Some definitions and descriptions

An interconnector, in the case of electricity, is a cable or overhead line connecting two separate control areas each with its separate system operator. An interconnector has a Rated Capacity, which generally varies with ambient temperature and other conditions. Limitations on one or both of the two transmission networks with one or more interconnectors can cause Total Transfer Capacity, i.e. the maximum continuous programmed power exchange between two areas consistent with the safe operation of both interconnected systems, to fall short of the rated capacity of the interconnectors. Its estimation starts with a base case load flow analysis performed for a given scenario relating to a generation schedule and consumption pattern (and hence programmed exchanges) for all the interconnected networks. The Total Transfer Capacity in each direction between two areas is then computed by incrementing generation in one of them and decrementing generation in the other, ceteris paribus, until the security limits in one of the two systems or the interconnectors themselves are reached. Net Transfer Capacity can then be determined as lower than total transfer capacity by the amount of a Transmission Reliability Margin. This takes into account the many uncertainties afflicting the estimation of total transfer capacity. Available Transfer Capacity is Net Transfer Capacity less Already allocated capacity, the total amount of transmission rights that have been allocated. These definitions, which constitute important indicators for market participants planning cross-border transactions and for system operators to manage these exchanges, relate to programme values, not to physical flows. (ETSO 200100 a)

In the absence of any limitations in the transmission networks that they connect, DC interconnectors can operate at their rated power. Power flows over them are directly controlled by their interconnector operators, so being essentially independent of the nature of the transmission systems they link and their characteristics and patterns of generation and demand within them. They will never be subject to unforeseen increases of power flow due to the outage of system components. Export through a DC interconnector can be
treated as a pre-scheduled load in the exporting system and the import can be treated in the same way as a must-run generator in the importing system, each being the aggregate of exchanges notified in advance. In consequence, with a single DC interconnector, in contrast to AC systems, the physical transmission path is identical with the contract path and it is not necessary to reserve a capacity margin; its net transfer capacity equals its total transfer capacity.

AC interconnectors can only be used between the two systems with synchronous frequencies. Adjusted for losses, the physical flow over a single such interconnector equates with the equal and opposite load/generation balances in the two systems. This flow, like the flows over the transmission networks which it connects is determined in accordance with physical laws by the whole pattern of loads and generation in the two systems. If ex ante calculations of these flows show that they would infringe some security constraint, the correction required may alter the interconnector flow. It may, in any case, comprise inadvertent components unless both system operators successfully balance their systems.

**Costs and benefits**

**Their nature**

There is little to be said in general terms about estimating the cost of a proposed new interconnector. The uncertainties of cost estimation are the same as with many other kinds of large engineering project, but, except perhaps for uncertainties about obtaining the necessary planning permissions for possible routes, they are of the second order as compared with the uncertainties afflicting estimation of the benefits.

It will be necessary to identify any limitations in the connected networks that may require the interconnector’s total transfer capacity to be sometimes constrained to below its rated capacity. This involves finding the critical credible contingency, normally the fault outage of a line, transformer or generation unit outage, the consequence of which would require the flow into or from the interconnector to be reduced such that no security constraints are breached in the interconnected systems and on the interconnector itself.

---

1 Except for possible Flexible AC Transmission Systems, known as "FACTS"  
2 Brazil's Itaipu HVDC Transmission Project is the world's most impressive HVDC interconnector. It has a total rated power of 6300 MW and a world record voltage of ±600 kV DC. It provides an asynchronous connection between the 50 Hz 12,600 MW Itaipu hydropower plant and the 60 Hz network in São Paulo.
This is done by load flow studies, usually assuming peak load conditions. In the case of the North-South Irish interconnector, for example, at times of high load in the Dublin area, interconnector exports have to be constrained to ensure security in the event of a contingency occurring on that part of the Irish Republic’s transmission system. Reinforcement of the transmission capacity in the area from Dublin to the border would allow greater use of the interconnector at such times.

The cost of any augmentations to existing networks feeding into and out of an interconnector which are necessary to relieve any such constraint can be investigated. Augmentation can take various forms, not only upgrading lines and transformers but also the installation of reactive plant or devices which automatically reduce the power flow on the interconnector on detection of a specific event. The resulting extra benefits from the interconnector must be weighed against the cost of the augmentation.

The benefits from a new interconnector will comprise cost savings from one or more of the following:

- Deferral of investment in generation;
- Reduction in unserved energy (which can be valued at the value of lost load);
- Reduction in fuel and other variable operating costs (net of transmission and distribution losses) by substitution of cheaper generation for more expensive generation; and
- Reduction in the cost of frequency control, spinning reserve and other ancillary services costs.

In addition, further net benefits may be secured if an interconnector reduces the market power of generators in the importing area. One of the objectives of the Tasmania-Victoria interconnector, Basslink, for example was stated to be to introduce competition into electricity supply in Tasmania, enabling energy prices to be set by competition rather than regulation.

There will be gains and losses in producer and consumer surpluses if the net transfer capacity of an interconnector is sufficiently large for flows through it to have an influence on prices in either of the two systems. These will be additional to the benefits from reductions in fuel and other operating costs. A simple long-run static one-period theoretical model assuming fully competitive behaviour serves to illustrate the
relationship between these savings in fuel and other variable cost resulting from an interconnector and such changes in producer and consumer surplus.

Since total variable cost saving in both power systems from the introduction of an interconnector is the change in the areas under the rising marginal cost curves, producer surplus rises by A+B+C in the low-cost exporting system on the left and falls by D in the high-cost importing system on the right. Consumer surplus falls by A+B in the former and rises by D+E+F in the latter. Hence there is a net gain of C in the former and of E+F in the latter, together with some redistribution from consumers to producers and from producers to consumers respectively. This is in addition to the major gain accruing to the owners of the rights to use the interconnector, namely the import volume times the import price minus the export volume times the export price. However, in the extreme case of an interconnector large enough to wipe out any price difference in excess of transmission losses, the changes in consumer and producer surpluses would constitute the whole of the benefits revealed by such an analysis.

An appraisal of the costs and benefits of a proposed North Sea Interconnector between Norway, with predominantly hydro generation, and Britain, with predominantly thermal generation, provides an example of a case where changes in producer and consumer surplus would add considerably to the direct benefits to the owners of the rights to use the interconnector. (ECON Analyse, 2003) In wet years such an interconnector would add to total Norwegian export possibilities, so raising prices, while in dry years it
would extend the import possibilities, so reducing import costs; in other words there
would be a favourable terms of trade effect in some years. As regards daily variations on
the other hand, such an interconnector would add to Norway’s capability for export using
its hydro capacity, allowing it to earn more on peak power exports.

