**Market Arrangements for Electricity**
**Margadh Aibhléise na hÉireann**

# Implementation of the Market Arrangements for Electricity (MAE) in relation to Renewables, CHP and Distribution-connected Generation

**An MAE Consultation by the Commission for Energy Regulation**
**Under S.I. 304 of 2003**

**10th October 2003**

**CER/03/253**

# 1 EXECUTIVE SUMMARY

This paper proposes how the centralised market being implemented in Ireland will operate in relation to renewables, CHP and distribution-connected generation.[1] In particular, the following issues are being consulted upon:

- Dispatch and pricing (Section 4)
- Reserves (Section 5)
- Contracting (Section 6)
- Certification (Section 8)

The Commission is keenly aware in designing the new trading arrangements with regard to renewables, CHP and embedded generation of the need to have regard to the following groups of market participants:

i. Large scale renewables/CHP
ii. Small-scale renewables/CHP
iii. AER-funded generation
iv. Renewable generation funded on a merchant basis
v. New-entrants

The Commission invites comments and suggestions in relation to these proposals by 5pm October 31st 2003.

## Dispatch

The Commission proposes, in line with the existing limits under the Trading and Settlement Code, that the System Market Operator (SMO) shall dispatch all generating units with a capacity greater than 10MW, generators with units between 5-10MW may elect to have these units centrally dispatched. Generating units of less than 5MW will self-dispatch. It is proposed that these limits will apply up to a maximum total site capacity of 30MW, at which level and above it will be a requirement to follow dispatch instructions for system safety and security.

Participants under the dispatch limits are not required to make offers of generation to the SMO. Participants above the dispatch limits will be required to make generation offers to the SMO (these may be once off standing offers).

Intermittent plant such as wind will be required to utilise up-to-date forecasting techniques, deliver technology that allows it to be controlled to the greatest extent possible and provide regular updates regarding production and other information deemed necessary to the SMO.

[1] This paper addresses some of the issues previously raised in the 'Trading Arrangements and Renewables Paper', published on 30th April 2003 (CER/03/099).

## Priority Dispatch

In line with the obligation under Article 7 of the Renewables Directive, the Commission invites comments on strategies to ensure priority dispatch for renewables, subject to the reliability and safety of the grid.

## Spot-Market Pricing

All transmission-connected generation will receive the Locational Marginal Price (LMP). The Commission invites comments on whether distribution-connected generation should receive the LMP, the Uniform Wholesale Spot Market Price, or whether some distribution-connected generation could receive the LMP and others the Uniform Wholesale Spot Market Price.

## Negative Pricing

The Commission proposes that there be no market floor price for renewables or CHP, other then the general market price floor of negative VoLL. If it is required, renewables and CHP should be compensated outside of the market arrangements, through an additional support mechanism. The Commission notes that, Environmental Directives (e.g. Emissions trading, Large Combustion Plant, National Emission Ceilings) are likely to increase the economic competitiveness of renewables and CHP because it places additional costs on conventional plant.

## Reserves

The Commission proposes that all generators be liable for the cost of reserves in line with a 'causer-pays' principle. These costs will be allocated in proportion to the requirements for reserves that are deemed to be due to each generating unit.

## Contracting

The Commission invites comments in relation to the use of CfDs by renewables, CHP and distribution-connected generation and specifically the process by which the existing AER contracts are converted into CfDs with the same financial effect as the original AER contracts.

## Certification

The Commission invites comments on the proposal to track the aggregate energy figures passing through the market on an annual basis, to comply with Article 3(6) of the Electricity Directive. In addition, the Commission invites views on the most-cost effective means to put in place a system of renewable/CHP tracking under the new trading arrangements.

## 2 INTRODUCTION

This document is a consultation paper by the Commission for Energy Regulation under Regulation 5(1) of S.I. No. 304 of 2003 – Electricity Regulation Act 1999 (Market Arrangements for Electricity) Regulations 2003.

