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Advancing *Both* European Market Integration and Power Sector Decarbonisation: Key Issues to Consider

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I. Introduction and Summary

The concept of a single European electricity market achieved through market integration originates from European Union (EU) internal market policy. From its origination in the late 1980s through ongoing development today,[2] European market integration policy emphasises the need for efficient, cost-reflective energy markets to maintain European competitiveness. However, the emergence of European climate change policies in response to global warming has given impetus to an additional set of design parameters for creating a single electricity market. In particular, delivering the EU objective of an economy-wide 80% reduction in greenhouse gases by 2050 will require the effective decarbonisation of the European electricity sector by that time. Moreover, the exploitation of Europe's considerable wind, hydro, solar and other renewable resources necessary to achieve decarbonisation will give rise to large and volatile power transfers. Recent studies highlight the need for additional interconnection capacity across national boundaries and market coordination on a European scale to effectively manage these developments. (European Climate Foundation, 2010) (European Commission, 2011)

The delivery of decarbonisation on a European scale is dependent on market integration that enables and supports a decarbonised resource mix and adequate infrastructure capacity. However, systematic coordination of efforts to create a single electricity market with the market reforms necessary to achieve Europe's aggressive carbon reduction targets appears to be lacking. In part, this is because the processes and timelines for addressing market integration and decarbonisation priorities are

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[2] The Single European Act, which entered into force in 1987, set out the objective of creating a single European market, followed as direct result by a 1988 European Commission internal paper summarizing the obstacles to creating a single, European energy market, and priorities and actions for removing them. See *Internal Energy Market; Commission Working Document*. COM (88) 238 final, 2 May 1988; available at: http://aei.pitt.edu/4037/.

proceeding on very separate institutional and procedural tracks. In addition, the translation of market integration policy into legally binding regulations (in the form of "network codes") involves a complicated comitology process at the EU level, the results of which can have far-reaching and long-lasting implications for Europe's decarbonisation agenda. Neither the process nor potential implications appear to be broadly understood.

More specifically, the complementary aims of developing a single and decarbonised European electricity system currently involve three separate work strands;

- work to achieve a single electricity market, implemented through an incremental, bottom up approach of harmonising existing, often disparate, national practices, within a framework of legally binding European network codes

- parallel but essentially disconnected activities as individual Member States strive to achieve national renewable and carbon reduction targets and consider how national electricity markets may need to respond to the challenges of decarbonisation[3], and

- the development of a European "roadmap" for achieving 2050 economy-wide decarbonisation targets [4]

The purpose of this paper is to draw attention to the need for greater coordination among these efforts and in particular, to provide a fuller context for policymakers, regulators and interested stakeholders for considering the regulations that are being developed to implement European market integration. We also seek to alert them to the importance of becoming involved in that process as early and actively as possible. Involvement is particularly time-sensitive given the accelerated schedule for putting the resulting network codes into legal effect, which will be binding on Member States.

To this end, we highlight four key issue areas currently being addressed through the market integration process:

(1) Capacity Allocation and Congestion Management,

[3] For example, the electricity market reform consultation currently underway in Great Britain, see : http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx
[4] See http://ec.europa.eu/clima/consultations/0005/index_en.htm

(2) Transmission Pricing and Locational Pricing,

(3) Balancing and Settlement Arrangements and

(4) Grid Connection Requirements.

We consider how decisions in these areas may act either to advance, or interfere with, Europe's power sector decarbonisation agenda--including policy and market reform initiatives to advance that agenda being considered by individual Member States. The key issues and messages from our evaluation are summarised below.

a) **Guidelines and regulations for market integration should be developed within the broader inquiry of how to achieve and sustain a decarbonised European power sector.** We offer the following two-part question to help frame this inquiry:

- What policies and related power market arrangements are needed in the near- and mid-term to attract sufficient investment in (and deployment of) low-carbon resources capable of putting Europe on track to meet its 2050 carbon reduction targets, and
- How should European market integration be accomplished so that it will sustain the decarbonised resource mix over the long-term, including the optimal trading of clean resources across national borders?

b) **Rules for optimising energy flows via cross-border trading should be designed to enable, rather than preclude, effective and necessary market support mechanisms for low-carbon resources.** Market integration should work in concert with decarbonisation policies and market reforms to enable such mechanisms, while seeking to minimise unnecessary distortions to cross-border trade. Annex 2 provides an example of how to achieve this balance in the context of national markets that might choose to offer capacity payments for reliability resources as a component of their market reform policies.

c) **Strong regulatory incentives for the efficient utilisation of network and interconnector assets should be a key focus in the development of market integration guidelines and codes.** Maximising the utilisation of these assets advances both the decarbonisation and market integration agendas by increasing power transfer capacity and reducing investment costs. In addition, regulations on both the Member State and European level that encourage objective choices between investment and “operational” or innovative alternatives promote the delivery of additional interconnection and transmission capability at minimum cost.

d) **European policies for congestion management, transmission charging and balancing/settlement arrangements should take into account the potential implications for deployment of intermittent renewable technologies and the cost of achieving decarbonisation objectives**. Policies that superficially appear cost reflective and non-discriminatory, may not ultimately deliver the best outcome. **Options that may better balance the full range of objectives for a single European market** include the following::

- Harmonise the methodologies for determining the level of Member State transmission charges as well as the approach for allocating these costs among system users (demand and generation). Where locational signals are included in these charges, consider replacing them with congestion pricing that is more consistent with the manner in which cross-border congestion will be managed under market coupling. [5]

- Adopt rules for market integration that differentiate between intermittent renewable generation that cannot respond to locational signals and generation resources that can. Providing renewables with preferential transmission rights is one approach; developing market coupling algorithms that take account of the carbon intensity of resources is another.

- Advance options for balancing wind generation on an aggregated basis, moving gate closure as close to real time as is practical, or creating a separate gate closure time for wind.

- Establish a single cash-out price for balancing settlements in recognition that dual (and particularly asymmetrical) pricing does not provide generation or demand-side resources with consistent access to the value of addressing

[5] See Section II below for a full description of “market coupling.” In brief, it is the model developed to optimise energy flows across interconnectors such that total energy demand is satisfied at a single, lowest price. However, where the interconnector capacity is insufficient (congested) to accommodate these flows, energy prices in the coupled markets will diverge—to reflect the value of removing that congestion to the market participants (bidders and sellers). This price divergence provides locational signals to generators, i.e., to encourage them to locate on the side of the constraint where the market clearing price is higher.

system imbalances. Dual-pricing also discriminates against intermittent resources and smaller players forced to trade in balancing timescales.

(d) **Development of European grid connection standards should avoid imposing unnecessarily onerous or costly technical requirements.** Notwithstanding the overriding need to ensure system security and resilience, connection standards should also be designed to reasonably accommodate the particular circumstances and characteristics of the emerging generation and demand-side technologies that will underpin electricity system decarbonisation. Experience in developing and implementing grid connection standards in other parts of the world for intermittent generation, demand-response and distributed generation could provide useful models for this purpose, and should be considered. Moreover, it should be possible to ensure a secure, well-functioning and transparent integrated European market, and still retain sufficiently flexible to accommodate differences in the technical and operating characteristics of individual Member State and regional systems.

To ensure that the grid connection standards are proportionate and appropriate, we present the following recommendations for consideration:

- Focus the development of European grid connection standards and requirements on technical parameters that *significantly* impact cross-border trade and market integration, rather than parameters that have little impact.

- Require that proposed enhancements in technical requirements be supported by an independent cost-benefit assessment. In addition, cost-benefit analysis should be employed to assess whether reliability requirements can be met more cost effectively at a “system” level, rather than by individual projects.

- Wherever appropriate, compliance through market arrangements should be permitted, and retrospective application should be encouraged through incentives. At the very least, mandatory retrospective application should be based on clear and independent cost-benefit analysis.

- System users, either individually or via trade associations, and other stakeholders should have a formal role in the development of the standards, and

(e) **Future guidelines and regulations should address important non-technical connection issues that are arguably as important in terms of competition and market integration.** User access to the transmission system will have a significant influence on cross border trade. Therefore, a specific timeline and process should be established for the development of guidelines to address greater harmonization of time-scales for connection offers, securitisation requirements, and other related user access issues.

(f) **A reasonable process for the "evolution" of European Codes should be developed.** This requires considering the appropriate level of detail to be included in European legislation, and the types of modifications that could be made to the standards by industry consultative processes or Member State interpretation.

We discuss the development of European guidelines and regulations for market integration in greater detail in the following sections, and outline how and when each issue will be moving forward.

II. Overview of the Market Integration Process, Target Model and Related EU Regulations and Directives

Under the Third Package Electricity Directive and Regulations[6] ("Third Package"), which came into force in March of this year, European market integration will no longer depend largely on voluntary cooperation. By way of background, we start with an overview of the market integration process and "target model" developed for putting the concept of a single European electricity market into practice. We also provide an overview of two EU framing regulations/directives that are particularly relevant to the issues discussed in this paper.

How Market Integration Will Proceed

[6] Directive 2009/72/EC concerning the common rules for the internal market in electricity and repealing Directive 2003/54/EC; see
http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF
Regulation No 714/2009 of the European Parliament and of the Council on Conditions for Access to the Network for Cross-Border Exchanges and repealing Regulation No 1228/2003; see
http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

Market integration will be driven by the development of Framework Guidelines and detailed network codes ("Codes") by ACER[7] and ENTSO-E[8] respectively. The Framework Guidelines and Codes are intended to cover a range of technical, market and tariff arrangements to be applied to electricity markets and networks as integration proceeds. These arrangements and associated Codes are primarily being developed via an incremental bottom up approach of harmonizing existing, often disparate, national practices.

The Codes will ultimately become European law and therefore binding on Member States. In brief, the process is generally expected to proceed as follows for each major set of Framework Guidelines and Codes, on a staggered schedule:[9] (1) ACER develops and issues the proposed Framework Guidelines for comment through a consultation process; (2) Following review by the European Commission ("Commission"), the Framework Guidelines are handed to ENTSO-E, (3) ENTSO-E develops corresponding, detailed Codes with opportunity for interested stakeholders to comment, (4) Following a review by ACER, the Codes are passed to the Commission and enter a "comitology" process, by which they are negotiated and agreed by Member States prior to being translated into European legislation. [10] Unlike existing governance arrangements for developing national grid codes, the outcome of the comitology process will be difficult to change once part of European legislation.

