MAE Consultation (CER/03/230) by the Commission of Energy Regulation Under S.I. 304 of 2003

A submission by Synergen 16th October 2003

1 Introduction

1.1 Overview

Synergen is pleased to submit this paper as its response to the CER's consultation. It is our view that broad industry consultation and involvement is vital for the MAE to be successful. Whilst the overall conceptual design is already determined, there are many areas where key decisions of principle are required. Successful resolution of these matters is vital to ensure the Irish electricity market will be robust, durable and efficient in the years to come. The CER consultation specifically requests responses on some, but not all, of these areas.

This paper is Synergen's initial response to the CER consultation. The intention is to provide constructive suggestions on specific areas where the CER requested input from stakeholders, and also to highlight areas where it believes that further information and analysis is required in order for Synergen to develop its views during the market design and implementation phases.

In formulating this response Synergen's ability to comment on the CER paper has been limited by the lack of (a) explanation and analysis of linked issues within CER consultation paper, (b) discussion on the FTR arrangements that will underpin the LMP model, and, (c) a lack of data available to undertake our own analysis of the impact of alternative proposals. Whilst the five items on which comment was expressly invited are important, they are not the only important issues to consider at this stage. Equally, or perhaps more importantly, the criteria for assessment of market design arrangements need to be set out, along with an inclusive process that allows the CER to draw effectively on the detailed expertise that resides within the industry – particularly through the use of Expert Groups. It is difficult to comment on more detailed aspects of market design without an equally detailed understanding of how nested arrangements (particularly the FTR arrangements) will operate.

1.2 Structure of this response

The rest of this paper is structured to address each of the main areas, on which the CER is consulting, in turn. Finally comments on other issues are provided.

2 Consultation 1 – Demand Participation

2.1 Discussion

The CER paper discusses the potential use of demand reduction within the MAE with respect to two concepts: "Supplier-Customer Demand Incentives"; and "Dispatchable Demand". We consider each of these in turn.

2.1.1 Supplier-Customer Demand Incentives

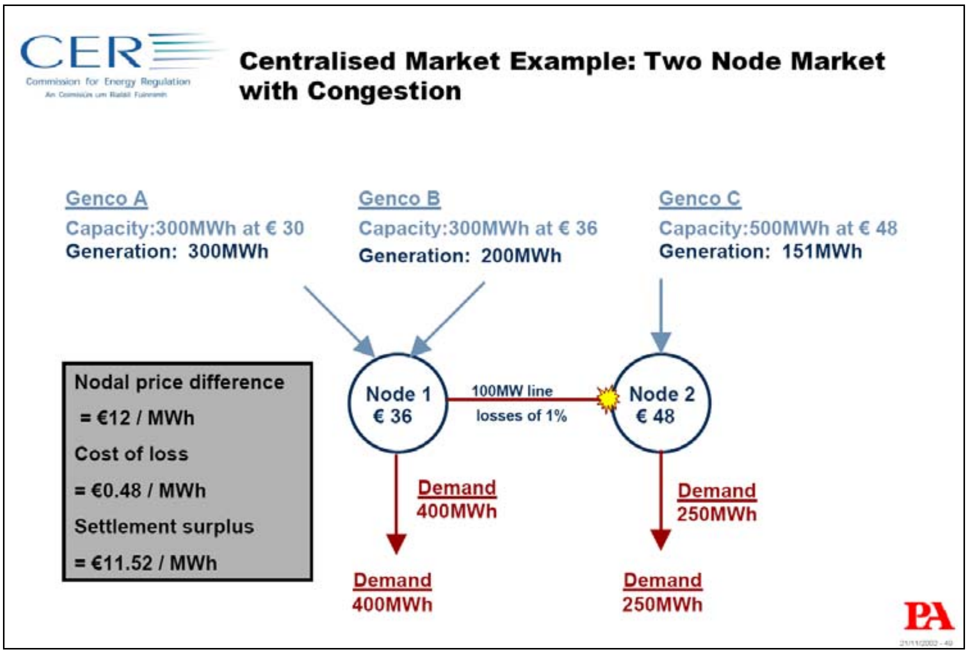
The CER states that there will be an incentive for suppliers to avoid peak prices by reducing demand as taken by their customers. This incentive is likely to exist in any ex-ante priced market. The observation made by the CER is that such a response happens "after gate closure and therefore does not change the amount of generation scheduled"[1]. Leaving aside the distinctions between gate closure and price setting, there will be a point at which the ex-ante price is determined by the SMO (and published) to which customers can react. The closer to real time that prices are set, the easier it will be to isolate price response as the cause of any difference between forecast and actual demand from any other demand forecasting errors.