**Merchant interconnectors**

These are built for profit, their owners obtaining the difference between prices at
either end of the interconnector multiplied by the flow, whether or not they dispatch it
independently as can be done with a DC interconnector. In the short-run, if a merchant
interconnector had sufficient capacity to reduce the price difference to zero, its owners
would not gain from using it in this way. Instead, ignoring losses, they would equate
marginal cost at the injection terminal with marginal revenue at the delivery terminal.
Alternatively, they could offer capacity contracts to traders and generators, providing a
more secure income than the uncertain price differentials. As regards the initial
investment decision, the most profitable size is that which would equate the average gap
between this marginal cost and revenue with the marginal cost of capacity, whereas the
social optimum would be larger, equating the price gap with the marginal cost of capacity.

It has been suggested that any benefit from an interconnector which arises from
deferring other investment and from contributing to reliability is an externality, disregard
of which will lead to suboptimal investment in the absence of an agreement with the
system or transmission operator for a contribution to its revenue.

Against these arguments for private enterprise must be weighed the powerful
arguments that the transmission operators may be unenterprising; that the real choice may
lie between a merchant interconnector of lesser capacity than ideally desirable and no
interconnector at all. (Littlechikd, 2003)

**Appraisal methods**

Estimating the probable benefits from an interconnector is extremely complicated.
The steps of an appraisal are:

1. Establish possible competitor projects to the interconnection
2. Formulate a range of possible market development scenarios;
3. Undertake an economic analysis, under each of the market development scenarios,
of the interconnection, of any competitor interconnection projects and of one or

---

3 An interesting discussion is provided in Brunekreeft, 2003.
more base cases which exclude a new interconnection, consisting of planned and contemplated generation and other transmission schemes.

The first of these steps requires constructive thinking by engineers. Often, possible alternative projects will have been put forward by those proposing the interconnector under consideration.

Market development scenarios are distinguished from one another by the different assumptions they make about the future growth of demand in the two systems being interconnected, about future fuel prices and, sometimes, about future government environmental policy with respect to emissions and renewable energy.

The third step involves simulations of the operation of the two systems and the interconnector and its alternatives under each of the development scenarios, employing Monte Carlo methods or at least postulating a number of alternatives in order to examine the sensitivity of the results to, for example, the rate of load growth, generator forced outage rates, water availability (in a hydro system)\(^4\), fuel costs and capital costs. It may also be useful to take past data and calculate what use would have been made of the interconnector if it had existed. The simulations have to rest upon assumptions about pricing behaviour on the part of generators. This will not only directly determine the flows across the interconnector but also the amount and type of new entrants and the timing of the retirement of old plant, with longer-run consequences for the size of these flows.

The uncertainties afflicting such computations can obviously be very substantial. Looking forward over a series of years, from knowledge of the costs of new generating plants it may be possible to predict trend levels of prices at periods of high and low load — if prospective expansion of renewables capacity and the nature and effects of future emissions controls can be allowed for. However, the actual volume of interconnector use will depend upon actual prices in the two systems, and, as historical data demonstrate, daily and even hourly fluctuations around the trend can be very considerable, depending upon a host of transitory factors.

The analysis can therefore become very complicated, requiring the use of computational models to simulate dispatch and necessitating judgements to be made about the investment responses to future price developments. As an example of such

\(^4\) In Norway where power supplies are 99% water based, changes in precipitation can reduce the annual production of electrical energy by 20-30%
judgements, one study (Intelligent Energy Systems, 2000) postulated an annuitised entry cost for open and closed cycle gas turbine plants and assumed that new entry would occur when the time integral over a year of the excess of market price over fuel and operating costs sufficed to cover that annuitised cost for a typically sized plant. Allowance was made for the fact that in the event of demand exceeding capacity, so that load shedding would occur, the market price would be capped at a level determined by the regulator as the value of lost load. The calculations were performed for more than one discount rate.

The extent and complexity of the analysis will vary very much according to circumstances. In the case of a possible interconnector between the Republic of Ireland and Wales it has been estimated that a full-scale feasibility study would cost €8 to €10m. (DKM, 2003).

The simplest cases arise when the proposed interconnector would link a permanently high cost centrally planned system with a permanently low cost centrally planned system. It would allow immediate savings in fuel and other operating costs for production and/or for the provision of reserve, while in the long run the interconnector could be expected to substitute directly for capacity in the importing system if one-way flows were expected to continue to dominate.

When price differences across the interconnector are likely to change sign, diurnally, seasonally or permanently, altering the direction of flow across the interconnector, and when there is uncertainty about the pricing behaviour of competing and sometimes colluding generators, analysis becomes extremely complicated. Forecasting prices in one system is difficult enough; forecasts of price differences between them are even more uncertain.

Further complications can be caused by differences in the way the two electricity markets function and by the possibility of pooling reserves. In the case of the proposed North Sea Interconnector, for example, to meet the reserve requirements imposed by the possibility of extremely high peak demands in the Nordpool area, Statnett could avoid some of the heavy costs of contracting for demand reductions or for reserve capacity (provided by adding to generating capacity at hydro plants) by contracting for reserve capacity in Britain. This benefit would be additional to the major benefit resulting from reduced generation costs. These, in the case of interconnector between a predominantly hydro and a predominantly thermal system have two roots. One is that thermal generation can vary between wet and dry years inversely with the availability of water; the other arises when one system is capacity-constrained and the other is energy-constrained, the
former exporting off-peak, the latter on-peak. (Turvey and Anderson, 1977) Tasmania and Victoria provide another example. Hydrological risk represents the major electricity supply uncertainty in Tasmania, where storage constraints constrain the capability to provide increased energy generation, while installed capacity of 2,263 MW exceeds the system’s average long-term energy supply capability of about 1,105 MW, taking into account average water inflows. Most of generation in Victoria is from brown coal stations (Basslink Joint Advisory Panel, 2002)

The benefits to be gained from price differences across an interconnector may be divided into two parts in the case of the interconnection of two pools (whether net or gross): those arising from (i) the pre-gate-closure inter-system transactions of generators and suppliers, and (ii) cost savings in balancing transactions undertaken by closely collaborating system operators. The latter can scarcely be estimated in advance for a period of years, however elaborate the simulations carried out. Opportunities for them will arise for balancing transactions across the interconnector in either direction when it is not used to its net transfer capacity, and only in the opposite direction to the flow when it is. In the particular case of the proposed North Sea Interconnector, for example, the lower cost of upward regulation in the Norwegian hydro system compared with the higher level and the volatility of System Buy prices in Britain implied that there would be profits to be made from Norwegian supplying balancing energy in many hours each year.