The Model for Market Integration

To put the concept of a single European electricity market into practice, the EU has focused in large part on facilitating more efficient use and allocation of interconnector capacity. For this purpose, the Third Package specifies the use of "explicit "or "implicit" auctions, and a "target model" has been developed to implement these requirements. Under this model, cross-border trading is facilitated by the explicit auctioning of interconnector capacity, with implicit auctioning of remaining capacity at the day-ahead and intra-day timeframes[11]. Explicit auctioning involves holding a separate auction to

[7] ACER, Agency for Cooperation of Energy Regulators, was established by Regulation 713/2009 and as of March, 2011 has assumed the role of the European Regulator's Group for Electricity and Gas (ERGEG) in the development of these guidelines and codes.

[8] ENTSO-E--European Network of Transmission System Operators for Electricity.

[9] As noted in the following sections, some of this sequence was initiative with ERGEG issuing preliminary draft Framework Guidelines to start some of the code drafting moving forward by ENTSO-E and to initiate a pilot run of this overall process.

[10] More specifically, once the Codes are submitted to the European Commission and accepted by Member States via the comitology process, they will be annexed to the relevant EU Regulation (i.e. EU714/2009) and therefore become part of European legislation.

[11] Final Draft Guidelines on Capacity Allocation and Congestion Management for Electricity; E10-ENM-20-03 at:

allocate cross-border capacity in advance (potentially many months or even a year "forward") of the day-ahead time frame. Under implicit auctioning, cross-border capacity is allocated (implicitly) within the pricing of energy in the interconnected electricity markets. (See Annex 1.)

The target model achieves implicit auctioning of interconnector capacity in the day ahead, intra day and balancing timeframes, through a process of "market coupling" that allows individual market power exchanges to coordinate sales and purchases of energy. Market coupling utilises optimisation algorithms to satisfy total energy demand at the lowest price, based upon participant offers and bids in the coupled regions. Where interconnector capacity is sufficient to accommodate the optimal energy flows determined by the market coupling algorithm, a single energy price will emerge. However, when capacity is insufficient the interconnector is said to be "congested" and energy prices in the coupled markets will diverge. In this instance, energy is effectively bought at one market price, exported across the interconnector and sold at a higher energy price, giving rise to a congestion "rent" (the product of the interconnector flow and the energy price differential.) Market coupling therefore produces energy prices that reflect the value of energy based upon participant offers and bids in the coupled regions, taking into account the impacts of interconnection congestion.

Market coupling also mitigates opportunities for gaming that can arise under alternative congestion management approaches. In particular, markets that permit unconstrained energy trading at a single energy price typically resolve congestion via re-dispatch by the system operator. Generators have opportunities to manipulate the re-dispatch process to their advantage by offering low bids to reduce output and high offers to increase output. In contrast, market coupling and other forms of locational marginal pricing utilise optimisation algorithms that factor in the re-dispatch required in the face of grid congestion and reflect those costs in an automated calculation of the energy price.

A related variation of market coupling, known as "market splitting," was also considered for the target model. Market splitting has long been applied in the Nordic market and elsewhere. Participants from several areas bid into a single exchange rather than (as with market coupling) separate national exchanges that then combine bids. As with market coupling, energy prices diverge only in the presence of congestion and both models should provide the same economic outcomes. Below, we discuss the potential advantages of market splitting within Member State borders to provide locational

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http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/draft%20Framework%20Guideline%20CACM%20Electricity/CD/E10-ENM-20-03_FG%20CACM_3-Feb-2011.pdf signals (as an alternative to disparate national use-of-system charges). However, as market coupling can accommodate differences in national market designs and does not demand the creation of a single exchange, it is considered to be a more pragmatic and practical solution for cross-border trading.

A fuller description of the implicit auctioning of interconnector capacity via market coupling and resulting energy prices is provided in Annex 1.

Overview of Relevant EU Regulations and Directives

Because some of the discussion below directly relates to the "reach" of the proposed guidelines and codes, as well as their specific impact on intermittent renewable resources, we provide a brief overview of two particularly relevant EU regulations and directives that are pertinent to these issues. We do not suggest in any way that we are presenting a definitive legal analysis. Rather, this overview is intended to put our observations and suggestions provided in the following sections in a broader context.

Specifically, we draw from Regulation 714/2009 issued on July 13, 2009 entitled: "Conditions for Access to the Network for Cross-Border Exchanges in Electricity" that sets forth the scope of as well as the process for developing the Framework Guidelines and Codes, and includes some guiding principles for several of the issues we discuss in this paper. In addition, we highlight relevant provisions from Directive 2009/28/EC issued on April 23, 2009 entitled: "Promotion of the Use of Energy from Renewable Sources."[12] In particular, Article 6 of that Directive governs Member State access and operation of the grids with respect electricity produced from renewable energy sources.

We refer to the former as the "Cross-Border Exchange Regulation," and the latter as the "Renewables Directive" in this paper.

The Cross-Border Exchange Regulation provides useful insights as to the intended reach of the Framework Guidelines and Codes, particularly with respect to European requirements for grid connection standards. Under Article 1 ("subject-matter and scope"), the regulation describes its objective as: "setting fair rules for cross-border exchanges in electricity, thus enhancing competition within the internal market in electricity, taking into account the particular characteristics of national and regional markets." Article 1 also states that the regulation "provides for mechanisms to harmonise the rules for cross-border exchanges in electricity," and notably there is no

[12] Under this directive, the EU also established the mandatory national targets for 2020 (20% share of energy from renewable sources.)

reference to the provision of mechanisms for any other purpose. In addition, in describing the scope of network codes to be developed by ENTSO-E and other related tasks, Article 8(7) states that the codes "shall" be developed "without prejudice to the Member States' right to establish national network codes which do not affect cross-border trade."

It is Article 16 of the Renewables Directive ("access to and operation of the grids"), however, that directly speaks to EU policy and law with respect to grid connection by renewables. The Third Package requires Member States and their system operators to act in accordance with its provisions.[13] In a variety of ways, Article 16 directs Member States to plan, invest and operate their electricity system and associated grid infrastructure in a manner that preferentially accommodates the further development of electricity production from renewable energy sources (including with respect to investments in interconnections between Member States).[14] Article 16 specifically prohibits network charging from discriminating against renewables in general or renewables connected to the peripheral areas of the transmission system in particular.[15]

In addition, Article 16 requires that network charging of renewable energy sources by transmission and distribution system operators reflect "realisable cost benefits resulting from the plant's connection to the network," such as cost benefits that could arise "from the direct use of the low-voltage grid. "[16] It also directs Member States to regularly review and take the necessary steps to improve their framework for cost allocation, including those associated with the cost "of technical adaptations, such as grid connections and grid reinforcements" to ensure the "integration" of "new producers feeding electricity produced from renewable energy sources into the interconnected grid."[17]

[13] Directive 2009/72/EC concerning the common rules for the internal market in electricity (July 13, 2009), Article 14 (Section 3).

[14] In particular, Section 1 of Article 16 directs Member States to develop its grid infrastructure and electricity system in order to allow the "secure operation of the electricity system as it accommodates the further development of electricity production from renewable energy sources." Section 2 establishes priority dispatch for renewables, with Member States directed to ensure that appropriate grid and market-related operational measures are taken to minimise their curtailment. If significant measures do need to be taken to curtail renewables in order to guarantee security of supply/system reliability, system operators are required to report to the regulator on the circumstances and what corrective measures will be taken to prevent inappropriate curtailments.

[15] Article 16, Section 7..

[16] Article 16, Section 8.

[17] Article 16, Sections 3 and 4.

With this information as background and context, we turn now to our discussion of key issues to consider for advancing both European Market integration and power sector decarbonisation.

III. Issues arising out of the Development of Framework Guidelines and Network Codes

The development of legally binding Codes provides a framework to drive the convergence of technical and market issues necessary for European market integration. However, the market integration process could, on occasion, give rise to proposals that conflict with actions that policy makers and regulators may wish to pursue in order to deliver national renewable or carbon reduction targets. More broadly, the process could work at cross purposes with European or regional efforts to accelerate power sector decarbonisation in order to meet economy-wide carbon reduction requirements.

For market integration to deliver a single electricity market design capable of facilitating decarbonisation goals at both a Member State and European level, the elements of that design must work in concert with the overarching policy imperative to attract sufficient (and sustainable) investment in clean energy resources for Europe’s power system. Support measures such as Feed in Tariffs (FiTs), quota schemes or capacity payments are likely to proliferate as Member States decarbonise their national electricity sector and implementation of the European Roadmap 2050 proceeds. The decarbonisation and market integration agendas therefore need to advance in a coordinated and complimentary fashion, if unnecessary conflicts and implementation difficulties are to be avoided.

The remainder of this paper reviews current market integration activity in an attempt to identify key issues that could potentially conflict with or preclude valid renewable or decarbonisation policies. We also put forward some options for the resolution of these issues in a way that can better balance European market integration and decarbonisation objectives.

1. Capacity Allocation and Congestion Management (CACM)

(a) Current Status

Following consultation, final draft CACM Framework Guidelines were published by ERGEG in February 2011.[18] The draft Guidelines envisage an efficient forward energy market based on accurate forecasting of interconnector capacity with allocation via explicit auctions, together with the evolution of continuous trading at the day-ahead and intra-day timeframes through implicit auctioning of interconnector capacity via market coupling.

(b) Potential Issues

As described in Section II, the focus of CACM through market coupling is to develop cost-reflective energy pricing across Europe that removes trade distortions across national boundaries. How best to achieve these objectives alongside the need to accelerate decarbonisation of the European power sector raises issues for consideration in designing and implementing a CACM approach that advances both agendas. In particular, we discuss below the advantages of implementing CACM alongside market support mechanisms for low-carbon and reliability resources in a complementary, reinforcing manner. In addition, we highlight the manner in which strong European (and national) regulatory incentives for the efficient utilisation of transmission assets will promote the development of an integrated, decarbonised European market.