Whilst the paper sets out an observed and rational reaction by supplier to high prices, it is not explained why any ***"reduction must be measurable and verified by the SMO"*** Such verification would clearly be appropriate for dispatchable demand, but as non dispatchable demand reductions would solely be commercial matter between the supplier and its customer**.** It is unclear (a) what mechanism would deliver this, and (b) the benefit of this approach.

The market price will be set ex-ante, with prices set against estimated demand. However, generators will be paid based on metered generation in the trading interval. Given it is also proposed that generators pool revenue will be based solely on its energy dispatch level (plus reserve payments), generators could be adversely impacted as a result of anomalies arising from the differential treatment of generators (paid LMP) and suppliers (paying the Uniform Wholesale Price - UWP). This may arise if a customer's demand reduction is as a reaction to the UWP whilst actual reduction in generators' despatch volumes and thus revenues are nodal. The combination of ex-ante pricing and the differential pricing of generation at LMP and demand at UWP has the potential to result in a pricing anomaly, which could adversely impact generators revenues through pricing/dispatch inefficiencies.

In order to examine this issue; consider the following example based on the Figure below extracted from a presentation made at the CER's industry forum on 8th May 2003.

Figure 1



[1] Page 35 of the CER consultation paper.

In this example the UWP would be calculated as 40.62 €/MWh ex-ante as per the Figure below which is extracted from the same presentation.

Figure 2

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An Coimisiún um Rialáil Fuinnimh

Centralised Market Example: Two Node Market with Congestion

Genco	Dispatch MWh	Market Price € / MWh	Revenue €	Margin €
A	300	36	10,800	1,800
B	200	36	7,200	0
C	151	48	7,248	0
Total	651	Av = 38.78	25,248	1,800

Load	Supply MWh	Export (Import) MWh	Market Price € / MWh	Cost €
1	400	100	36	14,400
2	250	(99)	48	12,000
Total	650	Av = 40.62		26,400

Settlement surplus = € 1,152 (also = 100 * 11.52)

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However, if 200 MWh of load at Node 2 is subject to a supplier-customer demand incentive with a strike price of 39 €/MWh (reflecting the SRMC of the customer), the customer would reduce its consumption (given the UWP of 40.62 €/MWh) and the ex-post load at Node 2 would be 50 MWh. Consequentially, the output of Genco B and C would be reduced, Genco C would not be required to provide any energy and Genco B would provide 150.51 MWh which equates to 50 MW delivered at Node 2. However, appropriate ex-ante price discovery within the market would have allowed for Genco B to supply more energy consistent with the network constraints between the two nodes and deliver 99 MWh at Node 2.

The fundamental concern with the example provided, is that the price signals to generation and demand are asymmetric and that the dispatch solution arrived at is sub-optimal (even though it may have appeared to be efficient at the ex-ante price setting stage). To the extent that the market delivers a total economic solution that is sub-optimal (i.e. demand de-loads even though a generator was willing to satisfy its demand at less than its out of market de-loading price) explicit consideration should be given as to any specific rules that would redress this. If this is not the case, Genco B would loose revenue through a pricing inefficiency.

2.1.2 Dispatchable Demand

As set out in the CER consultation paper, dispatchable demand which is in merit avoids buying electricity at a price above which it would prefer to not take demand. This avoids the need for the dispatchable demand to react to a price after it is published, with the resulting potential pricing anomalys similar to those described above.