The purpose of this paper is to examine the detailed design of the Market Arrangements for Electricity (MAE), in relation to renewables,[2]CHP[3] and distribution-connected generation[4] in Ireland. S.I. 304 of 2003, sets out the principles for the establishment of the new market.

The new market will be an energy-only centralised pool market using marginal pricing calculated in each half hour of the day. Generators (subject to certain provisions) will make offers to generate quantities at particular prices. The System and Market Operator (SMO)[5] will select the preferred offers on the basis of their price and location. The offers are chosen and plant dispatched to minimise the cost of supply to the market taking account of transmission losses and constraints and ancillary services. This results in a separate marginal price at each location that reflects the marginal cost of energy at that location. The same locational marginal price (LMP) is paid to all metered generation in that period at that location. There will be no side payments for unit start-up and shut-down and no separate capacity payments through the market

Although the market does not provide an explicit capacity payment, included in LMP is an implicit capacity payment. It is anticipated that in a competitive market participants will tend towards offering at their Short Run Marginal Cost (SRMC) but receive the LMP (a price set by the highest cost unit dispatched taking account of losses, transmission congestion and reserve co-optimisation). Where the LMP price is higher than a plant's SRMC it gives provides a contribution to fixed costs and profit. This implicit capacity payment will be higher at times of higher prices.

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[2] "Renewable, sustainable or alternative forms of energy" is defined under the Act as 'electricity which uses as its primary source one or a combination of more than one of the following - a) wind, b) hydro, c) biomass, d) waste, including waste heat, e) biofuel, f) geothermal, g) fuel cells, h) tidal, i) solar, j) wave'.

[3]CHP is defined under the Act as follows: "Combined heat and power" means the simultaneous production of utilisable heat and electricity from an integrated thermo-dynamic process where the overall process operating efficiency, based on the gross calorific value of the fuel used and defined as the ratio of energy output usefully employed to the energy input, is greater than 70 per cent. and where the integrated thermo-dynamic process satisfies such technical, operational, economic and environmental criteria as may be specified by the Minister from time to time, following consultation with the Commission."

[4] Distribution-connected generation is also known as embedded generation.

[5] There may be some exceptions such as small generator units with output less than a defined threshold. This issue is discussed in Section 4.1 below.

This consultation is being held to inform market participants of the Commission's thinking in this area and gain input from interested parties. The Commission is aware of interactions between the issues consulted on here and ongoing developments such as the Department of Communications, Marine and Natural Resources consultation on a renewable support mechanism post-AER and the review of the Grid Code for wind. The Commission will examine the outcome of these processes to ensure their compatibility with the MAE.

***The Commission invites comments and suggestions regarding the proposed implementation of S.I. 304 in relation to renewables, CHP and distribution-connected generation.***

# 3 GENERAL POLICY FRAMEWORK

## 3.1 Introduction

Under Section 9(4) of the Electricity Regulation Act ('the Act'), 1999, the Commission in carrying out its duties must have regard to the need to promote:

- Competition in generation and supply of electricity;
- Security and quality of supply;
- The use of renewable, sustainable or alternative forms of energy.

The Commission has taken account of these considerations in the design of the MAE, incorporating them in the evaluation framework (where evaluation criteria relating to efficiency, equity, environment, stability and practicality were adopted).[6] The Commission is also mindful of the separate mechanisms to provide explicit support for renewable and alternative energy forms and of the interaction of these support mechanisms with the MAE.

## 3.2 Renewable/CHP Support

### 3.2.1 Existing

Under the Green Paper on Sustainable Energy (1999) the target of an additional 500MW of renewable energy by 2005 was identified. In addition, Ireland has a target of producing 13.2% of gross electricity consumption from renewables by 2010 under the Directive 'on the promotion of electricity produced from renewable energy sources in the internal market'. (2001/77/EC). At present, the Government provides support for renewable energy under the Alternative Energy Requirement (AER) competition. AER awards successful renewable generators a 15 year Power Purchase Agreement (PPA) with ESB Public Electricity Supply (PES). Since the programme was launched, six AER competitions have been held. The technologies supported include wind energy, small-scale hydro, combined heat and power (CHP) and biomass.

