The Internal EU Electricity Market: Implications for Ireland

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The ESRI

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BETTA	British Electricity Trading and Transmission Arrangements
CACM	Capacity Allocation and Congestion Management
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CEPA	Cambridge Economic Policy Associates
CER	Commission for Energy Regulation
Commission	European Commission
CMG	Guidelines on the Management and Allocation of Available Transfer Capacity of Interconnections Between National Systems, Annex I of Reg. 714/2009.
DCMNR	Department of Communications, Marine and Natural Resources
DCENR	Department of Communications, Energy and Natural Resources
DETI	Department of Enterprise, Trade and Investment
EC	European Commission
EIB	European Investment Bank
ENTSO-E	European Network of Transmission System Operators for Electricity
ERGEG	European Regulators for Electricity and Gas
ERI	Electricity Regional Initiative
EU	European Union
FG	Framework Guideline
FUI	France-UK-Ireland
GW	gigawatt or one billion watts
IC	Interconnector
IDEM	Irish Dispatch Electricity Model
IFA	Interconnexion France Angleterre
IMF	International Monetary Fund
IU	Interconnector Unit
MW	megawatt or one million watts
MWh	megawatt hour
NIAUR	Northern Ireland Authority for Utility Regulation

North Seas Grid	North Seas Countries' Offshore Grid Initiative
NRA	National Regulatory Authorities
OCGT	Open Cycle Gas Turbine
Ofgem	Office of Gas & Electricity Markets
OTC	Over the Counter
PCG	Project Coordination Group
PPMG	Predictable Price Maker Generator
PSO	Public Service Obligation
REFIT	Renewable Energy Feed-In Tariff
REM	Regional Electricity Market
RTE	Reseau de Transport d'Electricite
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
SMP	System Marginal Price
SRMC	short run marginal cost
SSE	Scottish and Southern Electricity
Target Model	Target Model for Capacity Allocation and Congestion Management
TSO	Transmission System Operator
TUoS	Transmission Use of System Charge

Executive Summary

The European Union is creating a single electricity market. Like the single European market for goods and other services, if the price of electricity is lower in France than Ireland, traders will export electricity from France to Ireland, thus lowering the price in Ireland. The legal architecture has been enacted. Important implementation decisions still need to be completed. An EU-wide deadline of 2014 has been set. However, Ireland has been granted transitional arrangements until 2016. On completion the scope of the single EU electricity market is likely to include wind power from the North Seas and solar power from North Africa. What are the implications for Ireland?

First, costly undersea cables have to be built so that Ireland can participate in the single EU electricity market. Without such interconnection, Ireland will not be part of the wider EU electricity market, but instead be characterised as a small closed electricity system catering for a few million people and a smaller number of businesses. The Moyle Interconnector ("IC") already links the all-island electricity market to Scotland, while the East West IC to England is due for completion on Q3 2012. It is expected to cost €600 million. However, to fully participate in the single EU electricity market interconnection capacity will have to be at least doubled. This will not be completed until later in the decade at the earliest.

Second, participation in the single EU electricity market is likely to bring substantial benefits to Ireland. Ireland has high electricity prices by EU standards. Access to the wider EU electricity market should result in electricity prices that will be lower than they otherwise would be. Security of supply will increase through access to a greater diversity of fuels – hydro power from Northern Europe and nuclear power from Great Britain and France. There will be less need for reserve capacity to insure against supply interruption. The price benefits assume, however, no major policy failure in UK energy policy that results in higher electricity prices in the medium term that cannot be offset through increased interconnection between Great Britain and continental Europe. Such a policy failure might, for example, be Great Britain's inability to replace a quarter of its generation capacity by 2020.

Third, there is a strong role for government in assisting in building interconnectors. The benefits of increased security of supply and a smaller reserve capacity are difficult for private firms to appropriate or capture. As more and more interconnection capacity is built to Great Britain, electricity prices in Ireland will converge to those in Great Britain. However, the returns to interconnector owners will fall, since traders will be prepared to pay only a small price to use the interconnector – at a maximum the difference in price between electricity in Great Britain and Ireland. Hence there is a role for the State to ensure that enough capacity is built.

Fourth, the single EU electricity market will facilitate achieving the State's target of generating 40 per cent of electricity from renewable (virtually all wind) sources by 2020. Wind is a variable source of electricity. When the wind speed is too low or too high it cannot be used, and expensive thermal plants have to be ramped up; even when the wind blows at usable speeds, some of the wind generated electricity may not be used since the electricity transmission system can only use a certain proportion due to system security issues. Access to the wider EU market lessens these problems: when the wind does not generate electricity it can be imported; when the wind generates too much electricity for use in the all-island market it can be exported.

Fifth, although completing the single EU electricity market will facilitate achieving the 40 per cent renewable target in a cost-effective way, the building of additional interconnectors primarily to export renewable electricity would be costly. If all planned wind farms are completed, capacity will comfortable exceed the 40 per cent renewable target. As a result there are likely to be demands for the construction of interconnection capacity to export renewable electricity. However, if this additional capacity receives extensive public support it will feed through to higher electricity prices. To accommodate additional wind on the transmission system will require extra investment to strengthen the system, again feeding through to higher electricity prices. Finally, additional interconnection capacity is unlikely to be used when the wind does not blow, with the result that the interconnector may not be fully funded through congestion revenue and its costs will be borne by electricity consumers. One way in which a Member State that generates excess renewable electricity, such as Ireland, could capture value is through tradable renewable permits. The excess could be sold as renewable permits to a Member State for which reaching its target using domestic measures only was more costly.

Sixth, the all-island electricity market, the Single Electricity Market ("SEM"), must comply with the single EU electricity market regulations and network codes for trading over interconnectors. This may prove costly. Completing the single EU electricity market requires common rules for trading across interconnectors. This is important for encouraging trade in electricity between Member State markets. There are considerable differences between, for example, the electricity market rules in Ireland and Great Britain, which discourages trade in electricity. If these differences are not resolved then interconnectors will not be used efficiently and the benefits of the wider EU electricity market will not be fully realised. The SEM, four years old on 1 November 2011, has worked well for consumers. The issue becomes the extent to which the essential features of the SEM, such as a mandatory pool into which all generators have to bid short-run marginal cost, can be retained, while at the same time, complying with EU electricity market regulations and network codes. Initially small changes have been made to the SEM to comply which will come into effect in 2012. However, it is still unclear whether further small changes will be required or whether a fundamental and substantial redesign of the system will be required. Redesigning the SEM is not only likely to be costly but could also create considerable investor uncertainty.

An important aspect of the EU legislation creating the EU wide electricity market is the principle of subsidiarity. Under this principle responsibility for a particular task or area is assigned to the Member State where it can be more effectively dealt with at that level. There is no a priori reason why different electricity market designs cannot be interconnected using somewhat different arrangements in terms of, for example, frequency of trading electricity. The legislation creating the EU electricity market refers to Member States not being forced to redesign their systems so as to meet the interconnection rules. Hence, the rules for the market should permit Ireland the time and space to implement the policies of the EU electricity market in a manner consistent with its needs.

Chapter 1

Introduction: Peeling Back the Onion

The European Union ("EU") is striving to complete the single EU electricity market ("the internal market") by 2014.[1] Legislation has been passed. Deadlines have been set. On completion, the scope of the internal market is likely to include wind power from the North Seas and solar power from North Africa. While many of the important policy and other parameters of the internal market are binding on Member States, in other important respects, such as the timing and magnitude of building interconnectors,[2] individual Member States have considerable discretion over implementation and participation in the internal market. Furthermore, Member States can influence the structure and shape of the internal market through involvement in both drafting and applying/implementing EU legislation and guidance.

The purpose of this paper is to describe and evaluate the implications of the internal market for Ireland[3] and identify what important issues still need to be addressed through further research. The internal market agenda is driven by EU legislation, primarily the Third Package and its predecessors. However, attention also needs to be paid to a parallel and complementary development, namely Regional Electricity Markets ("REM"), which is part of the Electricity Regional Initiative ("ERI"). Indeed, the Third Package incorporates the REMs within its ambit. The major building blocks for the internal market and the institutional and legislative arrangements are set out in Chapter 2.

The paper addresses specific issues and questions relating to the internal market. These issues and questions revolve around the interconnection of the Irish electricity system with Great Britain and the rest of the EU:

1 The internal market.

2 Interconnectors are defined as equipment used to link electricity systems. In the case of Ireland, for example, the East-West Interconnector ("IC") links Ireland with Great Britain via an undersea cable. See Chapter 3 for further details of Ireland-Great Britain interconnection.

3 Unless otherwise indicated or it is obvious from the context, Ireland will be defined to include both the Republic of Ireland and Northern Ireland. This reflects the fact that the electricity wholesale market is organised on an all-island basis through the Single Electricity Market ("SEM") and hence it is reasonable in the context of the electricity market to treat the island of Ireland as a single unit. However, the retail electricity markets in the Republic of Ireland and Northern Ireland are regulated separately by the relevant local regulator.

- *Theoretical Rationale for Interconnection:* Why build interconnectors? Is there a role for government? (Chapter 3).
- *Current and Future Interconnection:* What are the current plans for participation by Ireland in the internal market via interconnection? What are the options? (Chapter 4).
- *Interconnection and Wind:* How much interconnection should be built to facilitate meeting in a cost-effective manner, the ambitious 2020 targets for the share of electricity generated in Ireland by renewable sources, primarily wind? (Chapter 5)
- Distributing Interconnection Rent/Congestion Income:
  - How should interconnector congestion income be distributed: regulated vs. merchant interconnectors? (Chapter 6).
  - Should the internal market winners compensate the losers, in terms of, for example, producers and consumers? (Chapter 7).
- *Interconnection Governance*. How should interconnectors be governed? What rules should obtain concerning their use? (Chapter 8)
- Market Design Options:
  - *SEM vs BETTA*. The all-island Single Electricity Market ("SEM") and the British Electricity Trading and Transmission Arrangements ("BETTA") are different electricity market models.[4] From an Irish viewpoint, which is the preferred model? (Chapter 9).
  - *Convergence to an EU Model*. Is the SEM consistent with the Congestion Management Guidelines, the Target Model and the Capacity Allocation and Congestion Management Framework Guideline? What degree of discretion should and will Member States be accorded in complying with these Guidelines? Do these Guidelines imply convergence to a single EU Model? How should any regulatory uncertainty be addressed? (Chapter 10).

Chapter 11 presents the main conclusions of the paper, while Chapter 12 details some of the issues that remain unresolved and what future research might be undertaken to address these.

The answers to the above set of questions are not, in the main, factual in nature. Rather they reflect judgements as to how best to respond to various internal market challenges such as the appropriate level of interconnection or the rules that apply to the governance of interconnectors. In approaching each of these questions, a two stage approach is employed. *First*, what from an economic welfare maximising point of view is the answer? Often it may not be possible to provide an exact or precise

[4] Of course, account will be taken of the fact that BETTA itself is currently undergoing change.

answer, but instead the factors that need to be taken into account in reaching the answer will be discussed. The direction may be clear, but not necessarily the precise destination. The issue also arises as to the relevant group whose welfare should be considered. In geographic terms, for example, attention could be confined, at one extreme, to residents of Ireland, or at the other, to residents of the EU. In general, the focus of this analysis will be on residents of Ireland; and, in distributional terms, consumers compared with producers. However, there may be trade-offs whereby EU residents are made better off and residents of Ireland suffer.

Second, are the incentives facing the participants responsible for delivering various aspects of the internal market aligned correctly in order that the appropriate solution or outcome is attained? This can be thought of as follows: what is the motivation of each of the market participants, including government? Given the motivation, does the regulatory framework, including State-mandated prices, send the correct signals so as to lead to the appropriate outcome? The motivation is usually a given – firms, for example, maximise profits; political parties put forward policies and proposals designed to appeal to the electorate so as to gain election[5] – so the issue becomes how to create the right regulatory framework that utilises that motivation to ensure that the appropriate outcome is reached.

In addressing the impact of the internal market on Ireland, the lens or conduit through which this is assessed is interconnection. Without interconnection, Ireland will not participate in the internal market, but instead be characterised as a small closed electricity system catering for a few million people and a smaller number of businesses. Interconnection, for Ireland, involves the building of costly undersea infrastructure to Great Britain and perhaps beyond. Hence, decisions need to be made concerning the financing, size, timing and governance of interconnectors. Interconnectors between Ireland and Great Britain link two quite different models for structuring the electricity market. That in turn leads to questions about whether or not, from an Irish point of view, it is preferable to switch to the Great Britain model (either in its current form or as reformed) or stay with the current all-island model. Indeed, once extensive interconnection takes place with Great Britain does Ireland have much choice over its model of the way in which the electricity market is structured and regulated? Moving beyond these islands, further issues need to be addressed concerning whether or not, irrespective of the merits of the Ireland or the Great Britain model for organising the electricity market wider EU legislation and plans mean that much of this discussion is irrelevant. Specifically, will the highly prescriptive access and other rules set out in the guidelines and network codes on

5 Hence, for example, if voters decide to switch their preferences to a pro-environment party, then the preferences and objectives of the government are likely to change.

the governance of interconnectors of necessity result in all EU Member State markets converging to a single market electricity model or will there be room for diversity? Thus, this paper is analogous to peeling an onion; beneath each layer is yet another layer, once one issue or question is resolved another appears.

It will not be possible in this paper to address all of the issues and questions that are either posed above or that arise in analysing the impact of the internal market on Ireland. In some cases, considerable additional research will be needed. Nevertheless, by identifying the issues and questions that still need to be addressed and resolved, it is anticipated that this paper will contribute to setting the research agenda on the impact of the internal market on Ireland.

Chapter 2

Building Blocks for the Internal Market: Setting the Scene

The creation of the internal market consists, at the risk of some oversimplification, of two inter-related building blocks that have been developed in parallel:[6] first, EU legislation, the Third Package and its predecessors; and second, the ERI/REM and associated initiatives of European Regulators for Electricity and Gas ("ERGEG"), many of which have subsequently been taken over by the newly created Agency for the Cooperation of Energy Regulators ("ACER").[7] ERGEG was dissolved by the Commission with effect from 1 July 2011. In this chapter, these two building blocks are briefly described, before attention moves to their interrelationship in taking the internal market agenda forward. Some concluding comments on the internal market process complete the chapter.

The Third Package

The Third Package came into effect on 3 March 2011.[8] It follows extensive EU research on the impact of previous legislation, dating back to 1999, also designed to create an internal market for energy.[9] However, these earlier measures "…neither provide the necessary framework nor provide for the creation of interconnection capacities to achieve the objective of a well-functioning, efficient and open internal market."[10] The Third Package is designed to fill this lacuna through an extensive and detailed set of regulations,[11] directives[12] and interpretative or guidance notes.[13] According to Commissioner Piebalds, it is now time to complete the internal market

6 Of course, the realisation of the internal market requires interconnection to make it effective. The discussion here is concerned with the legislative framework for the internal market.

7 Indeed, ACER is composed of the national energy regulators and hence there is likely to be considerable overlap with ERGEG. Lord Mogg, the first chair of ACER, for example, is also the chair of ERGEG.

8 While the Regulations have direct effect, Directives need to be transposed into domestic legislation, which can be a time consuming process.

9 The research is set out in the energy sector inquiry conducted by DG Competition. For details see EC (2007b).

10 Recital 4 of Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003. This will be referred to as Reg. 714/2009.

11 Regulation (EC) No 713/2009 of European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators (hereinafter referred to as Reg. 713/2009) and 714/2009 are those concerned with electricity.

12 Directive 2009/72 of European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, hereinafter referred to as Directive 2009/72.

13 To date three have been released by the Commission (EC, 2010c, 2010d, 2010e).

"…and ensure that the benefits of this market are real, effective and available to each and every person and company."[14]

The Third Package has effectively created a new institutional architecture. At the Community level ACER, in which the Commission for Energy Regulation ("CER") will participate,[15] and the European Network of Transmission System Operators for Electricity ("ENTSO-E"), in which both EirGrid and SONI, the Transmission System Operators ("TSO") in the Republic of Ireland and Northern Ireland, respectively, will be members. At the level of the Member State, the independence and objectives/powers of national regulatory authorities ("NRAs"), such as the CER, are strengthened and extended.[16]

At the same time the Third Package introduces a series of *structural* and *behavioural* reforms designed to increase competition between and within individual Member State markets. The former include unbundling the TSOs from generation and supply activities and the reduction in barriers to market integration between Member States. The latter include the Congestion Management Guidelines ("CMG") that set out the rules for the operation of interconnection where there is excess demand for use of the interconnector at a zero price (i.e. congestion).[17] Developing measures for greater transparency on, for example, network operation and common commercial and security codes are also instances of behavioural reforms. Of course, the reforms and the new institutional architecture are complementary, since the new and strengthened institutions are charged with shaping and implementing the structural and behavioural reforms.

The Third Package is designed to promote the internal market by encouraging greater competition between participants *across* and *within* Member States. In this paper attention is largely confined to measures that promote competition across Member States. Interconnection is a necessary, but not sufficient condition, for facilitating such competition. This is not to deny the importance of essential and necessary complementary measures to liberalise electricity markets within each Member State. Of particular importance in this regard is the ownership unbundling

14 EC (2007a).

15 But not the electricity regulator for Northern Ireland, the Northern Ireland Authority for Utility Regulation ("NIAUR"), whose interests will be represented through Office for Gas & Electricity Markets, the energy regulator for Great Britain.

16 In the case of Ireland the emphasis on regulatory independence goes against the grain of a recent government statement on policy towards economic regulators such as the CER. For further discussion see Gorecki (2011).

17 The CMG form Annex I of Reg. 714/2009. The full title of the CMG is given in the 'Abbreviations' at the beginning of this paper. Congestion is defined in Reg. 714/2009 at Article 2(2)(c) as " …a situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and/or the national transmissions systems concerned."

of the transmission system, which appeared to be the favoured option of the State.[18] However, it should be remembered that the European Commission ("the Commission" or "the EC") plays an important role in approving Member State proposals on the liberalisation of national markets and ensuring compliance in other ways.

Taking the Third Package Forward: The Target Model and Framework Guideline on Capacity Allocation and Congestion Management

The Third Package leaves a number of tasks to be fleshed out and developed. One of these is the development of network codes "…for providing and managing effective and transparent access to transmission networks across borders … ."[19] These codes cover a variety of topics from data exchange to energy efficiency regarding electricity networks.[20] The framework guidelines ("FG") are used to develop the network codes.[21] Here we pay attention to the development of the Target Model and FG, both on Capacity Allocation and Congestion Management.

The Target Model for Capacity Allocation and Congestion Management ("Target Model")

The Project Coordination Group ("PCG") originated in 2008 at the European Energy (or Florence) Regulatory Forum and chaired by ERGEG with the "…task of developing a practical and achievable model to harmonise interregional and then EU-wide coordinated congestion management and of proposing a roadmap for concrete measures and a detailed timeframe, taking into account progress achieved in the

[18] The 2007 White Paper on energy endorsed ownership unbundling (DCMNR, 2007, p. 48) as did the 2007 Programme for Government. However, the decision was then put on hold in 2008 in order for the Transmission Asset Analysis to be undertaken on the issue of unbundling. No decision was reached prior to the 2011 General Election. In the 2011 Programme for Government there is a commitment to the "hand-over of ESB's transmission assets to EirGrid" (Department of the Taoiseach, 2011, p. 15). However, when announcing the sale a minority stake in ESB in September 2011, the responsible minister referred to the sale as of "ESB as an integrated utility" (DCENR, 2011). Ownership unbundling is the option favoured by the European Commission and the Review Group on State Assets and Liabilities (2011, p. 44). A discussion of why this option is important in facilitating interconnection and the internal market may be found, for example, in Kapff and Pelkmans (2010).

[19] Reg. 714/2009 Recital 6.

[20] Reg. 714/2009 Articles 6 to 8.

[21] A Framework Guideline (on, for example, Capacity Allocation and Capacity Management) is the first step in the process, is non-binding, and is developed by ACER. The second step is the development of the network code which must follow the guiding principles set out in the Framework Guideline and is developed by ENTSO-E. The third step is when the network code goes through comitology and becomes legally binding on all Member States via an EU Regulation.

ERGEG ERI."[22] The PCG's efforts resulted in a draft Target Model, which included a roadmap for the integration of the REMs. It is wide ranging covering forward, day-ahead, intra-day and balancing markets[23] as well as capacity calculation and governance issues. Taken together the result forms the basis for the Framework Guideline, which is discussed below.

The PCG made a presentation on the target model in December 2009.[24] The presentation included an indicative possible sequencing of European market coupling with all REMs coupled by 2015, with the REM to which Ireland belongs joining in 2014, but with no decision about the SEM's market participation at that date. On 4 February 2011, however, the European Council set 2014 as the date for the completion of the internal market (EC, 2011a). This is generally regarded as ambitious and in the case of Ireland the target is extremely unlikely to be achieved.[25] The PCG presentation also envisaged that the Target Model for inter-regional cross border capacity allocation would be based, for intra-day trading, on implicit continuous allocation but, where appropriate, national/regional solutions may be developed.

Framework Guideline on Capacity Allocation and Congestion Management ("CACM FG")

Building on the Target Model and taking account of the relevant parts of the Third Package, such as the CMG in Reg. 714/2009, ERGEG (2010a, 2010b, 2011b) developed a draft CACM FG, drawing on an initial impact statement. The CACM FG deals, between zones, with "…the integration, coordination and harmonisation of congestion management regimes, insofar as such harmonisation is necessary in order to facilitate electricity trade within the EU … ."[26] A zone is a "…bidding area i.e. a network area, within which market participants shall submit their bids day-ahead,

22 This citation is taken from the ERGEG website on the PCG: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/Stakeholder%20Fora/Florence%20Fora/PCG. Full details of the Florence Forum may be found at: http://ec.europa.eu/energy/gas_electricity/forum_electricity_florence_en.htm. Both websites accessed 5 November 2010.

23 These markets refer to the period in which a trade takes place in relation to when the electricity is delivered. A day-ahead, for example, is a trade that takes place one day for delivery the next day. The Transmission System Operator ("TSO") is responsible for ensuring demand and supply equate. If, for any reason, an imbalance occurs, the TSO equates supply and demand using the balancing market.

24 The presentation was made to the Florence Forum meeting of 10-11 December 2009. See previous footnote but one concerning the Florence Forum.

25 Unlikely for two reasons: first, the legislative framework will not be completed, due to certain transitional arrangements lasting to 2016 with respect to CACM, which are discussed later in this chapter; and, second, there will not be enough interconnection capacity between Ireland and Great Britain (and between Great Britain and continental Europe) to ensure that any prices converge between Ireland and Great Britain (and between Great Britain and continental Europe), as discussed in Chapters 3 and 4.

26 ERGEG (2011b, p. 4), which also sets out the context within which the CACM FG is being developed.

in intra-day and in the longer term time frames."[27] In the context of Ireland the SEM would appear to constitute a zone. The CACM FG then addresses issues relating to capacity allocation methods for the day-ahead market, the forward market and the intra-day. On intra-day trading the CACM FG argues that trading should be as close as possible to real-time. It argues, as do a number of other sources, that such trading is important to accommodate intermittent power sources such as wind[28] as well as exploiting arbitrage opportunities between markets.

Taking the Agenda Forward

While ERGEG and PCG can map out a draft framework guideline, neither has the power to finalise the guideline. That is the responsibility of the ACER following a request from the Commission. On April 11 2011, ACER issued the draft CACM FG for consultation, and on 29 July 2011 the approved CACM FG.[29] It follows closely the ERGEG proposals, with an implementation date set for 2014. However, Ireland has been granted transitional arrangements until 2016.[30] Next the ENTSO-E develops a draft network code, on which ACER comments.[31] The network code is then adopted through comitology.[32]

Regional Electricity Markets

The creation of REMs in Europe is at the centre of the ERI of ERGEG, launched in the spring of 2006.[33] The CER is a member of ERGEG, which consists of national regulators.[34] The purpose of the ERI is to act "…as an interim step to creating a single-EU electricity market" (ERGEG, 2009, p. 2). Seven regional electricity markets have been created, as set out in Table 2.1. The indicative date for market coupling

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27 *Ibid*, p. 8.

28 See, for example, Poyry (2009).

29 See ACER (2011a, 2011b).

30 These transitional arrangements follow the submission of the CER and NIAUR (2011b) to the ACER (2011a) consultation paper. The transitional arrangements are contained in Article 1.2 of the CACM FG (ACER, 2011b). It states the transitional arrangements for the day-ahead and intra-day markets apply so long as they: are justified on the basis of a cost-benefit analysis; do not unduly affect other jurisdictions; guarantee a reasonable degree of integration with the markets in adjacent jurisdictions; and, do not extend beyond 2016.

31 There are various checks and balances built into the process to ensure consultation between various stakeholders, with reasons provided when one party (e.g. the Commission) does not follow the recommendations of another (e.g. ACER).

32 Comitology refers to the committee system which oversees delegated acts implemented by the Commission.

33 ERGEG was created in 2003 as an advisory body to the Commission on internal energy market issues. For details on the ERI reference should be made to ERGEG's website: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI. Accessed 27 October 2010.

34 NIAUR is a regional rather than a national regulator and hence is not a member of ERGEG. However, as discussed below, NIAUR is one of the four regulators on the France-UK-Ireland REM Regional Coordination Committee, which oversees progress on this REM.

of the seven REMs has been brought forward from 2015 to 2014.[35] Ireland is part of the France-UK-Ireland ("FUI") regional market. ERI is one of ERGEG's flagship projects. The Commission sees the regional initiatives as having "…a key role to play in … promoting the construction of an integrated energy networks for the needs of the next decades" (EC, 2010f, p. 9).

Table 2.1: Membership of EU Regional Electricity Markets, 2011

Regional Electricity Market ("REM")	Members
North	Denmark, Sweden, Finland, *Germany* & Poland
Central-West ("CW")	Belgium, *Germany, France,* the Netherlands, & Luxembourg
Central-South ("CS")	Italy, *France, Germany*, *Austria*, *Slovenia* & Greece
Central Eastern Europe ("CEE")	*Germany, Poland*, Czech Republic, Slovakia, Hungary, *Austria* & *Slovenia*
South-West ("SW")	Spain, Portugal & *France*
FUI	*France*, the UK & Ireland
Baltic	Estonia, Latvia & Lithuania

Note: Member States that belong to more than one regional electricity market are denoted in italics; the lead regulator for each REM is underscored. Neither Romania nor Bulgaria are assigned to a REM.
Source: Reg. 714/2009, Annex I, p. 31 and ERGEG (2009, p. 25).

Each of the seven REMs has a similar administrative structure that involves all of the major players in the electricity sector participating, in varying degrees, in three main committees.[36] For the FUI REM, the Regional Coordination Committee is composed of regulators from the Republic of Ireland, Northern Ireland, Great Britain and France, plus the Commission, with the Great Britain energy regulator, Office of Gas & Electricity Markets ("Ofgem"), taking the lead.[37] There is also an FUI Implementation Group, consisting of four TSOs, the four regulators, plus relevant interconnector operators, with the Commission invited to attend. Finally, there is a Stakeholder Group which has a wider membership. These groups meet with differing regularity to discuss practical issues surrounding creating an effective REM, with details of the meetings and related matters appearing on the ERGEG website.[38]

35 Market coupling is an implicit auction between two or more power exchanges. An implicit auction is one where the price of using an interconnector and the cost of the electricity are bundled together. The 2015 indicative date was included in a presentation of the Target Model by the Project Coordination Group discussed later in this chapter, while the 2014 deadline refers to the 4 February 2011 European Council statement referred to above.

36 In its review of REMs the Commission is proposing a fourth, a Regional Steering Committee which will include Member States reflecting a concern that there is not enough political direction in the current structures. For details see EC (2010f, p.8).

37 The lead national regulator for each of the seven REMs is identified in Table 1.

38 All the details of the meeting, workplans etc. for the FUI REM may be found on: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/France-UK-Ireland. Accessed 4 November 2010.

The seven REMs deal with the same three priority areas: "…harmonisation and enhancing congestion management on interconnections; harmonising regional market transparency; and developing balancing market exchanges at borders" (ERGEG, 2009, p. 24). ERGEG conclude that there has been convergence on target congestion management methods. For example, there is a growing consensus on intra-day allocation, with some REMs moving towards a continuous intra-day platform, while a single platform auction is favoured for allocation of space on an interconnector. The FUI REM has followed these priorities in its own work programme and, although not a priority per se, added transmission tariffication, which is concerned with ensuring that transmission tariffs do not act as a barrier to trade.[39]

The progress in integrating the electricity systems of the various REMs has differed.[40] In the Commission's 2010 report on progress towards creating the internal market, attention is drawn to the fact that the Central-East, Central South and Central-West REMs will "…soon have a single set of auction rules at regional level" (EC, 2010a, p. 6), while the ERGEG (2009) provides detailed discussion on key developments with respect to each REM. In the case of FUI, the major achievements have been "…significant progress in 2008 and 2009 on congestion management and cross-border balancing on the French-English interconnector" (*ibid*, p. 27). The creation of the SEM and the Moyle IC between Northern Ireland and Scotland, although promoting the FUI REM and the internal market, were not part of the FUI REM programme.

REMs & the Third Package: Ensuring Congruency

The ERI/REM and Third Package complement each other in creating the internal market. ERGEG furnished advice and assistance to the Commission in the development of the Third Package. Several initiatives developed by ERGEG, such as the ERI[41] and the CMG – concerned with access conditions to interconnectors between electricity grids of Member States[42] - have been given legislative backing in the Third Package. Other initiatives such as the CACM FG are in the pipeline. Legislative action is required since compliance with ERGEG's initiatives, although agreed by its member national regulatory authorities, is voluntary.

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39 This is one of a number of actions to remove barriers to trade in the FUI.

40 Although ERGEG's ERI is voluntary, in order for the REMs to function effectively regulatory and other legal changes are often required in order to progress the REM.

41 For details see Part 3 of Annex I of Reg. 714/2009.

42 For details see Reg. 714/2009.

The ERI and the Third Package also complement each other in other ways in promoting the internal market. The ERI has been characterised as a "bottom-up" approach, while the Third Package is "top-down". The bottom-up approach builds the internal market through the development of a series of regional electricity markets. This can lead to experimentation and learning across and within the REMs. However, these REMs need to be gradually linked to each other if the internal market is to be completed successfully. This suggests that if REMs develop in isolation from each other there may be difficulties in completing the internal market. There are likely to be significant transaction costs if participants have to adapt to REMs that have different electricity market models. However, there are at least five ways that this eventuality can be avoided, paying particular attention to these developments from an Irish point of view.