**Interconnector utilisation**

**Approximating the ideal**

An optimal use of a link would be achieved if a single system operator scheduled operation and dispatched (in a gross pool) or redispatched (in a net pool5) both of the two

---

5 A pool can be called a "market" if prices are determined by it that equate supply and demand; in the absence of a pool a network of bilateral transactions and/or a power exchange constitute the market. In a gross pool, all generators sell and all suppliers buy all their energy through the pool; in a net pool they notify bilaterally contracted generation and sales and provide bids for generation increments and demand decrements and offers for generation decrements and demand increments. The operator of a day-ahead gross pool, but not of an hour-ahead one, can determine what plant is to run (unit commitment) as well as scheduling the outputs of those plants that will run. These outputs may subsequently be modified ("redispatched") in an hour-ahead market. In the absence of a day-ahead market the operator running a gross pool will dispatch the system or, if running a net pool with generator and supplier notification of their plans, will redispatch the system. It is possible for a market for operating reserves to operate in parallel with the energy market, these markets being cleared
systems linked by it. An example is provided by the interconnector between North Island and South Island in New Zealand. In such cases the resulting security-constrained optimisation of generation would determine optimal flows across the link, taking account of its rated capacity in just the same way as the rated capacity of all the other transmission lines. The optimisation would entail reviewing the acceptability of the possible effects of a number of plausible single or dual contingencies including both outages of the interconnector and outages of the transmission connected to it. Thus the total southward transfer capacity of New Zealand’s interconnector is little more than half its northbound capacity because, with southbound transmission, sufficient instantaneous reserve needs to be available to avoid a risk of cascade failure of the South Island grid in the event of an interconnector failure and such reserve is both expensive to provide and limited in quantity.

We now consider how to approximate these results as well as possible, concentrating on the case of a single interconnector linking two separate systems with separate control areas, each with its system operator. We consider solutions which fall short of establishing some kind of combined day- or hour-ahead market run jointly by the different system operators. Studies have been made of how this might be achieved in the North East United States. (LECG, LLC and KEMA Consulting, Inc, 2001)

The problems of designing good arrangements are fewer with a DC interconnector than with an AC interconnector. Paired generation and demand offers into the markets at each end of the interconnector made by participants within the net transfer capacity of the interconnector, if accepted by or on behalf of both of the two system operators, would produce a firm interconnector transfer schedule before gate-closure. They would then achieve balancing separately. The net transfer capacity of the interconnector may, as already noted, be determined as falling short of its rated capacity both on account of transmission constraints in one or other of the systems it connects and by the amount of a simultaneous to minimise the total cost of meeting demand in these markets. In all cases real-time "balancing" or "regulation" instructions will have to be given by the system operator.

Another example is that although the Moyle interconnector between Northern Ireland and Scotland has a rated capacity of 500 MW (2 lines of 250 MW), the transfer capacity of this link is 450 MW due to constraints in Scotland. Again, interconnection capability southward from Scotland was increased to 2200MW by completion of the Cleveland to North Yorkshire Line. Such limitations below rated capacity of an interconnector depend on the design of its associated controls, the state of the power system at each end, including the system load at a particular time, and the direction of power flow. Capability may change with time in accordance with changes in the operating state of the transmission network at each end.
transmission reliability margin. If the flows on the transmission system of either of them regularly infringed the net transfer capacity limit, it should be reduced; if it did so only under occasional circumstances that system operator could allow for it in the same way as for any other must-run generation or unmodifiable demand which causes problems.

With a single AC interconnector, the problems of designing arrangements to accommodate planned energy transfers and post gate-closure deviations from them, are similar, though the flow across the interconnector cannot be directly decided by the system operators as it is a result of the whole pattern of generation injections and demand withdrawals within both of their systems. In all cases, of course, the net flow across the interconnector at any point of time equals the excess of generation over demand and losses in the exporting system, which will exceed the excess of demand and losses over generation in the importing system by the amount of interconnector losses.

The simplest case

To ensure that congestion on their interconnector is dealt with, the two system operators have to co-operate in some way. The most limited but simplest type of co-operation occurs when market participants do not undertake cross interconnector transactions and, as in the case of the Malaysia–Singapore AC interconnector, the two system operators use the interconnector only to economise on fast reserves. Each independently seeks to balance its own system, so that the only flows across the interconnector are inadvertent. (CER, 2003) Interconnector flows arising as the result of such contingencies as the sudden outage of an important generating unit are thus a result of pooled reserves. In the case of a DC interconnector, where flows are determined by system operators and ramp rate constraints may apply, there could be an arrangement whereby the energy taken is returned later in a scheduled transfer, so that no monetary transactions are involved.

With closer co-operation, but still without market participants undertaking cross interconnector transactions, the system operators could engage in cross-interconnector economy transactions, sharing out resulting cost savings.

An interconnector power flow that is acceptable under steady state operation may cause unacceptable overloads or voltage deviations in the event of a credible contingency, and it may be necessary to operate at lower power flow levels in anticipation of a contingency event. This is consistent with standard operating practice for a transmission grid, where loads under normal operation are not permitted to exceed load levels that could not be accommodated in the event of a credible contingency occurring.
Such limited relationships clearly miss out on all the savings and efficiencies which planned energy transfers resulting from cross-interconnector transactions by market participants could achieve. (Commission for Energy Regulation, 2003) For such more ambitious arrangements, mutually consistent pre-gate-closure procedures have to be designed. The two major problems that have to be solved in designing them are as follows:

1. Ensuring that both or neither of the system operators accept each cross-interconnector bid/offer pair or injection/withdrawal notification put forward by market participants.
2. Ensuring that the acceptances fit within the market participants’ rights to use the interconnector and, in aggregate, do not exceed net transfer capacity.

Note that a further problem with unit commitment processes running simultaneously but separately is the inefficiency, arising from the lack of any mechanism for the system operators to coordinate day ahead commitment and scheduling so as to minimise the joint cost of meeting reserve requirements. Ideally this requires simultaneous joint optimisation of generation and reserve provision. A simpler procedure is to set aside a fraction of interconnector net transfer capacity to allow for some reserve sharing.

1. Matching trades across the interconnector

Consider two systems, each with an independently functioning system operator which receives bids and offers for each hour or half-hour either to inject and withdraw, or to provide increments and decrements from notified bilateral trades. Some of these bids and offers and notified trades will be inter-system, i.e. cross-border, trades. Taking account of security constraints, each system operator can then act to produce an ex ante balance of total generation plus any net imports with total demand including any net exports, allowing for losses and transmission constraints.

