. However, the present political climate is not conducive to further the remit of the NSMC and given the commitment, particularly in terms of time-frame for deeper integration of the energy markets, this could not be considered practical at this time.

Thirdly, in terms of extending co-operation within a regional space, the BIC could potentially offer an institutional space for the administration of a regional energy market, made all the more relevant by agreement to build an East-West electricity interconnector between Ireland and Wales, in the time frame 2007-9. In terms of achieving energy price competitiveness and enhancing the competitiveness of both jurisdictions and their attraction to foreign direct investment, the creation of an all-island energy market is viewed as the correct strategic approach.

Further analysis of these options, in terms of the legal, constitutional and economic issues they raise, is required in order to make a reasoned assessment. This work is presently being undertaken by the relevant government departments in cooperation with the regulatory authorities. Initial legal opinion suggests that an exchange of letters between governments, subsequently supported by legislation in each jurisdiction will be sufficient to implement a single market between the two jurisdictions.

There are some areas of divergence in legislation and governance between the two jurisdictions some of which are listed in Appendix 1.

MARKET ARRANGEMENTS PRIOR TO INTEGRATION

This Section of the paper outlines the current trading arrangements in both markets in Ireland and Northern Ireland.

Transitional Trading Arrangements in Ireland

The existing trading arrangements for electricity were established on foot of a Policy Direction issued by the then Minister for Public Enterprise to the Commission for Energy Regulation ('the Commission') on July 26th, 1999 in accordance with Section 9(1)(a) of the Electricity Regulation Act 1999 ('the ERA'). These transitional arrangements provide for a bilateral contracts market with an imbalance mechanism whereby participants can trade energy and balance out their uncontracted energy needs with ESB Power Generation ('ESBPG'). The rules for trading and settlement under these arrangements are set out in the Trading and Settlement Code.¹¹ ESB National Grid ('ESBNG') currently performs both the market and system operator functions. The System Settlement Administrator ('SSA'), a unit within ESBNG, performs the market operation and settlement function.

Dispatch, Constraints and Pricing

Under this regime generators nominate to the Transmission System Operator ('TSO') the schedule of energy they wish to produce for trade a day ahead of real time operation. In addition, incremental and decremental prices are submitted for variance from this desired level of output. In carrying out the central dispatch role, the TSO endeavours to adhere to generator nominations. However, inevitably this is not always feasible due to system constraints, changes in plant availabilities and/or changes from forecasted demand. The TSO selects the lowest incremental price bids to increase generation and the highest decremental price bids to decrease generation to meet fluctuations in load and system security requirements in real time. In addition to these prices, start up costs, idling price, availability, minimum up and down times and minimum generation levels are submitted to ESBNG.

At the end of the trading day, and prior to the submission deadline for ex post bilateral contract nominations, generators and suppliers are provided with information by the System Settlement Administrator ('SSA') to afford them the opportunity to trade out imbalances amongst themselves. Any remaining imbalances are traded in the imbalance market. Under the Policy Direction, purchases of energy in this market are charged the 'top up' price and the 'spill' price is received for sales of energy.

Energy prices are primarily set under the terms of bilateral contracts between suppliers and generators. In the imbalance market the top up price is set ex-ante by the Commission. The top up prices in each half hour trading period is calculated as ex-ante estimates of ESB PG's avoidable fuel cost plus a capacity element weighted according to the expected loss of load probability. These prices average out to the best new entrant cost ('BNE') over the year. The spill price is set ex-post and is defined as the highest decremental price of any unit on in the ex-post unconstrained schedule that can be decremented. The spill prices contains a capacity related element which is paid under certain circumstances- the capacity related spill price - and is floored. In the event that the

¹¹ This can be found on the Commission's website at www.cer.ie.

spill price exceeds the top up price in a given trading period, the top up price is re-set by the spill price. These market prices are not location specific and at present a locational signal is provided to generators via the Transmission Use of System charge ('TUoS') which varies with location¹² and locational loss factors. TUoS charges are derived based on the dominant reverse MW-mile method and transmission loss factors are calculated based on marginal loss factors.

Ancillary Service Provision

The TSO is responsible for procurement of ancillary services. The TSO's objective here is to maximise the scope of competition to supply the services where this is possible. Under the Grid Code dispatchable generators are required to have the capability to provide operating reserves and reactive power when instructed to do so. The provision of these services is covered by contract with the TSO, the terms of which are approved by the Commission. Black start is also contracted for via competitive tender. Interruptible load, a type of operating reserve supplied by customers, is paid for under a regulated rate that customers can apply for. The costs of provision of ancillary services are recovered under TUoS from demand customers.

In addition to the above, demand customers can provide an ancillary service under the 'interruptible load' service to the TSO. Under this service customers that can withstand unplanned and instantaneous interruptions to their supply are paid by the TSO for the amount of energy they make available for interruption. Contracts for the provision of this service are awarded through a competitive tendering process.¹³

Demand Side Participation

At present demand customers do not participate directly in the market and participation is through specific demand reduction schemes offered by suppliers. Under the Winter Peak Demand Reduction Scheme ('WPDRS') customers of independent suppliers are rewarded via a rebate from their supplier for reducing their usage relative to historical usage over peak weekday hours in the winter months. ESB Public Electricity Supply customers can avail of a similar scheme, the Winter Demand Reduction Incentive ('WDRI'), although the rebate received here is not related to historical usage. In addition to the above, under the Powersave scheme customers receive a payment from ESB Power Generation in the event that they are called on to do so, must reduce load.

Current Trading Arrangements in Northern Ireland

In 1992, the state-owned electricity industry was privatised under the Electricity (Northern Ireland) Order 1992. The network and supply functions were vested in Northern Ireland Electricity (NIE) plc and the generation plant was sold to independent investors. Licences were issued to NIE for transmission & distribution and public electricity supply, along with others to independent Second Tier Suppliers.

¹² Further information on the transitional trading arrangements please refer to the following documents which can be found on the Commission's website (www.cer.ie): Helicopter Guide to Trading and Settlement (ESBNG), Guide to EPUS (ESBNG), Final Proposals for a Transitional Electricity Trading And Settlement System (CER/00/02).

¹³ Additional information on the above can be viewed on the 'System Operations' (Ancillary Services) page of ESBNG's website (www.eirgrid.com).

Under the trading arrangements put in place at privatisation, all generation was contracted under long-term Power Purchase Agreements (PPA's) to NIE's Power Procurement Business (PPB) and sold on to suppliers at a regulated Bulk Supply Tariff (BST). Under these arrangements all customers were free to choose their supplier, but all suppliers had to buy their power from NIE's Power Procurement Business (PPB) thus effectively constraining competition.

In 1999 new interim trading arrangements were introduced with the implementation of the EU Directive: Internal Market in Electricity (96/92/EC). This Directive in aiming to introduce competition required that suppliers no longer had to purchase their generation requirements from PPB. The lifting of this constraint meant that suppliers could therefore contract at a negotiated price with Independent Power Producers (IPPs) to meet the demands of their customers. The sources of independent power in NI have ranged from out of contract Ballylumford & Power Station West sets, the Moyle Interconnector and now ESB Coolkeeragh in 2005, with the remaining NI generation plant still contracted to PPB. These interim trading arrangements are still in place today and have facilitated the opening of the retail market to 35% of customers in 1999, and to 60% of customers in 2005 under the IME Directive. The Northern Ireland Authority for Energy Regulation (NIAER) regulates the industry, under the power of the Electricity (Northern Ireland) Order 1992, as amended by the Energy Order 2003.

Wholesale Market Trading Arrangements Overview

The current interim trading arrangements, as set out in the Interim Settlement Code¹⁴, are based on the scheduling and dispatch of bilateral contracts. While SONI acts as the market and system operator, settlement is facilitated by PPB, who sells Top-up energy at the regulated BST price and buys Spill energy at a regulated price based on the avoided fuel cost.

Under these arrangements, generators make nominations to the System Operator for Northern Ireland (SONI) for each of their generating units for a trading day by gate closure on the previous day. Dispatch by SONI is based on must run nominations by IPPs and imports nominated across the Moyle Interconnector. PPB contracted plant then makes up the remainder of the dispatch. IPPs may submit bids for additional dispatch to be placed in the merit order against PPB plant.

Ancillary services are provided for in the PPB contracts, and are funded through charges levied by SONI on all customers. IPPs are also paid to provide Ancillary services at a fixed regulated rate. Demand side participation is not currently active in the NI market through any central market mechanism.

Current interconnector trading arrangements

In the context of the island, there are two electricity interconnectors, one between NI and RoI (North-South) and one connecting NI with Scotland (Moyle). Each year the System Operator Northern Ireland (SONI) holds an auction to allocate capacity to the market across both these interconnectors. Auctions are held after NIAER consultation with the industry on allocation procedures, which takes into account the possible effects of recent market developments e.g. new BETTA trading rules in GB.

¹⁴ www.soni.ltd.uk

North-South Interconnector

The North-South interconnector currently has a net transfer capacity of 330MW in a north-south direction. In recent years the net transfer capacity in a south-north direction has been effectively zero for the majority of the time. This has been due to system security issues and transmission constraints. In the past, all north-south capacity has been allocated on a yearly product basis, with an additional 2 year product being introduced in the 2005 auction.

Superposition on the North-South interconnector was introduced in April 2003, due to constraints on the physical transfer capacity of the interconnector. This mechanism of netting off trades in opposite directions, by making available short-term capacity allocated two days prior to the trading day, maximises the utilisation of the physical transfer capacity of the interconnector.

In addition, there are arrangements in place between SONI and ESBNG, for marginal trading and reserve sharing, which minimise the costs of dispatching the interconnected systems and maintaining system security.

Moyle Interconnector

The Moyle interconnector between Northern Ireland and Scotland to date has been used solely for import purposes. It currently has 125MW out of an available 400MW contracted to PPB to facilitate its import contract with Scottish Power. The remaining 275MW are auctioned annually to appropriately licensed and authorised market participants. Moyle capacity to date has been auctioned by products that vary by duration, namely one, two and three years.

MARKET DESIGN FOR A SINGLE ELECTRICITY MARKET

In accordance with the MoU as signed by the Regulatory Authority on 23rd August 2004 and with the support of the DCMNR and DETI, the Commission and NIAER are progressing the SEM. The following section sets out an outline of the proposed new market design.

Definition

In designing the all-island wholesale electricity arrangements it is necessary to first arrive at a common understanding of an all-island market. The Regulatory Authorities are of the view that in order to facilitate delivery of potential efficiencies and benefits to consumers across the island such a market should ultimately be characterised by the following:

- a single set of electricity wholesale market rules applicable across the island that serve to meet the stated objective;
- a single wholesale market price for generators and suppliers;
- a single approach to market dominance;
- an integrated transmission system across the island, i.e., North/South interconnector(s) subsumed into the transmission system;
- a single connection policy;
- a single transmission planning regime;
- a single generation adequacy standard and report,
- a single grid code, transmission standards and agreements;
- single licensing conditions and procedures;
- a single appeals process;
- single supplier codes;
- single gas transmission standards and agreements;
- common treatment of renewables and CHP;
- a single market operator (MO);
- a single transmission system operator; and
- a single regulatory body.

The Regulatory Authorities are of the view that ideally all of the above should operate within a single legislative framework.

The Regulatory Authorities accept that with respect to some of the above, it may be pragmatic to adopt interim steps. In addition it is pragmatic to prioritise work around the deliverables with the potential to deliver the most benefits. Therefore, the Regulatory Authorities have identified the development and implementation of wholesale trading arrangements for electricity as the key priority, whereas the remaining aspects will be progressed in tandem with the development of the SEM.

The Regulatory Authorities define the Single Electricity Market (SEM) as:

A single wholesale market for electricity on the island of Ireland where all electricity is bought and sold and where participants operate under a single set of rules.

The Economics of a Single Electricity Market

The SEM has been designed to bring together the two existing separate wholesale markets on the island. The new market formed must be tested on the basis that electricity consumers in both jurisdictions should be better off than they would have been in separate markets, which merely trade with each other.

