ROI INTERFACE STUDY

A Final Report for
the IME Group

Prepared by NERA

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EXECUTIVE SUMMARY

This is the Final Report of our study of the interface between the Northern Ireland (NI) and Republic of Ireland (ROI) electricity markets. The purpose of our study has been to assess the impacts on NI of the ROI's proposed new market arrangements for electricity (MAE), and advise the IME Group on how NI should respond.

In our earlier Interim Report, we considered these questions in a scenario where the NI market remains separate from the ROI market. In that report, we analysed the possible impacts of the MAE on trade between NI and the ROI, and made a number of recommendations on the trading arrangements for the north-south (N-S) interconnector in a scenario where the ROI implements the MAE. The CER has now decided, in consultation with the NIAER, to opt for interconnector trading arrangements that are very close to the model that we recommended in our Interim Report.[1]

In this Final Report, we examine the question of whether the NI market should integrate with the ROI market to form an integrated all-island MAE market, and if so when. To help us answer that question we have carried out a detailed comparison of the costs and benefits to NI of joining the MAE versus staying out, using NI social welfare as our metric.

Our cost-benefit analysis of MAE Integration indicates that it would not be beneficial for NI to join the ROI's MAE market at the present time. In the specific circumstances of NI, we have found no evidence that the locational price signals the MAE market is designed to provide would produce any benefits for NI though the period to 2009-10. That assessment is based on our modelling of an integrated all-island LMP market under a range of demand and supply scenarios.

The only benefits we have been able to identify with any certainty have been possible savings in administrative costs associated with the removal of interconnector trading systems and the merger of SONI's market operator function with that of the SMO. However, these benefits are likely to be swamped by the costs of implementing and operating the new systems needed to run an LMP market within NI, and new administrative costs at Ofreg. While we have been unable to put values on the costs and benefits of a range of market effects that may result from MAE Integration, we see no reason to assume that the benefits (e.g., from more perfect optimisation of the use of interconnectors) would outweigh the costs (e.g., from the potential negative effects of "basis risk" on entry and competition).

In any event, the net benefits of the items that we have not been able to evaluate would have to be worth between £5.1 million and £17.4 Million in NPV terms to make MAE Integration worthwhile for NI. At present, we find it hard to see how these other items could yield that level of net benefits. We therefore recommend that NI should not join the MAE at the

[1] ***Interconnector Trading Arrangements: A Decision Paper by the CER***, 19th April 2004.

present time. Instead, we recommend that NI review the position again in three to five years, or earlier if conditions change significantly (e.g., the MAE design changes leading to a significant reduction in the costs of implementation), and decide again then whether the benefits of MAE Integration outweigh the costs.

1. INTRODUCTION

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In our earlier Interim Report, we considered these questions in a scenario where the NI market remains separate from the ROI market. In that report, we analysed the possible impacts of the MAE on trade between NI and the ROI, and made a number of recommendations on the trading arrangements for the north-south (N-S) interconnector in a scenario where the ROI implements the MAE. The CER has now decided, in consultation with the NIAER, to opt for interconnector trading arrangements that are very close to the model that we recommended in our Interim Report.[2]

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For the purpose of the comparison, we assume that a decision by NI to join the ROI's market would result in the MAE being transposed to NI with minimal modification. We refer to that outcome as the "MAE Integration" scenario.

We also have to define an alternative, assuming that the ROI goes ahead with implementing the MAE within its territory, but NI decides not to adopt it. It does not make sense to compare MAE Integration with the status quo, since adoption of the MAE would make some changes necessary in the operation of the interconnector. Instead, we must appraise MAE Integration against a baseline or "counterfactual" that represents a realistic and efficient interface between the two markets. For the purpose of our appraisal, we have taken the interconnector trading arrangements envisaged in the CER's 19th April Decision Paper, which are consistent with our own recommendations, as our "Baseline Interface".

The rest of this report is structured as follows:

- Section 2 describes in detail our assumptions about the Baseline Interface;
- Section 3 describes what changes would occur within NI as a result of MAE Integration, and clarifies how MAE Integration differs from the Baseline Interface;
- Section 4 details our cost-benefit analysis; and
- Section 5 presents our conclusions and recommendations.

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[2] ***Interconnector Trading Arrangements: A Decision Paper by the CER***, 19th April 2004.

2. THE BASELINE INTERFACE

2.1. NERA Recommendations from Interim Report

We discussed possible arrangements for this interface in our Interim Report.[3] In the executive summary to our Interim Report, we summarised our recommendations as follows:

- to ensure efficient co-ordination of third party trades prior to real-time, the MAE should recognise nominations to send power over the interconnector as commitments to deliver power at the spot price at the southern end of the interconnector;
- to ensure efficient dispatch of the NI and ROI interconnected system in real-time, the MAE should accommodate the current system of "marginal trading" between system operators, in some form or other;
- the CER must ensure that interconnector users have access to FTRs between the interconnector node or nodes and the uniform ROI demand price;
- the CER must ensure that interconnector users have access to contracts with suppliers by making sure there is a liquid contracts market in the ROI;
- the CER should exempt interconnector users from paying for the costs of reserves caused by the operation of the N-S interconnector, since they have no control over the way it is operated and cannot respond efficiently to such price signals. Any imbalances or errors in flows over the interconnector should be handled through inter-SO settlement;
- the point of sale for nominated trades over the NI-ROI interconnector should be restricted to the node corresponding to the main 275 kV interconnector between NI and ROI (since the 110 kV interconnectors are needed to provide mutual system support in emergency conditions); and
- the existing reserves sharing arrangement between the NI and ROI systems should be accommodated by the MAE.

Since the time of our interim report, we have had several opportunities to discuss these recommendations and alternative approaches, with the CER and other interested parties. The CER has now published a Decision Paper on interconnector trading arrangements,[4]

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[3] NERA (2003), ***ROI Interface Study: An Interim Report for the IME Group***, 13 November 2003.

[4] CER (2004), ***Interconnector Trading Arrangements: A Decision Paper by the CER***, 19th April 2004.

following an earlier Options Paper which developed alternatives to our recommendations.[5] We have therefore reviewed the CER's papers in deciding the appropriate baseline interface.

2.2. CER Options

In its Options Paper, the CER described four options which had in common many elements with our recommendations, such as FTRs for users of the interconnector and retention of the reserve sharing agreement. The CER defined the differences between the options in terms of two dimensions: point of sale into the ROI and form in which interconnector flows are offered to the MAE. Table 2.1 summarises these differences, drawing on Table 1 in the CER's paper. We give a more detailed description of these options in Appendix A.

Table 2.1:
CER Options for Management of the Interconnector

	Gate Closure	
Point of Sale	Interconnector flows fixed at NI gate closure	Interconnector flows fixed in MAE despatch
Northern end of interconnector (MCE manages congestion; users hold FTRs)	Option 1	Option 3
Southern end of interconnector (Users hold "physical" access rights equal to physical capacity)	Option 2	Option 4

2.3. The CER's Decision

In the end the CER decided, in consultation with the NIAER, to opt for a modified version of Option 2, that includes provisions for "marginal trading" after gate closure in Northern Ireland and before gate closure in the ROI. At present, marginal trading is arranged between the two system operators, on behalf of other parties, and we had envisaged that such a system might persist. Once the MAE is implemented, it would be possible for SONI and the SMO to signal the potential for such marginal trades and to let users compete in the MAE to make them. This is the system that has been chosen by the CER, who appear to envisage a process that works as follows:

5 CER (2004), ***4 Options for the Management of Interconnection with the MAE***, 1 March 2004.

1. After NI gate closure and before ROI gate closure, SONI and the SMO would identify any spare capacity that was going to be available on the N-S interconnector and signal this figure to electricity traders and adjust any system constraints affecting the representation of the interconnector in the MCE;

2. The amount of spare capacity would take into account not only the capacity of the interconnector itself, but also the extent to which the NI system could accommodate changes in the output of generators (or dispatchable demand of customers) inside Northern Ireland;

3. SONI and the SMO would make this spare capacity available to any trader that had qualified for access by signing a "framework agreement" for use of spare interconnector capacity and had paid the relevant fee;[6]

4. These qualifying traders would submit offers/bids to the MAE for power injections/withdrawals at the Louth (southern) node of the interconnector;

5. The MCE would accept these offers and bids up to the level of the spare capacity, and the SMO would settle the resulting claims, as with any other traders.

This process is capable of development at a later date into a full-blown version of Option 4 (offers at the southern node) or even Option 3 (offers at the northern node), if it were found to be beneficial to adapt the system within NI to accommodate the associated risks. However, at this stage, it would seem to be prudent to regard such a process of submitting marginal offers and bids as an adjunct to Option 2, constrained by the ability of the NI system to accommodate marginal changes in output or dispatchable demand at short notice. Many aspects of the future regimes in the ROI and NI remain uncertain and it would therefore appear premature to make further costly but irreversible changes to the NI system. Several important aspects of the electricity systems both sides of the border will be discussed and may change in the near future, including the method of defining and allocating FTRs (ROI), the arrangements for opening up the market to retail access (NI, especially), etc.

Given the importance of these changes, it would be prudent to keep open the possibility of reforming NI trading arrangements until later, rather than pre-judging what kind of reforms are likely to be appropriate. Option 2 (with marginal trading supervised by SONI) represents a low cost interface that keeps all future possibilities available for NI.

[6] This would be analogous to the existing arrangements for short-term N-S interconnector access, where those who do not have long-term physical rights acquired at auction pay a fee for short-term access.

2.4. Other Possible Options

During the course of our meetings with interested parties, we discussed other possible options for consideration as the alternative to full integration into the MAE. These other options involve the ROI adopting different systems from the LMP market currently under consideration.

2.4.1. NETA-style nominations

The dominant system that appears to be emerging in North-Western Europe is one of day-ahead or hour-ahead nominations by traders. The system is known in Germany and the Netherlands as "programme responsibility", because traders are held responsible for keeping to their "programme" (the nominations) and must pay penalties (relative to the market price) for deviating from them. The current ROI system is essentially a nominations system. NETA, BETTA and the Northern Irish system all take this form. The ROI's proposed LMP market will stand out as an exception against all these neighbouring markets.

2.4.2. Single "System Marginal Price" market

Some parties suggested to us that adoption of a single market with one "System Marginal Price" (SMP) would represent a useful stepping stone towards implementation of full LMP pricing, or even a permanent solution.

Our own modelling suggests that congestion within the ROI's transmission system is limited and that prices will often settle at similar levels throughout the country.[7] In our modelling, congestion arises systematically (though not only) when new plants are connected to the system (as at Tynagh Mines and Auginish). However, the resulting price signals give a false indication of value, since the transmission company would normally invest to remove congestion in such cases. Since the locational aspect of the market would be redundant in such conditions, and of little importance otherwise, a SMP market might produce prices that signal marginal generation costs ***reasonably*** accurately ***most*** of the time. Any side-payments to generators affected by congestion would be relatively small. Moreover, such a scheme would avoid the instability of generator prices at particular nodes and remove the need for FTRs.

2.4.3. Assessment of these options as alternative baselines

The continuation of the nominations system is possible (though difficult to reconcile with existing legal constraints on the CER), but we do not think that this baseline would adequately capture the costs and benefits of different decisions facing Northern Ireland. The purpose of the analysis in this report is to determine whether NI should integrate into the MAE, ***given that the ROI has adopted it***. Whilst comparisons between MAE integration and a

[7] Our modelling results are described in full in a separate ***Modelling Appendix***.

nominations scheme would capture the full effect of the ROI's reforms, they would not capture the effects of NI's decision alone. Since we are charged with writing this report for Northern Irish readers, we need to limit the scope of our analysis to the effects of decisions that Northern Ireland might take when faced with the MAE. Continuation of a nominations system does not represent a suitable baseline in that context.

