Market Arrangements for Electricity – Margadh Aibhléise na hÉireann (MAE)

Interconnector Trading Principles

An MAE Consultation by the Commission for Energy Regulation Under S.I. 304 of 2003

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1. INTRODUCTION

1.1 S.I. 304

S.I. 304 of 2003 came into force on the 21st July 2003. The S.I. sets out Regulations establishing a new system of trading in electricity.[1]

This document contains a consultation paper by the Commission for Energy Regulation under Regulation 5(1) of S.I. No. 304 of 2003 – Electricity Regulation Act 1999 (Market Arrangements for Electricity) Regulations 2003.

S.I. 304 of 2003 states that the market shall "be a mandatory centralised pool ("the spot market") requiring all electricity exported to or imported from the transmission system or distribution system to be sold to and bought from the SMO."

The implementation of the MAE will require the revision of current interconnector trading arrangements. This consultation paper considers a number of options for interconnector trading.

Responses and comments regarding the various methodologies for interconnector trading should be submitted to the Commission by 5pm on **Friday 14th November 2003**.

1.2 IMPLEMENTATION OF MARKET ARRANGEMENTS FOR ELECTRICITY (MAE)

The MAE is a centralised wholesale electricity spot market. All electricity generated and consumed is cleared through this market.[2] Generators must sell all their electricity to the market and suppliers must purchase all their electricity from the market. The System and Market Operator (SMO) settles all trading in the spot market.

The market is solved simultaneously with dispatch. Dispatch is determined by considering all the system constraints: losses, transmission congestion, system security and reserves. Consequently prices will also take these factors into account. This method prices dispatch according to the technical, physical, and economic structure of the system. This approach helps ensure that market dispatch is physically feasible.[3] Thus, prices can vary by location as a result of losses and congestion in the network. This leads to separate Locational Marginal Prices (LMPs) rather than a single market-clearing price.

The introduction in Ireland of a centralised mandatory spot market and locational marginal pricing (LMP) will ultimately impact upon the

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[1] S.I. 304 is available at http://www.cer.ie/cerdocs/cer03178.pdf

[2] There may be some exceptions such as small generator units with output less than a defined threshold.

[3] While the SMO must make every effort to ensure the market solution is technically feasible, on some occasions the SMO may need to use reserves or other ancillary services to ensure system security.

interconnector as dispatch and LMP prices will be derived from participants price and quantity offers.

1.3 REVIEW OF INTERCONNECTOR TRADING PRINCIPLES

OFREG, the Northern Ireland regulator, is currently assessing whether it would be beneficial to Northern Ireland to integrate its market with the new centralised mandatory pool market in Ireland. If Northern Ireland were to adopt the same trading regime and form a single all-island market then, in principle, the need for interconnector trading between the two jurisdictions would disappear.

If Northern Ireland maintains its current market or chooses a different form of market to that of the MAE then there will be a need for rules to trade across the interconnector(s). Either way there will always be a requirement for a method of trading over interconnection, as the Moyle interconnector would remain a link with a different type of trading regime and additional interconnection could be built in the long run (for example, an East-West interconnector).

Therefore, the methodology needs to work for all forms of interconnection (both AC and HVDC[4]) and for differing characteristics of grid connection. It must also be flexible as additional interconnection could be added in the future.

[4] Refer to Appendix C for an explanation of these lines characteristics for the purpose of trading electricity.

2. EXISTING INTERCONNECTORS & TRADING

2.1 PHYSICAL INTERCONNECTION

This paper addresses interconnector principles relating to existing or potential interconnection between the MAE market in Ireland, and Northern Ireland, Scotland, England and Wales[5].

2.1.1 Ireland – Northern Ireland

There are three physical grid connections between Ireland and Northern Ireland.

The main interconnector between Ireland and Northern Ireland (North-South Interconnector[6]) connects Co. Louth to Tandragee in Co. Armagh. This interconnector is an Alternating Current (AC) link – electricity flows in one direction or the other according to demand and is generally not directly controllable by either jurisdiction's system operator. The capacity of this interconnection is 600 MW (two lines of 300 MW) in both directions. However, the available transfer capacity (ATC) of the interconnector is 300 MW in a North-South direction and 0 MW in a South-North Direction[7].

This interconnector is the only interconnector between the two jurisdictions that is currently used for trading. The two smaller interconnectors are 110 kV connections between Letterkenny in Co. Donegal and Strabane in Co. Tyrone and Corraclassy in Co. Cavan and Enniskillen in Co. Fermanagh respectively. These two interconnectors are stand-by interconnectors and are used for reactive support purposes in the event of a loss of both North-South interconnector lines.

2.1.2 Northern Ireland (All-Island)- Scotland

There is an interconnector between Northern Ireland and Scotland. This interconnector, known as the Moyle interconnector, is a High Voltage Direct Current (HVDC) and has a capacity of 500 MW (2 lines of 250 MW). The transfer capacity of this link is 450 MW due to constraints in Scotland. The power flow over a HVDC link, however, is more directly controllable by the operator of the link.

