Cliona McNally,
Commission for Energy Regulation,
Plaza House,
Belgard Road,
Tallaght,
Dublin 24.

10th October 2003.

Dear Cliona,

Market Arrangements for Electricity – Consultation on CER Document CER/03/230

Please find attached Airtricity's comments on the above paper.

We are awaiting a paper from the CER relating specifically to renewables. We would therefore propose that we should meet with the CER once we have received this paper and go through with the CER our view of the detailed issues arising from these two papers.

We will be attending the CER's session on renewables on 13th October and the public forum on 23rd October. We would suggest it is probably appropriate to meeting on a mutually convenient date between these two dates.

In the meantime if you have any queries on the attached paper, please do not hesitate to contact us.

Yours sincerely,

Dermot O'Kane
Regulation & Trading Manager

MAE Consultation Paper – CER/03/230, dated 12 September 2003-09-30

Response by Airtricity

Airtricity has considered the above consultation document and wishes to comment as follows:

There are a number of issues which are not addressed in this paper and which we feel need to be addressed. They include:-

- De-minims threshold applicable to generation units
- Detailed treatment of embedded generation
- Interaction of renewables with the MAE
- Treatment of interconnectors
- Details on treatment of FTRs and CFDs
- Settlement surplus treatment
- Interaction between long term transmission planning and FTR instruments

Whilst we appreciate that some of the above issues will be the subject of future detailed papers, it is difficult to comment on some of the issues raised in this paper, without some views as to the range of options with respect to the above.

Airtricity's detailed comments on the CER paper are set out below:-

2.1 Spot market structure

Footnote 10 indicates that the situation regarding ESB PES being the difference provider to the market in terms of providing/absorbing the difference between QH metered plus profiled demand estimate and actual system energy requirements is being reviewed. In a market in which the primary concern is one of dominance, it is inappropriate for one Supplier to be treated differently from all others; no doubt receiving some balancing benefit from the market.

2.2.1 Structure of generation offers

It will be difficult in practice to police the requirement for generating units to bid in a manner that reflects the unit's characteristics. CER should publish proposals on how this can be achieved.

2.2.8 Re-declaration

It is unclear how rigorously this mandatory obligation will be applied/enforced. For example if we are aware that there is a potential fault on one turbine in a wind farm (e.g. 1MW) – are we obliged to tell the SMO of this immediately? If we become aware that a previous estimate of wind output is no longer accurate (outside a +/ ? % tolerance) – are we obliged to inform the SMO. Degree of materiality needs to be specified.

2.3 Demand forecasting

Demand is often difficult to forecast at the system level. Additional information is required to assure market participants that forecasting down to node level will be sufficiently robust that the LMP prices based thereon will be meaningful. Target levels of accuracy and incentives/penalties should be written into the MAE rules.

3.3 Market network model

The SMO is responsible for ensuring that the market network model consistently replicates the transmission network, albeit in a simplified representation. MAE rules should include a requirement for compliance with this obligation and with the appropriateness of its operation, to be subject to independent audit.

Regulation 2 of SI 304 defines a node in terms that include the Distribution system. If non-Transmission nodes are used, then the SMO network model will require extension and experience in demand forecasting for such nodes to be developed.

A regulatory framework will be required to determine the circumstances and procedures to be followed by SMO in adapting or adjusting the representation of the market network, to provide assurance to market participants that such changes will more accurately represent the market.

Appendix A - Demand participation

Supplier incentives for reducing non-dispatchable demand will be no different under MAE from the situation under the transitional arrangements, apart from the availability of hedging contracts that may provide additional value. Appendix A highlights the fact that price will not be affected because the reduction takes place after gate closure.

There is no real answer to the price issue, because if the SMO were able to estimate the impact of high prices on outturn demand and make appropriate adjustments to the nodal demand forecasts, then LMP prices would be lower and outturn demand higher than expected. If the system benefit of demand incentives is reduced load, then the price signal must remain in place to ensure that the demand reduction will actually occur.

We do not believe that there is any need for any reduction to be measurable and verifiable by the SMO, because it will have taken place without any explicit cash payment from the SMO. This requirement may have been left over from a demand side management programme where additional payments are made.

It is not clear how demand will become designated as dispatchable; whether individual customers are involved in the decision, or whether Suppliers will elect for a non-specific block of their demand to be treated as such. If customers volunteer their load in this way, then presumably the exchange of data on change of Supplier will include a code to indicate this and a node identifier? If so, then Suppliers will always know how much of their customer load is dispatchable, as will the MRSO. It would make more sense for any information on dispatchable load to be provided directly from MRSO to SMO, if this were required.