Complementary Roles for CACM and Market Support Mechanisms

Most Member States and many countries worldwide have adopted mechanisms to support low-carbon and reliability resources, either in the interests of supply security or the attainment of carbon reduction goals. Support mechanisms related to security may be a prominent feature of market design, for example PJM's Forward Capacity Market[19],

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[18] On April 11, 2011, ACER issued a draft for consultation on CACM Framework Guidelines, which presumably draw heavily upon the ERGEG consultation; however, we have not had an opportunity to review them prior to publication of this paper. Comments are due June 10, 2011 on the ACER consultation document, which is available at http://www.acer.europa.eu/portal/page/portal/ACER_HOME/Stakeholder_involvement/Public_consultations/Open_Public_Consultations/PC-03_FG_Electricity_CAM_and_CM/Consultation_document; The earlier ERGEG final draft CACM Framework guidelines are posted at: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/draft%20Framework%20Guideline%20CACM%20Electricity/CD/E10-ENM-20-03_FG%20CACM_3-Feb-2011.pdf

[19] PJM is a regional transmission operator that operates the largest competitive wholesale electricity market in the world, encompassing a number of large, US mid-western states. PJM runs a capacity auction three years in advance in

or take a less obvious form, for example contracting for reserve or peaking capacity.[20] Mechanisms designed to encourage the deployment of renewable technologies include FiT designs and renewables obligations or quotas, among others.

Irrespective of the particular design adopted, support mechanisms provide additional income for qualifying generation over and above that obtained from energy sales and have the potential to influence market energy prices. From the singular perspective of optimising energy flows via cross-border trading, support mechanisms could be seen as undermining the efficient operation of energy markets. However, in the context of Europe's aggressive decarbonisation agenda, the more relevant inquiry for CACM and other market integration issues would be to address the following, two-part question:

I. What policies and related power market arrangements are needed in the near- and mid-term to attract sufficient investment in (and deployment of) low-carbon resources capable of putting Europe on track to meet its 2050 carbon reduction targets, and

II. How should European market integration be accomplished so that it will sustain the decarbonised resource mix over the long-term, including the optimal trading of clean resources across national borders?

As progress is made towards a single European electricity market though market coupling and the integration of regional markets, the focus on ensuring that wholesale energy prices are both consistent in nature and economically efficient, could have unintended consequences that undermine Europe's broader decarbonisation objectives. The challenge will be to effectively coordinate the incremental, bottom up approach of harmonising existing national practices with the broader inquiry outlined above. Annex 2 presents an example of how these approaches could be coordinated in the context of a market that includes a capacity payment mechanism being coupled with a market that does not.

Rather than considering market support policies to advance power sector decarbonisation at direct odds with the target model for CACM, they should both be developed in a complementary, reinforcing manner.

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which both supply- and demand-side resources can compete to meet future peak demand in the region. See: http://www.roadmap2050.eu/attachments/files/PolicyBriefMay2010RM2050%5b4%5d.pdf.

[20] System operators often contract in advance for reserves in the form of generation capacity/demand reduction – for example National Grid's STOR arrangements for Great Britain's electricity market.

Efficient Utilisation of Interconnector Assets

Maximising the utilisation of network and interconnector capacity advances both the decarbonisation and market integration agendas by increasing power transfer capacity and reducing investment costs. Therefore, strong regulatory incentives for the efficient utilisation of these assets should be a key focus in the development of the Framework Guidelines and Codes.

It is generally acknowledged that regulation falls short of providing such incentives, both at the European and Member State level. (ERGEG, 2009). In particular, under current regulatory regimes, TSOs are motivated to conservatively estimate interconnector (and internal transmission) capacity and to mitigate internal congestion by limiting cross-border flows.[21] Although solving internal congestion by limiting cross-border flows is generally prohibited under European law, exceptions are permissible and existing interconnector capacity is often under-utilised (Glachant, 2010). Regulatory rules for cost recovery can also have the unintended consequences of encouraging TSOs to maximise the size of their regulated asset base, that is, to increase their investment in (and conservatively estimate available capacity of) "wires and poles." This creates little incentive for TSOs to increase the utilisation of existing assets or innovate if doing so imposes financial risks or reduces the justification for new investment. (Baker, 2010)

Nonetheless, existing European regulation does currently require TSOs to maximise the interconnector capability made available to market participants[22] and the draft Framework Guidelines call for flow-based methods that should allow interconnection capacity to be determined more accurately. These existing regulations could be strengthened through the development of Codes that focus on increased *utilisation* of interconnector and internal network capacity, over and above that achieved historically. More generally, a regulatory environment that encouraged TSOs to make objective choices between investment and operational measures or innovation, rather than

[21] Most TSOs are incentivised by national regulation to minimise internal network congestion. As interconnector flows generally add to internal congestion, there is an incentive to minimise those flows. This is sometimes referred to as "moving congestion to national borders". An example of this would be the Great Britain "System Operator Incentive Scheme", which exposes National Grid to most of the variation between the difference in the actual costs of managing congestion, relative to *ex ante* forecasts of those costs. As a result, on those occasions when Great Britain exports energy via the interconnector to France, congestion within Great Britain will increase, exposing National Grid to the risk of unrecoverable costs and reduced profit.

[22] Regulation (EC) 1228/2003, Article 6.3 requires that the maximum capacity of interconnectors and transmission networks affecting cross-border flows shall be made available to market participants – subject to maintaining secure system operation.

favouring investment in assets, can also promote increased utilisation of interconnector and other transmission assets. A concerted and coordinated effort on both the Member State and European level will be required to promote the delivery of additional interconnection and transmission capability at minimum cost.

(c) Key Messages to Policy Makers/Regulators

- Measures adopted by Member States to support the deployment of low carbon technologies or to ensure resource adequacy could impact on the nature of national energy prices, potentially distorting cross border trade under the target model (i.e., market coupling). However, rather than criticising (or rejecting) such efforts as incompatible with the objectives of market integration, European level guidance should encourage effective national and European policies that support deployment of low-carbon resources (including demand-side options), while at the same time promoting market rules that mitigate potential cross-border trade distortions.

- A "European" dimension to regulation is required in order to maximise the transfer capability of existing cross border and internal network assets, as well as investing in required new infrastructure. Regulatory incentives to improve asset utilisation will increase cross border trade capability, while at the same time minimising the need for new investment. More generally, regulation on both the Member State and European level that encourages objective choices between investment and "operational" or innovative alternatives would also promote the delivery of additional interconnection and transmission capability at minimum cost.

(d) How and When CACM Issues Will Be Addressed

Network codes for capacity allocation, intraday, day-ahead and forward trading are due to be developed by ENTSO-E over the period Q4/2011 to Q3/2013. Following ACER evaluation, the Codes will enter comitology over the period Q1 2013 to Q1 2014 (European Commission, 2011).

TSO Incentives

ERGEG (ACER's predecessor) issued a Call for Evidence on the need to incentivise cross-border trade at the end of 2009.[23] Although a number of possible performance indicators were proposed, no proposals for implementation have yet been adopted.

Interactions between Support Mechanisms and Market Operation

ACER intends to consider the impact of renewable support schemes on generation siting, markets and competition in its public consultation entitled "Advice on the Implications of non-harmonised renewable support schemes" expected Q2 2011[24]. At the Member State level, Great Britain's regulator, Ofgem, also intends to consider these interactions during 2011 in the context of Great Britain's proposed low-carbon support measures for national electricity market reform. [25]

2. Transmission Pricing and Locational Signals

(a) Current Status

Framework Guidelines to address transmission pricing ("Tariffication Guidelines") have not yet been developed. However, the Renewables Directive and Cross-Border Exchange Regulation provide some guidance on these issues. As discussed in Section II, the Renewables Directive requires that network charging reflect realizable cost benefits from connection of renewables to the network, and not discriminate against renewables in general or renewables connected to peripheral areas of the transmission system in particular.

The Cross-Border Exchange Regulation does not specifically address the issue of transmission pricing for renewables, but generally requires that charges for access to networks be transparent, non-discriminatory and cost-reflective and applied in a non-discriminatory manner. Further, such charges should not be distance-related. The regulation also directs that, where appropriate, the level of charges applied to producers and/or consumers provide locational signals at the European Community level. In its preamble, the Cross-Border Exchange Regulation also notes that the

[23] See E10-PC-47: Call for evidence on incentives to promote cross-border trade in electricity

[24] See CEER 2011 Public Work Programme, http://www.energy-regulators.eu/portal/page/portal/EER_HOME/C10-WPDC-20-07_public%20WP2011_15-Dec-2010-Clean.pdf

[25] See Ofgem Proposed Corporate Strategy and Plan, http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=410&refer=About us/CorpPlan

"pancaking" of tariff charges for access to cross-border interconnectors on top of national tariff charging schemes would be inappropriate. [26]

(b) Potential Issues

Many electricity markets worldwide provide at least some locational signals to encourage the efficient siting and operation of generation. Signals are typically provided either through (1) *nodal/zonal energy pricing*--which includes the costs of network congestion and losses, or (2) *use-of-system transmission charging*--which reflects the incremental costs of transmission investment.

The Cross-Border Exchange Regulation constrains the extent to which use-of-system charges (with or without locational signals) can be applied to cross-border trade. Nonetheless, locational signals are also inherent in market coupling (as illustrated by Annex 1, Figure 1b), where the presence of congestion will cause energy prices in coupled markets to diverge. Generation in the lower price market will therefore be denied access to higher prices in the adjacent market, thus providing a locational signal (i.e., a signal to locate on the other side of the border).

Therefore, the use of market coupling as a means of integrating national markets and ultimately delivering a single European market will expose generation and demand to locational signals, in addition to those which may be applied by some Member States through transmission use-of-system pricing. Experience to date with locational pricing in regional wholesale markets suggests that these pricing differentials can become quite dramatic and highly variable. [27] In the context of Europe's decarbonisation targets, the need to exploit areas of high wind, solar and hydro resources can be expected to result in large power flows across national borders, giving rise to congestion and potentially large locational market price differentials.