2.1.3 Ireland – Scotland/England/Wales

At present there is no direct interconnection between Ireland and Scotland, England or Wales. A number of studies have been made into the viability of such a proposal. In early 2003 the Commission initiated an economic study

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5 See Appendix A of this paper for further details of how interconnected markets function elsewhere.

6 The Louth-Tandragee interconnector will be referred to as the North-South interconnector for the remainder of the paper.

7 This difference is due to congestion on transmission lines south of the interconnector. The South-North ATC is 70 MW at night.

into ascertaining the need for a full feasibility study of interconnection between Ireland and Wales.[8]

2.2 CURRENT INTERCONNECTOR TRADING RULES

Arrangements for trading across the North-South interconnector have been in place since market opening, when the Commission and OFREG published proposals for trading across the Louth-Tandragee interconnector between Ireland and Northern Ireland.[9]

Capacity on the North-South interconnector is currently allocated to market participants through an explicit auction process[10]. Those participants allocated capacity gain the right to trade across the interconnector. Participants can also acquire short-term capacity two days in advance. Participants wishing to trade across the interconnector submit nominations to their respective TSOs.

The limited South-North transfer capacity, caused by increased load on the constrained network in Ireland, and the limited ATC of the interconnector in the other direction meant that the trading potential of the interconnector could not be maximised. To improve this situation, in April 2003, a scheme was introduced whereby nominations in opposite directions would be 'netted-off' against each other. This scheme is called superpositioning.[11]

The current arrangements also have two trades superimposed on top of the current market trading mechanism, as follows:

- marginal trading between system operators; and
- the export of the Ballylumford unit.

In addition, long-term interconnector capacity rights have been sold on the Moyle interconnector up to the year 2006.

How these issues are addressed needs to be considered when assessing interconnector trading principles.

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[8] This is referred to as an East-West Interconnector for the purposes of this paper. See Commission's report *Costs and Benefits of East-West Interconnection between Ireland and UK Electricity Systems* at http://www.cer.ie/cerdocs/cer03140.pdf for further details.

[9] For further information refer to the Commission's paper *Trading Across the Interconnector with Northern Ireland* at http://history.cer.ie/cer09909.pdf

[10] The reference for the current auction rules are as follows: Eirgrid Document details of - 'Invitation to bid South/North Interconnector Capacity 2003'

http://www.eirgrid.com/EirGridPortal/uploads/General%20Documents/210203Invite%20bid%2003.pdf

OFREG Consultation Paper - 'Interconnector Allocation Arrangements 2004-05'

http://ofreg.nics.gov.uk/pdf%20files/Interconnector%20Consult%20Pap%20July%2003.pdf

[11] In the event that this balancing flow exceeded the ATC some form of rationing would be applied to nominations. For details of interconnector nominations and the superpositioning process refer to *Trading & Settlement Code Agreed Procedure No. AP06: Interconnector Trading* at http://www.cer.ie/CERDocs/cer03089.pdf

3. NATURE OF INTERCONNECTED MARKETS

The nature of interconnector trading arrangements differs according to whether the interconnector connects two separate markets, as is presently the case with the North-South interconnector, or whether it connects two areas in the same market.

3.1 SINGLE MARKET – ALL-ISLAND MARKET

If a single market contains an interconnector[12], then trading arrangements are simplified. The interconnector is treated as any other line in the transmission network covered by the market. In this case, the interconnector is invisible to the market as any other transmission line and "trades"[13] and flows across it are seamless.

3.1.1 Energy Trading in a Single Market

Under this arrangement, those who wish to transfer energy across the interconnector simply offer generation at the appropriate generation node. When the market is cleared, the "trades across the interconnector" are simply a part and parcel of the generation dispatch as the market-clearing engine has no knowledge of the bilateral CfDs which have been arranged.

Therefore, generation units are dispatched according to the offers received and the constraints imposed by the transmission system and generators receive the LMP appropriate to their generation node. Consumers will pay the appropriate demand price; in the MAE, this is the Uniform Wholesale Spot Market Price.

3.1.2 Operating Reserves in a Single Market

By clearing the "trades" across the interconnector as an integral part of clearing the market, the scheduling and dispatch of operating reserves can also be carried out in a seamless manner through the co-optimisation process. Where, either for policy reasons or for system security reasons, there is a desire to restrict the amount of reserve transfer from one region to the other across the interconnector, this can be readily done as a part of the market clearing software.[14]

Because the reserves are co-optimised with the energy on both sides of the interconnector, the possibility of arbitrage of both energy and reserves prices across the interconnector may also be minimised.

3.1.3 Financial Transmission Rights in a Single Market

An FTR within a single electricity market is usually a point-to-point right between any two points or, possibly, between any two hubs, so there is no need to have an FTR specifically across the interconnector in addition to further FTRs from the interconnector to generation or demand nodes. The

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[12] Nordpool, New Zealand and Australia are examples of this.

[13] It is not really correct to refer to "trades across the interconnector" when the interconnector is included within a single market. However, we shall continue to do so for consistency with the other options.

[14] This is the approach currently taken in Australia.

interconnector is simply a line which crosses a boundary but is otherwise the same as any other line.

