Commission for Energy Regulation

Irish Electricity Trading Arrangements Second Options Paper

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1. INTRODUCTION

This is a paper to be released to Industry on January 24, 2003. The contents of this paper will form the basis for a second Industry Forum scheduled for February 6, 2003.

The paper includes the following major sections:

- a summary of industry comments to date,
- indication of a centralised market as the preferred market design option and significant detail on this option,
- a review of the generation adequacy issue and the presentation of several well-defined options to address this issue,
- a review of the market dominance issue and the presentation of several well-defined options to address this issue, and
- a discussion of future activities.

This paper forms part of the consultation on the Review of Irish Trading Arrangements currently being conducted by CER. Comments are invited on any aspect of the paper. Throughout the paper specific questions are posed and respondents are requested to address these in particular. The Commission will provide respondents with an opportunity to present orally on these issues at the industry forum on 6th February 2003.

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2. *INDUSTRY FEEDBACK*

The CER published a consultation paper, *Choices for Irish Electricity Trading Arrangements*, on 20 November 2002. This consultation paper provided information on three options for trading arrangements and issues related to market dominance and generation adequacy.

Comments from industry in response to this consultation paper were subsequently received. This chapter provides a summary of these comments, as they related to:

- trading arrangements & market design,
- consultation paper questions, and
- other issues.

Full documentation of industry responses is available on the CER's website (www.cer.ie).

2.1 TRADING ARRANGMENTS AND MARKET DESIGN

There was a strong general consensus that the current market structure is not working and has many negative points which commentators listed and discussed. In particular the issues of having two different prices in the imbalance market with asymmetric means of calculation and derivation were given as examples of trading structure difficulties. It was observed that the market structure, in terms of dominance among other things, compounded these problems.

Three responses favoured the decentralised market, noting that it would be a progression from the status quo. However a number of parties raised concerns regarding the size of the market and its resultant depth and liquidity, particularly in conjunction with the dominance of ESB.

Most respondents indicated that a centralised market was their preferred option. Many respondents noted the benefits of merit order dispatch, transparency, a single price and having an assured market for power sales. Nonetheless, it was noted that ESB dominance in the peaking and mid merit plant would have to be addressed.

2.2 CONSULTATION PAPER QUESTIONS

Parties were asked to respond to specific questions in the consultation paper. Eighteen responses were received in total.

2.2.1 Which of the three trading arrangement options are preferred?

The status quo was deemed undesirable and unsustainable, more respondents were in favour of a centralised market than a decentralised market, although some felt that more information was needed before making a final decision.

Fifteen responses indicated that they were not in favour of the status quo as a future model for trading. Seven parties expressed a preference for a centralised market, three favoured a decentralised market and only one response was in favour of maintaining the status quo.

2.2.2 Is a capacity mechanism necessary in the Irish electricity market?

Almost all respondents argued in favour of some form of capacity mechanism and many preferred the 'safety net' approach. Some respondents felt that the mechanism should be permanent while others asserted that it should have a planned obsolescence or gradual retirement as and when no longer required.

Fifteen responses considered that the introduction of a capacity mechanism would be necessary, four of which were in favour of the default buyer mechanism described in the paper; the rest did not express any particular preference.

2.2.3 Is it necessary for CER to undertake to design and implement measures related to mitigating ESB PG market dominance?

Almost all respondents felt that the dominance of ESB required measures to mitigate this market power in the trading arrangements. It was argued that some form of ongoing regulation should continue until the company was no longer dominant and some participants were in favour of this being done through the centralised buyer mechanism as proposed. As regards the issue of tariffs, it was argued that PES should face fuel cost pass through in the financial year if this is used as a form of ongoing regulation.

Eight responses argued in favour of the divestiture of ESB. Four respondents were against the introduction of price caps or regulated bidding, while one was in favour. Two parties expressed agreement with the idea that a dominant buyer mechanism be used to mitigate the dominance of ESB.

2.3 OTHER ISSUES

Many responses from industry addressed additional issues beyond the market design and implementation including the following:

- respondents welcomed the move by the CER to bring the review forward to address market uncertainty,
- many parties were concerned about the issue of market power and some requested divestiture or legal separation and restructuring of ESB,
- security of supply was considered to be an objective that supersedes any others and concerns were expressed that the liberalisation process could be stalled or reversed if the capacity problem was not addressed,
- it was suggested that the objectives of competition and promoting renewable energy be assigned a relatively higher priority
- demand side participation and management were highlighted as a critical for the efficient functioning of the market, and
- it was felt that there should be consideration of the Northern Ireland market design and the possibility of an all-island electricity market when designing the trading system.

3. BASIS FOR PREFERRED MARKET DESIGN OPTION

The centralised market design option is now the preferred option of CER and industry. This chapter includes sections which detail the:

- basis for centralised market as the preferred option,
- CER evaluation overall result,
- CER evaluation methodology, and
- details of the CER evaluation process by dimension.

3.1 BASIS FOR CENTRALISED MARKET AS PREFERRED OPTION

CER's preference for a centralised market design arises from consideration of the industry responses to the 20 November 2002 consultation paper and an internal CER evaluation of options:

As discussed in Chapter 2 above, the majority of industry respondents expressed a preference for a centralised market design.

CER's internal evaluation process, outlined below, resulted in a preference for a centralised market model.

3.2 CER EVALUATION OVERALL RESULT

CER applied the evaluation criteria to the options and the results are summarised in Table 1 below.

The application of the evaluation framework, along with the associated indicators and analytical tools and techniques, revealed differences and similarities across the three market design options.

On balance, the centralised market option was considered to be as good as or superior to the decentralised option. In the Irish electricity market context, the centralised option emerged as the overall preferred option.

It is important to note that irrespective of market structure there is an important issue of market power and the dominant position of ESB that must be addressed. It is unlikely that any market design option would provide satisfactory results without addressing this important structural problem.

Table 1 – Summary of CER evaluation results

	Efficiency	Equity	Environment	Stability	Practicality
Status Quo	Low	High	Med	Low	High
Centralised	High	High/Med	High/Med	Med/High	Med
Decentralised	Med	Low/Med	Med	Med/High	Med

3.3 CER EVALUATION METHODOLOGY

The CER evaluation process involved two steps. First, an evaluation framework was formulated . Second, this framework was applied to the three market design options presented to industry (ie centralised, decentralised and status quo). The objective was to determine the market design option that would best meet Ireland's requirements.

The evaluation framework was developed after consideration of:

- the stated CER objectives for the new trading arrangements (as articulated in the industry consultation document and the November industry forum),
- the broader policy environment within which the new trading arrangements will be implemented, including in particular: The EU Electricity Directive, the draft Irish Electricity Bill, and environmental directives, and
- a more generalised set of evaluation criteria typically associated with evaluations of this type proposed by PA Consulting Group.

The evaluation framework took the form of:

- dimensions (or "ends") considered important for the new trading arrangements, disaggregated into sub-dimensions where appropriate,
- indicators that allow CER to measure whether the desired ends are being met, and
- analytical tools and techniques used to discover whether the option being evaluated is likely to secure the desired ends (as measured by the indicators).

The dimensions and sub-dimensions are summarised in the table below.