First, the seven REMs are constructed so that they do not consist of a series of mutually exclusive groupings of Member States, but rather there is considerable overlap between the different REMs (Table 1). Indeed, all of the seven regional electricity markets, except the Baltic States, contain a Member State that belongs to at least one other regional electricity market. Several Member States belong to more than two REMs. France and Germany, for example, each belong to four REMs.[43] These overlapping groups should contribute towards ensuring the development of consistent rules across the REMs.

Second, in developing REMs participants can have regard to how other REMs are evolving. There is some evidence of this occurring. In the case of the East-West Interconnector ("IC"), between Ireland and Wales, for example, the access rules are being developed to ensure compatibility with the existing France-England IC and the BritNed IC, between England and the Netherlands completed in Q2 2011.[44] Furthermore, in the case of the UK, although it is part of the FUI REM, it is developing interconnectors with the Netherlands and Belgium, both of which belong to the Central-West REM, suggesting that integration between Member States' markets is also developing in response to market opportunities and is not confined or limited by the REM structure.[45] These interactions between the Central-West and the FUI REMs are likely to enable each REM to better take into account developments in the adjacent REM.

43 Thus this is likely to give these two Member States considerable influence over the shape of the internal market.

44 This observation is based on attending a workshop organised by EirGrid, the owner of the East-West IC, on access rules to the East-West IC held at Croke Park, Dublin, on 11 October 2010 and the proposed access rules for the East-West IC (EirGrid, 2011).

45 Equally, NorNed is an interconnector between the Netherlands, which is part of the Central-West REM, and Norway, which is part of Nordpool that includes Member States belonging to the North and Baltic REMs. Its rationale is based, in part, on the complementarities between the two systems connected. For details see ERGEG (2011a) and Kapff and Pelkmans (2010, Box 2, p. 17).

Third, although it would be disruptive to constantly change the composition of the seven REMs, nevertheless, over time, in the face of changing market realities there is likely to be a case for revising the number and composition. A 2010 Commission paper reviewed the REMs. Although the composition of the existing REMs was affirmed, the Commission (EC, 2010f, p. 6) did remark that, "…over time when sufficient interconnectors will have been built to physically link the relevant regions, it may be appropriate to integrate the France-UK-Ireland region with the Central-West region and the Baltic Region with the Northern region."

Fourth, the North Seas Countries' Offshore Grid Initiative ("North Seas Grid") will harness offshore wind and involve ten Member States[46] including the UK, Netherlands, Ireland, Denmark, Belgium, France and Luxembourg.[47] The EU proposed, as part of its 2009 programme to aid the current economic recovery by financing assistance to projects in the energy field, to make a €165 million contribution towards the North Seas Grid, which will have a capacity of 1GW.[48] The members of the North Seas Grid participate in all of the REMs in Table 1, except the Baltic. A *Memorandum of Understanding* was signed in December 2010 by the 10 Member States, which envisages much preparatory work to be completed by the end of 2012 in terms of identifying and proposing measures to remove barriers to the creation of a North Seas offshore grid. A market and regulatory working group will address "…options for market frameworks for combining offshore wind farms with interconnection and for facilitating the penetration of variable energy generation."[49]

Fifth, the top-down approach of the Third Package. This provides a set of rules that must be observed and adhered to by all REMs and Member States in developing the internal market.[50] For example, in the North Seas Grid *Memorandum of Understanding* reference is made of the necessity to take into account the Third Package. The Third Package draws on the experience of the REMs, the work of ERGEG and the Commission's energy sector inquiry which identified various market impediments to the creation of the internal market (EC, 2007b). Nevertheless, the Commission is concerned, despite the above, that there might be divergence in the

46 For expositional purposes Norway is treated as a Member State. The nine Member States account for 90 per cent of all EU offshore wind development (EC, 2010b, p. 26).

47 Initially it was the North Sea Grid (EC, 2008a, p. 5); however, it was subsequently extended in geographical scope and became the North Seas Grid (EC, 2010b, pp. 25-28). Hence, the Irish Sea and the Atlantic were included.

48 Regulation (EC) No 663/2009 of the European Parliament and of the Council of 13 July 2009 establishing a programme to aid economic recovery by granting financial assistance to projects in the field of energy, hereinafter referred to as Reg. 663/2009.

49 The North Seas Countries' Offshore Grid Initiative, *Memorandum of Understanding,* December 2010, Annex 2, p. 2.

50 Indeed, in a recent Commission discussion document on the future of REM, it is suggested that one of the roles of REMs should be implementing the Third Package in legislation. See EC (2010f, p. 4) for further discussion.

development of the REMs, thus retarding the development of the internal market. The Commission therefore intends to develop a Communication on "…the future role and shape of the regional initiatives, which might address issues such as the development of a common market model …" (EC, 2010a, p.6).[51]

There are other initiatives that are likely to impact on Ireland's electricity market which extend beyond the ERI, the North Seas Grid and the Third Package, but which are also likely to have implications for the internal market. For example, the DESERTEC initiative,[52] based on clean power from deserts, envisages building solar powered electricity plants in North Africa at a cost of up to €400 billion with electricity exported to the EU via interconnectors (*The Economist*, 2010). DESERTEC, which was founded in 2009 as a non-profit foundation, aims to provide 15 per cent of Europe's energy by 2050. If all these initiatives are realised the electricity market not only in the EU but also in Ireland is likely to change in quite dramatic ways in terms of market design, competition and so on.

It should be noted that Member States have experienced difficulty in implementing the internal market legislation. The Commission has initiated infringement procedures against twenty-five Member States, including France, Ireland, and the UK, with respect to EU legislation designed to promote the internal market (EC, 2010a, pp. 2-3).[53] The key violations include absence of regional coordination and insufficient coordination efforts by TSOs to ensure maximum availability of interconnection capacity. In the case of Ireland, these violations included the lack of provision for intra-day trading on the SEM and the absence of coordination up to day-ahead. The SEM developments discussed in Chapter 10 are designed to address these concerns.

Some Reflections on Creating the Internal Market

In examining the movement towards the internal market in electricity four related observations can be made. *First*, a complicated multilayered institutional structure has been created to design and implement the internal market. EU and regional institutions are set up involving an extensive array of stakeholders, governmental and non-governmental. This reflects the fact that success in creating the internal market necessarily involves all of these stakeholders, each of which has knowledge and information concerning particular aspects of the internal market and whose involvement and co-operation is necessary for the success of the internal market. A corollary is that these stakeholders or interest groups are in a position to influence,

51 A public consultation was commenced at the end of 2010. For details see EC (2010f).

52 For details of DESERTEC see: http://www.desertec.org/en/organization/. Accessed 2 December 2010.

53 The identity of the three Member States subject to infringement procedures was provided by regulatory and government sources.

either positively or negatively, the creation of the internal market. They may have the power to block or slow progress or alternatively provide the information that will ensure progress moves more quickly than would otherwise be the case. This raises the possibility that side payments may have to be considered to compensate groups expected to suffer a loss because of the internal market. However, as discussed in Chapter 7, there are considerable practical and conceptual problems in winners compensating losers. Hence ensuring that the incentives of these groups are aligned with the creation of the internal market is important.

Second, the creation of the internal market is a gradual process. The Commission initiated the process in 1998 and at the very earliest it will not be completed until 2014. This reflects a number of factors including the need to co-ordinate the involvement of so many stakeholders in the project as well as design, legislate, implement and enforce a set of rules that realise the internal market. However, irrespective of these concerns, the process of creating an internal market in electricity is inherently more difficult in technological and market design terms than creating an EU-wide market in goods such as (say) turnips or bottled beer. In part this reflects the much greater negative externalities that occur if the internal market in electricity fails resulting in extensive brown outs and power outages, compared to the negative externalities created by a diseased shipment of turnips or mice in a couple of bottles of beer.

Third, much remains to be settled in terms of the implementation and formulation of the internal market. Individual Member States thus have an important role in shaping the internal market. They are represented in all the major institutions. Ireland is no exception. For example, EirGrid co-chairs the market and regulatory working group set up under the North Seas Grid referred to above. Furthermore, EirGrid is developing access rules, as noted above, that align the East-West IC with the trading rules of the BritNed IC so as to ensure efficient participation in the internal market.[54] Finally, of course, decisions as to how much interconnection should take place between Ireland and other Member States is largely a decision of the State, although it is likely to be influenced by the EU given the level of EU support given to the East-West IC.[55]

Fourth, given the varying market models of the different Member States' electricity markets, the issue arises of the degree to which this heterogeneity is consistent with the creation of an internal market through interconnection. In other words, to what

[54] EirGrid also has other responsibilities with respect to implementation and formulation of the internal market such as its participation in ENTSO-E in market integration and network code drafting.

[55] For details see Table 2, Chapter 4.

extent does the access rules that will facilitate trade in electricity between Member States over interconnectors require Member States to adopt a common model for electricity within the Member State? There will clearly be some convergence, but the issue is the degree to which the EU legislation is some kind of Trojan horse that will result in convergence across the EU, a one-size-fits-all model irrespective of local circumstances. To some degree that will depend on the degree of existing commonality across the systems of Member States. It is an issue discussed further below, particularly in Chapters 9 and 10.

Chapter 3

Interconnectors: Costs, Benefits, Welfare Gains and the Role of Government

In deciding how much interconnection capacity to build, a framework for considering the costs and the benefits needs to be considered. In this chapter a simple diagrammatic framework is presented. While it cannot capture all aspects of costs and benefits, it nevertheless can be used to illustrate many of the issues that arise in this paper concerning interconnection. Next, attention turns to studies which have attempted to use this framework to estimate the gains from building interconnection capacity and how much capacity would be required to equalise prices between Ireland and Great Britain. The framework also provides grounds for government intervention to fund interconnectors because not all of the benefits of building interconnection are captured in market prices.

Welfare Impact of Interconnection[56]

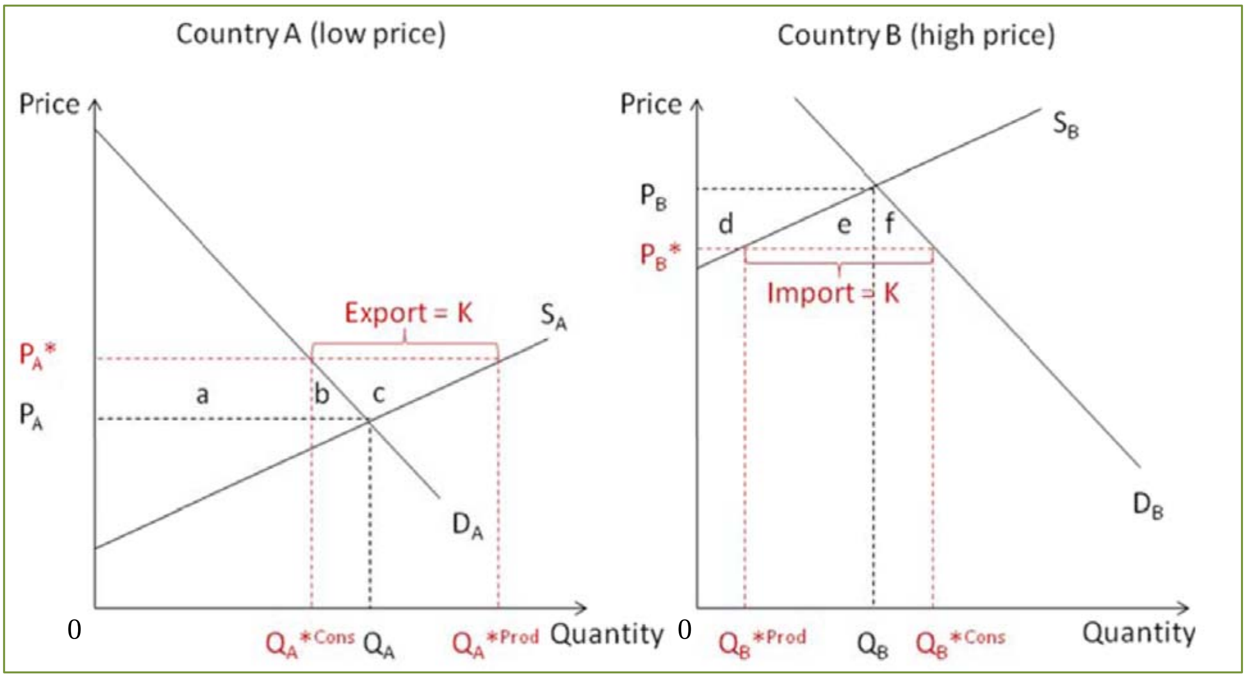
The impact of interconnection between Country A and Country B can be illustrated in a comparative static framework. This framework makes a number of simplifying assumptions. Markets are competitive and costs do not change with greater competition between suppliers in Country A and Country B. However, markets are frequently oligopolistic in nature. As a country's market is opened to competition costs may fall due to greater competition which acts as a spur to increased efficiency and the reduction in rents that may have been captured in the form of high wages and/or management perks. Although the Irish generation market can be characterised as oligopolistic, the SEM is designed to take this into account, an issue discussed in Chapter 9. Transaction costs are assumed to be zero or very low. If, however, there are different trading regimes in Country A and B – as occurs, for example, between Ireland and Great Britain – then there may be non-trivial transaction costs due to, for example, price uncertainty and different trading rules in the two countries. It is an issue we explore in Chapter 10.

Prior to the building of the interconnector Country A and Country B do not trade electricity. They are self sufficient. Prices and quantities are based on national supply and demand conditions only - P_AQ_A and P_BQ_B in Country A and B, respectively

[56] This discussion is based on Kapff and Pelkmans (2010, p. 8) drawing on Turvey (2006).

(Figure 3.1). Prices are higher in Country B than A: P_B>P_A. Country A is more efficient at producing electricity than Country B.

Figure 3.1: Welfare Effects of Interconnection: An Illustrative Example



Source: Kapff and Pelkmans (2010, Figure 4, p.8), adapted from Turvey (2006).

Now assume that an interconnector is built between Country A and B with a capacity of K. As a result K electricity is exported from A to B and correspondingly imported into Country B. Electricity flows from the low priced Country A, to the high priced Country B. This results in a partial convergence of prices. The price in Country A increases from P_A to P_A^* and output increases to Q_A^{*Prod}; OQ_A^{*Cons} is consumed in Country A, with Q_A^{*Cons} Q_A^{*Prod} exported. In Country B price declines to P_B^*, consumption increases to Q_B^{*Cons}, but production declines to Q_B^{*Prod}, with $Q_B^{*Prod}Q_B^{*Cons}$ imported from Country A. Electricity production now takes place to a greater extent where it can be more efficiently produced, Country A.

The interconnector also affects the welfare of producers and consumers in different ways. In Country A there is an overall net gain in welfare of c. The loss of consumer welfare (a+b) is more than offset by the gain in welfare of producers (a+b+c). In Country B there is also a net gain in welfare of e+f. The loss of producer surplus (d) is more than offset by the gains to consumers (d+e+f). Thus in overall welfare terms, interconnection leads to welfare gains. However, the pattern of gains and losses might lead to opposition to such interconnection by groups that are likely to be made worst off by interconnection – consumers in Country A and producers in

Country B. However, it seems unlikely that these two groups would be able to form a successful coalition preventing interconnection.

The congestion income that accrues to the interconnector owner is equal to the difference in price between Country A and B, multiplied by the capacity of the interconnector (i.e. $(P_B^*-P_A^*) \times K$). Clearly, as more interconnection capacity is built the price difference between Country A and Country B falls and for a given K congestion income falls. Indeed, when prices converge there is no congestion income. Under these conditions the interconnectors would likely come to resemble part of the national grid under the TSO and be funded in the same way as the rest of the grid.

As more interconnection is added – K becomes larger – the welfare gains increase: c in the case of Country A and e+f in the case of Country B.[57] However, a private firm would have little incentive to build such an additional interconnector since congestion income would fall to zero as P_A approached P_B.[58] Such a move would also reduce the returns to all existing interconnectors. In other words, the revenues accruing to the interconnector owner may be insufficient to recover the planning, construction, and operating costs. In these circumstances the interconnector may not be built even though the welfare gains exceed the costs.

This simple exposition illustrates many of the issues which will be explored in the paper. It shows, for example, although there may be overall welfare gains from interconnection, there are winners and losers and this may affect support for interconnection. The exposition also shows that there is a role for government since private and social costs do not necessarily coincide.

Cost and Benefits

Interconnection should be undertaken to the extent that it benefits Irish society. Interconnectors should be built until the marginal costs equal the marginal benefits. Interconnectors are large lumpy investments, typically – in the Irish context judging from Table 2, Chapter 4 – built in units of 500MW.[59] Thus in considering building

[57] This ignores the costs of interconnection.

[58] This discussion assumes, of course, that the only source of revenue is congestion income.

[59] In contrast when two larger markets interconnect the interconnectors are larger. For details of Great Britain/continental interconnection see Table 3, Chapter 4. DKM *et al.* (2003, p. ii) argue that capacity greater than 500MW "…would be difficult to accommodate given the scale of the Irish system." If an interconnector were to experience difficulty then the volume of electricity imported by the interconnector would need to be replaced by the use of other interconnectors and/or generators located in the SEM. In Ireland, generators rarely exceed 500MW in capacity. For details see EirGrid (2009b, Appendix 2, p. 63).

interconnectors what is relevant is whether the benefits of building an additional 500MW of capacity equal or exceed the costs. The benefits mainly arise from lower expected prices in Ireland due to competition from generators located elsewhere in the EU, mainly Great Britain. This is illustrated in Figure 1 where Ireland is Country B and Great Britain Country A. However, that simple comparative static framework does not take into account all of the benefits of interconnection. Interconnection permits a smaller reserve capacity to deal with unanticipated power outages in generating plants[60] as well as the introduction of greater competition in an oligopolistic market. However, there are also security of supply benefits from access to a large market, such as more diversified fuel supplies (e.g. nuclear) and suppliers (e.g. npower or London Energy or Centrica).

Drawing on the above framework the benefits and costs of greater interconnection have been set out in a series of papers by ESRI colleagues and others, including EirGrid (2009a), which are broadly consistent with one another.[61] These show that additional interconnector capacity of between 1,000MW and 3,000MW over and above the existing Moyle IC and the planned East West IC lowers the price of electricity in Ireland as the difference with Great Britain narrows.[62] The pattern of gainers and losers as between producers and consumers in Ireland and Great Britain is consistent with the comparative static framework above. However, the benefit, measured in terms of lower expected electricity prices in Ireland, of additional interconnector capacity declines as more capacity is built – the number of hours, for example, during which, on a typical day, prices converge (or differ by some small magnitude) – increases as more capacity is built. In other words, the marginal returns to additional interconnection decline.[63]

The discussion based on Figure 3.1 assumes that electricity will flow from Country A to Country B, which we have likened to Great Britain and Ireland, respectively. This reflects the fact that prices are lower in Great Britain than Ireland, which underlies the estimates referred to in the previous paragraph. However, this analysis oversimplifies in at least three ways. *First*, Ireland is on course to generate

60 These benefits are likely to be particularly important for a small electricity system, such as the SEM, compared with much larger systems, such as BETTA in Great Britain. For estimates see EirGrid (2009a, pp. 10-11).

61 See, for example, EirGrid (2008) on the East West IC; EirGrid (2009a) on not only the East West IC but several subsequent interconnectors; Malaguzzi Valeri (2009) on the impact of a series of additional interconnectors; Diffney *et al.* (2009) which place stress on the influence of climate change and the importance of renewable; and CER and NIAUR (2011a) on the impact of introducing more efficient trading (i.e. two intra-day gate closures in addition to D-1) over the Moyle and East West ICs.

62 Price is usually the wholesale price of electricity not the retail price. The SEM market determines the wholesale price, not the retail price.

63 See Malaguzzi Valeri (2009, Table 2, p. 4682, Table 4, p. 4683, and Table 5, p. 4683). The difference between these tables is the price of carbon, which varies between €0 and €30 per ton. EirGrid (2010, Figure 6, p. 9) reaches a similar conclusion when measuring the impact of additional interconnector capacity on SEM marginal prices.

substantial volumes of electricity from wind. On occasion wind, which has a low or zero marginal cost, is likely to be exported to Great Britain from Ireland, an issue discussed in Chapter 5. *Second*, depending on future energy policy in Great Britain prices in the medium to longer term may be higher in Great Britain than Ireland, an issue explored in Chapter 9. However, this does not mean that Ireland will not benefit overall from interconnection due to some of the non-price benefits from interconnection, such as a lower reserve capacity and access to a greater diversity of fuel supplies. *Third*, apart from consideration of wind, electricity is likely to flow in both directions due to differences in demand and the mix of generation capacity.

At the EU level, there appears to have been limited attempts to estimate the overall costs and benefits of increased interconnection necessary for the completion of the internal market. One estimate by the Commission suggests that compared with 2010, by 2020 EU wide GDP will be higher by 0.6-0.8 per cent, inflation 0.5-0.6 per cent lower and there will be 5 million extra jobs with the completion of the internal market.[64] No estimates have been undertaken by the Commission of the gains and losses by Member State,[65] perhaps not surprising in view of the discussion in Chapter 7 concerning the practical and theoretical problems of the winners compensating the losers. Nevertheless, Zachmann (2010, p. 2) comments that "…further market integration does promise significant efficiency gains" and cites some evidence in support of this contention.

What Role Government?

It is arguable that beyond the very important role of setting the rules within which the interconnectors operate and how the internal market is structured, there is a minimal role for government in developing and funding interconnectors. The situation is in some respects similar to building new electricity generation capacity, which is largely left to the market. In Great Britain a private firm, National Grid, albeit a TSO and heavily regulated, is building interconnectors to continental Europe after carefully evaluating the level of demand for such facilities. It is not doing so on foot of a government decision.[66] In contrast, in Ireland government intervention is much greater, with the East West IC being a government rather than a private sector decision.

64 See EC (2011a) and Barroso (2011). Note that these estimates refer to the gains from an internal market in both gas and electricity.

65 Based on a communication with the Commission, April 2011.

66 As Ofgem (2010a, p. 24) notes merchant interconnectors have the advantage that it leaves the decision to the "…hands of developers, with strong commercial incentives, rather than the central planner." This issue and subsequent developments are discussed further in Chapter 6.

Intervention by the Member State

Studies have shown for Ireland, however, what is optimal from the perspective of a private firm (or a public firm that only considers private returns and costs) may not be optimal if the wider societal implications of building interconnectors are taken into account.[67] In other words, consideration of private costs and benefits would result in too little interconnection capacity being built.[68] This is consistent with the discussion above on the welfare effects of interconnection. In addition, some of the benefits of interconnection, such as increased security of supply, are in the nature of public goods and hence unlikely to be taken into account by private firms.[69]

Thus, in view of the market failure in terms of building too little interconnection capacity, the State may have a role in ensuring that additional interconnection capacity is built. To ensure that the required capacity is built the government could contract for the additional capacity – through, for example, a design build and operate competitive tender. Alternatively, the State could provide a capital subsidy to ensure the completion of additional capacity.

There may also be capital market failures in financing interconnectors because of a bias that discounts future returns excessively (i.e. short-termism)[70] combined with the interconnector characteristics, noted in Chapter 4: capital intensive nature; long-lived assets; costs incurred upfront – in the case of the East West IC €600 million; and, revenue not realised for a considerable period of years. Haldane and Davies (2011, p. 14) argue that short-termism results in "…investment being too low and in long-duration projects suffering disproportionately. This might include projects with high build or sunk costs, including infrastructure …" To deal with this problem, the State could guarantee that if the congestion price fell below a certain level for a certain period of time that the State would pay the difference. This would be similar to put or pay clauses designed to share the risk between buyer and seller and ensure that the buyer cannot exploit the seller once the facility is built and irreversible investments made.[71]

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67 See, for example, Malaguzzi Valeri (2009). This research suggests that over and above the Moyle IC that perhaps an additional 500MW to a 1,000MW of interconnector capacity would be built by the private sector and an additional 1,000MW would be justified because the social benefits exceed the costs. The benefits to Irish consumers in terms of lower electricity prices more than offsets the loss experienced by Irish producers due to lower electricity prices.

68 There is also the issue that there may be an incentive for the interconnector owner to restrict use of an interconnector in order to maximise profits. However, as discussed in Chapter 8, rules in the Third Package seek to resolve this problem.

69 DKM *et al.* (2003, p. 52) make this point.

70 Haldane and Davies (2011) present evidence concerning the existence of short-termism using US and UK data.

71 Alternatively under EU legislation a merchant interconnector once approved by the Commission has its revenues protected "…from subsequent changes to market rules damaging the business case of the project" (Ofgem, 2010a, p. 28).

Nevertheless, it could be argued that the case for direct government intervention in the provision of interconnectors needs to be treated with a certain amount of caution. *First*, even if it is accepted that the benefits equal or exceed the costs, there may be other projects that government could fund which have a higher return in, for example, education or transportation or health or debt reduction than additional interconnector capacity. This, of course, assumes that borrowing is constrained, a not unreasonable assumption in the short and perhaps medium term for the State. *Second*, as additional capacity is built, as noted above, the marginal benefits of each additional 500MW of interconnection declines substantially. Indeed, at a certain point the benefits turn negative. Hence, the State would be investing in the most risky addition of interconnection capacity. This suggests that careful and thorough evaluation is required prior to any public funding of future interconnection.

Third, interconnectors are normally funded by the Transmission System Operator ("TSO") such as EirGrid, and only partly by governments. The Moyle IC received a 35 per cent grant, while the East West IC received an 18 per cent grant and a soft loan for 50 per cent of the cost (Table 2, Chapter 4). The TSO funds the balance and, should the congestion income be insufficient to fund the interconnector, electricity consumers are charged appropriately so as to guarantee the TSO's return. The TSO, EirGrid, may be able to borrow at more attractive rates than the State, if its regulatory treatment is seen as credible so that the TSO is viewed as separate and independent of the State.

The evidence suggests the State's incentives are correctly aligned. Ireland will face tight budgetary constraints over the short and perhaps medium term, with large but narrowing budget deficits, and a large debt to service. Ireland will also take some time to recover from the increased reputational risk due to the State's handling of the financial and budgetary crisis, which is likely to raise the cost of capital for all projects. However, once Ireland's budgetary and financial problems are resolved, the cost of capital is likely to return to more normal levels. These constraints should provide the right incentive to ensure that only worthwhile projects will be undertaken, while investors such as the European Investment Bank ("EIB") are likely to carefully vet such projects before investing in them to ensure that the benefits equal or exceed the costs. However, as noted above, it is the TSO which is responsible for the financing of most of an interconnector and it may be able to borrow at a lower rate than the State.

Intervention at the EU

As noted in the discussion surrounding Figure 3.1 some groups within a Member State may be winners and other losers, although overall both within the Member

State and at the EU level, completing the internal market leads to gains. Hence there is a role for the EU, in addition to the arguments adduced above due to capital market failures and because of a mismatch between private and social costs, for intervention to assist in facilitating the internal market. The examination in Chapter 4 of the funding arrangements of the Ireland/Great Britain and Great Britain/continental Europe interconnectors currently being built, demonstrates that there is substantial public support by the EU. The EU provides financial assistance through grants and/or soft loans. Such support appears to be important since the proposed Ireland/Great Britain Imera interconnectors, which have no such assistance, do not appear to be going ahead. Thus, the EU sources of funding can be seen as a mechanism – in part at least – for overcoming the barriers that might exist for promoting interconnection at the Member State level. However, the support does not appear to be a mechanism for compensating those groups that might experience declines in welfare because of interconnection, an issue discussed in Chapter 7.

Chapter 4

Integrating Ireland in the Internal Market: Current Interconnection Plans and Prospects

In considering the prospects for the integration of Ireland into the internal market attention needs to be paid to the current, planned and forecast interconnection capacity between Ireland and other Member States' electricity systems. Interconnection is a necessary condition for Ireland's participation in the internal market. In the absence of such interconnection, Ireland will not participate in the internal market.[72] In this chapter the current, planned and anticipated volume of interconnection is presented as well as related planning/construction and ownership issues.

Interconnection: Current and Planned

Ireland can interconnect with the EU market either directly with different Member State markets, such as Great Britain or France, or indirectly since these markets will in turn be interconnected with other EU markets through further interconnection, often within the same REM. Hence in considering the prospects for interconnection for Ireland attention needs to be paid not only to Ireland-Great Britain interconnection, but also to Great Britain-continental Europe interconnection.

Ireland-Great Britain interconnection

Between Ireland and Great Britain there is only one existing interconnector (i.e. Moyle IC), one under construction with operation anticipated for Q3 2012 (i.e. East West IC) and another planned but on which no construction has taken place while the grid connection offer lapsed in April 2010 (i.e. Imera IC). The Moyle and East West ICs are the equivalent of adding between 4.5 to 9 per cent to generation capacity in Ireland in 2013; with the Imera IC the total would increase to between

[72] It would, however, experience the indirect impact of a successful internal market in the rest of the EU, to the extent the internal market led to a more efficient and lower cost supply of electricity that placed Ireland at a competitive disadvantage vis à vis other EU Member States, with no option of currency devaluation to offset the resulting disadvantage due to membership of the euro.

8.0-12.5 per cent.[73] No interconnector is currently planned between Ireland and another Member State, such as France.

In terms of future interconnection, EirGrid (2009a) has sketched a profile for a series of possible additional interconnectors out to 2025 which, it argued, are economically feasible.[74] The results, together with existing interconnectors, are presented in Table 4.1, which also includes salient characteristics of the interconnectors. It should also be noted that the feasibility of the Ireland-France IC – ABC IC in Table 4.1 – is based on the assumption that there was only 900MW of interconnection (i.e. the Moyle and East West ICs). Thus if the two additional 500MW interconnectors to Great Britain were built – XYZ and QRS ICs in Table 4.1 - this would make it more difficult to justify the Ireland-France IC. Hence the interconnection capacity to Great Britain and France can be viewed as substitutes, at least over the medium term. In either case the expansion in interconnection capacity would mark more than a doubling over and above the Moyle and East-West ICs.