3.2 SEPARATE MARKETS

Where trading across an interconnector is to occur between different markets, the problem of determining the rules to facilitate that trading becomes more difficult.[15] Invariably, a special set of rules or agreements is required to regulate the inter-market trading.

The inter-market transfer rules tend to have a set of common components:

1. the transfer must be agreed by both System Operators or TSOs so as to ensure that neither system is placed in an insecure state as a result of the transfer;
2. the scheduling timescale of transfers are often longer than that for internal market transactions; and
3. each market applies its own internal market rules to the dispatch and pricing of the demand and/or generation units located within its jurisdiction which are involved in the transfer.[16]

Items 2 and 3 relate to the offering, scheduling dispatching and pricing processes of the transfers across the interconnector.

Section 4 deals with these issues and proposes options for trading across interconnectors.

Section 6 refers to the issue of interaction of different markets, or 'seams' issues, in greater detail.

[15] Even if the markets have the same rules, because they are clearing against different sets of offers on different, although congruent, transmission systems, they will not necessarily get the same set of prices at the interconnector.

[16] This is usually due to constraints on one jurisdiction applying its legal framework to another jurisdiction (e.g. Canadian Law versus US law)

4. INTERCONNECTOR TRADING PROPOSALS

4.1 INTERCONNECTOR RIGHTS & MAE DISPATCH

4.1.1 Price-based Dispatch at the Interconnector

The MAE is a centralised wholesale electricity spot market in which all electricity bought and sold.[17] Generators must sell all their electricity to the spot market and suppliers purchase all electricity they require from the spot market.

Dispatch is merit-order and is based upon generator or dispatchable demand quantity/price pairs subject to system constraints such as losses, transmission congestion, system security and reserves.

The principle of price-based dispatch will also apply to all energy entering or leaving the market via interconnection irrespective of rights to trade on the interconnector.

4.1.2 Rights to Trade across the Interconnector

Rights to trade across any interconnector may be *explicit* or *implicit*.

- *Implicit capacity rights* are rights that are conferred by way of successful dispatch by the MAE Market Clearing Engine for any trading period.

  In the MAE, when a generator/demand is dispatched it is implicitly given the right to use the transmission system. This *implicit capacity right* is conferred as result of its price/quantity offer being accepted by the SMO.

  The dispatched participant gains the right *as a result of* its financial offer being accepted by the SMO.[18]

- *Explicit capacity rights* refer to rights to guaranteed capacity (allocated or auctioned or owned) typically to support a physical supply contract across the interconnector. Holders of explicit capacity rights hold the rights to the physical capacity on the interconnector (this is akin to leasing or a form of rented 'right').

  In the present arrangements, explicit interconnector rights are conferred by auction for the period of a year.

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[18] Financial offers or implicit capacity rights to offer across interconnection should not be confused with Financial Transmission Rights (FTRs). FTRs confer on the owner of the right the financial benefit accruing to an allocated capacity of the line without conferring a right to physical capacity.

The introduction of the MAE will change how dispatch occurs at the MAE side of the interconnector. This may require a revision of what interconnector rights are conferred and the manner in which they are conferred.

4.1.3 Interconnector Rights Options

All three options presented are based on the principle that all energy is bought and sold in the MAE and is cleared in the MAE Market Clearing Engine (MCE)[19] i.e. that electricity coming across the interconnector will be based on economic dispatch. Principles governing interconnection with MAE will be discussed in section 5.

The **options** for the treatment of interconnection are as follows:

- Option 1: Economic Dispatch at the Interconnector (Implicit Rights only);
- Option 2: Economic Dispatch with Capacity Rights (Explicit Rights);
- Option 3: Economic Dispatch with Use-it-or-lose-it Capacity Rights (Explicit & Implicit Rights combined)

4.2 OPTION 1: ECONOMIC DISPATCH AT THE INTERCONNECTOR – NO EXPLICIT CAPACITY RIGHT

Electricity exported from the MAE to Northern Ireland is treated as demand in the Market Clearing Engine (MCE) by the SMO. Accepted demand offers confer an implicit interconnector capacity right on the participant whose demand offer was accepted (i.e. the demand at the interconnector node).

Energy imported into the MAE is treated in the MCE by the SMO as generation. Accepted generation offers confer an implicit interconnector capacity right on the participant whose generation offer was accepted.

Imports, or generation, at an interconnector node(s) will receive the LMP price. Accepted exports, or demand offers, will be treated as negative generation and pay the LMP price. This ensures that generation is scheduled and priced optimally in the MAE and demand that is importing from the MAE does not gain from or lose to, the averaging process that creates the Uniform Wholesale Spot Market Price.

For purpose of dispatch, this option treats the interconnector as any other node on the transmission system.

Advantages

- Dispatch is price-based which means that everyone competes on price and no participant gets preferential treatment.

[19] Refer to Appendix B for proposed procedures for offering in MAE across interconnection.

- Market participants can offer energy into the market at a very low price (e.g. zero or less), thereby increasing the likelihood of dispatch.[20]
- Market participants can purchase from the MAE if their offers are not accepted.

Disadvantage

- The current policy of auctioning long-term explicit capacity would be discontinued.