This raises two related issues to consider in the development of the Framework Guidelines and Codes, particularly in the context of the Renewables Directive and more generally, Europe's overall decarbonisation agenda. There are: (1) the impact of locational signals on intermittent renewable generation and (2) harmonization of

[26] Regulation 2009/714/EC Article 14' Preamble at 15.

[27] For example, PJM's forward capacity market incorporates locational pricing that is based on the same pricing principles as market coupling. In the most recent capacity auction, locational pricing resulted in market prices as high as $245 per MW-Day in certain transmission congested zones, compared to a low of $27.73 per MW-day in uncongested zones. For the previous auction year, capacity prices ranged from $16.46 per MW-year (uncongested) to a high of $139.73 (congested). See Figure 2 (page 11) PJM market results at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx

locational signals and transmission charging at the Member State level. We discuss each of these issues below.

Locational Signals and Intermittent Renewable Generation

Addressing the issue of locational signals in isolation may well suggest that a technology-neutral approach would best serve the interests of cost reflectivity and non-discrimination. However, considering how locational signals may impact on the deployment of intermittent renewable technologies—particularly in the context of the objectives and requirements of the Renewables Directive -- suggests an alternative solution.

While providing locational signals that accurately reflect costs incurred seems appropriate for conventional generation, which has some ability to respond both in terms of location and subsequent operation, the same may not be appropriate for intermittent renewables. Wind, marine and solar technologies are more constrained in terms of location than conventional generation and, in the interests of reducing carbon emissions, need to operate whenever their primary resource is available. Furthermore, as renewable targets become more demanding, areas of renewable resource will need to more heavily exploited (i.e. North Sea, Baltic coast or Scottish wind resource) with renewable projects effectively directed to locate in specific areas. Applying locational pricing signals to generation technologies that have little or no ability to respond may constrain deployment and delay the achievement of Europe's renewable objectives and/or increase the cost of achieving those objectives.

One way of achieving a more appropriate balancing of policy objectives might be to preferentially allocate to renewables the transmission rights associated with a congested boundary. Where transmission rights are purely physical, they could be utilised by intermittent generation to gain access to higher value in adjacent markets (created by interconnector congestion) or sold on to other users. Under implicit auctioning, financial transmission rights could be allocated to intermittent renewables providing them access to congestion rents, and thereby at least some protection from energy price differentials. [28]

[28] In a purely "physical" world of transmission rights, transmission rights holders in the exporting region would nominate flows and gain access to higher prices in the importing area via bilateral transactions. Where no flow was nominated, for example if insufficient renewable (wind) resource was forecast to be available, the capacity would either be sold on or auctioned implicitly at the day-ahead or intra-day stage, with the revenues accruing to the holder of the transmission rights. . In either case, without the transmission access right, the generator would have received a lower price for its power. In a "financial" world of transmission access rights, on the other hand, holders of these rights gain access to a portion of the "congestion rents" generated through the implicit auction..

Where locational signals continue to be delivered via use-of-system charges, discounts could be offered to intermittent renewable generation to reflect the lower costs associated with these technologies on the transmission system. Work undertaken by National Grid suggests that discounts of up to 40%[29] could justifiably be offered to intermittent renewable generation through technology-differentiated use-of-system charges. (National Grid, 2010)

Alternatively, or in addition to the options outlined above, the algorithms employed in market coupling or other forms of marginal locational pricing may need to advance to take into account the carbon attribute of the resource selling into each zone or pricing node. Whatever route is chosen, it will be necessary for market integration to proceed on a basis that does not jeopardise the deployment of the renewable and low carbon resources necessary to deliver Europe's ambitious decarbonisation objectives.

Harmonising Locational Signals and Transmission Charges

As suggested above, the extent to which locational signals are reflected in electricity markets varies across Europe. Most Member States do not apply locational signals although some, including Great Britain, Norway and Sweden, do. In addition, the recovery of transmission-related costs also varies considerably, notably in the allocation of transmission charges between generation and load. Table 1 (attached) highlights some of these differences among wholesale markets in Europe and North America.

These types of transmission pricing and cost allocation variations can create substantially different cost impacts on generators across Member States, and such differential treatment does not appear to systematically advance either market integration or decarbonisation objectives. For example, any generator sited in Germany, where no locational signals are applied and all use of system charges are allocated to demand, would have a significant advantage over generators sited in Scotland, which is currently exposed to locational transmission charges of up to £23/MW.

The avoidance of unnecessary cross-border trade distortions implies the need for a more harmonized approach to transmission charging and locational signals. A start in this direction was made in 2005 with the publication of Guidelines on Transmission

[29] Just how much additional transmission capacity will be required to accommodate intermittent technologies such as wind will depend on the specific circumstances. Locating a wind farm in an area already populated with wind or nuclear generation will require significant additional transmission capacity almost equal to the capacity of the new wind farm, as its output will be additional to that of existing plant. However, a new wind farm located in an area where conventional generation dominates may require little additional infrastructure, as wind and conventional generation can "share" existing transmission capacity.

Tariffication [30]which limit the range of charges that can be applied – although exceptions are permissible. Further progress is required however, particularly in terms of harmonizing the application of locational signals.

To this end, it seems more appropriate to rely consistently on implicit auctioning to address congestion—both internal and cross border—rather than layering market coupling onto disparate national approaches to use-of-system charges, which may or may not apply locational signals and often allocate charges to generation and demand quite differently. Applying market coupling principles to deal with internal congestion is referred to as "market splitting" as only one power exchange is involved. Market splitting works the same way as market coupling (via implicit auctioning) to reflect transmission congestion in energy prices and shares the same advantages over alternative congestion management approaches (see Section II and Annex 1, Figures 1a and 1b) .

Applying market splitting to address internal congestion could facilitate a move to flat (non-locational) transmission charging across all Member States, sending more consistent locational signals to both generation and demand. Still, for the reasons discussed above, the impacts of locational signals on the deployment of intermittent renewables should be carefully considered in the context of Europe's aggressive decarbonisation objectives. There are viable options for mitigating those locational impacts that can work well in tandem with the target model for market integration.

(c) Key Messages to Policy Makers/Regulators

- European policies for transmission pricing should take into account the potential implications for rapid deployment of intermittent renewable technologies and the cost of achieving decarbonisation objectives. Policies that superficially appear cost reflective and non-discriminatory, may not ultimately deliver the best outcome.

- The target model (market coupling) developed to manage interconnector congestion and facilitate cross border trade could result in significant price differentials opening up across Europe. The locational signals inherent in these

[30] ERGEG consultation on Transmission Tariffication Guidelines; see http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/Transmission%20Tarification%20Guidelines/CD/E05-PC-02-01a_INTRODUCTORY_NOTE_ERGEG_AMENDMENTS_GUIDELI.PDF

price differentials, reinforced by locational transmission pricing applied by some Member States, could significantly disadvantage intermittent renewable generation and thereby jeopardise Europe's ability to meet its renewables and carbon reduction targets

- Where intermittent renewable generation is effectively required to locate in specific areas, for example to ensure that areas of natural resource are fully exploited, it may be appropriate to differentiate between intermittent renewable generation that cannot respond to locational signals, and conventional or low-carbon technologies that can. Providing renewables with preferential transmission rights is one option; developing market coupling algorithms that take account of the carbon intensity of generation is another.

- Locational transmission charges applied at Member State level sit uncomfortably with the use of market coupling to manage interconnector congestion. As market integration will involve the increasing use of market coupling, a more consistent approach would be to use the same mechanism, i.e. market splitting, to manage internal network congestion and remove locational signals from Member State's transmission charges.

- Even where national transmission charges are not locational, differences in the level of charges and how they are allocated to generation and demand can lead to differential treatment of generators that do not advance either European market integration or decarbonisation objectives. Consideration should be given to harmonising the methodologies for determining the cost-basis for these charges and allocation principles in order to mitigate these distortions. This includes appropriately differentiating among generation technologies, based on the extent to which additional transmission capacity is required to accommodate their output.

(d) How and When Transmission Pricing/Locational Signals Will Be Addressed

Tariffication Framework Guidelines are scheduled to be developed during Q3 &Q4 2012, and the corresponding Code during 2013. (European Commission, 2011)

Applying Market Coupling (Splitting) Principles within Member States

Dealing with congestion and the application of locational signals within national boundaries is considered an issue for Member States. However the CACM Framework Guidelines do envisage that market coupling (splitting) principles may be applied within national boundaries to resolve congestion. It is also worth noting that Svenska Kraftnat will be splitting the Swedish market into four bidding areas as of November 2011, in line with commitments given to the European Commission.

Harmonising Use of System Charges and Locational Signals

In response to issues raised by stakeholders during the consultation on the Tariffication Guidelines, ERGEG (ACER's predecessor) noted the need to further harmonise generation charges and address the issue of locational signals.

Use of System Charges in the Context of Decarbonisation

On the Member State level, Ofgem's Project TransmiT will consider use-of-system charging in the context of national decarbonisation and renewable targets.[31]

3. Balancing and Settlement Arrangements

(a) Current Status.

As alternating electrical energy cannot be stored directly, generation and energy consumption need to be balanced on a continuous basis in order to ensure the integrity of the power system. "Balancing" is the process undertaken by system operators to ensure that differences between physical positions nominated by trading parties at market ("gate") closure and actual outturn, are reconciled. "Settlement" is the process of allocating the costs of balancing actions taken by system operators to individual system users.

Revised Guidelines of Good Practice for Electricity Balancing Markets Integration (GGP) were published by ERGEG in 2009[32] and Framework Guidelines are scheduled for development during 2011. While taking a pragmatic view in noting that complete

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[31] See Ofgem's Project TransmiT webpage at; http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx

[32] ERGEG Good Practice Guidelines for Electricity Market Balancing Markets Integration, see: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/New%20GGP%20Balancing%20Markets%20Integration/CD/E09-ENM-14-04_RevGGP-EBMI_2009-09-09.pdf

market harmonisation is not necessary to facilitate cross border trade, the GGP identifies gate closure timing, balancing product technical characteristics, balancing settlement and imbalance settlement as areas where harmonisation would be of most benefit in avoiding trade distortions.

(b) Potential Issues.