Dimension	Sub-dimension	Description
Efficiency	Allocative	Trading arrangements provide price signals that lead to the appropriate amount of electricity being produced /consumed by the appropriate producers /consumers
	Productive	Trading arrangements lead to electricity being produced at least cost
	Dynamic	Trading arrangements result in timely additions of new capacity
	Transaction Costs	The cost of trading is minimised
Equity	Availability to all users	Trading arrangements do not compromise the continued availability of electricity to all consumers
	Uniform pricing	Trading arrangements are (or can be) consistent with uniform consumer tariffs.
	Incumbent financial viability	Costs and benefits of change are distributed in a fair manner
Environment	Renewable energy	Trading arrangements do not adversely impact on renewable energy sources
	Demand side participation	Trading arrangements allow the demand side to play an active role in the market
Stability	Certainty/ Predictability	Trading arrangements will be stable and predictable over time
	Capacity to evolve	Trading arrangements have the ability to continue to evolve as industry structure and other factors change
	Price levels	Trading arrangements lead to prices that are efficient and sustainable
	Interconnects	Trading arrangements can accommodate increased levels of interconnection with UK and Europe
Practicality	Implementation	Implementation is well-defined, timely and reasonably priced

3.4 DETAILS OF THE CER EVALUATION PROCESS BY DIMENSION

In this section, a more detailed discussion of the evaluation process is provided for each dimension in the evaluation framework:

- efficiency,
- equity,
- environment,
- stability, and
- practicality.

3.4.1 Efficiency

On balance, the centralised market emerged as likely to be the most efficient in the Irish context – although questions still remain with respect to the dynamic efficiency component (i.e. timely new investment) and the dominant position of ESB.

A. ALLOCATIVE

The centralised market emerged as the best option with respect to allocative efficiency. This is a direct consequence of its ability to deliver location specific marginal cost pricing.

It is important to note that an important assumption underlying this conclusion is that the market dominance issue can adequately addressed. The market dominance issue presents problems for any market design option. The centralised market option, with unit-specific bidding and high levels of price transparency in the spot market, will facilitate the monitoring of market power that may not be present in other market design options.

B. PRODUCTIVE

The centralised market also delivers productive efficiency, as generating units are likely to be dispatched in accordance with Short-Run Marginal Cost (SRMC)[1]. This is in contrast to both the status quo and the decentralised option. We note that both the centralised and the decentralised market options are likely to create incentives for generators to reduce costs.

C. DYNAMIC

A centralised market produces accurate and transparent price signals for encouraging new investment. However, there is insufficient empirical evidence and a lack of confidence that any market design, including a centralised market, will bring on new investment in a timely manner (dynamic efficiency) in the absence of accompanying additional incentives. While there is a possibility that a liquid market for long-term hedge contracts will emerge, this is not certain in the near term. This argues for the consideration of specific mechanisms to address generation adequacy concerns (as discussed in Section 5.2).

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1 The *order* of dispatch (ie, lowest marginal cost first) does not necessarily mean that unit bids will be equal to SRMC.

In theory, a decentralised market may provide a higher level of assurance that new capacity will come on stream in a timely manner as a result of bilateral contract incentives. As with as a centralised market, there is insufficient evidence that these markets will deliver new investment in a timely manner. In practice, the small and emerging Irish electricity market may not have sufficient liquidity to allow this to happen in a timely fashion, so that generation adequacy mechanisms may be necessary for this market design as well.

D. TRANSACTION COSTS

The status quo option scores highly in minimising transaction costs, as there will be few costs associated with implementing a new market design. With respect to the other two options, transaction costs are likely to be significantly lower in a centralised market than in the decentralised option. These transaction costs are composed of those incurred by the central market operator and by market participants. As a centralised market incorporates a complete market, including the management of counterparty and prudential issues, it may present lower costs than a decentralised market, where each participant will manage these issues.

3.4.2 Equity

With respect to the equity dimension, both the centralised option and the decentralised option are likely to expose the underlying commercial viability of existing generators. As such it is expected that some will emerge as being profitable, to varying degrees, while others might be shown to be unprofitable. There are, however, mechanisms available outside the trading arrangements for managing these distributional effects.

The centralised market differs from the decentralised market in that it can be configured to give a uniform price for suppliers. The decentralised market, by virtue of the fact that prices are set in the context of each individual contract will result in different prices – although the extent of this difference may not be particularly significant.

This evaluation is not focused on whether uniform prices[2] are the best approach to overall electricity market design. Rather, this evaluation seeks to determine how the CER objective of uniform supply tariffs can best be achieved through wholesale electricity trading arrangements.

The status quo option allows a great deal of flexibility in setting administered prices.

3.4.3 Environment

Industry comments noted the difficulties encountered within the decentralised market, particularly NETA, by non-controllable power sources (eg, wind and CHP). Decentralised market requirements for balanced schedules, coupled with strong financial incentives, are seen to disadvantage renewable generation. A centralised market may produce more favourable outcomes for renewables.[3]

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[2] Uniform prices are defined at the wholesale level in a locational sense; the total cost for the same amount of wholesale energy would be the same anywhere in Ireland.

[3] Some have argued that the disincentives faced by variable/non-controllable generators in a decentralised market reflect the costs imposed on a system by such generators. A centralised market may charge for ancillary services that are necessary to balance the system in real time in a manner (eg, payments linked to causation) that may also impose costs on these variable/non-controllable generators.

With respect to demand side participation, the opportunities given to the demand side in rectifying system imbalances the balancing market component of the decentralised option in is a point in its favour.

Achieving an active demand side participation in centralised markets has proved somewhat problematic Design features such as *ex ante* pricing and the inclusion of demand-side bidding may improve the situation [4].A centralised reserve market such as that adopted in New Zealand, has proved quite effective in terms of encouraging demand side participation in the form of 'interruptible load', with consequent significant reductions in the need for generation capacity. The status quo design has not been shown to be particularly favourable to demand side participation.

On balance, the centralised market is likely to be marginally better for the environment. This is largely because of its perceived favourable treatment of renewables.

3.4.4 Stability

The status quo is a transitional market. It is also perceived as having shortcomings (particularly with respect to new investment) which suggests that significant changes are required if it is selected as the final Irish market design. This means that the status quo is the least stable of all of the options being considered.

There is, arguably, little basis for choosing between the other two options on the basis of stability.

The centralised market now has a well-established track record in places like New Zealand, Australia, and the USA (PJM and New England). However, the greater price volatility observed in a centralised market can be unsettling for market participants and governments alike – as can concerns about market dominance and generation adequacy. Likewise, the original England & Wales pool version was less than perfect, although many of the problems in that market seem to have been structural (eg, a virtual generation duopoly was allowed).

The decentralised option may offer less volatile prices for the energy traded through the contracts market, while balancing mechanisms may produce prices that are volatile and unconnected from underlying market supply and demand. The decentralised option has the advantage of familiarity in that it would be similar in type to both the existing market architecture and neighbouring NETA. However, the track record of decentralised markets for electricity is thinner and less consistent (eg, Nordpool, NETA, Texas, and California). In some instances, the local market situation is unique, as with Nordpool with widespread hydropower.

3.4.5 Practicality

The status quo, for obvious reasons, would be the easiest to implement. Superficially, at least, it would simply require a continuation of the present arrangements. However, for reasons outlined above, those arrangements status quo in their current form would probably not be sustainable in the longer term.

Of the remaining two market design options, neither will be trivial to implement. The centralised option represents a significant change to the existing arrangements, and will

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[4] In the long-term, the centralised market may be a more suitable design for real-time demand response by consumers.

require some adjustment from existing market participants. However, markets of this type have now been introduced in a number of jurisdictions around the world. The implementation tasks and process are reasonably well defined. There are a number of centralised models that could be used as platforms to begin development in Ireland.

Although the decentralised market has some similarities with the status quo, its implementation will also be a reasonably significant exercise. The decentralised market will require, in addition to the central market mechanisms, significant investment on the part of all of the market participants to prepare themselves for the necessary (decentralised) trading.