73 Dispatachable capacity (excluding the interconnectors) is in 2013 forecast to be 8,845MW, while partially/non-dispatchable capacity (primarily wind) is – taking into account that it is only likely to be available 30 per cent of the time – 1,130MW, yielding a total capacity of 9,975MW (EirGrid, 2009b, Appendix 2, pp. 63-64). Assuming the restrictions are removed on the Moyle IC then the two interconnectors would add 900MW or 9.0 per cent. EirGrid (2009b, p. 34) makes quite conservative prudent assumptions concerning the capacity of these two indicators, yielding 450MW or 4.5 per cent. With the 350MW from the Imera IC the addition rises to 8.0 to 12.5 per cent. An alternative indication of the importance of the Moyle and East West ICs is as a percentage of peak demand. In 2013, using a low growth scenario for the economy – which is almost certainly too optimistic – yields a range of 7 to 14 per cent, depending on whether the interconnectors are valued at 450MW or 900MW, respectively. Peak demand is taken from EirGrid (2009b, Table A-3, p. 62).

74 In the Government White Paper on energy specific reference was made to asking EirGrid to undertake such an exercise. See DCMNR (2007, p. 21) for details.

Table 4.1: Current, Planned and Future Interconnectors: Ireland and Great Britain and/or France

IC (Date in Operation)	Origin/ Destination	Capacity	Merchant or Regulated,[a] & Ongoing Charging	Owner	Capital Funding Assistance
Moyle (2002)	N. Ireland/ Scotland	500MW (Import: 450MW winter; 410MW summer; Export: 287MW summer; 295MW winter)[b]	Regulated, 3rd party access, ongoing costs funded by use of IC, TUoS for shortfall; surplus electricity tariff reduced	Mutual Energy, an energy mutual firm[d]	35% European Regional Development Fund grant, £150 million capital cost
East-West (Q3 2012)	Ireland/ England	500MW	Regulated, 3rd access, ongoing costs funded by use of IC, TUoS for shortfall	EirGrid, semi-State firm, operates electricity grid in the SEM	50% loan EIB on favourable terms, 18% grant EEPR[e]
Imera (Regulatory approval 2009. Construction yet to start & grid connection offer lapsed on 12 April 2010)[f]	Ireland/ Wales	350MW	Merchant, 100% allocated to long-term contracts, funded by use of IC.	Joint venture, Oceanteam ASA, a Norwegian company, & private investors	None, it would appear
XYZ (2020-2025)	Ireland/ Great Britain	500MW	To be decided	To be decided	To be decided
QRS (2025)	Ireland/ Great Britain	500MW	To be decided	To be decided	To be decided
ABC (2015-2025)	Ireland/ France	500MW, & 2 x 500MW	To be decided	To be decided	To be decided

a. Merchant interconnectors are funded by the developer who bears all the risks, costs and rewards. It may or may provide third party access. Regulated interconnectors where the developer relies in part on the financial support from a regulated stream of revenues to support the interconnector, probably through a transmission use of system charge ("TUoS").
b. The 287MW & 295MW are contractual limits. Attempts are being made to remove the limit.
c. TUoS=Transmission Use of System Charge.
d. The original owner was Viridian Group plc, the Northern Ireland TSO.
e. Total cost €600 million, EIB €300 million and European Energy Programme ("EEPR") €110 million grant. The EIB rate for the loan and the loan period are lower and longer, respectively than would be provided by the markets. Actual terms and conditions are confidential. Information supplied by EIB.
f. Regulatory approval was received from the CER and Ofgem in 2009 for Imera to be exempt from third party access and use of revenue requirements as set out under the relevant legislation under the Second Package. Imera envisaged a second 350MW interconnector but there is no evidence it has been progressed. In EirGrid (2009a) consideration of interconnection no account is taken of the Imera IC.

Source: EirGrid (2009a); Imera (2007); Deloitte (2010); NIE (1999); Ofgem (2010a, pp. 35-42) and Northern Ireland Energy Holdings website.

Great Britain-continental Europe interconnection

There is one long standing interconnector between Great Britain and continental Europe (i.e. IFA IC) and one was completed and in operation in Q2 2011 (i.e. BritNed IC), details of both are provided in Table 4.2. Beyond these a number of additional Great Britain-continental Europe interconnectors are under consideration including EliaNG, that will link England with Belgium, and ElecLink, that will link England with

France using the Channel Tunnel. The BritNed and the EliaNG interconnectors are not, as noted above, between Member States in the same REM, but between Member States in the FUI REM and the Central-West REM, respectively. Thus the commercial realities of interconnection cut across the boundaries set up by the configuration of REM membership detailed in Table 2.1. However, for reasons set out in Chapter 2, this is likely to promote rather than retard the development of the internal market.

Table 4.2: Current, Planned and Future Interconnectors: Great Britain and Continental Europe Ranked in Chronological Order[a]

IC (Date in Operation)	Origin/ Destination	Capacity	Merchant or Regulated,[a] & Ongoing Charging	Owner	Capital Funding Assistance
IFA[b] (1986)	England/ France	2,000MW	Regulated	Joint ownership & operation National Grid & Reseau de Transport d'Electricite ("RTE")[c]	Not clear. At time of construction both owners were state owned firms
BritNed (Q2 2011)	England/ Netherlands	1,000MW	Merchant (subject to exemption conditions)	Joint ownership National Grid & TenneT[d]	European Investment Bank ("EIB") provided a loan covering 50 per cent of the €600 million construction cost on favourable terms[e]
ElecLink (announced May 2011, using Channel Tunnel, completion expected 2015)	England/ France	500MW	Merchant (regulatory approval yet to be obtained)	Joint ownership: Groupe Eurotunnel, 49%; and STAR Capital Partners, 51%.[f]	Investment €250 million. Not clear if will receive capital assistance
Elia/NG (under consideration)	England/ Belgium	700-1,300MW	Regulated	Joint ownership National Grid & Elia[g]	To be determined

a. IMERA has under consideration an interconnector to France. For details see CER and NIAUR (2009c, Table 1, p. 25).
b. IFA = Interconnexion France Angleterre.
c. These two entities are the TSOs for Great Britain and France, respectively.
d. These two entities are the TSOs for Great Britain and the Netherlands, respectively.
e. The rates for the loan and the loan period are lower and longer, respectively than would be provided by the markets. Actual terms and conditions are confidential. Information supplied by EIB.
f. Neither Eurotunnel, nor Star Capital Partners are TSOs. If the interconnector is successful it might be expanded to 1000MW.
g. These two entities are the TSOs for Great Britain and Belgium, respectively.

Source: Blair (2011), CER and NIAUR (2009c, Table 1, p. 25), EIB, Eurotunnel and STAR Capital Partners (2011), and National Grid websites.

Direct or Indirect Interconnection with Continental Europe/Internal Market?

There are two channels through which Ireland can become part of the internal market: (a) Great Britain through interconnection becomes part of the wider EU market. Prices in Great Britain converge to those in continental Europe. Hence, interconnection with Great Britain integrates Ireland with the wider internal market. It is not clear that there are any further advantages of building Ireland-France interconnectors, particularly in view of the higher capital costs of such interconnection; and, (b) Great Britain prices diverge from those in continental Europe both in magnitude and duration (i.e., for a significant period each day prices differ). Great Britain-continental Europe interconnection is insufficient for prices to converge to continental EU price levels, with, it is assumed, little prospect of additional Great Britain-continental Europe interconnection. At the present time, there does not appear to be any published research on the volume of interconnection needed for prices to converge between Great Britain and continental Europe.[75]

In the second scenario Ireland has a number of choices. *First*, Ireland can accept the partial integration into the internal market via Great Britain.[76] *Second*, Ireland could build one or more Ireland-France ICs and thus become more fully integrated with continental Europe. The price of electricity in France is lower than the UK and Ireland, for industrial (Table 4.3A)[77] and residential (Table 4.3B) consumers.[78] In part this reflects the fact that about three-quarters of electricity in France is accounted for by nuclear power (Kapff and Pelkmans, 2010, p. 6). However, the price of electricity is likely to rise in France as it becomes further integrated into the internal market.[79] Thus, future gains from an Ireland-France IC in (say) 2025, more than 10 years after the anticipated completion of the internal market, are unlikely to be as large as those based on current price differentials. Set against these problematic gains is the fact that the annualised capital costs of an Ireland-France IC has been estimated to be 50 per cent higher than those for the same sized Ireland-Great Britain IC (EirGrid, 2009a, p. 3).

75 Based on a discussion with UK academics, Ofgem and National Grid.

76 It could be argued that Ireland could import cheaper French electricity over the Great Britain-France IC. However, this argument does not stack up since Ireland would still have to pay the congestion charge for using the Great Britain-France IC.

77 Table 4.3A is for industrial consumers with an annual consumption of 2,000 to 20,000 MWh. These consumers were selected because, according to Forfas/National Competitiveness Council (2009, p. 33, fn. 65), this is the "…most relevant band for the enterprise base."

78 These data refer to 2007-2010 and refer to retail prices. The pattern is consistent with comparisons covering 2000-2006, but using wholesale prices. See EC (2007b, Figure 38, p. 113) for details. Trade over the interconnector takes place at the wholesale, not retail level. Industrial retail electricity prices are closer to wholesale prices than consumer retail electricity prices. In the case of Ireland wholesale costs in 2008 accounted for 80 per cent of industrial retail prices and slightly less than 60 per cent of consumer retail prices (Devitt and Malaguzzi Valeri, 2011, p. 364).

79 Spot electricity prices increased in France following interconnection with Germany. This convergence caused some discontent in France. See Kapff and Pelkmans (2010, Box 1, pp. 6-7). The May 2011 announcements by the German government to phase out its reliance on nuclear electricity by 2022, following the Fukushima 1 nuclear accident earlier in 2011, is likely to further increase German demand for electricity from France.

Table 4.3A: Industrial Electricity Prices (euro cent/per kWh), Selected EU Member States, 2007-2010

Member States	2007	2008	2009	2010
Ireland	10.86	12.76	9.66	8.60
UK	9.06	9.75	8.66	8.53
France	4.71	5.08	5.52	5.70
Belgium	7.48	8.38	9.02	8.36
Luxembourg	n.a.	n.a.	9.18	7.68
Germany	7.76	8.31	8.33	8.00
Netherlands	7.90	8.50	8.73	7.90
Denmark	7.61	8.85	7.93	8.62
Sweden	5.77	6.81	5.96	7.30
Finland	5.38	6.16	6.38	6.41
Poland	6.26	7.38	7.94	8.09

Note: Member States were selected if they were members of the FUI, CW or North REMs. Prices exclude taxes and refer to prices paid by industrial consumers with an annual consumption of between 2,000 MWh to 20,000 MWh. Prices refer to July-Dec of each year except for Germany for 2010 where Jan-June was used. The price for the Netherlands for 2010 is provisional.

Source: Eurostat.

Table 4.3B: Residential Electricity Prices (euro cent/per kWh), Selected EU Member States, 2007-2010

Member States	2007	2008	2009	2010
Ireland	16.70	17.91	16.35	16.29
UK	14.11	15.30	13.40	13.80
France	9.24	9.10	9.08	9.71
Belgium	12.86	16.19	13.90	14.60
Luxembourg	14.42	13.91	16.53	14.49
Germany	12.79	13.41	13.59	13.01
Netherlands	12.90	13.20	13.86	12.63
Denmark	10.27	13.23	11.22	11.99
Sweden	10.13	11.37	10.59	12.80
Finland	8.68	9.55	9.68	10.26
Poland	10.69	10.05	10.10	10.82

Note: Member States were selected if they were members of the FUI, CW or North REMs. Prices exclude taxes and refer to prices paid by domestic consumers. Prices refer to July-Dec of each year except for Germany for 2010 where Jan-June was used. The price for the Netherlands for 2010 is provisional.

Source: Eurostat.

Third, Ireland could build a Great Britain-Netherlands/France/Belgium IC that would more fully integrate Great Britain (and thus Ireland) into the internal market. However, this option faces a number of problems. Such an investment would benefit from the assistance of the Great Britain TSO, National Grid plc ("National Grid"), in terms of access to the grid and guidance in terms of planning and related issues.[80] However, National Grid might be less than supportive of additional interconnection which would lower the congestion income from its existing

[80] National Grid owns and operates the grid in England and Wales and since 1 April 2005 operates but does not own the grid in Scotland.

interconnectors to France, the Netherlands and by 2025 Belgium and elsewhere. A similar argument could be made with respect to TSO's in France and the Netherlands. Furthermore, the major beneficiaries of such interconnection would be consumers in Great Britain, rather than Ireland. However, it is not clear who would be a suitable joint venture partner for EirGrid to act as an agent on behalf of these consumers. Finally, there are likely to be funding difficulties for EirGrid, since it is extremely unlikely that the investment would be underwritten by TUoS charges on Irish electricity consumers. Hence this option is unlikely to be feasible.

In sum, it appears that Ireland's integration into the internal market will depend critically on the extent of Great Britain-continental Europe interconnection. Alternatives such as direct interconnection to France or building an additional Great Britain-continental Europe interconnection seem less cost effective options.

Interconnection: Future Prospects

In considering the pattern of future interconnection investments, three sets of considerations need to be taken into account. *First*, the constraints imposed by planning, building and providing a sound assessment of the business case for a future interconnector. *Second*, the economic constraints; the papers cited above concerning the case for interconnectors were written in 2008-2009. There have been a number of changes which are likely to result in a slowing down in the building of interconnectors, which are also considered. *Third*, regulatory constraints, since appropriate regulation plays a vital role in determining the efficiency of trading over the interconnector, a necessary condition for successful interconnection.

Physical and Planning Constraints

Building interconnectors requires long lead times and careful analysis. The EirGrid (2009a) analysis can be considered only indicative of the future scale of interconnection. By examining the record of the two Ireland-Great Britain interconnectors that are operating or will shortly be commissioned, an indication of the relevant time frames can be gained. Of course, there is likely to be some learning by doing, so that these historically-based time frames may be biased upwards. On the other hand, local opposition to interconnectors could grow, slowing down the planning process, particularly with the emphasis in the current UK Coalition Government on localism.[81]

[81] Localism gives local communities a greater say in issues such as planning.

While the completion date of an interconnector can be easily ascertained the start date is a somewhat different matter. In the case of the Moyle IC it was 12 years from the first seabed survey in 1990 to full operation in 2002, with planning consents only granted in 1998.[82] For the East West IC, the process was somewhat quicker; planning permission was applied for in 2008, granted in 2009, with full operation expected in Q3 2012. However, prior to the government decision approving the East West IC in December 2007, there was a study on the technical feasibility by the TSOs in the Republic of Ireland and Great Britain completed in 2002 as well as on the costs and benefits of interconnection (DKM *et al.,* 2003, which also refers to the earlier study by the two TSOs). In sum, the evidence suggests that 10 to 12 years is required to build an interconnector from consideration of technical and economic feasibility to completion, with the time divided roughly equally between the project assessment/decision stage and the project construction stage.

While arguably some of the background work for additional Ireland-Great Britain interconnection has been set out in EirGrid (2009a), there will nevertheless be the requirement to make the business case for such interconnection before the government can make a decision, particularly in view of the scarcity of government funding and the likely higher price of capital, although this is likely to be only a short-term consideration and apply much less to the TSO, EirGrid, raising funds than the State.[83] Based on Table 4.1, and the foregoing, discussion, it is unlikely that any new additional interconnection capacity with Great Britain will be operating before 2021-2023, unless the process is accelerated. Thus past time lines may not be entirely appropriate.

Economic Constraints

One way of viewing an interconnector is as an alternative to building a generating plant in Ireland. In other words, electricity is imported rather than being generated domestically.[84] Viewed in this way, the benefits of additional capacity are likely to be lower than estimated in the 2008-2009 papers cited in Chapter 3, because of the recession which has lowered the demand for electricity.[85] This reduction in demand has been both cyclical and structural in nature, in that the effects of the recession

82 Details of the history of the Moyle IC may be found at: http://www.nienergyholdings.com/The_Moyle_Interconnector/History_and_Development_of_the_Interconnector.php. Accessed 16 November 2010.

83 Both factors reflect the impact of the financial crisis and the consequent recession in Ireland, combined with an increased country risk due to adverse reputational impacts. In addition according to some commentators (e.g. MGI, 2010) the cost of capital is likely to increase in the medium term.

84 Of course, as noted in Chapter 3, there may be exports of electricity from Ireland to Great Britain and beyond.

85 This ignores the impact of plant retirements in the medium term.

will be felt over the medium term. The current recession "…will dramatically reduce demand for energy over the coming decade" (FitzGerald, 2011, p. 11).[86]

Interconnector costs are also likely to increase due to cost of capital considerations in the short term.[87] Interconnectors are large capital intensive projects, with upfront payment for construction and the returns, if any, that flow from the use of the interconnector will only occur if there is congestion (i.e. demand for the interconnector exceeds supply), as discussed below in Chapter 8.[88] Hence, the economics of such projects are likely to be particularly sensitive to the cost of capital. One of the effects of the recession, combined with Ireland's financial and budgetary situation, is that the risk premium of investing in Ireland has increased and hence interconnectors will have become less attractive investments as the cost of capital has risen. However, if Ireland successfully resolves its budgetary and financial problems, then the current risk premium is likely to decline to more normal levels. Furthermore, the increased risk premium applies much more to the State raising funds than the TSO-EirGrid.

In terms of the time profile of the additional capacity that merits being built over and above the Moyle and East-West ICs this is addressed, as noted above, by EirGrid (2009a). It appears that there is limited benefit from additional interconnectors before 2015, which is somewhat moot given the timelines for assessment, decision and construction of an interconnector referred to above. However, EirGrid consider that an economic case for a third interconnector to Great Britain in 2020, with a fourth interconnector post-2020 is only feasible in some scenarios, such as renewables accounting for a high percentage of electricity generation in Ireland, a position consistent with Diffney *et al.* (2009). However, in view of the implications of the recession for demand this time profile needs to be reviewed, with the 2020 deadline for the next Ireland/Great Britain IC likely to be pushed back to perhaps at least 2025.[89]

86 This is also consistent with the forecasts of Devitt *et al.* (2010).

87 On the other hand, there may be learning by doing economies in building interconnectors so that costs fall as more interconnectors are built. However, no estimates are available as to the existence and magnitude of such economies.

88 Of course, as noted in the discussion in Chapter 3, while congestion income may not merit construction of an interconnector, the interconnector may still merit completion because the consumer/producer gains.

89 To meet the 2025 completion date implies that a decision is taken in 2014, given the 10-12 year lag. However, as noted in the text, these are historical-based time lines and it is possible fast track procedures in areas such as planning approval could be introduced, while preparations can be made concerning the interconnector route ahead of the decision to build the interconnector, rather than after.

Regulatory Constraints

The discussion concerning interconnection is based on the assumption that electricity flows will operate in an efficient manner akin to the stylised picture in Figure 3.1. However, if that is not the case then the full benefits of interconnection may not be realised. At the present time there are difficulties concerning trading over the Moyle IC. Under access rules being developed by the East West IC and the introduction of intra-day trading in the SEM, both of which will apply to the Moyle IC., these trading difficulties should be considerably reduced.[90] However, if these problems are not resolved then this is likely to inhibit further interconnection. In any event the efficacy of these measures will be apparent in 2012/13 prior to any decision to build another interconnector.

In sum, from a project assessment/decision and project construction perspective new interconnectors with Great Britain are unlikely to be built before 2021-2023, assuming that the project assessment/decision process for a new interconnector starts in 2011. This seems unlikely to happen. Turning to the economic constraints, reflecting recent budgetary and fiscal developments, it seems unlikely that the project assessment/decision process for a new interconnection will commence before 2015, with a completion of the project construction date of 2025-2027. By that time it will become apparent if the access rules for operating on the two interconnectors combined with the introduction of intra-day trading on the SEM are working efficiently.[91] However, these are historically-based timelines and government could always shorten the timelines and so accelerate the completion of future interconnectors.

Ownership of Interconnectors and Incentives

The Ireland/Great Britain and the Great Britain/continental Europe interconnectors are virtually all owned by TSOs, albeit in some cases through separate corporate arrangements.[92] Nevertheless, as discussed in Chapter 6, there are differences between regulated and merchant interconnectors. In the former case the risks and benefits are socialised through Transmission Use of System Charge (“TUoS”), while in the latter the developer assumes the risk and reward, with the interconnector not included in the regulated asset base.[93] However, what is striking is that the two Ireland/Great Britain ICs are (or were) owned solely by TSOs that are located in Ireland, despite the fact that in the early stages of the planning of what became the East West IC was undertaken jointly between the TSOs in Great Britain and the

[90] These issues are discussed further in Chapters 9 and 10.

[91] Assuming, that is, there are no further changes to comply with the Target Model.

[92] In the case of the Moyle IC, it was originally owned by the TSO. For details see Table 4.1.

[93] However, merchant interconnectors are still subject to regulation, an issue discussed further in Chapter 6.

Republic of Ireland (DKM *et al.*, 2003, p. 1). In contrast, the Great Britain/continental Europe interconnectors are owned by the Great Britain TSO, National Grid, and the TSO in the Member State at the other end of the interconnector – France, the Netherlands and Belgium. The exception is the ElecLink, the proposed interconnector that uses the Channel Tunnel.

There are certain advantages to the development of interconnectors that are joint ventures between TSOs at either end of the interconnector, compared to a situation where the interconnector is wholly owned by a TSO at one end of the interconnector. *First*, a joint venture means that the risks are spread. Interconnectors are large risky long lived investments, with a high element of sunk costs (no pun intended). To be sure the returns are also shared, but the costs are all upfront spread over perhaps a decade, while the benefits do not start to accrue until that decade is completed and continue for a minimum of 25 years (DKM *et al.*, 2003, p. 54). These considerations are likely to be particularly important for a small Member State, such as Ireland, compared to a larger Member State, such as the UK. *Second*, for interconnectors to work requires that two different markets interconnect. As noted in Chapters 9 and 10 this is neither an easy nor straightforward exercise. If an interconnector is a joint venture between the TSOs at either end, then each will have a strong incentive to ensure that interconnection is successful. This is important not only in understanding the two systems, but also in the wider political economy sense of having a large powerful player in each market pushing for success in everything from the development of interconnection policy to facilitating the physical linking of the interconnector to the grid at either end. *Third*, having interconnectors owned by TSO's more appropriately aligns the incentives in terms of building interconnectors that are designed to maximise interconnection. Incumbent thermal generators might, for example, try to slow the building and/or restrict the capacity of interconnectors in order to lessen competition were they given a bigger role.[94] In addition, if the interconnector is a joint venture between the TSO at each end of the interconnector then there is less likelihood that the TSO owner at either end of the interconnector will in some sense favour narrow national industry interests.

The issue of ownership of interconnectors seems to get little, if any attention in Ireland. In the Government's White Paper on energy there is a clear preference for public ownership of infrastructure (DCMNR, 2007, p. 21 and pp. 52-53). This does not, of course, preclude a joint venture in developing interconnectors. However, be that as it may, the difficulties alluded to above concerning State funding of such

[94] Suppliers, on the other hand, would welcome the additional capacity and push for more rapid construction to reduce their exposure to the market power of incumbent generators. However, to the extent that suppliers are also vertically integrated will blunt the desire for more interconnection.

projects may make joint ventures more likely in the future.[95] Nevertheless, it appears that National Grid, the likely joint venture partner with EirGrid, has its focus firmly on interconnectors with continental Europe not Ireland.[96] Thus, even if EirGrid wanted to form a joint venture with National Grid it is not at all clear that the latter would be interested in looking west. Nevertheless, there is a possibility that in order to ensure renewable targets in Great Britain are met that funding may be forthcoming so that the renewable electricity is exported. Furthermore, if interconnection with France were considered a viable option – unlikely in view of the earlier discussion – then a joint venture between EirGrid and Reseau de Transport d'Electricite ("RTE"), the France TSO, could be explored. In sum, without these developments, it appears that the ownership and development of interconnectors from Ireland will be driven primarily by Irish public policy, with little, if any, private sector involvement and/or of another TSO, apart from EirGrid.

[95] Any rethink towards public ownership towards infrastructure may also change the situation. For a discussion of these issues see Gorecki *et al.* (2011) and Review Group on State Assets and Liabilities (2011).

[96] In a consultation exercise carried out by National Grid in 2008/2009, jointly with the TSOs from France and Belgium, the focus was firmly with interconnection to continental Europe. One table showing future interconnectors did not show or suggest Ireland as a possible destination. For details see National Grid (2008, 2009).

Chapter 5

How Much Interconnection: Meeting Ambitious Wind Targets

Interconnection and wind generated electricity complement each other. This reflects the fact that wind is a variable source of electricity generation. If the wind speed is too low or too high wind cannot be used to generate electricity, in the latter case for safety reasons (EirGrid, 2009b, p. 16). Furthermore, when the wind does generate electricity in Ireland the wind pattern tends to be similar across the island (*ibid*, p. 16). As a result, if there is no wind generated electricity in (say) the south-west due to wind speed it is unlikely to be offset by wind generating electricity in another part of Ireland. Thus, the higher the level of wind generated electricity, the greater the requirement for back-up generation capacity for when the wind speed is too low or too high. This is expensive: electricity available at short notice often is high cost and less efficient. Interconnection is one method of resolving this dilemma, since electricity can be imported from Great Britain and beyond when the wind does not blow or blows too hard. Furthermore, interconnection has an added advantage. When wind generated electricity's share of all electricity reaches certain limits it is curtailed off the system.[97] With interconnection this surplus can be exported. This is confirmed by a number of studies such as Poyry (2009, p. 19) which in an examination of wind variability for the SEM and BETTA concluded, "[O]ur findings underline the almost critical importance to the Irish market of having connection to the British market, although the opposite is not true."[98] In this chapter the interaction between wind and interconnection is considered. The targets set by the State for wind generation are first examined, together with the support mechanism designed to assist in reaching the target. The next issue considered is the interaction between wind and interconnection, which suggests that the projected levels of wind generated electricity are consistent with 1,000MW of interconnection capacity over and above the Moyle and East West ICs. Two caveats concerning the analysis are then discussed. An important consideration is to

[97] For details see EirGrid (2009a, Figure 7, p. 10; 2010, p. 21) and Poyry (2010b, p. 30). This curtailment is for security of supply reasons. In many cases wind cannot exceed a certain proportion of demand. The limit is currently around 50 per cent, but studies carried out for EirGrid and SONI "indicate that, subject to the fulfilment of a number of technical and operational criteria" the limit could be raised to 75 per cent (EirGrid and SONI, 2011b, p. 8).

[98] This reflects the fact that the correlation between wind speeds in Ireland and Great Britain is less than 0.50 as estimated by Poyry for 2030. This relatively low correlation reflects the sizeable portion of future Great Britain wind generated electricity located in places such as the Dogger Bank off the east coast of England with little correlation to wind speeds in Ireland. (See Poyry, (2009, Figure 1, p. 3) for the location of installed wind capacity in 2030 for Great Britain and Ireland). See also Irish Academy of Engineering (2011, p. 23) concerning the importance of interconnection in accommodating wind generated electricity in Denmark.

ensure that the incentives are aligned so that the wind electricity generation capacity that is built is:

- cost effective. Although the targets for electricity generated by wind are designed to meet Ireland's EU renewables obligations, these targets should be complied with at least cost. This is likely to involve a mix of policies. The chapter suggests how existing policies might be improved to deliver the same outcome at a lower cost, while exploring other options that might enter the mix; and,
- not built ahead of interconnection capacity or else wind generated electricity is likely to be curtailed off the system with the result that at least some of the investment in such generation, built with a large element of public subsidy and support, will be yielding a low if not zero return.

Wind Targets

The government has set targets for electricity generation from renewables. In the 2007 White Paper on a sustainable energy policy for Ireland the target for electricity from renewables was set at 15 per cent of electricity consumption by 2015 and 33 per cent by 2020 (DCMNR, 2007, p. 29). Subsequently, the renewables target was raised for 2020 to 40 per cent of electricity consumption on 15 October 2008 in the Carbon Budget,[99] the target for 2010 having been met. Virtually all of the renewable electricity is to be generated by wind: 37 per cent of Ireland's electricity consumption will, it is envisaged, be from wind in 2020; 3 per cent from other renewables (EirGrid, 2010, Figure 1, pp. 8-9).[100] This projected share of wind generated electricity is higher than any other Member State: Denmark projects the next highest wind penetration at 30 per cent,[101] followed by Greece at 25 per cent, with Hungary at 4 per cent, the lowest. The UK target is 20 per cent (EirGrid, 2010, Figure 7, pp. 18-19). Thus, it appears that Ireland has set ambitious targets for wind generated electricity.[102]

In 2010 it was estimated that to meet the 40 per cent wind target in 2020 translated into 6,232MW of wind.[103] However, with the recession and the consequent decline

[99] For details see the speech by the Minister for Energy, Heritage and Local Government to the Dail on 15 October 2009. See: http://historical-debates.oireachtas.ie/D/0663/D.0663.200810150007.html. Accessed 17 November 2010.

[100] The 3 per cent consists of biomass, tidal and wave power. The comments made below concerning the high cost of offshore wind also apply to these other renewable sources.

[101] Denmark's electricity system is so closely integrated with that of its neighbours that national penetration levels cannot be directly compared. In 2004 average hourly import capacity relative to installed generation capacity for Denmark was 50 per cent (EC, 2007b, Table 24, p. 177).

[102] It should be noted that while Ireland is a leader in terms of the contribution of wind, overall Ireland's renewable target is much lower than Austria (71 per cent), Sweden (63 per cent), Portugal (55 per cent) and Denmark (52 per cent), but higher than the UK at 30 per cent. See EirGrid (2010, Figure 1, pp. 8-9).