The benefits, which accrue from the SEM, will include the following:

- More efficient generation dispatch, leading to lower cost of generation
- A larger single market
- Energy prices set competitively
- Predictable and Stable trading system
- Increased attractiveness for generation investment and supplier entry
- Increased security of supply
- Integrated system planning leading to more robust infrastructure on the island
- Shared costs of maintaining fuel diversity

The single market will allow the most efficient dispatch of generation plant on the island. At present both system operators dispatch independently, but take advantage of opportunities to reduce overall system costs through trading, where available. The existing interconnector in the island is available for third party trading and the combined effect of market and TSO trades captures some element of efficient dispatch. There will however be savings gained by a single economic dispatch. It is important to note that the interconnector is heavily used at present and the predominant direction of flow is North-South. The regulators and TSOs have developed a superposition system (“paper trades”) to allow energy trades to take place to the maximum extent. Under the SEM, the interconnector will be treated as a transmission line and the system will be dispatched accordingly.

The savings from joint dispatch accrue from increased dispatch of cheaper plant (mainly in NI) and lower running of more expensive plant (mainly in the RoI). The cost of maintaining system reserves should also fall since reserve will be treated as a single island resource. At present the reserve is split between NI and RoI on an agreed basis. It is also important to note that the Regulatory Authorities and the Departments support the case for further interconnection on the island to further capture the benefits of integration.

An all-island electricity market will be of around 2.5 million electricity customers (1.8m in RoI, 0.7m in NI). While this is small in the EU context, it is still a considerably larger market than the two single markets operating independently and should provide a much-improved base for the entry of new market participants, both generators and suppliers. This market dynamic will increase the competitive pressure on prices.

The creation of a gross mandatory pool, where bidding is at marginal cost, will also serve to deliver an efficient price formation. Competition between generators for dispatch, combined with a financial contracts market with suppliers, should lead to lowest cost production.

The development of a single market with a clearly defined and stable trading mechanism, through the gross mandatory pool, will also serve to boost investor confidence. A market that exists for a significant period of time with rules and oversight that are clearly

established will allow investors to properly assess the risks and rewards of investing. A trading arrangement where price signals and forward markets will telegraph the need for new investment should allow for efficient and timely new generation build. Equally, suppliers who see a stable market and particularly a gross mandatory pool will be encouraged to enter. Supply competition will also be enhanced by the larger total market size.

The regulatory authorities are of the view that the SEM will deliver a new, larger and more competitive market, which should lead to more efficient allocation and use of resources, delivering lower prices to consumers. The economic benefits of the market will also be felt in terms of an improved climate for investment and market entry.

Objective of the Single Electricity Market

The Commission and NIAER, in light of their statutory duties and functions under the ERA and the Northern Ireland Electricity Order S.I. 1992/231 ('the Electricity Order') respectively and taking into account the spirit of the Draft Framework, have developed the following primary objective for the SEM:

The wholesale electricity trading arrangements should deliver an efficient level of sustainable prices to all customers, for a supply that is reliable and secure in both the short and long-run on an all-island basis.

This primary objective is supplemented by the following five objectives:

- security of supply;
- promotion of competition;
- minimisation of transaction costs for participants and customers;
- fostering renewables; and
- enabling demand side management

Security of Supply

The new arrangements should serve to deliver efficient and sustainable prices in the market which should in turn result in efficient investment decisions regarding timing of investment and plant type, size and location.

Promotion of Competition

Under competitive market conditions, market prices are set at the supply/demand equilibrium resulting in efficient allocation of resources. Competition amongst profit maximising market participants incentivises participants to increase output, reduce costs, and increase availability. The achievement of the primary objective of the new arrangements as outlined above is highly dependent on the promotion of competition.

Minimising Transaction Costs for Participants and Customers

In reviewing the trading arrangements the Regulatory Authorities are mindful of the transaction cost implications for participants and customers. In this regard, it is noted that costs incurred during the implementation of the SEM should be proportionate to

requirements and that no unwarranted costs should be incurred. Transaction costs for interacting with the market under the new arrangements should not act as a barrier to participation in the market.

Fostering Renewables

The Commission has a duty under Section 9 of the ERA to promote the use of renewable, sustainable or alternative forms of energy. NIAER has a similar duty under the Electricity Order, to have regard in carrying out its functions, to the effect on the environment of activities connected with the generation, transmission or supply of electricity. Therefore, throughout this review the Regulatory Authorities will be mindful of the potential impact of any proposed arrangements on the renewable energy producers.

Demand Side Management

The Regulatory Authorities are of the view that the trading arrangements should facilitate demand side participation in so far as this is practicable in order to capture the benefits that this brings. In this regard, market prices should provide signals to customers to react to them. Where this occurs the market as a whole may benefit through reductions in prices during peak and customers may benefit additionally through profits from the provision of reserves where this is facilitated.

Proposed Market Design

Following public consultation the regulatory authorities have decided on their initial preferred market design model and means of delivering a single market. The preferred market design can be summarised as having the following high-level features:

- It shall be a Gross mandatory pool;
- Unit shall be committed through central commitment;
- The price offer form shall be detailed conforming to a central commitment market model;
- The market shall have explicit capacity payments the details of which are yet to be devised;
- Gate closure shall be 12 hours ahead;
- Basis for optimisation and optimisation timeframe shall be over 24 hours;
- Congestion management shall be through constrained on and off payments;
- Transmission losses shall be locational in nature
- Prices shall be set ex-post based on an unconstrained network optimised over 24 hours;
- Dispatch and trading periods will be 30 minutes;
- Ancillary services are to be contracted;
- Operating reserves are to be deployed through dispatch instructions and compensated through constraint payments;
- Reserve charging should be based on the causer pays principle;
- Demand side participation shall be facilitated;
- The North – South Interconnector shall be treated as part of the transmission system.

CONCLUSION

Under normal circumstances, the first problems that are highlighted on the prospect of combining markets are distributional benefits and the risk of participants in one jurisdiction losing out to that of the other. Unusually perhaps in the context of the SEM, is the unanimous support for the development of a combined market, to date. One possible explanation for this lies in growth in electricity consumption allied to the institutional factors in both jurisdictions.

Electricity consumption has grown in Ireland over the past decade at approximately 5% per annum. The existing plant portfolio in Ireland is relatively old and investment in new capacity particularly from outside the island has been relatively slow in developing. Incumbent in each jurisdiction have invested across the border, leading to concerns that a duopoly may result.

These factors and the fact that both markets in isolation are small have resulted in significant support for the development of a single market. To some degree the roadmap to a single market has been led by commercial interests where companies in each jurisdiction have established businesses in their neighbouring jurisdiction. This has led to calls for simpler and conjoined approaches to administrative procedures and pricing, which taken to its natural conclusion is a single market.

It is a little early to make any statements, as to what has been learned to date. However, to a large degree the development of the market can be market by a number of key milestones. Obviously physical barriers to trade across borders must be eliminated by the establishment of interconnected networks. In parallel, cooperation between regulatory institutions must be developed in order to build cross border confidence in institutions and trading rules. Commercial barriers to trade across borders must be eliminated or ameliorated by the establishment and development of trading rules. The role of the regulatory authorities is paramount in so far as they must proactively pursue commercial and economic benefits of cross border activities and develop the political will in cooperation with interested parties to support the case for greater integration. In this regard, it may rest with the regulatory authorities to make the economic case for the development of regional markets.

APPENDIX 1: LEGAL & GOVERNANCE DIFFERENCES

Currency Regimes

The Euro/Sterling exchange risk will apply to cross border trades, and is a risk not faced by participants in Continental European cross border markets (e.g. the Iberian model). The risk can be minimised by appropriate exchange risk strategies, and should not be considered significant, and exchange risk currently applies to certain generators whose fuel purchases are predominantly in US dollars.

Taxation Regimes & Emissions Trading

The two tax regimes are different, in relation to end user consumption tax. There are likely to be some differences also in emissions as the allocation of allowances may differ somewhat between the two jurisdictions. These may cause some market distortion in relation to renewables, and new generation location between the two jurisdictions. Emission-trading puts a value on the externalities caused by fossil fuel burning because the price of production from fossil fuel sources relative to renewable sources will rise. This will drive up the price received by all generators, in which case renewables, such as wind, will become more profitable and in turn more attractive to investors. With respect to the electricity-trading regime we must devise a market that has no inherent carbon distortions either between north and south or between east and west.

Any divergence in energy taxation policy, such as upstream or downstream charging methodologies, will have a distortionary impact, and create potential barriers to economic trade. Future government policy must take note of this, and where possible co-ordinate their approaches. Other end user taxes are jurisdiction-specific, e.g. VAT, and are non-distorting.

Powers of the Regulators

The two regulators have a number of similar duties, but there are important differences in duties and powers. The main differences are summarised below:

It is important that these differences should be considered by policy-makers when drafting legislation, such that further divergence does not occur, and where possible, convergent powers should emerge. It would be unhelpful to market participants to face two regulators with widely different obligations and duties. This would add further complexity to the regulatory structures.

Contractual Issues and Generation Ownership

In Ireland the future shape of ESB's generation contracts after 2005 is still under consideration. In Northern Ireland the long term Power Purchase Agreements (PPAs) are in force between NIE and independent generators, and their revision will need to be considered in market opening. The issue is of moderate significance, and will need to be considered as a part of market rules in dealing with market power and dominance.

In Ireland the final position of the generation owned by ESB's generation business remains to be determined. In Northern Ireland all generation is owned by independent companies. In all island terms, each utility has a generation project planned or operational in each other's existing licence area.

PSOs and Fuel Poverty Measures

The Irish market will have a PSO to support the additional costs of peat and renewables. Northern Ireland has a separate defined PSO levied across all customers to cover the excess costs of renewable energy, retirement of old power plant, and to cover a small fuel diversity payment. There is also a System Support Services Charge which covers system costs, and ancillary services. NIE also collects under its price control, £2 per customer Energy Efficiency Levy, to invest in energy efficiency projects, under the supervision of the Energy Savings Trust. These projects are aimed at the fuel poor in general.

Differences in these areas are not significant – although the means by which they are levied on final customers are different (in Northern Ireland the charge is per consumption, in Ireland it is by capacity) - the costs are charged to all end users in each jurisdiction, cannot be exported, and hence would not cause a trade distortion.

Regulatory Powers

The main differences in the roles, duties and responsibilities of the regulators in each jurisdiction are identified, and listed below.

Establishment of the Commission

In Northern Ireland, the electricity regulator is an individual - the Director General of Electricity Supply. However, in the Republic, the electricity regulator is a body corporate - the Commission for Electricity (now “Energy”) Regulation.

Consumer Councils

The Northern Ireland legislation provides for the establishment of a Consumer Committee for electricity. Recently similar provision has been introduced into the legislation in Ireland, although it has yet to be established in practice.

Annual Reports & Other Reports / Forward Work Programmes

Both pieces of legislation contain similar reporting provisions to the relevant government departments (in Northern Ireland, to DETI, and in Ireland, to the Department of Communication, Marine and Natural Resources). Note however, that in Ireland, the Commission must publish a forward work programme. The Northern Ireland legislation does not require the Director to publish a forward work programme. Notwithstanding this however, the Director General publishes a forward work programme as a matter of good practice.

Functions

Broadly, the functions of the Director General and the Commission are similar under both sets of legislation. The Irish Electricity Regulation Act 1999, however, confers a specific function on the Commission to establish a trading regime. However, even though there is no such provision in the Northern Ireland legislation, a trading regime has been established in Northern Ireland. Furthermore, in Northern Ireland, the Competition Act 1998 provides for concurrent competition law jurisdiction by the Director of Fair Trading and the Director General of Electricity Supply. There is no equivalent provision in Irish legislation.

Duties

The duties of the Director General and the Commission are broadly similar. Please note, however, that the primary duties of the Director General (to secure all reasonable demands for electricity are met, to ensure licensees are able to finance their activities and to promote competition in electricity generation and supply) are secondary duties under the Electricity Regulation Act 1999. The Commission's primary duties are not to discriminate between licence holders and to protect the interests of final customers.

Provision of Information

The Electricity Regulation Act 1999 in Ireland confers wide powers on the Commission to obtain information. The Northern Ireland Electricity Order does not contain equivalent powers. However, the Director has similar powers under the Competition Act 1998.

Licensed Activities

In Northern Ireland, the Director exercises his licensing functions under the NI Electricity Order under the General Authority granted to him by the DETI.

In Ireland, the Commission may grant licences pursuant to the Electricity Regulation Act. Please note that there are differences in the categories of electricity licences in Ireland, due to the differing market structures - there are separate licences for transmission system operation, transmission system ownership and distribution system operation.