4. CENTRALISED MARKET DESIGN

This chapter provides a more detailed description of the centralised market option. Industry comments, while favouring this option, suggested that the details of the design were of great interest.

This chapter includes the following details on the market design components:

- spot market structure and function,
- pricing and dispatch,
- congestion management and losses,
- ancillary services,
- interconnectors,
- market information,
- metering and communications, and
- institutional arrangements.

4.1 SPOT MARKET STRUCTURE AND FUNCTION

A centralised market involves a Market Operator running a bid-based spot market. All electricity is cleared through this spot market. Generators sell all power to the Market Operator and Supply/Retail companies and other buyers (eg, customers participating in the spot market directly)[5] buy all power from the Market Operator. All electricity sold and bought through the spot market will be at the same price [6]

In the centralised spot market envisioned for Ireland, there are no side payments and no separate capacity payments (eg, unlike the LOLP payments in the original England & Wales pool). While some type of payment related to capacity may be included, such payments will be provided separately from the spot market (refer to section 5.2).

The market envisioned for Ireland would be similar to the wholesale electricity market in Australia, New Zealand, and Singapore.

The following is an overview of this spot market, including a discussion of:

- system and market operator,
- real-time market,
- market-clearing price,
- generator bidding,
- demand bidding,

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[5] Customers participating in the spot market directly will likely be required to have a licence.

[6] The total delivered electricity cost would include a number of additional items to the wholesale electricity spot price. These costs would include market costs, transmission cost, distribution cost, PSO levies, etc.

- hedging,
- pre-dispatch indicative markets,
- forward markets, and
- market suspension.

4.1.1 System and Market Operator

The System Operator will be the same entity as the Market Operator, Eirgrid. This entity is referred to as the System and Market Operator (SMO).

The SMO will accept simple price and quantity bids from participants and provide a single[7] electricity-only market clearing spot price.[8]

The SMO, as the counterparty to all spot market transactions, settles all trading in the spot market on a monthly basis.

4.1.2 Real-time market

The real-time market will cover a 30-minute dispatch interval with a consistent 30 minute trading interval.

The spot price will be set just prior to real time (*ex ante*), with dispatch and pricing based on bids and SMO estimates of load during each dispatch interval at each withdrawal node in the transmission network. Actual volumes cleared through the market will be determined by meter data and settled *ex post*.

Ancillary services (eg, load following, spinning reserves, etc) will be used by the SMO to balance the market during each dispatch interval, as described in more detail in section 4.4 below.

4.1.3 Market-clearing price

This market will use the market-clearing price approach. This means that the spot market (or each node in the spot market) will have a single price that reflects the market-clearing bid.[9]

4.1.4 Generator Bidding

In this bid-based spot market, all generators will be required to place bids to the SMO. Simple bids will be used that consist of a set of price, quantity pairs (€,MW). These bids will be "electricity-only[10]," as there will be no provision for fixed costs, start-up or shutdown costs or minimum run.

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[7] To the extent that locational pricing is pursued, there is a single price at each location.

[8] An electricity-only market is one where the spot price only includes the bid-based market-clearing price for electricity sales and does not include any additional amounts, such as capacity payments. Generators cover fixed costs and returns on investment from the difference between the market-clearing price and the actual marginal cost of generating electricity.

[9] This is distinct from a market that pays each participant the price bid (ie, pay-as-bid).

[10] Electricity-only bids include only an offer to sell electricity (eg, 30 MW of output for the trading interval at €30 per MWh).

Each separately dispatchable generating unit will submit separate bids (ie, portfolio bids will not be allowed). Each generating unit may submit up to 10 bids for each unit, so that each unit can bid its own "supply curve" reflecting the unit's characteristics.

Generators develop bidding strategies that are aimed at achieving desired generator operation levels and profitability. A standing set of offer bids will be required, with these bids subject to modification at any time up until "gate closure"[11]. Standing bids will be adjusted to reflect actual conditions, as these differences become known.

4.1.5 Demand Bidding

The SMO may also take demand bids, but no participant will be required to submit demand bids. Demand bids must reflect a demonstrable ability to respond to dispatch signals. In practice, demand bids will have to show that they have reduced demand by the amount dispatched by the SMO. Failure to do respond to dispatch signals will result in penalties proportional to the costs incurred by the SMO as a result of non-performance.

4.1.6 Hedging

Generators and supply companies will earn revenues and incur costs from mandatory participation in the spot market. However, bilateral financial instruments (eg, contracts for differences or "CfDs") will allow parties to hedge the financial risk of this mandatory spot market participation. CfDs are not directly related to the physical sale or delivery of electricity.

Risk management practices of each participant will determine the nature and scope of that participant's financial contract portfolio. The net financial impact on market participants is highly dependent on the hedging approach selected. In most centralised markets, participants have a large part of their output/purchases covered by hedge contracts.

4.1.7 Pre-dispatch indicative markets

Pre-dispatch estimates of market prices will be developed by running the market-clearing software for periods prior to real time, using as inputs generator and demand standing bids and SMO demand forecast scenarios. The SMO will make available pre-dispatch estimates that reflect the latest bid information, demand forecasts and expected status of the physical system (eg, known line or generator outages) for:

- a week ahead, with prices for each trading interval seven 24-hour periods prior to the current day calculated daily, and
- a day ahead, with prices for each trading interval 24 hours prior to each trading interval calculated prior to each trading interval.

4.1.8 Forward markets

There will be no formally organised financially binding forward markets. All trading in the financial hedge contracts will be done by participants on a bilateral basis.

The market operator will not operate formally organised day-ahead or hour-ahead markets, but will provide indicative market prices only.

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[11] After gate closure, generators will no longer be able to change their bids except in emergency situations. The exact length of time that gate closure occurs prior to real time has not yet been defined. It is likely, however, to be at least one hour before real time.

There will be no restrictions on the ability of market participants to organise and operate forward markets or exchanges in traded CfDs, although the SMO will not operate such markets.

4.1.9 Market suspension

Rules for market suspension will permit the SMO, with the approval of the CER, to suspend the market only under the extreme situation of the failure of the power system or the failure of the market clearing system. During market suspension there shall be an administered price regime.

4.2 PRICING AND DISPATCH

In this section, there is a discussion of the following topics:

- pricing methodology,
- generator self-commitment, and
- dispatch determination.

4.2.1 Pricing methodology

The spot market price will be determined by the offer of the most expensive generating unit called on to dispatch, as adjusted to reflect system losses and congestion.

There are at least three options for forming the spot market price. As there is less than full agreement on the best option, CER has presented three options:

- Locational Marginal Prices (LMP),
- LMP for sellers & uniform for buyers, and
- uniform prices.

A. LOCATIONAL MARGINAL PRICES (LMP)

In this option, the SMO will calculate and present spot prices at each designated node in the transmission system. Generators will settle at the spot prices for the node where they inject power and loads will settle at the spot price for the node where they withdraw power. Since LMP is based on actual system dispatch it will incorporate losses and congestion into spot prices. There is the possibility that LMP will differ significantly across nodes when there is transmission congestion [12].

Financial transmission rights will be introduced in the market when it is apparent that they are required to adequately hedge the locational price differences in this option.

Additional information on LMP is available in Chapter 6.LMP for sellers & uniform for buyers

This option uses LMP for sales into the spot market, but charges wholesale market buyers a load-weighted average of the LMPs for all withdrawal nodes. This is the approach used in Singapore and intended in the Philippines. Like the LMP approach, financial

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[12] Losses and congestion rentals under an LMP pricing approach create a settlement surplus. This surplus is available to underpin FTRs or is otherwise reimbursed to participants.

transmission rights will be introduced to allow generators to hedge the difference between their LMP and the single sell price.