The SMP market has a number of merits, but was not on the CER's agenda at the time of writing. Hence, again, as a basis for a decision that Northern Ireland might take when faced with the MAE, as specified at the time of writing, it would provide a misleading basis for comparisons.

Therefore, having considered these alternatives, we have decided that (whatever their intrinsic merit) they would not provide a suitable baseline for comparisons with MAE Integration.

2.5. Conclusion

The CER suggested various options for the interface between the MAE and the (current) Northern Irish system. Having reviewed them, the CER, in consultation with the NIAER, opted for a modified version of Option 2, which is very close to the model that we recommended in our Interim Report. We regard it as feasible and consistent with current arrangements on the N-S interconnector and within the NI market (including the arrangements on the Moyle interconnector). It remains our preferred model, and we have therefore used it as our Baseline Interface in assessing the costs and benefits of MAE Integration.

Other options, including those proposed by other parties, may have merit in themselves for Irish traders and consumers, but they do not represent a suitable basis for appraising the decision facing Northern Ireland.

3. IMPLEMENTATION OF MAE INTEGRATION

In order to appraise the costs and benefits of MAE Integration for NI, we need to specify what changes would be required to implement MAE Integration.[8] We also need to specify how the position under MAE Integration would differ from that under the Baseline Interface.

3.1. NI-ROI Interface

3.1.1. Access

Under MAE Integration, there would no longer be any special arrangements governing access to the N-S interconnector. The N-S interconnector would effectively become invisible to market participants in an enlarged all-island market or, rather, indistinguishable from any other piece of the transmission network. Access to the interconnector would be decided by the market-clearing engine (MCE) based on the offers the SMO receives from market participants.

In contrast, under the Baseline Interface we assume that the existing arrangements for auctioning N-S interconnector capacity, and scheduling nominations, would continue to operate as they do today, albeit with the addition of with-in day trading envisaged by the CER and in our Baseline Interface.

3.1.2. Transfer Capacity

The total transfer capacity (TTC) of the N-S interconnector is determined by the level of installed transmission capacity and system security constraints (e.g. system separation constraints). Under the existing arrangements, the TTC is fixed in advance on an annual basis. The allocation of the TTC between reserves (the transmission reliability margin or TRM) and energy (the net transfer capacity or NTC) is also fixed annually in advance.

In reality, however, the TTC of the N-S interconnector varies in real-time depending on the level of load on the NI and ROI systems. Furthermore, the optimal allocation of the TTC between the TRM and NTC also varies in real-time depending on market conditions on both sides of the border.

The TTC, TRM and NTC parameters are currently fixed annually as part of the process of allocating annual contracts for use of the N-S interconnector to the market. Since we assume that the SOs will continue to allocate interconnector capacity on this basis under the Baseline Interface, we also assume that these parameters will continue to be fixed annually in advance.

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8 In Appendix B, we outline the main features of the MAE as specified by the CER at the time of writing.

Under MAE Integration, however, there will be no need to fix any of these parameters annually in advance, since N-S interconnector capacity will no longer be allocated on an annual basis. Instead, the SMO's MCE will decide how to allocate N-S interconnector capacity close to real-time, based on system and market conditions in NI and ROI.

3.2. Market Rules in NI

3.2.1. Energy Pricing

Under MAE Integration, all injections and withdrawals in NI will be settled by the SMO based on LMPs. Each generator in NI will receive the LMP price at their node for the energy they inject into the system. The implications of MAE Integration for demand pricing in NI, on the other hand, are not clear-cut.

The ROI is adopting a uniform demand price equal to the weighted average of LMPs at withdrawal nodes in the ROI. Transposing that approach to NI under MAE Integration would imply a uniform demand price in NI based on LMP prices at withdrawal nodes in NI. An alternative to this approach would be to adopt a uniform all-island demand price based on LMPs at all withdrawal nodes throughout the island.[9] We consider both of these options as part of our appraisal of the costs and benefits of MAE Integration.

Under the Baseline Interface, we assume that the existing system of regulated top-up and spill prices would continue to operate in NI.

3.2.2. Gate Closure

Under MAE Integration, the timing of gate closure in NI will be aligned with that in the ROI, which is expected (eventually) to be 1 hour ahead of real-time. Further, the nature of gate closure (i.e. the deadline for final offers to be submitted to the SMO), and the rules for dispatching generators on the basis of their offers, will also be the same on both sides of the border.

Under the Baseline Interface, gate closure in NI is for physical nominations, rather than offers, and is 24 hours ahead of real-time instead of 1 hour. That means there will be a difference both in the nature and timing of gate closure between the NI market and the ROI market under the Baseline Interface, although there will be provision for with-in day trading over the N-S interconnector in between NI and ROI gate closure.

9 It would only be feasible for NI to adopt the latter approach if the ROI also adopted that approach, since otherwise there would be no guarantee that the SMO's receipts from the spot market would be sufficient to cover the payments it would owe to generators, let alone to finance FTRs.

3.2.3. Settlement

Under MAE Integration, the SMO will take no account of contracts between generators and suppliers during the settlement process. This means that all injections and withdrawals in NI will be settled (i.e. bought and sold) by the SMO.

Under the Baseline Interface, most injections and withdrawals are settled on a bilateral basis between generators and suppliers. The SMO only settles (i.e. buys and sells) imbalances between the nominations made by generators and suppliers and their metered quantities.

3.2.4. Operating Reserves

- Reserve Sharing

We assume that the existing reserve sharing agreement between SONI and ESB NG would continue to operate under the Baseline Interface. Under that agreement, NI carries about 110 MW of primary spinning reserves on its system, and ROI carries about 220 MW. Whenever one system calls on spinning reserves from the other system, that system provides the required energy and receives a payment in return to cover the cost of the enery it provides.. In effect, these arrangements mean that:

- the allocation of the supply of primary spinning reserve between NI and ROI is fixed by long-term agreement between the two SOs;
- the cost of scheduling primary spinning reserve is shared between NI and ROI consumers approximately in proportion to the size of the two systems; and
- the cost to each system of using primary spinning reserve depends upon the relative frequency of ROI calls on NI reserve and NI calls on ROI reserve, but assuming that these are roughly equal, the cost of using primary spinning reserve is also shared between NI and ROI consumers approximately in proportion to the size of the two systems.

- Procurement and Cost Recovery

Within NI, primary spinning reserve and other reserve products are currently procured from generators in NI through long-term contracts.[10] And the costs of procuring these reserve products are currently socialised across all NI consumers pro rata to their consumption. We assume that these arrangements would remain in place under the Baseline Interface.

[10] The availability of capacity capable of supplying reserves and other ancillary services (e.g., reactive power, black start, etc.) is remunerated through system service agreements with SONI. The costs of "re-dispatching" the system in NI to meet reserves requirements is met currently through NIE PPB's bulk supply tariff (BST).

Under MAE Integration, on the other hand, there will be a single all-island spot market for operating reserves, which is cleared simultaneously with the energy spot market. The allocation of operating reserves between NI and ROI, and between individual generators and units of dispatchable demand, will therefore be decided close to real-time based on the offers received by the SMO.

Any existing long-term reserves contracts in NI running into or beyond 2006 would have to be converted into financial contracts at the time of MAE Integration, or else they would have to be terminated early.

The CER has proposed that the costs incurred by the SMO in scheduling and dispatching operating reserves should be charged to market participants on a "causer pays" basis. We therefore assume this is the principle that will apply throughout the all-island market under MAE Integration.

3.3. Contracts

3.3.1. Energy Contracts

Under the Baseline Interface, we assume that the existing physical contracts between the generators, PPB and suppliers in NI would persist.

Under MAE Integration, all contracts between generators and suppliers must take the form of financial contracts, or "contracts-for-differences" (CFDs), which means that the existing physical contracts in NI may need to be renegotiated. However, the arrangements for bidding and metering in the MAE might allow a third party (i.e. PPB) to act as the interface with the MAE on behalf of the operators of a generator. If so, it might be possible for the third party to continue to take title to the output of the generator at the station gate before it enters the MAE, i.e. to have a "physical contract" settled by a cash payment in return for delivery of energy at a defined MAE injection point.

Under MAE Integration, if the rules allow change of title before entry to the MAE, PPB's existing long-term contracts with NI generators may not need to be renegotiated, but PPB would have to offer its contracted generation onto the spot market rather than selling it direct to suppliers.[11] The contracts would have to allow PPB to adjust instructed output in accordance with the MAE timetable, i.e. between hour-ahead gate closure and actual delivery, but the contracts already provide for such flexibility. The existing long-term contracts will hedge the generators against volatility in the LMPs at the generator nodes but, even if PPB signed CFDs with customers, one of them would be exposed to basis risk on the

[11] All generation in NI (except for a small amount of renewable generation) is currently under long-term contract to NIE PPB, NIE's regulated procurement and bulk supply business, which takes physical delivery at the station gate. NIE PPB then sells most of that generation to suppliers in NI at a regulated bulk-supply tariff (BST), or to the eligible customer market through virtual power auctions or bilateral contracts.

difference between the LMPs at the generator nodes and the LMP(s) at demand node(s). It is likely that PPB would take on this basis risk, as customers would be less willing or able to do so. Since PPB is a diversified player with a large portfolio, the basis risk it faces may not be significant, but to hedge against the risk it faces it would need to obtain financial transmissions rights (FTRs) from the SMO (see next section). Similarly, although ESB Coolkeeragh may not be exposed to significant basis risk as part of the diversified ESB group, it would also need FTRs to hedge any risk it does face.

3.3.2. FTRs

Under MAE Integration, generators and suppliers in NI will need access to FTRs to allow them to hedge basis risk. The SMO will need to issue a set of FTRs linking generation nodes in NI to an appropriate demand node. The definition of the FTRs will need to be linked to the choice of demand pricing rule under MAE Integration. For example, if there are separate NI and ROI demand prices, the SMO will need to define (i) a set of FTRs linking generation nodes in NI to the NI demand node (for sales within NI), (ii) a set of FTRs linking NI generation nodes to the ROI demand node (for exports to the ROI) and (iii) a set of FTRs linking ROI generation nodes to the NI demand price (for imports from the ROI). The creation of two demand nodes complicates the design of rules for defining FTR capacity. In particular, it is not immediately clear how much FTR capacity would link each generation node to the demand node in the other market.

An alternative way of defining FTR capacity would be to link (1) NI generation nodes to the NI demand node, (2) ROI generation nodes to the ROI demand node and (3) the NI demand node to the ROI demand node (for cross-border trades). Cross-border traders could then hedge risks with a combination of (1) and (3), or (2) and (3).

The SMO will also have to define a mechanism for allocating FTRs in NI. The CER has proposed that FTRs are allocated by auction in the MAE. We therefore assume that FTRs would be allocated by auction as part of MAE Integration.

Under the Baseline Interface, generators and suppliers are exposed to basis risk only when they sell to, or buy from, the ROI's LMP market over the N-S interconector. We assume, as described in Section 2, that under the Baseline Interface NI generators and suppliers will have access to FTRs that hedge them against this basis risk.

3.4. Market Institutions and Regulation

3.4.1. SONI's Role

Under MAE Integration, there would have to be a single ***market*** operator with responsibility for operating the all-island LMP market. We assume that this entity will be created by merging the market operation functions of SONI with the equivalent part of the ROI's SMO.