Modification of Licence Conditions

The Electricity Regulation Act 1999 in Ireland makes specific provision for the establishment of public hearings and an Appeals Panel in relation to modifications, and the grant, of licences. The Appeals Panel has wide powers to direct the Commission in respect of modifications to licences. In Northern Ireland, the appeal route against modifications is through a reference to the Competition Commission. However, the Director General can make such modifications as appear to him requisite for the purposes of remedying any adverse effect specified in the report from the Competition Commission, (i.e. the Competition Commission does not have the power to direct the Director General to make a specific modification).

Regulation of Transmission activities

The Commission and the Director General have similar regulatory powers in respect of the terms and charges for use of system and connections to the transmission system. The difference lies in where these powers are to be found. In Northern Ireland, they appear in NIE's Licence Document whereas in Ireland, they can be found in the legislation (the Electricity Regulation Act 1999).

Licence Enforcement

Under the Northern Ireland legislation, the Director is obliged to enforce breaches/potential breaches of licence conditions (unless certain conditions apply). However, in Ireland, the Commission has an option to enforce breaches of a licence condition. There is no provision in either Ireland or Northern Ireland legislation to allow a generator contract directly with a market participant in another jurisdiction; however neither is this expressly forbidden.

Overall Energy Efficiency Targets

In Northern Ireland, the Director has specific powers to set energy efficiency targets. However, the Commission does not have such powers.

Public Service Obligations

In Ireland, these are specifically mentioned in the legislation (Electricity Regulation Act 1999). In Northern Ireland, public service obligations may be imposed pursuant to the IME Directive rather than by virtue of the Northern Ireland Electricity Order.

Annex 4 – Case study – wholesale electricity markets (Spain and Portugal)

1. BACKGROUND ON MARKETS IN QUESTION

– Technical features:

- Comparison between the generation capacity and the demand (2003):

	Installed Generation Capacity (GW)	Import Capacity (NTC) (GW)	Amount of reserve generation capacity as % of installed capacity	Import Capacity as % of installed capacity
SPAIN	62	2,1	11%	3%
<i>PORTUGAL</i>	10,7	0,9	24,6%	8,4%

Spain data Source: REE, ETSO

Portugal Data Source: REN (Technical Report 2001-2003)

Note: data before Alqueva-Balboa line entry into operation

	Annual Demand (2003) (TWh)	% increase in annual demand (2003/2002)
SPAIN	224	6%
PORTUGAL	43,1	5,9%

- Type of generation plants:

SPAIN (AS OF DECEMBER 2003)

Type of plant	Installed capacity (MW)
Hydro	16.657
Thermal Nuclear	7.876
Thermal Conventional	22889
Renewables	13.801
TOTAL	61.223

PORTUGAL (AS OF DECEMBER 2003)

Type of plant	Installed capacity (MW)
Hydro	4.247
Thermal Conventional	5.115
Renewables, cogeneration and waste (PRE)	1.305
TOTAL	10.667

Source: REN (Technical Report 2001-2003)

- Actual and available interconnection between countries:

Spain - Portugal (WINTER 2004/2005)

The next table shows the evolution of the interconnection capacity between Spain and Portugal, having as reference the situation in 2002. It includes an indicative probable range of values.

From	To	Summer/Winter	Interconnection Capacity (MW)		
			2002	2004/2005	2007/2008
Portugal	Spain	Winter	600-850	1390-1545	2100-2330
		Summer	550-750	1200-1375	1680-1920
Spain	Portugal	Winter	750-1050	1000-1225	1700-2080
		Summer	600-850	1250-1250	1610-1980

Source: MIBEL-Progress report about the state of the interconnections (December 2004) REN-REE.

– Market structure

SPAIN

In Spain there are two companies that are the principal market players: ENDESA and IBERDROLA. Those companies are vertically integrated as regards the different activities in the electricity sector. During the year 2003, and from the generation side, these two companies represent a 69% share over the market (approximately 57% of the total generation during this year). From the demand side in 2003, both companies had a share of 77,5% of the total (including distribution to regulated consumers and retailing activities). There are three other companies that are vertically integrated as well: Unión Fenosa, Hidrocantábrico and Viesgo. These companies sum a 20,4% share of the total generation and a 20% share of the total demand during the year 2003. Apart from the above mentioned vertically integrated companies there is another group that is to be mentioned: GAS NATURAL. This company is the main operator in the gas sector and is rapidly increasing its market share, both in the generation and retailing activities.

Regarding the generation side, it has to be mentioned the increasing number of new generation units corresponding to the Special Regime (renewables and cogeneration)

following to the regulations that aim to boost the participation of this type of generation plants in the electricity market. In the retailing activity there also are new entrant companies that operate and that are grouped under the title 'others' in the tables below.

Consumption	
2003-%Energy	2003
DISTRIBUTORS	
ENDESA	26,9%
HIDROCANTÁBRICO	3,9%
IBERDROLA	24,7%
OTHERS	0,0%
UNIÓN FENOSA	9,4%
VIESGO	1,0%
	65,8%

RETAILERS (SELLING TO NATIONAL CONSUMERS)	
ENDESA	12,5%
GAS NATURAL	1,6%
HIDROCANTÁBRICO	2,4%
IBERDROLA	13,4%
OTHERS	0,9%
UNIÓN FENOSA	3,2%
VIESGO	0,2%
	34,2%
TOTAL	100,0%

Source: CNE

The energy market share, during the year 2004 for customers in the liberalized market, has increased 3 points in percentage respect from the year 2003, so the final data by the end of 2004 is about 37,2%.

GENERATION	
2003-%Energy	2003
Producers (ordinary regime)	
ENDESA	38,6%
GAS NATURAL	1,6%
HIDROCANTÁBRICO	6,2%
IBERDROLA	30,5%
OTHERS	1,7%
UNIÓN FENOSA	11,6%
VIESGO	2,6%
Imports	3,3%
Special Regime Producers	4,0%
	100,0%

Source: CNE

PORTUGAL

The Portuguese supply market is divided in two systems: the public system (SEP) where the customers are supplied with regulated tariffs, and the so called non-binding system (SENV), where customers are free to choose their supplier and, therefore, being supplied by market agents.

Within the Portuguese supply market, both in public system retailing and in the liberalized market, there is one major market player: EDP. In public distribution and retail, EDP accounts for nearly 90% of market share, holding some other 6,63% of total demand through its subsidiaries in the SENV (the part of market opened to competition). Until the end of 2003, Endesa and Iberdrola, both supplying in the SENV market, account for, respectively, 2,85% and 0,45% of total demand.

By the end of 2004, the share of market effectively opened to competition (share of SENV consumption in overall national consumption) has registered an evolution to 15,8%, compared with around 10% in the end of 2003. Due to this fact, EDP accounts for nearly 84% of market share through its participation in the public system and some 9,9% more through the subsidiaries in SENV (93,9%, in total). The SENV suppliers Endesa and Iberdrola accounted, by the end of 2004, for some, respectively, 4,3% and 1,5% of total demand in mainland.

Consumption	2003 - % Energy
EDP Distribuição	89,55%
Other Distribution in SEP	0,50%
SEP - total	90,05%
EDP Energia Ibérica	0,98%
EDP Energia	1,05%
Endesa	2,85%
HDN	1,22%
Hidrocantábrico	2,00%
HIDROCENEL	1,38%
Iberdrola	0,45%
Others	0,03%
SENV - total	9,95%
Total	100,00%

Source: REN, ERSE

In generation, the Portuguese system is also composed of two sub-systems: Public System (SEP) and Independent System (SEI). Within SEI generators in the non-binding system sell the generated energy through free price agreements and the special regime generators (renewables, cogeneration and waste) sell their generation to the grid

according to administrative price conditions. Within SEP each generator has a binding contract (PPA) with the transmission grid concession holder. Each power plant celebrated a contract with the transmission grid concession holder. PPA pay for the fixed costs of the power plants (investment and remuneration) and relevant maintenance costs, through the fixed charge, and allows the recovering of the variable costs on the variable charge.

During 2003, generation from SEP power generators accounted for 83% of total demand, with CPPE (a company of EDP Group) achieving some 61% of market share. The SENV generators (also part of EDP Group) represented 2% of total market demand and the special regime generators were responsible for 8,5% of total demand. The net imported generation represented 6,4% of total demand in Portugal during 2003.

Considering provisional data, in the whole of the year 2004, the generation from SEP suppliers represented approximately 67,6% of total demand, representing CPPE around 65,9% of generation within the SEP system and 44,6% of total demand. The SENV suppliers have reached a share of 8,3% of total demand in Portugal mainland, registering a sharp increase due to the CCGT plant of EDP in the SENV, which initiated operation in December 2003. In 2004, the special regime generators were responsible for 9,8% of total demand in 2004 and the net imported generation accounted for 14,1% of 2004 total demand.

Generation	2003 - % Energy
CPPE	61,03%
Tejo Energia	9,57%
TURBOGÁS	12,41%
SEP - total	83,01%
HDN	0,28%
HIDROCENEL	0,66%
EDP ENERGIA	0,68%
TER	0,47%
SENV - total	2,08%
Renewables (PRE)	8,49%
Net imported generation	6,41%
TOTAL	100,00%

Source: REN, ERSE

– Wholesale electricity market

SPAIN

The electricity market is based on spot pool transactions that take place in both the day-ahead and intraday markets, complemented with physical bilateral contracts, that only represent less than a 1% share of the total transactions (during the year 2003 and also in

2004). A competitive balancing market is also in place comprising mainly the secondary and tertiary reserves. It is envisaged the establishment of an organized forward market. Market participants need and authorization to participate in the electricity production market as electricity buyers and/or sellers. Entities that are authorized to engage in the market are electricity producers, distributors and retailers, qualified consumers and companies or consumers resident in other countries that are authorized to participate as external agents.

Producers and qualified consumers may participate in the Power Exchange as market participants or sign physical bilateral contracts. Regulations stipulate that individuals entering into such bilateral contracts must be registered with the corresponding Administrative Register depending on their nature.

Production units required to enter into these types of contracts are exempted from the obligation to present bids on the electricity production market for the part of their generated power linked to the contract. These physical bilateral contracts must identify the production units required to comply with said contracts and the forecast consumption levels. These contracts must have a minimum duration of one year.

Physical bilateral contracts must specify the contracting party required to make corresponding payments for balancing. Parties to these types of contracts must inform the Market Operator and the System Operator of the execution of said contracts, providing details of the time periods in which the contract must be executed and the supply and consumption points in order for these to be taken into consideration when preparing daily schedules.

Production unit owners signing physical bilateral contracts must participate, when requested by the system operator, in the ancillary services market and must comply at all times with any restrictions established by the latter, on a non-discriminatory basis with respect to any other supplies that are made.

The Production Market is based on several interrelated processes:

- Day-ahead Market: its purpose is to perform energy transactions for the following day.
The System Operator notifies the agents of its demand forecast, generation availability and transmission grid conditions.

The agents that wish to participate in the day-ahead market present their energy buy or sell offers to the Market Operator. The Market Operator matches the various offers and determines the marginal price and the volume of energy that is accepted for each buy and sell unit and each time period.

The assigned (or matched) energy buy and sell transactions give place to the Matching Base Programme, adding the physical bilateral transactions. Once this programme has been reviewed from a supply safety perspective by the System Operator and any technical constraints have been resolved (by rescheduling generators), the Final Day-ahead Viable Programme is obtained.

- Intraday Market: managed by the Market Operator. It is a market for adjustments on generation or demand deviations that can happen after setting the Final Day-

ahead Viable Programme. No bilateral trade is allowed in intraday time.

This market is organized into six sessions and agents that have previously participated in the day-ahead market can present new energy buy or sell offers. The transactions programme resulting from each intraday market is analyzed by the System Operator to assure compliance with safety criteria, and the Final Hourly Programme is obtained.

- Balancing Markets: managed by the System Operator as responsible for system operations. Consists of processes that resolve unbalances between production and demand. It is a group of competitive auctions that complement the production market. The balancing services are managed after each intraday market session.
- Capacity payments: Generators are due a Capacity payment, independent from the energy sold, based on their availability.

The Power Exchange (OMEL) is the Clearing and Settlement agency. It makes the final settlement for the pool transactions, the system operation costs and the imbalances. By the first of July 2005, it is foreseen that the System Operator is going to have settlement functions (Royal Decree 5/2005 establish the new functions for the System Operator), so the System Operator should set up the settlements on all the markets managed by himself.