Both Option 1 and Option 2 appear to be inconsistent with the wording of Regulation 3(14), which states that "Suppliers of dispatchable demand, as certified under Regulation 3 (8) will pay the LMP at the node at which they are located[2]". This is not, as worded, limited to the dispatchable or dispatched load volumes being priced at the nodal LMP, and is not

[2] Note, we believe that the correct reference should be 3 (7).

consistent with Appendix A Demand Participation (page 35) which states that "for settlement purposes, this dispatchable demand will be treated as negative generation and charged at its nodal price". As worded Regulation 3(14) will create distortions as suppliers will be free, in the extreme to declare 1kW of load as dispatchable at "cheap" nodes and bid at VoLL in the confidence that is never likely to be despatched. There is also a lack of distinction between "dispatchable load", and "load that has been dispatched".

In relation to the options set out in the CER consultation paper, Synergen believes that no further explicit payments for dispatchable demand is appropriate i.e. hence Option 1. An economic incentive to bid dispatchable demand already exists - the ability to purchase locally, thereby avoiding the UWP. This approach is consistent with the CER example in which it is assumed that customers would be dispatched at their own rationing price, and do not require payment for not taking electricity at times when the market price exceeds the price that they were prepared to purchase at.

Under a dispatchable demand regime historic price response should not be factored into demand forecast by EirGrid, to avoid the risk of systematically under forecasting demand.

2.2 Synergen's Views

The CER's focus on demand participation appears in conflict with CER 03/097 (Key Design Issues: Generation adequacy, dominance and pricing - 30 April 2003) in which the CER stated "the option of LMP for generators and uniform prices for customers provides a credible second best alternative given the expected lack of significant customer response to locational prices." Consequently, it would seem prudent to quantify the likely extent of demand participation in order to confirm that the MAE should be required to take explicit account of this matter. The following comments assume that this is a material issue and put forward proposals accordingly.

2.2.1 Supplier-Customer Demand Incentives

Synergen believes that many significant issues are unexplained or unanswered within the CER paper. A detailed understanding of these issues is required for both the CER and participants to fully understand, and be sufficiently informed to comment on, what is being proposed at a high level. This includes, but is not limited to:

- What causes current demand forecasting error[3]?
- What is the materiality of demand forecasting error on a short term forecast basis (as the existing demand forecasting figures are based on longer time spans between forecast and actual demand?
- The extent to which non-dispatchable demand price elasticity will be used in the calculation of demand forecasts and thus generator scheduling?
- What are the pricing impacts on a generator which is despatched below its scheduled generation as a result of demand forecasting error?
- What financial incentives are envisaged to minimise demand forecasting error, based on the causer pays principle?

[3] For figures, see section on "Reserve"

Synergen recommends that the impacts of non-dispatchable load competing at a nodal point on the system with generation whilst being exposed to a UWP are explored and quantified. In order to assist smaller players in developing an understanding of the proposed arrangements this would be most effectively undertaken by the CER, in conjunction with the relevant Expert Group. . This may give rise to a re-evaluation of the pricing of generation and demand and the asymmetry of treatment.

2.2.2 Dispatchable Demand

Synergen is not persuaded as to the robustness of the rationale for the payments of dispatchable demand. On that basis Synergen is in favour of Option 1 as presented in the CER consultation.

Further, Synergen recommends that:

- any compliance rules in respect of dispatchable demand mirrored those associated with generation, and in particular cost allocations for non compliance with dispatch instructions should mirror those developed for generators;

- Market information on dispatchable load should be in the same form and available at the same time as generator data is made available; and

- The intended treatment of dispatchable load reduction within the demand forecast is set out in more detail.

- The impact of dispatchable demand alternatives on nodal design and pricing be evaluated.

3 Consultation 2 – Access to Information

3.1 Discussion

There are three key types of question that require addressing:

1. What should be released?

2. To whom should data be released (and as a secondary question, under what terms?)

3. When should different data items be released?

The CER position is that ex-ante information should be made available to participants only, and not more broadly. Ex-post information would be made available post event (at a time unspecified). Broadly, Synergen is in favour of the widest possible disclosure of market information (bar that which is commercially sensitive and available to participants only). Synergen thus broadly supports the CER position.

3.2 Synergen's Views

3.2.1 What should be released?

Synergen supports an approach whereby the starting assumption is that every data item is released, and information should only remain confidential if a class of participants can make a strong case for confidentiality on commercial grounds, or it is determined that the release of a data item would lead to market distortions.

With respect to ex-ante information and its disclosure, we have not seen any argument as to why pre-dispatch information (except that which relates directly to a participant and is confidential) would not be made more widely available, or the rationale for such a restriction.