MAE Integration does not require that both the NI and ROI transmission systems are operated by a single ***system*** operator. Further, while there may be efficiency savings on an all-island basis from having a single system operator for the whole island, those savings could ***in principle*** be achieved under the Baseline Interface just as easily as under MAE Integration. (In other words, the creation of a single market does not in itself remove any of the current barriers to integrated system operations.) For the purpose of our appraisal, therefore, we assume there is no difference between the arrangements for system operation under MAE Integration and the Baseline Interface.

3.4.2. Ofreg's role

- Market Governance

The MAE rules give a range of market oversight powers to CER in the ROI. Under MAE Integration, Ofreg will require the same market governance powers as the CER.

However, since Ofreg's and the CER's jurisdictions will remain separate for the foreseeable future, new mechanisms will need to be included in the MAE market rules for joint or co-ordinated decision-making.

- Controlling Market Power in NI

All existing generation in NI is currently under long-term contract to NIE PPB. While Ofreg does not directly regulate the costs of these long term contracts, it effectively caps NIE PPB's resale price to ensure NIE PPB does not exploit any market power it has within NI.

We assume that Ofreg will maintain these controls on NIE PPB both under the Baseline Interface and MAE Integration for as long as it judges that these are necessary. We also assume that Ofreg will act to control ESB Coolkeeragh's market behaviour if it concludes that it has market power in NI.

MAE Integration could potentially create conditions in which there is an effective competitive constraint on the bidding behaviour of NIE PPB and/or ESB Coolkeeragh. In that case, Ofreg would no longer need to cap NIE PPB's re-sale price, or introduce any controls on ESB Coolkeeragh, and the costs associated with administering these arrangements could be saved.[12] To help us appraise this potential benefit, we have carried out modelling to test whether NIE PPB and/or ESB Coolkeeragh would be subject to effective competitive constraints under MAE Integration.

3.5. The Moyle Interface

Under the Baseline Interface, we assume that the existing arrangements for access to the Moyle interconnector will remain as they are today.

Under MAE Integration, there is no requirement for the arrangements for access to the Moyle interconnector to be changed relative to the Baseline Interface. The arrangements for nominating flows on the Moyle interconnector are similar to the existing arrangements governing trade on the N-S interconnector. Moyle nominations can be accommodated within MAE Integration in the same way as the existing arrangements for N-S nominations have been accommodated within the Baseline Interface

We therefore assume that under MAE Integration the current nomination based trading arrangements on the Moyle interconnector remain as they are today. Further, under MAE Integration we assume that nominations on the Moyle interconnector will be accepted into the MAE as firm commitments, rather than as offers.

3.6. Renewables

3.6.1. Renewables Obligation Certificates (ROCs)

NI is in the process of putting in place a system of renewable obligations and tradeable certificates (ROCs), and we assume that system will operate in NI under the Baseline Interface.

The Department of Communications, Marine and Natural Resources in the ROI is currently consulting on the appropriate approach to supporting renewable energy in the ROI in the future. One of the options on which the Ministry is consulting is a system of ROCs, similar to that being developed in NI. This option is favoured by the CER on grounds of economic efficiency. The CER also concludes that such a system could operate alongside the MAE without any difficulty.

It therefore seems likely that compatible systems of ROCs will operate in NI and ROI under both the Baseline Interface and MAE Integration.

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[12] Because of the long-term nature of the "legacy contracts" between NIE PPB and the existing thermal generators in NI, there is likely to be an ongoing need for Ofreg to control how the costs of these contracts are recovered from customers under both MAE Integration and the Baseline Interface.

3.6.2. Accreditation of Green Energy

Under MAE Integration, it will no longer be possible to determine what proportion of the green energy injected in NI flows south to the ROI, or vice versa. This is because without a system of nominations on the N-S interconnector, it will no longer be possible to attribute ownership of the flows over the N-S interface. For that reason, the current system for accrediting green energy in NI (and the ROI) would have to be changed to accommodate MAE Integration.

Under the Baseline Interface, there would be no need to make any changes to the system for accrediting green energy in NI.

3.7. Other Issues

3.7.1. Government Policy

Currently, a range of government policies affects the operation of electricity markets in NI and ROI.For example, policies on:

- emissions trading and environmental standards;
- fuel diversity policy;
- consents policy on new power stations and transmission lines;
- fuel taxation; and
- public service obligations (PSOs).

MAE Integration does not in itself require that government policy in NI or ROI in the above mentioned areas be changed in any way. We assume, therefore, that government policy is the same under MAE Integration as under the Baseline Interface.

3.7.2. Currency

Unless the UK joins the Euro zone, it would be necessary, as part of the implementation of MAE Integration, to revise the MAE's pricing rules to accommodate the fact that NI and ROI use different currencies. To implement these changes would require some revision to the legal documents that set out the market rules, as well as to the MCE and other systems used to operate the market.

4. COSTS AND BENEFITS[13]

In this section, we analyse the costs and benefits of MAE Integration measured against the Baseline Interface. Where possible, we provide quantification of these costs and benefits, drawing on our modelling results.[14]

This chapter follows the same structure as the previous one. We go through each of the changes required to implement MAE Integration, set out in the previous chapter, and analyse the costs and benefits of these changes. We also consider at the end of this chapter the potential effects of ESB's market power, and the CER's proposal for dealing with it, on the costs and benefits of MAE Integration for NI.

4.1. Costs of Implementing the MAE

4.1.1. Nature of Costs

The costs of implementing the MAE within the ROI consist of two main components:

1. the costs of designing the MAE, including the costs of industry consultation, professional advice for the regulator, SMO and market participants from economists, lawyers, IT specialists and engineers, etc.; and
2. the costs of implementing the new systems required to make the MAE design operational.

As we assume that the MAE would be extended to NI with minimal modification under MAE Integration, NI's ***incremental*** MAE design costs are likely to be small compared to the costs incurred in the ROI. On the other hand, the ***incremental*** costs of implementing new systems in NI are likely to be proportional to those incurred in the ROI, unless these systems are subject to significant economies of scale.

In informal discussions, the CER has indicated that NI might also have to pay a share of the costs incurred in designing and implementing the MAE within the ROI, as a condition of joining the MAE.

We have therefore calculated a range for the costs NI would incur under MAE Integration, with:

13 All figures are in 2003 money terms, unless otherwise indicated.

14 Our modelling results are described in full in a separate ***Modelling Appendix***.

- the ***upper end*** of the range corresponding to the sum of the incremental costs of implementing the MAE within NI and a one third share of the costs of designing and implementing the MAE within the ROI; and

- the ***lower end*** of the range corresponding only to the incremental costs of implementing the MAE within NI.

We have used a one third share in calculating the upper end of the range on the basis that NI represents one third of the all-island market.

4.1.2. Cost Estimates[15]

We have analysed the costs incurred in implementing LMP markets in PJM, New Zealand, Singapore and the Philippines as a basis for estimating the cost of implementing the MAE in the ROI, and extending it to NI. We have supplemented this analysis with cost estimates drawn from budgetary figures quoted by ESB NG, and the DTI's cost-benefit analysis of the British Electricity Trading and Transmission Arrangements (BETTA).

The cost estimates we have compiled from other LMP markets vary widely (e.g., from £3.2 million to £20 million for the SMO's market-clearing engine and associated data transfer systems), but these wide differences conceal differences in (1) the size of the network or the number of involved parties and (2) the strictness of the procedures required for regulatory consultation and decision-making.

For example, the highest figure for the cost of the SMO's systems comes from the PJM, which is a large system bound by US quasi-judicial procedures designed to protect private property rights. The smaller figures come from smaller systems that were predominantly state-owned and that therefore probably encounter fewer obstacles to redistributive reforms. We estimated the costs for the ROI and NI based on their relative size alone, without making any explicit allowance for relative complexity and cost of its regulatory procedures. (If their regulatory procedures involve relatively more consultation and analysis than their size might dictate, this approach will underestimate the costs.)

Based on our analysis, we estimate that the cost of extending an ROI LMP market to NI will be in the range of:

- £5.6 million to £15.9 million of one-off costs; and

- £0.4 million to £0.7 million of additional annual running costs.

The derivation of this range of costs is summarised in Table 4.1.

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15 The detailed analysis that lies behind the figures presented in this section is set out in Appendix C.

Table 4.1
Cost of Extending the MAE to NI, £ million

	ROI Costs		Range of Costs for Extending MAE to NI			
			Minimum = NI Incremental Costs		Maximum = NI Incremental Costs + one third ROI Costs	
	One-off (A)	Annual (B)	One-off (C)	Annual (D)	One-off (E)= 0.33*(A)+(C)	Annual (F)= 0.33*(B)+(D)
Design costs	19.0		1.9		8.2	
Implementation Costs						
Central/SMO costs	6.3		1.9		4.0	
Market participants	2.8		0.8		1.7	
FTRs	3.0		1.0		2.0	
Sub-total	12.0	1.1	3.7	0.4	7.7	0.7
Total	31.0	1.1	5.6	0.4	15.9	0.7

Source: NERA Analysis (see Appendix B).

4.2. NI-ROI Interface

Since there would be no need for any special arrangements governing access to the N-S interconnector under MAE Integration, the costs currently incurred in operating those arrangements (annual capacity auctions, administration of nominations, marginal trading systems, etc.) could all be avoided

SONI estimates that the costs it incurs in running the current system for interconnector access are of the order of £60,000 per annum, all of which would be avoided under MAE Integration.

As we discussed in the previous chapter, dynamic optimisation of the use of the N-S interconnector under MAE Integration is likely lead to an increase in the NTC of the interconnector relative to the current system, in which the NTC is fixed annually. This change in the NTC of the N-S interconnector would come at no incremental cost (compared to the MAE Integration implementation costs described above), but may result in significant benefits in the form of lower production costs within NI, or higher export earnings for NI producers.

4.2.1. Effects on optimal dispatch

To help us evaluate these potential benefits, we have modelled a variant in which the NTC of the 275 kV interconnector is increased to 500 MW in both directions under an MAE Integration scenario (i.e. assuming an all-island LMP spot market). Setting the North-South NTC equal to 500 MW N-to-S represents an increase of 170 MW, or about 50%, over our base case assumption of 330 MW. SONI informed us that this is the maximum N-to-S NTC that could be achieved on the 275 kV interconnector without new transmission investment. Our base case assumed a S-to-N NTC of 0 MW on the 275 kV interconnector, reflecting our assumption that the constraints in ESB's system, which currently limit the NTC to 0 MW, will persist for the foreseeable future. An increase in the NTC from S-to-N of 500 MW would probably not result directly from setting the NTC dynamically, but would also require significant investment by ESB. This variant is therefore a limiting case, which shows the scale of the maximum benefits that could be achieved for NI by setting the NTC dynamically.

We have modelled this variant in 2006-07 summer and winter peak conditions as, according to SONI, it is during periods of system peak demand that the dynamic capacity of the interconnector is likely to be at its highest. In summer peak conditions, we find that increasing the NTC to 500 MW in both directions has no effect on the optimal all-island dispatch, and hence produces no benefits. This is because in the base case the NTC constraints on the 275 kV interconnector do not bite, i.e. do not influence the optimal dispatch. In the base case, the optimal dispatch resulted in an uncongested N-to-S flow of about 117 MW across the 275 kV interconnector. Increasing the NTC to 500 MW has no effect since a N-to-S flow of 117 MW is still optimal whether the N-to-S NTC is 330 MW (as in the base case) or 500 MW (as in this variant).