4.3 OPTION 2: ECONOMIC DISPATCH WITH EXPLICIT CAPACITY RIGHTS

In addition to implicit interconnector capacity rights gained as a result of accepted offers, actual explicit capacity on the interconnector could be auctioned or allocated.

This option combines two approaches:

- implicit rights which are derived from financial offers and are short-term in nature(e.g. a trading period); and
- explicit rights which are physical in terms of a 'right' and are generally longer term for a fixed period (e.g. a year_.

The holder of explicit capacity rights acquire the right to offer electricity into/from the MAE.

If the offer:

- to import (i.e. to generate and send into MAE) is above the Market Clearing Price; or
- if the offer to export (i.e. demand at the interconnector node) is below the Market Clearing Price;

The holder of the capacity right will not be dispatched, as the offer will not be accepted by the SMO.

However, in this option, the holder of the explicit right, may not be dispatched if their offer is not accepted and this will stop other participants from using interconnector capacity. In other words, the explicit right-holderif not dispatched does not release the capacity back into the market. This raises the issue of market power across the interconnector and the potential for capacity withholding.

However, the recent Regulation on Cross Border Tariffs[21] would suggest that the withdrawal of interconnector capacity is precluded. Article 6.4 of the regulation, which will come into effect in 2004 states:

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[20] Market participants might wish to do this, for example, if they had to fulfill a physical bilateral contract outside of the MAE.

> 'Market participants shall inform the transmission system operators concerned a reasonable time ahead of the relevant operational period whether they intend to use allocated capacity. Any allocated capacity that will not be used shall be reattributed to the market, in an open, transparent and non-discriminatory manner'

Advantage

- Market participants as holders of explicit capacity rights would gain preferential access to capacity.

Disadvantages

- Holders of explicit physical capacity rights would possess ability to effectively congest the interconnector to a much lower capacity than its physical capacity by either offering a very high price for dispatch or withholding some or all of their generation altogether they can effectively congest the line at a much lower capacity than its physical capacity. In so doing they could limit the supply of electricity into the market and limit the ability of competitors to get their supply to market.
- **This option may be contrary to forthcoming CBT Regulation.**

4.4 OPTION 3: ECONOMIC DISPATCH WITH USE-IT-OR-LOSE-IT CAPACITY RIGHTS

Again as in Option 1 and Option 2, dispatch would be based on merit order and, as in Option 2; explicit capacity rights would be auctioned/allocated.

As in Option 2 the capacity holder receives the right to offer into the MAE. However, these rights would be reallocated in the event that the explicit right-holder is not dispatched. This overcomes the difficulty of market power and the potential for capacity hoarding.

Advantages

- Dispatch would be price-based thereby everyone competes on price and no one gets preferential treatment.
- Market power on the interconnector would be reduced as a failure to be dispatched on the part of a explicit capacity holder would result in the holder losing that right.
- Market participants as holders of explicit rights would be guaranteed dispatch if the offer is accepted by the SMO.

The Commission invites comments on the three Options for interconnector trading discussed in this chapter.

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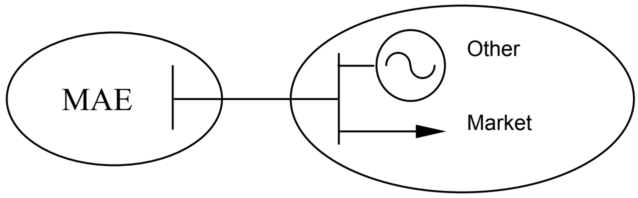
[21] Regulation (EEC) No 1228 of the European Parliament and of the Council on Conditions for Access to the Network for Cross-Border Exchanges in Electricity of June 26th 2003.

5. PROTOCOL BETWEEN MAE & A NET POOL MARKET[22]

In addition to rights to sell or buy from the MAE across the interconnector, there are a number of governance arrangements or principles that may need to be put in place if the MAE as a centralised or 'gross' pool is to trade with a decentralised or 'net' pool whether that is Northern Ireland, Scotland orEngland and Wales (NETA).

5.1 PROPOSAL: INTERCONNECTOR TRADING PROTOCOLS

The principles set out below relate to trading across any interconnection with the MAE irrespective of type of rights to the interconnector which



participants may hold.

As far as possible, the MAE sees participation from importing or exporting to the other market in the same way as it views an internal transaction with a few technical and institutional differences.

- Any trading across the interconnector is understood to be financial and not physical, in as much as a generator located in either market can meet its demand commitment by (effectively) purchasing from the MAE spot market. This means:
  - a generator in MAE that has contracted with demand in the other market must meet that (external) demand from generation based within MAE; and
  - a generator outside MAE that has contracted with demand located in the MAE need not be physically dispatched if it is more economic to let other generation be dispatched instead.
- Market participation needs to be extended so that:
  - market participants registered in the MAE will operate as normal for "inter-jurisdictional trading".
  - participants in the other market can operate in the MAE via a specially registered "boundary entity" that acts on their behalf.
    - the task of performing the boundary entity role could be performed by a System Operator or by another entity.
  - the boundary entity will offer external generation capacity into the MAE market as if it were a MAE generator located at the interconnector generation node.
  - the boundary entity acting for an external demand (exporting from MAE) must declare that demand to the SMO as a demand located at the interconnector demand node.