[103] This refers to the island of Ireland. Both the Republic of Ireland and Northern Ireland have set a 40 per cent target. EirGrid (2010, p.14) suggest that it is expected that 4,632MW of wind will need to be installed in the Republic of Ireland and 1,600MW in Northern Ireland. These estimated were based on 2009 forecasts of demand.

in demand for electricity the volume of wind needed to meet the target also falls. As a result, subsequent analysis reduced the amount of wind to meet the target to 5,450MW: Northern Ireland, 1,100MW; and the Republic of Ireland, 4,350MW.[104] However, this revised estimate is almost certainly too high. It is based on the ESRI's forecast growth GDP for the Republic of Ireland of 2.25 per cent in 2011 and 4.6 per cent per annum for 2012-2015.[105] The most recent ESRI forecasts have reduced these estimates: 1.8 per cent growth in GDP for 2011 and 2.3 per cent for 2012.[106] Hence a more reasonable estimate of the wind generated electricity needed to meet the 40 per cent target is likely to be closer to 5,000MW by 2020.[107]

In order to meet the wind targets set by the Republic of Ireland, the CER has set up a process under which applications by wind and other renewable generators for connection to the electricity grid are dealt with in groups. The first of these was referred to as Gate 1, in 2004, the most recent, Gate 3, in 2008. If all the wind farm applications under Gates 1 to 3 were built capacity would be 6,000MW.[108] This is substantially above the volume of wind necessary to meet the 40 per cent target not only for the Republic of Ireland, but also Ireland (i.e. the Republic of Ireland and Northern Ireland).[109]

Meeting Wind Targets: REFIT and SEM Pricing Rules

A number of support mechanisms have been put in place to facilitate the attainment of the wind targets. These vary from minimum price guarantees to under pricing the provision of certain services. Furthermore, the level of support is more for offshore than onshore wind electricity generation. In 2010 offshore wind accounted for less than 1 per cent of wind capacity; by 2020 it is projected to account for 34 per cent of all wind capacity (DCENR, 2010, Table 10, pp. 139-140). The support mechanisms are not the same in the Republic of Ireland and Northern Ireland. Attention here is confined to the supports in the Republic of Ireland, although in some instances they are the same across both jurisdictions.

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104 SONI and EirGrid (2010, p. 33-37).

105 SONI and EirGrid (2010, Table 2-A, p. 16). Based on estimates made in July and October 2010.

106 Based on the ESRI's Summer 2011 *Quarterly Economic Commentary*. See Durkan, Duffy & O'Sullivan (2011) for details.

107 We discuss below the consequences if growth turns out to be higher than expected. EirGrid and SEMO will update their *All-island Generation Capacity Statement* in 2011 to take into account the recent ESRI forecasts.

108 See CER (2010, pp. 19-23) for details. It is unlikely that all of these will be built due to planning and financial difficulties. For example, in August 2011, An Bord Pleanala refused planning permission for a wind farm of 27 turbines in Connemara because of its adverse visual and environment impact. This is one of a series of similar decisions by An Bord Pleanala. See McDonald (2011).

109 Ten per cent and 38 per cent respectively, using 5,450MW (for Ireland) and 4,350MW (for the Republic of Ireland) as consistent with the 40 per cent target.

The ***Renewable Energy Feed-In Tariff*** ("REFIT") scheme, building on earlier schemes, provides financial incentives for the building of wind farms in the Republic of Ireland.[110] It does this by guaranteeing minimum prices, or so called feed-in tariffs, for wind generated electricity that is dispatched – electricity that is curtailed off is not reimbursed under REFIT.[111] In other words, under REFIT if the SEM determined SMP price is less than the guaranteed price, then the difference is paid to the wind farm operator.[112] There is also a fixed element that is independent of the SMP.[113] The support or subsidy is funded through a levy on electricity users through the Public Service Obligation ("PSO"). Devitt and Malaguzzi Valeri (2011, p. 364) estimate the impact of REFIT is to raise the retail price of electricity for residential consumers between 4.1 to 10.3 per cent and for industry between 5.4 and 13.7 per cent.[114] However, the arrangement is asymmetric – if the price of electricity is substantially above the guaranteed price then the wind farm operator retains all the revenue.[115] Thus consumers through the PSO provide free insurance against low prices for wind farms, but do not participate in any upside in terms of sharing the gains of high prices.[116]

The REFIT tariffs differentiate between offshore and onshore wind in 2009. The guaranteed price for offshore wind is much higher than for onshore wind: for onshore wind, €66.353 per MWh, compared to offshore wind, €140 per MWh (or more than twice).[117] However, the fixed element, 15 per cent of €66.35 per MWh, is paid irrespective of whether or not the electricity source is onshore or offshore wind (Devitt and Malaguzzi Valeri, 2011, Table 1, p. 346 and Table 2, p. 347). The guaranteed price difference between onshore and offshore wind reflects the fact that the capital, running and connection costs of offshore wind are all much higher than the corresponding costs for onshore wind (Green and Vasilakos, 2011, pp. 498-

110 In Northern Ireland the Renewables Obligation places a legal requirement on all Northern Ireland licensed electricity suppliers, from 1 April 2005, to provide Ofgem (on behalf of the NIAUR) with evidence that a specified quantity of the electricity supplied to final consumers can be accounted for by generation from renewable sources. For further details see: http://www.detini.gov.uk/deti-energy-index/deti-energy-sustainable/northern_ireland_renewables_obligation_.htm. Accessed 16 August 2011.

111 The alternative method that has been adopted by some other Member States is tradable green certificates. However, the evidence suggests that feed-in tariffs are preferable. Hybrid schemes are also possible. For a discussion of these various options see Green and Vasilakos (2011, p. 501) are references cited therein.

112 SEM is described in Chapter 9.

113 For details see Devitt and Malaguzzi Valeri (2011, Table 2, p. 347). There is also a technology payment.

114 The higher the fuel price the less the price increase due to the use of renewables. The estimates are based on a mixed portfolio of onshore, offshore, wave and tidal. The price impact would be less if all the renewable electricity is generated by onshore wind.

115 The UK's Electricity Market Reform plans to introduce a mechanism that will address this issue by capping returns above a certain level. For details see DECC (2011).

116 The REFIT payment, which lasts 15 years, also has other support elements such as fixed payment and a technology payment. These and other aspects of the programme are discussed in Devitt and Malaguzzi Valeri (2011, pp. 345-350). The guaranteed prices quoted in the text refer to REFIT II.

117 The guaranteed price for wave and tidal generated electricity was even higher at €220 per MWh.

500 and Table 5.1). These additional costs are typically borne by the wind farm operator.

In the case of ***connection to the grid, the policy is for shallow connection,*** i.e. the operator pays for the cable to the nearest substation on the grid and any increase in the capacity of the substation. However, in the case of offshore wind some ambiguity might arise if there is a move to build an offshore grid to connect the various wind farms: should the offshore grid be paid on a pro rata basis by the offshore wind farms that use the offshore grid or should it be paid for through TUoS – i.e. increased electricity charges for consumers? In the case of both offshore and onshore wind, however, reinforcement of the transmission system by EirGrid is not charged to the wind farm, but forms part of the TUoS and hence feeds through to higher electricity prices.

The ***pricing system for wind generated electricity also arguably provides another support***, irrespective of whether it is offshore or onshore wind. The SEM may be only able to use a certain proportion of the electricity generated by wind, because of concerns over system security. Over and above this level wind electricity is curtailed. It is not used by SEM to supply electricity to businesses and homes. However, under the SEM rules such curtailed wind generated electricity is, subject to some exceptions, paid the SMP and capacity payments.[118] This reflects the fact that there is no difference, for windfarms, under the SEM pricing rules between constraining off and curtailing off.[119] However, at times when wind is curtailed electricity prices are likely to be low, since wind is likely to account for a substantial portion of demand. Thus, a wind farm owner does not take into account the fact that by building an additional wind farm that the probability that wind generated electricity will be curtailed off increases, apart that is from a reduction in REFIT payments that do not compensate curtailed off electricity.

[118] Payments are made for the volume difference between actual output and market scheduled quantity. This is generally the same as the unconstrained output but, where the wind farm's connection capacity is non-firm, the operator is not paid for any amount above the firm access quantity.

[119] Curtailment is defined as "…changes to generator output from the most economic dispatch in order to ensure that sufficient quantities of the system services necessary to run a safe and secure electricity system are available. At very high wind generation levels, further reduction of wind generator output may be required if wind generation levels still exceed demand." In contrast, constraining is "[C]hanges to generator output from the most economic dispatch due to transmission network limitations, specifically the overloading of transmission lines, cable and transformers. Constraint is location-specific and can be reduced by transmission network reinforcements" (O'Donnell, 2010, slide 3). As it is difficult to define exactly why a wind farm is constrained down (e.g. is inflexibility of other plant the fault of the other plant or of the wind farm for needing flexibility on the system), there is no distinction between constraint and curtailment in terms of payment.

Table 5.1: A Qualitative Assessment of the Technical Characteristics of Different Electricity Generating Technologies, 2010

	Capital Costs	Build Time	Technological Risk	Operational and Maintenance Risks	Generating Costs Linked to Gas/Coal	Flexibility/ Ability to Dispatch Generation on Demand
Gas (CCGT)	Low	Short	Low	Low	Closely aligned	Flexible
Onshore Wind	Medium	Short	Low	Low	Not linked	Intermittent
Offshore Wind	High & uncertain	Medium	High	High	Not linked	Intermittent
Biomass	Medium	Medium	Medium	Medium	Not linked	Flexible
Nuclear	High	Long	Medium	Medium	Not linked	Inflexible
CCS (Gas or Coal)	High & uncertain	Long	High	Unknown	Somewhat aligned	Untested

Source: DECC (2010b, Table 1, p. 29).

There are ***other methods of support and investment required in order to accommodate high volumes of wind***. These relate to issues surrounding the integrity of frequency response and the dynamic stability of the system (EirGrid & SONI, 2011a; 2011b). In addition, the greater volume of wind, combined with increased interconnection, is likely to lead to increased volatility of wholesale electricity prices with pronounced peaks that may obscure investment signals (Poyry, 2009). Furthermore, increased volumes of wind are likely to lower investment returns on conventional power source, and perhaps raise costs (Irish Academy of Engineering, 2011).[120]

The Interaction of Wind and Interconnection

The increase of the renewable target for 2020 to 40 per cent was based on a joint DCENR and DETI (2008) study which, according to the Minister for Communications, Energy and Natural Resources (DCENR, 2008), "…tells us that it is feasible to generate 42 per cent of our electricity from renewable sources" by 2020. That study assumed that the total interconnection capacity between Ireland and Great Britain was 1,000MW, slightly more than equivalent to the Moyle and East West ICs. DCENR and DETI (2008) did not test the sensitivity of their results to the level of interconnection.[121]

[120] The Irish Academy of Engineering (2011, p. 25) has estimated, "on a very conservative basis," some of the costs in addition to the REFIT support, as approximately €30 per MWh. However, it is not entirely clear how the additional €30 per MWh is derived.

[121] The same applied to another study which examined the degree to which high levels of wind penetration on the SEM could be accommodated. See CER & NIAUR (2009a) for details.

Diffney *et al.* (2009) did, however, undertake this task, with levels of interconnection varying between 900MW (the Moyle IC and the East West IC) 1,400MW and 1,900MW, which is the equivalent of one then two additional 500MW interconnectors, respectively. The authors concluded that:

> We find that investing in a lot of wind generation is economic only if there is also parallel investment in interconnection. This allows wind to generate whenever it is available, instead of being curtailed at times of low demand or imposing additional costs on thermal plants by making them ramp up and down (*ibid*, p. 485).[122]

More specifically, *given* the decision to build wind generation capacity of 6,000MW[123] then the cheapest option in terms of the net costs to the Irish electricity system always involves 1,900MW of interconnector capacity irrespective of whether or not the fuel cost is low, medium or high (*ibid*, Table 2, p. 477).[124] If, however, fuel costs were low then net costs would be lowest with less interconnection (i.e. 900MW) and less wind (2,000MW). Nevertheless, the difference compared to 6,000MW of wind and 1,900MW of interconnection would be small. As a result "…a high level of wind generation would provide a hedge against high fuel prices" (*ibid*, p. 485).[125,126]

This analysis suggests that an additional motive for building interconnectors is to utilise wind generated electricity in an optimal manner. Such electricity can serve as a useful hedge against high fuel prices of thermal generated electricity. If additional interconnection is not built over and above the Moyle and East West ICs then wind generated electricity will be curtailed off the system more than would otherwise be the case, but for which SMP and capacity payments will nevertheless still have to be made. However, that does not in itself provide a justification for building additional

[122] The two electricity regulators CER and NIAUR (2009c, p. 2) reached a similar conclusion, which drew on an unpublished study by Poyry.

[123] For the island of Ireland 6,232 MW of wind generation is needed to meet the 40 per cent renewables target for electricity by 2020 (EirGrid, 2010, p. 14). However, as noted above this estimate is probably biased upward.

[124] However, if the volume of wind generated electricity is allowed to vary, then if the fuel price is low the cheapest option is 900MW interconnection capacity, but if fuel prices are medium or high then the cheapest option is 6,000MW if wind and 1,900MW of interconnection. Diffney *et al.* (2009, p. 477) in favour of the latter combination of wind and interconnection capacity.

[125] Diffney *et al.* (2009, p. 474) base their estimates on the assumption that all wind generated electricity is from onshore rather than offshore wind. Offshore wind, as noted above, has higher fixed and variable costs than onshore wind. Hence Diffney *et al.* (2009) are likely to underestimate the cost of providing wind generated electricity if the offshore wind farms are built.

[126] Policymakers are, of course, aware of these cost differences. The High-Level Group on Green Enterprise (2009, p. 19, fn. 21), for example, assert that the "…market for off-shore wind is expected to experience rapid growth in the coming years as the technology becomes more advanced and energy costs increase." This begs the obvious question that surely it would be in Ireland's best interests to wait for these developments before embarking on an expensive public subsidy programme of offshore wind when it is anticipated that costs will fall.

interconnection capacity. For reasons set out in Chapter 4, the recession and associated budgetary crisis has made the economic case for building additional interconnectors less attractive, albeit to some extent temporary as the economy recovers. However, these same factors are likely to make it even less attractive to finance offshore wind farms which are highly capital intensive, while the decline in electricity demand compared with what it would have been when the 40 per cent target for renewable was set, means that less wind generated electricity will be required. Hence there is less justification for additional interconnection.

Aligning Incentives

In considering whether or not incentives are correctly aligned so that wind generation capacity is supplied at least cost and that interconnection and wind capacity decisions are coordinated three issues are considered: the interrelationship of wind with interconnection capacity; offshore vs. onshore wind; and how to price the provision of free insurance to wind farms against low prices.

Interconnector Capacity

The level of renewable energy capacity should be consistent with the interconnection capacity built or likely to be built. As more and more wind capacity is built, for a given level of interconnection, then: the probability of wind being curtailed off the system increases as does the probability that it will be replaced by higher cost thermal electricity. This is a waste of resources; and, there will be pressure/demand for additional interconnector capacity to export the resultant electricity. There is thus a need to ensure that the level of wind generated electricity needed to meet the 40 per cent renewable target is consistent with the reduction in the demand for electricity to something closer to 5,000MW than 6,000MW for Ireland.

The policy objective here is to ensure that firms building new wind farms take into account that there will be an increasing probability of curtailment as more and more wind generation capacity is built, given the planned interconnection, which at present is limited to only the Moyle and East West ICs with little prospect of an additional interconnector coming on stream until probably 2025, unless the process is accelerated, well beyond the 2020 renewable 40 per cent target date.[127] Thus, there is a need to align the meeting of the 2020 target with the likely date of more interconnection, perhaps by extending the time frame over which the 40 per cent target is met to match the time profile of greater interconnection, although this will

[127] To some extent, of course, firms will need to take this into account when they seeking funding for investment.

be difficult given the binding nature of the targets. Furthermore, if for some reason, electricity demand is higher than anticipated – thus justifying more wind to meet the 40 per cent target – there appears to be sufficient excess generation capacity available (SONI and EirGrid, 2010; Irish Academy of Engineering, 2011). In addition, while wind provides an insurance against high fossil fuel prices there is evidence that use of shale gas in the US may lead to lower fossil fuel rather than higher prices, although there is considerable uncertainty with respect to production due to environmental and regulatory issues (Irish Academy of Engineering, 2011, pp. 16-17; FitzGerald, 2011, p. 19).

As noted above curtailed electricity is an economic waste. Furthermore, it will have to be funded by SEM payments and hence feeds through directly in higher electricity prices damaging competitiveness and jobs. Thus, the costs are not borne by the firms building the additional wind generated electricity capacity, nor those making the decision. The costs are externalised, with the exception of the linking of REFIT payments that do not reimburse for curtailed off wind. The issue then becomes how to internalise those costs such that those firms building the new wind farms take them into account. Possible solutions include:

- Guaranteed prices under REFIT should fall as the existing stock of wind generation capacity increases.[128] The CER and NIAUR have done extensive modelling on the impact of wind on the system and could be asked to provide advice on an appropriate schedule of prices;
- When wind is curtailed off the system,[129] it should receive no payment, whether SMP or capacity, under the SEM rules. It already receives no payment under REFIT for wind that is curtailed; and,
- REFIT payments should not be paid for exports.

Such solutions would have to be announced sooner rather than later so that firms could take such considerations prior to building such capacity. Furthermore, there are likely to be practical problems in implementation such as identifying exports on which REFIT should not be paid and existing contractual arrangements may be difficult to revise.

The ultimate objective with respect to wind generation should be to support an efficient system for reaching the EU target. Buying tradable renewable permits – if

[128] Devitt and Malaguzzi Valeri (2011, p. 366) recommend that the fixed element of support should be removed, since it "…dampens the hedging quality of wind generation and adds to the costs to final consumers."

[129] Due to lack of demand or because of system stability concerns.

for example a system similar to the EU Emission Trading System were created – might be an alternative to building excess capacity.[130]

Offshore Versus Onshore Wind

A second issue relates to ensuring that wind generated electricity is achieved in a cost effective manner. It is not at all clear why consumers of electricity are via the PSO incurring large contingent liabilities through guaranteeing minimum prices for the building of relatively expensive offshore wind capacity, as well as potentially at least subsidising the constructing of a costly offshore grid, when much lower cost onshore wind is available. There are also various tax reliefs and incentives by which taxpayers subsidise the renewable energy, although take-up has been low because of the low profits tax in Ireland.[131] Furthermore, imposing these extra costs via offshore wind is not consistent with the Government's *White Paper on Energy* which stated that, "[T]he Government's key policy objective is to ensure a reliable and competitively priced energy supply … Ensuring the relative competitiveness of Irish energy prices is a key concern, reflecting the needs of the enterprise sector and all consumers" (DCMNR, 2007, p. 6).[132] Nor is it consistent with the Government's Smart Economy which places emphasis on achieving the 40 per cent renewable target "in a cost-effective way" (Department of the Taoiseach, 2008, p. 17).[133] Nor is it obvious Ireland in its current period of austerity can afford such costly subsidy programmes. Finally, there appears to be no shortage of onshore wind sites, but that does not mean of course that there are not problems concerning obtaining planning permission and a grid connection.

There are two options that could be introduced to better align incentives so that wind is generated in a cost effective manner:

- Ensure offshore wind farms are charged the full cost of grid connection[134] (or at least the difference between onshore and offshore connection for wind farms) and limit the guaranteed price under REFIT to offshore wind to the same rate as onshore wind; and,
- More generally off-budget measures, that are the equivalent of or substitute for direct public expenditure, should be subject to the same degree of analytical and legislative scrutiny as public expenditure. If such a procedure had been in place,

[130] This option is discussed further at the end of this chapter.

[131] Commission on Taxation (2009, various pages). It should be noted that the Commission supports the continuance of some of these tax breaks for renewable energy. However, when considered in view of all the other support renewables received, whether the same view would obtain is a different matter.

[132] Furthermore it is not clear that such a policy is consistent with the other objectives of energy policy (DCMNR, 2007, pp. 5-7).

[133] Nor is it consistent with the recommendation of the Review Group on State Assets and Liabilities (2011, p. 36).

[134] This reflects the situation where some ambiguity might arise if there is a move to build an offshore grid to connect the various wind farms. Here it is suggested that offshore wind farms fund the offshore grid.

the decision in 2009 may not have been taken to extend REFIT guaranteed prices to offshore wind (and wave and tidal) generated electricity, at a time of considerable fiscal austerity, and a dramatic decline in economic growth, may not have been taken.

These are not necessarily mutually exclusive choices.

Sharing the Benefits of Free Insurance for Wind Generation

A third issue concerns the fact that under REFIT – for both onshore and offshore wind, as noted above – the State provides free insurance against low prices for wind farms, but does not share in any of the benefits should electricity prices substantially exceed the guaranteed price. This is inequitable. A price cap could be placed above which any revenues are shared between the wind farm operator and electricity consumers.[135] Alternatively, royalties could be levied above the cap.

The *2011 Programme for Government* has proposals which would address some of the problems identified above with respect to REFIT. In the energy section it is stated that:

> We will review and reform the PSO levy to ensure that only cost-effective projects are supported by ReFIT tariff and that consumers can benefit from claw-back when market prices exceed tariff or where appropriate, share of profits or royalty (Department of the Taoiseach, 2011, p. 60).

Although not explicitly stated the reference to cost-effective projects should sound the death knell of differential subsidies for offshore wind.

Conclusion

In sum, there is a need to align incentives better so as to ensure that wind generation is built at the appropriate time and on a cost efficient basis. On the first issue, there is likely to be an inconsistency in the timing between the 40 per cent renewable target of 2020 and the fact that there is little chance of a new Ireland-Great Britain interconnector coming on stream until at least 2025, unless the process is accelerated. This may mean deferring reaching the target, albeit that this is binding. In order to ensure wind is not unduly curtailed off the system,

[135] This is part of the UK's proposals for feed-in tariffs. For details see DECC (2011, pp. 38-39).

interconnection is of vital importance. To ensure timing consistency it is thus suggested that guaranteed prices under REFIT should fall as the existing stock of wind generation capacity increases. When wind is curtailed off the system, it should receive no payment, whether SMP or capacity, under the SEM rules. It already receives no payment under REFIT for wind that is curtailed.

On the second issue, the current REFIT scheme subsidises expensive offshore wind power and the costs of building too much wind generation capacity are being externalised. This paper therefore proposes that: offshore wind farms are charged the full cost of grid connection (or at least the difference between onshore and offshore connection for wind farms) and limit the guaranteed price under REFIT to offshore wind to the same as onshore wind.

It is inequitable and inefficient that while REFIT guarantees a minimum price for electricity generated from wind farms there is no sharing of the benefits should high prices be experienced. It is suggested that above a certain price, electricity consumers share in the returns from higher prices.

Finally, there is a need to examine the volume of wind capacity required to meet the 40 per cent target by 2020. It appears that for Ireland to meet this target in 2020 requires somewhere in the region of 5,000MW of wind capacity. However, at the present time approval has been given for the Republic of Ireland for 6,000MW of wind to be connected to the grid. Clear signals need to be sent sooner rather than later that REFIT and other supports will be restricted to less than 4,350MW not 6,000MW, before the latter level capacity is installed and operating.

But what if for some reason, electricity demand is higher than anticipated – thus justifying more than 5,000MW wind to meet the 40 per cent target by 2020? *First*, there appears to be sufficient excess thermal generation capacity available so that there is no danger of shortfalls in supply. *Second*, if demand increases more than expected then this should become evident well before 2020. Even if this is not the case, the 40 per cent target will still be reached but deferred by a few years, although this is unlikely given the binding nature of the target. Furthermore, it is anticipated that there will more stringent targets for the decades after 2020, so that if a Member State under or over shoots the 2020 target there will be an opportunity to adjust subsequently to attain the next target in (say) 2030.[136] *Third*, while wind provides an insurance against high fossil fuel prices there is evidence that use of

[136] On future possibilities for low carbon economy see EC (2011c).

shale gas in the US may lead to lower fossil fuel rather than higher prices, although there is considerable uncertainty with respect to production due to environmental and regulatory issues. *Fourth*, there is evidence that some of the large Member States, such as Germany and the UK, may have difficulty in reaching the various EU renewable targets with the result that there may be some revisiting of the targets (FitzGerald, 2011, p. 19).[137]

Fifth, if a system of tradable renewable permits is introduced then this would offer an alternative to way of dealing with deviations from the renewable target. Under this system each Member State would, for example, be given a renewable target and each source of renewable electricity would receive certificates based on the amount of renewable electricity generated and used. Each Member State would be required to surrender certificates equal to the target level. However, if a Member State exceeds its target then this can be sold to a Member State that falls short of its target. Such a system would be similar to the EU Emission Trading System and would build on the voluntary cooperation arrangements that are set out in the renewable directive.[138]

In sum, all this suggests that erring on the conservative side in setting wind volumes is likely to incur lower costs compared with overbuilding wind that will be curtailed off but still attract a series of supports, in varying degrees, thus driving up the price of electricity.[139]

[137] It has also been suggested that the 2020 deadline is too short a time horizon in any event. See, for example, Helm (2011b).

[138] For a discussion of the EU Emission Trading System see Matthes and Neuhoff (2007), the renewable directive is, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77//EC and 2003/30/EC.

[139] Since such wind generated electricity would be curtailed off the system such electricity would not be eligible for a renewable certificate.

Chapter 6

Distributing Interconnector Congestion Income: Regulated Versus Merchant IC

Interconnectors can be built by either public or private operators, subject of course, to meeting all the various regulatory and associated conditions. However, irrespective of the ownership of an interconnector, the Third Package (and its predecessors) set out rules that not only specify how use of the interconnector should be priced and what kinds of capacity allocation mechanisms are permissible,[140] but also sets out two options concerning how interconnector rents can be allocated: merchant or regulated. Needless to say, these rules are likely to impact on who builds interconnectors and possibly on the number/capacity of such interconnectors. In other words, the rules, albeit indirectly, can have an important influence on the success of the internal market.

Interconnector rents or congestion income, are likely, other things being equal, to be much larger for the initial interconnectors than those built subsequently. Congestion income will only be generated on the interconnector where there are differences in electricity prices between the markets at either end of the interconnector, as illustrated in Figure 3.1. The greater the price difference the greater the demand for interconnector use and for increased interconnection capacity. Given limited interconnector capacity, the interconnector is likely to become very congested. The interconnector owner can thus charge a high price for use of the interconnector, reflecting its scarcity. However, as noted above, as more and more interconnectors are built, other things being equal, inter-country prices will tend to converge[141] with the result that congestion income will drop accordingly for all interconnectors, irrespective of when they were built. Thus it is important to get the rules concerning rent allocation correct, especially at the initial stages of interconnection.

In this chapter the rules concerning the allocation of rent or congestion income are set out for regulated and merchant interconnectors. Each mechanism has important shortcomings that may lead to underinvestment in interconnection. The chapter is

140 The latter two issues are discussed in Chapter 7. Interconnector capacity has to be auctioned off and cannot be allocated in non-transparent ways such as a beauty contest.

141 Apart that is from differences in demand patterns that may differ by Member State due, for example, to different time zones.

completed with a discussion of recent developments that suggest some convergence between merchant and regulated interconnectors.

Reg 714/2009 – Distributing the Rent

Reg. 714/2009 offers two solutions to the question of interconnector income distribution: *first*, the regulated or default position is that congestion income is used to build more interconnectors and, having achieved that objective, used to reduce TUoS; and, *second*, merchant interconnectors, where the congestion income largely or exclusively accrues to the owners.[142] Merchant interconnectors are exceptions that need to be justified (*ibid*, recital 23). Ireland/Great Britain and Great Britain/continental Europe interconnectors are presented in Tables 4.1 and 4.2, respectively, classified by whether or not they are regulated or merchant.

Regulated Interconnectors

Reg. 714/2009 sets out three options for the use of the proceeds of congestion income in Article 16(6):[143]

> "(a) guaranteeing the actual availability of the allocated capacity; and/or
> (b) maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors" (*ibid*, Article 16(6)).

If revenues cannot be efficiently spent on (a) or (b) they may be used, subject to some caveats,[144] as:

> "(c) income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs and/or fixing network tariffs" (*ibid*, Article 16(6)).

The allocation of congestion income for (c) is subject to review by NRAs, the CER in the case of the Republic of Ireland and NIAUR in the case of Northern Ireland. NRAs shall be transparent in the way in which the congestion income is to be used (*ibid,* Annex I, paragraph 6.2).

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[142] However, in approving the merchant interconnector it is possible that conditions will be attached that in certain circumstances part of the return is used to reduce TUoS. See the discussion below under 'Merchant Interconnectors' with respect to the BritNed IC for an example.

[143] On the use of congestion income see Article 16(6) and Section 6 of Annex I of Reg. 714/2009. These rules apply whether the interconnector is publicly or privately owned.

[144] The revenues may be used "…subject to approval by the regulatory authorities of the Member States concerned, up to a maximum amount to be decided by those regulatory authorities" (*ibid*, Article 16(6)).

The East West IC is subject to Article 16(6) since it is a regulated interconnector as is the IFA IC. The Moyle IC is solely within a Member State, the UK, and hence it would not appear to be subject to the Third Package. However, it is increasingly being designated as an interconnector subject to EU legislation.[145] In addition, the use of Moyle IC congestion income to reduce TUoS, combined with the fact that it is not-for-profit with its principle stakeholders the energy consumers of Northern Ireland, means that it is not unreasonable to classify the Moyle IC as a regulated rather than a merchant interconnector.

It could be argued that this approach to managing congestion income in terms of rent allocation is sensible. The use of congestion income under Reg. 714/2009 can be viewed as analogous to a hypothecated tax that is designed to alleviate, if not remove, the problem of congestion in interconnectors by contributing towards the maintenance and expansion of interconnector capacity. Furthermore, revenue from the interconnector can be used to reduce tariffs – TUoS. The beneficiary under these options is the consumer.[146] To the extent that an interconnector is funded by or its return guaranteed by the TSO, then the returns should be symmetric: if the interconnector earns returns over its costs, due to congestion income, then this should be used to reduce TUoS, since if the interconnector does not cover its costs then the TUoS is likely to be increased to fund the shortfall. In other words, the incentives are correctly aligned if the purpose of interconnection is concerned with consumer welfare, since the consumers bear the costs and the benefits.

However, if attention is concentrated exclusively on consumer surplus with little or no attention paid to producer (i.e. electricity generator) surplus, the result is that there may be under-investment in interconnection.[147] Recall in Figure 3.1 that both Country A and B gain from interconnection: Country A because the increase in producer surplus more than offsets the decline in consumer surplus, while the reverse is the case for Country B. Hence, while Country B has an incentive to build a regulated interconnector, this is not the case for Country A, where consumers experience higher prices as a result of interconnection. The reference in Chapter 3 to concerns in France when interconnection with Germany led to higher French

[145] When the Moyle IC announced the increase in interconnector capacity, it stated in a press release dated 19 January 2011, that, "[I]n the near future the East to West capacity available for interconnection users will be specifically reviewed to ensure that the quantity is in line with the requirements of EU Regulation 714/2009 Article 16(3) which applies to interconnectors between Member States." (For details see: http://www.mutual-energy.com/Download/Moyle%20Interconnector%20West%20to%20East%20capacity%20increase%20notice%20final%20110118.pdf. Accessed 18 August 2011). This is consistent with a statement by CER & NIAUR (2011c, p. 15) that "…the UK government has agreed to treat Moyle as if the Electricity Regulation applies."