On the other hand, in winter peak conditions we find that increasing the NTC to 500 MW in both directions has a significant effect on the optimal all-island dispatch, and results in some potential net benefits to NI. In the base case, LMPs in NI are determined by traders importing power to NI across the Moyle interconnector at the relatively high price of £41/MWh, reflecting our assumption about GB spot market prices in average winter peak conditions in 2006-07. When the S-to-N NTC on the 275 kV interconnector is increased to 500 MW, about 170 MW of imports across the Moyle interconnector are displaced by an equivalent quantity of lower cost imports from the ROI across the 275 kV interconnector. This has the effect of reducing LMPs within NI by approximately £2.9/MWh, or 7%.

If there is a single demand price for NI, a reduction of £2.9/MWh in LMPs within NI is worth £5,000 to consumers in the 2006-07 winter peak hour. However, this saving for consumers is offset by a loss of infra-marginal profits for NI generators of £4,850, so that the net benefits to NI are £150 in the winter peak hour. To evaluate the scale of this potential benefit on an annual basis, we amalgamated the peak and off-peak results, assuming that the peak result applies in all peak hours, i.e. in 35% of winter hours, or 17.5% of all hours in the year. This assumption is likely to overstate the benefits, but still implies a potential net benefit to NI of only £0.2 million per annum. If, on the other hand, the MAE rules were to define a single all-island demand price, NI consumers lose out, as do NI generators. This is because the all-island demand price is actually higher in this variant than in the base case, due to an increase in LMPs within ROI. As a result, NI generators and consumers would both be worse off under this variant, so that the potential net benefits to NI would be negative.[16]

In reality, however, because the costs of the "legacy contracts" between NIE PPB and the existing thermal generators in NI still have to be recovered, the potential net benefits identified above would not be achieved. For example, when LMP prices fall in NI as a result of increasing the transfer capacity of the NI interconnector, the market prices paid by NI consumers and the market revenues of NI generators fall. But the payments NIE PPB owes to existing NI generators under the "legacy contracts" do not change, and nor therefore do the costs that NIE PPB has to pass-through to NI customers. The only outcome which would produce real benefits for NI is if the increase in N-S interconnector capacity resulted in an increase in sales for NIE PPB, since then the fixed costs of the "legacy contracts" would be spread over a larger number of units, thus lowering the average unit cost that NIE PPB passes through to NI customers. But we do not see that effect in the modelling runs we have analysed.

16 We also looked at the effects of opening up access to the 110 kV interconnectors under an MAE Integration scenario. We found that this has little effect on the optimal all-island dispatch, and hence does not change the conclusions set out here.

4.2.2. Potential dynamic efficiency effects

An increase in the transfer capacity of the N-S interconnector could potentially result in a lower required plant margin in NI, because of the increased opportunity for NI to call on imports from ROI at times of plant failure in NI (and vice versa for ROI). Before that benefit could be realised, however, there would need to be a review of system planning and security standards in NI to decide how interconnector capacity should be factored into the assessment of generation adequacy. So while MAE Integration may create the conditions in which this benefit could be achieved, it will not in itself produce this benefit automatically.

Finally, an increase in the transfer capacity between the NI and ROI may make the NI market more attractive to new entrants, since then generators located in NI would have access to a bigger market. All else equal, we would expect that to result in increased production efficiency due to increased competitive pressure on incumbents, although any such benefits are unlikely to materialise until many years into the future since the existing thermal generators in NI operate under long-term contracts the costs of which are passed through to customers independent of competition.

4.2.3. Benefits relative to the Baseline Interface

The benefits we have identified above are measured relative to the current system in which the NTC of the N-S interconnector is fixed annually. We would expect all, or a large proportion, of the above potential benefits to be captured under the Baseline Interface through "marginal trading" after D-1 gate-closure. Thus we would only expect limited incremental benefits due to an increase in N-S transfer capacity under MAE Integration.

4.3. Energy Pricing

4.3.1. Locational price signals: short-term effects on output and demand

Under MAE Integration, the ROI's LMP spot market would be extended to NI. An LMP spot market is commonly claimed to promote (1) efficient operation ("dispatch") of generators, (2) efficient management of demand, and (3) efficient choice of location for new investment in generation and facilities that use energy, but there is little empirical evidence available to support this claim.

It is notoriously difficult to estimate the potential benefits of improving the efficiency of despatch, since it is virtually impossible to model an ***in***efficient despatch realistically. We can however appraise the claims made for locational marginal pricing.

The MAE, like other LMP markets, relies on central despatch and does not offer any more efficient optimisation processes than other markets with central despatch. The source of claims for the efficiency of LMP markets lies instead in two features.

The first source of potential efficiency gains is the process for collecting information on the marginal costs of each generator. The process of setting LMP market prices is "incentive compatible", in the sense that it gives ***competitive*** generators (i.e. generators who are price takers) an incentive to submit offer prices equal to their marginal costs, so that the outcome of any normal optimisation process is a least-cost pattern of output. This outcome contrasts with "pay-as-bid" markets, or markets built around generators' nominations, where the efficiency of despatch depends partially on generators' ability to anticipate what the market price will be. The Northern Irish market allows generators to nominate their outputs, and so would be subject to the normal problems of pay-as-bid markets, but for a number of special factors. In practice the potential for central despatch to reduce the costs of operation in NI is limited by these factors:

- Much of the capacity inside NI is covered by long-term Power Purchase Arrangements, which already define the marginal cost of each generator fairly accurately, thus reducing the potential for improving efficiency by imposing an "incentive compatible" system of declaring offers;
- The NI market contains a small number of generator units, which limits the flexibility of choice over patterns of output, because of the need to allocate reserve securely;
- the marginal costs of different plants are distinct and differ by relatively large amounts, such that small errors in understanding marginal costs would not have a big effect on the "merit order" (relative ranking of generators) or on the pattern of output;
- the degree of concentration within the NI market (assuming, as our modelling indicates, it is effectively a separate market) means that generators may have incentives to offer prices other than their own marginal costs, in order to benefit from the exercise of market power, such that an LMP market is no longer "incentive compatible".[17] (We note that, within the ROI, ESB will be required or incentivised to submit offers based on marginal costs by regulatory constraints, rather than by the features of the MAE.)

These factors would all reduce the potential for adoption of the MAE within Northern Ireland to improve the efficiency of dispatch.

The second source of potential efficiency gains lies in the signals for generators to vary their output (and consumers their demand) in real time. LMP markets create a nodal spot price which signals the marginal cost of extra demand at each node. In principle, therefore, it provides a signal for generators and consumers to make efficient decisions about their actual output. In contrast, the NI market offers the corresponding incentives through its tariffs for spill and top-up, which are set in advance based on forecast costs. Such tariffs might

[17] The "legacy contracts" in NI counteract any incentive that Kilroot and Ballylumford would have to raise their offer prices above marginal cost in an LMP market.

occasionally encourage traders to deviate from their nominations in a manner which is inefficient and which raises the total costs of generation.

In practice, however, the MAE rules do not rely on LMP prices to encourage efficient decisions about generation and demand in real time. The signal to demand is distorted by the adoption of a single average price for demand, and we anticipate that NI would adopt a similar approach. Furthermore, the CER does not propose to use LMP prices alone to settle fluctuations in output from generators in real time. Instead, the MAE sets LMP prices applicable to a pattern of despatch instructions issued before the start of each period (and not, as in some markets, applicable to the actual pattern of metered output). In order to encourage adherence to these despatch instructions, the CER anticipates a set of penalties for deviations from instructions, linked to the cost of holding reserves. Incentives for efficient real-time decisions about output will depend on the method of calculating these penalties, rather than the LMP pricing system itself.

The CER has not yet explained how the market will calculate these penalties. However, there is no reason to believe they will offer more efficient real-time signals than any other tariff process. Indeed, the CER has indicated that the purpose of these penalties will be to encourage adherence to the hour-ahead instructions, rather than efficient deviations from them (much as NI's spill tariffs are intended to encourage adherence to nominations). We do not therefore anticipate any major reduction in costs from an improvement in real-time incentives.

4.3.2. Improvements in availability

The locational price signals offered by a LMP market also encourage more efficient decisions about availability. They reward generators for being available in the right place at the right time, by setting higher prices for output in congested areas, when the congestion occurs. By improving the accuracy of signals about the need for capacity by time and place, it may be possible to reduce the overall reserve margin of capacity and hence the need for installed capacity on the system as a whole.

However, in the ROI, incentives provided by LMP may be overridden by vesting contracts (for ESB) and other arrangements (for new generators under contract via the Generation Adequacy Scheme). Indeed, the proposal to adopt a Generation Adequacy Scheme implies that total installed capacity will remain centrally determined. As a result, the LMP system by itself may have little or no effect on incentives to make capacity available.

In NI, the effects of market pricing are also likely to be dominated by the incentives in the contracts covering existing capacity. Indeed, one of the beneficial effects of the contracts has been to increase availability considerably, compared with what was expected at the time of privatisation. Although this benefit has come at a relatively high cost, the savings in terms of the avoided cost of new investment in generating capacity have also been substantial. Further, generators in NI have achieved a high level of average annual and peak availability since privatisation. Therefore, even if the long-term contracts were not in place, the benefits of enhanced availability incentives under an LMP market would be small in NI because availability is already so high. This contrasts with the position in the ROI, where historically the availability of ESB's plant has been low, and the gains from improvements in availability could be substantial. Moreover, in a small market like Northern Ireland's, changing the location of generator availability offers less scope for reducing reserve margins and the need for total installed capacity.

4.3.3. Locational price signals: long-term effects on location of generation capacity

Our modelling shows that there is no congestion within the NI network through the period to 2009-10, across a range of demand scenarios. That means LMPs will not provide price signals for the location of generation investment in NI over that period, and so we would not expect cost savings in NI as a result of the theoretically efficient locational signals provided by LMPs.

Further, our modelling shows that addition of new generators to the ROI system (at Tynagh Mines and Auginish) would depress spot market prices at the node of connection, unless the transmission company upgrades capacity to take power away from the power station. Hence, in practice, the realisation of the benefits from efficient signals about the location of new investment depend as much on the investment incentives and responsiveness of the monopoly transmission company as on nodal spot prices. We anticipate the same being true within Northern Ireland and so discount more efficient location of generation as a potential benefit of MAE Integration.

4.3.4. Demand pricing

An NI demand price is equivalent to the wholesale price that would prevail in NI under the Baseline Interface, so we would not expect any costs or benefits, were NI to choose this option under MAE Integration. An all-island demand price, on the other hand, could be lower than an NI demand price, and hence potentially result in savings for NI consumers. Further, since any such savings would represent a wealth transfer from ROI consumers to NI consumers, they would represent a welfare gain to NI.

In our base case 2006-07 runs, we find that an all-island demand price would be lower than, or equal to, an NI demand price. As can be seen from Table 4.2, the range of potential savings for NI consumers is £1.2/MWh to £1.4/MWh in winter, and £0/MWh to £0.5/MWh in summer. If we assume that the middle of these ranges of savings correspond to the average value of the savings in winter and summer, respectively, we can make a rough estimate of what they might be worth on an annual basis. Based on this calculation, we estimate that the savings for NI consumers could be as much as £8 million per annum.[18]

As can be seen from Table 4.3, however, our base case 2009-10 runs tell a very different story, with the all-island demand price significantly above the NI demand price in both winter and summer maximum demand conditions. If we apply a similar calculation procedure to the one we have used above to estimate what this difference in demand prices would be worth to NI consumers on an annual basis, we find that NI consumers would suffer a large net loss with an all-island demand price.