[22] This model is similar to that taken by the Ontario IMO for "inter-jurisdictional transfers".

- As shown above, the MAE market network model must define:

    - o market network nodes for both the near end and far end of the interconnector with the properties of the interconnector fully represented in the market network model.
    - o market network nodes are associated with the far-end node for the demand exported from MAE and for the generation imported by MAE across that interconnector with one market node.

- The MAE market is cleared using its normal methodology.
- The boundary entity is responsible to ensure its position is consistent with both markets.
- The transaction timetable (e.g., submission times, gate closure, etc) should ideally conform to both of the markets, although this is not essential. Some markets do operate with differing gate closures and dispatch periods in the two markets. However, the duration of the scheduled transfer is the same in each market.
- Reserve can be traded in an equivalent way, allowing participants to offer reserves into either market, or can be subject to a fixed supply / requirement protocol between the SMO/other market's TSO as is presently the case in Ireland.

The Commission invites comments on MAE-Interconnector trading protocols.

6. INTERCONNECTOR “SEAMS” ISSUES

1. Difficulties may occur across interconnectors between different markets, involving operational and economic inefficiencies as a result of transactions between markets with different rules and procedures. These types of problems are often collectively referred to as “seams” issues and directly impact the scheduling, dispatch and settlement of power flows across market borders. Seams issues can refer to differences in operating procedures, market timing protocols, and administrative definitions and practices.In terms of market operations, differences can include: the calculation of transmission capability (total and/or available), scheduling quantities (MWs) and operational characteristics (e.g., ramp rates), curtailment procedures to manage congestion, or the representation of proxy busses for external markets on the other side of the interconnections. A significant operational issue arises if there is a the lack of transparency of actual market operations and communication and coordination between system operators on either side of an interconnector.
2. Differences in market timing protocols can also pose a problem. Such issues include: the timing of market closing and/or the posting of prices, the frequency of transaction scheduling and the auctioning of transmission, generation capacity or related services.
3. Administrative differences between markets can also lead to barriers and inefficiencies. Differences in scheduling, bidding, and operating rules are examples of administrative seams, as are differences in the accounting and treatment of external capacity resources located on the other side of an interconnector.

Together these incompatibilities can introduce barriers to efficient trade between markets as well as inefficiencies within each market due to the disparate treatment of transactions and power flows. The persistence of these inefficiencies can have a material impact on the economic operations of markets by altering the signals sent to market participants and to system operators on both sides of an interconnection. Some of the potential impacts include:

- curtailment of economic transactions due to differences in congestion management procedures;
- lost revenue or increased expenses due to unaccounted for parallel path flows;
- increased market prices due to gaming opportunities;
- deceased opportunities to optimise between markets;
- increased time and expense of trading between markets

Over time the persistence of these problems can reduce market confidence and limit liquidity as well as risk management options.

Often the approach to resolving seams issues focuses on adopting similar market rules, or creating mechanisms to effectively bridge between differences in internal market rules as has been done with the existing markets in Ireland and Northern Ireland for example.

Another significant step in relieving seams issues lies in improved coordination between market operators and the transparency of market operations data and information. Improved information availability and data management between markets, and between markets and market participants, is vital for the assessment of seams problems and the development of practical remedies.

Seams issues, such as discussed above, are of considerable importance in a highly interconnected system such as the USA. This will be less of a case with interconnection with the MAE. Nevertheless this issue may prove important in the implementation of interconnector trading arrangements.

The Commission invites comments on interconnector 'seams' issues that may occur with interconnection to the MAE.

APPENDIX A: EXAMPLES OF INTERCONNECTOR TRADING ARRANGEMENTS

This appendix describes the trading arrangements across a number of interconnectors.

The first examples described consist of interconnectors which are embedded with a single market, although one of the examples describes interconnectors between different jurisdictions which have agreed to join a single market. This is followed by descriptions of the trading arrangements across interconnectors between different markets.

A.1 New Zealand Interconnector Trading

The interconnector in New Zealand consists of a HVDC link[23] which connects the North and South Islands of New Zealand. This link is operated in either a constant power mode in which the level of transfer is fixed, or in a frequency responsive mode, in which the required level of transfer is set but the HVDC is able to respond to frequency fluctuations in each island, allowing the transfer of operating reserves between the two islands.

Because the HVDC link does not connect different jurisdictions, it is an integral part of the New Zealand transmission system and is seen as such by the market. The market participants in each island offer generation or bid demand into the market and the optimal transfer across the link is automatically determined by the market clearing software which optimises the generation schedule on a national basis.

Because the interconnector is internal to the market, FTRs are not necessarily offered across the link but can be sold between a location in the North Island and a location in the South Island. Equally, if a participant wanted to hold a FTR between the terminals of the HVDC link, this would be possible.[24]

A.2 Australian Interconnector Trading

The interconnectors in Australia consist principally of AC links. Although some have HVDC links in parallel with the AC interconnectors, these HVDC links are not deemed to be interconnectors within the market rules.