The Minister for Communications, Marine and Natural Resources, will shortly be issuing a consultation paper on a future renewables support mechanism post-AER. In this context, it is vital to explore how a future renewable or indeed CHP support mechanism will interact with the new market.

[6] Friday 24 January 2003 - Irish Electricity Trading Arrangements Second Options Paper and Industry Forum - Thursday 6th February from 9.00am-5.00pm at the Citywest Hotel http://www.cer.ie/cerdocs/PA240103.pdf

### 3.2.2 Future

While renewables undoubtedly will become more competitive in the future there may be a need in the short term for some support mechanisms. The question arises as to whether renewables/CHP could be more effectively supported through a mechanism outside the market arrangements, through preferential treatment or via 'special rules' under the trading arrangements.

Irrespective of the nature of any new renewables support mechanisms, the Commission notes that Emissions Trading (COD(2001)0245), the Large Combustion Plant (2001/80/EC) and the National Emission Ceilings (2001/81/EC) Directives will bring some of the external costs associated with emissions to bear on conventional plant. The combined impact of these measures will increase the relative competitiveness of renewable generation by increasing the cost of generating electricity from fossil fuels. The effect is likely to be an increase in spot market prices, making renewables/CHP more profitable.

If required, the Commission is in favour of supporting renewable/CHP plant outside of the trading arrangements as this would:

- allow true market signals to be seen;
- minimise market distortion;
- minimise system and market operation costs to the final customer;
- afford greater transparency.

## 3.3 Impact of New Trading Arrangements

A number of benefits will accrue to renewables/CHP and distribution-connected generation under the MAE. Some of these benefits will apply to all market participants; others are particularly advantageous to renewables/CHP, including:

- A guaranteed market for generators through the spot market
- Implicit capacity payments for generators included in the spot market price;
- No requirement for balanced supply and generation schedules;
- No requirement for top-up and spill and a single price for all generation at the same transmission node;
- Simple offering strategies for offering power into the market;
- Standing offers for generation that do not have to be changed – minimising administration for smaller participants in particular;
- The potential for improved returns associated with higher LMPs for generators located in favourable areas;
- Price visibility and predictability;
- Price stability through Contracts for Differences (CfD) and Financial Transmission Rights;
- Co-optimisation of reserves;
- Gate-closure proposed ultimately to be one hour prior to commencement of trading.

# 4 MAE MARKET OPERATION

This section discusses the proposed treatment of renewables, CHP and distributed-connected generation under the following headings:

- Centralised and self dispatch thresholds
- Priority dispatch
- Pricing
- Treatment of negative prices

## 4.1 Dispatch Thresholds

All generators, subject to Regulation 3(3) of S.I. 304, and suppliers must comply with the MAE Rules. Regulation 3(3) states that an exemption to this may apply to generators on the basis of:

- installed capacity;
- amount of electricity exported or likely to be exported to the transmission or distribution network on an annual basis;
- primary source of energy used; or
- a combination of the above as determined by the Commission.[7]

The dispatch[8] threshold will determine which generators will make offers to the System Market Operator (SMO) and which generators will be self-dispatching.

The requirement for central dispatch in electricity markets raises particular issues for intermittent generation sources, such as wind. Wind generators have limited ability to predict their availability in advance. Furthermore, they have limited control over the quantity that they dispatch as compared to large dispatchable thermal plant.

This creates difficulties for the SMO in determining how to accommodate the plant in dispatch and how to handle the variability of generation when it is being dispatched. In line with the provision under Regulation 3(3), the Commission considers that certain types and sizes of plant including small-scale wind and small hydro or other small-scale plant will be permitted to register with the SMO as 'not-dispatchable' and thereby will not be subject to dispatch instructions. The same cannot apply for large installations in order to ensure the reliability and safety of the grid.

[7] Regulation 3(3), S.I. 304 of 2003

[8] For the purposes of this paper dispatch also covers intermittent generators that may not be dispatched in the sense that a thermal plant may, but could at least receive central instruction to curtail generation if necessary.