3.2.2 To whom should the data be released?

Synergen believes that the best protection for smaller players with limited resources is through the widest disclosure of market information. Thus, high levels of timely information should be made available to ensure that players, regulatory bodies and other interested and informed observers can monitor the activity of all players, thus affording some protection to smaller players who cannot (a) match the resources of larger players, (b) assess market activity on a deductive basis. Consequently, all information released to participants as a whole (i.e. not participant confidential) should be in the public domain.

All information required to simulate the market should be within the public domain, as should any information necessary to understand and verify network decisions.

With respect to outage information as discussed in Section 5.1 of the consultation paper, Synergen has some concerns that the advance publication of a single site generator's outage programme may prejudice its ability to enter into the hedging market as anything other than a potentially distressed purchaser. This is a risk, not an assertion of what will arise; as such an outcome would be dependent on the degree of secondary market liquidity that develops. Over a long term timeframe Synergen suggests that the information the market requires centres on the assumed level of demand, generator availability and adequacy of margin. This would be sufficient to signal to generators times when low availability margins would potentially lead to higher prices, and thus signal that they should make capacity available at those times. Identifying individual generators at this stage does not assist this process. During medium term, and even into pre-dispatch timeframes, it is unclear if there is a rationale for identifying individual generation unit outage programmes, and what this achieves that could not be accomplished through the disclosure of global demand, availability and margin information.

On that basis Synergen supports the release of all the outage information set out in Appendix B of the consultation paper, except "scheduled generation outage plans – short, medium and long term".

3.2.3 When should information be released?

In determining when data should be released it is necessary to balance:

1. The cost of information provision;

2. The ability participants to handle significant data volumes meaningfully;

3. The need for timely information; and

4. The need to balance of the advantages of rapid disclosure of ex-post information to participants in allowing them to formulate competitive responses that give rise to increased market efficiencies against the potential detrimental effects of some players using such information to exert market power[4].

In balancing these criteria Synergen's initial position with respect to information disclosure timings is that:

- Ex-post information should be made public after an interval of one trading day, (on a rolling 24 hourly basis);
- Pre-dispatch information should be provided (a) on a rolling 24 hour basis, or (b) every 4 hours or more frequently if there is a material change; and
- Real time system frequency data is made available.

4 Consultation 3 – Node Design

4.1 Discussion

The CER approach is to define market node through a one to one mapping of physical and market nodes. Synergen assumes that there would be no technical difficulties or other imitations in associated with this approach as the absolute number of nodes would be readily solvable within the MCE. Direct physical to market node mapping appears to be a sound approach as it removes any arbitrariness or judgement from the definition of market node, although it is unclear to what extent node configuration would be dynamic in nature.

Synergen considers that the overall MAE and associated detailed nodal design cannot be determined in isolation (or prior to) determining the Financial Transmission Rights (FTRs) arrangements. Ofgem in the UK tried to design the NETA market in isolation of resolving the directly related transmission issues, with the consequential deficiencies over constraint charging and cost allocation that are still evident.

Given a nodal design, generators and their hedging counterparties, may be exposed to significant price differentials between nodes and the UWP. To date Synergen has not seen any estimation of these differentials which would provide a robust basis for assessment of the volatility and level of these differentials. However, the CER has previously stated that under circumstances where transmission constraints apply, the LMP market will produce a settlement surplus (which would equate to transmission rents). Whilst, Synergen understands the intent is to provide a hedge to cover the basis risk, the exact nature of FTRs allocation and operation is unclear and Synergen believes that further and detailed consideration needs to be given to the implications of ex-post / ex-ante FTR regimes. In short will the FTR provide a perfect hedge or will generators carry some residual risk?

It is also unclear from the CER examples previously provided whether the "settlement surplus" may be negative, the conditions which might give rise to this and what settlement arrangements would apply in the event of this occurring.