Historically, each State in Australia had jurisdiction over its own electricity market until the introduction of the National Electricity Market (NEM) in 1998. The introduction of the NEM required each State to accept that they would be a part of a single market and to surrender jurisdiction to a national body, the National Electricity Code Administrator (NECA).

The NEM has each State, plus the Snowy River Hydro, as a separate region connected one to another by a "notional" interconnector, which is a simplified representation of the multiplicity of physical lines between the States. Each region has a single market-clearing price at a reference node.

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[23] See Appendix C for an explanation of AC and DC links.

[24] Note that a FTRs regime has been designed in New Zealand but has not yet been implemented.

The interconnectors join the reference nodes. The reference price is then spread to market nodes in that region by Transmission Loss Factors.

As in New Zealand, because each State is now a part of the single market, the interconnectors are an integral part of that market and the both the energy and operating reserve transfers across them are determined by the generation offers and demand bids cleared by the Market Clearing Engine and dispatched by the SMO.

However, the HVDC links which also interconnect regions are not dealt with as interconnectors in the market. Each of these HVDC links is deemed to be a Market Network Service Provider. These are entrepreneurial interconnectors who obtain revenue from trading in the wholesale NEM. With a minimum capacity of 30 MW, these interconnect two price regions and offer their capacity to transport power into the market through a bidding process similar to that used by generator operators. The transfer across the HVDC links are determined by the market clearing software as a set of coupled generation/demand dispatch instructions and the HVDC control systems are then used to set the dispatched level of transfer across each link.

A.3 Malaysia – Singapore Interconnector Trading

The interconnector between Malaysia and Singapore connects a Day Ahead plus balancing market (Malaysia) with a real time nodal market (Singapore). The "rules" governing the use of the interconnector are confidential and the subject of an inter-governmental agreement. However, the following information is available.

The Malaysia – Singapore interconnector is intended for the transfer of operating reserves between the two power systems to increase the power system security of each and is not used for energy trading purposes between the two countries. Because the interconnector is an AC link, the Malaysia and Singapore SMO must actively manage the balancing of generation and demand within their own power system such that the energy transfer across the link is minimised. Following the transfer of operating reserves across the link as a result of the tripping of a generation unit, the energy received is returned as soon as is practical, after which the policy of zero energy transfer resumes.

A.4 Ontario – United States ISO Interconnector Trading Arrangements [25]

Ontario has an electricity market which is similar in its design to that proposed for Ireland. In addition, there are a number of interconnectors between the province of Ontario (Canada) and neighbouring electricity markets. These are principally between Ontario and

- Manitoba (Canada) which does not have a LMP market;
- New York ISO, which has a LMP market;
- Michigan, which does not have a LMP electricity market; and

[25] This is well documented in IMO training material at http://www.theimo.com/imoweb/marketplaceTraining/cc_ijEnergyTrading.asp

- Minnesota, which does not have a LMP market

These interconnectors - known locally as interties - consist of primarily 230 - 765 kV AC lines. The Independent Market Operator (IMO) is the entity established to operate the Ontario electricity market.

Inter-regional trade is treated almost identically to participating purely within the Ontario market. Scheduled imports are treated like an internal generator with a supply curve at the interconnection point, and scheduled exports are treated like dispatchable demands with a demand curve at the interconnection point.

These generation and demand offers are added into the inputs used by the market algorithm during the pre-dispatch process. The market algorithm will determine which generation and demand offers are accepted and price an hourly schedule of interconnector transfers. Although generators and dispatchable demand within Ontario are dispatched on a 5-minute basis, the interconnector transfers are kept at the scheduled pre-dispatch level for the entire hour.

The IMO also takes into consideration the taxes applicable to various inter-regional trades and transfers.

A.5 United States Inter-ISO Interconnector Trading Arrangements

There are a number of Independent System Operators operating in the North Eastern area of the United States, principally New England, New York and PJM. Each of these uses a different form of market model, although all are based on some form of LMP. Each ISO's region is interconnected with its neighbouring ISOs and an emerging significant concern is how the trading over those interconnectors should be treated.

A.5.1 Current Arrangements

Pennsylvania New Jersey Maryland (PJM)

PJM shares significant AC interconnections with surrounding regions, some of which operate transparent markets and others that do not. Power can be imported/exported across these interconnections between PJM and surrounding regions based on generation schedules and transmission reservations submitted to the PJM Local Load Centre. The submission of bids and transmission reservations is subject to published protocols and is facilitated by PJM's use of various web-based electronic forms to simplify the process.

Transmission reservations are made through the PJM Open Access Same-time Information System (OASIS) and must specify a path, source, sink, and type of service (firm, non-firm, etc.). All external transaction requests, with the exception of import spot market transactions, require a confirmed transmission reservation from the PJM OASIS. PJM offers several transmission product types, such as hourly, daily, weekly, monthly, yearly, on and off-peak, non-firm, firm and network transmission. PJM also offers the opportunity to state whether or not the market participant is willing to pay congestion.