Balancing demand and generation output in a decarbonised European electricity market containing large amounts of intermittent renewable capacity will require a significant increase in short-term trading and balancing activity. Liquid intra-day markets will be required that allow market participants to adjust their contractual positions in response to short-term output forecasts, while liquid balancing arrangements will be required to allow the resolution of residual energy imbalances following gate closure. Effective settlement arrangements that both encourage trading parties to minimise energy imbalances and apportion the costs of reconciling residual imbalances appropriately will also be required.

As with transmission pricing and locational signals, taking a broader view of the impact of balancing and settlement arrangements on the deployment of intermittent renewable technologies and the costs of achieving decarbonisation on a European scale suggests that a more refined approach than cost reflectivity alone is justified. Consideration of these impacts is particularly relevant and appropriate in the context of the Renewables Directive. (See Section II.) The implications of fully exposing intermittent renewables to the costs of integration (mostly balancing costs) should be set against potential risks to deployment or need for increased market support (e.g., via FiTs or other investment support policies). Not differentiating between generation technologies in terms of balancing charges could disadvantage intermittent renewables as deployment progresses and technologies such as wind more frequently determine the direction of system imbalance, i.e. are increasingly on the wrong side of the balancing argument.

Several options for reflecting a broader set of objectives in the design of balancing and settlement arrangements are outlined below.

Balancing on an Aggregated Basis

Consideration should be given to allow renewable technologies such as wind to settle on an aggregated national or zonal basis rather than targeting imbalance charges on individual wind farms. This could be accomplished through comprehensive aggregation or by establishing a separate balancing market for wind. Permitting intermittent renewables to balance on an aggregated basis is consistent with the manner in which generation and demand are balanced on a system-wide basis, leaving aside the need to resolve congestion. Aggregated balancing would take advantage of geographic diversity to reduce the overall balancing charges to these resources. This approach could be readily accommodated as system operators are developing increasingly sophisticated national or regional forecasting tools for wind and other intermittent renewables.

Gate Closure Arrangements

A critical gate closure point is 3-4 hours out, when most conventional plant needs to synchronise. However there is considerable value in moving gate closure closer to real time in order to allow intermittent resources such as wind to more accurately forecast output. Therefore, the Framework Guidelines should advance the practice of moving gate closure as near to real time as possible. Consideration should also be given to creating a unique and separate gate closure time for wind. Allowing wind to flex its forecast output within "normal" gate closure timescales would recognise the particular characteristics of this resource and be helpful in terms of managing imbalance. Such measures are about to be considered in Great Britain via the Grid Code Panel.[33]

Imbalance Settlement

A number of Member States employ dual-price imbalance settlement, where different "cash-out" prices are applied to imbalances, depending on direction. Duel pricing can be symmetrical or asymmetrical.

Under dual pricing, a higher cash-out price is paid by resources that are in a "short" position and a lower price paid to resources that are" long", providing an additional incentive to balance. An example of *symmetrical* dual-pricing would be +/-10% of the actual costs incurred by the system operator. With *asymmetrical* cash-out prices, differentials can be particularly pronounced and unpredictable. For example, under the British Trading & Transmission Arrangements (BETTA), the cash-out prices charged for imbalances in the same direction as the aggregate imbalance are an average of the highest tranche of actual costs incurred by the system operator in resolving the imbalance. In contrast, the prices applied to imbalances that reduce aggregate imbalance (i.e. which are helpful) reflect the, typically much lower, short-term market price.

[33] See National Grid Code web page; http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/reviewpanelinfo/

Because the pricing differential under dual-pricing can be large and, in the case of asymmetrical pricing, unpredictable, this approach is particularly discriminatory against intermittent technologies and smaller players, which have little option but to trade in the imbalance market. Intermittent renewables are at a unique disadvantage under these pricing schemes because forecasting output is more difficult, particularly where market ("gate") closure is well in advance of real time. Therefore, they will regularly and unpredictably find themselves on either side of the aggregate imbalance. More generally, dual-pricing exposes those participating in the balancing market to the full costs of reducing the aggregate imbalance when they exacerbate it, but does not provide them access to their full value to the system when they reduce the aggregate imbalance.

Consideration should be given to advancing the alternative of a single-price imbalance settlement in the development of balancing Framework Guidelines and Code. Single-pricing based on the value of addressing system imbalances would be cost reflective, while still providing a strong incentive to balance. It would mitigate the disadvantages of dual-pricing to intermittent generation and enable all resources, including demand, to access the full value of "helpful" imbalances.

(c) Key Messages to Policy Makers/Regulators

- Designing balancing and settlement arrangements for an integrated European electricity market should take into consideration the potential impacts of these arrangements on Europe's ability to meet renewables and carbon reduction targets, as well on the total level of market support required to attract sufficient private investment in clean, intermittent resources.

- To this end, the forthcoming Framework Guidelines and Code should provide options that advance both integration and decarbonisation objectives for the European electricity market, including the following:

  - Balancing wind on an aggregated basis within national or zonal boundaries in order to take advantage of geographic diversity and reduce imbalance charges imposed on individual wind projects.

  - Moving gate closure as close to real time as is practical or creating a separate gate closure time for wind, in order to allow more accurate forecasting of output.

- Establishing a single cash-out price, in recognition that dual (and particularly asymmetrical) pricing does not provide either generation or demand-side resources with consistent access to the value of addressing system imbalances. Dual pricing also discriminates against intermittent generators such as wind and smaller players forced to trade in the imbalance market.

(d) How and When Balancing Issues Will Be Addressed

Development of balancing Framework Guidelines is scheduled for Q3 & Q4 2011. Code development is scheduled Q3/2013, with ACER evaluation in Q4 2013 and comitology in Q1 2014. (European Commission, 2011) Gate closure timing, balancing and imbalance settlement will likely be addressed in these forums. In addition, the Council of European Energy Regulators (CEER) recommends that the need (if any) for specific balancing arrangements for wind should be addressed when developing Framework Guidelines for balancing. (CEER, 2009)

4. Grid Connection Requirements

(a) Current Status

Grid connection was selected as a pilot to demonstrate the framework guidance, code development and comitology process. ACER's predecessor (ERGEG) issued draft pilot Framework Guidelines in July 2010 to inform and direct the pilot process. In parallel with finalisation of these guidelines, ENTSO-E has been developing a draft network code for the connection of generation (new and existing.)[34] ACER has recently circulated draft Grid Connection Framework Guidelines[35] ("Guidelines") for consultation, based on the earlier version developed by ERGEG.

The Guidelines require the development of network codes that set minimum requirements to be met by all system users, defined for each type of grid user, i.e. conventional, distributed or intermittent generation, demand or distribution system

[34] The latest draft Requirements for Grid Connection Applicable to all Generators can be viewed at https://www.entsoe.eu/fileadmin/user_upload/_library/news/110322_Pilot_Network_Code_Connections.pdf

[35] See http://www.energy-regulators.eu/portal/page/portal/ACER_HOME/Stakeholder_involvement/Public_consultatations/Open_Public_Consultations/PC-01_FG_El_Grid_Connection/Consultation_document/DFGC_2011E001_FG_Elec_GrConn.doc

operators (DSOs), together with the possibility of additional requirements being applied to specific grid users, where justified.

For generation, the Guidelines require the network code to set minimum requirements that would include the capability to operate within a particular voltage and frequency range, the provision of reactive power, load-frequency control, and to provide various balancing and other ancillary services. For demand, the requirements will address issues such as automatic low frequency and emergency demand response to system incidents.

We refer to these requirements generically as the "Connection Code" in our discussion below.

(b) Potential Issues

As a general observation, we note that the Guidelines are silent on the issue of grid "access" issues, such as timely connection, timescales for connection offers, among others. These issues are arguably as important as technical parameters for grid connection in terms of providing a level playing field for generation. There has been some indication (e.g., by ERGEG in response to comments on the draft pilot Framework Guidelines) that they will be addressed in a future network code, and we encourage their development.

In the following sections, we discuss issues that are specific to the Guidelines and Connection Code, as well as cross-cutting issues revealed through the pilot process that are generic to the development of all market integration guidelines and network codes.

Scope and Interface with National Codes

The pilot has identified a significant divergence in understanding over the intended scope of the Connection Code, and in particular, its interface with Member State grid codes. The Cross-Border Exchange Regulation described in Section II, echoed by the Pilot Framework Guidelines for connection issued by ERGEG[36], states that network codes should be developed for "cross-border network issues and market integration issues and without prejudice to the right of Member States to establish national codes which do not affect cross-border trade."[37] However, the draft Guidelines issued for consultation by ACER make no reference to this point, while the draft network code for

[36] See ERGEG document E10-PC-52 at; http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/Pilot_Framework_Guideline_Electricity_Grid_Connection/CD/E10-ENM-18-04_EGC-FG_7-Dec-2010.pdf

[37] Regulation 714/2009/EC, Article 8(7).

generation connection issued recently by ENTSO-E is very broadly based. Stakeholder[38] comments strongly suggest that the proposed generation connection network code extends beyond cross-border and related market integration issues, sets potentially onerous requirements that would result in a considerable amount of existing generation becoming non-compliant and would effectively replace national grid codes.

Considerable divergence has been observed in the detailed grid connection requirements of national codes (Fuentes J A, 2006) There are clearly advantages to greater harmonisation of these requirements so that similarly-situated resources face comparable connection costs and manufacturers do not need to customize equipment to meet multiple requirements across Europe. However, there are also important trade-offs if the harmonization process moves too far in the direction of "harmonization for harmonization's sake." In fact, excessive harmonization may prove counter-productive in many instances, due to the differing technical characteristics of individual national electricity systems. [39] It should be possible to meet the aims of the Cross-Border Exchange Regulation and still retain sufficient flexibility to accommodate these differences.

A reasonable balancing of these trade-offs, and one that seems fully consistent with the language of the Cross-Border Exchange Regulation, would be to focus harmonization efforts on technical parameters that *significantly* impact cross-border trade and related market integration issues rather than parameters that have little impact. In any case, the intended scope of the network code and interface with national grid codes will need to be clarified satisfactorily before moving forward with final European legislation on the Connection Code.