As from January 2003, all consumers became eligible, this mean that they can trade freely through physical bilateral contracts signed with producers or retailers, or directly access the organized market. The amount of energy that corresponds to the liberalized market has been 36% of the total amount of energy bought during the period from January 2004 to December 2004. Referring to the number of consumers accessing the market, they represent only the 5,7% of the total number of consumers within the country (over 38% if only High Voltage consumers are considered).

PORTUGAL

In the Public System electricity transactions are based on long term contracts between the following entities:

- Binding generators – National Transmission Grid Company (Power Purchase Agreements – PPA).
- National Transmission Grid Company – High and Medium Voltage Distributor.
- High and Medium Voltage Distributor – Low Voltage distributors.

In the Public System, customers are supplied by distributors. In the liberalised market (SENV) the supply of electricity may be made by means of:

- Bilateral contracts.
- Purchase electricity in foreign markets.

Eligible customers may sign bilateral contracts with Portuguese non-binding producers or with foreign suppliers.

Bilateral contracts must be registered with the National Transmission Grid Company, the entity responsible for settlement and imbalances management. Contracting parties will present an implementation statement for each bilateral contract, with information about the amount of contracted energy for each hour of the next week. This information should be received by the National Transmission Grid Company until 10:00 a.m. of the day before the time period of one week. This information can be modified on a daily basis under the following conditions:

- Until 10:00 a.m. to modify the programme correspondent to the following day.
- Until 10:00 a.m. to modify the programme for the time period between 12:00 and 24:00 of the day.
- Until 21:45 to modify the programme for the time period between 0:00 and 24:00 of the following day.

Energy imbalances are calculated for each hour taking into account the amounts of energy that have been declared in the programme previously presented to the National Transmission Grid Company. Contracted energy is adjusted for losses according to the regulations established in the Network Access Code and losses parameters published by ERSE. Imbalances of contracts that correspond to one supplier can be aggregated (for each hour, the imbalance that corresponds to the supplier is the algebraic sum of imbalances of all contracts).

There is no market for energy imbalances. Prices of the imbalance energy are approved by the Regulator (ERSE).

According to the law, all customers are eligible since August 2004. Nowadays, electrical Codes are being up-dated in order to include the necessary regulations that will allow domestic customers to be effectively eligible. Suppliers and external agents will be considered in this revision of electrical Codes foreseen for January, 2005.

At the end of 2004, the amount of energy that corresponds to the liberalised market in an annual basis was about 19,8% of the total consumption in Portugal. Referring to the number of customers supplied in the liberalized market, they represent less than 0,1 % of the total number of electricity customers within the country.

– **Balancing**

SPAIN

The balancing services are the following ones.

- **Secondary Regulation:** The product negotiated is the capacity to increase or reduce production, and there are payments on both availability (power capacity) and usage (energy).

- Tertiary Regulation: The product negotiated is the variation in power that is obtainable in no more than 15 minutes and can be maintained for at least 2 consecutive hours. Only energy payment (no capacity).
- Deviation Management: Supplementary to the tertiary regulation. Only energy payment (no capacity).

Other **ancillary services** are not market based such as primary regulation, voltage control, and autonomous start-up.

The responsible party for balancing processes is the Transmission System Operator, which receives and selects bids. The imbalance regarding tertiary control is the difference between scheduled generation and load foreseen. For deviation management the imbalance is the difference between scheduled generation and load foreseen when that difference is higher than 300 MW. The Generators which are included in a balancing area pay the imbalance of this area, and other generators and consumers have to pay their own imbalances (difference between scheduled and measured values).

Regarding bidding in the tertiary control processes the generators are obliged to offer their available power plant capability to go up and down. The bids are arranged in a merit order according to energy price bid. Deviation management processes are not compulsory regarding bidding. The bids are arranged in merit order according to energy price bid and providing that technical and economical requirements of complex bids are fulfilled. For both processes bids are required for every hour and include price and energy.

Regarding pricing tertiary control and deviation management are dealt with in the same way: the price for up-regulation and down-regulation is the marginal price in each case (price of the last bid used). There are two clearing prices, up and down. Payments are only for energy (no payment for capacity).

The price of the imbalance includes the following costs: energy cost (based on day-ahead market price) plus or minus (depending on the sign of the imbalance) balancing costs.

PORTUGAL

In Portugal, there is no market for balancing services. The National Transmission Grid Company (Portuguese Transmission System Operator) is the entity responsible for managing balancing and ancillary services.

Technical and commercial conditions to supply balancing services (secondary regulation, tertiary regulation and deviation management) as well as ancillary services (primary regulation, voltage control, black start, etc.) are established in the Power Purchase Agreements signed between public system binding generators and the National Transmission Grid Company.

Since the total installed capacity in the Public System corresponds to approximately 70% of the total capacity in the country, in practice, balancing and ancillary services are provided by generators of the Public System.

Energy imbalances related to bilateral contracts in the liberalised market are calculated for each hour taking into account the amounts of energy that have been declared in the programme previously presented to the National Transmission Grid Company. Imbalances of contracts that correspond to one supplier can be aggregated (for each hour, the imbalance that corresponds to the supplier is the algebraic sum of imbalances of all contracts). Prices of the imbalance energy are approved by the Regulator (ERSE).

– **Present arrangements for cross border capacity allocation**

SPAIN

Regarding the cross border capacity calculation, two different base cases are used for peak and off-peak periods. Planned outages, foreseen generation and demand are taken into account. Different base cases are used for different time horizons and for different borders, taken into account the best information and available foreseen values as well as neighboring countries information.

All the capacity is allocated in the day-ahead horizon. Intraday allocations take place only when there is non-used capacity. The capacity is allocated in the day-ahead market taking into account those bids with lower prices. Regarding the bilateral transactions an explicit auction takes place in the day-ahead horizon. The total capacity is allocated in a pro-rata basis between the day-ahead market and bilateral transactions.

PORTUGAL

Available capacity for commercial purposes is obtained by reducing the technical interconnection capacity by a reserve margin equivalent to 100 MW. The purpose of this safety margin is to cope with the uncertainty of modelling and with the unavoidable imbalances between generation and consumption.

The export restrictions are solved by the Portuguese system operator with a pro-rata mechanism applied to all contracted exports. The reducing factor is the ratio between the available capacity for commercial purposes and the total netting of exports and imports contracts.

The import restrictions are solved by the Spanish system operator.

– **Long term contracts**

SPAIN

There are two major long term contracts in place, both are between REE and EDF and involve the Spain-France border.

Contract	Direction	Capacity	
EDF – REE	Import	250 ⁽¹⁾ + 300 ⁽²⁾ MW	Until 30 Sept. 2004
		250 + 250 MW	1 Oct. 2004 – 30 Sept. 2005
		250 + 50 MW	1 Oct. 2005 – 30 Sept. 2010
REE – EDF ⁽³⁾	Export	500 MW	1 Nov. 2004 – 31 March 2005
		300 MW	1 Nov. 2005 – 31 March 2010

Contract conditions:

⁽¹⁾ Power guaranteed except force majeure.

⁽²⁾ Power conditional on interconnection lines availability.

⁽³⁾ This power is supplied through five months a year, from November to March, if it is required by EDF in advance.

Market conditions:

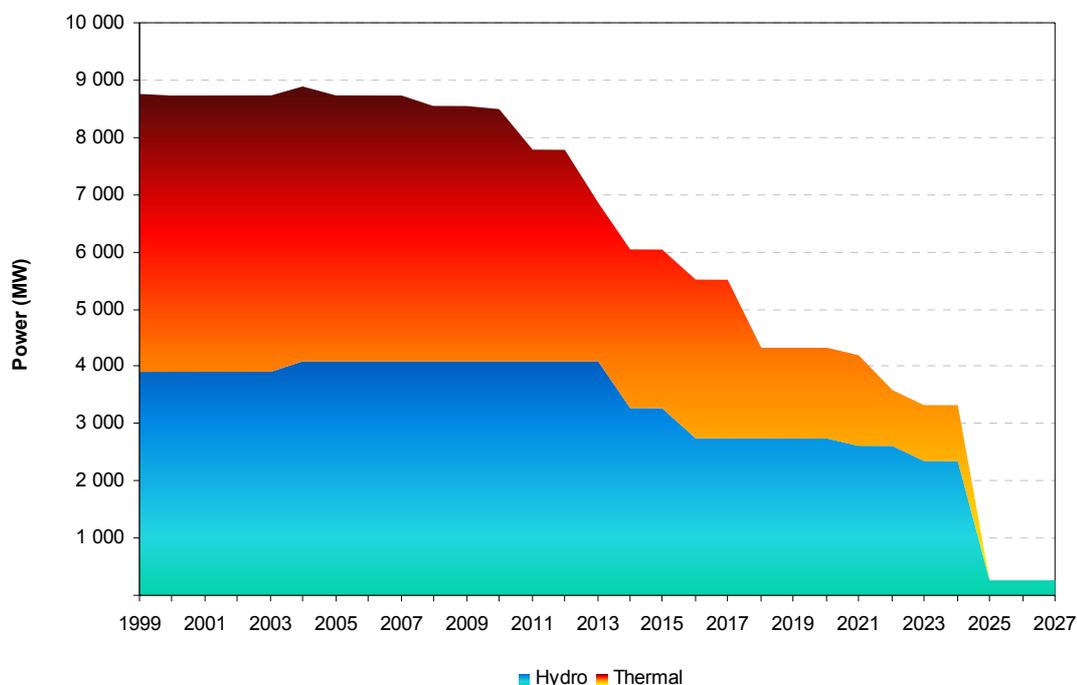
Both contracts are executed out of the electricity market in the Spanish side. Nevertheless, the EDF-REE contract is not scheduled if prices in the Spanish market are lower than the variable price of the contract, relieving in these cases the interconnection capacity for other market transactions.

PORTUGAL

In Portugal, long term contracts (PPA) establish the commercial conditions between the SEP generators and the transmission grid concession holder. Each power plant celebrated a contract with this concession holder. PPA pay for the fixed costs of power plants (investment and remuneration) and relevant maintenance costs, through the fixed charge, and allows the recovering of the variable costs on the variable charge.

The following figure presents a short overview of PPA actually into force. The evolution of the contracted power under these contracts, since the beginning of 2004 until the date of extinction of the last PPA, is presented on the figure. The contracted power line results from the chronogram of the decommissioning of each of the plants that belongs to SEP.

Contracted Power on SEP



Actually, SEP celebrated PPAs with 26 hidroelectric power plants and 9 thermoelectric power plants, with an installed capacity of, respectively, 4082 MW and 4882,5 MW. The Portuguese Government has decided to terminate PPA. The Government has defined the amount of stranded costs related to the termination of these contracts and has asked the European Commission for approval, which was obtained recently. These costs will compensate the generators for the early termination of the PPA, and will be paid by the consumers through network access tariffs (CMEC scheme).

– Transmission access and tariff methodology

SPAIN

In Spain the transmission access to the network is regulated. It is established the postage-stamp system. The access tariffs that must be paid when a consumer uses the network are established each year by the Government by means of a Royal Decree related to tariffs. This Royal Decree includes as well the regulated tariffs that must be paid for those consumers that remain in the regulated market. As of 1st January 2003 all consumers in Spain became eligible in the electricity market, but they are still given the option to buy the electricity at a full regulated tariff.

Regarding the costs included in the regulated access tariffs, these costs are mainly: the transmission and distribution costs, the diversification and security of supply costs (nuclear

related costs and special regime production) and the permanent electricity system costs (System operator, market operator, regulator, stranded costs...).

Both the ancillary services and the losses are paid apart from these access tariffs. Ancillary services are paid when the settlement process is done and the losses are paid based on standard loss factors.

In Spain it doesn't exist any G charge.

PORTUGAL

In Portugal the access to the transmission network is regulated.

To access to the transmission networks customers must pay three tariffs:

- Transmission network tariff. The price variables are: average peak power, contracted power and reactive energy.
- Global Use of the System tariff. The price variable is active energy by time period.
- Metering, reading and commercial costs related to the use of networks. The price is a fixed charge per customer and month.

The costs included in the regulated transmission network tariff are mainly related to investment and operation costs of the transmission network.

In the Global Use of System tariff are included the following costs: ancillary services, system operator costs, energy policy costs (includes renewables and cogeneration promotion costs), costs with the Regulatory Entity, etc.

Metering and reading costs, as well as invoicing costs of network tariffs are considered in a specific tariff.

In the Public System losses are paid by customers of this system through the Energy and Power tariff.

In the liberalised market losses are bought by the customers because they have to buy the energy registered in their meters plus the energy related to network losses calculated according to losses factors published by ERSE.