[146] In the broad sense that freer trade promotes EU consumer welfare, and, as discussed in Chapter 4, Irish consumer welfare specifically.

[147] This is particularly the case if the TSO is a publicly owned firm with a mandate to ensure low prices as compared to a privately owned TSO which maximises profits.

electricity prices is such an example. Indeed, there may be a reluctance to promote and facilitate regulated interconnection in Country A.

In sum, the rules concerning the distribution of rent for regulated interconnection may lead to under-investment in interconnection, if the emphasis in decisions concerning interconnectors is maximising consumer surplus. More specifically, there may be a reluctance to build interconnectors for export when this is likely to lead to a rise in prices in the exporting country. However, this does not necessarily have to be the case. There may be important complementarities between the Member States that mean that there are gains from trade,[148] while there are also unpriced public goods such as increased security of supply which benefit consumers. This is likely to be particularly important for a small electricity market such as Ireland compared to a much large market such as the UK or Germany. It may also be difficult to predict inter-Member State price differences. For example, although prices are lower in Great Britain than Ireland, it is quite possible that prices could be higher in the future in Great Britain, an issued explored in Chapter 9.[149]

Merchant Interconnectors

Interconnectors of the type between Ireland and Great Britain and between Great Britain and continental Europe[150] may be exempted from Article 16(6) and various parts of Directive 2009/72 (relating to unbundling and third party access) for a limited period of time, if certain conditions are met, including as per Article 17(1):[151]

"(a) the investment must enhance competition in electricity supply;
(b) the level of risk attached to the investment is such that the investment would not take place unless an exemption is granted;
(c) the interconnector must be owned by a natural or legal person which is separate from the system operators in whose systems that interconnector was built;
(d) charges are levied on the users of that interconnector;
(e) no part of the capital or operating costs of the interconnector has been recovered from any component of charges made for the use of transmission or distribution systems linked by the interconnector; and

148 For example, an "…appraisal of the costs and benefits of a proposed North Sea Interconnector between Norway, with predominantly hydro generation, and Britain, with predominantly thermal generation … [found that in] wet years such an interconnector would have added to total Norwegian export possibilities, so raising prices, while in dry years it would have extended import possibilities, so reducing import costs; in other words there would have been a favourable terms of trade effect in some years" (Turvey, 2006, p. 1459).

149 An additional point also relevant to Ireland: if the interconnector owner is State owned, as is EirGrid, then any profits from congestion income due to exports will accrue to the State.

150 I.e. direct current.

151 Article 17 of Reg. 714/2009 deals with these issues in more detail.

(f) the exemption must not be used to the detriment of competition or effective functioning of the internal market for electricity …"

Thus, although a TSO can own a merchant interconnector, provided it is via a separate entity (condition (c)), it is unable to include the costs of the interconnector in the regulated asset base,[152] with the costs socialised as a TUoS or as a charge to the distribution system (condition (e)). Exemptions are decided upon by the relevant NRAs;[153] if, however, they cannot decide the decision is referred to ACER. In any event, the Commission may request that any decision is either amended or withdrawn. In exceptional circumstances alternating current interconnectors – the type between Ireland and Northern Ireland – may also be exempted.

Imera has been awarded licences to build two merchant interconnectors between the Republic of Ireland and Wales with initial completion dates of 2010 and 2011 (Imera, 2007). However, as noted above, it is unlikely that either of these Imera ICs will be built. The first Imera interconnector has been exempted from the third party access rules set out in Reg. 1228/2003, which preceded Reg. 714/2009: 100 per cent of the capacity in the interconnector will be allocated on the basis of long-term contracts in order to be able to finance the interconnector; any one party can purchase only up to 70 per cent, except for a dominant player in the electricity market where the limit is 40 per cent; and capacity that is not used will be allocated through a secondary market. The last two conditions reflect competition concerns and were added at the request of the Commission (Ofgem, 2010a. p. 41). The exemption order was made in February 2009.[154]

Other merchant interconnectors, such as BritNed IC, do not fit this description of a merchant interconnector since the BritNed IC has 100 per cent third party access via implicit and explicit auctions, rather than long-term contracts.[155] Indeed, there will be no long-term contracts on this interconnector. However, the BritNed IC is only the second interconnector built between Great Britain and continental Europe. Great Britain has extremely low levels of interconnection compared to all other Member States (Ofgem, 2010a, Figure 1.1, p. 6) while the existing IFA IC is close to 100 per cent utilised (EC, 2007b, Figure 60, p. 174) and so there may be substantial returns to be made at this relatively early stage in the roll-out of Great Britain-continental Europe interconnection. Indeed, the Commission limited the return to

[152] In the UK interconnectors cannot by law be part of the regulated asset base (EC, 2007c).

[153] The NRAs also have a role in setting the conditions regarding the length of the exemption and ensuring non-discriminatory access to the interconnector.

[154] CER (2009a) contains the regulatory decision on this matter.

[155] For details see: https://www.britned.com/trading/pages/default.aspx. Accessed 14 December 2010. Note the BritNed IC is jointly owned by two 100 per cent subsidiaries of the England and Netherlands TSOs.

the BritNed IC and if this is exceeded then the surplus will be used for purposes similar to those set out for regulated interconnectors (Ofgem, 2010a, p. 39). The Commission was not convinced that the capacity of the BritNed IC did not reflect monopolistic behaviour that restricted its capacity (EC, 2007c). Thus there are concerns that merchant interconnectors may restrict the size of interconnectors.

Merchant interconnectors are different from regulated interconnectors where the latter are able to use the transmission system to absorb risk. Merchant interconnectors do not have this option. The risk cannot be socialised in this way. However, the risk can be reduced by entering into long-term contracts as appears to have been the intention of Imera or by building an interconnector when congestion is likely to be high as is the case for the BritNed IC. Furthermore, once the interconnector has gained merchant status and the Commission has signed off, individual Member States cannot then retrospectively alter the interconnector's return, by, for example, capping if not reducing the return to investors.[156] Indeed, in the case of the BritNed IC specific reference is made to this possibility as a reason for seeking merchant status (EC, 2007c). Thus, again incentives are correctly assigned since the merchant interconnector owners bear both the costs and the benefits, subject to regulatory oversight, in building an interconnector.

Furthermore, merchant interconnectors are only concerned with the congestion income that is generated from the interconnection. The distributional implications are of no concern for a merchant interconnector. In terms of Figure 3.1, it is irrelevant to the merchant interconnector that consumer surplus increases in Country B, while producers surplus increase in Country A: all that is relevant is that is the revenue stream from the interconnector due to the price difference between the two markets. Hence, in contrast to the situation where a TSO may be reluctant to build a regulated interconnector because of its impact on domestic prices, the merchant interconnector is far less likely to be swayed by such considerations.

Regulated Versus Merchant Interconnectors: Convergence?

One of the major differences between regulated and merchant interconnectors is the allocation of risk. For a merchant interconnector the owner assumes all the risk, reaping the rewards if there is high levels of congestion, but equally experiencing low or zero return if there is no congestion due to lack of use of the interconnector. In contrast, for the regulated interconnector the risk is assumed by electricity users,

[156] In the UK there is an example in electricity regulation where the regulatory rules of the game have been retrospectively changed to the detriment of existing players by the introduction of a windfall levy on profits. For a discussion see Helm (2010b).

since if there is insufficient congestion income to cover interconnector costs, these are paid for by higher electricity prices. Ofgem (2011a) has proposed that a cap and floor regime for merchant interconnectors that blurs the distinction between regulated and merchant interconnectors. Under these proposals, merchant interconnectors would be able to earn a return between the floor and the cap. However, if the return went above the cap the difference would be assigned to the TSO to reduce TUoS; equally if the return fell below the floor, the difference would be paid by the TSO based on raising the TUoS. These proposals arose in relation to the Commission's intervention, noted above, to cap the returns in the BritNed IC that led to a "…level of uncertainty in the regulatory process," with the result that "…several investors signalled that they were now unwilling to go through this process, given the increased regulatory risk of the exemption process (*ibid*, p. 4)."

In sum, both regulated and merchant interconnectors – for different reasons – may lead to an under-investment in interconnection. In the case of regulated interconnectors because of the tendency to pay attention primarily to consumer surplus, in the case of merchant interconnectors because market power considerations lead to restrictions on capacity. However, this does not necessarily have to be the case. In terms of regulated interconnectors there may be important complementarities between the Member States that mean that there are gains from trade, while there are also unpriced public goods such as increased security of supply which benefit consumers. This is likely to be particularly important for a small electricity market such as Ireland's compared to a much larger market such as that of the Great Britain or Germany. In the case of merchant interconnectors, the oversight role of the NRAs and the Commission should serve to a considerable extent to lessen the tendency to under-invest by imposing conditions should returns prove excessive. However, this may suppress market signals and thus discourage additional investment. Ofgem's proposed floor and cap regime may go some way to address these issues.

Chapter 7

Interconnectors: Should the Winners Compensate the Losers?

The internal market, in which interconnection plays a vital role, is likely to create winners and losers. It could be argued that public policy should intervene such that the winners compensate the losers. However, there are a number of practical and conceptual problems in winners compensating losers. In this chapter these are explored. The conclusion reached is that, given these problems, that such compensation should not be paid. This accords with the approach in the Third Package.

It is assumed that greater interconnection results in increased price competition and price convergence initially between adjacent markets such as Ireland and Great Britain in the same REM, then between different REMs and eventually across the whole EU. To illustrate the distributional impact, the discussion concentrates on the relationship between Ireland and Great Britain, where a number of studies have addressed this issue.

Practical Problems

There are at least four practical problems that need to be addressed in assessing the merits of compensation.

First, identifying the winners and the losers is neither an easy nor straightforward task. Two states of the world need to be compared: the world with the interconnection and the world without the interconnection. Prices would be compared in order to estimate the impact of interconnection on the welfare of consumers and producers so as to estimate the relevant magnitudes. Finally, of course, not all producers are the same. As noted above, developers of wind power are likely to benefit from being able to export surplus electricity when curtailment occurs.

Based on current market prices, for example, interconnection between Ireland and Great Britain is likely to:

- make Irish consumers better off and Irish producers (i.e. generators) worse off; and,
- make consumers in Great Britain worse off and Great Britain producers better off.[157]

However, for reasons set out in Chapter 9, prices in Great Britain may be higher than in Ireland in the future, with the result that consumers might lose in Ireland, but producer's gain, in which case compensation based on current prices would be incorrect. In other words, there is considerable uncertainty as to the identity of the winners and losers over the near to medium term.

Second, the issue arises as to who should compensate whom. If all the policy-induced redistribution takes place within a single Member State, then it is clear the issue can be dealt with at that level. However, in respect of the internal market redistribution takes place both within and across Member States as suggested by the example, albeit hypothetical, in Chapter 3. A system of bilateral transfers across Member States will be difficult to agree since there will be considerable differences of opinion on the magnitude of the gains from the internal market and the geographical distribution of the winners and losers, given the inherent uncertainties over relevant variables such as the price of carbon and the volume of interconnection.[158] Indeed, such moves may well be divisive and counterproductive as Member States dispute and contest with each other, thus possibly losing sight of the larger picture of promoting the EU project and seeing the internal market as – incorrectly – a zero sum game – rather than positive sum game as illustrated in Figure 3.1.

Third, it is not clear why compensation should only be limited to one energy policy intervention, important though it is to the EU.[159] There are many other policies such as the Emission Trading System ("ETS") that have resulted in large windfall gains for thermal generators because of the grandparenting of emission permits (FitzGerald, 2011, pp. 30-31). Hence, it could be argued that there is a need to broaden the

[157] Malaguzzi Valeri (2009) provides estimates of the likely magnitude under various assumptions.

[158] It is perhaps for these reasons that the Commission has not undertaken an analysis of the winners and losers by group (i.e. consumer vs. producer) and Member State. Based on a communication with the Commission, April 2011. It should be noted that there are compensation mechanisms relating to transfers of electricity across borders, but the purpose is not for winners to compensate losers (i.e. a distributional issue), but rather to develop a methodology for paying for transmission of electricity across Member States transmission systems (i.e. a pricing issue). See Commission Regulation (EU) 774//2010 of 2 September 2010 on laying down guidelines relating to inter-transmission system operator compensation and a common regulatory approach to transmission charging.

[159] This, of course, raises the broader issue of redistribution within the EU. This issue, it could be argued, is addressed under regional policy, which is designed to assist lagging regions.

canvass against which compensation should be considered. This, of course, makes it much harder to estimate the magnitude and distribution of the gains and losses.

Fourth, it is not clear how compensation could or should be funded. It could be argued that some of the revenue generated from the use of the interconnectors should be redistributed to those that are made worst off: generators in Ireland and consumers in Great Britain based on current prices. However, that does not appear possible given the discussion in Chapter 6 concerning the allocation of revenue from interconnectors under the Third Package. Furthermore, even if such an approach was possible it has the potential to distort the incentives for funding and building interconnectors. If Irish electricity consumers fund the interconnector rather than those in Great Britain then unless Irish consumers benefit they are unlikely to fund the interconnector. Hence, if compensation is to be paid new mechanisms would have to be introduced that do not lead to such distortions.

In sum, there are important practical issues in winners compensating losers that reflect issues ranging from the uncertainty entailed in identifying the winners and losers to designing mechanisms to bring about such redistribution.

Conceptual Problems

Given that government does not routinely compensate the losers for policy-induced changes or tax the winners, the issue arises as to what makes interconnection and the internal market an exception. Nothing similar occurred in recent examples of deregulation in Ireland such as opening up the electricity market to competition or relaxing the entry controls in the taxi industry or the open skies policy for air travel. No doubt the reader can think of many other public policy changes where compensation was not paid. Hence, unless a compelling argument is put forward it is not clear that there are good a priori grounds for compensating losers.

Is interconnection and the internal market an exception to this argument? Greater interconnection and the creation of the internal market is largely driven by public policy considerations, and, as a result, the State should, it could be argued, compensate the losers. However, these arguments are neither compelling nor credible. The policy of greater interconnection, which is an essential part of the internal market, has been well flagged since at least 1998 in various EU moves towards greater integration in electricity markets. The SEM rules explicitly allow for trading over interconnectors. The Moyle IC was announced as far back as 1990, while the feasibility study for the East West IC was published in 2003 (DKM *et al*, 2003). In other words, investors – and the evidence suggests that they would be the losers in Ireland, initially at least[160] – have long been aware that public policy is moving towards an internal market and thus should have incorporated this development into their business investment and related decisions. Hence, given that this is or should have been the case, there is no need to compensate losers, which based on current prices would be generators.[161]

In sum, it is difficult to see that there is a strong, or even a weak, case for the winners compensating the losers due to greater interconnection leading to the successful completion of the internal market. Nevertheless, from a public policy point of view the internal market should satisfy the Kaldor-Hicks criterion (i.e. the winners should be able to compensate, in theory at least, the losers) so that the Pareto optimum is satisfied (i.e. nobody can be made better off without making somebody worst off).

160 Reflecting the initially lower prices in Great Britain than Ireland that might subsequently be reversed, for reasons set out in Chapter 9.

161 Compensation should be considered where public policy experiences radical unpredictable changes, especially if there is no strong a priori rationale.

Chapter 8

Interconnector Governance

One of the critical factors which will determine the success of integrating Ireland into the internal market is the efficient operation and use of interconnectors. If interconnectors are operated efficiently then the benefits outlined in Chapters 3 and 4 are much more likely to be realised and future interconnectors built. For trade to take place in electricity between participants in two different Member State markets efficiently, requires the development and implementation of a set of rules that are easily understood, that minimise transaction costs, that discourage abuse of market power and, at the same time, are flexible enough to respond to short-term arbitrage opportunities due to price disparities between the two markets. Since the conduit through which trade takes place in electricity is the interconnector, the rules concerning interconnector access are critical in determining whether or not electricity can be traded efficiently between different markets.

There are EU-wide rules that govern trading over an interconnector. These can be divided into two sets of interrelated rules: *first*, the pricing, transparency and pro-competition rules for interconnection in the Third Package; and, *second*, the rules for capacity allocation and congestion management for interconnection that are in part set out in the CMG of Reg 714/2009 and in part in ACER's CACM FG. These rules do not dictate directly the market design of a Member State's electricity market, but may indirectly result in changes in market design in order for trade to take place efficiently over the interconnector. In other words, the binding constraint is the EU rules: the market design of the Member States will have to adjust.

The Third Package

Reg. 714/2009 of the Third Package is concerned with conditions of access to cross-border exchanges for electricity. More specifically, it aims at "…setting fair rules for cross-border exchanges in electricity, thus enhancing competition in the internal market in electricity…" (*ibid*, Article 1 (a)). This will involve "…the … setting of harmonised principles on cross-border transmission charges and the allocation of available capacities of interconnections between national transmission systems" (*ibid*, Article 1(a)). Reg. 714/2009 also aims to facilitate "…the emergence of a well-functioning and transparent wholesale market … [and] provides for mechanisms to harmonise the rules for cross-border exchanges" (*ibid*, Article 1(b)). Two aspects of Reg. 714/2009 are considered here under the headings: competition; and, pricing rules.

Reg. 714/2009: Promoting Competition

One of the recurrent themes of the discussion not only of SEM (CER and NIAUR, 2010a and b) and BETTA (Newbery, 2006) but also across the EU (EC, 2007b) is the prevalence of competition problems in electricity. This should not be surprising given the oligopolistic nature of the market, combined with in many instances, but particularly Great Britain and Ireland, closed markets with limited imports. In 2004, for example, of 21 Member States, the UK ranked lowest in terms of the proportion of import capacity relative to installed generation (2 per cent) with Ireland fourth from the bottom at 6 per cent. The most open system was Luxembourg where import capacity was 90 per cent of installed generation capacity (EC, 2007b, Table 24, p. 177).

As a result, the rules for capacity allocation on an interconnector need to be carefully designed to ensure that the firms, either unilaterally or collectively, do not restrict access or engage in other anticompetitive practices that limit use and raise price for interconnector use. Anticompetitive practices are, of course, likely to be illegal under both EU and domestic competition law. However, rather than rely on *ex post* enforcement of competition law, Reg. 714/2009 includes provisions to try to create a competitive market and hence obviate the need for such enforcement.[162] Some of these were identified in the Commission's sector inquiry into the energy sector (EC, 2007b). These include, but are not limited to:

- Non-discriminatory, market based methods are to be used to allocate space on the interconnector, "…which give efficient economic signals to the market participants and transmission system operators involved" (Reg. 714/2009, Article 16(1));
- "Capacity shall be allocated only by means of explicit (capacity) or implicit (capacity and energy) auctions" (*ibid*, Annex I, paragraph 2.1);
- Maximum capacity of the interconnector consistent with safety standards "…shall be made available to market participants" (*ibid*, Article 16 (3));
- Market participants that anticipate unused capacity shall inform the TSO so that such capacity can be reattributed "…in an open, transparent and non-discriminatory manner" (*ibid*, Article 16(4));
- "To avoid creating or aggravating problems related to the potential use of dominant position of any market player, the relevant … authorities, where appropriate, may impose restrictions in general or on an individual company on account of market dominance" (*ibid*, Annex I, paragraph 2.10).

[162] General principles for congestion management are set out in Article 16 and Section 2 of Annex I of Reg. 714/2009. There is no Commission guidance available on these issues at this time.

The TSOs are responsible for administering the allocation of space on the interconnector, but the NRAs "…shall regularly evaluate the congestion-management methods" (*ibid*, Annex I, paragraph 1.10). There are also various obligations to publish information on the auctions results.

These rules can be seen as attempting to ensure that all market participants have access to interconnectors, rather than just incumbents. Allocation of space is to be based on price rather than non-transparent alternative methods. As Article 16(1) of Reg. 714/2009 states "[N]etwork congestion problems shall preferentially be solved with non-transaction based methods, i.e. methods that do not involve a selection between contracts of individual market participants." Transaction-based methods would appear to include beauty parade systems which are often somewhat arbitrary and can result in the winner accessing the rent generated by interconnector capacity constraints, an issue discussed above.[163] Attempts to restrict use of the interconnector are limited by the necessity of ensuring that unused capacity is released in a timely manner for use by other market participants.

Reg. 714/2009: Market Design & Pricing Rules

Each Member State has its own set of market design and pricing rules, which often differ in quite important ways. For example, the SEM and BETTA, as discussed in Chapter 9, are based on two quite different models as to how the electricity market should be organised. Thus, if there is to be trade between participants in different Member States there needs to be some common rules of frame of reference to facilitate such trade. Furthermore, since eventually the internal market will enable electricity to be traded between any two Member States, irrespective of their geographical location, these common rules need to apply to all possible interconnections between different markets, whether direct or indirect. To some degree there is, of course, an overlap between the rules outlined above to promote a competitive market and those designed to facilitate trading between different markets.

Reg. 714/2009 sets out some market design rules which include the following:[164]

- "Intra-day trading … shall be established in a coordinated way and under secure operational conditions, in order to maxmise opportunities for trade and to provide for cross-border balancing" (*ibid*, Annex I, paragraph 1.9);

[163] In the context of telecommunications this is discussed in Binmore and Klemperer (2002). Two other examples of beauty contests that garner great media attention – and not always for the right reasons – are the awarding of the venues for the Olympic Games and the World Cup for football.

[164] See especially Annex I of Reg. 714/2009.

- "The access rights to long and medium-term allocations shall be firm transmission capacity rights. They shall be subject to use-it-or-lose-it or use-it-or-sell-it principles at the time of nomination" (*ibid*, Annex I, paragraph 2.5);
- "Capacity allocation shall not discriminate between market participants that wish to use their rights to make use of bilateral supply contracts or to bid into power exchanges. The highest value bids, whether implicit or explicit in a given time frame shall be successful" (*ibid*, Annex I, paragraph 2.7); and,
- "Market participants shall firmly nominate their use of the capacity to the TSOs by a defined deadline for each relevant time frame. That deadline shall be such that TSOs are able to reassign unused capacity for reallocation in the next relevant time frame – including intra-day trading" (*ibid*, Annex I, paragraph 2.11).

Thus, the Reg. 714/2009 does not specify a particular model of congestion management, but rather a set of conditions to which that model must conform. In order to assist in clarifying what the model might look like the CACM FG has been developed, which is discussed further in Chapter 10.

The challenge for individual Member States is twofold. *First*, the prospect of the internal market offers the opportunity to reconsider the appropriateness of existing market design rules. A market design that may, for example, be appropriate for a small closed market such as Ireland's, may not be appropriate once integration into a much larger market takes place. *Second*, the market design may have to be changed, of necessity, in order to comply with the CMG and the CACM FG. This can be a costly process, not only in terms of the changeover costs themselves, but also to the extent that uncertainty is created then this may undermine investor confidence, thus increasing risk premiums. It is therefore important that EU rules should be framed to allow discretion to Member States in complying with the Third Package while at the same time realising the benefits of the internal market, an issue discussed in Chapter 10.

Capacity Allocation and Congestion Management

As noted above in Chapter 2, there have been moves to develop a practicable and achievable model to harmonise interregional and then EU-wide coordinated congestion management. This task was delegated to the PCG which reported in December 2009. ERGEG then took the process forward by developing a guideline, with ACER issuing the CACM FG in July 2011. Although the network code has not finalised the direction of change is clear.

The PCG presentation in December 2009 has been summarised as follows:[165]

- explicit longer-term auctions of capacity on interconnectors (e.g. monthly, annual and possibly multiannual), for either physical or financial transmission rights with secondary markets to trade between capacity holders;
- at the day-ahead stage, implicit allocation of all remaining capacity through price coupling between power exchanges, beginning with regional models and moving to a Single Price Coupling with matching algorithm encompassing the entire EU;
- intra-day adjustments, for bundled energy and capacity products, based on a two-layer approach; with continuous implicit allocation (matching bid and offers on a first-come-first-served basis) at least for the inter-regional layer but with the possibility of other approaches within the REMs; and,
- balancing between TSOs using remaining available capacity, through a multilateral TSO-TSO concept with a common merit order following pilot projects and including harmonisation of gate closures and technical characteristics as well as roles and responsibilities of major parties.

It appears according to Ofgem (2010a, p. 17) that explicit auctions of capacity, with the capacity holders determining the use of the interconnector, has led to underutilisation of interconnectors even where there are apparently profitable opportunities for arbitrage as demonstrated by material differences in prices; indeed, sometimes the flow has gone from the high to the low priced markets. Implicit auctions combine energy and capacity allocation into a single joint or bundled product. Hence, longer term usage of an interconnector will be based on explicit auctions (capacity only auction), while day-ahead auctions will be implicit (capacity and energy bundled together).

The issue which arises is the extent to which the SEM can and should be adapted to conform or at a minimum be consistent with the CMG in Reg. 714/2009 and the CACM FG. In part, that depends on whether the SEM model works well, particularly compared with BETTA, for Irish consumers. The better the SEM model is considered in relation to BETTA the greater the case for its retention and adaption to these governance guidelines and the less the case for following the BETTA model. These issues are addressed in Chapters 9 and 10.

[165] This discussion closely follows Ofgem (2010a, pp. 16-18).

Chapter 9

Market Design: the SEM and BETTA Models

An understanding of the wholesale market in Ireland, the SEM, and Great Britain, the British Electricity Trading and Transmission Arrangements ("BETTA"), is necessary when considering what changes may be necessary and desirable to ensure efficient trading over the Moyle and East West ICs. As will become readily apparent these two models of pricing and organising the wholesale electricity market are quite different. Hence after outlining each model the question is asked which, from an Irish point of view, is the better model. This is an important prior question to consider before attention turns to how the SEM might have to be revised or changed to accommodate trading across the interconnector with the BETTA. If the evidence shows that SEM is a much better model for Ireland, then there is much to be gained by preserving SEM's essential features as much as possible; if, on the other hand, the BETTA is felt to be a better model then there is a much stronger argument for the SEM to be restructured along the lines of the BETTA, particularly as Great Britain is the larger market and already has interconnection with France since 1986.[166]

The SEM Market Design

The SEM started on 1 November 2007. It followed a joint policy decision by the relevant ministers in the Republic of Ireland and Northern Ireland and much discussion over the appropriate market design. The cost of implementing the SEM was €256.4 million in 2006 prices.[167] The design recognises the characteristics of the all-island market: in particular, its small market size and concerns about market power of leading generators and suppliers. Legislation was passed in both jurisdictions to underpin the SEM, which is an all-island electricity market. It is regulated through the SEM Committee consisting of representatives of the CER and NIAUR. The rules governing the operation of the SEM are set out in the Trading and Settlement Code ("TSC"). Regular revisions of the TSC occur to accommodate new developments.[168] The SEM is a wholesale market; the retail markets of the Republic of Ireland and Northern Ireland are regulated separately by the CER and NIAUR, respectively.

[166] It should be noted that most EU Member State electricity markets are organised on a bilateral contract model usually mediated through a power exchange. This is similar to the BETTA model.

[167] For details see NERA (2006). Implementation costs refer to market operator, market participant, TSO and regulatory design and administration costs.

[168] SEMO is the administrator of the TSC and through the Modifications Committee Secretariat publishes updates on the SEMO website: http://www.sem-o.com/Pages/default.aspx.

In this chapter a brief overview of the SEM is provided before attention is turned to specific aspects of the market design. These include the difference between *ex ante* and *ex post* price determination, how interconnectors interact with SEM, and the impact of wind on the SEM price. Finally, some discussion of the success or failure of the SEM is presented, before attention turns to BETTA, which is compared to SEM.

An Overview[169]

The way in which the SEM works has been summarised as follows by the two regulators, the CER and NIAUR:

> The SEM consists of a [mandatory] gross pool, into which all electricity generated on or imported into the island of Ireland must be sold, and from which all wholesale electricity for consumption or export from the island of Ireland must be purchased. Under the gross pool arrangements, a single system marginal cost for electricity is determined on a half hourly basis based on generators' submitted bids and technical characteristics and the demand target to be met. Generators who are scheduled to run, as well as those whose capacity is available for dispatch, are paid a capacity payment. The SEM market design incorporates interconnection with other electricity markets (CER and NIAUR, 2009b, p. 6).

The SEM is operated on a day to day basis by the Single Electricity Market Operator ("SEMO") which was set up as a joint venture between EirGrid and SONI, the TSOs in the Republic of Ireland and Northern Ireland, respectively.[170]

The time lines for the bidding, dispatching and price determination under the SEM are as follows:

- 10:00 on D-1: bidders[171] submit a price/quantity pair (Commercial Offer Data or "COD") for all trading periods (i.e. 30 minutes) for delivery the next trading day ("D" or the following twenty-hour period between 06:00 to 06:00).[172] These pairs are the same for all trading periods of the trading day. The bids reflect short-run marginal costs ("SRMC"), essentially fuel costs, as well as generator

[169] For an introduction to the SEM see NIAUR and CER(2007), SEMO (2011), CER (2011A) and material on the SEMO's website. This may be accessed at: http://www.sem-o.com/JoiningTheMarket/Training/Pages/MarketTraining.aspx.

[170] EirGrid owns SONI. Hence the two TSOs on the island are under common ownership.

[171] Referred to as Predictable Price Maker Generators ("PPMGs").