Requirements for Intermittent Generation, Demand and Distributed Generation

As described above, the Guidelines provide for development of minimum standards, defined for each type of user, which reflect technical prerequisites for grid connection—such as capability to operate within a particular voltage and frequency range. Where

[38] See, for example Eurelectric's response; http://www.energinorge.no/getfile.php/FILER/AKTUELT/INTERNASJONALT/Working%20draft_EURLECTRIC%20response%20to%20network%20code.pdf

[39] For example, UK/Ireland are connected to the rest of Europe via a dc connection and have quite different requirements in terms of frequency control and voltage requirements. In terms of frequency, the UK/Ireland have very coarse control and "harmonizing" these requirements across Europe would impact a range of operating and technical parameters, including reserve requirements and grid connection requirements such as low frequency relay settings and fault ride through. The range of frequency over which generation has to operate would also be quite different, as could be the power factor range required of generators (voltage capability. Black start requirements could also be quite different.

justified, additional requirements to those set out by the minimum standards will be specified in the Connection Code.

While potentially helpful in moving away from the one-size-fits-all approach of many national grid codes, there is a risk that unduly onerous, restrictive and expensive requirements could be placed on particular categories of resource. The challenge will be to develop these technical requirements in a manner that is proportionate and appropriately recognises the different capabilities[40] of different resources. Experience in developing and implementing connection codes in other parts of the world for intermittent generation, demand-response and distributed generation could provide useful, inclusive models for this purpose.[41] This also speaks to the need for adequate system user involvement in the Code development process, discussed below.

Member State and System User Involvement in Code Development

The role of ENTSO-E and individual national TSOs in developing detailed codes is crucial, given their unique technical expertise and system operator experience. However, an ENTSO-E/ TSO-dominated process, without adequate Member State and system user involvement at an early stage, has the potential to create unnecessary problems later in the process and produce a less than optimum outcome. The pilot Connection Code process has highlighted this possibility, with the publication of the draft network code for generation connection by ENTSO-E raising a number of significant concerns and reportedly an overwhelming number of individual comments.[42]

Ensuring that stakeholders have a formal role in the code development process and are actively involved from the outset should serve to avoid these issues in the future. Developing these codes at a European level may, of necessity, require a rather different governance process than the more inclusive arrangements adopted by Member States, due the increased number of interested parties. However, the formal and early involvement of system users in the process, properly represented by strong European

[40] For example the different capabilities of intermittent sources such as wind and solar in terms of providing system inertia.

[41] For example, the North American Reliability Council (NERC) has developed a standards development process that is open to all impacted parties and is designed to promote balance. Voting arrangements give industry sectors equal weight in the development of standards and no particular sector or interest group can dominate the process or veto proposals. Similar arrangements are adopted by the North American Energy standards Board (NAESB) for the development of business practices.

[42] The comments are not yet posted on the ENTSO-E website, but it has been reported to the authors that the number is staggering (on the order of 3000). .

trade associations capable of delivering a consensus view amongst their members, should result in the production of more balanced proposals, avoiding unnecessary problems at the comitology stages. Similarly, Member States should be brought into the development process for both Framework Guidelines and Codes well before the comitology process.

Mandates vs. Market Approaches to Service Delivery

Adopting a market-based approach for procuring services to meet Connection Code standards (wherever possible) has clear advantages as an alternative to mandating compliance. Competition between providers would reveal the real value of services, encourage innovation and develop alternative sources of provision, including demand side participation.

For example, rather than mandating that each generator provide a particular level of load-frequency control, an alternative would be to allow a generator to purchase those services from other generators. Alternatively, the provision of some services could be voluntary with the TSOs required to establish markets to procure the required level of service. System inertia[43] is a good example of a valuable service that could be market-based. Wind generation could provide this service to the system by installing state-of-the-art control systems. However system inertia could also be provided via frequency-sensitive or "dynamic" demand[44] and a market-based approach would minimise the overall costs of provision.

The final Framework Guidelines and associated Connection Codes should provide for market approaches to acquire ancillary and other services, wherever appropriate. Doing so would be consistent with the manner in which TSOs are directed to procure ancillary services such as reserve capacity via market-based procedures under Article 15(6) of Directive 2009/72/EC.

Retrospective Compliance

The Guidelines published by both ERGEG and ACER state that the Connection Code standards "shall" be applied to all generation, including existing generation subject to the outcome of a quantitative impact assessment. Retrospective application could

[43] System inertia describes the "stiffness" of the power system in responding to changes in frequency and can enhance the system value of other services, such as primary reserves.

[44] Frequency-sensitive or dynamic demand can be provided by fitting a device that consumes energy on a cyclic basis with a controller that monitors supply frequency and adjusts energy consumption accordingly. Large numbers of dynamic demand devices have the collective potential to increase system inertia considerably, reducing the need for fast-acting system reserves to be held on synchronised plant. To date, the application of this technology has been restricted mainly to refrigeration, but could be applied to a wide range of consumer or commercial demand.

impose considerable cost on some existing generators, raise issues of regulatory uncertainty and could arguably discourage investment at the margin. It would be preferable for retrospective compliance to be achieved through financial incentives--as is the case (for example) in Spain and Germany. At the very least, the full economic justification intended by the Guidelines should be demonstrated via independent cost-benefit analysis before requirements are retrospectively applied. The issue of retrospective compliance also underlines the importance of ensuring that stakeholders are formally and actively involved in the development of network codes.

Provision of Services at a System Level

There are examples in national grid codes where requirements are imposed on projects that could be more cost-effectively delivered at a "system" level through economies of scale. Before imposing technical requirements on individual generators, consideration should be given whether these requirements could be provided more economically through system investment. The provision of dynamic voltage control is one example, where TSOs may be able to provide necessary static var compensator (SVC)[45] capacity much more cost-effectively than requiring each individual projects to provide its own SVC capacity.

An allied point is the need to define requirements to be met by the system, as well as by system users and connected parties. Turning to system-level solutions to address the types of technical requirements discussed in the Guidelines is already contemplated under European law, specifically in the case of grid connections by renewable energy producers.[46] The final Framework Guidelines should provide guidance on these issues to ENSO-E and the TSOs in developing the Connection Code.

Evolution of European Codes

Some of the European Codes will be able to draw on established national grid codes, and will therefore be reasonably robust over time. Nonetheless, modifications to network codes in response to omissions or changing circumstances will undoubtedly be required. Currently, the process for modifying the Codes is not entirely clear.[47] Without further clarification, any modification to the Codes will likely require a lengthy process comparable to the timeline expected for developing the original Codes, e.g., of the

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[45] Static Var Compensator (SVC) refers to a static device user to produce the dynamic reactive output and voltage control necessary to maintain the integrity of the system during fault conditions.

[46] See Directive 2009/28/EC, Article 16, Sections 3 and 4.

[47] See CEER document "Implementing the 3rd Package – The Next steps". http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_ERGEG_PAPERS/Cross-Sectoral/2009/C09-GA-52-06a_Imlementing_3rdpackage_18-Jun-09.pdf

order of 12 to 36 months[48] to complete the drafting of Code modifications, to develop proposed legislation and obtain Member State approval.

Requiring that changes to any element of the adopted Codes be subject to this lengthy process may not be reasonable or necessary. Some Codes may be less prescriptive by nature, leaving greater room for voluntary agreement via a stakeholder governance process or modified by Member States within certain guidelines. These and other options for enabling the Codes to evolve in a reasonable and timely manner require further consideration and development.

(c) Key Messages to Policy makers/Regulators.

- The grid connection pilot has demonstrated the pivotal role of TSOs, through ENTSO-E, in developing Code requirements. It has also revealed the need for adequate and early involvement of both system users and Member States in order to avoid problems later in the process and help to ensure that requirements are proportionate and appropriate.

- The pilot has revealed significant inconsistencies between the draft Guidelines and Connection Codes being developed by ENTSO-E with respect to the scope and interface of European connection standards vis-à-vis national grid codes.

- The approach to harmonising national grid connection requirements in the development of the Connection Code should avoid imposing onerous technical requirements that add unnecessary cost and leave significant amounts of existing plant non-compliant. Any enhancement in technical requirements should be supported by independent cost-benefit justification.

- The Connection Code should be developed in a manner that appropriately recognises the different capabilities of different resources connecting to the system and the different technical characteristics of individual national or regional systems. Experience in developing and implementing connection standards in other parts of the world for intermittent generation, demand-

[48] Estimates based on an analysis of the timescales implied by the EC/ACER/ENTSO-E 3-Year draft Work Plan, February 2011.

response and distributed generation could provide useful models for this purpose.

- Focusing the development of minimum technical connection requirements on those parameters that *significantly* impact cross-border trade and related market integration issues would address concerns over the "reach" of the draft Connection Codes, mitigate the potential adverse impacts discussed above, and be fully consistent with the intent of the Cross-Border Exchange Regulation.

- The Guidelines and Connection Code should permit delivery of requirements through market-based arrangements, as an alternative to mandating technical requirements on each generator. They should also encourage system-level solutions, where doing so would be more cost-effective than requiring individual projects to meet technical standards.

- Retrospective application should be encouraged through financial incentives whenever possible. At the very least, mandatory retrospective application should be based on independent cost-benefit analysis.

- Harmonisation of the commercial arrangements for access to the grid and electricity markets are arguably as important as technical parameters to cross border trade and related market integration issues and should to be addressed in future Framework Guidelines and Codes.

- More thought should be given to the need to modify Codes over time, the level of Code detail to be included in legislation, and the types of Code revisions that could reasonably be left to an industry consultative processes or interpretation by individual Member States.

(d) How and When Grid Connection Issues Will Be Addressed

ACER's current consultation on its draft Framework Guidelines provides the opportunity address the grid connection issues described above. ACER's draft Guidelines were issued for comment on March 3, 2011. A draft Connection Code was published by ENTSO-E on March 22 and is expected to be finalised by the end of 2011. ACER evaluation will take place in Q1 2012, followed by comitology in Q2 2012 through Q1 2013. (European Commission, 2011)

IV. Conclusions and Next Steps

This paper highlights some of the key issues affecting the achievement of Europe's market integration and decarbonisation objectives that are being considered directly—or indirectly--through the development of Framework Guidelines and Codes at the EU level. We suggest a number of options for advancing these objectives in a complementary manner, but certainly more work is required to fully evaluate them and to develop for consideration additional or alternative options.