Such a process would require the same gate closure time in the two systems and agreement about the net transfer capacity of the interconnector, but does not necessarily require each system to have the same kind of trading arrangements. Thus one could have a gross pool into which all generation and demand is bid and offered, while the other could have a net pool with bids and offers for increments and decrements from notified bilateral trades. They could have their own arrangements for dealing with imbalances and their calculations could take account of dynamic constraints and block bids.
A net export or import schedule could be produced by each system operator to show how the aggregate cross-border flow would vary with market price in its system. The two system operators could then share information about these schedules, starting an iterative process to combine ex ante balance within each system with matched aggregate import and export volumes falling within the capability of the interconnector, taking account of security constraints.

Even if such co-operation can secure an aggregate balance of exports and imports, unmatched acceptances by the two system operators of individual market participants’ imports and exports will be a problem. Participants will be exposed to risk. Thus take the case of a generator in A selling to a supply business or consumer, or anonymously to a market, in B

- With day ahead unit commitment and scheduling it may get scheduled to generate but not to deliver, or vice versa, if either its generation bid or its delivery offer is priced too high. It may then subsequently find that it subsequently gets an unfavourable market price if it seeks to offset and so undo the half-trade, for example by selling the generation in its own market if it has not received a matched delivery acceptance in the other. Alternatively it can accept the risk of paying a balancing charge in one system and receiving a balancing price in the other.

- Otherwise, to ensure acceptance in both system operators’ unit commitment and scheduling processes it could simply nominate the amount of energy it wishes to generate and deliver, or bid and offer extremely low prices. But the prices determined independently in the two day-ahead markets may turn out to be such as to make the transaction unprofitable, while undoing it by later counter-transactions in the two markets may equally entail a loss.

- Without a day ahead market, and so with self commitment, the risks from bidding in one market and offering in the other are similar. Prices may be unfavourable or failure to match will lead to imbalance charges which may entail a loss. This risk will be less if both markets are highly liquid, for then a participant can be fairly confident that he will pay the going price in his home market and receive the going price in the other market.
Arbitrage transactions for a generator to profit from temporary or short-term price differences across an interconnector can thus be risky; the same holds for pure traders. But if a generator in A has a longer term arrangement including a contract for differences with a supply business or consumer in B, the net cost to the customer will be the strike price agreed in that contract and this will also be the revenue to the generator. If, on the other hand, there is a net pool in B, one of them can nominate the amount of the customer’s energy offtake and the price will be as agreed.

The conclusion is that some of the price risks can be hedged under gross pools which settle prices that clear the market in both systems and that they can be avoided if they have similar net pool arrangements where generation and offtake nominations are accepted and honoured. However, trading can be much more difficult where the two systems have different types of market, as, for example, in Ireland. (NERA, 2003) But that is not all. Cross interconnector trades also involve a risk that the interconnector capacity required by a trade will not be available or that an excessive price will have to be paid for it.

2 Transmission rights

The second problem which arises, even when import and export trades are matched individually (and, in consequence, aggregatively), is the management of congestion on the interconnector. It constitutes a problem even if the interconnector is wholly owned by the owner of one of the two transmission systems and its system operator treats the far end in the other control area as one of its transmission nodes. The possibility remains that the nominations for planned matched export and import trades across it could exceed its net transfer capacity.

Administered allocation

Ascertaining demands for interconnector transfers and then scaling them all down in the same proportion to fit the agreed net transfer capacity is one administrative method. Another is to allocate capacity on a first come first served basis. Enforcement is much easier with a DC interconnector. Both methods have been used and both are clearly inferior in principle to allocations which make some use of price signals. These signals may relate to charges for using the interconnector or to price differences across the interconnector. However in the extremely complex case of multiple interconnectors between multiple control areas, as exist in continental Europe, administrative methods
have sometimes had to be used pending development and acceptance of multilateral price-reflective methods.

Implicit rights

1. Market arrangements
2. et flow equal to the net transfer capacity (allowing for losses).
3. By differences in market clearing prices, “market splitting”. Differences in such prices between the two systems ensure that, allowing for losses, the excess of accepted bids over offers in the one market and the excess of accepted offers over bids in the other both equal the net transfer capacity of the interconnector. Congestion then results in higher day and hour ahead prices at the importing end of the interconnector than at its exporting end.

Redispatching through counter purchases is usually done after gate closure as part of system operators’ balancing operations, just as they deal with transmission constraints that are internal to their systems. The market arrangements under which they do this may differ between the two control areas; one or both may not produce market clearing prices. Market splitting, on the other hand, requires a common market mechanism. If this includes a day ahead mechanism, appropriate unit commitment decisions can be made, whereas the time for that is past closer to and after gate-closure. Differences in market clearing prices can therefore produce a more economical way of constraining interconnector flows, besides conveying appropriate incentives for the location of generation and demand.

Redispatching imposes a net cost upon the two system operators, since what the one pays on accepting bids to increase generation on the import side of the interconnector will exceed what the other receives on offers accepted to reduce generation on the export side. Some arrangement for agreeing the net cost of the counterflow transactions and sharing them is needed. This cost can be recovered either through uplift charges or by levying a transmission use of system charge on inter-area transactions. In the latter case, the tariff could be levied to recover actual costs estimated ex post, or calculated ex ante on the basis of simulation studies, under or over recovery being allowed for and carried forward.

Split markets, in contrast with redispatching, require that prices clear the market in both systems. They result in a net revenue from the interconnector, equal to the price difference times the net flow across it, accruing to the owners of rights to use the
interconnector. (The institution of financial transmission rights is a subject discussed below.) Where the market clearing prices are determined in a gross pool, they can either be uniform within each control area or vary between nodes, reflecting both transmission losses and internal transmission constraints. Such Locational Marginal Prices, determined using optimal power flow methods, are used in parts of the United States and, for generation, in the Republic of Ireland. Each terminal of the interconnector constitutes a node for which a price is determined as part of the dispatch process. All transmission use, not merely interconnector use, is thus priced and financial transmission rights can be used for all parts of the system where there is congestion.

**Financial Transmission rights**

Where market prices in each area are determined so as to ensure that planned flows between them do not exceed the net transfer capacity of the interconnector, congestion will result in price differences which can produce a revenue surplus. The flow across the interconnector will be worth more at one end that at the other. Rights to this revenue can be sold to market participants who wish to sell in one of the markets and buy or generate in the other. They will thus be able to acquire hedges against the price differences and the transmission owner can be remunerated by the sale of these rights. The rights can be of varying terms, perhaps sold in auctions or traded in a secondary market.