Assuming specific customer load is identified as dispatchable, the proposed requirement on Suppliers to offer dispatchable demand is unduly onerous, as it excludes the input of the final customers in deciding whether or not they are prepared to drop load. It therefore assumes an unrealistic degree of control by the Supplier over its customers' businesses. Customers should be able to define their own willingness to drop load over time; e.g. if they have dropped load on 3 days in a week already, the impact on production may be such that they will not be able to drop load under any circumstances for the next three weeks. Load reduction requires deliberate action by final users and it is unreasonable to require bids from Suppliers on which their customers may refuse to deliver.

In terms of payment options, the economic incentives under Option 1 are too indirect to be effective in encouraging customers to accept disruption to their production schedules. It would also require Suppliers to be able to forecast with some accuracy, the impact on LMP of their customers' load reduction in order to offer appropriate load reduction incentives to their customer; again too weak a signal to deliver the required demand benefit. Under this option, demand bidding is irrelevant and there would be no incentive for any rational bidding by Suppliers.

Option 2 provides a more appropriate structure, which explicitly balances the value of load reduction with system benefit.

It is important that penalties for failure to dispatch down are not unduly aggressive, as it is by no means obvious that such failures are likely to result in additional generation being called on from the reserve market. The inaccuracy of the SMO's demand forecast may be of a far higher magnitude than any undelivered load reduction; indeed the outturn demand with full load could be lower than forecast demand with full load reduction. As a minimum, a broad "deadband" of non-delivery would be required before any penalties would be invoked, to avoid provoking a high volume of disputes and potential litigation involving behaviour that would be extremely difficult to prove.

There is also the issue of discrimination against a particular class of customer. Non-dispatchable load pays the LMP price no matter how far outturn demand is from that assumed by the MCE in deriving prices. If there is no penalty on this customer group for using more than forecast, why should dispatchable load be penalised for a similar inaccuracy? The scope for reserve cost allocation disputes in terms of cost allocations between customer groups, accuracy of SMO forecasting and other "might-have-beens" is immense.

It would be more pragmatic, particularly as retail customers are not market participants, for the SMO to take a prudent view of the likely level of compliance with load dispatch instructions and run the MCE on that assumption. Such an approach would result in payments for delivery, no penalties and fewer disputes because customers would potentially see gains with limited production pain. As proposed, customers would see some gains but experience settlement penalties in addition to lost production costs.

Appendix B - Access to information

Airtricity supports MAE market information being made freely available to market participants as a matter of course and at a frequency in line with settlement processes. There is a difference between "made available by the SMO" and "sent to market participants by the SMO according to the settlement timetable". The MAE rules should provide for the latter interpretation, as is the case for reporting under the current, interim trading arrangements.

It is difficult to see the value to the general public of creating and maintaining a database that is easily accessible to the public. This would be an additional financial burden that would ultimately be borne by market participants. Market information of this nature will be of minimal interest to the majority of the population, who will have extremely limited understanding of the meaning of LMP market data. Industry participants will have the data in their own systems and they or their advisers will be able to use it as they see fit. The need for wider availability of information will therefore be limited to academic researchers, for whom a more restricted form of access to information may be both sufficient and less costly.

A distinction should be made between providing ex post information to market participants, to whom it should be made available as soon as possible after the event and provision of data to a wider audience, for whom a more extended timescale may be appropriate.

The proposed scope of data to be provided to market participants is comprehensive for the outline market structures as they are currently understood, but as the MAE rules are finalised it is likely that additional parameters will be defined and issues identified, for which additional reporting will be appropriate. The final scope of market data provided to market participants should be agreed as part of the MAE Project Reporting workstream.

Appendix B makes no mention of the method of providing SMO data to market participants. It is Airtricity's view that this should be done using the same technology, infrastructure and "black box" as is being introduced as part of the Market Opening Project.

Appendix C - Node design

The expressions "system node", "pricing node", "market node", "electrical node", "injection node", "busbar" and "offtake point" have been used throughout Appendix C, without clear definition other than by reference to the SMO's Energy Management System (EMS). From the first bullet point in Appendix C they can be connections between lines or generation units. On the other hand, the definition of "node" in SI 304 refers to "a location on the transmission and/or distribution system where electricity is injected or withdrawn for which an LMP is calculated". It would have been helpful for some explanation of the relationship between electrical and geographical location to have been included. It is also unclear clear how embedded generation will be treated in relation to system nodes.