[172] Bidders can place conditions on their bids such as a minimum level of supply or minimum number of trading periods supplied. The bids also include start-up and no load costs.

start-up costs. Wind is priority dispatch and hence does not bid. Its marginal cost is zero.[173]

- 12:00 on D-1: indicative dispatch quantities set for each bid submitted for the trading day by SEMO. For unsuccessful bids this will be zero. All bid prices are ranked from highest to lowest. Overall dispatched quantity set based on when anticipated demand is served at minimum cost. An indicative *ex ante* system market price ("SMP"), EA, is also generated as part of this exercise. The SMP largely reflects SRMC.[174]
- 06:00 to 06:00 on D: electricity dispatched on the trading day by the TSOs (i.e. EirGrid, for the Republic of Ireland and SONI for Northern Ireland). Generators are dispatched in merit order, with the lowest priced generator dispatched first, the next lowest priced next and so on.
- D+4: the SMP for electricity delivered on D for each trading period is set four days later by SEMO. This is referred to as EP2, where EP refers to *ex post*. SMP is based on the cost of the marginal plant scheduled by SEMO, infra marginal plants thus earn rents.[175] This is illustrated in Figure 9.1, where demand is OQ_1 and price is SMP. While the marginal unit, generator 5, earns no rents, all other generators earn rents which sum to a. The most efficient generator, 1, earns the highest rent. The infra marginal rents make a contribution towards the fixed costs of the generators since there is an inverse relationship between SMP and fixed costs (CER, 2011a).
- D+1 to D+364: capacity payments based on availability are set at the end of the year by the SEM Committee. Plants that are available when the gap between demand and supply is particularly close are allocated a larger portion of the payments. Capacity payments are designed to cover fixed cost of a Best New

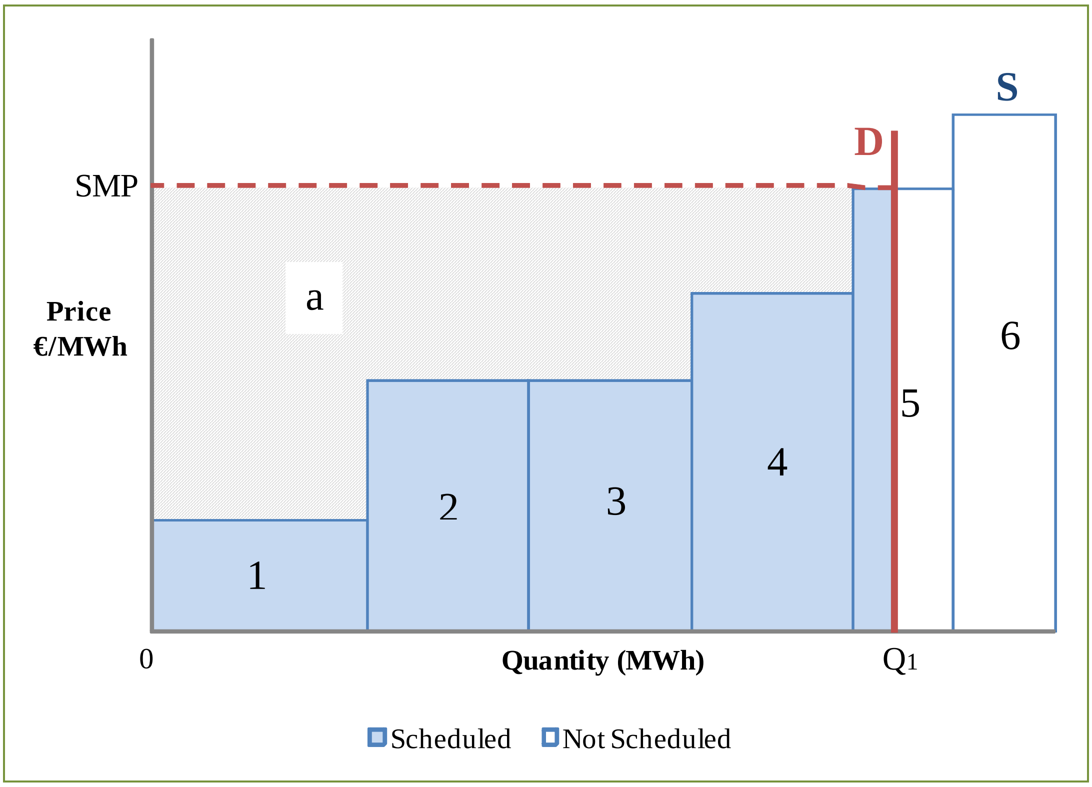
[173] This is, of course, only a summary. A fuller description is as follows: Participants are required to submit bids into the SEM in respect of each generating unit for each trading day. The data contained within bids apply equally for all trading periods within the relevant trading day, except in the case of interconnector units who are able to submit individual bids to apply for each trading period (to enable effective interaction with the Great Britain market). Bids must be submitted by 10:00 on the day before the relevant trading day (i.e. 10:00 D-1). Bids consist of both commercial offer data and technical offer data. Technical offer data relate to the technical capabilities of the generating unit and consist of parameters such as ramp rates. Standard commercial offer data consist of one no load cost, which is the element of operating costs which is invariant with the actual level of output; a minimum of one and a maximum of three start up costs, which reflect the costs associated with starting up the generating unit from cold, warm or hot states; and a minimum of one and a maximum of 10 price quantity pairs, each of which sets out a quantity up to and equal to which the associated price applies. Price quantity pairs must be strictly monotonically increasing with only one price for each quantity.

[174] For further details see, for example, CER (2011a) and NIAUR and CER (2007, p. 13).

[175] It should be noted that the this statement needs to be qualified. The objective function of the software that determines the unconstrained market schedule over an optimisation horizon of 30 hours is total cost minimisation. So the shadow price in each half hour is the change in the objective value (i.e., total cost over 30 hours) of the optimal solution obtained by relaxing a constraint by one unit. (More formally, the shadow price is the value of the Lagrange multiplier at the optimal solution, which means that it is the infinitesimal change in the objective function arising from an infinitesimal change in the constraint.) Because of inter-temporal constraints, this price is not necessarily equal to the cost of the marginal plant on the system in that half hour. The SMP comprises both the shadow price (as described above) and an uplift element, which is designed to ensure that all generating units recover operating costs associated with start up costs and no load costs over a 24 hour period.

Entrant, which is usually an Open Cycle Gas Turbine ("OCGT"), and encourage availability when capacity is needed the most.[176]

Figure 9.1: Market Schedule and Price Determination



Source: SEMO (2011).

Gate closure is at 10:00, with the price/quantity bid held firm for electricity supplied for the next 20 to 44 hours. As a result, there is no opportunity to respond to short-term price changes in input costs such as fuel price movements. The market price, or SMP, is not known for four days after the trading day, D. Capacity payments, to cover fixed costs, are set at the end of the year. Electricity is dispatched centrally through the TSOs.

Ex Ante and Ex Post Price

An important feature of the SEM is that there is uncertainty as to the price that the generator will receive and that the supplier will pay. Although an *ex ante* SMP is set, EA is only an indicative price. The final price is set *ex post*, four days after the

[176] CER (2011a) shows most of the return to generators comes from SMP payments, but that capacity payments are also significant. In 2007/08, for example, SMP payments were just in excess of €2,500 million, while capacity payments were around €500 million. With the recession and the decline in demand for energy, SMP payments declined – to around €1,700 million in 2009/10, while capacity payments remained largely unchanged.

electricity is dispatched (EP2).[177] The *ex post* price in the SEM is set on an unconstrained basis, "…ignoring the impact of, for example, transmission constraints, voltage and reserve requirements" (NIAUR & CER, 2007, p. 15). The market operator, SEMO, thus takes all the bids submitted into account, the volume of wind electricity that actually was available as well as the peat fired power generators. It then estimates the SMP. In doing so, as noted above, it ignores, for example, the fact that a particular generator might in reality have had to be constrained off or that the wind is curtailed off once certain limits are reached.

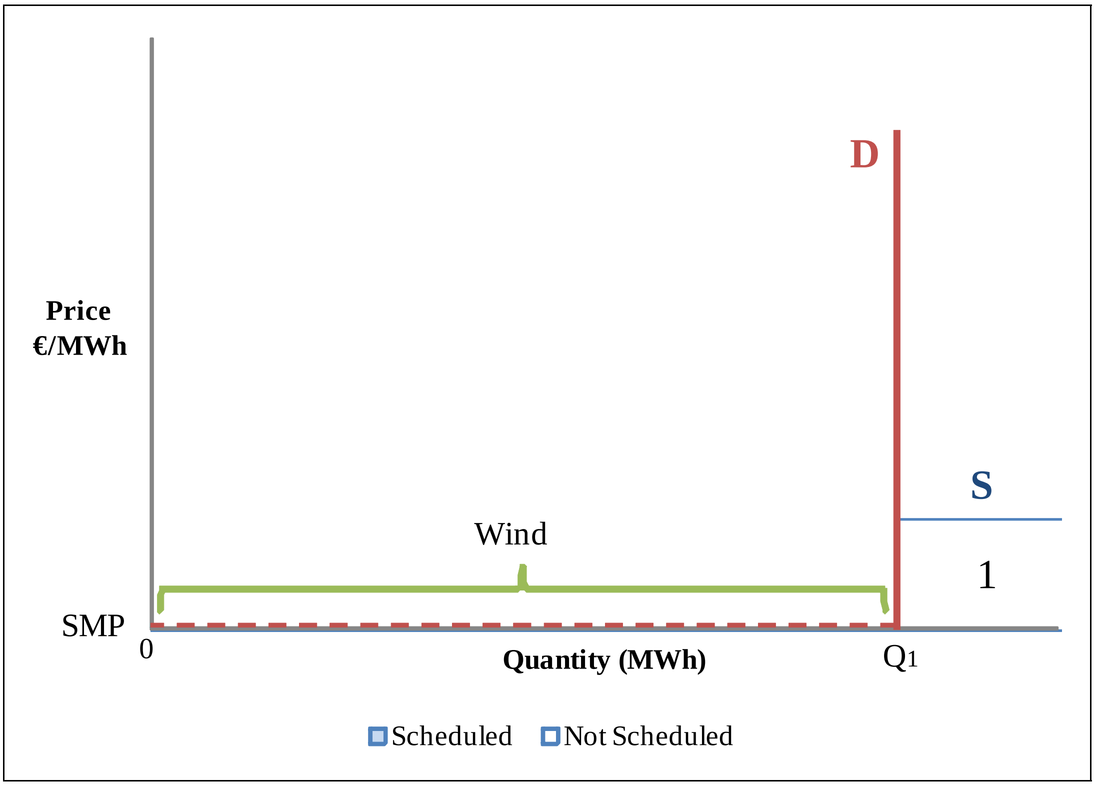
The EA and the EP2 SMP might differ for a variety of reasons, including the fact that wind may blow more or less than forecast or that demand may be more or less than forecast or that a generator scheduled to be dispatched has an unanticipated outage. However, as the gap between submission of bids and the dispatching of the generation units becomes shorter the difference between EA and EP2 should narrow. The forecasts of demand, wind and other factors which determine SMP become more accurate. It is an issue that will be returned to in Chapter 10.

Wind and Price Determination

Wind generated electricity is assigned priority dispatch reflecting that it has a zero marginal cost and so will always be ahead of other plant in the merit order. It must be dispatched, subject to system security concerns, which means that once a certain penetration is reached then wind is curtailed off the system. As more and more wind capacity is built, unless demand expands commensurately, then wind will be curtailed off with increasing frequency and duration. However, as noted above, in setting the SMP none of these practical matters are taken into account. Wind is unconstrained. As a result, it is possible that during a summer evening with low demand that wind could, in an unconstrained world, supply all of the electricity; thus, setting an SMP of zero as illustrated in Figure 9.2. However, if cognisance was taken of the fact that wind could only supply a maximum of 50 per cent of electricity then the SMP would be positive as indicated in Figure 9.3. If prices are too low there is a possibility that the returns might not be high enough to attract new thermal entrants (CER & NIAUR, 2009a, pp. 38-41) and that this might lead to a shortage of capacity. While this might not be a problem at the present time, this does not mean that it can be safely left until the medium to long run to address, given the lead times for building generators.

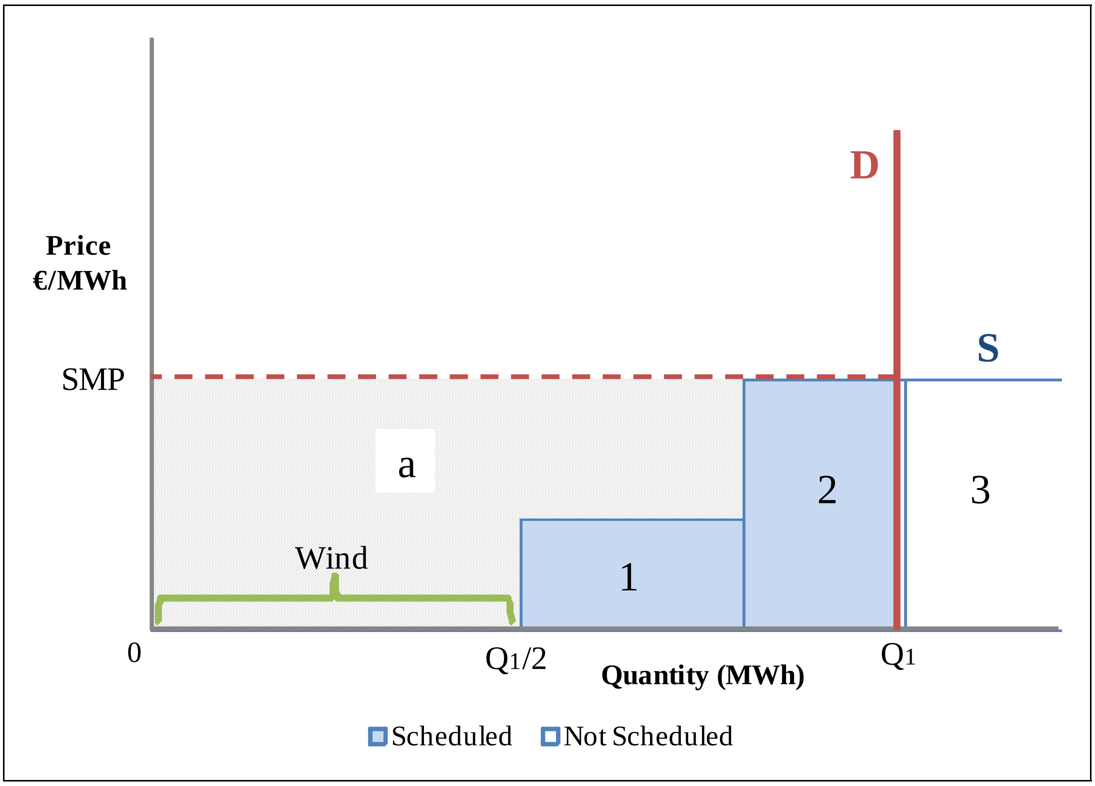
177 In this discussion *ex ante* and *ex post* relate to time at which the generator delivers electricity and the supplier receives the electricity.

Figure 9.2: Market Schedule and Price Determination, Wind Unconstrained



Source: See text.

Figure 9.3: Market Schedule and Price Determination, Wind Constrained



Source: See Text.

Interconnection

The SEM design includes rules for interconnection with other markets. An interconnector user must register with SEMO, as an Interconnector Unit ("IU"),[178] under the TSC so that they can participate in the all-island wholesale electricity market. Like a generator, an IC settles as a Predictable Price Maker Generator ("PPMG"). There are, however, some important differences as to the treatment between generators bidding into the SEM, as set out above, and IUs bidding into the SEM. These include:[179]

- IC Units may submit *different* priced bids for each half hour trading period for a trading day, rather than the *same* price for all trading periods in a trading day;
- IU bids do not necessarily have to reflect short-run marginal costs, the IU is free to decide how the price is set; and,
- IC Dispatch Quantities are firm at 12:00 on D-1, rather than indicative.[180]

IC Units that import electricity receive an energy payment and a capacity payment based on its Market Schedule Quantity ("MSQ") and its Dispatch Quantity, respectively.[181] IC Units that export pay an energy payment and receive a negative capacity payment based on the same. When the IC Unit is importing it is acting as though it were an additional generator, while when it is exporting it is buying from the pool and thus reducing the availability of generation capacity. These bidding rules are a reflection of the differing circumstances that operate in BETTA.

Fit-for-purpose

An analysis of several alternative market designs for the all-island electricity market by FitzGerald *et al.* (2005) came to the view that bidding into a gross pool, with price based on short-run marginal cost, combined with capacity payments, offered the best outcome in terms of encouraging "…supply at a minimum price" (*ibid*, p. 75). Furthermore, such a market design "…would provide the right signals for new investment ensuring the provision of adequate electricity generation capacity at least cost" (*ibid*, p. 75). FitzGerald, in subsequent work with colleagues, concluded that the "…new wholesale electricity market … appears to be working well – it is producing a wholesale price that approximates the long-run marginal costs that would apply in a large liquid competitive market" (Devitt *et al.,* 2011, p. 1).

[178] For this the IU needs a contract with an interconnector owner.

[179] This discussion draws on CER and NIAUR (2009b, pp. 6-8), which follows the wording closely.

[180] Prices are, however, determined *ex post*.

[181] MSQ is defined as the quantity of output of a generator unit prior to adjustment for transmission or distribution losses. Dispatched quantity is the average active power production for a generation unit. Active power and output are the same.

The SEM has largely worked as expected (Diffney *et al.*, 2009, p. 473). At the present time the CER and NIAUR are currently reviewing the working of the SEM with respect to competition and liquidity, with a final report expected later in 2011.[182] As part of that process a report was commissioned from Cambridge Economic Policy Associates ("CEPA") that concluded: "The SEM wholesale market appears to be working well. Competition is increasing, in part due to the current market mitigation strategy" (CEPA, 2010, p. 8).[183] The report presented options to improve the workings of the SEM.

Nevertheless, there are several challenges that the SEM needs to resolve in order to function in an effective manner. *First*, there are difficulties with the current SEM arrangements for trading over the interconnector. These are, however, being considered and are discussed in Chapter 10. As part of this exercise the rules for trading over the interconnector will have to be consistent with the Third Package and associated guidelines. *Second*, the current price determination method may lead to difficulties as more and more wind is connected to the system, with the result that SMP will fall, perhaps to zero, and may not provide enough remuneration for new thermal sources of electricity.[184] *Third*, the margin of error in predicting the availability of wind generated electricity is reduced, the closer in time to the dispatch that the prediction is made (Borggrefe and Neuhoff, 2011). As a result, if trade in electricity can take place on a frequent intra-day basis then wind can be used in a more efficient and effective manner (Weber, 2010). It is not clear to what extent the SEM can accommodate such trading, an issue discussed further in Chapter 10.

The BETTA Market Design[185]

BETTA was introduced in 2001.[186] It followed a review of the pre-existing system, which consisted of an Electricity Pool, together with capacity payments, a model that resembles the SEM.[187] The costs of implementing the new system were estimated by Ofgem at "…between £136 million and £146 million a year for the first five years and £30 million a year thereafter" (NAO, 2003, p. 27). However, these are estimates that likely overstate the costs for a variety of reasons (*ibid*, p. 27). Furthermore, while the absolute numbers are large, if passed on in full, electricity prices would rise

[182] CER and NIAUR (2010a), a factual information paper was released, followed by a consultation paper (CER and NIAUR, 2010b), accompanied by CEPA (2010) which is referred to in the text.

[183] Market mitigation strategies are designed to mitigate or lessen any market power that generators may have in the SEM.

[184] See discussion on this issue earlier in the chapter.

[185] This discussion draws heavily on CER&NIAUR (2009b, pp. 6-8; 2009c, p. 22-23); Corby (2010); Giulietti *et al.* (2010); Helm (2003; 2010a); NAO (2003) and Newbery (2006).

[186] Initially it was called the New Electricity Trading Arrangements ("NETA") covering England and Wales; when it was subsequently extended to include Scotland, NETA became BETTA.

[187] However, SEM was built in the experience of the Pool and addressed some of its shortcomings.

imperceptibly – for between 0.6 to 1.6 per cent per year for industrial users and 0.5 to 0.8 per cent per year for residential consumers between 2001 and 2005.[188]

The change occurred because of concerns over lack of competition manifesting itself in high prices/profits and discrimination against coal as a fuel source.[189] However, it has been argued that the validity of these concerns were not carefully reviewed, nor was the detailed analysis presented to justify the belief that BETTA would address these problems (Newbery, 2006). While it is true that wholesale prices fell post-BETTA there is considerable debate as to whether it is due to BETTA or was largely attributable to other factors (NAO, 2003; Newberry, 2006). Nevertheless, at the retail level BETTA associated restructuring "…seems not to have reduced retail prices compared with underlying costs, if anything the opposite" (Giulietti *et al.*, 2010, p. 1167). It has also been argued that BETTA creates barriers to investment and makes new entry more difficult. Helm's (2010a, p. 13) rather pithy summary is that BETTA, "…is not fit for purpose (and arguably never was)."

BETTA's market design contrasts quite sharply with SEM, with some of the major differences summarised in Table 9.1. Instead of generators selling to a mandatory pool with centralised dispatch through the TSOs, under BETTA electricity is traded bilaterally between buyers and sellers under agreed terms with self-dispatch.[190] Since it is common for generators to vertically integrate into the downstream supply business, a considerable portion of electricity is traded within the firm. As a result, less than 5 per cent of electricity is spot traded in Great Britain, compared to much higher levels in, for example, the North REM where spot trades for individual Member States' markets accounted for between 20 per cent and in excess of 95 per cent of consumption.[191] Price is thus determined *ex ante* either through contracts within the firm or by arms length transactions, rather than being determined four days after the electricity was dispatched, as occurs in the SEM.

[188] Based on Eurostat data. The cost of the switch was taken as £146 million. Price refers to prices before taxes, for industrial consumers the price range refers to small, medium and large users.

[189] See Ofgem (1999) where these concerns over lack of competition are set out.

[190] Market participants are incentivised to self balance. Participants that do not meet their contractual agreements are subject to potentially penal system buy and sell prices.

[191] These data are drawn from EC (2010g, Table 3.3, p. 14). The data relate to 2007 and 2008. For the North REM the data in the text ignore Poland where spot trades are like Great Britain less than 5 per cent of electricity consumption.

Table 9.1: The Market Design of BETTA and SEM: A Comparison

Market Dimension	SEM	BETTA
Type	Gross mandatory pool	Bilateral market
Notification of bilateral contracts	Not applicable	Bilateral contracts notified for each half-hour up to 1 hour ahead
Dispatch	Central dispatch – merit order	Self-dispatch
Pricing	*Ex post* system marginal cost	System buy price & sell price paid by participants that are short or long, respectively.[a]
Gate Closure	Day-ahead	One hour ahead
Capacity Payment	Explicit mechanism	None
Currency	Dual currencies €/£	Single currency £
Market Operator	SEMO	Elexon

a. The pricing information for BETTA refers to *ex post* prices in the half-hourly balancing mechanism. The vast majority of trades in electricity take place before gate closure at prices that are not transparent.

Source: Corby (2010).

In contrast to the SEM, the gate closure for BETTA is one hour ahead of each 30 minute trading period. Subsequent to the gate closure, only National Grid, the TSO, can act as counterparty to trades in order to ensure generation and demand are in balance. Thus, the trading system is rolling one-hour gate closures. Transactions under the balancing mechanism account for less than 2 per cent of electricity traded. Finally, unlike SEM, under BETTA there are no capacity payments.

BETTA is in a state of some flux as a result of the UK Coalition Government's Electricity Market Reform[192] which is designed, amongst other things, to decarbonise the economy, increase the share of renewable sources for electricity generation and replace a quarter of generating capacity by 2020 (DECC, 2010b, pp. 4-5; 2011). The reforms modify the BETTA model rather than replace it with a new model. Nevertheless, two important proposals appear to move BETTA closer to the SEM model. *First*, in order to ensure security of supply in the face of increased variable sources of electricity some form of capacity payment will be introduced, although the proposals are different from capacity payment mechanism in the SEM (DECC, 2010b, pp. 87-88; 2011, pp. 59-80). Two options are being considered: some kind of central body tasked with maintaining a set capacity margin; or a market-wide mechanism in which "…all providers willing to offer capacity … can sell their capacity (DECC, 2011, p. 71). A final decision will be made in late 2011/early 2012. *Second*, various attempts are being made to increase the level of liquidity in the electricity market, since the current low levels make entry more difficult and have other disadvantages that make the market work less well (DECC, 2010b, pp. 109-110; 2011, pp. 89-96). Various attempts are being made to resolve this issue, with Ofgem presenting a number of options (Ofgem, 2010b; 2011b; DECC, 2011, p.92), including

192 For details see DECC (2010a; 2010b; 2011) and Redpoint (2010). The Electricity Market Reform is likely to have implications for the SEM which are discussed in Chapter 12.

a new licence condition for large vertically integrated electricity generators to make available between 10 and 20 per cent of their power generation to the market. A final decision will be made in late 2011, without the industry not being able to find solutions that addresses the liquidity issue (Ofgem, 2010c). If the issues surrounding capacity payments and entry are not successfully resolved then there is a danger that insufficient additional capacity will be built in Great Britain.

The House of Commons Select Committee on Energy and Climate Change argues[193] that under the Electricity Market Reform proposals the core of the wholesale electricity market "would not be changed" (House of Commons, 2011, para. 60). Instead, those proposals would "…'bolt-on' measures that reform the subsidies and structures around the market, not the market itself" (*ibid*, para 60). The Select Committee is very much of the view that the wholesale market needs to be reformed in view of its shortcomings identified above. It cites Helm's view as presented to the Select Committee, that there should be a return to the 'pool' arrangements (*ibid*, para 63) and quotes Dr Barrie Murray that "…'it is a delusion to think that DECC or Ofgem are going to establish an optimal way forward by tinkering with [the] market' and that much more substantial change is required" (*ibid*, para. 63). The Select Committee concludes that "…the current market arrangements do not facilitate a fully functioning wholesale electricity market which transmits price information necessary to attract investment" (*ibid*, para. 70).

SEM Versus BETTA Market?

The discussion of the SEM and BETTA models of market design strongly suggest that Ireland, given the choice of the two models, should remain with the SEM, providing of course that it can address successfully the issues raised above, including consistency with the Third Package and accommodate the efficient trading of wind. On this latter issue, in selecting the SEM specific account was taken by CER & NIAUR (2005) of the SEM's ability to accommodate wind compared to a decentralised system such as BETTA. Reference was made to wind generators being at a "…disadvantage in a decentralised market because of the strong incentives given to participants to submit balanced schedules. Suppliers seeking bilateral contracts may consider intermittent generation unfavourable because of its unpredictable nature" (*ibid*., p. 19). Furthermore, as noted in the previous section of this chapter, BETTA is an illiquid market, although moves are being made to address this issue.

[193] Although these arguments were made with respect to the DECC (2010b) consultation proposals they also apply to the subsequent White Paper (DECC, 2011) given the similarity between the two set of proposals.

FitzGerald *et al.* (2005, pp. 58-61) considered a model similar to BETTA,[194] but still came to the view that the SEM was the best option for Ireland. This is in some ways a not altogether surprising conclusion, given that the switch in Great Britain to BETTA in 2001 from a pool arrangement similar to SEM does not appear to have been justified. This, therefore, suggests that in linking Ireland with Great Britain, and further afield through interconnection, that the current market design of the SEM should be retained. However, this does not mean, of course, that the SEM should be preserved in aspic. Rather changes are required to allow more efficient use of the interconnectors and thus benefit Irish consumers. The trick is to retain the essential elements of the SEM in such a way as to improve its efficiency. It is an issue addressed in Chapter 10.

The conclusion that the SEM is a better system for Ireland than BETTA is strengthened by a number of additional factors, but this should not be overstated. *First*, the costs of change can be substantial. Although no estimates have been prepared of the cost of shifting from the SEM to BETTA, reference was made above to the costs of shifting for an analogous move for Great Britain, which suggests substantial absolute once and for all costs, but not when expressed as a percentage of electricity prices.[195] However, these costs may be biased upwards, in the sense that in moving to BETTA would not require the creation of a completely new bespoke system, but rather joining an existing system. *Second*, as Lyons *et al.* (2007, p. 64) stress regulatory credibility is necessary "…for enabling investment incentives to operate effectively." This means that the rules of the game, the market design system's rules, should be as stable as possible such that investors do not unexpectedly experience sudden changes once they have made irreversible investments, particularly since the SEM has only been in existence since November 2007. If a jurisdiction acquires a reputation for policy uncertainty – in energy or other fields such as waste management – then investors will demand a premium which be reflected in higher costs. *Third*, BETTA, like SEM, is subject to ongoing change, reflecting, for example, changing demand patterns, ongoing monitoring such as that mentioned above for the SEM and meeting new challenges such as decarbonising the economy. The preferences of how the UK government may decide to address these concerns may be different to the Government of Ireland, in part because market conditions are different and in part because of differences in belief about the efficacy of different policy instruments. Switching to BETTA to better interact with the Great Britain market may compromise the independence

[194] FitzGerald *et al.* (2005) refer to a model called "Finding Yourself a Customer" which existed in Ireland prior to the SEM.

[195] FitzGerald (2011, p. 20) reports that the software required to allow consumers to switch electricity supplier in the SEM cost €100 million.

and policy discretion for Ireland. [196]

The success of the reforms to BETTA is important for Irish consumers. Much of the discussion concerning the impact of more interconnection is based on the assumption that prices will fall as a result of the internal market. This in turn reflects the view that prices will be lower in Great Britain. However, this may not be the case (Devitt *et al.* 2011). A quarter of generating capacity in Great Britain will close and needs to replaced in the next decade, in part because it is ageing and in part because of the Large Combustion Plant Directive and the Industrial Emissions Directive (House of Commons, 2011; Poyry, 2010a). There are concerns that the current market arrangements may not yield the required investment (Helm, 2010a). If there is a policy failure and insufficient generation capacity is built, then prices are likely to rise in Great Britain and Ireland, as a price taker, will, of necessity, experience price increases. However, any price rise will be modified by the increased interconnection between Great Britain and continental Europe, referred to in Chapter 4, which is likely to reach 10 per cent of installed capacity by the 2020s (DECC, 2011, p.109).

[196] However, this point should not be overstated, since by participating in the SEM the Republic of Ireland is subject to the influence of UK policy decisions since the SEM also consists of Northern Ireland. For example, the UK Electricity Market Reform proposes to establish a carbon price floor that will operate from 1 April 2013 that will cover all of the UK, including Northern Ireland. This will place Northern Ireland generators at a competitive disadvantage compared to those in the Republic of Ireland in bidding into the SEM. This is, therefore, likely to distort the merit order and the functioning of the SEM. Solutions include exempting Northern Ireland from the carbon floor price or that the Republic of Ireland adopts the carbon floor price.

Chapter 10

Market Design: Towards an EU Model?

Although electricity is traded between SEM and BETTA over the Moyle IC, it would be incorrect to infer because of this that the SEM is in compliance with the internal market rules and regulations. *First*, although electricity is traded over the Moyle IC it is not achieved in an efficient manner, an important objective of the Third Package. Modifications are therefore needed beyond the current trading rules to achieve efficient trading. This is likely to require changes to the SEM, on which SEMO, CER, NIAUR and the industry are currently working. Thus the challenge will be to maintain the current market design, while at the same time efficiently interconnecting with BETTA. *Second*, irrespective of the resolution to the first issue, there is a need to ensure consistency with the governance and the access rules set out in the Third Package, especially the CMG, subsequently elaborated in the CACM FG and eventually in a network code. These guidelines, rules and laws are binding constraints and will, in varying degrees, need to be taken into account in designing the trading rules over the East West IC and the Moyle IC. However, they are also important because compliance with these rules will facilitate trade beyond Great Britain.