Table 4.2
Comparison of All-island and NI Demand Prices 2006-07, £/MWh

	All-island (A)	NI (B)	Difference (C) = (A) - (B)
Winter peak hour	39.4	40.6	-1.2
Winter minimum hour	18.5	19.9	-1.4
Summer peak hour	19.0	19.0	0.0
Summer minimum hour	11.6	12.1	-0.5

Table 4.3
Comparison of All-island and NI Demand Prices 2009-10, £/MWh

	All-island (A)	NI (B)	Difference (C) = (A) - (B)
Winter peak hour	1024.0	85.2	938.7
Winter minimum hour	18.8	19.9	-1.0
Summer peak hour	30.6	21.0	9.7
Summer minimum hour	11.6	12.1	-0.5

18 Winter peak demand in 2006-07 is 1,807MW. Assuming a seasonal load factor of 70%, that translates to average winter demand of 1,265 MW. Multiplying this by an average value of savings in winter of £1.3 and by the number of hours in winter (approximately equal to half the number of hours in the year), gives an overall saving of £7.2 million in winter. The equivalent savings in summer are £1.2 million. So the total annual savings are £8.4 million.

Similarly, the sensitivity analysis we have carried out of the effects of (a) CO_2 trading and (b) wind generation indicates that NI consumers could be worse off with an all-island demand price.[19]

This analysis suggests that the appraisal of the costs and benefits of an NI demand price versus an all-island demand price is sensitive to the underlying assumptions about market conditions on the island. Further, in reality NI consumers are unlikely to benefit significantly from a lower all-island price in any event because they still have to pay the costs of the "legacy contracts" between NIE PPB and the existing thermal generators in NI.

4.3.5. A common all-island system of imbalance pricing

A common all-island system of imbalance pricing will avoid any possible distortions in cross-border trading caused by different systems of balancing prices on either side of the border. It is hard to quantify these potential benefits since it is difficult to model inefficient arbitrage trade caused by artificial differences in balancing prices.

Our modelling indicates that north to south flows across the N-S interconnector are only efficient during summer maximum demand conditions. However, since the beginning of 2002, when the Moyle interconnector started operation, significant north to south flows have occurred at most times during the year. That suggests that a large proportion of the trade which has taken place in recent years may be inefficient.

A large proportion of the power shipped south since the Moyle started operation has been power sourced from large-scale hydro facilities in Scotland, which counts as "green electricity" in ROI, but not in NI. This suggests that the distortions in north-south trade are more to do with differences in rules for the accreditation of "green" electricity either side of the border, and government policy on encouraging green energy, than differences in balancing rules.

Before the Moyle interconnector began operation, flows across the north-south interconnector were fairly marginal (averaging 0-20 MW in 2000 and 2001). So if differences in balancing rules caused distorted trade over the interconnector before January 2002, then the costs associated with that distortion were probably relatively small. Although the plant mix and marginal costs on the island have changed to some extent since then, this suggests that the benefits from aligning balancing rules on either side of the border may be small.

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19 In the CO_2 trading sensitivity, the all-island demand price is significantly above the NI demand price in 2006-07 winter peak conditions, and the two prices are equal in summer peak conditions. In the wind generation sensitivity, the all-island demand price is significantly above the NI demand price in summer peak conditions.

4.4. Other Changes to NI Market Rules

4.4.1. Gate Closure

As we discussed in our Interim Report, while NI remains separate from the MAE, NI traders could be exposed to added volume risk on cross-border trades due to the difference between the nature and timing of gate closure in NI and the MAE. Under the Baseline Interface, however, that volume risk has been removed because nominations fixed at NI gate closure are accepted by the MAE as a firm commitment to run. Therefore no risk mitigation benefit would arise from MAE Integration in respect of this aspect of cross-border trading.

Under MAE Integration, gate closure would be closer to real-time than under the Baseline Interface. In theory, that should increase the efficiency of dispatch in NI, as it increases the role of the market in deciding how to adjust to changes in market conditions close to real-time. In practice, however, adopting the gate closure of the MAE inside NI would impose new risks on the system operator in NI because of the uncertainties inherent in not fixing nominations at the day-ahead stage. The net effect of this rule change will therefore depend on whether the cost of this added risk is out-weighed by efficiency gains from the greater flexibility the MAE offers to traders. As the value of these costs and benefits cannot be estimated with any certainty, the net effect of this rule change is uncertain. Also the inflexibility of the plant on the system and operational requirements in NI (e.g., load cycling) add further constraints and risks in a small system.

Moving gate-closure for the Moyle interconnector to one hour before real-time carries particular risks for the system operator in NI and ROI because it is the largest in-feed on the island. However, any costs or benefits arising from such a change do not affect our appraisal as we assume that gate closure for the Moyle Interconnector will continue to be 24 hours before real-time under both the Baseline Interface and MAE Integration (cf. Section 0).

4.4.2. Settlement

The SMO would buy and sell all the energy traded in each half hour under MAE Integration, whereas under the Baseline Interface SONI would only buy and sell imbalances between nominations and metered quantities. This means that the SMO would face a higher level of counter-party credit risk under MAE Integration than SONI would face under the Baseline Interface. This increase in risk offsets a reduction in the counter-party credit risk faced by parties who sign financial contracts (since such contracts only require the transfer of "differences" between spot market and contract revenues, rather than the payment of full contract revenues). However, the SMO is unlikely to be able to manage credit risk as efficiently (i.e. using as much discretion) as individual contracting parties, raising costs in NI under MAE Integration relative to the Baseline Interface. This effect is likely to be small, but adverse to MAE Integration.

4.4.3. Operating Reserves

The creation of an all-island spot market for operating reserves that is cleared simultaneously with the energy spot market could potentially lead to savings in the form of lower reserve costs on the island as a whole. While any such savings would initially be captured by the SMO, we would expect NI to receive a fair share of these savings through joint control of the SMO or some arrangement for sharing the SMO's costs between NI and ROI.

Although we have not been able to model the effect of optimising the allocation of operating reserves across the island, SONI have informed us that previous studies have indicated that the current allocation is close to optimal. We see no reason to repeat these previous studies, as we would in any case be dependent upon the information in them. The result of these previous studies is not surprising, given that SONI and ESB NG already co-operate to minimise the joint costs of system operation, and given that SONI has regulatory incentives to achieve a least cost outcome for NI.

On that basis, we would not expect MAE Integration to produce significant savings in reserve costs over the Baseline Interface.

The adoption of a "causer pays" principle under MAE Integration, to allocate the costs of operating reserves to network users, could result in an increase or decrease in the costs borne by NI users, compared to the Baseline Interface. Improved cost signals as a result of "causer pays" pricing of reserves are likely to result in a reduction in the need for reserves. On the other hand, it could result in NI users bearing a higher or lower share of these costs. For example, the "run-way" approach floated by the CER allocates the costs of operating reserves in proportion to the size of users' connected capacity. Under that approach, NI users would be likely to end up bearing a greater proportion of the costs than under the baseline interface, since there is a greater proportion of large baseload plant in NI than in ROI. However, as the CER has not yet specified exactly how the "causer pays" principle will be applied under the MAE, it is not possible to say whether this aspect of MAE Integration will result in benefits or additional costs for NI.

4.5. Contracts

4.5.1. Existing PPAs in NI

If the MAE offers sufficient flexibility to accommodate the existing physical PPAs in NI without the need for re-negotiation, there will be no costs or benefits arising from this aspect of MAE Integration. However, many disputes arose in England and Wales over conversion of financial PPAs into a form suitable for NETA, and these disputes concerned the allocation of new costs and charges, as well as the new method of settlement. Existing contracts therefore face a risk of renegotiation for a number of reasons. We have not tried to quantify the ***expected*** cost of such (potential) renegotiations, but the cost of any actual renegotiations could be significant, say £250,000-£500,000 per contract (depending on the scale of the dispute resolution process).

4.5.2. FTRs

If the NI demand price is separate from the ROI price, NI players will need FTRs linking them to the NI demand price, and those that want to trade with the ROI will also need an FTR between the NI and ROI demand prices. However, only the cost of the first type of FTR would be incremental to MAE Integration, since players wanting to trade with the ROI would need the second type of FTR anyway under the Baseline Interface.

If the MAE sets a single all-island demand price, NI players would need FTRs linking them to the all-island demand price, but there would no longer be any need for additional FTRs linking two separate NI and ROI demand prices. That would lead to some cost savings relative to the Baseline Interface.

Our estimate of the cost of implementing the MAE in NI (cf. Section 4.1) already includes the incremental cost of FTRs linking NI traders to a demand node, whether that is an NI node or an all-island node. The savings in FTR costs that would result from an all-island demand price are hard to estimate, but it seems reasonable to assume that they will be proportional to the volume of trade between NI and the ROI. Our modelling indicates that in most conditions, the volume of trade is likely to be nil. Only in summer maximum demand conditions, do we predict any significant N-to-S trade. That suggests that there would be limited demand for FTRs between the NI and ROI demand prices under the Baseline Interface, and hence that the savings in FTR costs resulting from an all-island demand price would be small.

On the other hand, as we have already mentioned, since the Moyle Interconnector opened in January 2002, there have been large volumes of electricity traded N-to-S, and smaller volumes S-to-N. Our modelling may therefore imply that such trades are truly marginal (i.e. that they offer a minimal margin), or that they arise due to arbitrage between different traders with differing forecasts of electricity prices. One such form of arbitrage arises from the differences between GB, NI and the ROI in accreditation standards for green energy, which we believe has a significant (and predictable) effect. Were these levels of trade to persist in the future, then the savings in FTR costs as a result of the implementation of an all-island demand price under MAE Integration would be more significant than indicated by our modelling. However, since NI and the ROI are moving to harmonise renewable energy policy across the island, reflecting similar moves at an EU level, we do not expect these levels of trade to persist. We therefore think our modelling provides a better guide to the future levels of trade (or trading margins) between NI and ROI.

Due to uncertainties about the level of available transmission capacity, and the need to limit the frequency with which the SMO curtails the use of FTRs, the SMO cannot provide market players with enough FTRs to provide a perfect hedge against basis risk. That means NI players will still bear some of the cost of basis risk under MAE Integration. While this residual risk may be small, it could act to deter new entry and investment relative to the Baseline Interface, in which there is no basis risk in the NI market.

4.6. Market Institutions and Regulation

4.6.1. SONI's Role

As noted in Section 3, we only consider possible economies from merging SONI's ***market operator*** function with the SMO's under MAE Integration. SONI has informed us that it incurs annual costs of approximately £0.75 million in performing this function, which immediately places an upper bound on the potential savings from this aspect of MAE Integration. In practice, we envisage that potential savings would be lower than this, since the costs SONI incurs as the agent of PPB in managing the existing PPAs would not be avoided under MAE Integration. We therefore assume that savings would be of the order of £0.5 million per annum.

It is not clear, however, that a merger of the SMO's and SONI's market operator functions would result in net benefits to NI, since post-merger NI would be required to pay a share of the merged market operator's cost base. If that share were higher than SONI's current market operator costs (e.g. say because the SMO's existing cost base is high relative to SONI's), then NI would actually suffer a loss as a result of the merger.