**Physical rights**

Physical rights which market participants have to own in order to trade across an interconnector constitute an alternative to market coupling along either of the above lines. They are feasible when there is but a single interconnector. Rights owners scheduling bilaterals can submit transactions between control areas that have to be accepted in both markets.

In total they obviously have to add up to no more than the net transfer capacity of the interconnector. There has to be a scheme for imposing any emergency curtailments that prove necessary and an accompanying set of physical ramping rights for each control area. Also, their total has to be adjusted when rated capacity changes seasonally between winter and summer. As was explained above, the extent to which net transfer capacity falls short of total transfer capacity may vary through time, depending upon changes in the availability of different parts of the two transmission networks and upon alterations in the geographical patterns of demand and generation. The forecasts jointly made by the
system operators will gradually become firmer until the time for unit commitment and scheduling arrives and net transfer capacity is definitively announced — by 07:00hrs one day ahead in the case of the French-English interconnector.

However rights are initially awarded, an efficient secondary market can ensure that they come into the hands of participants most willing to pay for them and, indeed, in most cases, rights are transferable. Physical rights may initially be awarded to whoever has provided the equity finance for the construction of an interconnector, they can subsequently decide whether and how they wish to use or sell them. Otherwise all or some of the rights can be auctioned, including rights which have not been sold under long-term contracts and rights not sold through previous auctions. Auctions, which are not especially complicated where there is but a single link, can be pay as bid or can apply a market clearing price; a use it or lose it rule is common.

Rights can be for different durations, in either direction and interruptible or not. In the interests of preserving competition there may be a maximum limit on the capacity any one participant may acquire. A balance must be struck between the presence of certainty in the market, achieved by rights of a longer duration, and short term trading which enhances competition. Yet new supplier entrants will want some security and hence prefer longer contracts. Uncertainty about the future market system in the connected countries will make participants want contracts of shorter duration.

An example of auctioned rights is provided by the Moyle interconnector, a 500MW cable link between Scotland and Northern Ireland.

The 2003/04 auction was conducted via a multi-stage process. The available interconnector capacity was divided into equal amounts over two separate auctions held seven days apart. Any unsold capacity in the first auction became available in the second iteration (by the same product type). The process left open the possibility of a third, or residual auction if the auction did not clear in round two. A pay-as-bid rule applied to the auctions. The multi-stage approach was decided upon to allow bidders the opportunity to correct/reassess their bids following the disclosure of the average price bid in the first iteration. A time period of one week was given between the first and second iterations to allow bidders to revisit their bidding strategy and reassess the market. 1.8 Products of 3, 2 and 1 year duration were auctioned, along with an interruptible product. Three-year capacity, auctioned the previous year, was still in place thereby reducing the total amount of capacity available for auction. (OFREG, 2003)
Rights to use the French-English interconnector are auctioned annually, periodically and one day ahead, different categories of use it or lose it capacity rights being put up for auction under a pay as bid system. Each category is characterised by its direction, England→France or France→England, and by its duration, multiple Contract Years, one Contract Year, a season or one or more Contract Days. The amount put up for sale consists of a predetermined amount plus capacity left unsold from longer-term auctions. Capacity rights in both directions are auctioned on a non-firm basis, with users directly responsible for any trading consequences as a result of changes to interconnector capacity. Thus they are sold on the basis of a target level of availability (100% for day-ahead sales) with rebates paid by the system operators or additional capacity payments paid by users depending on whether the actual availability exceeds or falls short of the target. The rights apply at mid-Channel, with 2.34% allowed for losses, which must be taken account of by users in their nominations and their contracts in both countries.

Owners of rights for one year or more can transfer them in either of two ways. Firstly, they can reassign all or part of them to another user for one or more calendar months. (They must still pay the Operators for the reassigned capacity but, of course, can recover their payments from their counter party. Secondly, if they do not intend to use their capacity they can ask National Grid and RTE to reallocate that capacity to another user in annual, periodic and (two-days-ahead) daily auctions after previously unallocated capacity has been auctioned but before capacity lost under the use-it-or-lose-it rule is auctioned. Again, they are still required to pay for their capacity but, if the reallocation capacity is sold will receive the auction proceeds, less a fixed fee (initially nil) and adjusted for curtailment reconciliation payments. Furthermore, to the extent that users indicate that capacity will be unused, and subject to outages, the system operators will make the capacity available in the daily auction.

How well can a physical rights arrangement secure economic efficiency in scheduling and dispatch? Users of the French-English interconnector with rights longer than a day must give the system operators two days’ notice of their intended level of use of the Interconnector (taking into account reassignment, reallocation, contract volumes and bids/offers). This allows unused rights to be made available in the daily auction, but does introduce a certain rigidity. However this is recognised; National Grid and RTE are seeking to develop a collaborative procedure to facilitate bids and offers being made in the respective balancing mechanisms of England & Wales and France. For a bid or offer
from a user to be accepted in one market, the system operator concerned will need the
consent of the other. (National Grid Company, 2003, paragraph 2.4.)

**Superpositioning**

Where there are interconnector use rights in both directions, it becomes possible
for the larger of the two opposing sets of trades to exceed net transfer capacity by the
amount of the smaller set of trades. Such netting off against each other of nominations in
opposite directions is known as superpositioning. Without it, trades in the minority
direction at times of congestion would result in an uneconomic underutilisation of the
interconnector. If auctions for each of the two directions of flow are conducted
simultaneously, the netting off can be a result of the auction. But, whether or not rights
are auctioned or otherwise allocated, firm rights in excess of capacity in the majority
direction can only be granted if trades in the opposite direction are firm, that is to say that
they are obligations. If they are only options, but are subject to use it or lose it terms, a
day-before auction, or resale by the interconnector administrator may allow the rights to
be transferred to another market participant who will use them. With easy transferability
of the rights, transfer by means of a bilateral contract may also be possible. Otherwise any
excessive rights will have to be interruptible, their exercise being contingent upon the
rights in the minority direction being actually utilised.

If the exercise of physical rights requires participants to submit a fixed
transmission schedule a day or more in advance, transferability will be enhanced.
However if participants want to transfer an energy flow which varies through the day,
thus making available excessive rights which vary oppositely through the day, both
netting off and transfer of excesses may prove too complicated, so that rights can be
exercised only in respect of blocks of energy. In the case of the French-English
interconnector, where the minimum duration of rights is one day but Users may wish to
vary their usage through the course of the day, superposition capacity is currently
not made available.