The Commission proposes the following thresholds[9] in line with the existing limits under the Trading and Settlement Code:

- All generating units with capacity above 10MW shall be required to register with the SMO as dispatchable;

- Generators with units of between 5-10MW may elect to have those units centrally dispatched;

- Generating units of less than 5MW will self-dispatch.[10]

In addition, it is proposed that the above limits will apply up to a maximum total site capacity of 30MW, at which point and above plant will be required to follow dispatch instructions to the best of its ability.

In the case of CHP plant, the dispatchable quantity will be the quantity exported to the grid net of the in-house load. This will be the Maximum Export Capacity (MEC) in the connection agreement. The amount traded will be the quantity generated less in-house consumption, netted in each trading period.

- Participants under the dispatch limits shall not be required to make offers to the SMO.

- Participants above the dispatch limits shall be required to make generation offers to the SMO.

In addition, the Commission proposes that where plant is deemed dispatchable and is intermittent (e.g. wind) it shall:

- produce for the SMO a schedule of its likely output on a "best endeavours" basis utilising best available wind forecasting techniques;

- deploy technology that allows it to be controlled to the greatest extent possible. This may include:

    - the ability to remotely control the unit(s);
    - the functionality to remotely turn the unit on or off;
    - the functionality to remotely decrease the unit and where possible allow some rate of increase;

- provide periodic updates regarding production and other information deemed necessary by the SMO for maintaining efficient dispatch and system security.

[9] The Commission is of the view that these limits should be based on rated capacity.
[10] Self-dispatched plant will be required to produce for the SMO a "best-efforts" schedule.

***The Commission proposes that:***

- ***the SMO shall dispatch all generating units with a capacity greater than 10MW;***
- ***generators with units between 5-10MW may elect to have these units centrally dispatched; and***
- ***generating units of less than 5MW will self-dispatch.***
- ***these limits will apply up to a maximum total site capacity of 30MW;***
- ***At and above 30MW participants will be required to follow dispatch instructions for the security and safety of the system.***
- ***Participants under the dispatch limits will not be required to make offers to the SMO.***
- ***Participants above the dispatch limits will be required to make generation offers to the SMO.***
- ***Intermittent plant, such as wind, will be required to utilise up-to-date production forecasting techniques, deliver technology that allows it to be controlled to the greatest extent possible, provide regular updates regarding production and other information deemed necessary by the SMO.***

## 4.2 Priority Dispatch

The Act states that without prejudice to the Commission's other functions it shall have the duty 'to require that the system operator gives priority to generating stations using renewable, sustainable or alternative energy sources when selecting generating stations.'

The Renewables Directive states,

> 'Without prejudice to the maintenance of the reliability and safety of the grid, Member States shall take the necessary measures to ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of electricity produced from renewable energy sources. They must also provide for priority access to the grid system of electricity produced from renewable energy sources. When dispatching generating installations, transmission system operators shall give priority to generating installations using renewable energy sources insofar as the operation of the national electricity system permits."[11]

[11]Article 7, Directive 2001/77/EC

The expected future increasing scale of wind farms both on-shore and off-shore presents issues for managing and controlling the electricity system. The Commission proposes two options for dispatching renewables which could give effect to this directive.

1) Dispatchable renewable generators will be permitted to offer price and quantity pairs to the SMO for dispatch in the same way as any other generator. This allows the renewable generator to set the locational marginal price. However, they run the risk of not being dispatched if the offer price is too high,

   or;

2) Dispatchable renewable generators will be permitted to have standing offers at the market floor price. This option ensures that renewables will always be dispatched system security constraints permitting. However, under this option, renewables take the market price.

These two options are described in more detail below:

### 1) Offer Based Dispatch

In an offer-based centralised market prioritisation is achieved by the offering strategy of the generator. Dispatch is secured by offering at a price below that of competitors.