4.6.2. Ofreg's Role

The MAE would change Ofreg's role in market governance. The relative complexity of the MAE compared to the current market arrangements in NI, together with the need for much closer co-ordination with the CER under MAE Integration, mean that Ofreg's administrative costs are likely to be higher under MAE Integration than under the Baseline Interface. Ofreg currently incurs annual costs of £1.4 million per annum in regulating the NI electricity industry.[20] Were Ofreg's budget to increase by 10% as a result of Ofreg's increased duties under MAE Integration, then that would add £0.14 million per annum to the costs of regulation in NI (approximately equal to the cost of hiring two new staff).

These additional costs would not be incurred under the Baseline Interface.

Ofreg would remain responsible for controlling market power. Our modelling indicates that NI would effectively remain a separate market under MAE Integration, due to transmission constraints between NI and the ROI. On that basis, we expect that Ofreg would still need to regulate NIE PPB's re-sale price within NI, since ROI generators will not provide an effective competitive constraint on NIE PPB, as well as continuing to regulate the way the costs of the "legacy contracts" are recovered. We do not anticipate any savings,

[20] Ofreg's Resource Accounts 2002/03.

therefore, in terms of the avoided costs of regulating PPB's market dominance as a result of MAE Integration.

As our modelling indicates that NI will remain a separate market under MAE Integration, Ofreg may find it necessary to introduce measures to control the market behaviour of ESB Coolkeeragh. However, since any such controls would also be necessary under the Baseline Interface, the cost of implementing these controls cannot be attributed to MAE Integration. It might be argued that it will be more complicated to control ESB Coolkeeragh's behaviour in the MAE than under the Baseline Interface, but since the solution in both cases is likely to be some sort of regulated contract, that argument does not appear to us to be well founded.

4.7. The Moyle Interface

There would be no difference between MAE Integration and the Baseline Interface in terms of the operation of the Moyle interconnector, so we do anticipate any associated costs and benefits as a result of MAE Integration.

4.8. Renewables: ROCs and Accreditation of Green Energy

There would be no difference between MAE Integration and the Baseline Interface in terms of the operation of a system of ROCs in NI, so we do not anticipate any associated costs and benefits as a result of MAE Integration.

The need to change the accreditation system for green energy in NI as a result of MAE Integration may impose some additional administrative costs on NI. However, these costs are likely to be minimal provided that compatible systems of ROCs are put in place in NI and ROI, as we assume would be the case.

Any changes to the accreditation system for green energy would not produce any benefits relative to the Baseline Interface.

4.9. Other Issues

4.9.1. Government Policy

While differences between government polices adopted in NI and ROI (e.g., on carbon trading) have the potential to distort trade and investment decisions on the island of Ireland, these distortions would occur independent of whether or not NI chooses to integrate with the ROI's MAE market. We do not therefore anticipate any costs or benefits related to changes in government policy, or differences in government policy, as a result of MAE Integration.

4.9.2. Currency Issues

If the UK remains outside the Euro area, there would be some administrative costs associated with changing the MAE rules to work with Pounds as well as Euros, or to convert NI bidding and settlements systems to work with Euros. Assuming that an integrated MAE market would work in Euros, NI market participants are also likely to incur some costs in hedging the value of their trade balances in-between the end of the trading period and the period when they are cashed out. This could potentially impose significant costs on NI as the currency risk would apply to all sales rather than just exports, but since we have no data with which to estimate these costswe have not factored them into our estimate of the costs of implementing MAE Integration in NI (cf. Section 4.1).

Changing the MAE rules to accommodate Pounds, or the NI market systems to work in Euros, would not result in any benefits relative to the Baseline Interface.

4.10. The Effect of ESB's Market Power

ESB's market share is so high that there is a strong presumption ESB holds significant market power in the ROI market.[21] Our modelling indicates this presumption is valid, as we find ESB can profitably raise prices in the ROI market in both summer and winter peak conditions (at least, in the short-term, without allowing for any impact on entry into the market).

As part of our appraisal of the costs and benefits to NI of MAE Integration, we need to consider the impacts of ESB's market power, and the CER's proposals to control ESB's market power, on NI. Our modelling looks at the incentives facing ESB to raise its prices above its marginal costs. The CER acknowledges the need to control ESB's market power under the MAE, and plans to impose vesting contracts to incentivise ESB to behave like a "competitive generator". We consider the impact of these constraints later.

It is only where the impacts differ as between MAE Integration and the Baseline Interface, that we need to count them in our cost-benefit calculation.

4.10.1. The effect of ESB raising its offer prices

To help us assess the effect of ESB market power on NI, we modelled the effect of ESB raising its offer prices by 10% in 2006-07 winter and summer peak conditions, under an MAE Integration scenario (i.e. assuming an all-island LMP spot market).

21 ESB's market share at the generation level is well above the 50% threshold level at which there is a presumption of dominance under European Community competition law (cf. ***AKZO v Commission***, Case C-62/86 [1991] ECR I-3359).

In winter peak conditions, we find that while it is profitable for ESB to raise its offer prices by 10%, confirming that ESB has market power, this has no knock-on effects on LMP prices and output levels within NI. In the base case, LMP prices within NI are well-above those in the ROI, and the 275 kV interconnector is therefore congested S-to-N. When ESB raises its prices by 10%, LMP prices rise in the ROI, but not by enough to reverse the direction of flow on the 275 kV interconnector. Hence, LMPs in NI continue to be determined by conditions within NI, as in the base case. So in this variant, the only way ESB's market power would affect NI is if there were a single all-island demand price. In that case, the price paid by NI consumers would rise by about 11% as a result of higher LMP prices in the ROI. That would represent a transfer of wealth from NI consumers to ROI generators, and hence a loss of social welfare for NI.[22]

In summer peak conditions, we again find that it is profitable for ESB to raise its offer prices by 10%, but this time LMP prices and output levels in NI are also affected. In the base case, LMP prices are more or less constant across the island, and there is an uncongested N-to-S flow of about 117 MW. When ESB raises its prices by 10%, the steam units at Ballylumford, which were not dispatched in the base case, displace some of ESB's higher price (but lower cost) units. This results in increased N-to-S flow over the 275 kV interconnector and 5% higher LMPs throughout NI (and the ROI). Higher LMPs across the island mean that NI consumers must pay higher wholesale prices, independent of the rule used to set the demand price.

Given the low elasticity of demand for electricity, this price rise has little impact on costs and benefits within NI. In effect, the increase in LMPs inside NI causes a transfer of wealth from NI consumers to NI generators but, because of the low elasticity of demand of electricity, electricity consumption and, hence, social welfare in NI fall very little.

Most of the increased profits earned by generators and importers in NI would eventually be recycled to consumers anyway through regulation of PPB, and increased revenue from the interconnector auctions for Moyle. So even the transfer of wealth from NI consumers to NI generators under this variant is likely to be limited.

4.10.2. The effect of CER's measures to constrain ESB market power

The potential negative effects of ESB's market power would all be avoided, of course, if the vesting contracts the CER plans to impose on ESB function as intended. The analysis above suggests that ESB's market power is likely to have little effect on NI social welfare, even if the vesting contracts imposed on ESB are too weak. As we discussed in our Interim Report, however, there is also a risk that the vesting contracts, in combination with the CER's

22 Even though we have not run this variant in winter and summer minimum demand conditions, we believe that we would obtain the same results as in winter peak conditions, since in both cases the N-S interconnector is again congested S-to-N in the base case.

planned Generation Adequacy Scheme, have the unintended effect of depressing ROI LMPs below the level needed to remunerate new investment.

The CER's current proposals for vesting contracts anticipate some kind of "LOLP-related" mark-up (i.e. an increase in ESB's offer prices above marginal costs that is derived from a model of the Loss of Load Probability (LOLP), or a similar indicator of capacity shortage). The Generation Adequacy Scheme, by avoiding any shortages of capacity, may mean that LOLP is never very high, so LMPs in the ROI never reach the level required to encourage independent investment. This outcome would depress export earnings, but our modelling suggests that this would have little effect on NI since in most of the variants we have analysed LMPs in NI are determined by conditions within NI and not ROI.

4.10.3. Summary

Our modelling and analysis suggests that neither ESB's market power, nor the vesting contracts the CER proposes to use to constrain ESB market power, have a significant effect on the costs and benefits of MAE Integration for NI.

Furthermore, were we to have modelled the same ESB market power variants under the Baseline Interface scenario, we would have got more or less the same results, due to the absence of congestion within the NI network. The only differences would have related to demand prices, as an all-island demand price is not an option under the Baseline Interface. So while ESB market power, and the CER's proposals for controlling ESB's behaviour, may have adverse effects on NI, they are likely to be the same regardless of whether NI joins the MAE. Therefore, we do not anticipate any costs and benefits from MAE Integration in relation to this aspect of the market.

4.11. Conclusion

Table 4.4 summarises our evaluation of the costs and benefits of MAE Integration compared to the Baseline Interface. The only items we have been able to put a value on are either implementation costs or changes in administrative costs. While we have not been able to value a range of items that relate to the potential market effects of MAE Integration, our analysis of these items leads us to conclude that the net benefits associated with these other items are probably close to zero. In particular, as we find no evidence that an LMP market would provide any locational price signals within NI through 2009-10, we conclude that one of the main potential benefits of an LMP market is of little or no value in NI.

Table 4.4
Summary of Costs and Benefits of MAE Integration, £ million

	NPV	One-off (Yr 0)	Annual (Yrs 1-10)	Notes
BENEFITS				
Avoided interconnector trading system costs	0.5		0.1	
SONI's avoided market operator costs	3.8		0.5	
Other benefits	?		?	Our analysis indicates that these are probably close to zero
Total benefits to NI	4.2		0.6	
COSTS				
NI incremental costs	8.2	5.6	0.4	
Ofreg's additional regulation costs	1.1		0.2	
NI contribution to ROI's costs	0 to 12.3	0 to 10.3	0 to 0.3	Our analysis indicates that these are probably close to zero
Total costs to NI	9.3 to 21.6	5.6 to 15.9	0.6 to 0.9	
NET BENEFITS	-5.1 to -17.4	-5.6 to -15.9	0.2 to -0.1	

5. CONCLUSIONS & RECOMMENDATIONS

Our cost-benefit analysis of MAE Integration indicates that it would not be beneficial for NI to join the ROI's MAE market at the present time. In the specific circumstances of NI, we have found no evidence that the locational price signals the MAE market is designed to provide would produce any benefits for NI though the period to 2009-10. That assessment is based on our modelling of an integrated all-island LMP market under a range of demand and supply scenarios.

The only significant benefits we have been able to identify with any certainty have been possible savings in administrative costs associated with the removal of interconnector trading systems and the merger of SONI's market operator function with that of the SMO. However, these benefits are likely to be matched by the additional costs of operating the new systems needed to run an LMP market within NI, and new administrative costs at Ofreg.

We have been unable to put values on the costs and benefits of a range of market effects that may result from MAE Integration, but we see no ***a priori*** reason to assume that the benefits (e.g., from more perfect optimisation of the use of interconnectors) would outweigh the costs (e.g., from negative effects of "basis risk" on entry and competition).

In any event, as can be seen from Table 4.4, the net benefits of the items that we have not been able to evaluate would have to be worth between £5.1 million and £17.4 Million in NPV terms to make MAE Integration worthwhile for NI. At present, we find it hard to see how these other items could yield that level of net benefits. Further, we would not expect that conclusion to change until one or more of the following conditions occur:

- significant new investment in generation and or transmission capacity on the island, above and beyond that envisaged in ESB NG's and SONI's latest forecast statements;
- the commissioning of the planned interconnector between the ROI and Wales;
- the termination of the long-term contracts in NI;
- a change to the MAE design leading to a significant reduction in the costs of implementation and/or change to the other costs and benefits of MAE Integration.