B. UNIFORM PRICES

This alternative will provide a common price at all nodes (ie, the load-weighted average of the LMPs for all nodes) for sellers and buyers. Although uniform pricing is an apparently simple concept it is rather more complex to implement than LMP. For example, generators who are scheduled to dispatch at an offer above the uniform price will be compensated for the difference between their offer and the uniform price.

Please indicate your preference for a pricing approach and reasons for this preference:

- Locational Marginal Prices (LMP),
- LMP for sellers & uniform for buyers,
- uniform prices, or
- other (please specify).

4.2.2 Generator self-commitment

Generators, through the development of a generating unit's bids, will determine the dispatch of that unit. For example, a generating unit that is to be operated at full load all the time to meet the requirements of an inflexible fuel contract might bid at zero or even negative prices that are lower than the market price and thereby be dispatched at all times.

Pre-dispatch indicative price estimates, incentives presented by financial hedge contracts, and other factors (fuel supply contracts and generator operating characteristics) will drive the bidding strategy of each generator. No side payments will be made by the SMO. Ancillary service contracts (eg, for load following or spinning reserve) may also lead to generator unit commitment decisions.

4.2.3 Dispatch determination

The computer software that produces market-clearing prices, called the Market-Clearing Engine (MCE), will also determine dispatch instructions. These instructions will be consistent with the bids and offers presented by market participants and accepted by the SMO. To achieve this, the market-clearing engine must contain all of the system transmission and security conditions required to specify accurate dispatch instructions.

4.3 CONGESTION MANAGEMENT AND LOSSES

Congestion will be managed by determining the dispatch based on optimisation of the market and dispatch simultaneously at each node – irrespective of the use of LMPs for pricing. There will be no constrained-off payments to generators.

Transmission-level losses are managed by dispatch optimisation and included in LMP spot prices, with additional rules required if LMP is not used.

4.4 ANCILLARY SERVICES

In a bid-based spot market with self-commitment, the SMO will need some ancillary services to balance the real-time market during each dispatch interval and in the event of abrupt changes in the system (ie, a sudden power plant outage). This section discusses the issues related to :

- responsibilities of the SMO in real-time,
- classes of reserves,
- contracting for ancillary services,
- reserves and energy markets,
- charging methodology, and
- other ancillary services.

4.4.1 Responsibilities of SMO in real-time

The SMO is responsible for maintaining the security of the system in real time (ie, during the dispatch interval). In order to accomplish this, the SMO will define, procure and use ancillary services related to reserves.

4.4.2 Classes of reserve

The SMO will define the types and amounts of ancillary services needed to operate the system. Typically this would include such reserves as:

- frequency response[13] or load following service (sometimes referred to as AGC services or regulating reserve), as supplied by generation operated at some level below full load on automatic governor control (AGC) that adjusts generator output to maintain system frequency, and
- operating reserve[14] or contingency reserve that is used to keep the system operational in the event of a sudden power plant or transmission line outage; composed of spinning reserve (ie, quick response reserves supplied by generation operating at less than full output with the remainder ready to ramp when called on), interruptible load, and 10-minute reserves (ie, generation that is not operating but that can be started and brought to full load quickly.

4.4.3 Contracting for ancillary services

The SMO will procure contracts for the provision of the desired types and amounts of ancillary services. The provision of ancillary services will form another source of income for those power plants selected.

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[13] Refer to the Grid Code Section CC.7.3.7 for a detailed explanation of frequency response.

[14] Operating reserve is classified by time to respond after the event and amount of required reserve as percentage of registered generator capacity. Current classifications are Primary (5-15 seconds; 5%), Secondary (15-90 seconds; 5%), Tertiary 1 (90 seconds – 5 minutes; 8%), and Tertiary 2 (5-20 minutes; 10%). Refer to the Grid Code Section CC.7.3.1.1 subsection (u) for a more detailed exposition.

As there may not initially be a competitive market for the provision of such services, the contract rules should include a provision for cost-based pricing when there is insufficient competition to provide a reasonable price in each auction.

4.4.4 Reserves and energy markets

The provision of AGC and spinning reserves is provided by power plants that might otherwise be operating at full load providing energy. While probably not envisioned as an option in the Irish market at market start, a real-time reserves market might be established, where trading of operating and regulating reserve will be performed in a spot market co-optimised with the spot market for energy.[15]

4.4.5 Charging methodology

The cost of the SMO acquiring reserves and other ancillary services will, as far as possible, be charged to those market participants who make it necessary for the SMO to hold those ancillary services. Ideally, those putting strain on the market will pay for the reserves needed to maintain system reliability.

4.4.6 Other ancillary services

The SMO will be responsible to purchase and employ other ancillary services as required.

4.5 INTERCONNECTORS

The Irish electricity market must have the ability to interface with the existing interconnector to Northern Ireland and any new interconnectors (eg, an East-West interconnector to Wales) system effectively and efficiently. The existing protocols for the interconnector to Northern Ireland may need to be modified. Any market design must accommodate the operation of interconnects. There are two separate options, although an actual interconnect may operate with a combination of the two methods;.

- SMO interchange, and
- interconnector trader.

4.5.1 SMO interchange

In this option, the SMO would manage the interconnector as another part of system operation. An interchange agreement would be reached with the system operator on the other end of the interconnector that would govern this.

This is similar to the system-to-system interchange agreements that are in effect in the US (where different regional markets are now in place on either ends of some interconnectors) and that were in place in Australia prior to the NEM (where both ends of the interconnector are now inside the single market).

This arrangement gives the SMO maximum flexibility to use the interconnector to maintain system security and reliability. It does not, however, allow the market to determine the operation of the interconnector.

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[15] This type of market would have a bid-based market for reserves and for electricity, with the market operator seeking to minimize total costs by clearing both markets simultaneously. For more information on how a co-optimised electricity and reserves market might work,

4.5.2 Interconnector trader

In this option, the rights to trade on the interconnector are auctioned to private parties that gain the rights to trade the interconnector in both markets to maximise revenue and profits. The proceeds from the auction of these rights would be used to recover the capital investment in the interconnector.

This arrangement has the advantage of strong incentives to operate the interconnector to achieve efficient dispatch on both ends of the interconnector. On the other hand, the SMO may have little or no flexibility (unless the Interconnector trader is also a provider of ancillary services) to use the interconnector to maintain system security and reliability.

4.6 MARKET INFORMATION

Market-clearing prices, SMO estimates of load and system configuration as well as anticipated congestion will be published to all market participants immediately after each dispatch run and pre-dispatch of the MCE , prior to the commencement of the dispatch period.

Dispatch quantities by plant and participant bids (and rebids) will also be provided to the market. This information should be made available as soon as possible.

4.7 METERING AND COMMUNICATIONS

Wholesale metering standards and requirements have largely been defined and may not change as a result of a shift in market design. Communication links between the SMO and generators (and perhaps large customers and those bidding demand into the market) will be based on the information to be transferred. Depending on the solution chosen some details may need to be clarified and detailed implementation issues will need to be agreed.

4.8 INSTITUTIONAL ARRANGEMENTS

There are a number of institutional arrangements that must be put in place for any market. In this section we discuss the following aspects of these arrangements:

- regulatory framework,
- membership and participation in the market,
- role of CER ,
- role of System and Market Operator,
- industry participation, and
- arrangements for enforcement, monitoring, dispute resolution and rule changes.