This chapter first considers the problems experienced in trading across the Moyle IC. Attention then turns to how the SEM is being made consistent with the CMG. Next the much more thorny issue of ensuring consistency between the SEM and the CACM FG is addressed. A major difficulty here concerns what is meant by continuous intra-day implicit trading. The more this is interpreted to mean trading in real time, the greater the costs of revising the SEM, indeed at some point it may not be feasible to maintain the SEM in its current format and an alternative model would need to be considered. A framework is presented for thinking about this issue. These unresolved issues are likely to create regulatory uncertainty, thus damaging future investment prospects. The chapter concludes with a discussion of policy implications of the analysis.

Ireland-Great Britain Interconnection: Trading on the Moyle IC

Efficient operation and use of an interconnector implies that if there are profitable Ireland/Great Britain price arbitrage opportunities then they will be taken. However, there is evidence that the only interconnector between Ireland and Great Britain, the Moyle IC, is not working efficiently. The CER&NIAUR (2009b, pp. 14), for example, found:

> … it is apparent that the Moyle IC has not been used to its full potential since November 2007, either for the import of energy from GB or for exports to GB; and that there are times when profitable price arbitrage opportunities were available but were not taken up by participants.

CEPA (2010, pp. 62-63) came to a similar conclusion. The CER and NIAUR (2009b, p. 18) also found, over a fourteen month period ending in December 2008, only 25 per cent of the variation of daily average electricity imports could be explained by Ireland/Great Britain prices; the corresponding figure for exports was 40 per cent.

The CER & NIAUR (2009b, pp. 18-20) list a series of market design and related factors as responsible for the shortcomings in the usage of the Moyle IC. These include: the risk of the Moyle IC being unavailable; the lack of price arbitrage traders in the SEM; differences in gate closure times; the lack of a liquid day-ahead market in Ireland; and, *ex post* pricing in the SEM which creates uncertainty for those exporting from Great Britain. The latter point was also stressed by CEPA (2010, p. 63). If the Moyle and East West ICs are not fully utilised then it is "…unlikely that any new ICs will be built" (CER & NIAUR, 2009c, p. 13). In other words, an investor, irrespective of whether it is public or private, is not likely to risk investing in an asset that yields little return.[197]

The lack of arbitrage traders is linked in part to the uncertainty over future prices. This can be demonstrated by a comparison of the *ex ante* (EA) and *ex post* (EP2) price in the SEM, illustrated in Table 10.1 for selected weekdays and times in July and December 2010.[198] It is EP2 which is the SEM price. The times chosen were the demand peak, in the early evening, and trough, in the early morning. Reading down the columns in the table, apart from the morning trough in December, the ratio of EP2 to EA is anything but constant. For example, at 18:30 the EP2/EA ratio is 1.21 on 6 July, but 0.82 on 7 July and 1.51 on 8 July. Such uncertainty is not conducive to the development of a market and it is perhaps for this reason that much of the trade over the Moyle IC is by firms with operations in both the SEM and BETTA which, thus, are able to hedge or spread the risk of price uncertainty.[199]

[197] Of course, if the interconnector is covered by TUoS then this is not an issue.

[198] The correlation of EA and EP2 was measured over the period 1 January 2009 to 2 December 2010. It declined from 0.8 to 0.6. Based on a presentation by Jerry Sweeney, Enabling Broad Adoption of Demand Response, 2011.

[199] Based on information provided by industry sources.

Table 10.1: Ratio of *Ex Post* (EP2) to *Ex Ante* (EA) Prices, SEM, Selected Dates and Times, 2010

Time/ Date	04:00	04:30	05:00	05:30	18:00	18:30	19:00	19:30
06/07	1.66	1.77	1.75	1.75	1.30	1.21	0.56	0.64
07/07	1.18	1.18	1.19	1.18	0.80	0.82	0.82	0.76
08/07	0.92	0.88	0.92	0.90	0.35	1.51	2.00	2.01
07/12	0.91	0.91	0.91	0.90	1.34	1.02	0.34	0.60
08/12	0.88	0.90	0.89	0.88	3.62	2.55	0.71	1.29
09/12	0.91	0.89	0.89	0.88	1.34	1.55	0.82	0.90

Source: SEMO.

The impact of the price and other uncertainties of trading over the Moyle IC can be characterised as an increase in transaction costs, which result in an under-utilisation of the interconnector. The SEM delivers volume certainty, but retains price risk for interconnector users. An alternative or equivalent characterisation is that there will be a range between BETTA and SEM prices within which trade will not take place over the interconnector. This is referred to as a deadband. Based on a consultation conducted by CER and NIAUR in 2009 with Moyle IC users, it was estimated to be between €10-15 per MWh (CER & NIAUR, 2011a, p. 9). Although it has been argued that the deadband has subsequently narrowed it nevertheless continues to exist, given that differences between SEM and BETTA persist (*ibid*, p. 10).

In order to test the sensitivity of interconnector flows between Ireland and Great Britain to transaction costs, the ESRI's *Irish Dispatch Electricity Model* (*IDEM*) model is used, details of which are presented in Box 10.1.[200] The Moyle IC is assumed to operate at full capacity while the East West IC is assumed to be operational in 2013. The *IDEM* model is estimated assuming different levels of transaction costs: €0, 1, 3, 10, 30, and 60 per MWh. The impact of transaction costs on total trade between SEM and BETTA (Figure 10.1) exports from SEM to BETTA (Figure 10.2), and imports (Figure10.3) are presented annually for 2010 to 2020. In each case the use of the two interconnectors is expressed as a proportion of interconnector capacity.

Box 10.1: The Irish Dispatch Electricity Model ("IDEM"): A Description

The simulations rely on an optimal dispatch model for the all-island wholesale electricity market, modelled as a mandatory pool market with capacity payments. In every half-hour, generation has to match demand, determined by an exogenous demand curve that is assumed to be price-inelastic. In line with the bidding principles of the SEM, generators bid their short-run marginal cost, which includes

[200] See also the description on the ESRI website: http://www.esri.ie/research/research_areas/energy/idem/. Accessed 23 August 2011.

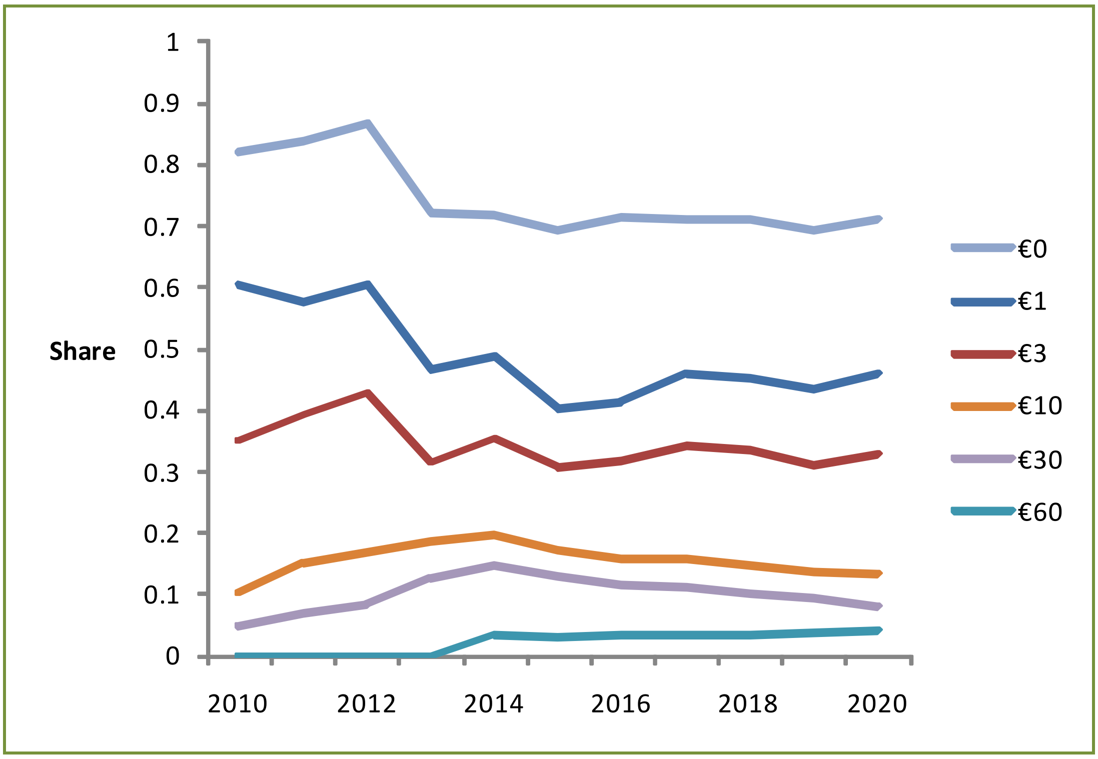
the cost of fuel and CO_2 emissions. Plants are stacked according to their bids, from the cheapest to the most expensive, and the cheapest plants that are needed to meet demand in each half-hour are dispatched. The most expensive plant that is dispatched determines the SMP paid to all plants that are generating during that period. The model assumes that there are no transmission constraints, no costs to increasing and decreasing the level of production, and no minimum down times. Wind is constrained off the system where necessary to ensure that base-load generating capacity is not forced to cycle on and off too frequently.

To analyse the effects of interconnection a similar model is set up for Great Britain. We assume that the wholesale market in Great Britain is governed by the same regulations as Ireland, i.e. that it is a mandatory wholesale market where generators bid their short-run marginal cost of production. Great Britain faces its own (separate) demand curve, which is also assumed to be inelastic to price changes. Fuel prices are assumed to be the same in Ireland as in Great Britain. Whereas each plant on the Irish system is modelled separately, for the British system plants of the same type and similar efficiency are aggregated. We abstract from the actual arrangements on the British market, which is governed by BETTA (British Electricity Trading and Transmission Arrangements) and is based on voluntary bilateral arrangements between generators, suppliers, traders, and customers.

Source: Diffney *et al*.(2009, p. 475).

The utilisation of interconnector capacity is sensitive to transaction costs (Figure 10.1). With zero transaction costs utilisation of interconnection capacity is between 70 and 90 per cent, not 100 per cent. This reflects the fact that the SEM price is only able to displace a certain amount of BETTA capacity, combined with discontinuities in the schedule of generators bidding in short-run marginal costs. For small transaction costs – €1 to €3 per MWh – utilisation of interconnection capacity drops to around 30 per cent; the €10 per MWh transaction cost sees utilisation fall to less than 20 per cent. Further increases in transaction costs result in utilisation falling to below 10 per cent.

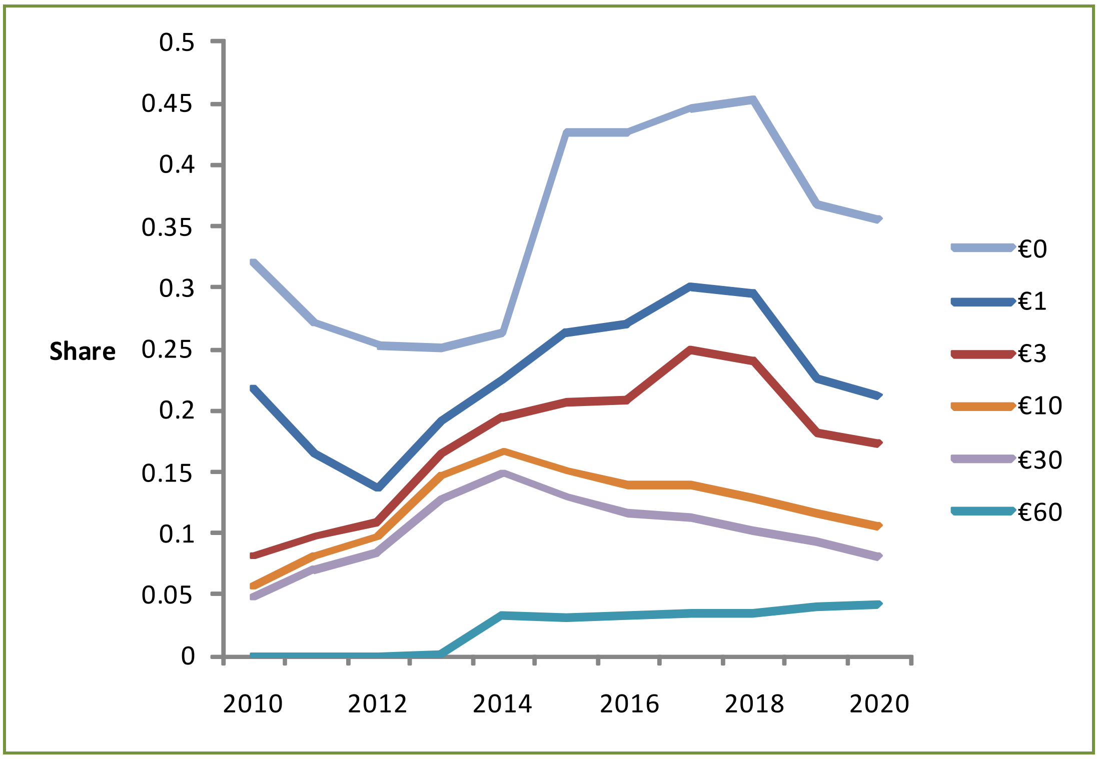
Figure 10.1: Interconnector Capacity, Ireland – Great Britain, Share of Total Capacity Utilised for Imports & Exports, Selected Transaction Costs (€/MWh), 2010-2020



Source: IDEM.

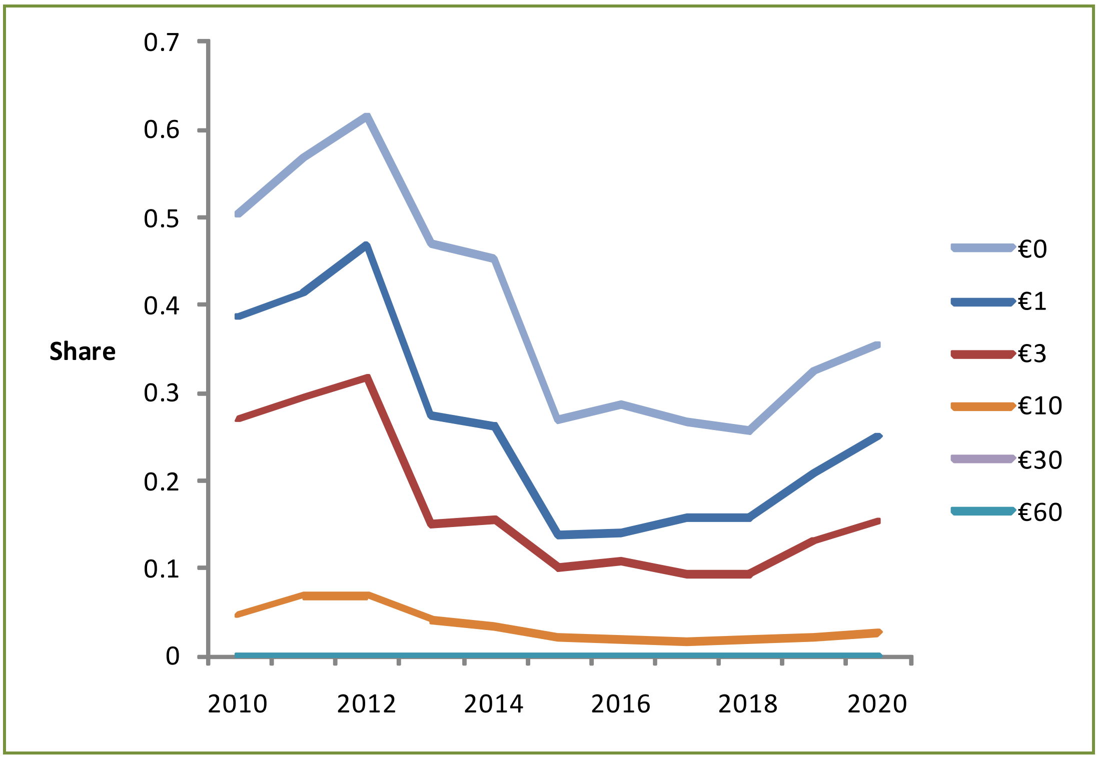
Exports to BETTA from SEM and imports from BETTA are sensitive to transaction costs (Figures 10.2 and 10.3, respectively). Imports tend to be more sensitive than exports to transaction costs. This suggests that the arbitrage gains or margins are greater on exports than imports and thus increased transaction costs have less effect on exports. This in turn is likely to reflect the fact that for exports the SEM price is set by wind and as a result tends to be low, perhaps even zero. In contrast, imports are likely to reflect differences in marginal costs between fossil fuel generators in SEM and BETTA which will be much lower. Irrespective of the level of transaction costs, the importance of exports increases and imports decreases (at least to 2017/18), reflecting the growing significance of wind as a source of electricity generation in the SEM.

Figure10.2: Interconnector Capacity, Ireland – Great Britain, Share of Total Capacity Utilised for Exports, Selected Transaction Costs (€/MWh), 2010-2020



Source: IDEM.

Figure 10.3: Interconnector Capacity, Ireland – Great Britain, Share of Total Capacity Utilised for Imports, Selected Transaction Costs (€/MWh), 2010-2020



Source: IDEM.

Having established the importance of transaction costs in determining the use of interconnection,[201] attention now turns to changes in the rules governing interconnector use and related issues so as minimise such costs.[202]

Developing Efficient Ireland-Great Britain Interconnection: Ensuring Consistency with the Congestion Management Guidelines (CMG)

EirGrid is designing the rules for the East West IC which comes into operation in Q3 2012. The Moyle IC is also involved since it wishes to ensure that its rules are compatible with those of the East West IC. A decision on the approval of the access rules for these two interconnectors is expected in September 2011. In addition to the maximum extent possible, attempts are being made to ensure that these rules are consistent with those developed for the BritNed IC as well as any refinements of the IFA IC.

The access rules for the East West IC being developed by EirGrid will be consistent with the CMG, and eventually the network code that follows the CACM FG.[203] SEM has decided that there will be two intra-day gate closure times in addition to D-1 – although there were suggestions of up to six[204] – so as to comply with the CMG.[205] These will be in place by mid-2012. As noted in Chapter 8 reference is made in the CMG to the necessity of establishing intra-day trading, but not continuous implicit intra-day trading, which is optional.[206] Intra-day trading should enhance usage of the Moyle and East West ICs, compared with the current arrangements on the SEM. The gap between making a bid and dispatch will narrow thus reducing uncertainty as to price. Forecasts are likely to be more accurate and reliable when being made for trades that take place in a few hours compared to those that take place between 24

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201 It should be noted that although the use of the interconnector is sensitive to what appear to be quite small transaction costs does not necessarily mean that the gains from trade (i.e., the arbitrage opportunities) are similarly affected. A paper by CER & NIAUR (2011a) shows even with a deadband of €10 per MWh that there are substantial gains from trading over the Moyle IC when two intra-day gate closures are introduced in addition to D-1.

202 We do not explore the inter TSO compensation arrangements for hosting cross-border flows of electricity. DC interconnectors, such as those between Ireland and Great Britain and between Great Britain and continental Europe, are not currently subject to the inter TSO compensation arrangements. However, that may change in the future. On the background see EC (2008b) and Commission Regulation No. 838/2010 of 23 September 2010 on laying down guidelines relating to inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging.

203 As EirGrid (2011) notes, intra-day trade takes place within the SEM so it is the SEM that is responsible for ensuring compliance with the intra-day rules.

204 Six gate closures imply trading periods every four hours. A widely traded product on BETTA is the Electricity Forward Contract which is sold in four hour blocks.

205 The two additional intra-day gate closures also ensure compliance with the infringement procedures brought by the Commission against the UK and Ireland referred to in Chapter 2 and CER & NIAUR (2011a, p. 3).

206 However, the CMG does state that "[F]or intra-day trade continuous trading may be used" (Reg. 714/2009, Annex paragraph 2.1).

and 30 hours in the future. The risk is much lower and hence trade is more likely to take place.

The implementation costs for SEMO and the TSOs of adapting SEM to accommodate the two extra intra-day gate closures have been estimated as €13.0 million, with an ongoing cost €1.5-€2.0 million per year (CER & NIAUR, 2011a, p. 4). Nevertheless, the evidence suggests that the benefits are likely to outweigh the costs (*ibid*, pp. 10-12).

Developing Efficient Ireland-Great Britain Interconnection: Ensuring Consistency with the Capacity Allocation and Congestion Management Framework Guidelines (CACM FG)

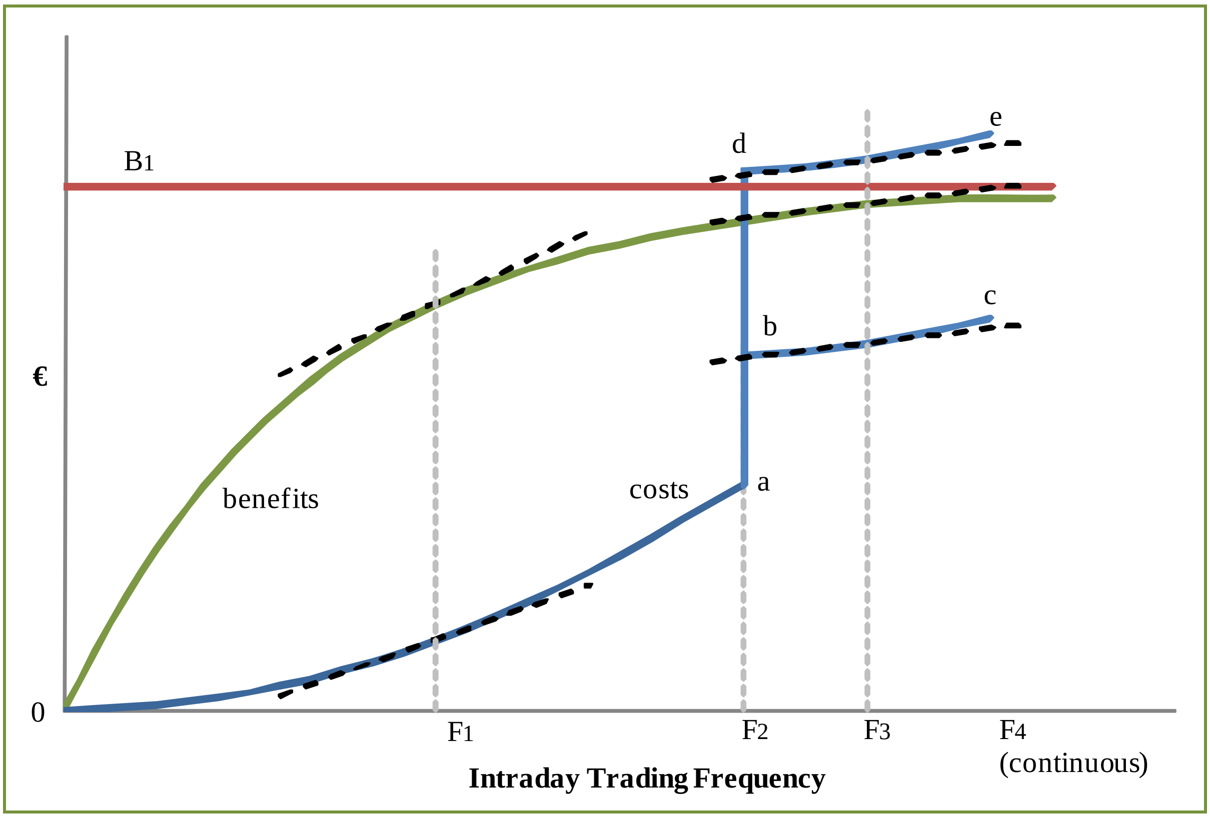
While the revision to the SEM makes it consistent with the CMG it is not clear that it is consistent with the CACM FG which calls for continuous intra-day implicit trading, whereas the CMG only called for intra-day trading. This implies that under CACM FG that the frequency of trading within a day will increase compared to the two gate closures that are consistent with the CMG. The issue thus becomes what is meant by continuous intra-day implicit trading: 24 hourly gate closures; 48 half hourly gate closures (e.g. Germany); 96 fifteen minute gate closures (e.g. the Netherlands) or continuous trading in real time without interruption? As yet this issue has to be decided. The current CACM FG does not define what is meant by continuous intra-day implicit trading, although it does state that the "…objective is enable participants to trade energy as close to real-time as possible in order to (re-) balance their position (ACER, 2011b, p. 11)." Here we explore the implications of the various options in the context of the SEM.

The benefits of more frequent trading are that the difference between *ex ante* and *ex post* prices in the SEM will narrow and in the limit – continuous trading – there is no difference. When trades get closer together the ability to match bids more accurately to the forecast volume of wind generated electricity or the level of demand increase. There is less thus need to design strategies to hedge, such as ownership of generation and/or supply at either end of the interconnector. Transaction costs fall. More players are likely to enter the market. Competition and liquidity increase. Congestion is more likely on the interconnector as demand increases for capacity. However, it seems reasonable to assume that the returns or benefits from increasing the frequency of intra-day trading will increase, but at a declining rate.

The situation with respect to the SEM costs of increasing frequency of intra-day trading is not, however, symmetrical. As the frequency of trading increases the marginal costs to the SEM are likely to increase not decrease. Recall that the SEM is a central dispatch model with a mandatory pool. As trading frequency increases the SEMO will have to compute the market schedule and TSOs centrally dispatch the relevant generators with increasing rapidity. However, there is likely to come a point at which the central dispatch model/mandatory pool model will be unable to deal with trades that are being conducted over very short periods of time. At that point a new market design system will need to be introduced, in which, for example, generators self dispatch. This suggests that SEM costs will, at this point, experience a discontinuity reflecting the once off costs of switching systems away from the current model. Then the costs of increasing frequency would, as before, increase.

These costs and the benefits of increased frequency of Intra-day trading are illustrated in Figure 10.4. The benefits curve increases gradually approaching some asymptote, OB_1. In the case of the costs, these increase at a rising marginal rate until a discontinuity occurs at OF_2. The costs of the change in system may result in total costs being less than (Oabc) or exceed (Oabde) the benefits of increased frequency. Given the change to the SEM has occurred then the marginal costs of increasing frequency also increase.

Figure 10.4: Frequency of Intra-day Trading: Costs + Benefits



Source: See Text.

The optimal frequency of trading will occur where the marginal cost of the addition of an extra increment to frequency is equal to the marginal benefit. In Figure 10.4 there are two solutions: at OF_1 and OF_3. However, OF_1 is superior to OF_3 since the surplus or return is greater at the former than the latter. The surplus is represented by the difference between the total cost and total benefit curves. Thus, if Figure 10.4 were an accurate representation of reality then the current SEM model would be retained but the frequency of trading would fall well short of continuous trading in real time.

In sum, to comply with the CACM FG is likely to require an increased frequency of intra-day trading. More frequent trading is likely to lower transaction costs, increase competition and liquidity. However, as frequency increases and TSOs dispatch generators at much shorter intervals, at some point (OF_2 in Figure 10.4), central dispatch may be prove impossible to achieve, given the constraints of the system. At such a point it would be reasonable to consider alternative models to the SEM, which would involve once off costs to move to the new model. Whether the change is desirable depends on the costs and benefits of SEM compared with the alternative model, taking into account the once off switching cost.

At the present time, however, we are not aware of evidence on either of the cost or the benefit curve. However, when the SEM rules that result in compliance with the CMG come on stream, then there will be evidence of the gains of adding two gate closures within a day. Will trade flow over the interconnector and stimulate more competition? Will traders as well as businesses involved in both ends of the interconnector become involved in trade?

Interconnection, Revising the SEM, CACM FG and Regulatory Risk

Investors demand a rate of return that reflects the riskiness of the project or investment. One of the elements of risk is changes in government policy sometimes referred to as regulatory risk. The more credible the policy framework, the more stable the pricing and other rules, the more predictable and certain the pattern of regulatory/policy change, the lower is the regulatory risk. This feeds through into lower prices since the cost of capital is lower than it otherwise would be. Consumers benefit. If, however, regulatory risk increases due to an unexpected and unanticipated change, such as a radical overhaul of the SEM then the reverse is likely to occur.

At the present time there is a concern that although steps are being taken to ensure that the SEM is consistent with the CMG in Reg. 714/2009, complying with some of the provisions of the CACM FG, which envisages continuous intra-day implicit trading over an interconnector, may require a major overhaul of the SEM model. This can take at least two forms: first, the essential features of the SEM would remain unchanged except for increased frequency of trading in real time.[207] This would require some investment in adaption of IT and other systems by generators to be compliant with the new system; and, second, a new market design such as the bilateral contract system in Great Britain or trade through power exchanges often found in continental Europe in countries in the CW and North REMs (Table 2.1). Here the change is likely to be more profound and the consequent compliance costs by generators and others correspondingly higher.

An important issue concerns timing of any switch to a new model. Instead of being required to comply by some arbitrary date such as 2014 or 2016 independent of the costs and benefits, the decision should be made on the basis of careful evaluation of the benefits and costs with different speeds of implementation considered as alternative options. The costs would consider not only the implementation costs referred to in Chapter 9 concerning the creation of the SEM and BETTA, but also in terms of regulatory risk.

It is not clear, based on current information, whether SEM will survive with minor revisions or require radical overhaul to a new model. This naturally creates uncertainty. However, this should not be overstated. Given that 2014 has been set for the date at which the internal market is to be completed, but with a derogation for Ireland from the CACM FG until 2016, the uncertainty will not be resolved immediately, although the consequences might be profound if OF_3 is selected rather than OF_1 in Figure 10.4. Furthermore from the SEM point of view there is ample current capacity so if new investment decisions are deferred for a year or so then the consequences are unlikely to be significant. Nevertheless, that should not mean that the process is not carefully planned so that a sensible and pragmatic solution can be implemented. All the signs are that such a careful planning process is underway.[208]

[207] This raises the question of what are the essential features of SEM. While the *ex post* nature of the pricing is not a central feature, the various mechanisms designed to ensure open and transparent pricing and mandatory bidding of all generators using short-run marginal cost are central features.

[208] For details see CER & NIAUR (2011c).