**Transmission charges**

Access to a facility whose capacity is limited can, in principle, be regulated by
imposing charges for its use which limit the demand. Such charges for use of an
interconnector, would have to be fixed in advance in order to influence market
participants’ behaviour appropriately. This is scarcely practicable when price differences
across the interconnector are not fairly stable. Charges fixed well in advance for extended
periods at levels which would prevent demand from exceeding net transfer capacity at time of potential maximum flow, would obviously lead to gross underutilisation of the interconnector at other times.

Circumstances could exist in which the total transfer capacity and hence the net transfer capacity of an interconnector could be varied at a short run marginal cost. These would arise if, firstly, there was congestion on the part of a transmission system that feeds or takes from an interconnector and, secondly, this congestion could be ameliorated by redispatching. The system operator could then accommodate larger interconnector transfers and should levy a charge reflecting the marginal cost of the redispatching upon all trades in the dominant direction. 7

**Post Gate-closure**

Forced outages, demand forecast errors, deviations of generator output from schedules, and within the hour economic commitment/decommitment of fast start resources or dispatchable loads collectively can cause deviations from schedule. Some of these real-time developments may, if not offset, raise flows across the interconnector above its net transfer capacity or lower that capacity. In either case a counterflow is needed: a reduction of generation in the exporting system and an increase in the importing system. This requires joint or co-ordinated real-time action by the two system operators.

Even when arrangements to such action have been in place by the two system operators, all the possible savings that would be achieved if a single operator dispatched or redispatched both systems linked may not be achieved. It could well happen that there would be times when the interconnector was not congested but the real-time market clearing prices differed between each end of it. Post gate-closure arbitrage to take advantage of the possible production cost savings thus available being impossible or limited for market participants, taking full advantage of them would require even closer collaboration between the two system operators to conduct such arbitrage operations. It would involve adjustment of interchange schedules by the ISOs in real-time, to enable

7 The scope for such action will be much higher when there are multiple interconnectors linking two control areas, for then congestion on them is compatible with some of them operating at less than capacity and redispatching can raise the overall net transfer capacity. The French transmission owner, RTE, does in fact compute such congestion costs and levies them ex post upon the supplementary "commercial" capacity thus made available.
lower cost production that is available in one system to serve the load in the other system.8

The French-English interconnector.

The Interconnector "gate closure" is day-ahead, whilst NETA gate closure is 1 hour ahead. At present, the continental markets mostly co-ordinate their international power exchanges day-ahead and the Interconnector daily auction timescales were designed for compatibility with this. The capacity not previously sold in the longer-term auctions and capacity not required is auctioned, with pay as bid. One would expect the prices for transmission rights paid in these auctions to reflect price differences one day ahead, and this has tended to be the case. Because capacity is auctioned for a whole day but users may vary their use during a day, when it is expected that France will export for part of the day and import for part of it too, capacity in both directions will have a value. Higher auction prices are marked for France→England rights when English day-ahead base load prices are higher in relation to day-ahead base load prices on the French power exchange Powernext, and conversely for England→France. When pressure on the interconnector’s capacity is foreseen, as for example for January 2nd 2004, France→England export capacity was fully nominated throughout and the daily auction price was as high as €42.77 per MW/day. The day-ahead base price of €44.3 in England and Wales much exceeded the corresponding price in France of €27.3. There were no import nominations and no import capacity was sold for this day and others like it. For January 7th 2004, in contrast with January 2nd, day-ahead base prices were higher in France than in England; French export nominations were low and were exceeded by import nominations, so that the net flow was England→France. However, the day-ahead nominations frequently fall short of the interconnector’s capacity.

In the absence of congestion9, the interconnector’s full 2000MW capacity being available for flows in the dominant direction10, there have been many such occasions

---

8 Such collaboration has been termed Virtual Regional Dispatch and has been discussed in ISO New England, Inc. and New York ISO, Inc., May 2003.
9 When internal constraints in the French transmission system limit the Available Transmission Capacity of the interconnector, Supplementary Commercial Capacity may be provided by the French system operator constraining some plant on and other plant off. The costs that this incurs are recovered from users of the interconnector as a congestion charge. (RTE, 2004)
10 Superposition of rights in the two directions is ruled out. Superpositioning is the netting off of the use of rights in the minority direction against those in the majority direction. The rights in the minority direction must be exercised, i.e. they must be obligations, not options. The two sets of rights must relate to coincident periods.
when nominations were made in opposing directions, the net flow being the difference between the larger and the smaller opposing sums of nominations. The following diagram shows how, for three days in November 2003, day ahead rights in both directions were used most of the time, except for the peak evening hours. During these hours, when prices rose sharply, both on the French Powernext exchange and in England, nominations almost fully utilised the interconnector to send power from France to England, even though French day-ahead prices were lower than English. Otherwise, the relation between the direction of the price difference and the direction of nominations corresponds to expectations.

Statistics for the whole of 2003 showed that for France→England flows valued by the price difference, negative value flows amounted to as much as 60% of the positive value flows. Regression of hourly flows against price differences showed only a very weak relationship in the expected direction from low to higher prices. (Frontier Economics & Consentec, 2004, Appendix A3) This is very different from what would be expected according to the theoretical construct introduced above in the discussion of costs and benefits. On days with no capacity congestion, prices in the two markets would differ
only by the cost, including the 2.34% losses, of using the interconnector. But in practice, imperfect foresight and transaction costs make a difference. UKPX prices (here shown as an hourly average of two half-hourly prices) and Powernext prices are fixed the day before, and nominations are made in advance of real time. Users pay transmission use of system charges.

**Multiple interconnectors**

When there are several interconnectors providing meshed links between several control areas, the actual power flows in all of them, in accordance with physical laws, depend upon the configuration of all their transmission systems and upon the power injected and withdrawn at all nodes. The different control areas, each with an independent system operator, may have different market systems. In Europe there is a continent-wide meshed system of 24 countries with synchronised frequency. It consists of some 200,000 km of 400 and 220 kV lines, hundreds of generating stations directly linked to the system, and thousands of substations. In a planning phase, the European Transmission System Operators organisation annually estimates indicative transfer capacities for a typical winter and a typical summer peak period according to recent observed states of the power system. Subsequently, with revisions as the time-frame shortens, operators determine allowable transactions between adjacent areas bilaterally, in almost all cases, separately from the energy market, by undertaking load flow analyses which take as given the patterns of generation and consumption elsewhere. The ways in which transmission rights are allocated vary. In determining their totals between adjacent areas, margins have to be allowed because of uncertainty regarding those patterns; in any case, where the transfer capacity estimates differ between a pair of systems, the lower figure of the two is adopted. System operators, who have no direct control over the interconnector flows, then have to balance their systems, while ensuring that security constraints are observed. The resulting pattern of physical flows across borders will not, in general, coincide with the cross-border commercial exchanges notified by the possessors of cross-border transmission rights. “In fact, it is very common on the UCTE system to have a significant ‘border flow’ in one direction, while the ‘border exchange’ is in the other direction.” (ETSO, 2004)

These arrangements are decidedly sub-optimal. Three possible market solutions which might achieve co-ordination which would ensure an efficient security-constrained dispatch have therefore been discussed. The first two were mentioned above in the context of interconnection between only two control areas. The problems in a multilateral context
are similar but very much more complex. Increased generation in one control area matched by increased demand in another will have impacts upon flows in other control areas and across other borders as well.