In Portugal it does not exist any G charge.

2. AIMS FOR MARKET INTEGRATION

2.1. PROCESS FOR THE IMPLEMENTATION OF THE IBERIAN ELECTRICITY MARKET

The first steps towards the Iberian Electricity Market were the talks and studies that the Spanish and Portuguese Administrations commenced in 1998 in order to progressively remove the obstacles and foster the creation of the Iberian Electricity Market. To that end, on July 29th 1998, a Protocol Memorandum was signed between the Ministry of Economy of the Republic of Portugal and the Ministry of Industry and Energy of Spain for cooperation in the field of electric power.

Following to that, it was signed a Collaboration Protocol between the Spanish and Portuguese Authorities in Madrid on 14th November, 2001. In this Protocol it was stated that the main aim was to “establish the measures that will allow the “Iberian Electricity Market” to be set up” and so the Protocol set out “the stages and procedures that are to be implemented successively, thus allowing progressive convergence of the electricity systems in Spain and Portugal”. It was also stated in the document that the regulatory authorities in both countries would submit a model for the organization of the Iberian Electricity Market, bearing in mind the aims set out in the Protocol, the applicable Community Legislation, the way electricity markets work in both countries and good regulatory practices. In preparing that model the regulatory authorities were asked to involve consumer other stakeholders of the development of the above mentioned market.

As a result of this Protocol and in order to foster the works on the organizational model, the regulatory authorities of Spain (CNE) and Portugal (ERSE) published a Discussion Paper on December 2001 and asked for comments to the different parties. The comments received were analyzed and a set of points about which there was a high degree of agreement was identified together with some aspects on which differences of opinion were expressed. It was also organized a public debate on this issue in Barcelona on February 2001, which was attended by different organizations (companies, associations...). As a result of these works, a document with a proposed organizational model was drafted on March 2002 by the CNE and ERSE.

Although it was foreseen that the Iberian Electricity Market would start its operation on 1st January, 2003, the process was decelerated due to changes in the political situation in both countries. Since then further political talks have taken place and as a result of it two new Agreements were signed between Spain and Portugal (20th January 2004 and 1st October 2004).

2.2. SCOPE OF THE INTEGRATION

The scope of the integration of the Portuguese and Iberian Electricity Markets can be obtained from the texts of the different agreements signed by the two countries. The main consideration taken into account in the agreement is that the integration of the two electricity systems will benefit the consumers of the two countries and should make it

possible for all the participants to access the market in conditions of equality, transparency and objectivity and with full respect of the applicable community law. This integration is based on the coordination between the two countries in order to develop the common regulations that will permit the operation of the Iberian Electricity Market and the creation of a legal framework that will enable the electricity system operators to develop their activity throughout the Iberian Peninsula. The creation of the Iberian Electricity Market involves the recognition by both countries of a single electricity market in which all agents will enjoy equal rights and obligations.

The first stage of the process will be the establishment and development of a common wholesale electricity market for the two countries. In a later stage, it is envisaged the convergence of the retail markets. The harmonization of the different aspects relating to the electricity sector would be gradual.

3. DESCRIPTION AND ANALYSIS OF APPROACH TO (FURTHER) MARKET MERGER

General aspects:

- It is established the aim to create a stable legal framework that will enable the operators of the electricity systems of both countries to develop their activities throughout the Iberian Peninsula.
- All agents will enjoy equal rights and obligations.
- Both Countries undertake to develop, in a coordinated manner, the internal regulations that will be necessary in order to permit the functioning of MIBEL.

Market Operation:

- It is established the creation of an Iberian Market Operator. This Iberian Market Operator will assume the functions from the Iberian Market Operator-Portuguese Pole (initially in charge of the futures market) and The Iberian Market Operator-Spanish Pole (initially in charge of the spot market). Until such time as the Iberian Market Operator is created, there will be a transition period during which two market operators will coexist.
- Both Countries must promote the competition of the different agents to the MIBEL in order to encourage liquidity in this market.
- The following ones are considered as agents:
 - Generators
 - Those who incorporate energy to the transmission and distribution networks from other electricity systems by means of its acquisition in third countries.
 - The management entities of the organized markets and, once created, the Iberian Market Operator.
 - The System Operators of each of the countries.
 - Regulated retailers or last resort suppliers, in the terms contained in the Directive 2003/54/CE of the Parliament and the Council.
 - Retailers.
 - Final consumers.
 - Agents that act representing other subjects of the MIBEL, acting according with the legislation.
 - Agents that negotiate financial instruments in the MIBEL markets.
 - Any other agents defined by means of an agreement between both countries.
- After a transition period (never less than two years) both Countries will adopt the necessary measures to make it possible that the market operators are financed by their own. During this period the funding could be supplemented by the tariffs.

System Operation:

- Each System Operator will continue operating its own individual system with increasing coordination between the two TSO as regards the operation of the system and planning.
- The System Operators should work on harmonized procedures allowing for the joint operation of the two systems in optimal efficiency, economy and safety conditions.

- System Operators of each of the Countries are responsible of the technical management of the system and must guarantee the continuity and security of supply, by means of the management of the adjustment services in the system.
- After a transition period to be agreed, the system operators will not be able to carry out any electricity retailing operation.
- Before one year after the entry into force of the MIBEL, the system operators (REE and REN) will submit a proposal to their respective governments in order to definitively solve the historical energy contracts of which they are holders.

Contracting Markets:

- MIBEL will be composed by different organized and non-organized markets in which electricity transactions and contracts are made and financial instruments that take this energy as a reference are negotiated.
- The organized markets are composed by:
 - a) Forward market, including transactions referred to energy blocks with delivery later than the day after the contracting. The settlement will be made both by physical delivery and differences.
 - b) Day-ahead markets, including transactions referred to energy blocks with delivery in the day after the contracting and settlement by physical delivery.
 - c) Intraday market, settlement by physical delivery.
- The non-organized markets comprise the bilateral contracts between the different agents in the market.
- In the different markets above mentioned it should be applied the legislation corresponding to the country in which those markets are constituted. The development of the normative frame of the MIBEL will establish the way in which each of the Countries could participate in the market authorization processes that the other country should develop.

Tariffs:

- Both countries, by means of the necessary agreements, should tend to the harmonization of their tariff structures.
- The harmonization process should reflect the real incurred costs in the electricity supply and should be referred to the market prices as defined above.
- Before a one year period after the entry into force of the MIBEL, both countries should define a plan, to be informed by the Council of Regulators, in order to implement the tariff harmonization.
- The process of tariff harmonization will follow the principle of tariff additivity.

Regulation, consultation, supervision and management procedures:

- The supervision entities of the MIBEL correspond to the Electricity Sector Regulator and the Stocks Markets Regulator of each country. The supervision will be done by the country in which the markets are constituted and according with the legislation of each country in this issue. The supervision entities will coordinate their functions.
- Both Countries shall proceed to create a Council of Regulators made up of the representatives of the National Energy Commission (CNE) and the Energy Services

Regulatory Authority (ERSE), as well as the Stocks Markets Regulators. The tasks of this Council are to coordinate the follow-up of the application and development of the MIBEL, to inform previous to the imposition of sanctions, to coordinate the supervision agents, to elaborate coordinated reports on the proposal of regulation of the functioning of the MIBEL or its modifications.

- Market operators could create Committees of Market Agents as consultation bodies.
- A Technical and Economic Management Committee shall be created for MIBEL, made up of representatives of system and market operators, in order to manage the communication and the necessary information flows between the different operators, as well as to facilitate the day-ahead development of their functions.

Agents authorization and guarantee of supply:

- The recognition by one of the Countries will automatically credit an agent to act in the other country. Administrative proceedings for the authorization and registration of agents for the exercise of the different activities in Spain and Portugal should be harmonized on the basis of reciprocity.
- Both Countries compromise themselves to act according to the principle of solidarity, that must be applied in emergency case and specially when the guarantee of supply is questioned within the MIBEL. Each of the countries could, in case of emergency, adopt the necessary measures to guarantee the energy supply. This adoption should be communicated to the other country as soon as possible.

Infractions, sanctions and competent jurisdiction:

- The infractions related to the violation of the regulation of the MIBEL and its corresponding sanctions should be defined in the internal legislation of each of the countries. The competent authorities should inform the supervision entities about the applied sanctions.
- Regarding the sanctioning procedure they should be instructed and solved by the bodies designated by the internal legislation. This competence should be determined following the criteria of the place in which the infraction was committed.
- The competent jurisdiction to know about the resorts that are dictated as a consequence of the application of the MIBEL, will be determined by the nationality of the authority that have dictated the act that is resorted.

Interconnection reinforcement:

- Regarding new interconnections, which is a key issue in the process of the development of the Iberian Market, it must be underlined the recent entry into service of the line Alqueva-Balboa last 22nd December 2004 which has significantly increased the interconnection capacity (nearly doubled in some periods and given more stability along the time to ATC values). It is also envisaged to build and reinforce other lines until 2006.

4. CONCLUSIONS

The issues that appear to be most important in the process to develop the Iberian Electricity Market (MIBEL) are the following ones:

- A minimum level of compatibility between the legislations and regulations of both countries. In particular, regarding the following aspects:
 - Level of liberalization of the markets.
 - The role of both the System Operators and Market Operators.
 - Agents that can participate in the market and their rights and obligations.
- Political will.
- Interference of Competition Transition Compensations :
 - Existence of Long term contracts signed by the system operator in Portugal.
 - CTC scheme existing in Spain and CMEC scheme in Portugal could distort competition in MIBEL.
- Development of interconnections.
- Level of concentration.
- Homogeneous of system tariffs in both countries.

Annex 5 – Case study – wholesale electricity markets (Scandinavia)

1. Background

Since the beginning of the 1990's the Nordic countries have reformed their electricity sectors. Norway, Sweden, Denmark and Finland have access to a common wholesale power market. In the open electricity market, the public market price of electricity is established at the electricity exchange.

Power trade between the Nordic countries uses the advantages of interconnecting hydropower and thermal power systems. It is expensive to build thermal power plants to meet short-term peaks in demand, and it is both time-consuming and costly to adjust production up and down in existing thermal power plants. Electricity generation in hydropower plants can be adjusted up and down rapidly and at low costs to meet short term fluctuations in consumption or unexpected changes in power supplies. Thus, trade reduces the need for costly adjustment of thermal plants. In hydropower plants the limiting factor is the inflow of water and the amount of water in the reservoirs. The pattern of demand for electricity, and thus the amount that must be generated, is generally the reverse of the fluctuations in inflow. When the inflow is high, production is often low, and vice versa. A system based entirely on hydropower production would have to rely on the ability to store water in the reservoirs. Trade reduces the need to invest in multi-annual water reservoirs.

The creation of an integrated Nordic market is also advantageous to competition. The reason is that the largest national producers have most of their production capacities located in their home country. In such a situation an enlargement of the market means an increase in the number of competitors and reduced market concentration.

The combined electricity generation in the Nordic countries in the year 2003 was 371 TWh. The corresponding figure from the year 2002 was 391 TWh and from the year 2001 388 TWh.¹⁵

From 1990 to 2002, output in these countries rose by 44 TWh, or about 14 per cent. The decline in inflow to the Nordic hydropower stations reduced electricity output in 2003 by 19 TWh compared with the year before. Under more normal precipitation conditions, output will return to the 2002 level.

Hydropower and nuclear energy are the two most important energy sources for Swedish electricity generation, and together account for about 90 per cent of total output. Most of the remainder comes from power stations based on bioenergy, gas and coal. Electricity output totalled just over 133 TWh in 2003, while gross consumption was roughly 145 TWh. Almost all available Swedish generating capacity based on oil condensate has been closed down in recent years. The Swedish government has decided to shut down nuclear power stations, including capacity at Barsebäck. However, new generating capacity is also

¹⁵ Nordel, Annual Report 2003, p. 36. The diminution of the production is mainly due to the diminution of production in Norway (-18 % compared to year 2002). The high rain water level in the year 2002 lead to exports of electricity to the continental Europe from Nordel area (see Nordel, Annual Report 2002, p. 3).

planned. This includes two new gas-fired power stations in Gothenburg and Malmö respectively.

Danish power output is based mainly on fossil fuels, particularly coal as well as some gas. Total output in 2003 was 33 TWh, with total consumption almost 35 TWh. Denmark's electricity output in 2003 was about 10 TWh higher than normal because of the tight power supply position in the Nordic region. Cogeneration stations, which generate both electricity and heat, account for about 85 per cent of Danish power output. Wind power accounted for roughly 12 per cent of electricity generated in 2003. Electricity prices to consumers are relatively high in Denmark at present, compared with the other Nordic countries, partly because of heavy taxes on consumption.