4.8.1 Regulatory framework

This section outlines the regulatory framework under existing legislation that will govern the new market. Many necessary details remain to be determined. The intention here is to provide an indication of that framework, so that institutional arrangements can be seen in context. Typically such a framework would incorporate a hierarchy, including:licences that, amongst other things, require participation in aspects of the new market and that may require certain actions by key central participants (ie, the SMO),

- codes that impose common obligations on participants, and
- contracts of many forms, including connection agreements.

In what follows, this broad structure is assumed, although as noted many details remain to be resolved.

4.8.2 Membership and participation in the market

The wholesale electricity market, would be open to participation by each of the following (the categories are not mutually exclusive):

- all licensed generators and suppliers,
- all customers who choose to participate
- all licensed ancillary service providers,
- unlicensed generators or exempt generators (if these are to be permitted in Ireland),
- parties outside Ireland who wish to buy or sell electricity in Ireland by use of interconnection,
- trading parties (may include power exchanges, brokers, customer aggregators and others), and
- other relevant parties that are not direct participants (eg, the CER and the SMO).

Membership of the market would be mandatory for some classes of participants.

4.8.3 Role of regulator (CER)

The CER's functions in the electricity market are specified in the Electricity Regulation Act, 1999 ('the Act'). These provide for establishing a system of trading in electricity, licensing market participants and dispute resolution. The CER will continue to exercise these functions under the new trading system and will need to have regard to its duties under the Act.

In carrying out its duties the CER is required to have regard to the need to:

- promote competition in the generation and supply of electricity,
- secure that all reasonable demands by final customers of electricity for electricity are satisfied,
- secure that licence holders are capable of financing the undertaking of the activities which they are licensed to undertake,
- promote safety and efficiency on the part of electricity undertakings,
- promote the continuity, security and quality of supplies of electricity, and
- promote the use of renewable, sustainable or alternative forms of energy.

The CER will have at least three roles in the new wholesale electricity market.

A. ESTABLISHING THE NEW MARKET

CER will establish the market. CER will implementing institutional arrangements, define and implement licence regimes, and adjust the existing regulatory regime.

B. SUPERVISION OF THE NEW MARKET

CER will supervise the market, assisted by the SMO (an important source of information, even if CER has responsibility). A clear process for hearing and deciding disputes and complaints must be established.

C. ROLE IN RELATION TO RULE CHANGES

It is a certainty that market rules will never be precisely correct and will need to change as the market grows and evolves. CER will have an important role in defining where various rules as to market operation and conduct reside, how any changes to such rules are proposed, assessed, consulted upon and implemented.

D. OTHER FUNCTIONS

There will be other roles played by CER in the new market, including:

- approving and enforcing licences for market participants,
- determination and implementation of a cost recovery regime for SMO, and
- other enforcement and compliance activities.

4.8.4 Role of SMO

The SMO will be Eirgrid. Eirgrid controls and operates the transmission system that is owned by ESB National Grid and will act as both system operator and market operator:

- the system operation function may be provided with incentives to efficiently and effectively operate the system and perhaps to minimise system congestion, and
- the market operator function will be a not for profit entity that charges out costs to participants on some agreed basis (eg, a mix of participant fees and pro rata MWh charges).

4.8.5 Industry participation

It is important that industry be provided with an opportunity to participate in market oversight and governance. One or more industry boards could be appointed to handle responsibilities, for example:

- an industry board to advise CER on market design and implementation and issues,
- an oversight board with a general remit to oversee the market, report on conduct, decide on issues allocated to it,
- a rule change board to initiate, consider, and make recommendations to CER as to market rule changes, and
- the SMO board, if possible given its legal identity, might include industry representation.

Whatever boards are established, decisions must be made as to:

- how industry representation is defined (eg, representatives by type and class; elected representatives from across the whole industry, or other arrangements),
- whether and how customer representatives will be included, and

- what rules will govern qualification for involvement in industry boards.

4.8.6 Arrangements for enforcement, monitoring, dispute resolution and rule changes

A. ENFORCEMENT

This would involve enforcing compliance with market rules and licences; defining obligations to provide relevant information to support enforcement action and a process for monitoring prices.

B. MONITORING

Monitoring should be an integral part of a well-defined market supervision regime. The SMO will have an obligation to provide information to CER and, as defined, to the market so that conduct can be assessed. The SMO may have a role in analysing market data to support market monitoring.

C. DISPUTE RESOLUTION

Resolution procedures, including independent arbitration, a committee of peers, or other procedures will be defined. Normal legal processes should as far as possible, handle commercial disputes between parties.

D. RULE CHANGES

This is normally a critical issue in electricity market. A clear process for this must be established in accordance with the appropriate legislation (eg, Statutory Instrument 49 of 2000)

5. INSTITUTIONAL AND STRUCTURAL ISSUES

In Ireland, two major institutional and structural issues have the potential to significantly influence the market outcome of any trading arrangements selected. These issues are generation adequacy and market dominance. The overall Irish electricity market may experience significant disruption and dislocation if measures are not in place to address these two issues. These two issues were addressed in the earlier November 20,2002 industry paper.

In response to this earlier Industry Paper, participants almost universally agreed that these two issues were of concern and that something must be done to address them. However, there was less than clear consensus on the preferred option to do so.

Accordingly, CER has developed more defined options that we ask parties to review and consider. CER invites your views on these options and requests that you express any clear preferences.

5.1 DOMINANT PARTICIPANT ISSUE

As discussed in the earlier Industry Paper, ESB is a large presence in the Irish electricity market and the situation is likely to continue for some time after the market is fully opened. ESB's dominance is present in generation, transmission, distribution and supply. The transmission and distribution sectors will remain regulated monopolies. Also, ESB transmission and distribution will be functionally and operationally separated from ESB's generation and supply activities.

ESB's supply business, the ESB Public Electricity Supplier (PES)[16], and generation business, ESB PowerGen, are the sectors of concern in relation to dominance.

CER believes that there are a number of approaches to limiting ESB market dominance that should be considered. In this section, these options are presented along with some of the advantages and disadvantages of each. These are intended to show that there is no obvious solution and examples of countries where each have been tried along with a link to the appropriate regulator are included. Further, it should be noted in the discussion that follows that not all of the following options are mutually exclusive.

CER requests comments on each of the options; please provide a preferred option for the way forward and examples or ideas of any new options.

5.1.1 Options not considered

A. DO NOTHING

The comments received from industry almost universally agreed that the issue of ESB market dominance is an important one. In addition there was almost universal agreement that some actions were needed to resolve this important issue.

CER does not consider this option as viable. It is important that there is confidence in the market and that one player does not have the ability to influence the operation of the

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16 The draft Electricity Bill, 2002 provides for an economic purchasing obligation for PES. The exact nature of this obligation is yet to be defined, but this obligation may have an impact on the ability of ESB to exercise market power.

market. The presence of a single dominant participant will undermine the benefits of any market design that could be implemented and measures to control this market power must be in place.

B. PRICE CAPS

This option was presented in the earlier Industry Paper. This option has been discounted due to:

- industry comments were generally unsupportive of this approach,
- price or bid caps may exacerbate the generation adequacy problem, as new entrants will view such mechanisms negatively, and
- price or bid caps may subvert the efficiency and effectiveness of the spot market, removing proper marginal price signals to participants.[17]

5.1.2 Structural change options

ESB's market dominance is a result of its ownership and control of a large part of the generation and supply business in Ireland. The "textbook" approach to resolving this structural problem would be to effect a restructuring of the industry.

The first step in a structural solution would be for ESB generation and ESB supply to be broken into smaller viable business units that would be established as separate legal entities.

Structural solutions alone may not necessarily produce the desired outcome. Due to the capacity shortage situation and the large size of some ESB power stations relative to total market demand, some of the newly formed generating companies may retain market power in some situations.