It is anticipated that in a competitive market, participants will tend towards offering at their Short Run Marginal Cost (SRMC); at any LMP above this level, the generator is better off if dispatched.

Many renewable plants have almost zero avoidable or marginal cost (e.g. wind/run of river etc. have zero fuel costs) and thus can be expected to offer at a low price (i.e., zero). In most cases, this will be sufficient to ensure the dispatch of all available renewables as a priority, subject to system security constraints. However, an SRMC offer price also leaves open the option of renewables not being dispatched if price conditions become unfavourable – in particular, the market clearing price dropping below the SRMC bid of the renewable plant.

In this option dispatch is achieved through the competitive nature of the offers renewables and CHP may make. They may also choose to offer at higher prices that may set the appropriate LMP and thus payments to all generators. However, by offering in this manner, they take the risk that their available output will not be fully dispatched in all hours, with the resulting loss of some revenue.

**2) Floor Price Offer**

In this option dispatch is achieved using special offering rules that effectively pre-set renewables' offers at the market floor price.

This will ensure that renewables are always dispatched first, subject to system security constraints. However, as the offer prices for renewables are set at the market floor, they play no part in determining the market clearing price; effectively renewables become price takers.[12] It also effectively removes the option for renewables to elect not be dispatched if the market clearing price goes too low.[13]

***The Commission invites comments on strategies to ensure priority dispatch for renewable generators, subject to the reliability and safety of the grid.***

## 4.3 Pricing for Distribution and Transmission Connected Generators

Regulation 3(13) of S.I. 304 of 2003 states,

> 'A generator whose offer is accepted by the SMO will be paid the locational marginal price (LMP) pertaining to the node at which it is located for actual volumes traded in the spot market subject to the rules governing same as set out in the Market Arrangements for Electricity Rules to be developed under Regulation 5.'

This means that parties at different nodes in the network may face different prices known as Locational Marginal Prices (LMP). The prices may be different at each location as the pricing takes into account, transmission congestion, transmission losses on the system and the offer price of the next MW of generation at each node.

In order to provide a single price to be paid by all suppliers irrespective of the location of demand, the SMO will calculate a single weighted average of all LMPs at the demand nodes for each price period. This is termed the Uniform Wholesale Spot Market Price and will be paid by all suppliers for their metered demand.

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[12] Clearly renewable generators cannot be permitted to set the market price. Since under this scenario renewable generators would be guaranteed to be dispatched and thereby would be able to offer very high prices, setting a high Market Clearing Price (MCP) for all participants.

[13] Note, the extent to which renewables may wish to be dispatched will in practice only be partly influenced by the spot price. Other considerations will include, in particular, the nature of any renewable energy support mechanism provided outside the market.

All transmission-connected generation shall receive the LMP price.

There are a number of options for distribution-connected generation:

1. All distribution-connected generation could receive the appropriate LMP price. This treats all generators equally irrespective of grid connection. As with other generators this would benefit those who are in advantageous regions and disadvantage those in other areas. In so doing it sends the correct investment signal.

2. All distribution-connected generation could receive the Uniform Wholesale Spot Market Price. This would provide a single price for all distribution connected generators, however, there would be no signal to invest in the right areas. In addition there will be perverse signals in all locations for new plant to attach to the distribution network where the Uniform Wholesale Spot Market Price is on average higher than the appropriate LMP and to the transmission grid where the Uniform Wholesale Spot Market Price is lower on average than the appropriate LMP.

3. Some distribution-connected generation could receive the LMP and others the Uniform Wholesale Spot Market Price:

    a. Generators could opt for one or the other form of pricing; or

    b. Generators who are dispatchable receive the LMP and those who are not dispatchable do not.

    c. Alternatively, the price paid could be based on technical criteria, for example:

        i. Generation units greater than 10MW and sites greater than 30 MW will receive the LMP price at a transmission node to be determined by the SMO with CER approval.

        ii. Any generation unit, which has elected to be dispatchable, will receive the LMP price at a transmission node to be determined by the SMO with CER approval.

        iii. Generation units of less than 10MW and sites less than 30 MW, who have elected to be non-dispatchable, could receive the half-hourly Uniform Wholesale Spot Market Price.