Insufficient data exists in order for participants to undertake quantitative analysis of the LMP market, and the impact of alternative treatments of demand, reserve, pumped storage, ramp

[4] It should not be assumed that Synergen believes that only a dominant player can exert market power, as it expects that at different times any market player could be in a position to exercise nodal market power – whether it realises it or not.

rates, FTR's and other critical issues. Quantitative analysis is required. Ideally this would be undertaken by the CER, as part of developing participants understanding of the proposed arrangements. Additionally, Synergen requests that the CER makes available the data used in the modelling of LMP undertaken by ILEX. Participants can then undertake similar analysis, utilising broader data sets than the 22 sample days if they so wish. Furthermore, EirGrid should put in place a regime for further data release over the coming months to assist MAE implementation, under direction from the CER.

4.2 Synergen's Views

In order to progress the MAE, and related arrangements in a manner that produces a robust and internally consistent suite of arrangements, Synergen believes that:

- The CER needs to set out the process through which the related issues (FTRs, market governance, transitional arrangements) will be taken forward, and identify the key interdependencies;
- The development of FTRs needs to be undertaken in parallel, not post, MAE design decisions;
- It would assist participants understanding of the model if the CER were to publish its view on the number of nodes that it envisages, whether it is intended that nodal configuration be static or dynamic and the impact of this under a range of transmission network configuration scenarios. It would greatly assist participants if CER clarified whether there are any material impacts on LMPs of alternative treatments of a number of generating units being treated as a single node or multiple nodes.
- More data (or preferably analysis) is required to sufficiently inform participants and other stakeholders. To this end, it would assist participants and other stakeholders if the CER produced an initial paper on this, including quantification of potential settlement surpluses nodal volatility and nodal price differentials. Additionally, the information to allow participants to undertake the analysis should be put in the public domain as a matter of priority;
- The implications of the various demand participation arrangements on Nodal Design needs to be outlined; and
- In line with the CER assessment criteria utilised in the evaluation of market models, detailed consideration should be given to the stability of the LMP model (a) with respect to a future all-Ireland market, and/or (b) future interconnection to the UK thus enabling a wider UK / all-Ireland electricity market as envisioned by the EU Commission.

5 Consultation 4 – Treatment of Pumped Storage

5.1 Discussion

As the paper observes, the commercial viability of pumped storage is based upon peak and off peak differentials. The CER paper also briefly describes the role of pumped storage within both energy markets and the provision of ancillary services. The main function of Pumped Storage is in the provision of generation capability at peak (high prices) times and reserve cover for (sudden) loss of generation. Under the MAE proposals, it appears that (at least theoretically) PS can change modes of operation many times within a trading period. Because of the scale of the Irish Electricity Market, it is possible that Pumped Storage could have a significant bearing on both energy and reserve pricing.

5.2 Synergen's Views

At this stage, Synergen is not able to authoritatively comment on the appropriate future treatment of Pumped storage in any detail. In order to assist participants and wider stakeholders in making informed comment it is necessary to outline in more detail the options and modes of operation available for pumped storage and the potential impact of pumped storage on price setting in both the energy (modal LMP and UWP) and the reserve markets.

Synergen believes that it will be able to substantially comment on any specific rules to apply to pumped storage once these areas are developed, and the materiality of alternative arrangements is explored. Such analysis should consider (a) the impact of the LMP market on reserve costs, and (b) the impact of the LMP design on time weighted and demand weighted price differentials.

6 Consultation 5 – Charging for Reserve Costs

6.1 Discussion

The CER does not make any definite proposal on how reserve costs should be charges out under the MAE. In this section Synergen sets out the issues that have to be considered, and a model that could be adopted.

It is important at the outset to differentiate between two forms of reserve service:

- Load following (regulation) –this will cover the incrementing and decrementing of generation to account for demand forecasting error and discrepancies in generators instructed and actual volumes; and

- Contingency Services – this will be provided to secure the system against the single biggest loss on the system (assuming n-1 reserve criteria applied). It should be noted that the volume of what is held is not contingent on the probability of the contingency arising.

Reserve can also be viewed as giving rise to two forms of costs:

- **Usage** – costs incurred when the service is provided (i.e. regulation services); and

- **Insuranc**e - costs incurred regardless of how often the service is used – i.e. securing against the single biggest loss has the same cost regardless of whether the service is used each day or only once a month.

Synergen does not have the data to determine what the present costs, or relative costs of these two forms of reserve are. However, and estimation of the relative costs from another market that adopts (albeit on a diluted basis) many of the market design elements likely to be found in an LMP market would suggest that a 80:20 split between usage and insurance costs may be a starting point for discussion.