These options are presented here, even though CER's remit in this Review of Electricity Trading Arrangements and its statutory authority does not extend to ordering such restructuring and privatisation options.

CER is of the view that ESB market dominance must be dealt with in order for any market to work in Ireland. As there is no assurance that a restructuring of ESB will occur or that a restructuring of ESB will occur in an appropriate manner[18], CER believes that other viable alternatives must be pursued to address the market dominance issue.

A. COMPETING STATE-OWNED GENERATORS

In this option, the companies newly formed from disaggregating ESB would remain under government ownership. This could be a temporary solution or permanent solution.

Each of the new enterprises would be constituted along normal company lines (albeit with state shareholding) and would compete against each other as well as private sector

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[17] Price capping and bid controls have been used in California and may be a part of the proposed FERC Standard Market Design (SMD). See http://www.caiso.com/docs/09003a6080/06/7c/09003a6080067c14.pdf and http://www.ferc.gov/Electric/electric.htm for more information.

[18] A lesson from the England & Wales market is that the details of restructuring are important. The privatised duopoly regime remaining after the restructuring of the generation in England & Wales has been recognised as a problem. See www.ofgem.gov.uk for more information.

market participants. This option addresses the dominant participant issue while retaining government ownership of generation assets.

While this option was used as in New Zealand with some success[19], the experience in Australia has been less positive[20].

B. ATOMISTIC PRIVATISATION OF ESB

In this option, the companies newly formed from disaggregating ESB would be privatised by trade sale or flotation. This would have the result of creating many market-driven competitors to replace ESB as a single large competitor.

Many of the industry comments expressed a strong preference for this approach in some form.

The details of such an atomistic privatisation approach are important. While structural remedies may provide significant relief from the market dominance of ESB, a close analysis of the details and consequences of such an approach must be made before such an option should be undertaken.

5.1.3 Supporting measures

There are two other measures and actions that may be undertaken to provide monitoring and control of market power exploitation. These other measures are not presented as stand-alone alternatives to the Central Trader and Regulation options, but will be used as necessary to help achieve the objective of a competitive market.

A. DEMAND SIDE RESPONSE

Demand Side Response (DSR) is postulated as a means of limiting the exploitation of market power. The general concept is that if any player attempts to artificially raise prices then the demand side may react by reducing demand and thus suppressing prices. DSR may also have the effect of reducing peak prices even if they are at competitive levels. It is generally agreed that DSR can make a positive contribution to any market structure. Its role in mitigating market power, however, is likely to be limited.

In the preferred centralised market design, DSR will take the form of allowing the demand side to bid to reduce demand. Since the majority of customers in Ireland will not have real-time metering and will be profiled for settlement and pricing, some adjustments will be necessary to encourage more widespread DSR.

B. MARKET MONITORING

It is certain that the Irish market will require some level of monitoring of participant activity. This will be a part of ensuring compliance with licensing conditions and market rules.

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19 There have been two major enquiries into the New Zealand electricity industry in the last three years. State ownership per se was not a major focus of these investigations, but it is notable that none of these inquiries identified state ownership of the generation sector as a problem warranting any policy response. See further www.electricityinquiry.govt.nz and www.winterreview.govt.nz.

20 While industry disaggregation in Victoria and South Australia have produced competitive outcomes, the disaggregated and corporatised government-owned companies in New South Wales and Queensland have shown a tendency to subvert the market. See http://www.energymarketreview.org/FinalReport20December2002.pdf for details.

An additional level of market monitoring may be put in place that is intended to reveal anti-competitive activity such as separate ESB generating units bidding in concert.

5.1.4 Options under consideration

A. CENTRAL TRADER OPTION

In this option, ESB would not be restructured. Instead, this option would control the behaviour of the remaining dominant player by imposing a suite of hedge contracts. These contracts would be held by a new entity (the "Central Trader")[21].

These contracts would remain in effect so long as ESB has potential market power. CER would set the terms, conditions, amounts, and types of contracts, with the ability to modify these contracts from time to time to ensure that the desired outcomes are achieved.

Some details of the proposed Central Trader option are provided here.

i. Generator contracts

A set of hedge contracts with stipulated terms and prices, would be put in place for each of the ESB generating stations. This would be a suite of contracts that include a mix of two-way hedges, one-way hedges, insurance contracts, and options contracts. There may be a different contract set for each plant, maybe for each generating unit.

This suite of contracts, in total, will largely determine the overall return to ESB generation, providing CER with a mechanism to regulate the returns to ESB generation.

The counterparty to these contracts will be the ESB generating stations or units on the one hand and the Central Trader on the other hand. To the extent that ESB generation has unhedged capacity, it will be free to offer that capacity to the market.

ii. PES Contracts and Tariffs

CER will impose a suite of contracts on ESB PES, with the Central Trader acting as the counterparty to these contracts. This suite of hedging contracts will, in conjunction with PES contracts with other market participants[22], form the cost basis for PES.

Tariff levels for PES, set by CER, will reflect these contracts.

iii. Central Trader

This will be a new government-owned entity that acts as the counterparty to the imposed contracts with ESB generation and ESB PES. The Central Trader will act to separate the economic interests of ESB generation and ESB PES, removing some economic incentives to act in a coordinated fashion to limit competition.

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[21] The later section on generation adequacy proposes, as one option, the creation of another new entity referred to as the 'Default Buyer.' If the Central Trader option and the Default Buyer option were both selected and implemented, these two entities would likely be combined into a single new entity to lower cost and allow benefits of coordination.

[22] PES will enter into other contracts as a result of, for example, the Capacity 2005 programme and the economic purchasing obligation imposed on PES.

B. REGULATION OPTION

A regulatory and licensing regime is presented in this section as a stand-alone option that will be considered as an alternative to the Central Trader option in section 5.1.4.[23]

CER would implement a regulatory and licensing regime that would have the effect of removing the ability of ESB to profitably exercise market power. While the Central Trader option would place commercial incentives and financial penalties on ESB through a suite of imposed hedge contracts, this option would place direct controls on ESB.

Regulation has long been used in the electricity industry, where natural monopolies existed (eg, distribution and transmission) and it was not feasible to induce competition. While generation is no longer considered as a natural monopoly, regulation can provide a powerful and tested means of controlling the behaviour of ESB.

Such a regulatory and licensing regime would, among other features, include:

- separate accounts for each power plant or power station (this is typical regulatory accounting),
- regulation of each ESB generating station or unit to retain incentives to operate commercially, but remove the ability to earn super profits through the exercise of market power.
- a requirement to deal with all supply companies equally when negotiating hedge contracts (to prevent affiliate exploitation related to PES), and
- a requirement to sell to the market any power plants that are to be retired, mothballed, or shut down (to prevent ESB from shutting plants to increase the profits of other ESB plants).

Please indicate your preference for addressing the market dominance issue and reasons for this preference:

- Central Trader option,
- Regulation option, or
- other (please specify).

5.2 GENERATION ADEQUACY ISSUE

CER has presented several approaches to the generation adequacy problem. In this section, the options are presented along with some of the advantages and disadvantages of each. These are intended to show that there is no obvious solution and examples of countries where each have been tried along with a link to the appropriate regulator are included.

CER requests comments on each of the options examples or ideas of any new options and a preferred option for the way forward.

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[23] It is certain that some level of regulatory control and licence conditions will be present in any case, although more stringent regulation would be required if they were selected as the sole option to control market dominance. For example, ESB may be required to keep separate accounts for each generating station/unit and to operate each station/unit separately in the market under any option.

The various generation adequacy mechanisms described below may also be used as a mechanism to provide incentives for renewables. This section includes a discussion of the generation adequacy issue and presents several options for consideration.