***All transmission-connected generation will receive the LMP price.***

***The Commission invites comments on the options for the treatment of distribution- connected generation.***

## 4.4 Treatment of Negative Prices

Minimal limitations will be placed on acceptable prices that may be offered into the market. Offers will be accepted for any price between a negative floor price (-VOLL) and a positive cap price (+VOLL).[14] Generators may choose to offer below zero so that they can accurately signal their cost of shut down and start up. This may mean that on occasion the market-clearing price would be negative[15].

Allowing the market to clear at a negative price gives the following signals:

- any plant that needs to receive a positive price should not run, as it will be oversupplying the system;

- customers may reap the benefits and would be encouraged to switch their demand to these periods;

- generators will be encouraged to improve the flexibility of plant operations.

The negative offer enables generators to signal their true SRMC, taking account of shut-down and start-up costs and will provide the correct signals to the market. By allowing plant to offer at their true SRMC the system allows the dispatch of all plant to be correctly prioritised in merit order

In other markets that allow negative pricing, experience suggests that negative prices (although not negative offers) are a rare occurrence. In Australia, there has been 6 or fewer half hour trading periods with negative prices in each calendar year since 1st January 2000, including 2003 year to date. In 1999, after the zero price floor was removed in early December, there were 21 half hour trading periods with negative prices. Therefore, although negative pricing is permitted it may not be a feature of the new MAE.

There are two options for the treatment of negative pricing in relation to renewables and CHP:

1. All generation faces negative pricing for settlement if appropriate. In this option renewable plant and CHP facing a negative market price may choose to turn-off instead of generating. This requires the plant to have the technical capability to turn off at short notice, although week and day ahead price projections will be available in advance for participants to consider their position

[14] VoLL is “Value of Lost Load” and will be determined by the Commission.
[15] It is also possible under circumstances with extreme congestion to have a negative LMP despite all plant offering positive prices.

2. Renewables and CHP do not face negative prices they are settled at a price floor of zero in the case that negative LMPs would otherwise have been applied. For this option a concern could be that preferential dispatch using special offering rules would distort the market, placing some market participants at a commercial disadvantage and leading to inefficient There may also be considerable system cost implications as a result of a price floor provision. In addition, any additional payment to renewables if a price floor is implemented would need to be recouped from the market through the PSO, uplift or an alternative mechanism, leading to an additional cost on all customers. Using this approach any cheaper plant than renewables in the merit order would be dispatched down or off and renewables would in effect, be subsidised by all energy consumers through higher prices.

The Commission is minded that there should be no market floor price for renewables, aside from the overall market price floor of negative VoLL. It is considered that negative prices will be infrequent.[16] Furthermore, it is expected that if there are negative prices these are likely to be counterbalanced by higher prices during the day. [17]If renewables are financially disadvantaged overall this should be addressed outside the market mechanism, such as through a renewable energy support mechanism. In addition, other initiatives are likely to increase the competitiveness of renewable plant due to the increased costs on conventional generation arising from requirements under Environmental Directives (e.g. Emissions Trading, Large Combustion Plant, National Emission Ceilings).

***The Commission proposes that there should be no market floor price for renewables.***

***The Commission considers that if support for renewables is required that it should be provided outside of the market arrangements, through a renewable support mechanism.***

[16] See Section 4.2.2 above.
[17] Large thermal plant may offer negative prices because it is cheaper to keep running rather than incur large shut down and start up costs

## 5 RESERVES

S.I. 304 sets out that operating reserves shall be co-optimised with the energy market. The co-optimisation of operating reserves with the energy market ensures that energy and reserves are dispatched in unison, achieving an optimal allocation of both simultaneously, thereby, minimising reserve requirements and the cost of providing reserve in conjunction with energy offers.