Who should pay for reserve?

Usage – primarily customers benefit from the provision of reserve for regulation purposes, and give rise to most of the costs. Analysis of the demand forecasting error would suggest that there is a considerable variance between actual and forecast demand. These costs are not attributable to generators and should be allocated to the customer side, potentially in conjunction with financial (price control) incentives on EirGrid to reduce the level and cost of DFE. Insofar as regulation services are caused by generators deviation from dispatch instructions, the costs arising should be attributed to the generatior in question. Any such provisions would need to specifically allow for ramping accuracies, metering tolerances and ambient temperature impacts on generation.

We have conducted a short assessment of the forecasting errors during last winter (1st December 2002 to 28th February 2003). This analysis is based upon on public domain data available from www.eirgrid.com. It shows that demand forecasting error ranged between -16% and +34% within each half hour trading period with the mean error of +10%. Synergen recognises that this data is based on a differential between forecast and actual demand which is considerably longer than the timescales envisaged for demand forecasting in the MAE. We would expect the difference between forecast and actual demand to be significantly lower than the figures below, but we do not have data available to us to assess the extent of demand forecast error from, say a +4 hours or a +30 minutes from real timeframe horizon.

It is not clear whether this trend for a demand forecasting surplus is in some way related to existing customer price response but consider that this matter requires further consideration within the MAE implementation.

Insurance (contingencies) – These costs are associated with an instantaneous generation (or potentially network) failure. The allocation of these costs would be broadly the opposite of those for regulation services, maybe split in the ratio of 80:20 between generators and consumers.

The question then arises as to how contingency costs should be allocated between generator. Some generators as a result of their absolute size are more likely to be the single biggest loss on the system at any point in time. It would be over-simplistic, however, to assume that it would be reasonable to allocate the whole of the contingency cost to a generator that was the largest loss on the system by 1MW at a given time – clearly a more equitable approach is required.

The optimisation of energy and reserve costs.

The allocation of reserve costs needs to be allocated after a robust optimisation of energy and reserve costs has been undertaken by the MO through the MCE. Generators need to be assured that their revenue net of reserve costs allocated to them is greater than their bid price. For example, if the market clearing price is 30€/MWh and a generator with the single biggest loss bids at 29€/MWh it would be inappropriate to allocate 5€/MWh of reserve costs to that generator as its net revenue would be 25€/MWh – some 4€/MWh below its bid. In a co-optimised market (which what is envisaged) this outcome would be inappropriate. It is thus necessary that the MCE ensures that a generator is always whole in terms of its bid.

The runway approach

Notwithstanding the comments above, Synergen sees the "runway approach" adopted in Singapore as potential methodology for allocating contingency costs between generators. In short, this would mean that the largest loss on the system paid the incremental cost of its MW differential above the second biggest unit, so, for example if it was the largest unit on the system by 10MW it would pick up the incremental cost of that 10MW. For the second largest unit, it would split with the largest unit the cost of its MW's of generation greater than the 3rd largest unit etc. This is set out in the example below.

Figure 3

	MW of generation	Differential MW above next largest unit	Contingency cost
Unit 1	400	20	Incremental cost of 20MW, plus 50% of the cost of 50MW, plus 33% of the cost of 15MW
Unit 2	380	50	50% of the cost of 50MW, plus 33% of the cost of 15MW
Unit 3	365	15	33% of the cost of 15MW

Synergen recommends that, in addition to the runway approach, a refinement to the above methodology should be given active consideration, which would involve applying a reliability weighting to each unit.

6.2 Synergen's Views

With respect to reserve costs, Synergen view is:

- Reserve cost allocation will be one of the critical market design elements that have to be got right. The approach will be dependent on whether energy/reserve co-optimisation is undertaken from market start up. If this is not the case, a clear glide-path from transitional to final arrangements will be required to avoid price/revenue shocks;

- Most reserve costs are supply side based, and a majority of reserve costs thus need to be allocated to suppliers. To the extent that some forms of generation give rise to regulation costs, these costs should be allocated to them – e.g. intermittent generation;

- Regarding the insurance (contingency) costs that arise, any causer pays principle should (a) ensure that a generators net revenue (energy payments less reserve costs) are greater than its bid, and (b) there is an equitable methodology of allocating contingency costs across generators based on their marginal impact on costs; and

- The absolute level of reserve will be dependent on the gate closure interval. Synergen would support more detailed analysis being undertaken to determine the impact on reserve costs that would arise under a 4 hour gate closure, and one much closer to real time. Our assumption is that shorter gate closure timeframes would reduce reserve costs. Was this assessed as part of the LMP modelling undertaken by the CER/PA/ILEX?