5.2.1 Discussion

A. NEED FOR ACTION

There is growing evidence that an uncapped spot market coupled with a functioning hedge contracts market will produce sufficient capacity to clear the market.[24] To some degree, this may depend on price level that is in effect if the market does not clear so that load is shed (ie, the Value of Lost Load or VoLL).

The US market has moved strongly toward price caps in the real-time market largely as a reaction to the events in California in 2000 and 2001. While uncapped spot market prices may well suffice to drive market entry of new capacity, spot prices in the US are likely to be capped in some manner, so that some capacity mechanism is needed there.

This need not be the case in Ireland. However, the experience to date with market entry of new generation may not be sufficient to provide assurance that the Irish market will have a sufficient level of generation.

B. SAFETY NET

Accordingly, CER proposes to implement mechanisms to ensure generation adequacy that will function as safety nets that only take affect when and as needed.

The current Capacity 2005 programme and the general agreement amongst industry participants that some mechanism is needed in the post-2005 period have reinforced the need for some immediate intervention in this area.

Any intervention option (ie, those presented below) should have (a) a role as only a safety net, not to be used unless there is a failure of the market to deliver generation adequacy, and (b) a finite life cycle, so that the option would remain in place only so long as is necessary to confirm that the market will deliver generation adequacy.

C. TRIGGER CONDITIONS

The Default Buyer option in section 5.2.2a and the development incentive option in section 5.2.2b only take effect if trigger conditions are reached. These trigger conditions are likely to be based on predictions of available capacity compared to demand. To ensure equality of information, these criteria will be published but CER will decide if and when the trigger conditions have been met.

Other options will be implemented on an ongoing basis.

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[24] In South Australia and Queensland, an uncapped spot market has given incentives for significant new generation entry (including large baseload coal plants in Queensland, a large combined cycle gas turbine station in South Australia, peaking units in both states, and even merchant transmission lines), refer to http://www.energymarketreview.org/FinalReport20December2002.pdf. In New Zealand plans are well advanced for new market plant installations by Genesis Power (CCGT) and Meridien Energy (Hydro).

D. GAMING OF GENERATION ADEQUACY MECHANISMS

There will be some potential that any option selected to address generation adequacy will be subject to gaming.[25] This potential may exist for any mechanism chosen for use in Ireland. CER retains the right to intervene if it believes that artificial gaming of any mechanism is being practiced. A number of arrangements, however, may be put in place at the outset to prevent participants profiting from gaming.

To address the longer term issue of plant closure or mothballing, plant slated for closure or significant reduction in output, by any participant, must be offered for sale. Thus if plant does still have an economic life a new party may purchase and operate the plant.

E. GREATER INTER-CONNECTION

There is potential for a greater level of interconnection between Ireland, Northern Ireland and the UK. Such interconnection could provide benefits, acting to add competition and increase reliability in the Irish market [26]. Interconnects may not present the same beneficial effect on Irish reliability as would be provided by a local power plant for a number of reasons, including:

- market conditions on the other end of the interconnect,
- the interconnector itself and the transmission lines connecting the interconnector to the broader market may be subject to failure, and
- capacity shortages (and outages) across an interconnect could have an impact in Ireland.[27]

5.2.2 Safety net options for consideration

The following safety net options are presented. These measures would be triggered in the event of market failure to provide sufficient capacity.

- Default Buyer option,
- Development incentive option, and
- SMO builds generating plant option.

A. THE DEFAULT BUYER OPTION

This option is similar to the Capacity 2005 Programme currently being implemented.

The Default Buyer would be tasked with providing incentives to a new generating plant. These incentives could be in the form of hedge contracts. The Default Buyer would then on-sell these hedge contracts or bi-lateral contracts in a non-discriminatory manner.

The Default Buyer may be faced with financial risk, depending on the details of the contract package offered to the new entrant and the prevailing market. This may be a

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[25] Gaming was reported to have occurred in the original England & Wales market LOLP features.

[26] CER is currently undertaking a study to evaluate the overall net benefits, if any, of an east-west interconnector.

[27] In the Australian market, regions that are connected by an interconnector "share the pain" of outages resulting from inadequate generation, unless the interconnector is fully loaded in supplying the capacity-short region.

particular problem if the amount of new generation is greater than that desired by the market.

B. THE DEVELOPMENT INCENTIVE OPTION

The CER (or other competent body, including the SMO) could hold tender processes that are aimed at providing a financial incentive that would induce sufficient new entry into the Irish market, with the incentive payment supplementing the new entrant's expected profits from participation in spot and contract markets. In this situation, an incentive payment is provided in return for a demonstrated commitment to build capacity on an agreed schedule.

The costs under this option would be clearly defined and monetised at the outset. There is no lingering financial exposure to the market. There is no need to create and maintain a new "Default Buyer" entity, as the development incentive auction could be run by existing entities.

C. THE SMO BUILDS GENERATING PLANT OPTION

This option is somewhat similar to the development incentive option, but features a more targeted and timely generation construction programme. The SMO would identify a site and a plant design and complete siting, permitting, and other development activities. The SMO would then commission the building of a new generating plant if and when trigger conditions were met.

This new power plant would, when operational, be offered for sale to the market through an auction. Any shortfall or profit from the sale price would be distributed across customers and may take the form of an uplift charge, which may be negative in the case of a profit on the sale.

The benefit of this option is that the time from a trigger event to power plant operation may be the shortest of all the options.[28]

Please indicate whether you consider the generation adequacy issue requires a safety net option and if so indicate your preference for addressing the generation adequacy issue and reasons for this preference:

Safety net options:

- Default Buyer option,
- Development incentive option, and
- SMO builds generation plant option.

[28] The SMO may gain the necessary planning permissions and permits in advance, in order to reduce the total power plant development period and allow for triggers to be defined that are closer to predicted capacity needs.

6. LMP EXPLANATION AND EXAMPLES

This chapter provides a brief discussion and examples of Locational Marginal Pricing (LMP).

Locational pricing uses market prices, not administrative restrictions, to manage transmission congestion by:

- locational prices determined by market participant bids
- the cost of transmission is based on re-dispatch to meet required flows
- no need for restrictions on access to transmission grid or wholesale market

Transmission congestion will cause locational prices to differ. Without transmission congestion, the lowest-cost generators could serve all loads. With transmission congestion, some low-cost generation must be constrained down or off, while higher-cost generation is constrained on to serve load.

Locational prices reflect the difference in the cost of energy that results from re-dispatch of generation to avoid violating transmission limits and managing congestion. Under a locational pricing system:

- each generator that sells into the spot market is paid the locational price at its transmission bus.
- each customer that buys from the spot market pays the locational price at the location of its load.
- each transmission customer pays the difference between:
  - the locational price at the withdrawal location for its transaction; and
  - the locational price at the injection location for that transaction.