The active involvement of Member States and interested stakeholders will be critical to this effort. While ACER and ENTSO-E are the lead organisations tasked with the development of the Framework Guidelines and Codes required to support market integration, the delivery of successful and proportionate outcomes will be dependent on the active involvement of Member States, system users and other stakeholders in what will be highly time-constrained process.

There will also be need for close coordination between the market integration and decarbonisation agendas in order to ovoid outcomes that either close down, or are unable to accommodate, valid low carbon support mechanisms preferred by Member States. Furthermore, and notwithstanding the need to ensure system security and resilience, it will be necessary for Framework Guidelines and Codes to accommodate the particular circumstances and characteristics of the emerging generation technologies that will underpin electricity system decarbonisation. The delivery of Europe's decarbonisation targets and objectives will require market and operational mechanisms that complement these emerging technologies and that are sensitive to their particular economic and technical characteristics as well as locational constraints. Framework Guidelines and Codes will also need to be sufficiently flexible to accommodate genuine differences in the technical characteristics of individual Member State and regional systems, and to avoid harmonisation for harmonisation's sake.

The development of the grid Connection Code, which was chosen as a pilot to demonstrate the Framework Guidelines and Code process, and the CACM Framework Guidelines have highlighted a number of these issues relating to stakeholder involvement, decarbonisation and harmonisation. One lesson to be drawn from the work undertaken so far might be that Codes should restrict their attention to issues that *significantly* impact cross border trade and market integration and remain silent on issues of less significance. Some Codes, for example CACM, will need to be more prescriptive than others. However, Codes that articulate principles and are not unnecessarily detailed are likely to result in a smoother and less contentious process overall, be more robust in nature, and provide Member States the flexibility to customise requirements to their own circumstances.

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Table 1: Variations in Transmission Use-Of-System Charges

	Market Structure	Use of System Charges	Locational Signal
Ireland	Day-ahead mandatory pool	Capacity charge	No
Germany	Bilateral trading plus voluntary day-ahead power exchange (PX)	Demand pays 100% of shared network[49] costs, generation pays costs of ancillary services and losses	No
Great Britain	Unconstrained bilateral trading plus voluntary day-ahead (PX)	Generation pay 27% of shared network costs, demand 73%. Locational charge varies according to zone, charged on a capacity basis	Yes, via locational use of system charges
Norway	Part of Nordpool market, which includes Sweden, Finland & Denmark	Generators pay 33% of shared network costs, demand pays 67%. Shared network costs recovered by an energy charge, a capacity charge and a residual charge	Yes, energy charge based on marginal losses, capacity charge occurs when market splits due to congestion while residual charge is differentiated by location.
Sweden	As Norway	Generators pay 25% of shared network costs, demand 75%, which are recovered by capacity and energy charges.	Yes, capacity charge based on latitude, energy charges based on losses and differentiated by location.
PJM (US)	Mandatory wholesale energy and capacity pools.	Demand pays 100% of remaining[50] shared network costs via a capacity charge and usage charges arising from nodal pricing.	Yes, via locational marginal (nodal) pricing and deep[51] connection charging.
Spain	Bilateral trading with voluntary day-ahead and multi intra-day PX	Demand pays 100% of shared network costs	No

[49] "Shared" network costs: The cost of assets that are shared with other system users, and not unique to a particular user.

[50] Excluding the contribution to costs made by generators via "deep" connection charging – see footnote below.

[51] "Deep" connection charging: Where generators are require to pay all costs associated with their connection, i.e. including the cost of assets unique to their connection and shared assets. In the case of PJM, generators are required to pay all costs associated with ensuring that their capacity is available when required.

Annex 1. Market Coupling and the Implicit Auctioning of Interconnector Capacity

As discussed in the main body of the report, the Target Model for coupling national electricity markets envisages that forward energy trades across national boundaries will be facilitated by the explicit auctioning of interconnector capacity. At the day ahead and intra-day stages, remaining interconnector capacity together with that made available through "use it or sell it" (day ahead) and "use it or lose it" (intra-day) provisions, will be implicitly auctioned via a price coupling mechanism.

Figure 1 below presents a simplified, visual depiction of implicit auctioning under market coupling under circumstances where there is no transmission congestion, and when there is congestion. Implicit auctioning through price or market coupling requires each national power exchange to submit energy purchase and sales information to a central coupling algorithm, which will calculate flows between, and prices in, the individual coupled markets. Energy will flow from the market with the lowest energy price to markets with higher energy prices until either a single energy price is achieved (Figure 1a) or the interconnection capacity between markets is fully utilised (Figure 1b).

In either case, the price PA for the exporting Market A will be higher in the coupled market than if Market A were isolated (e.g., in Figure 1a the price increases from PA without a coupled market to PB'; in Figure 1b the price increases from PA to PA'). The converse holds true for the importing Market B (the price decreases).

Market coupling allocates interconnection capacity without the need for "explicit" auctions. In the absence of congestion, use of interconnection capacity is essentially "free". However, when the optimal flow across the interconnection exceeds available capacity, a congestion rent arises equal to the product of the flow across the interconnector and the price differential. As indicated in Figure 1b, energy is produced in Market A at a price PA', but flows across the interconnector and is sold in Market B at the higher energy price PB'. This creates a congestion rent equal to the product of the interconnector flow and the price differential (PB'-PA').

Market coupling requires cooperation between TSO and market operators, with the TSOs calculating interconnector capability and the market operators/power exchanges returning congestion rents to the TSO to either fund additional interconnection capacity or offset use-of-system charges. Harmonising the characteristics of coupled markets will facilitate cross border trading. However, as distinct from market splitting where a single power exchange is created and markets split only in the presence of congestion, market coupling allows the continued operation of separate national power exchanges and avoids the need for complete harmonisation.

Figure 1: Implicit Auctioning under Market Coupling

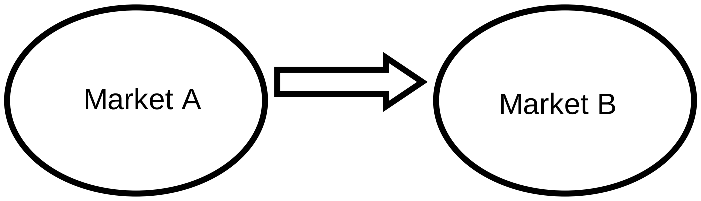
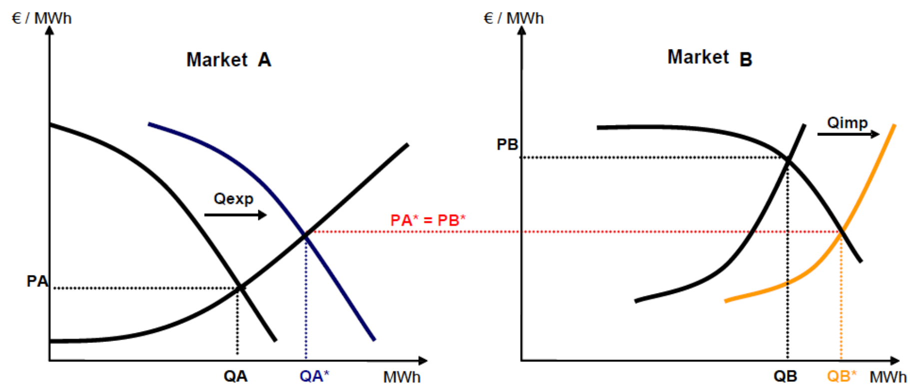


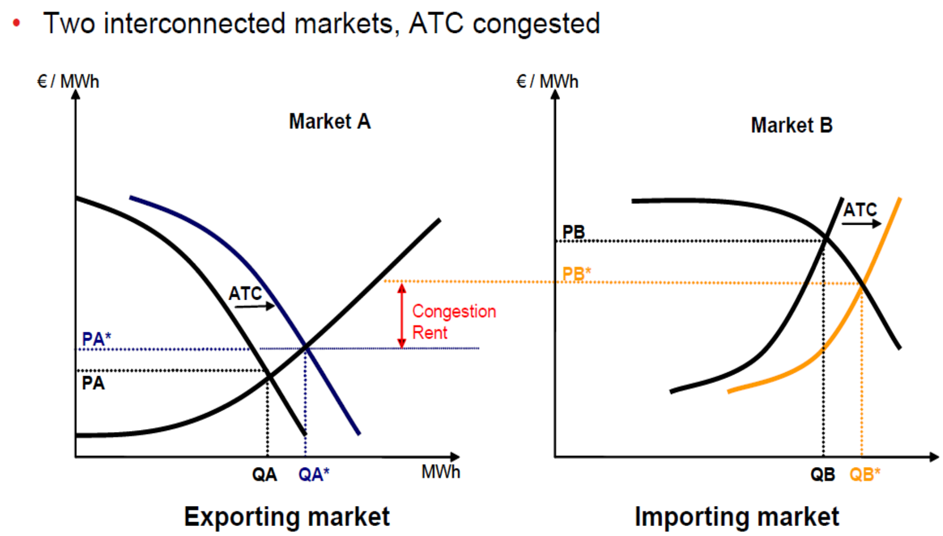
Figure 1a: (quantity of exports (Qexp) is unconstrained)

- Two interconnected markets, ATC non congested



Exporting Market **Importing Market**

Figure 1b: (ATC = available transmission capacity, constrains exports)



Annex 2. Support Mechanisms and Cross-Border Trade

Support mechanisms such as Feed- in-Tariffs (FiTs) and Renewables Obligations (RO), which reward qualifying generation on the basis of output, have been adopted in Europe to advance power sector decarbonisation and related climate and energy policies. They do, however, have the potential to influence energy prices and weaken wholesale energy market signals to generators to modify their operation in response to those prices. In circumstances where technologies such as wind become the marginal plant, output-based support mechanisms could drive energy prices into negative territory as generation attempts to retain access to subsidies based on output (or energy suppliers fulfill RO requirements). More generally, the incidence of near zero or even negative prices is likely to become more common as intermittent renewables and other clean resources with high capital costs and very low running costs enter the mix to meet Europe's renewables and carbon reduction targets. [52]

Whereas support mechanisms have evolved to meet national and European priorities and member states are presumably comfortable with the effects on energy price internally, the existence of differing designs having different effects on energy price could lead to distortions in

[52] A useful description of the impact of a growing decarbonized resource mix on wholesale electricity prices is presented in the Electricity Market Reform consultation document issued by the UK Department of Energy and Climate Change (December 2010). As noted in that discussion, output-based support mechanisms for renewables are not the only reason energy prices can actually become negative when the short-run marginal cost of generation is close to zero, i.e., nuclear generators would also tend to bid negative because instead of saving cost, turning off would incur additional costs and risks. The discussion also notes that negative pricing incentives associated with output-based support schemes could be limited by providing support based on availability (rather than output) or ensuring that support is not payable when prices are negative. See Box 6, page 60 of the consultation document, available at: http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx.

cross border trade. Many electricity markets designs also include mechanisms that reward capacity in order to ensure security of supply, either via capacity payments or contracts for reserve/peaking generation. As these capacity mechanisms also provide additional income over and above that obtained from energy sales, they therefore also have the potential to influence energy prices and therefore distort cross border trade.