External generation with firm transmission service to PJM can be used to satisfy PJM Load Serving Entity reserve requirements.

New York

New York is interconnected with the organised markets in PJM, Ontario, and New England and with the Hydro Quebec system. The New York market is similar in many respects to PJM in terms of its treatment of interconnections and inter-regional trade. Transmission reservations can be made through the NYISO OASIS site and power transfers scheduled through the NYISO market operator.

A.5.2 Inter-market "Seams"

As discussed in section 6, seams issues are a particular problem that may occur across interconnectors between different regions.

In North America seams issues have taken on increasing importance over the past decade as regional markets have developed at their own pace and often with their own unique market rules and procedures. The North American market is a patchwork of both organised central markets at various stages of development and different market structures in proximity to traditional bilateral markets without transparent spot markets.

The increase in market transparency and data availability within centralised wholesale markets has drawn the attention of market operators and participants to the inefficiencies caused by seams. Some of the most significant progress in North America is being achieved by the more mature centralised markets in the Northeast: the PJM LLC, the New York ISO, and ISO New England. These three markets have studied the seams issues among their markets in considerable detail and are currently implementing an action plan to harmonise their market rules and procedures, creating a standard market design of the Northeast.[26] This market design will include: similar market interfaces for participants, similar transmission and transaction procedures, and greater coordination among market operators in congestion management and system planning. Eventually these markets may even move to develop and operate a common capacity market.

In addition to its work with the other centralised markets in the Northeast, PJM is also in the process of establishing seams related agreements and procedures with the Midwest ISO (MISO). This is a more difficult process in many ways since the MISO has yet to establish a centralised wholesale market and PJM is expected to soon have control area responsibilities for regions within MISO (Commonwealth Edison).[27] To deal with these issues PJM and MISO are developing a congestion management procedure to bridge the differences in market structure. PJM operates an LMP market while MISO is still functioning as a bilateral market. The current congestion management plan calls for the identification of flowgates within each market that are impacted by inter-regional dispatch as well as internal dispatch

[26] "Update on Northeast Seams Issues", FERC Commission Meeting, January 15, 2003. See: http://www.pjm.com.

[27] "PJM's Operations of the ComEd Control Area", Seams Update Congestion Management, Chicago, IL, August 13, 2003. See: http://www.pjm.com.

within the other market.[28] When the operational limits are exceeded on these flowgates the system operators will work together to determine the most economic approach to curtailing transactions in each market to relieve the congestion. The success of this approach relies on close and transparent communications between the two market operators.

In addition, to harmonise their market rules PJM, MISO and Southwest Power Pool (SPP) are developing a proposal that would result in a "joint and common wholesale energy market".[29]

These approaches to seams issues are intended to increase the efficiency of the electric system dispatch across regional control areas. They enable the market operators to achieve an interchange that is very similar to the results of operating two or more systems as a single market, with a coordinated dispatch.

A.6 (Former) England & Wales Pool Interconnection Arrangements with Scotland & France

Interconnection between the pool that operated in England & Wales between 1990 and 2001 and Scotland and France is a good example of how interconnector trading took place between a centralised mandatory pool (although the England and Wales Pool was not a constrained dispatch LMP market. Therefore it managed congestion by constraining plant) and other electricity systems.[30]

Capacity rights on the interconnectors between England and France, a 2000 MW HVDC-link, and England and Scotland, a 2,200 MW link, was divided into 10 tranches of capacity. These tranches varied in size and were known as Generation Trading Units for capacity rights used to import into the England & Wales (treated by the pool as generation) and as Demand Trading Units for capacity rights used to export from the England & Wales system.

Generation tranches or trading units were allocated to what were known as External Pool Members (EPM) in France and Scotland. In the case of France, EdF was allocated all 10 tranches. Tranches for Scotland were allocated to BNFL and Scottish Power.

EPMs were allocated one Demand Trading Block each. Only EPMs could purchase for the purpose of export.

Despite the allocation of capacity rights over the period of the pool, EPMs would only be dispatched if their offer price into the pool or from the pool was accepted.

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[28] "Managing Congestion To Address Seams: A Proposal for Congestion Management Coordination", PJM and MISO, Version 4.0, August 4, 2003. See: http://www.midwestiso.org.

[29] See http://www.miso-pjm-spp.com.

[30] For further information refer to the Pool's Interconnector Guidance Paper at http://www.elecpool.com/Sitemap/sitemap_f.html

The introduction of England & Wales' New Electricity Trading Arrangements (NETA) in 2001 has resulted in this process being replaced by interconnection capacity auctions on both interconnectors.

APPENDIX B: PROPOSED PROCEDURES FOR OFFERING IN THE MAE ACROSS THE INTERCONNECTOR

Particiapnts wishing to 'trade across' an interconnector with the MAE, under conditions of economic dispatch must use procedures that are in accordance with scheduling and dispatch timescales of both markets. The following is an example of what those procedures might resemble.