1. Market splitting (EuroPEX, 2003) Net or gross pools or power exchanges on both sides equate generation plus imports with demand including exports so as to limit imports and exports to the net interconnection transfer capacities across borders. Thus whenever net transfer capacity is fully used, prices will differ between control areas, reflecting this interconnector congestion.

2. Flowgate auctions (ETSO, 2001 b): Co-ordinated auctioning of rights to inject power in one control area and withdraw power in another, the amount of rights awarded being determined as part of the auction process so as to take into account all cross border security constraints.

3. Co-ordinated Re-dispatching Cost +. Charges for cross-border transit reflect the cost of the co-ordinated redispatching necessary to limit imports and exports to the net transfer capacity of interconnections

All three would require ETSO, the European Transmission System Operators organisation, to play an important role, including computation of transfer capacities, for which data on line capacities in the European system, together with assumptions or forecasts of injections and withdrawals at all nodes are necessary.

Net border transfer capacities fall short of the sum of the rated capacities of the interconnectors linking control areas for three reasons. Firstly, they provide security by allowing for n-1 contingencies; secondly, when one line reaches its limits the others may not be fully loaded; thirdly, some of the capacity may be set aside to allow the systems to share reserve capacity.11

In practice, it is suggested that the computations should be simplified by limiting the analysis to a simplified system in which the nodes within each control area are treated as though they constituted a single node and the only transmission lines taken into account are the interconnectors between control areas. Thus the location of loads and generation within each control area are implicitly taken as given. However changes within

---

11 3000 MW of primary frequency response is shared among Union pour la Coordination du Transport de l'Électricité (UCTE) members proportionately to each control area’s annual energy output; sharing of secondary response is bilaterally agreed between some pairs of control areas.
the total will alter flows across the interconnectors. There are therefore two reasons why actual flows may exceed the calculated flows, in some cases breaching the security constraints:

i) The nodal distribution of loads and generation within control areas differs from what was assumed.

ii) The aggregate of loads and generation within a control area differs from what was assumed. Even when the forecast is recent, this can occur because of unplanned generation or transmission outages or because weather conditions were imperfectly foreseen.

On the continent of Europe, the international auctioning of rights or price determination under market splitting would have to be done well in advance of real time, possibly with market closure on the day ahead. It is therefore necessary to consider how divergences of either type (i) or (ii) could be dealt with, for some of them would increase interconnector flow levels above the transfer capacities auctioned or price-rationed. One or more of the system operators of the interconnected control areas would have to undertake counter-purchases and sales before gate closure\(^ {12} \) (through bilateral contracts or, if there is one, a short-term power exchange) and, after gate closure, through whatever balancing mechanism is used in their control areas. How often and how many such actions would become necessary would depend upon the conservatism with which the amount of rights to be auctioned or the acceptable import/export flows were determined. But whereas such conservatism would reduce the frequency and magnitude, and hence the net cost of counter-purchases, it would result in an uneconomic under use of the interconnectors at all times except when near-real-time load flow analysis shows that security is threatened.

Market splitting, which entails implicit auctioning of transmission rights, is applied by Nordel where several of the interconnectors are DC so that there are hardly any loop flows on the remainder to create the complications which afflict the meshed systems of the rest of Europe. In consequence, total transfer capacity on each interconnector equals the maximum feasible physical flow. But in a meshed system, where loop flows

---

\(^ {12} \) Gate closure is the time after which generators cannot vary their nominated outputs (which must balance with nominated consumption except in England and Wales) unless instructed by the system operator. The time between gate closure and the start of the period varies between countries, from 1 minute ahead in Sweden, 1 hour ahead in England and Wales, Norway and Netherlands to 3 hours in France. Generators (and sometimes loads) submit their balancing mechanism bids to increase or decrease their output during the period to the system operator on the day ahead or at gate closure.
are important, the transmission capacities of different interconnectors cannot be defined independently of each other. Where such flows are significant, as in the case of the bloc F, I, CH, D, B and NL, the three co-ordination market solutions would all require the use of load flow analysis to compute maximum acceptable cross-border power flow limits and Power Transfer Distribution Factors.

Transfer Capacity assessment requires a multi-country network description and a “base case” postulated load and generation level at each node in the system, covering “normal” levels of exports and imports. The effect upon line flows of a small generation increment\(^{13}\) in one control area and a corresponding load increment in another is then calculated for a series of outage contingencies so that fulfilment of the system operators’ security requirements can be checked. If they are all satisfied the process is repeated until a security constraint is reached. The additional power transfer over the base case is then added to the initial base case transfers to obtain the estimated total transfer capacity. Uncertainties are treated implicitly by allowing subtraction of a transmission reliability margin from total transfer capacity to obtain Net Transfer Capacity.

Power Transfer Distribution Factors express the marginal flow on each line in the aggregate system as a function of marginal increments of generation at each node assuming a marginal increment of demand at some hub node. The effect on flows of an increment in generation at node \(x\) matched by an increment in demand at node \(y\) is the sum of the Power Transfer Distribution Factors from \(x\) to the hub and from the hub to \(y\).\(^{14}\) The estimates of Power Transfer Distribution Factors can be limited to cross-border flows, at the risk of some error, by treating all the nodes in each control area as one hub on a set of assumptions about the internal nodal generation and demand pattern within each control area.