Part of the reason we have not identified larger benefits from MAE Integration is that we have appraised it against a Baseline Interface that already captures some of the potential savings from more efficient trading between NI and ROI. Indeed, since the Baseline Interface already includes provision for "with-in" day third-party trading between NI and ROI on the MAE model, it can be said to already incorporate a degree of all-island market integration.

In the light of these findings, we recommend that NI should not join the MAE at the present time. Instead, we recommend that NI review the position again in three to five years, or earlier if one of the above conditions changes, and decide again then whether the benefits of MAE Integration outweigh the costs. This approach has the advantage that many of the uncertainties concerning, for example, the design of the MAE and the potential for a wider UK market on the BETTA model, are likely to have been resolved. Further, the ROI's LMP market will have a track-record that can be used to appraise the effects of MAE Integration on NI. All of which will put NI in a better position to appraise the benefits of joining the ROI's MAE market to form an integrated all-island market.

APPENDIX A. CER'S INTERCONNECTOR OPTIONS PAPER

A.1. Option 3

In the course of meetings, we established that the CER and its advisors envisaged Option 3 as a system in which traders inside Northern Ireland would submit offers at MAE gate closure to use the interconnector. The MCE would then accept the lowest cost combination of offers, up to the capacity of the interconnector. This approach is not consistent with current NI arrangements, which do not permit traders to submit offers that may be accepted or rejected at the hour-ahead stage. Instead, NI trading rules require traders to nominate fixed ("firm") quantities at gate closure. (Even moving gate closure to one hour ahead of despatch would not change this principle.) Option 3 would therefore require a radical change in NI trading arrangements and would, in practice, be tantamount to acceptance of the MAE approach to despatch and pricing within NI. We have therefore decided to exclude it as a possible baseline for comparison with MAE Integration.

A.2. Option 1

Option 1 is consistent with current NI trading arrangements, in that it assumes firm nominations. It still requires a process for allocating capacity to enter the interconnector (e.g. an auction of capacity at the Tandragee sub-station), so it does not avoid the costs of allocating interconnector capacity. More importantly, trading at the northern end of the interconnector creates further problems for pricing and risk management, which had led us to reject it in our Interim Report.

At the interface between NI and the ROI, the capacity of the interconnector is not defined by the physical characteristics of the cross-border lines, but by the security considerations of both systems and by the needs of the reserve sharing agreement. The "Net Transfer Capacity" available to interconnector users is therefore a contractual device, intended to ensure that third party nominations are consistent with the requirements of system security. The MCE would need to incorporate the same measure of cross-border capacity to ensure that the accepted flow was equally secure.

Our modelling shows that there are conditions in which congestion on the N-S interconnector leads to "price separation", whereby the price at the northern node would equal the highest accepted offer at that node, rather than any price determined by offers in the ROI. (As we said in our interim report, the price at the northern node would be determined by conditions inside Northern Ireland, rather than by market conditions inside the ROI.)

In itself, price separation need not create a problem for traders or for Northern Irish consumers. The difference between prices at the northern and southern ends of the interconnector can be offset by possession of FTRs (in addition to any FTRs covering the price difference between the southern end and the uniform ROI demand price). However, the CER has yet to detail how FTRS will be designed and allocated, which lends this solution a degree of risk at this stage.[23] In any case, offering FTRs for the interconnector is equivalent in terms of economic incentives and financial outturns to allocating physical capacity rights and trading at the southern end (as in option 2).

In discussion with the CER's advisors, we identified an alternative solution, which is to define the cross-border capacity within the MCE to be always one or two MWs larger than the Net Transfer Capacity awarded to interconnector users. Under this approach, the interconnector would never appear congested to the MCE and prices at either end would remain the same. However, this approach requires a rule that is special to the interconnector and is tantamount to trading at the southern node anyway.

Option 1 is therefore feasible, but requires either an additional set of FTRs (in addition to a new scheme for allocating access at Tandragee) or special rules for defining interconnector capacity to avoid congestion and price separation. It therefore seems to entail higher transactions costs than options in which the interface is placed explicitly at the southern end of the interconnector, whilst offering no advantage.

A.3. Option 4

Our discussions with the CER highlighted a likely outcome of adopting Option 4, namely that interconnector users would be likely to offer their power at prices equal to the spill tariff applicable in Northern Ireland at the time. The reasoning behind this conclusion was that LMP markets give generators an incentive to offer power at their own marginal cost of generating. For interconnector users, once they have made their nominations inside NI and over the interconnector, their marginal cost is the spill tariff – i.e. the revenue that they would receive for any nomination that was rejected and hence spilled inside NI.

If the LMP price at the southern node (Louth) falls below the spill tariff inside NI, interconnector users would want their offer to be rejected, so that they could capture a higher price, by spilling power inside NI. Interconnector users would find this risk of rejection manageable, if they were protected against the fall in the Louth LMP by possession of (1) FTRs covering the difference between the Louth LMP and the uniform demand price and (2) CfDs covering the difference between the uniform demand price and their contract price. Hence, Option 4 offers some advantages to interconnector users, if they can acquire the necessary contractual protection against market and basis risk.

SONI expressed major concern about this possible outcome, however, because accepting or rejecting interconnector users' offers based on the difference between the Louth LMP price and the NI spill tariff is unlikely to result in efficient decisions. If offers were rejected, such

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23 Some high-level principles are set out in the CER's recent ***Draft Decision on FTRs in the MAE***, 23rd April 2004.

that large amounts of energy were spilled within NI, SONI could react in several different ways:

- First, SONI could absorb the surplus power inside NI, by reducing output from Northern Irish generators. However, it would be expensive – or even infeasible - to ask generators to reduce their output at short notice, given that they might have to increase it again in the next half-hour (i.e. when the MAE next accepts offers from interconnector users).

- Second, SONI could ask the Moyle interconnector to reduce the power it was feeding into Northern Ireland, thereby passing the surplus power back into the British system. At present, SONI has no means for requesting such short-term adjustments to flows over the Moyle interconnector and the owners of the interconnector would not grant such additional privileges without a charge. Even if they did amend the agreement, the despatch of interconnector users based on the NI spill tariff would be inefficient, to the extent that the tariff differed from the spill tariff (or marginal costs) in Britain.

- Third, SONI could engage in some kind of real-time trade (i.e. a trade arranged after MAE gate closure) with the System and Market Operator (SMO) in the ROI, to restore the flow over the interconnector. The SMO could arrange this trade by picking a "default offer" submitted by SONI. This response system would take the risk of low Louth LMPs from interconnector users and impose it on SONI (and hence NI consumers).

Each of these three ways of using the interconnector bears little relation to relative marginal costs in NI and the ROI, which would determine an efficient pattern of usage. Instead, each response is a form of arbitrage between spill tariffs and other prices, with different allocations of risk between various parties. Therefore, given that NI stays out of the MAE, Option 4 is not necessarily any more efficient than Option 2. Indeed, Option 4 may cause operational problems, if SONI is not able to arrange the disposal of surplus power in an orderly manner. For this reason, we do not regard Option 4 as a desirable outcome.

A.4. Option 2

Option 2 comes closest to the recommendation set out in our interim report of November 2003. It involves trading electricity at the southern end of the interconnector based on the acceptance of firm nominations by interconnector users. To be able to make such nominations, interconnector users would buy interconnector capacity rights in an auction, as at present. The CER's preferred method of arranging the acceptance of firm nominations within the MAE is to calculate an offer (or bid) price which ensures that each nominated North-South (or South-North) flow is accepted, whereas we had foreseen that the Market Clearing Engine (MCE) would simply treat nominations as a commitment, but the effect is the same in either case. Both schemes remove any risk that a nomination will not be accepted by the MCE.

APPENDIX B. MAIN FEATURES OF THE MAE

The high-level principles of the MAE were laid down in ministerial regulation S.I. 304.[24] This regulation mandates the CER to implement a new spot market in the ROI, as well as a number of other measures aimed at ensuring efficient operation of this market. The CER has subsequently fleshed out some of the details of these arrangements in a series of consultation documents.

B.1. The Spot Market

The main features of the ROI's proposed new spot market are summarised in Box B.1. This type of "nodal spot market" for electricity, which the CER calls "Locational Marginal Pricing" or LMP, is said to promote (1) efficient operation ("dispatch") of generators, (2) efficient management of demand, and (3) efficient choice of location for new investment in generation and facilities that use energy. An LMP market design provides for efficient ("incentive compatible) pricing of congestion in the transmission system, but it does not remove congestion.

Box B.1
Main Features of the Spot Market

The centre-piece of the new MAE will be a mandatory centralised spot market, or pool. The spot market is mandatory in the sense that all generators (or importers[25]) are obliged to sell, and all suppliers (or customers acting as suppliers) are obliged to buy, all their electricity on the spot market.

The spot market prices received by generators and paid by suppliers will be based on market clearing locational marginal prices (LMPs). The spot market price received by all generators located at the same node will be the LMP at that node. Generators located at different nodes may receive different spot market prices, reflecting differences in LMPs. Suppliers will pay a uniform demand-weighted spot market price irrespective of the location of their demand.

The SMO will clear the spot market and dispatch the system simultaneously. The SMO will dispatch and operate the ROI power system in accordance with the spot market rules, the grid code, and other operational procedures.

The SMO will be responsible for settlement of spot market trading. Settlement will be on the basis of the gross quantities traded through the spot market. The SMO will take

[24] ***S.I. No. 304 of 2003, Electricity Regulation Act 1999, (Market Arrangements for Electricity) Regulation 2003.***

[25] Throughout this section, references to generators should be interpreted to include importers unless otherwise stated.

no account of any financial hedging contracts (e.g. CfDs) between generators and suppliers in the settlement process.

The spot market will be an electricity, or energy, only market. There will be no side payments for unit start-up, shut-down, etc. and no separate capacity payments.

A supplier can elect to define part of its demand as dispatchable. A supplier is required to offer its dispatchable demand into the market.

The SMO will operate a spot market for operating reserves in parallel with the energy spot market. The SMO will clear these markets simultaneously to ensure that the joint cost of meeting demand in these markets is minimised. Other ancillary services will be procured by the SMO under long-term agreements.

B.2. Other Aspects of MAE

The main other measures which the CER plans to introduce to support the operation of the new spot market in the ROI are as follows:

- ***market power mitigation measures*** – the CER plans to control ESB market power through a regulatory process including imposition of vesting contracts on ESB Power Generation (ESB PG);
- a ***Fast Build Agent*** – the CER proposes to appoint a Fast Build Agent with the aim of ensuring that there is adequate generating capacity available to the ROI market; and
- ***financial transmission rights (FTRs)*** – the CER will require the SMO to issue FTRs to allow market participants to hedge price differences between injection nodes and the uniform demand price.

APPENDIX C. MAE IMPLEMENTATION COSTS

In this appendix we set out our estimates of the costs of implementing the MAE market in the ROI and extending it to NI. Our estimates are based on the costs of implementing LMP systems in other markets, information we have gleaned from sources in the ROI, and data on the costs of implementing change in other non-LMP markets. Since the comparability of the data we have obtained is uncertain, because of possible variations in accounting conventions, and data drawn from other markets may not be representative of the peculiarities of the ROI and NI markets, our cost estimates are necessarily subject to a large degree of uncertainty. Further, because the allocation and classification of costs may vary across the markets we have studied, the accuracy of the break-down of costs presented in this appendix is particularly uncertain.