1. Boundary entities submit to SMO a schedule of demands in the other market for each half-hour up to 7 days in advance (for the week ahead predispatch it will be enough to start with standing data but this should be reviewed at least in time for the day-ahead predispatch.
2. All generators and boundary entities submit offer curves to the SMO according to the normal MAE requirements and timetable (i.e., standing offers, re-offers, gate closure etc.)
3. SMO prepares a predispatch run using all of its market data with including generation and demand attached to the interconnector nodes. A dispatch schedule is published according to standard procedures.
4. Boundary entity after reconciling its requirements in both markets submits re-offers in the MAE including, if necessary revising its demand estimate for imports into the MAE. Re-offering ceases at MAE gate closure. The final schedule is fixed and represents firm commitment by the SMO's in both jurisdictions to the corresponding flow on the interconnector.
5. MAE software determines a nodal price at the interconnector node(s) for exports from and imports to MAE.
6. Settlement within the MAE:
   - all contracts across the interconnector are CfDs and settled bilaterally outside the market;
   - all generation is paid at the respective generator nodes (including to the boundary entity importing at the interconnector generation node);
   - MAE demand pays at the uniform MAE selling price;
   - exports pay at their interconnector nodal price.
7. FTRs are available for hedging the basis risk between a generation MAE node (or MAE uniform selling price) and the interconnector nodes.

An earlier gate closure in the other jurisdiction can create a "seam" problem in MAE. The other jurisdiction might require that the interconnector flows be fixed at its gate closure. However, re-offering and pre-dispatch in MAE can then continue with the interconnector flow fixed. If the market subsequently settles at an interconnector nodal price below the offer price of the importing boundary entity it has been constrained on and would normally receive a constrained on payment. Naturally, if the importing boundary entity has not been dispatched and the MAE nodal price subsequently rises above entity's offer price it has no recourse in the MAE. These anomalies may be an unavoidable effect of different gate closure times. There is a risk of gaming around this anomaly.

APPENDIX C: NATURE OF PHYSICAL INTERCONNECTION

Interconnectors may be either AC or DC and the physical characteristics of the interconnector may have an impact on the nature of the trading arrangements.

Alternating Current (AC) Links

The main interconnector between the Ireland and Northern Ireland connecting Co. Louth to Tandragee in Co. Armagh is an Alternating Current (AC) link[31] – electricity flows both ways according to demand and is not directly controllable by either jurisdiction's system operator.

The energy flow in an AC line is (essentially) uncontrollable directly by the SMOs.[32] Instead, the flows are determined by the electrical characteristics of the transmission lines making up each and all interconnected markets, together with the magnitudes and location of the demand and generation. Where the interconnector is a single line between two markets (as is the case for the Lough-Tandragee interconnector[33]), the flow across it is determined by the net generation/demand balance in each market and is relatively easy to control.

The two smaller interconnectors are 110 kV connections between Letterkenny in Co. Donegal and Strabane in Co. Tyrone and Corraclassy in Co. Cavan and Enniskillen in Co. Fermanagh respectively. These interconnectors are stand-by interconnectors and are used for reserve purposes in the event of a loss of both North-South Interconnector lines.

Direct Current (DC) Links

The interconnector between Northern Ireland and Scotland, known as the Moyle interconnector, is High Voltage Direct Current (HVDC) and has a capacity of 500 MW (2 lines of 250 MW).[34]/[35] The power flow over a DC link, however, is directly controllable by the operator of the link.

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[31] The physical interconnection consists of three 220/275kV transformers in the Louth station, one 600 MVA unit and two parallel-connected 300 MVA units, connected to a double circuit 275 kV line from Louth to Tandragee.

[32] A degree of control can be imposed by the use of phase-shifting transformers. However, these usually have a limited effect and are generally used to balance the transfer over parallel paths to reduce undue congestion.

[33] Although there are two other interconnectors between the two jurisdictions, this interconnector is the only North-South interconnector that is currently used for trading.

[34] The Moyle interconnector cables operate at 250kV DC as two monopolar HVDC transmission systems rated at 250 MW per pole, thus providing 500MW transfer capability. Converter stations at each end convert the electricity from AC to DC for transmission along the cable and then back to AC again. Power can flow in either direction. For further information see http://www.soni.ltd.uk/interconnector_moyle.asp

[35] The capacity of the Moyle signifies the equivalent of the largest single unit on the island of Ireland. Northern Ireland and (Southern) Ireland share reserve on an all-island basis. As such, energy flowing into Northern Ireland on the Moyle often sets the reserve requirement in both jurisdictions.

The interconnector operator simply “dials up” the flow required and the HVDC converter control systems “produce” that flow in the link. Therefore, a further option is open to the operator of the DC link. The DC operator may be able to make coupled generation and demand offers at each end of the link into the markets which will then be cleared to produce a interconnector transfer schedule which is essentially independent of the transmission system characteristics and generation/demand patterns, other than the demand and generation balance.

Where the interconnector is enclosed within a single market, as they are in Australia and New Zealand, this operation of the DC link is of little consequence. When the DC link connects two markets, the principle advantage it has is that the transfer can be set as required by some *ex ante* agreement and the two markets then left to do their balancing of supply and demand separately; that is, one market can have a (slight) generation deficit and run at a lower frequency than the other without the interconnector attempting to equalise the generation and demand over both markets.