At commencement of MAE the SMO will be responsible for procuring all reserves and ancillary services. The SMO will co-optimise primary, secondary and tertiary reserves by 'offering' them to a reserve spot market at appropriate prices[18]. In the future the functionality to allow participants to offer these reserve classes directly may be implemented. The timeframe for allowing participants to make reserve offers directly to the reserve spot market shall be determined by the Commission, in conjunction with the SMO and participants.

Renewables and CHP, as well as other forms of generation, are users of reserves and contributors to the cost of reserves, which in turn places a cost on the system and the final customer. The competitive sourcing of reserves, and ultimately the reserve spot market, will have advantages for renewable generation since certain reserve requirements may be more economically provided by conventional generation.

### 5.1 Payments to Reserve Providers

An SMO contracted reserve provider will receive the reserve payment for each half-hour that the SMO calls upon the services of that provider and places it on reserve duty.

In addition to receiving this reserve payment each reserve provider called upon by the SMO will be paid the LMP at its location or the Uniform Wholesale Spot Market Price as appropriate for the extra electricity it produces.

It is important to note that only metered generation will receive payment from the energy market. Also that any dispatchable generator that fails to follow dispatch instructions and not produce the required quantity will generate less and forfeit some of its expected revenue.

[18] Experience in other similar electricity markets has been that where an open spot market for reserves has been introduced at the start of the market, the price of reserves has fallen to levels lower than those that had existed at or before the start of the market, for example, New Zealand and Singapore. Those markets that initially obtained reserves under a contractual arrangement found that the agreed contractual price was higher than the prices obtained when they later moved to an open spot market for reserves, for example, NEMMCO in Australia.

The reserve provider that is dispatched (in addition to its reserve payment) will be paid the energy price that the dispatched generator that should have generated would have received.

CHP or embedded generators, particularly units on standby or in seasonal operation, could be a provider of reserves.

## 5.2 Charging for Reserve Costs

The underlying rationale for reserve charges is the 'causer' pays principle; those that contribute most to the requirement for reserve shall be charged most for its provision. Charges for reserve will fall into two categories

- **Operating reserve** is to provide for the failure of a generating unit or importing interconnector. Generally the size of the contingency is the highest energy dispatch of any generation unit or importing interconnector in the dispatch interval. However, since in the absence of larger units some reserve would still be required to cover breakdown of the smaller units the system costs should be shared by all units. The cost of reserves shall be charged in proportion to the requirements for reserves that are deemed to be due to each generating unit irrespective of their connection point or generation type.
- **Demand following reserve** is to provide for the variability in both demand and supply from estimated values (for example. intermittent generators such as wind). This requires a formula for charging demand and all generators where necessary for the cost of demand based proportionately on the variability they create.[19]

Participants who offer operating reserve quantities which when dispatched do not deliver all or any of the quantity that they committed to shall be deemed to have exacerbated the requirements for reserves and shall be treated as increasing the size of any contingency and will pay for the reserve.

***The Commission proposes that all generators pay for the cost of reserves in line with a 'causer' pays principle. These costs will be allocated in proportion to the requirements for reserves that are deemed to be due to each generating unit.***

***The Commission will consult separately on the detailed allocation of reserve costs.***

[19] CER/03/230

# 6 FINANCIAL CONTRACTING

## 6.1 Operation of CfDs

Contracts for Differences (CfDs) between generators and suppliers are financial arrangements that may be utilised to hedge exposure in the centralised market.[20] If prices are anticipated to be high the generator is likely to want to be available to receive the high payment.

Intermittent electricity producers, such as wind turbines, cannot guarantee their availability to capitalise from high spot prices although in the centralised market a generator is not required to provide reserve capacity to the SMO to cover its failure to generate; rather the generator simply sells less energy and earns less revenue, as discussed in the previous section.

As intermittent or non-controllable plant will not be able to guarantee generation at peak price periods, a fixed-volume firm CfD would expose an intermittent generator to the risk of difference payments at peak price periods without spot market revenue to support it. Intermittent generators will need to develop contracting strategies for both the reserves and energy markets to manage their risk accordingly.