C.1. Costs of Implementing Other LMP Markets

Most of the information we have collated on other markets concerns the costs of implementing the systems needed to make an LMP market operational, rather than the cost of designing an LMP market. Only for Singapore did we obtain some information on the design costs.

C.1.1. Design Costs

The total upfront costs of restructuring the electricity industry in Singapore were approximately £42 million.[26] However, a large part of these costs, approximately £17.5 million, resulted from the creation of retail competition in Singapore. Deducting this cost item from the total gives a figure of £24.5 million for the costs of designing and implementing the new LMP market in Singapore.

Of this £24.5 million, we estimate that approximately £13 million is attributable to system implementation costs (including £4.9 million for the SMO's new IT systems, which we discuss further below), rather than designing the market. So we estimate that the total costs of market design in Singapore were approximately £11.5 million, or £1,290/MW.

C.1.2. Implementation Costs

- Nature of Costs

Once the design of an LMP market has been decided, a range of new information and communication systems need to be put in place to make the new market operational. These include:

[26] All figures are in 2003 money terms, unless otherwise indicated.

- SMO systems
  - the market clearing engine (MCE);
  - the systems used to capture offers from market participants, and communicate with market participants about their offers and the results of the MCE pre-dispatch and market dispatch runs, etc.;
  - the settlement systems;
- systems used by market participants
  - the systems used to submit offers to the SMO, and communicate with the SMO about offers and the results of the MCE pre-dispatch and market dispatch runs, etc.; and
  - the settlement systems.

In addition to implementing the above systems, it is also necessary to carry out a study to verify the data needed by the MCE, and prepare the legal documentation that governs relations in the new market.

- Cost of the MCE and Associated Data Transfer Systems

Our analysis of other markets indicates that the single biggest one-off implementation cost is the IT system needed to operate the centralised LMP spot market (i.e. the MCE and associated systems). The cost estimates for this item range from approximately £20 million for PJM in the north-eastern US (quoted to the CER) to £3.2 million for New Zealand (based on our contacts). The difference in cost between these two systems seems to be a function of their size. At the time PJM implemented an LMP system, it covered about 58 GW of installed capacity, whereas New Zealand covered only about 8 GW of capacity. The other two LMP markets for which we have obtained equivalent cost estimates are Singapore and the Philippines. Singapore's system cost approximately £4.9 million for 9 GW of installed capacity, and the Philippines' cost £6.4 million for about 13 GW. Table C.1 shows this data and the cost per unit of generator capacity.

Table C.1
MCE and Associated System Costs of Selected LMP Markets

Item		PJM	New Zealand	Philippines	Singapore
Total Cost Estimate	(£ million)	20.0	3.2	6.4	4.9
Installed Capacity	(MW)	58,000	8,000	13,000	9,000
Unit Cost Estimate	(£/MW)	345	400	492	544

The data in the above table suggests that MCE system costs are strongly related to the size of the system. While we would expect some relationship with size, reflecting the need for larger networks to accommodate larger data flows from more sources, the strength of the observed relationship is surprising given that software procurement costs are likely to be relatively fixed. There is some evidence of economies of scale at the scale of the PJM system. PJM's IT system cost £345/GW of installed capacity, compared to £400-£500/GW for New Zealand, the Philippines and Singapore, but the pattern is not clear within the smaller scale examples. New Zealand achieved a lower unit cost than the other two examples, despite being a smaller system. We believe that this lower cost reflects the more informal methods used at the time in New Zealand to develop the market rules and do not necessarily capture all the costs of an organised, centralised procurement process. For systems the size of the ROI, a higher unit cost of £500/MW of installed capacity is likely to be more accurate.

- Settlement System and Other Central Costs

The other one-off costs of setting up an LMP market include changes to settlement systems, data verification studies, legal documentation, and process management. The only market for which we have obtained an estimate of these costs is New Zealand. There these other costs amounted to approximately £3.7 million, or £480/MW of installed capacity.

We were not able to obtain any direct estimates of the additional running costs of operating an LMP market, but have compiled an estimate on the following basis:

- two additional full-time employees at £55,000 per annum each to operate the new IT systems;
- IT system maintenance at 10% of the set-up costs of these systems.

These parameters are similar to those used by Elexon to estimate the cost of software changes to the Balancing and Settlement Code in Britain.

- Market participants' costs

The cost estimates presented above cover only the costs of the central systems that the SMO needs to operate an LMP market. However, market participants would also incur new one-off and additional running costs associated with the installation and management of new systems that are required to operate in an LMP market. We have not been able to obtain any estimates of these costs from other LMP markets.

In its appraisal of the costs and benefits of BETTA for GB, Ofgem put the costs to market participants in Scotland of developing new systems to operate under BETTA at about £4 million, with additional running costs of £0.5 million per annum. This translates into about £430/MW of extra one-off costs, and £55/MW per annum of extra running costs. We use these figures as an estimate of the costs to ROI and NI market participants of adopting new systems to operate under an LMP market.

C.2. Costs of Implementing the MAE in ROI

C.2.1. Design Costs

The ROI has already incurred significant costs in designing the MAE, and will incur further design costs this year and possibly next. A recent ESB NG document estimated that ESB NG would incur costs of €20 million (£13 million) in Phase I ("Analysis and Design") of its MAE work programme. We understand from discussions with IME members that this cost estimate excludes the costs of procuring and installing the MCE and other new systems, and so represents a "design cost" in the terminology we have used above.

To that figure must be added the CER's own costs of designing the MAE, which we assume will be of the order of £4 million,[27] and ROI market participants' consultation costs, which we assume will be of the order of £2 million.[28]

That gives an overall figure for the cost of MAE design of £19 million, or £2,950/GW, which is considerably higher than the equivalent figures for Singapore. Some of the difference may be explained by differences in market design between the MAE and Singapore (e.g. Singapore does not have FTRs), but even allowing for such differences it is hard to understand why the MAE should cost so much more to design. For the purpose of our appraisal, however, we have used the above estimates of MAE design costs, rather than a figure based on costs for the Singapore market.

C.2.2. Implementation Costs

Using the cost data we have obtained for other markets, we estimate that the ***one-off*** costs of implementing an LMP market in the ROI will be of the order of £9.0 million. The calculation of this estimate is illustrated in Table C.2.

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27 This is half the level of Ofgem's costs for development of BETTA (cf. ***Energy Bill: Portfolio of Partial Regulatory Impact Assessments***, DTI, 2004).

28 This is equal to Ofgem's estimate of the costs to Scottish market participants' costs of participating in consultations as part of BETTA development (cf. ***Energy Bill: Portfolio of Partial Regulatory Impact Assessments***, DTI, 2004).

Table C.2
Estimate of the One-off costs of Setting-up an LMP market in the ROI

	Unit cost, £/GW (A)	ROI capacity in 2006, GW (B)	One-off cost, £ Mn (C) = (A) * (B)
Central / SMO costs			
IT systems	500,000	6.4	3.2
Other one-off costs	480,000	6.4	3.1
Market participants	430,000	6.4	2.8
Total	1,410,000		9.0

In terms of additional central ***running*** costs, the figures from other LMP markets imply £110,000 per annum for the extra staff costs of administering the IT systems, and extra maintenance costs of £375,000 per annum for maintaining the IT systems (approximately 10% of the set-up costs). And for market participants in ROI, they imply an additional £350,000 per annum of running costs.

These cost estimates exclude the costs of setting-up and operating financial transmission rights (FTRs). We do not have any data from other markets, or estimates from industry participants, upon which to calculate a figure for the cost of FTRs. However, since it is widely acknowledged that this is a complex task, we would expect these costs to be non-negligible. In practice, they effectively require a "duplication" of the central market software and settlement systems, and so would be likely to add at least another £3 million or so, plus 10% of that figure for annual operating costs.

In total, therefore, we estimate that the cost of implementing an LMP market in the ROI, including the cost of FTRs, will comprise:

- one-off costs of around £12 million; and
- additional running costs of the order of £1.1 million per annum.

C.2.3. Summary

In summary, therefore, adding together design costs and implementation costs, we estimate that the total costs of implementing the MAE in the ROI will comprise:

- one-off costs of around £31 million; and
- additional running costs of the order of £1.1 million per annum.

C.3. Costs of Extending the MAE to NI

C.3.1. Design Costs

As we have already mentioned, we expect the ***incremental*** design costs of extending the MAE to be small relative to the ROI's because of our assumption that the MAE is extended to NI with minimal modification under the MAE Integration scenario. Nonetheless, we expect that NI would still incur some incremental design costs (e.g., to reform the legal framework and undertake consultation with interested parties in NI). We therefore assume that NI 's incremental design costs will be equal to 10% of the ROI's, adjusted pro rata to reflect the difference in the size of the NI and ROI markets. That gives a figure of £1.9 million.

Were the CER also to require NI to pay one third of ROI's MAE design costs, reflecting the fact that NI market represents one third of the all-island market, that would raise the overall design costs for NI to £8.2 million.

C.3.2. Implementation Costs

Since the MAE will already have been implemented in the ROI, one might expect the unit cost of extending the MAE into NI to be less than the unit cost of implementing it in the ROI. However, we found no evidence of economies of scale in the costs of the IT systems in other small markets, and we see no reason to expect economies of scale for other cost items. We have therefore used a similar procedure to calculate the implementation costs of extending the MAE to NI, as we used to calculate the costs of implementing the MAE in the ROI.

We estimate that the one-off implementation costs of extending the ROI's LMP market to NI, including the cost of FTRs, will be of the order of £3.7 million.[29] The calculation of this figure is illustrated in Table C.3.

Further, we estimate the additional running costs would be about £350,000 per annum.[30]

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[29] These figures are based on projected installed capacity in NI in 2006 of 1.95 GW (i.e., after the commissioning of the new CCGT being constructed by ESB at Coolkeeragh).

[30] One extra full-time employee at £55,000 per annum to administer the IT systems; extra maintenance costs of £100,000 per annum for maintaining the IT systems (approximately 10% of the set-up costs in NI); additional running costs for market participants of £110,000 per annum; and FTR system operation costs of £90,000 per annum.

Table C.3
Estimate of the One-off costs of extending the ROI's LMP market to NI

	Unit cost, £/GW (A)	ROI capacity in 2006, GW (B)	One-off cost, £ Mn (C) = (A) * (B)
Central / SMO costs			
IT systems	500,000	1.95	0.97
Other one-off costs	480,000	1.95	0.93
Market participants	430,000	1.95	0.80
FTRs	470,000	1.95	0.97
Total	1,410,000		3.7

Were the CER also to require NI to pay one third of the ROI's MAE implementation costs, that would raise NI's overall implementation costs to:

- £7.7 million of one-off costs; and
- additional running costs of the order of £0.7 million per annum.

C.3.3. Summary

Using the above estimates, we can calculate a range for the costs of extending the MAE to NI. Were the CER to require NI to pay one third of the ROI's MAE design and implementation costs, we estimate that the costs of extending the MAE to NI would comprise:

- one-off costs of around £15.9 million; and
- additional running costs of the order of £0.7 million per annum.

Were NI to make no contribution to the ROI's MAE design and implementation costs, we estimate that the costs of extending the MAE to NI would comprise:

- one-off costs of around £5.6 million; and
- additional running costs of the order of £0.4 million per annum.

Together these estimates give a range of:

- £5.9 million to £15.9 million of one-off costs; and
- £0.4 million to £0.7 million of additional running costs.