Policy Implications

The policy implications for Ireland are clear. The framing in the CACM FG of the definition of continuous intra-day implicit trading should be sufficiently flexible that Ireland can decide on the frequency of intra-day trades. This is so for several reasons. *First*, the optimal frequency has as yet to be determined. More evidence will be available when SEM intra-day trading, that complies with the CMG applies to the Moyle IC and subsequently to the East West IC, when it comes on stream. The costs of making the incorrect choice for Ireland are likely to be substantial. *Second*, given this uncertainty it is not clear that the EU should determine the frequency of continuous intra-day trading with sufficient precision that Member States have little or no discretion. The purpose of the internal market is to benefit the citizens of the EU through a more efficient functioning EU-wide market. If in the case of Ireland that requires an intra-day trading frequency that may differ somewhat from (say) the BritNed or IFA ICs, but at the same time allow trading over these interconnectors, then surely the relevant rules should facilitate such arrangements. Furthermore, with a large potential volume of wind to export, Ireland has a strong interest in developing such a market so its incentives are correctly aligned. *Third*, sufficient flexibility in the CACM FG and other aspects of the Third Package are consistent with the important EU principle of subsidiarity. Under this principle responsibility for a particular task or area is assigned to the Member State where it can be more effectively dealt with at that level. There is no a priori reason why different market designs cannot be interconnected using somewhat different arrangements in terms of frequency of continuous intra-day implicit trading. The various EU directives and regulations that form the Third Package refer to Member States not being forced to redesign their systems so as to meet the interconnection rules. Hence, the rules for the internal market should permit Ireland the time and space to implement the policies of the internal market in a manner consistent with its needs.

Chapter 11

Conclusions and Policy Recommendations

The creation of the internal market, on both theoretical and empirical grounds, should benefit Ireland in terms of lower electricity prices, a more competitive market and greater security of supply. However, there are three important caveats. *First*, it assumes no major policy failure in UK energy policy that results in an unanticipated increase in electricity prices that cannot be offset by increasing interconnection between Great Britain and continental Europe. *Second*, it assumes that in complying with the Third Package, particularly the CACM FG and the subsequent network code, that Ireland will be given sufficient flexibility to avoid potentially costly changes to the SEM. *Third*, it assumes that the internal market and interconnection do not become used as a reason for exporting heavily subsidised renewable energy,[209] particularly offshore wind as well as wave and tidal, leading to higher prices through increased TUoS and PSO.[210]

Introduction: Peeling Back the Onion

The EU is striving to create the internal market. Legislation, primarily the Third Package – which came into effect on 3 March 2011 – and its predecessors, has been enacted to take this forward. Completion of the internal market has been set for 2014, although Ireland has been granted a transitional arrangement that does not extend beyond 2016. The purpose of this paper has been to describe and consider the implications of the internal market for Ireland and identify what important issues still need to be addressed through further research, the subject of Chapter 12.

Absent interconnection, Ireland will not participate in the internal market, but instead be characterised as a small closed electricity system. Interconnection involves the building of costly undersea infrastructure to Great Britain and perhaps beyond. Hence, decisions need to be made concerning the financing, size, timing and governance of interconnectors. Interconnectors between Ireland and Great Britain link two quite different models for structuring the electricity market. That in turn leads to questions about whether or not, from an Irish point of view, it is preferable to switch to Great Britain's BETTA model (either in its current form or as reformed) or retain the current all-island model, the SEM. Indeed, once extensive

[209] Of course, wind generated electricity is not exported directly, but it influences the SMP and hence the opportunity for exports.

[210] The PSO is also influenced by payments to peat fired generators. For details, see, for example, CER (2011b).

interconnection takes place with Great Britain does Ireland have much choice over its model of the way in which the electricity market is structured and regulated?

Moving beyond these islands, further issues need to be addressed concerning whether or not, irrespective of the merits of the Ireland or the Great Britain model for organising the electricity market wider EU concerns mean that much of this discussion is irrelevant. Will the highly prescriptive access and other rules set out in guidelines and network codes on the governance of interconnectors of necessity result in all EU Member State markets converging to a single market electricity model or will there be room for diversity? Thus, this paper is analogous to peeling an onion; beneath each layer is yet another layer, once one question or issue is resolved another appears.

Interconnection: Cost and Benefits

Interconnection should be undertaken to the extent that it benefits Irish society. Interconnectors are large lumpy investments, typically – in the Irish context judging from the evidence – built in units of 500MW. Thus, in considering building interconnectors what is relevant is whether the benefits of building an additional 500MW of capacity equal or exceed the costs. The main expected benefits are measured in lower prices in Ireland due to competition from generators located elsewhere in the EU, mainly Great Britain. Interconnection also permits a smaller reserve capacity to deal with unanticipated power outages as well as the introduction of greater competition in an oligopolistic market. However, there are also security of supply benefits from access to a large market, such as more diversified fuel supplies (e.g. nuclear) and suppliers (e.g. npower or London Energy or Centrica).

The benefits and costs of greater interconnection have been set out in a series of papers by ESRI colleagues and others, including EirGrid, which are broadly consistent with one another. These show that additional interconnector capacity of between 1,000MW and 3,000MW over and above the existing Moyle IC and the planned East West IC lowers the price of electricity in Ireland as the difference with Great Britain narrows. Irish consumers gain, while consumers in Great Britain lose. However, the benefit, measured in terms of lower electricity prices in Ireland, of additional interconnector capacity, declines as more capacity is built – the marginal returns to additional interconnection decline.

This analysis oversimplifies in at least three ways. *First*, Ireland is on course to generate substantial volumes of electricity from wind. On occasion wind, which has a low or zero marginal cost, is likely to be exported to Great Britain from Ireland.

Second, depending on future energy policy in Great Britain prices in the medium to longer term may be higher in Great Britain than Ireland. However, this does not mean that Ireland will not benefit overall from interconnection due to some of the non-price benefits from interconnection, such as a lower reserve capacity and access to a greater diversity of fuel supplies. *Third*, apart from considerations of wind, electricity is likely to flow in both directions due to differences in demand and the mix of generation capacity.

At the EU level there appears to have been limited attempts to estimate the overall costs and benefits of increased interconnection necessary for the completion of the internal market. One estimate by the Commission suggests that compared with 2010, by 2020 EU wide GDP will higher by 0.6-0.8 per cent, inflation 0.5-0.6 per cent lower and there will be 5 million extra jobs with the completion of the internal market.[211] No estimates have been undertaken by the Commission of the gains and losses by Member States.

Interconnection: Existing Infrastructure

Between Ireland and Great Britain there is only one existing interconnector (i.e. Moyle IC) and one under construction with operation anticipated for Q3 2012 (i.e. East West IC). No other interconnectors are currently in the planning and development stage. The Moyle and East West ICs are the equivalent of adding between 4.5 to 9 per cent to generation capacity in Ireland in 2013. There is one long standing interconnector between Great Britain and continental Europe (i.e. IFA IC) while another was completed and in operation in Q2 2011 (i.e. BritNed). Beyond these a number of additional Great Britain-continental Europe interconnectors are under consideration including EliaNG, that will link England with Belgium, and ElecLink, that will link England and France using the Channel Tunnel.

Interconnection: Future Infrastructure Choices

There are two channels through which Ireland can become part of the internal market: (a) Great Britain through interconnection with continental Europe becomes part of the wider EU market. Prices in Great Britain converge to those in continental Europe. Hence, interconnection with Great Britain integrates Ireland with the wider internal market; and, (b) Great Britain prices diverge from those in continental Europe both in magnitude and duration. Ireland has a number of choices to become part of the internal market in this latter situation.

[211] These Commission estimates refer to the internal market for gas and electricity.

- Ireland can accept the partial integration into the internal market via Great Britain.
- Ireland could build one or more Ireland-France ICs. The price of electricity in France is markedly lower than the UK and Ireland. However, the price of electricity is likely to rise in France as it becomes further integrated into the internal market. Thus, future gains from an Ireland-France IC in (say) 2025, are unlikely to be as large as those based on current price differentials. Set against these problematic gains is the fact that the annualised capital costs of an Ireland-France IC are estimated to be 50 per cent higher than those for the same sized Ireland-Great Britain IC.
- Ireland could build a Great Britain-Netherlands/France/Belgium IC that would more fully integrate Great Britain (and thus Ireland) into the internal market. However, this option faces a number of problems. The major beneficiaries of such interconnection, for example, would be consumers in Great Britain, rather than Ireland. It is not clear who would be a suitable joint venture partner to EirGrid acting as an agent on behalf of these consumers. Hence this option is unlikely to be feasible.

In sum, it appears that Ireland's integration into the internal market will depend critically on the extent of Great Britain-continental Europe interconnection. Alternatives such as interconnection to France or building an additional Great Britain-continental Europe interconnection do not seem feasible options.

Interconnection: Timing

In considering the timing of future interconnection investments three sets of considerations need to be taken into account. *First*, the constraints imposed by planning, building and providing a sound business case for a future interconnector. *Second*, the economic constraints. *Third*, regulatory constraints, since appropriate regulation plays a vital role in determining the efficiency of trading over the interconnector, a necessary condition for successful interconnection.

From a project assessment/decision and project construction perspective new interconnectors with Great Britain are unlikely to be built before 2021-2023, assuming that the project assessment/decision process for a new interconnector starts in 2011. This seems unlikely to happen. Turning to the economic constraints, reflecting recent budgetary and fiscal developments, it seems unlikely that the project assessment/decision process for a new interconnection will commence before 2015, with a completion of the project construction date of 2025-2027. By that time it will become apparent if the access rules for operating on the Moyle and East West ICs combined with the introduction of intra-day trading on the SEM are working efficiently. However, these are historically-based timelines and government could always shorten the timelines and so accelerate the completion of future interconnectors.

Interconnection: Ownership

It appears that the ownership and development interconnectors from Ireland will be driven primarily by Irish public policy, with little, if any, private sector involvement or of another TSO apart from EirGrid. The Great Britain TSO, National Grid, only has plans to develop interconnectors to continental Europe. Furthermore, these interconnectors are usually joint ventures between National Grid and the corresponding TSO, which has advantages in terms of sharing risk, knowledge and expertise and sharing the costs between some of the parties that benefit.

Interconnection: Wind

Interconnection and wind generated electricity complement each other. This reflects the fact that wind is a variable source of electricity generation. If the wind speed is too low or too high wind cannot be used to generate electricity, in the latter case for safety reasons. Furthermore, when the wind does generate electricity in Ireland the wind pattern tends to be similar across the island. Thus, the higher the level of wind generated electricity, the greater the requirement for back-up generation capacity for when the wind speed is too low or too high. This is expensive: electricity available at short notice often is high cost and less efficient. Interconnection is one method of resolving this dilemma, since electricity can be imported from Great Britain and beyond when the wind does not blow or blows too hard. Furthermore, interconnection has an added advantage. When wind generated electricity's share of all electricity reaches certain limits it is curtailed off the SEM system. With interconnection this surplus can be exported.

A 40 Per Cent Renewable (Wind) Target

A 40 per cent target for electricity consumption from renewables has been set for 2020.[212] Virtually all of the renewable electricity is to be generated by wind. In 2010, the 40 per cent wind target translated into 6,232MW of wind. However, with the recession and the consequent decline in demand for electricity, subsequent analysis reduced the amount of wind needed to meet the target to 5,450 MW: Northern Ireland, 1,100MW; and the Republic of Ireland, 4,350MW. With further downward revisions to growth forecasts, a more reasonable estimate of the wind generated electricity needed to meet the 40 per cent target is likely to be closer to 5,000MW. Offers already made by the CER to wind farms for access to the electricity grid

[212] By both the Republic of Ireland and Northern Ireland.

amount to 6000MW, although due to planning and financing difficulties all this capacity is unlikely to be built. Nevertheless, this is substantially above the volume of wind necessary to meet the 40 per cent target not only for the Republic of Ireland, but also Ireland (i.e. the Republic of Ireland and Northern Ireland).

Meeting Wind Targets: REFIT and SEM Pricing Rules

A variety of support mechanisms are currently in place to facilitate the use of wind as a source of electricity. These include, but are not limited to:

- REFIT*,* which guarantees minimum prices or so called feed-in tariffs for wind generated electricity. There is also a fixed payment element of support. The impact of REFIT is to raise the retail price of electricity, through the PSO, for residential consumers between 3.3 to 9.1 per cent and for industry between 4.4 and 12.1 per cent.
- Wind farms pay a shallow connection charge to access the national grid, i.e. the wind farm pays for the cable to the nearest substation on the grid and any increase in the capacity of the substation. Grid strengthening is paid by EirGird and thus consumers through increased TUoS.
- Wind generated electricity is paid, subject to some exceptions, when it is curtailed off the system because, for example, of concerns over system security or lack of demand.[213] Consumers pay for electricity that is not generated but not consumed. Thermal stations are not treated on an analogous manner.

The level of support under the first two items is greater for offshore than onshore wind; there is no difference for the third.

Interconnection: Necessary for Wind?

The evidence suggests that wind generation in Ireland is only economic if there is investment in interconnection. When the wind blows electricity is exported, rather than being curtailed off the system and generating no economic return at all – at least for society if not the wind farm owner. When the wind does not blow the shortfall can be made up with imports rather than relying on costly ramping up and down of thermal generators. Wind also appears to be a useful insurance policy against high fuel prices, although if expansion in shale gas supplies – by no means assured in view of environmental and regulatory issues – leads to lower electricity prices this is likely to lower the value of the insurance policy.

[213] Payments are made for the volume difference between actual output and market scheduled quantity. This is generally the same as the unconstrained output but, where the windfarm's connection capacity is non-firm, the operator is not paid for any amount above the firm access quantity.

Joined-Up Policy

It is important that policy with respect to the amount of wind generation capacity and interconnection is consistent and co-ordinated. There is likely to be an inconsistency in the timing between the 40 per cent renewable target of 2020 and the fact that there is little chance of a new Ireland-Great Britain interconnector coming on stream until at least 2025, unless the process is accelerated. This may mean deferring reaching the target, albeit that this is binding. In order to ensure wind is not unduly curtailed off the system, interconnection is of vital importance. To ensure timing consistency it is thus suggested that guaranteed prices under REFIT should fall as the existing stock of wind generation capacity increases. When wind is curtailed off the system, it should receive no payment, whether SMP or capacity, under the SEM rules. It already receives no payment under REFIT for wind that is curtailed.

But what if for some reason, electricity demand is higher than anticipated – thus justifying more than 5000MW wind to meet the 40 per cent target by 2020? There appears to be sufficient excess thermal generation capacity available so that there is no danger of shortfalls in supply. If demand increases more than expected then this should become evident well before 2020. Even if this is not the case, the 40 per cent target will still be reached but deferred by a few years, although this is unlikely given the biding nature of the target. Furthermore, it is anticipated that there will more stringent targets for the decades after 2020, so that if a Member State under or over shoots the 2020 target there will be an opportunity to adjust subsequently to attain the next target in (say) 2030. There is evidence that some of the large Member States, such as Germany and the UK, may have difficulty in reaching the various EU renewable targets with the result that there may be some revisiting of the targets. If a system of tradable renewable permits between Member States is introduced then this would offer an alternative way of dealing with deviations from the renewable target at the Member State level. All this suggests that erring on the conservative side in setting wind volumes is likely to incur lower costs compared with overbuilding wind that will be curtailed off but still attract a series of supports, thus driving up the price of electricity and damaging Ireland’s ability to compete on international markets.

Securing Value for Money

It is important that policy achieves its objectives at least cost. At the present time this does not appear to be the case with respect to the support programmes for securing wind generated electricity. The current REFIT scheme subsidises expensive offshore wind (as well as wave and tidal) and should either be abolished or limited to the same level as onshore wind electricity. It is inconsistent with a series of government statements to support high risk high cost offshore wind when a lower cost alternative exists, namely, onshore wind. Furthermore, offshore wind farms should be charged the full cost of grid connection to the onshore grid[214] and not subsidised at the expense of electricity consumers. It is inequitable and inefficient that while REFIT guarantees a minimum price for electricity generated from wind farms there is no sharing of the benefits should high prices be experienced. It is suggested that above a certain price, the electricity consumers share in the returns from higher prices.

Interconnection: Distributing the Rent

Interconnectors are likely to generate income when there are price differences between the markets at either end of the interconnector. Interconnector capacity will be scarce relative to demand and space will command a premium referred to as a rent or congestion income. The Third Package offers two solutions to the question of interconnector income distribution: first, the regulated or default position is that congestion income is used to build more interconnectors and, having achieved that objective, used to reduce TUoS; and, second, merchant interconnectors, where the congestion income largely or exclusively accrues to the owners. Merchant interconnectors are exceptions that need to be justified. Regulated interconnectors are able to socialise the risk since electricity consumers assume the costs and reap any benefits; merchant interconnectors bear the risks themselves. Ireland/Great Britain interconnectors are regulated; Great Britain/continental Europe interconnectors are more likely to be merchant.

Both regulated and merchant interconnectors – for different reasons – may lead to an under-investment in interconnection. In the case of regulated interconnectors because of the tendency to pay attention primarily to consumer surplus; in the case of merchant interconnectors because market power considerations lead to restrictions on capacity. However, this does not necessarily have to be the case. In terms of regulated interconnectors there may be important complementarities between the Member States that mean that there are gains from trade, while there are also unpriced public goods such as increased security of supply which benefit consumers. This is likely to be particularly important for a small electricity market such as Ireland’s compared to a much large market such as that of the Great Britain or Germany. In the case of merchant interconnectors, the oversight role of the NRAs and the Commission should serve to a considerable extent to lessen the tendency to under-invest by imposing conditions should returns prove excessive. However, this

[214] This reflects the situation where some ambiguity might arise if there is a move to build an offshore grid to connect the various wind farms. It is suggested that offshore wind farms fund the offshore grid.

may suppress market signals and thus discourage additional investment. Ofgem's proposed floor and cap regime for merchant interconnectors may go some way to address these issues.

Interconnectors: Should the Winners Compensate the Losers?

The internal market will create winners and losers both within and between Member States. It could be argued that public policy should intervene such that the winners compensate the losers. However, there are a number of practical and conceptual problems. These include, identifying winners/losers, who should compensate, how should compensation be funded without distorting the incentives for those who invest in interconnectors, and the rationale for the compensation. Furthermore, there are alternative EU policy instruments, such as regional aid, to promote growth and development in lagging areas. Thus it is difficult to see that there is a strong, or even a weak, case for the winners compensating the losers due to greater interconnection leading to the successful completion of the internal market. Nevertheless, from a public policy point of view the internal market at the EU level should satisfy the Kaldor-Hicks criterion (i.e. the winners should be able to compensate, in theory at least, the losers) so that the Pareto optimum is satisfied (i.e. nobody can be made better off without making somebody worst off).

The SEM and BETTA Models: The Preferred Model?

The Third Package contains a set of rules, guidelines and laws that have the potential to change dramatically the character of Ireland's wholesale electricity market, the SEM. Such change is likely to be costly and time consuming. In coming to a view as to the merits of change, it is important to consider the performance of the SEM. For these purposes the comparator is Great Britain's BETTA, which is quite different in terms of price determination and organisation. The discussion of these two models of market design strongly suggests that Ireland, given the choice of the two models, should remain with the SEM, providing of course that it can be made consistent with the Third Package and accommodate efficient trading of wind, both of which are likely to prove challenging.

Implications of Reform of BETTA

The UK government is currently reviewing BETTA through the Electricity Market Reform, which is likely to have important implications for Irish consumers. Much of the discussion concerning the impact of more interconnection is based on the assumption that prices will fall as a result of the internal market. This in turn reflects the view that prices are likely to be lower in Great Britain. However, this may not be the case. A quarter of generating capacity in Great Britain will close and needs to replaced in the next decade, in part because it is ageing and in part because of the

Large Combustion Plant Directive and the Industrial Emissions Directive. There are concerns that the current market arrangements may not yield the required investment. If there is a policy failure and insufficient generation capacity is built, then prices are likely to rise in Great Britain and Ireland, as a price taker, will, of necessity, experience price increases. However, any price rise will be modified by the increased interconnection between Great Britain and continental Europe which is likely to reach 10 per cent of installed capacity by the 2020s.

Interconnection: Increased Frequency of Intra-day Trading

If interconnectors are not used efficiently and effectively then the return on an important asset is less than it might otherwise be. If appropriate trading rules cannot be put in place then there is a danger insufficient interconnectors will be built. The evidence suggests that electricity is not traded efficiently over the Moyle IC. A variety of reasons for this state of affairs including the difference in gate closures and the *ex post* nature of price determination under SEM compared to BETTA. Efforts are being made to address these problems while at the same time ensuring consistency with the Third Package. For example, in order to comply with the Third Package's CMG, two intra-day gate closures are being added to SEM, in addition to D-1.

The CACM FG, envisages continuous intra-day implicit trading. An important issue concerns what is meant by continuous intra-day implicit trading: 24 hourly gate closures; 48 half-hourly gate closures; or continuous trading in real time? As yet this issue has to be decided. The closer trade gets to trading in real time, the more likely that the SEM will require a radical and costly overhaul. Yet such trading is important to accommodate wind in an efficient and effective manner.

The framing in the CACM FG of the definition of continuous intra-day implicit trading should be sufficiently flexible that Ireland, through the SEM, can decide on the frequency of intra-day trades. This is so for several reasons. *First*, the optimal frequency has as yet to be determined. More evidence will be available when SEM intra-day trading that complies with the CMG applies to the Moyle IC and subsequently to the East West IC when it comes on stream. *Second*, given this uncertainty it is not clear that the EU should determine the frequency of continuous intra-day trading with sufficient precision that Member States have no discretion. The purpose of the internal market is to benefit the citizens of the EU through a more efficient functioning EU-wide market. If in the case of Ireland that requires an intra-day trading frequency that may differ somewhat from (say) the BritNed or IFA ICs, but at the same time allow trading over these interconnectors, then surely the relevant rules should facilitate such arrangements. Furthermore, with a large potential volume of wind to export, Ireland has a strong interest in developing such a market so its incentives are correctly aligned. *Third*, sufficient flexibility in the CACM FG and other aspects of the Third Package are consistent with the important EU principle of subsidiarity. Under this principle responsibility for a particular task or area is assigned to the Member State where it can be more effectively dealt with at that level. There is no a priori reason why different market designs cannot be interconnected using somewhat different arrangements in terms of frequency of continuous intra-day implicit trading. The various EU directives and regulations that form the Third Package refer to Member States not being forced to redesign their systems so as to meet the interconnection rules. Hence, the rules for the internal market should permit Ireland the time and space to implement the policies of the internal market in a manner consistent with its needs. Both Ireland and the EU have a shared policy objective of optimal use of interconnection and success of the internal market so a resolution of any differences should be possible.

Interconnection, the Internal Market and Wind

Greater interconnection between Ireland and Great Britain and beyond is driven by two factors: the internal market and the policy target of high volumes of wind. It is important to separate the two. The internal market motivation for greater interconnection is that consumers will benefit through a more efficient and competitive market for electricity. Resources will be allocated in an optimal manner. In the case of high volumes of wind, interconnection is a mechanism for dealing with the variable nature of the power generation from this source, exporting when plentiful and importing when the wind does not blow. However, great care needs to be taken to ensure that all the costs of wind are taken into account by those making the decisions – politicians, public officials, and wind farm owners. At the moment this is not the case. Mechanisms are suggested in Chapter 5 to address this problem, including the creation of tradable renewable permits. Failure to develop such mechanisms could result in too much expensive subsidy funded wind (and wave and tidal) infrastructure being built and then, once built, used as a justification for building additional interconnection, leading to higher electricity prices via TUoS charges to fund the interconnector. This will not only raise prices for consumers but also damage Ireland's competitive position.

Chapter 12

Future Research Questions

One of the purposes of this paper has been to identify future areas of research that might be undertaken based on an examination of the internal market's implications for Ireland. This paper has taken a broad view of the issues related to the internal market, paying particular attention to the impact of increased wind penetration. This it was felt, given the interconnected nature of the electricity market and its regulation, needed to be investigated. If the focus was too narrow then important ramifications of the internal market would be missed.

Optimum Interconnection Routes: Great Britain and/or France?

As discussed in Chapter 4 above, Ireland can interconnect to continental Europe either directly to France or indirectly via Great Britain. In making this choice, it is important to know the extent to which electricity prices in Great Britain will converge to EU levels since this implies that Ireland can gain the benefits of the internal market via interconnection to Great Britain. Equally, as France becomes increasingly integrated into the internal market its low price will be expected to rise, so that the benefits may not be sufficient to offset the fact that the annualised capital costs of interconnection to France for the same sized interconnector are 50 per cent higher than to Great Britain. Hence, the research questions that need to be addressed are:

- To what extent will planned and proposed interconnection between Great Britain and continental Europe lead to price convergence? and,
- To what extent will planned and proposed interconnection between France and adjacent Member States lead to price increases in France?

Judging from discussion with leading UK academics, Ofgem, and the National Grid there does not appear to be published research on the former question. The House of Commons (2011, paras 82-85) also drew attention to importance of the EU dimension of UK energy policy. At the moment interconnection between Great Britain and continental Europe is quite small, but the evidence suggests that this is expanding to reach 10 per cent of installed capacity by the 2020s.

What Price Wind (and Other Renewables)?

One of the most dramatic developments in the EU electricity market is the advent of increased wind penetration. Ireland is no exception to this except insofar as the target share for wind in satisfying electricity demand, at close to 40 per cent by 2020, is unprecedented within the EU. In order to meet this target a variety of supports have been put in place, including but not limited to:

- guaranteed minimum prices through REFIT, with higher guaranteed prices for offshore wind (and tidal power);
- charging a shallow connection charge; and,
- paying for wind irrespective of whether or not it is dispatched.

Given that the overall cost of these various supports could be reduced, while meeting the renewable target, means that electricity prices for consumers are unnecessarily raised and thus damage Ireland's ability to compete. If these various supports had been financed through taxes and the budgetary process then there is little doubt these costs, together with the benefits, would have been more carefully examined before any decision was made. In the current environment, it seems especially reasonable that a similar exercise is undertaken for these off-budget supports.

Are Incentives for Renewable Energy Optimal?

Interconnection, as noted in Chapter 5 above, will play an important role in ensuring that the 40 per cent renewable target is met in a cost-effective manner. However, a number of issues still need to be resolved in order to ensure that wind can be accommodated in an appropriate manner:

- What mechanisms can and should be introduced to ensure that the right price signals are sent to investors in new thermal generators that may be discouraged from investing due to low SEM prices resulting from large volumes of wind generated electricity?
- What mechanisms should be introduced to ensure that plant is rewarded for 'flexible' services?
- Will the changes proposed in Chapter 5 of the paper to ensure there is consistency between the timetable for the 40 per cent wind target and the likely date of new interconnectors with Great Britain – 2025 -2027, unless the process is accelerated – be successful? If not what additional policies should be introduced?

These are important issues that need to be resolved if Ireland is to incorporate renewable energy within its portfolio of generation options in a cost-effective manner.

Should Ireland's Electricity Consumers be Subsidising Great Britain Consumers?

Interconnection will facilitate the export of wind generated electricity that would otherwise be curtailed off the system. Proponents of wind and other renewable sources of electricity laud the export of electricity as though that was in and of itself a good thing. However, if export of electricity from renewable sources are heavily supported by electricity consumers through a series of not altogether transparent mechanisms, it is not clear that this is a sensible policy.[215] Hence, key research questions concern the policy supports and the use of alternative policy instruments towards renewable electricity:

- How should the support mechanisms be modified to reflect the fact that the renewable electricity exporters receive substantial support from SEM electricity consumers?
- What mechanisms exist, such as tradable renewable permits between Member States,[216] that could be used to capture some of the value of wind generated electricity for Irish consumers?

Failure to address either question will result in implicit subsidies from Irish electricity consumers to Great Britain consumers.

What is the Optimal Frequency of Intra-day Trading?

The CACM FG calls for continuous intra-day implicit trading, but the meaning of continuous in terms of frequency has as yet to be defined, although reference is made to trading as close to real-time as possible. This is likely to have profound implications for Ireland, possibly leading to a radical and costly overhaul of the SEM. It is, therefore, important that the research is undertaken immediately to estimate the optimal frequency of intra-day trading to ensure that the decision is based on a careful evaluation of the costs and benefits and not imposed pursuant to some one-size-fits-all EU policy. Thus, the key question that needs to be addressed is:

- Given the current SEM trading arrangements, what is the optimal frequency of continuous intra-day implicit trading? If a radical overhaul in the SEM is warranted, what is the optimal model? How much will the transition to the new model cost?

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[215] As Helm (2011a, p. 5) comments, "[I]t is repeatedly claimed that these sort of projects [offshore wind] create jobs ... Now it is true that if an offshore wind farm is built, people will be employed to do the work. But the money spent on one activity, taken from household bills, is not available for another activity. If the economic returns are low, and offshore wind is about the most expensive deployable technology to reduce emissions, then the created green jobs will destroy more jobs elsewhere that would have been supported by the same spending resources. It turns out for some green projects that is indeed very much the case. What's more, by increasing the costs of decarbonisation by more than is necessary, competitiveness is reduced, and yet more jobs are lost to the wider economy."

[216] These were discussed in Chapter 5.

It is precisely these types of issues that the CER and NIAUIR are considering in order to comply with the CACM FG.

Beyond SEM & BETTA; Are There Better Models?

In this paper attention has been focussed primarily on two electricity market models, SEM, the all-island model, and BETTA, the Great Britain model, either in its current form or as proposed under the Electricity Market Reform. This reflects the fact that these two markets are already linked via the Moyle IC and will be in Q3 2012 via the East West IC. There are, of course, other models such as those centred on power exchanges (e.g. Nord Pool), found in continental Europe or the Iberian model (MIBEL) which has some similarities with SEM (e.g. capacity payments, complex bids, liquid pool, relative isolation and high penetration of renewables). These models offer an alternative market design if it proves prohibitively costly to adjust the SEM to meet the requirements of the Third Package and the need to accommodate a high volume of wind. Hence future research should consider;

- If the SEM has to be replaced, what are the merits of alternative models currently employed elsewhere in the EU?

Not only would such models need to comply with the Third Package and accommodate a high volume of wind, but also need to take into account the small size of the all-island market which can all too easily lead to a market structure that is not conducive to competition. Increased interconnection will increase the size of the market and lessen problems of a less than competitive market, which suggests that interconnection is not only important in the context of the internal market and the issue of wind, but also facilitating any new market structure that may be required if the SEM requires a radical overhaul.

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