A comprehensive review of how various output and capacity based support mechanisms could influence energy prices is beyond the scope of this paper. It is also beyond the scope to address the fundamental changes that meeting European renewables and carbon reduction targets will have on dispatch and investment signals from wholesale energy-only markets.   However, as discussed in the main body of the paper, European level guidance should encourage ways to both enable effective national and European policies that support deployment of low-carbon resources (including demand-side options) while promoting harmonisation rules that mitigate potential cross-border trade distortions. In this context, the remainder of this Annex considers two issues that might rise when a market that includes a capacity payment mechanism is coupled with a market that does not.   Firstly, the need to ensure that generation in receipt of capacity payments does not overly benefit from scarcity pricing in an adjacent "energy only" market and, secondly, whether the inability to reserve interconnector capacity may prevent generation in an "energy only" market from participating in a capacity auction in an adjacent market.

Ensuring that Generation in Receipt of Capacity Payments does not overly Benefit from Scarcity Pricing in an Adjacent Market.

In a well-conditioned, competitive market, fully rewarding generation for capacity costs should result in energy prices remaining close to marginal fuel price, even during periods of scarcity. With "energy-only" markets however, energy prices can be expected to rise above marginal fuel price when capacity is scarce as peaking plant is required to recover its fixed costs over a limited number of running hours.

During periods of scarcity, this divergence of energy price could distort cross border trade where markets that include capacity support mechanisms are coupled with markets that do not. Energy could conceivably flow from the market with capacity payments to the "energy only" market even though the marginal fuel cost may be lower in the "energy only" market. In effect, market coupling would result in generation in the market with capacity payments being paid twice for that capacity.   In practice, this problem may only occur occasionally as in competitive markets energy prices should remain close to marginal costs for the majority of time. However, divergences will occur when capacity is scarce and the effect could be expected to become more pronounced as wind generation deploys, and displaced conventional plant is increasingly forced to rely on price spikes during periods of scarcity to cover its fixed costs.

There are, however, mitigating measures available that should allow markets with different designs to be coupled effectively. For example, if cross border trades are to be considered “physically firm” then a generator in a market with capacity payments could contract bilaterally with demand in the "energy only" market, but would need to consider the possibility of having to buy in the local market in the event of plant unavailability. The firm nature of the trade would need to be taken into account in pricing the trade and this would act to harmonise prices.

For anonymous trading via a power exchange, a different approach would be required as all generation in the market with capacity payments would benefit from a higher cleared price due to exports to the “energy only” market. In this case a “contract for difference” approach could be adopted with capacity payments reduced to take account of the higher cleared price. This approach, which is illustrated below, would reduce the possibility of capacity being rewarded twice.

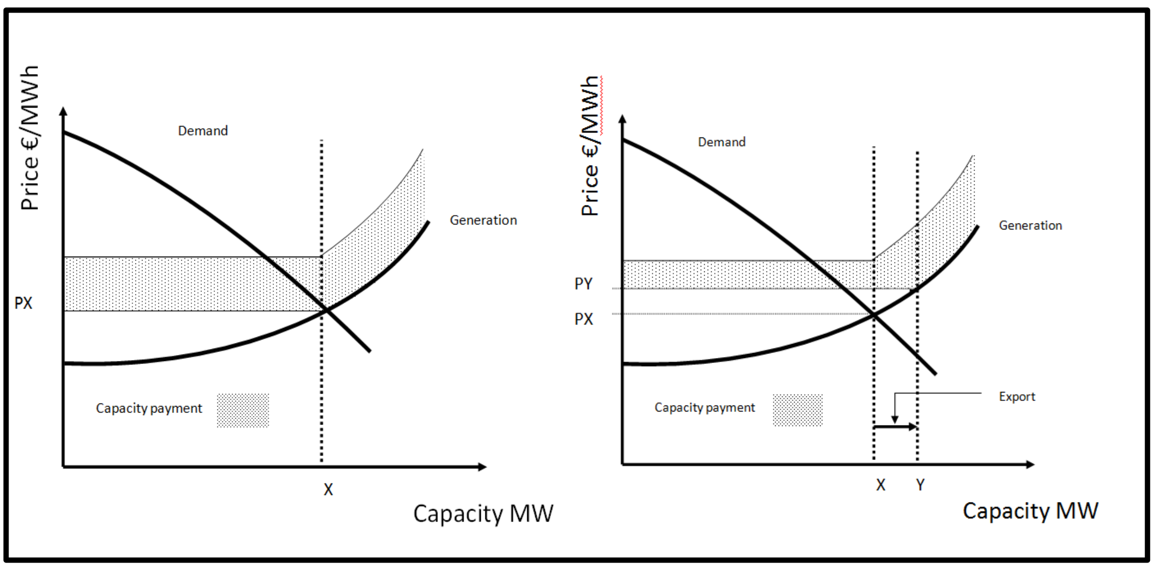


Figure A1 Figure A2

In Figure A1, the shaded area represents the additional income in terms of €/MWh of a capacity payment made to all plant declared available in market X. All capacity that clears the auction also receives the marginal energy price €PX/MWh. In figure A2, market X is coupled with “energy only” market Y, and exports ΔXY MW, resulting in an increased marginal price PY. If the market X capacity payment remained unchanged, generation in market X would receive additional capacity payments due to the “energy only” nature of market Y. In order to avoid this, capacity payments could be reduced by a €/MW amount equivalent to difference in marginal price PY-PX. It should be noted, however, that market X generation that did not clear in the uncoupled market but did clear in the coupled market, should have its capacity payment reduced by the difference between PY and bid price. Generation that did not clear in the coupled market should continue to receive the full capacity payment.

Does the Inability to Reserve Interconnector Capacity in the Day-ahead and Intra-day timeframes Prevent Generation from Participating in a Capacity Auction run by an Adjacent Electricity Market?

As discussed in Annex 1, the Target Model includes a "use-it-or-lose-it" requirement that interconnector capacity reserved in the forward markets be offered into the day-ahead implicit auction, unless a flow is nominated. As bids into a capacity auction (or other form of capacity payment mechanism) would normally be backed by firm interconnector capacity, the need to offer up this capacity at the day-ahead stage would, at first sight, appear to invalidate such bids or at least limit their usefulness on a temporal basis. This position, recently set out in Energy Market Reform consultation issued by the UK Government[53] may, however, not be entirely justified as contracted external generation capacity is capable of responding to externally driven events, for example a reduction in interconnector flow due to a fall-off in external wind output, or indeed to internal events up to the level of firm interconnector capacity.

Generation clearing a capacity auction would typically be required to offer that capacity at the day-ahead scheduling stage and to maintain availability until some nominated point in time before delivery. In a market coupling context, these requirements should ensure that an external capacity contribution up to full interconnector capability can be made, should this become necessary. If the generation in receipt of capacity payments successfully clears the day-ahead auction, it would be available into the intra-day stage to provide capacity or balancing services despite having given up its reserved interconnector capacity. If however the external generation in receipt of capacity payments is displaced at the day-ahead stage, then the replacement generation will provided the equivalent capacity across the interconnector. Effectively, the capacity payments are an "insurance policy" to ensure that the interconnector capability is backed by adequate external generation capacity. Only if the interconnector capacity was fully and consistently utilised due to market price differentials, i.e. the interconnector was consistently congested, would insurance become unnecessary and capacity payments to external generation be unjustified.

As an example, take a situation where an "energy only" market with wind capacity was interconnected to a "capacity payments" market. Say that 30% of maximum wind capacity was contacted bilaterally in the forwards market and interconnector capacity was reserved to support the trade. Some other interconnection capacity was reserved to support participation of conventional capacity in the adjoining system's capacity market.

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[53] See DECC EMR consultation, page 97, para:72. http://www.decc.gov.uk/Media/viewfile.ashx?FilePath=Consultations/emr/1041-electricity-market-reform-condoc.pdf&filetype=4&minwidth=true

At the day-ahead stage, wind output was forecast to be higher than the contacted amount and the offered conventional capacity in receipt of capacity payments was displaced by the additional forecast wind output. However, in real time, wind output was less than forecast and the external conventional resource was in the event required to contribute balancing energy.

External generation capacity can therefore contribute where external events cause a requirement for additional capacity or balancing contributions, as in the case of reduced interconnector flows due to fall-off in wind output referred to above. External generation can also respond to internal events, up to the level of firm interconnector capacity[54], provided that capacity is backed by capacity contracts. Internally contracted generation can, of course contribute to both internal and external events. However, external generation capacity up to the level of firm interconnector capacity, should be able to compete with local generation on equal terms in a forward capacity auction or other form of capacity payment mechanism, such as the targeted capacity approach proposed in the DECC consult paper.

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[54] Note that interconnector capacity is required to be firm. TSOs will be required to either withhold interconnector capacity to cover for secured contingencies or contract with local generation capacity.