If nodes of any kind are embedded in the distribution system to take account of generation at that voltage, then the EMS will have to be modified to include a greater number of nodes than are currently included in order to avoid operational problems. However there must obviously be a limit to the number of nodes that add value to the calculation and some form of de minims level of load/generation should be included in node definition because:

- paragraph 2.3 (CER/03/230, page 13) requires the SMO to forecast the demand for every withdrawal node;
- future development of generation is likely to result in significant growth in the number of small embedded generation units on the system, for example combined heat & power (chp) schemes;
- an excessive number of LMPs is unhelpful, as is recognised in Appendix C

A system node should therefore be explicitly defined as a point on the transmission and/or distribution system that is electrically sensible; possibly along the lines that it is a point where the aggregated maximum generation or demand of connected load is at least eg 100 MW, or that connected generation represents more than eg 30 % of the aggregate maximum demand of the connected load. A definition of this type would produce a reasonably stable number of nodes, impose a materiality threshold on market clearing calculations and limit the amount of market data produced.

The issue of how embedded generation is treated remains to be determined.

Airtricity supports the proposal for a notional single supply node having a uniform wholesale spot market price.

Appendix D - Treatment of pumped storage

It is useful that pumped storage has been considered as a special category of generation source and it seems intuitively correct to suggest that in pump mode its demand is separated from normal demand when calculating LMP.

The reality of imposing almost 300 MW of demand on the system is that generation somewhere else will be run to provide the energy and there will be significant additional power flows on the system as a result. In providing this energy, system losses, congestion, or plant availability bids are likely to impact on LMPs and thus feed through to a higher uniform wholesale spot market price if pumping load is included in the LMP calculation process. If pumping load is then excluded from the denominator in the calculation of the weighted average price, as seems to be suggested by the last sentence of the second-last paragraph on page 42, then the Supply side price will be higher than if the pumping load is included.

On the other hand, if LMPs are calculated initially with no pumping load, to provide the price at which energy is bought for pumping, then there should be no impact on the Supply side price.

Airtricity supports the separation of pumping load from other demand for settlement purposes, but would like reassurance that the rules for implementing this will not impact on Suppliers through a higher uniform wholesale spot market price at times of pumping.

From the generation perspective, it would seem unfair for the impact of pumping load on the system not to be recognised in the price paid for pumping energy. We therefore believe that the price paid by pumped storage for pumping energy, should reflect the marginal impact of pumping load on the system rather than being simply the local LMP price that is based on Customer demand alone.

Appendix E - Charging for reserve costs

In principle it is appropriate that the causer pays for the cost of reserves, but there are some circumstances in which rigid application of this approach is inappropriate. Appendix E suggests that some generator units automatically trip when frequency falls during a contingency; exacerbating the situation and increasing the effective size of any contingency, hence increasing reserve requirements and costs. The argument for charging such generators for reserve is then built on the assumption that this is done for good technical reasons; being the reason that this course of action is not prohibited. However this basic assertion is inaccurate.

Distribution connected generation must comply with the Distribution Code. This requires connected generators to install G10 protection to ensure that the plant shuts down on loss of mains supply. The defined technology used to meet this requirement operates on the basis of the rate of change in mains frequency.

Distribution connected generation plant that trips on frequency drop should not pay for exacerbating contingency events, as it is complying with its legal obligation. MAE rules should not provide economic signals that act as incentives to breach Network safety requirements.

Development of the market structures for renewable generation is not yet sufficiently advanced to reach any conclusion on the applicability of load following reserve to intermittent and non-dispatchable generators (wind is specifically mentioned in Appendix E in the context of the reserve charging regime). There are issues of responsibility for output estimation, how the appropriateness of charging is deemed and possible creation of a new class of generator, akin to that for pumped storage, applicable to such technologies. No conclusion on the scope and applicability of reserve cost charging should be reached until these issues have been satisfactorily addressed.

However one issue that needs to be addressed is the impact on the system (and therefore the cost of holding reserve) of trips by the different types of generation. Reserve costs incurred in ensuring the system is able to cope with the tripping of a single unit CCGT plant (350-400 MW) are very different from the failure of an individual turbine in a wind farm, the largest of which is currently 3.6 MW.