The locational marginal cost model is consistent with least-cost, security-constrained dispatch. Under locational pricing:the price of power at each bus is the cost of providing incremental power at that bus; this is the locational marginal cost or the spot price of power

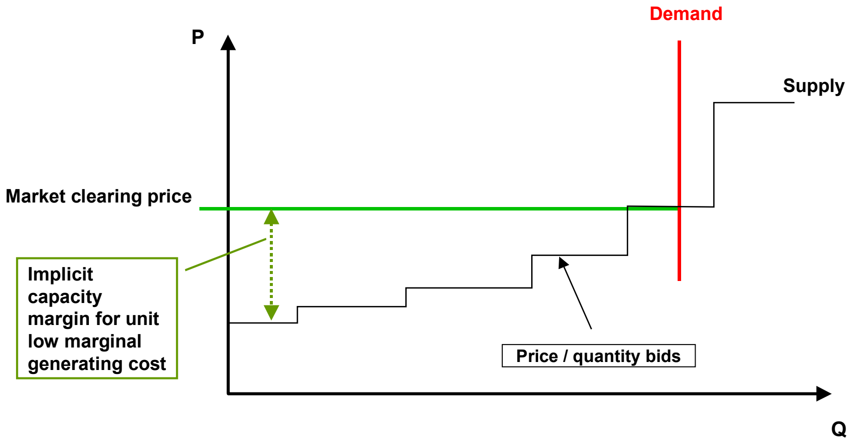
- All generators sell to market operator at the locational marginal cost at the location at which they inject power into the grid
- All buyers purchase from market operator at the locational marginal cost at the location at which they withdraw power from the grid
- If the transmission grid is constrained, the market operator will collect congestion rents, the difference between the market operator's revenues from power sales, and the market operator's costs of power purchasesThe spot price of transmission

between any two busses is the locational price at the receiving bus minus the locational price at the sending bus. This ensures that the cost of buying power at one bus and then transmitting that power to another bus is exactly the same as the cost of buying power at the second bus.

The following figures provide further explanation of locational marginal pricing.

Price Formation – Centralised Market

Market clearing price is paid to all accepted bids



Illustrative trading period (e.g., 1 hour)

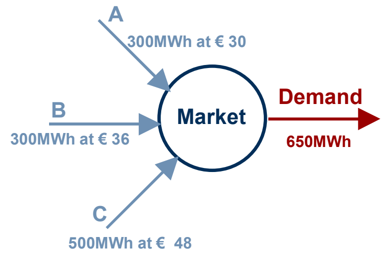
Centralised Market Example: Single Node Market

Three generating companies

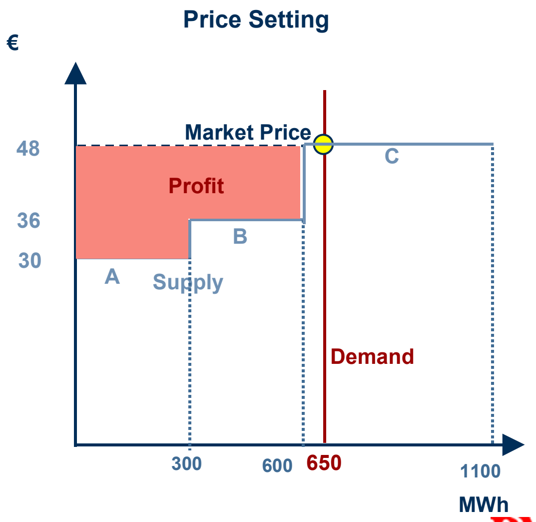
Genco	Capacity	Offer Price
A	300 MW	€ 30 / MWh
B	300 MW	€ 36 / MWh
C	500 MW	€ 48 / MWh

Demand of 650 MWh in the next 1 hour trading interval

Centralised Market Example: Single Node Market



Genco	Dispatch	Revenue	Profit
A	300 MWh	€ 14,400	€ 5,400
B	300 MWh	€ 14,400	€ 3,600
C	50 MWh	€ 2,400	€ 0



Centralised Market Example: Two Node Market without Congestion

Market split into two "nodes" and a linking transmission line

Genco	Capacity	Offer Price	Node
A	300 MW	€ 30 / MWh	1
B	300 MW	€ 36 / MWh	1
C	500 MW	€ 48 / MWh	2

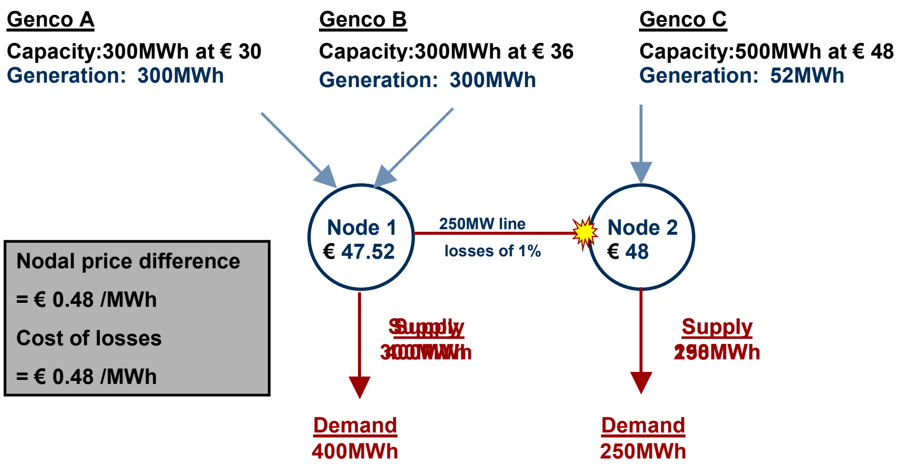
Transmission system between the nodes:

- **Capacity of 250MW with 1% linear losses**

Demand for next trading interval (hour)

- **Node 1: 400 MWh,**
- **Node 2: 250 MWh**

Centralised Market Example: Two Node Market without Congestion



Centralised Market Example: Two Node Market without Congestion

Genco	Dispatch MWh	Market Price € / MWh	Revenue €	Profit €
A	300	€ 47. 52	14,256	5,256
B	300	€ 47. 52	14,256	3,456
C	52	€ 48	2,496	0
Total	652	Av = 47.558	31,008	8,712

Load	Supply MWh	Export (Import) MWh	Market Price € / MWh	Cost €
1	400	200	€ 47. 52	19,008
2	250	(52)	€ 48	12,000
Total	650	Av = 47.705		31,008

Centralised Market Example: Two Node Market with Congestion

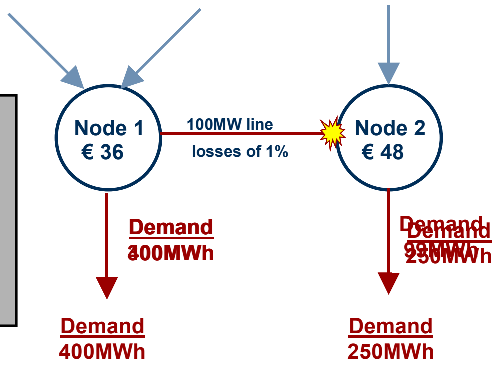
As before but with line capacity reduced to100MW

Centralised Market Example: Two Node Market with Congestion

Genco A
Capacity:300MWh at € 30
Generation: 300MWh

Genco B
Capacity:300MWh at € 36
Generation: 200MWh

Genco C
Capacity:500MWh at € 48
Generation: 151MWh



Nodal price difference
= €12 / MWh
Cost of loss
= €0.48 / MWh
Congestion Rent
= €11.52 / MWh

Centralised Market Example: Two Node Market with Congestion

Genco	Dispatch MWh	Market Price € / MWh	Revenue €	Profit €
A	300	36	10,800	1,800
B	200	36	7,200	0
C	151	48	7,248	0
Total	652	Av = 38.78	25,248	8,712

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 = 100 * 11.52

Price Formation – Centralised Market

Locational energy pricing

Locational pricing uses market prices, not administrative restrictions, to manage transmission congestion.

- Locational prices are determined by market participant bids.
- The cost of transmission is based on dispatch to meet required flows.
- No need for restrictions on access to transmission grid or wholesale market.

Locational price arise from dispatch to serve an increment of load at a location, calculated from dispatch data:

- After dispatch is complete, the required data are available.

Using locational pricing there is no “out-of-merit” dispatch