7 Implementation of S.I 304

7.1 Discussion

Synergen supports the CER's consultation on the implementation of S.I. 304. A key part of this implementation process will be the development of success criteria. Success criteria were used by the CER in its paper "Irish Electricity Trading Arrangements Second Options Paper" of January 24 2003. These criteria (at a high level) were efficiency, equity, environment, stability and practicality. Synergen accepts these criteria as being a sound high level basis for the objective assessment of available options. This would also seem to be a valid approach at the present stage of consultation on MAE, as it was in determining the high level centralised compared with the decentralised model options previously. Synergen would encourage the CER to adopt and publish objective assessment criteria during the market design phase.

7.2 Synergen's Views

Synergen believes that the CER should set out its approach for the assessment of key market design decisions, and that the CER should assess all aspects of market design including the responses to the 12th September Consultation Paper against these success criteria.

Synergen also considers that the basis on which the costs of MAE implementation be controlled and allocated should be consulted upon at the earliest opportunity.

8 Other Matters

8.1 Market Governance

Synergen believes that the CER should consult on the market governance regimes that will apply up to, and post MAE implementation at the earliest opportunity.

8.2 Cost Allocation

Typically central market costs are allocated across the value chain, on both suppliers and generators as a mixture of fixed and variable charges. However this introduces inefficiencies as generators seek to include these fixed costs in their bids on a €/MWh basis based on volume assumptions, an arrangement often referred to as "variablisation". This places additional risks onto each generator for which an additional margin is included. An alternative worth consideration is to allocate all fixed costs to suppliers. Such an allocation would be via a fixed fee, say per metering point, levied on all suppliers thereby ensuring these fixed costs are split equally across all electricity customers.

Synergen believes that participants should not pay for the central costs of the MAE until it goes live. Also, any such costs should be allocated to suppliers and recovered from customers as they will benefit from the reforms.

8.3 Settlement Surplus

It is unclear what the proposed treatment of any settlement surpluses is, and how it would be re-distributed.

8.4 MCE

In relation to the MCE, does the CER expect EirGrid to procure an “off the shelf” solution that will co-optimise energy and reserve on a five minute basis, or will such a system need have a significant bespoke element? What are the cost and timing implications? What are the implications of key design parameters (e.g. node design, dynamic Vs static node configuration, choice of gate closure time, pre-dispatch information volumes and timing, ex-post market information volumes and timing, treatment of demand initiatives, etc.) on both central and participant costs and on implementation timescales.

8.5 Constraint issues

Synergen notes that the intention of FTRs is to ameliorate the differences between LMP and UWP (i.e. a basis risk hedge), and that there is envisaged to be no “constrained-off” payments. The treatment generators under the LMP and FTR arrangements should not adversely impact generator investment decisions that have already been made on the basis of (paid for) firm transmission access rights to market. To this extent it is unclear whether the FTR arrangements will sufficiently compensate such generators.

Furthermore, it is not clear to Synergen that portfolio bidding behaviour and/or the asymmetry of pricing signals to generation and demand will not give rise to transmission constraints that are beyond the foreseeable control of a single site generator. Synergen suggests that only controllable risks should be allocated to generators, and questions whether further investigation is required by the CER to determine that only controllable risks are being passed onto generators under the proposed arrangements.

With respect to intra dispatch / trading interval changes in a generator’s output from its ex-ante instructed dispatch level, Synergen seeks clarification how the costs of either de-loading or increasing the output of a generator are recovered given that a generator’s revenue output is the ex-ante LMP price applied to its metered generation. This could lead to generators being de-loaded through a price band, or having generation called on in a dispatch interval at an output level above their ex-ante LMP price band. It is unclear how within dispatch / trading interval variances are to be treated.