The way in which such calculations would be utilised under each of the three market solutions listed above are as follows:

1) **Market splitting.** Contingent incremental cross-border interconnector flows would be computed daily for a base case set of injections and withdrawals for each of a set of postulated outages. The maximum flow which could be added to the assumed base

---

\(^{13}\) The location of generation within each control areas affects the power flows on interconnectors as well as on internal lines and transformers. The outputs from the calculations therefore depend upon how the increments are assumed to be spread among generators, some system operators assuming that it is according to merit order while others assume equi-proportional changes for all generators

\(^{14}\) This assumes no losses. Allowing for them adds a small complication.
case flow across each border without reaching the physical capacity of any of its interconnectors under any of the postulated contingencies would then be estimated. The power exchanges within each control area would then equate interior demand with interior supply plus or minus the acceptable import or export flow so determined. Thus security constrained dispatching would be implemented by the acceptance of bids and offers on the power exchanges; price differences between control areas resulting for times when interconnector capacity would be fully utilised. After power exchange closure, counter purchasing in a balancing market would be required not only to deal with constraints internal to each control area, but also to cope with changes from the conditions envisaged when making the interconnector calculations. Such changes may arise from generation or transmission outages and from unforeseen demand developments. A single power exchange or at least very closely linked power exchanges providing day ahead scheduling and unit commitment followed by co-ordinated counter purchasing up to and during real-time would be required to produce fully optimised solutions.

2) **Auctions.** These would rest upon similar calculations, being held possibly annually and then repeated monthly or weekly and then daily. The MW of rights auctioned at each stage would consist of those quantities not already committed in previous auctions, plus or minus amendments due to revisions in the calculations resulting from the new information obtained as real time approaches, plus any previously committed rights put up for sale by their owners. Again, after closure of the daily auctions, co-ordinated counter purchasing in a balancing mechanism would be required, not only to deal with constraints within each control area, but also to cope with changes from the conditions envisaged when making the interconnector calculations.

a) Under the ETSO co-ordinated auction procedure, the auctioned rights would relate to pairs of control areas and the set of bids maximising the total value of accepted bids subject to all the cross-border constraints would be selected. The auction operator would thus take account of the matrix of Power Transfer Distribution Factors.

b) Under a flowgate procedure (which has been proposed in the USA) the matrix of Power Transfer Distribution Factors would be published for use by market participants and the rights auctioned would relate separately to each of the cross-border constraints. Participants would bid for whatever bundles of rights were shown to be necessary by the chains of Power Transfer Distribution Factors.
linking the injection control area with the withdrawal control area of each of their envisaged transactions.

3) **Co-ordinated Re-dispatching Cost**+. Prices would be fixed by ETSO for different daily and seasonal periods for firm and for interruptible MWh rights between each pair of control areas covered by the scheme. Participants would pay these prices upon nominating their transactions between each pair of control areas. The prices would be calculated as the cost differences for given base scenarios between:

a) The costs of optimal re-dispatching necessary to satisfy cross-border constraints in the absence of any outage contingencies;

b) A probability-weighted average of the costs of optimal re-dispatching necessary to satisfy cross-border constraints if these outage contingencies occur.

In addition to all the data required under alternatives (1) and (2), in order to determine these prices ETSO would need to know the incremental costs of all re-dispatchable generation in all participating control areas in each period.

Although the methodology used by different system operators for calculating net transfer capacities is fundamentally similar, the assumptions and data used by them vary considerably. (Institute of Power Systems and Power Technology of Aachen University of Technology and CONSENTEC, 2001) Estimated net transfer capacities between to neighbouring control areas made by their two system operators thus frequently differ. The lower of the two estimates is usually adopted by both of them when scheduling and dispatching. Unique authoritative calculations for any group of countries would require detailed agreement about: the concept and quantifications of base case flows, the types of outage contingencies covered, whether switching operations to preserve security are taken account of, how thermal line current limits are decided for continuous operation and for temporary overload, whether voltage limits are considered, what uncertainties are to be allowed for and how the allowances are made.

Counter purchasing would be necessary under all three market solutions to ensure that real time dispatch conformed to security requirements. If not achieved by establishing a single operator for the control areas, combining them into one, optimisation would demand very close co-operation between the separate system operators. It would presumably entail an iterative process, with successive exchanges of information on each system’s load flows, generation and load bids and offers and constraint shadow values following each system operator’s re-dispatch. Thus one system operator would provide the others with constraint costs for its constraints and offers and bids for inter-area dispatch.
from its generators and loads. Another system operator would then redispach its generation to meet its load, taking account of these data. It would then provide the other system operators with constraint costs for its constraints and bids and offers available for inter-area dispatch, a process continuing through all the other system operators and then repeated until the solutions converged.

Various settlement issues would have to be dealt with, “First, as generation could be dispatched in one control area to manage a constraint in another control area, the settlements process will need to provide for assigning the cost of this interchange. Second, and less obviously, each control area could potentially capture in its internal charges for generation and load a portion of the congestion rents attributable to constraints in the adjacent control areas. Revenue adequacy of each system operator visa-vis its day-ahead settlements will require procedures to track the collection of congestion rents and appropriately reassign these rents.” (Harvey, S.M., et al. p.19)

**Concluding remarks**

Interconnectors yield undoubted benefits, but whether their likely level would justify their probable cost is in most cases subject to great uncertainty. Benefits from an existing interconnector can more easily be maximised when a single system operator is responsible for both unit commitment and dispatch in the connected areas. When there is no such single operator, but two, securing optimal utilisation of the interconnector is difficult, even with a single DC link, as the phenomenon of two-way nominations attests. Ways of dealing with the vastly more complex problem of achieving an approximation to optimal use of multiple AC links have been discussed. They all would require hourly or more frequent iteration between load flow analyses and auctions or power exchanges and extremely close and continuous co-ordination between system operators.
References

CER (Commission for Energy Regulation), 2003, Market Arrangements for Electricity – Interconnector Trading Principles An MAE Consultation
DKM Economic Consultants, Economic and Social Research Institute and Electrotec Ireland, 2003, Costs and Benefits of East-West Interconnection between the Republic of Ireland and UK Electricity Systems: Report to the Commission for Energy Regulation
ETSO, 2001 a, Definitions of Transfer Capacities in liberalised Electricity Markets
ETSO, 2004, Cross-border electricity exchanges on meshed AC power systems
Institute of Power Systems and Power Technology of Aachen University of Technology and CONSENTEC, 2001, Analysis of Electricity Network Capacities and Identification of Congestion; Final report.
Intelligent Energy Systems, 2000, Application of the ACCC Regulatory Test to SNI. Report to TransGrid,
NERA, 2003, ROI Interface Study An Interim Report for the IME Group
OFGEM, 2004, Review of electricity and gas arrangements for winter 2004/05, Consultation Document
RTE, 2004, Détermination des capacités commerciales d'échange et des coûts de congestion associés,
Turvey, R. and Anderson, D, 1977, Electricity Economics, chapter 18 "Cost structure in hydro and hydro-thermal systems"