Finland's system includes hydropower, nuclear energy and cogeneration. The country generated almost 80 TWh in 2003. Thermal power accounted for 60 per cent of this output, with nuclear and hydropower providing 27 and 12 per cent respectively. Total Finnish consumption in 2003 was 85 TWh. The bulk of Finland's power imports come from Russia, with the rest mainly supplied by Sweden – the only Nordic country with significant transmission capacity to Finland.

Hydro is near dominant in Norwegian generation. Electricity generation totalled about 107 TWh in 2003, with 99 per cent coming from hydro resources. Generation in 2003 was well below expected generation in a normal year, which is calculated to about 119 TWh. Total Norwegian consumption in 2003 was 115 TWh, which was lower than previous years due to high prices because of very dry weather and reduced water inflow to the reservoirs in the winter 2002/2003. The Norwegian government has stated as an objective that by 2010 wind power producing 3TWh yearly shall be installed.

2. History

2.1. The first spot-market

The first spot-market in was decided in Norway in 1971 when 4 different Norwegians regions were integrated into one system operation (SO)-area. The decision to establish a spot market was taken by the system operation organisation, which assembled members from the different generators and transmission owners. The decision must be seen on the background of a clear expectation from the authorities, that the electricity system should be utilised in way that was socio-economic favourable.

The market was open only to the SO organisation members (which was generators above a minimum volume of 100 GWh). Based on bids from the participants, prices was set for one week ahead, but with the possibility of new price determination with major changes in the power situation. As most Norwegian generators are hydro producers with reservoirs, their bids could be both on the selling and the buying side. When the interconnecting transmission capacity between to areas was insufficient, different prices was determined for the two areas. The area prices were stipulated such that balance between supply and demand in each area was created together with full utilisation of the interconnecting capacity.

2.2. Market development

In June 1990 the Norwegian parliament decided on a new energy act with full competition in generation and supply based on open access to the network for all customers. The act came into force 1 January 1991. The unilateral role for generators in system operation and the pricing system was regarded not to be in accordance with the new act. The government decided to unbundle the state owned Power Company into a separate TSO and a generation company. After a negotiating process the generators decided to transfer the former SO organisation, including the spot-market, to the state owned TSO. In May 1992 the spot market, still operated by the SO organisation, was opened to all actors, traders and consumers included. 1st January 1993 the spot market was transferred to a new company, Statnett Marked, fully owned by the TSO. The driving force behind this process was a clear understanding that the energy act required market organisation and system operation to be completely independent from the powers of the generators.

From 1992 until 1 January 1996 Statnett Marked operated as a competitive and open market place in the Norwegian Market. Statnett Marked also organized short term cross-border trade. Short term trade comprised day-ahead spot trade and physical weekly contracts up to 6 months ahead. Cross border trade on the exchange was organised through a separate unit in Statnett Marked. Through this unit Swedish actors, which was mainly generators, could trade in the spot-market and in the market for weekly contracts. Long term trading was organised as bi-lateral contracts under specific licences. From 1993 until 1998 a system with tradeable 5 year export rights was organised on the Norwegian side.

In 1995 the Swedish Parliament decided on a new energy act based on the principles of a market based electricity system similar to the system in Norway. The Swedish market was dominated by the two big companies Vattenfall and Sydkraft which owned 50 and 25 percent of production capacity respectively. After some discussions, it was decided not to split up the generators, and a bigger and open integrated Nordic market was from the Swedish side seen as a prerequisite for a market with competition also in Sweden. Sweden had from 1995 set up a separate and unbundled TSO, Svenska Kraftnatt, owned by the government and with similar responsibilities as the Norwegian TSO.

With similar organisations and market-arrangements in place, with the political interest in an integrated market on both side of the border and with the long history of co-operation through Nordel and the experience with Statnett Marked in the Norwegian market and in the cross border exchange, the stage was set for real political discussions on the role and organisation of a Swedish-Norwegian power-exchange. The result of these discussion and negotiations was that Statnett Marked was transformed into Nord Pool, owned with 50 percent each by the Norwegian and the Swedish TSOs.

From 1st January 1996, a common Norwegian-Swedish market was established with Nord Pool as a joint power exchange. All capacity at the border, except some existing bi-lateral contracts, was at the disposal of the power-exchange. All tariffs on cross border trade were abolished. Paying entry-/exit tariffs and balancing requirements in each country,

provided access to the whole system, without any extra tariffs or costs related to cross border exchange.

The physical weekly market was abolished and replaced by financial forwards and futures markets. These financial markets were open to all actors, and did not require physical connection to the system, as was required for participation in the spot-market. These markets were open to foreign participants; both from Nordic and other countries.

Finland had parallel to Sweden started a process of opening the electricity market parallel to Sweden, and the possibility of expanding the market with a common Norwegian, Swedish and Finnish power exchange was seen and discussed already from the beginning in 1995/96.

In 1997 forward contracts were introduced on the Nordic Power Exchange's financial market. Nord Pool offered financial market participants expanded clearing services; in addition to clearing all contracts traded on the Nordic Power Exchange, Nord Pool clears OTC and bilateral contracts.

In 1998 Finland joined the Nordic power exchange market area, and the EL-EX power exchange in Helsinki entered into an agreement to represent Nord Pool in Finland. Nord Pool opened an office in Odense, Denmark.

In 1999 Elbas was launched as a separate short term market for power balance adjustment in Finland and Sweden. Western Denmark (Jutland/Funen) Elspot area trade began in July.

In 2000 the Nordic power market became fully integrated when Eastern Denmark became a Nordic Power Exchange price area.

In 2002 Nord Pool was licensed as a regulated exchange and as a clearinghouse. Nord Pool's spot market activities were organised in a separate company, Nord Pool Spot AS, owned by all of the transmission system operators in the Nordic power exchange area and Nord Pool ASA

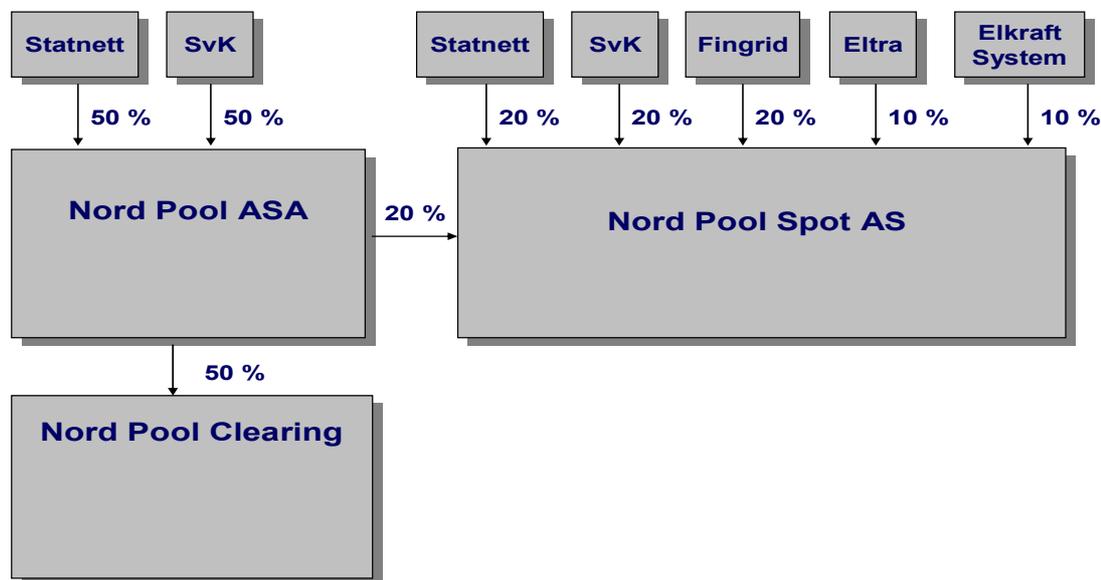


Figure 1. Nord Pool's company structure and ownership

Nord Pool operates in the following marketplaces and market services:

- A spot market for physical contracts, Elspot
- A financial derivatives market – futures and option contracts
- Clearing services for contracts traded in OTC and bilateral markets.

The volume of the trade in Elspot market in the year 2003 was 117.9 TWh. This equals to about 40 % of the Nordic electricity consumption in the common Nordic market. About 280 participants from Norway, Sweden, Finland and Denmark, as well as some other European countries and the USA, trade through Nord Pool. Participants are power producers, retailers, grid owners, brokers, market makers, traders and industrial companies.

Nord Pool – volume development

Volume (TWh)	1996	1997	1998	1999	2000	2001	2002	2003	2004
Physical market	41	44	57	76	97	112	124	118	167
Financial market	43	53	89	216	359	910	1019	545	590
Bilateral contracts, clearing	*	147	373	648	1180	1748	2089	1219	1207

* Introduced 1997

2.3. TSO cooperation - Nordel

Nordel was originally an association of people active in the field of power supply in the Nordic countries. It was founded in 1963, and was an advisory and recommendatory organisation aimed at promoting international, mainly Nordic, cooperation in the field of generation, distribution and consumption of electrical energy.

Today Nordel is a body for co-operation between the transmission system operators (TSOs) in the Nordic countries (Denmark, Finland, Iceland, Norway and Sweden), whose primary objective is to create the conditions for, and to develop further, an efficient and harmonised Nordic electricity market.

The organisation adopted new By-Laws at its Annual Meeting in June 2000, thereby formalising Nordel's changed status as an organisation for the TSOs in the Nordic countries. Under the amended By-Laws, the companies themselves are now the members of the organisation and not individual persons, as previously.

Nordel also serves as a forum for contact and co-operation between the TSOs and representatives of the market players in the Nordic countries. In order to create the right conditions for the development of an efficient electricity market, it is important for the TSOs to be able to consult with the market players. Likewise, it is important for the market players to be given the opportunity to make useful contributions and proposals to the TSOs. A Market Forum has been set up within the new Nordel organisation in order to pursue this dialogue.

Nordel's tasks fall mainly into the following categories:

- system development and rules for network dimensioning

- system operation, operational security, reliability of supply and exchange of information
- principles of transmission pricing and pricing of ancillary services
- international co-operation
- maintaining and developing contacts with organisations and regulatory authorities in the power sector, particularly in the Nordic countries and Europe
- preparing and disseminating neutral information about the Nordic electricity system and market

2.4. Transmission access and tariffs

Unambiguous and non-discriminatory tariffs for use of the grid are crucial. The connection point tariff system has proven to be an appropriate system. The consumer and the producer both pay a tariff for connection to the grid as well as a tariff for use of the grid. The tariff, which is paid to the TSOs, entitles them to transmission within a single trading area, which can encompass several sub-systems or countries. The principle of point-based entry/exit tariffs is applied in the whole Nordic area. By paying local network charges all actors have access to the whole Nordic system. There is no transaction based charges.

The Nordic TSOs enter into an agreement in 2002 on harmonization of the G-tariff in the Nordic market. The agreement stated that the G-tariff should consist of a component that cover cost of network losses and a residual component covering the rest of the cost. The residual component is often referred to as the “G-charge” or “Basic G”. It was recommended that the loss component were to be based on cost of marginal losses and that it was time differentiated. The residual charges should on average be within this interval: 0, 5 sv.øre/kWh + 0, 3 sv.øre/kWh.

In all the Nordic countries the G-charge is positive and generation in Sweden and Norway pay a significant part of the network costs. For Norway the G-charge is relatively higher than for the other countries.

As for generation all the Nordic countries have a loss component in the tariff for load. In Norway, and Sweden, this component is point based/differentiated as well as time differentiated, while for the other countries it is not. While Norway and Sweden calculate the loss factor in each connection point based on the load float in the Norwegian and Swedish system, the other countries calculate the average losses based on the difference between in- and out float from the network.

All the Nordic countries have the possibility of charging customers in the transmission grid a connection charge. All countries have shallow connection charges.

2.5. Balancing mechanisms

Since the middle of 1990's, the Scandinavian electricity market has developed into a common market, and one of the reasons for this is effective balance management. An important task for the system operator is to offer the market players an impartial balancing service and balance settlement. The objective is to perform a control action where it is most effective. When power is traded – either via the exchange or bilaterally – sooner or later the situation will arise whereby the agreed delivery is deviated from. Imbalances

between agreed and physical deliveries can easily arise and are handled by the system operator in a way that is impartial for all parties.

Each TSO collects regulation bids within his system area and sends the bids to NOIS (Nordic Operational Information System), that is a web based information system for exchange of operational information between TSOs. In NOIS a list of all regulation bids are put together and form of a “staircase” visible for all TSOs.

Balance regulation of the synchronically linked system is frequency-controlled and regulations are in general activated in order of price of operation from the common list of the regulation bids. At the end of each hour, the common regulation price is determined in accordance with the marginal price for the operation. This price applies as reference price and is included in the calculation of the settlement prices for all the sub areas when the balance/imbalance is settled. Still, different models for balance settlement are used in the sub areas (one/two-price model, marginal price or middle price).

For situations with net congestions the regulation market is divided into different price areas and bids for regulation that are locked in are excluded from the “staircase”. Under these circumstances different regulation prices occur for different sub areas.

The TSO that carries through an operation is to be paid for his costs. The price for balance power between the different sub areas is determined to the common regulation price or middle price if these are different.

Statnett and Svenska Kraftnät share the responsibility for the frequency regulation, in a similar way as today, and take initiatives to regulation operation within the synchronically linked system. Jutland will be managed in a similar way as today with planned supportive power exchange and will in that sense participate on the regulating power market. Eltra contributes frequency regulation within the UCTE-system and consequently operates balance regulation within the Eltra area (Eltra and Elkraft have merged 1.1.2005).

Nordel has developed a new order for the balance regulation cooperation within the Nordic countries. The goal has been to create a common regulation power market for all countries. The regulation cooperation will work in a way so that regulations come about in that part of the system that has the lowest cost for regulation and the players in the different parts of the system will meet as harmonised rules and prices as possible.

First, the new order will be implemented in the synchronically linked system. Second, Jutland (Western Denmark) that belongs to another regulation area will also be a part of the cooperation.

The imbalance settlement distributes income and expenditure for balance management. After the 24-hour period of operation, the imbalances of the players in the individual countries are computed. The imbalances are considered as an equivalent purchase or sale of balancing power, which is settled between the players and TSOs in the country concerned. The imbalance between the countries is settled between the TSOs based on the regulating power price, which is set as the hourly marginal price of accepted offers for regulating power.

The TSOs buy regulating power to cover the imbalances of the players and hence their purchases of balancing power. The net purchases of regulating power made by the TSOs equal their net sales of balancing power hour by hour.

Electricity trading		Regulating power	Balancing power
Nord Pool Spot		TSOs	TSOs
ELSPOT	ELBAS	Regulating power market	Balancing power
12 - 36 h	1 - 32 h		max 3 months
OTC -trading		Balancing management	Players balances

2.5.1. Functions of the Nordic Balance Management

Because of varying local conditions the Nordic countries have developed different principles of balance management; however, as part of their objectives, Nordel intends to harmonise this. Initially, the target has been to combine the regulating power markets to achieve the best possible use of the resources and ensure that the price of regulating power is determined on the same background in all of these countries. From a long-term perspective, another target could be common principles for balance settlement.

The regulating power markets were combined in September 2002. The balance of the synchronous part of Nordel is now controlled based on the frequency. Bids for regulating power in all the countries are compiled in a merit order list available to all Nordic ISOs in a common information system NOIS (Nordic Operational Information System).

The various operational and settlement functions demand extensive exchange of information between the TSOs and the players. The exchange is electronic using the so-called EDIEL format (ED1 in the Electricity industry). For internal exchange of information between the TSOs, the information system NOIS has been set up.

The countries price balancing power according to different principles. Norway uses a ‘one-price model’ according to which the same price applies to both the purchase and sale of balancing power. The other countries use a ‘two-price model’ according to which the price of the purchase or sale of the individual balance responsible player depends on whether the purchase or the sale has been to the advantage or disadvantage of the total regulation of the power system for the hour concerned.

The ‘one-price model’ is simple and gives fast settlement. Players may, however be tempted to produce deliberate imbalances to achieve a better price for the balancing

power than the spot price. This is not allowed, however, and there has been no need for the TSOs to intervene against major and systematic imbalances. The “two-price model” is more complex, but it also gives the players better incentives to maintain their balance.

The “one-price model” creates a balance between expenditure and income for balance and regulating power hour by hour. With the “two-price model”, the TSOs generate a surplus that can help cover the expenditure for balance management.

2.6. Congestion management – implicit auctions

Development of Nord Pool’s markets has led into different price areas. The permanent price areas in the Nordic region are Sweden, Finland, Denmark West (DK1) and Denmark East (DK2), South Norway (NO1) and Middle/North Norway (NO2). Last winter Norway was divided further into four price areas. The System Price is the reference price for handling potential grid congestions.

Within Nord Pool Spot price areas the system operators handle congestions by means of “counter-trade”, based on bids from producers. In Sweden and Finland (now also Eastern Denmark), Elbas, is used as a short term market operating after closing of the spot market. Due to the lengthy time span of up to 36 hours between the Nord Pool Spot price fixing and delivery, participants need market access in the intervening hours to improve their balance of physical contracts.

Nord Pool is a non-mandatory pool. Actors are free to sell or buy power via the pool, or to enter into bi-lateral contracts. There are however exemptions. When a seller is located in one price area, and the buyer in another price area, the bi-lateral contracts are transferred into bids in the Elspot market on both side of the price area border.

There are permanent bidding areas between the TSO-areas and there are no bi-lateral physical contracts between the TSO areas. All power that flow between these bidding areas is thus spot power. Up to some years ago this system of spot-trade across areas was combined with priority given to some amount of bilateral physical contracts. But today all capacity is at the disposal the day-ahead Elspot market. The physical and financial aspect of bi-lateral contract can be replicated by a buying and selling physical volumes in the different bidding areas and signing a financial contract of difference with reference to the elspot-prices.

The Elspot market at Nord Pool is a closed-book (sealed-bid) auction market. In general in typical large markets, auction is continues throughout the day’s trading. In the case of an open-book for a discrete auction, the auctioneer communicates with the participants in finding an equilibrium price to match their bids and requests, comparing them, and then telling the participants how they differ. Participants then have the opportunity to revise their bidding, and the auctioneer will once more compare and communicate with the participants. This process goes on stepwise until demand matches supply.

In the case of a closed book auction market like Elspot, however, participants submit their orders – their planned sales and purchases – to an administrator, who keeps them as

personal information, i.e. in a closed book. After a deadline for submissions, the administrator compares the bids in the book and estimates the price which will maximise sales.

With regard to transparent pricing, only occasional traders generally prefer auction markets, because they treat all participants alike. In bilateral negotiations, however, professional and large traders may have, and utilise, an information advantage to obtain a better price than with an auction.

The case for closed order-books primarily rests on the administrator's ability to estimate prices which are efficient with respect to the aggregate of the orders, without needing to match individual orders.

In Nord Pool the quantity purchased or sold by someone results from aggregation over all bids and offers; it is an element of gross balancing of the market. This formation of the markets-price by aggregation implies that Nord Pool has to be the counterpart of both the purchaser and the seller of spot power.

Each market participant has an account at Nord Pool. Every participant's purchases and sales, as well as their trading and capacity fees, enter into this account and change the balance. Nord Pool practises a weekly settlement of accounts. Before 1998 there were some problems due to settlement of Finnish and Swedish trade in Oslo (Finnish and Swedish traders had to declare their trade according to guidelines given by Norwegian Customs Authority. Transfers of these accounts to Helsinki and Stockholm and later to Copenhagen have solved this problem).

The model of implicit auction in the Nordic areas is based on the described closed book auction model. This model establishes hourly market prices day ahead. These market prices provide a gross balancing if the whole market based on continues supply and demand curves for every hour. The intersections of the demand and supply curves determines the market prices which at the same time represent the cost to society of a marginal increase in consumption, and the society costs of a marginal increase in generation. The demand and supply curved cover the whole price-interval from zero prices up to a technical price ceiling. In an implicit auction between to exchanges using this auction principle, new regional market prices can be found for different volumes of cross border trade between the regions simply by applying parallel movement of the supply/demand curves. This is possible because the closed-book auction as practised, provide information on the demand and supply curves over the whole relevant price/volume schedule.

In a system based on implicit auctions the interconnecting transmission capacity is at the disposal of the spot-market. A market actor can accomplish any cross-border transaction by putting price-dependent or price-independent bids into the spot-markets on both side of a potential constraint, and signing a contract of difference if desired (standard forward contracts of difference may also be established). By bidding in price-dependent bids the actor can co-ordinate his volumes with the actual price-differences hour by hour.

In an implicit auction the whole price-difference ends up as income to the owner of the interconnecting transmission capacity. This is parallel to the result in an explicit auction with full information and no transaction costs.

2.7. Market Concentration and market power in the Nordic market

The information in this chapter is taken from:

Report from the Nordic competition authorities. Towards a more coherent competition policy in the Nordic market for electric power. Copenhagen, Oslo, Stockholm, 20 June 2003

The Nordic Working Group (competition authorities) has examined market power in the Nordic power market with a view to suggest measures to increase competition and improve co-operation on national competition policy enforcement. The Working Group's opinion is that the deregulation of the Nordic electricity sector has been largely successful. However, some obstacles to competition remain:

- Bottlenecks in the grids divide the Nordic region into shifting constellations of relevant geographic markets.
- Market concentration figures in these geographic markets are very high.
- The high market concentration figures are partly due to cross-ownership and jointly owned production plants.
- Inflexibility of the production plants and capacity constraints on production enhances market power. Even a small firm can exert market power.
- Demand for electricity is very inelastic.
- Practises with negative effects on competition may have ripple effects all over the Nordic region.
- There are high barriers to entry.
- The Working Group would like to draw attention to the following actions which could be used to promote competition:
 - Mergers leading to increased market concentration must be carefully reviewed.
 - The reasons for concern are more predominant regarding mergers between companies having flexible production technologies than between mergers involving inflexible technologies.
 - One or two major producers dominate all national markets. The large extent of cross-ownership is an obstacle to well functioning markets. Authorities should consider if and how more pro-competitive company and ownership structures could be created.
 - Transmission system operators should endeavour to increase the effective capacity utilisation of the transmission grids.
 - Transmission system operators should pay due attention to competition considerations in investment analyses of new transmission capacity.
 - Increased transmission capacity will usually reduce the scope for exerting market power.

However, increases in transmission capacity will not fully eliminate market power. In order to improve co-operation on competition policy enforcement in the Nordic region, the Working Group would like to point out:

- Although there are separate regional geographic markets the effects of many mergers and anticompetitive business practises are inter-Nordic.
- Market power being exerted in one region may have detrimental effects in all parts of the market.
- When national competition authorities handle mergers and anticompetitive business practises there is a risk that the overall effects will not be taken into consideration.
- In the power market the opportunity for exchanging information under the Nordic agreement on exchange of information will be of particular importance.
- The procedures should be implemented that will enable involvement of the Nordic national competition authorities in the handling of cases with effects in more than one country.
- An inter-Nordic working group should be established in order to exchange views and promote harmonisation of the analytical framework.
- The Nordic group should not be a closed forum but invite other European competition authorities to participate when relevant.
- Information exchange between Nord Pool, Nordic energy agencies, financial authorities and competition authorities should be strengthened.

2.7.1. The unadjusted HHI

The unadjusted HHI indicates that the Nordic market is an unconcentrated market: HHI = 892.

The Nordic market	Production GWh 2001	Market share	HHI
1. Vattenfall	75200	19 %	376
2. Fortum	60600	16 %	244
3. Statkraft	44800	12 %	133
4. Sydkraft	33200	8 %	69
5. Teollisuuden Voima (TVO)	15100	4 %	15
6. Elsam	14600	4 %	14
7. Energi E2	11800	4 %	9
8. E-CO	10200	3 %	7
9. Norsk Hydro	9800	3 %	6
10. Pohjolan Voima (PVO)	8000	2 %	4
11. BKK	8000	2 %	4
12. Agder Energi	7900	2 %	4
13. Lyse Energi	5900	2 %	2
14. Helsingin Energi	5400	1 %	2
15. Vannkraft Øst	4900	1 %	1
15 largest producers	315400	81 %	892
Total market production	388000		

There is no cross-ownership between the three largest Nordic electric power producers. The most important cross-ownership holdings are Statkraft's ownership positions in its competitors Sydkraft (45%), E-CO (20%), BKK (50%), Agder Energi (46%) and Vannkraft Øst (13%). Other important crossownership holdings are Fortum's 27% share of TVO, which is also owned with 27% by PVO.

3. Regulation on TSOs and Nord Pool Spot

National energy authorities are responsible for regulating the TSOs. However, the responsibilities have differed significantly due to the varying powers given to authorities in the each national electricity market legislation. Due to implementation of the Energy Directive regulatory responsibilities are changing and will now be more equal.

Nordic Energy Regulators have founded a co-operation forum named FNER (Forum of Nordic Energy Regulators). FNER's intention is to promote and enhance the Nordic Energy Market. According to the statutes of FNER, the Nordic regulators are committed to co-operate in regulating the market within legislative powers given to each regulator. FNER arranges annual and ad hoc meetings with TSOs organization Nordel in which the Nordic market issues are dealt with.

3.1. Regulation of Nord Pool Spot

Nord Pool Spot is located in Norway and therefore regulated by the Norwegian regulator (NVE) with powers given to it in the Norwegian Energy Act. According to the Energy Act NVE can ask for information considering both Nord Pool Spot AS and OTC –market.

According to Energy Act an organised market place need to apply for a licence to operate.

The conditions for market place operators licence are defined in the regulations:

- a) The licensee has to enhance within reasonable efforts the efficient pricing and energy flows. The licensee has to operate in a nondiscriminatory mode. It has to provide all market participants a neutral and efficient access to information which affects to the market price formation.
- b) The licensee has to create compatible organisation, rules for trading and contracting as well as rules for system security and clearing. This will confirm the reliability and predictability to the market participants.
- c) The licensee can have reasonable earnings after cost efficient organisation an operation of the market place.
- d) The licensee has an obligation to supply the information needed by the authority.
- e) Market place has to enhance and support efficient system operation.

In the license NVE has given more specific conditions one the above issues.

According to the Energy Act section 4-5 Nord Pool Spot can be imposed further conditions when required in particular cases for general reasons.

3.1.1. Guidelines for Nordic co-operation in regulation of Nord Pool Spot AS

For information exchange and consultation in connection with NVE's exercise of authority over

Nord Pool Spot AS:

1. In order to produce an efficient regulation of the power market and in order to establish mutual information exchange, the NVE wishes to contribute to close collaboration between the Nordic regulators within the electricity sector.
2. These guidelines deal with issues that are related to the NVE's exercise of authority over Nord Pool Spot AS and that can be considered to be of importance or interest for the power market in the Nordic countries.
3. To the best of its ability and as far as it is possible, the NVE will notify or consult the regulators in Denmark, Finland and Sweden at an early date and in the most appropriate manner.
4. Depending on the type of issue and the time available for exercising authority, the NVE will determine fairly whether there should be consultation in the matter or whether notification should be provided.
5. The regulators in Denmark, Finland and Sweden may propose and bring up issues related to the regulation of Nord Pool Spot AS to be considered jointly by the Nordic regulators within the co- operation established through these guidelines.
6. In order to maintain an efficient exercise of authority, in matters of consultation the NVE can establish a reasonable delay for a response.
7. Individual regulators will cover their own expenses related to the collaboration in accordance with these guidelines.
8. In consultation with the other regulators, the NVE can make changes to these guidelines.
9. These guidelines are in force as of 2002.01.02.
10. These guidelines can be declared null and void.

3.1.2. Nord Pool's internal market surveillance

NP's internal market surveillance is organised within the Nord Pool ASA (financial market). Nord Pool has published specifications and guidelines on operational work of surveillance.

The main objective for market surveillance at Nord Pool is to monitor the trading activities at the spot and derivatives markets at Nord Pool and ensure that the operations are in accordance with the Norwegian Exchange Act 2000, other laws and public regulations, the rulebook for physical market at Nord Pool Spot AS and the rulebook for financial electricity market at Nord Pool ASA.

The main areas of responsibility for the market surveillance function, corresponding to the provisions in the rulebook (market conduct rules), are described below.

Disclosure of price relevant information (insider information)

Market surveillance is responsible for monitoring that participants comply with the disclosure rules the rulebook at both Nord Pool ASA and Nord Pool Spot AS. In accordance with these rules the participants have an obligation to disclose price relevant information so that the power market is promptly and uniformly informed about incidental or planned limitations related to production, consumption and transmission facilities within or directly connected to the Nordic electricity area. Such price relevant information must be provided to the Nordic Power Exchange before being publicly available for the market. The duty to disclose information is a key in developing transparency and thus confidence in the market.

Prohibition on Insider Trading

Market surveillance is responsible for monitoring that the participants do not misuse any insider information by entering into exchange trading when holding information which is not made public and which is considered to influence on market pricing as defined in the disclosure rules.

Reporting of non-exchange trades

Market surveillance is responsible for monitoring that participants comply with the rules of reporting non-exchange trades in listed products at Nord Pool ASA. In accordance with these rules the participants have an obligation to report all non-exchange trades to be cleared with Nord Pool Clearing ASA within 15 minutes of the trade being closed.

Market manipulation

Market surveillance is responsible for monitoring that the participants do not manipulate the market by publishing prices that do not reflect the real market value by giving incorrect or misleading information, entering into fictitious agreements or using unreasonable business methods.

Market surveillance is responsible for reporting to relevant authorities if its investigations reveal any unlawful behaviour.

4. The role of authorities

4.1. The Nordic Council of Ministers

The Nordic Council of Ministers, formed in 1971, is the forum for Nordic governmental co-operation. The Ministers of Energy have been active in promoting the Nordic market development. The principles supporting the Nordic regional Electricity market was stated by the Nordic Council of Ministers in its Louisiana declaration from 1995. The objective of the market development was to achieve mutual benefits in the energy system with regard to economic, environmental and security conditions. The Council stated that the point of departure for the co-operation in the field of electricity should be that the authorities in the respective Nordic countries have an overall responsibility for the functioning of the market.

In September 2004 The Nordic Council of Ministers in its Akureyri-declaration stated that the Nordic market in an international perspective is an efficient and well-functioning market. But even as there have been great developments since 1995, it is important to take new steps ahead.

The Nordic Ministers of Energy in the Akureyri-declaration stated that they are in agreement to ask the system operators

- to consider how increased coordination of system responsibility, joint organisation and financing of network investments and peak load handling can be achieved
- to elucidate different organisational models for joint handling the network activity and system responsibility, and that these issues will be discussed at the next Council meeting in 2005.

4.2. The regulators (FNER)

FNER has published work plan for the year 2005 and several of the projects aim to enhance the co-operative measures in balancing, TSO-regulation and co-operation between Nordic authorities (regulators, competition authorities, financial inspectorates)

4.2.1. FNER's project to develop a common balance management and settlement system

The aim of this project is to map the pros and cons of a common balancing system within the Nord Pool system. What are the possibilities with, and threats to such a system? The aim of the work in 2005 is to outline a roadmap for developing the Nordic market in this area by investigating if a common balance management and settlement system is a reasonable way to increase the possibilities for retailers to act in a more pan-Nordic way.

During 2005 the FNER-work within this area should:

- A) Identify the purpose of, and possible gains of a common balance management and settlement system.
- B) Identify associated arrangements which may be affected by alternative solutions for common balancing, such as the working of the TSOs information exchange and Nord Pool.
- C) Identify the necessary obligations to be placed on TSOs, power exchange operators and other actors.
- D) Examine appropriate arrangements for regulatory oversight, including obligations placed on TSOs. Consideration should be given to the cross border nature of the alternative solutions examined and the problems caused by multiple jurisdictions.
- E) Examine the effects for the suppliers as well as the large customers (that may be or become active on Nord Pool).
- F) Assess the options for co-ordinated balance management and settlement system in the Nordic market.

4.2.2. FNER's project to ensure a well-functioning power exchange

The purpose is to organise a joint meeting between the relevant Nordic authorities and Nord Pool to share experiences and discuss different viewpoints. Such a meeting will give both the authorities and Nord Pool the opportunity to address different issues regarding the power exchange and the Nordic power market.

Relevant issues in this joint meeting will be

- Roles and responsibilities of various parties and authorities
- Nord Pool
 - Products
 - Liquidity
 - European development

4.2.3. FNER's project to regulate and monitor the TSOs with focus on efficiency and Nordic harmonisation

The purpose of this project is to evaluate whether the present regulation of the TSOs in the Nordic countries is adequately harmonised and efficiently sustains to the development of the Nordic electricity market.

It should explicitly be evaluated if a further harmonised Nordic regulatory set-up could contribute to an enhanced development of the common Nordic electricity market. This evaluation should comprise an examination of whether partly or full harmonisation or the setting of common minimum standards for the regulation in selected priority areas would encourage the market development further.

The working group shall map:

- The present overall legal framework of the TSOs in each Nordic country
- The present degree of unbundling and ownership conditions of the TSOs in each Nordic country
- How the TSOs are regulated in each Nordic country as concerns supervision of tariffs and prices – including how benchmarking is used as a tool in this respect
- The explicit regulatory mandate of the TSOs in each Nordic country, including PSOs, security of supply, rules on planning, operation and connection, establishment of the market place as well as cooperation between TSOs on these areas

Based on the mapping of the above mentioned issues the working group should evaluate – if necessary - how and by which means further harmonisation of the regulation of the TSOs can be achieved.

5. Lessons

Market design

The development of the Nordic regional market was initiated by early market design in Norway and at later stage in all other Nordic countries. The combination of multiple production methods in the Nordic region was one of the key drivers to integrate the region.

TSO co-operation

Close co-operation of the TSOs has been important to develop methods for handling all system operations needed for the regional market. However, the Nordic market is still developing and some obstacles have to be tackled on the way to an even more competitive market. Common organisation and financing of new network investments, common peak load handling, capacity allocation and congestion management are some areas where there still is a need for improvements. Experience on the case in study is that it is important for the TSOs to have a strong focus into the arrangements in harmonising the market.

Nord Pool Spot

The electricity spot market is a vital part of the competitive Nordic electricity market. Founding of the Nord Pool Spot has been a market based solution involving relevant market participants. Nord Pool Spot is based on the implicit auction mechanism which has proved to be efficient way to auction. Transparency is one of key elements of the Nord Pool Spot's functions. All the relevant information is published nearly on line and the needed information is required from the market participants by the rules of the Nord Pool.

Governmental and regulatory co-operation

The Nordic Council of Ministers, formed in 1971, is the forum for Nordic governmental co-operation. The Ministers of Energy have been very active in promoting the Nordic market development. The objective of the market development has been to achieve mutual benefits in the energy system with regard to economic, environmental and security conditions. The Council stated that the point of departure for the co-operation in the field of electricity should be that the authorities in the respective Nordic countries have an overall responsibility for the functioning of the market.

Nordic Energy Regulators have founded a co-operation forum named FNER (Forum of Nordic Energy Regulators). FNER's intention is to promote and enhance the Nordic Energy Market and it co-operates on different issues considering the Nordic market. Nord Pool Spot is located in Norway and therefore regulated by the Norwegian regulator (NVE) with powers given to it in the Norwegian Energy Act. All though, NVE has published guidelines for a Nordic co-operation in regulation of Nord Pool Spot.

Functionality of the market

The first supply shock, the dry winter of 2002-2003, the electricity market was put to its first major test. The main concern – was the impact of high prices on customer bills. After a sustained period of low prices, consumers were not prepared for a sudden price increase. Nevertheless, all in all it must be said that the market withstood the test and handled the supply shock rather well; prices adjusted rapidly and both demand and supply responded. Drastic measures such as rationing were never warranted or needed.

The Future of the market

After a decade of functional operation it can be stated that:

- Nordic operational efficiency has increased and needs to be increased
- Nord Pool has proved its' "case" with survival of the ultimate market test in the extreme condition in winter 2002/2003
- Harmonising some rules and operations has to continue (Congestion management and Balancing)
- More interconnector and transmission investments are needed
- Demand response need to be improved

The Nordic electricity market is still developing and some obstacles have to be removed on the way to an even more competitive market. For example, Nordel has published a plan to invest in five prioritized projects in the Nordic countries and one of them has already been approved by the TSOs. This is expected to make the prices converge even more, but also to increase the possibilities to handle extreme situations like the aforementioned dry winter.

Further, a common Nordic retail market is less developed than may be desirable. Thus, there may be an important task to have compatible rules, and identify and remove obstacles for retailers, so, also, a true Nordic retail market can be created.