## 6.2 AER Contracts

With regard to existing AER contract holders current arrangements can be facilitated under the MAE through the use of CfDs. Although CfDs are generally designed to minimise the volatility and costs for generators and retailers they can be shaped to deliver revenue security to the AER generator.

S.I. 304 of 2003 requires all generators to offer into the spot market. There are proposed exemptions set out above under the dispatch limits based on size. The output from AER generators, subject to this caveat, will be offered into the spot market. This may be done by the generators themselves or by an agent on their behalf (e.g. a supplier). There is only a need to make an offer once and it will then stand unless the participant chooses to alter it.

The CfD AER contracts will act as a hedge against pool prices. Thereby, AER generators will simply receive the AER contracted price. It is proposed that any differential between the AER contracted price and the spot market price will be passed through the Public Service Obligation levy (PSO). It is anticipated that this may serve to reduce the PSO cost to final customers.

***The Commission invites comments in relation to the use of CfDs by renewables, CHP and distribution-connected generation and their use for existing AER contract holders.***

[20] Wednesday 29 January 2003 - Electricity Trading Arrangements Tutorial Presentation Slides http://www.cer.ie/cerdocs/cer03015.pdf and a paper www.cer.ie/cerdocs/PA170103.pdf

# 7 DESIGN OF FINANCIAL TRANSMISSION RIGHTS

A Financial Transmission Right (FTR) is a tradable instrument that allows the holder of the FTR to hedge the spot price differential between two locations in a Locational Marginal Pricing (LMP) electricity market. The Uniform Wholesale Spot Market Price can be regarded as a "location" for the purposes of FTRs[21].

FTRs are paid out for every dispatch interval (half-hour) of the energy market. The FTR is similar to a CfD that returns to the holder the price difference between the locations,[22] for the quantity of the FTR, irrespective of the energy dispatched by the holder. Up to the level of the volume cover of the FTR, the holder has no financial risk as a result of LMP price and Uniform Wholesale Spot Market Price differences.

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| ***The detailed design of FTRs will be consulted on in 2004.*** |

[21] This will not normally be relevant to self-dispatch generators except if they are hedging with reserve capacity as discussed in the previous section.
[22] This may or may not cover losses depending on the specification of the FTR.

# 8 CERTIFICATION

## 8.1 Energy Tracking

Article 3(6) of the Electricity Directive states,

> 'Member States shall ensure that electricity suppliers specify in or with the bills and in promotional materials made available to final customers:
>
> a) the contribution of each energy source to the overall fuel mix of the supplier over the preceding year…
>
> With respect to electricity obtained via an electricity exchange or imported from an undertaking situated outside the Community, aggregate figures provided by the exchange or the undertaking in question over the preceding year may be used.'

The Commission proposes to put a system in place to track the aggregate energy figures passing through the market on an annual basis.

## 8.2 Renewable/CHP Tagging

With regard to renewables and CHP additional tracking arrangements will need to be put in place. The Renewables Directive requires a system guaranteeing the origin of electricity. A similar tracking system is proposed under the draft CHP Directive (COD/2002/0185). In particular Member States shall ensure:

- the origin of electricity from renewables/CHP can be guaranteed reliably and accurately;
- a guarantee of origin is issued to this effect in response to a request;
- measures are taken to ensure the reliability of the tracking system.

Member States may designate one or more competent bodies, independent of generation and distribution activities to supervise the issue of such guarantees of origin.

A guarantee of origin shall, in the case of renewable energy:

- specify the source from which the electricity was produced, the date and places of production and for hydro-electricity installations the capacity;
- serve to enable producers of electricity from renewable energy to demonstrate that the electricity is from a renewable source within the meaning of the Directive;
- be mutually recognised by Member States.

In terms of CHP:

- specify the fuel source from which the electricity was produced, specify the use of the heat generated together with the electricity and finally specify the dates and places of production;

- specify the quantity of electricity from CHP that the guarantee represents;

- specify the efficiency reference values for separate production of electricity and heat, and the efficiency of the CHP plant in accordance with the Directive;

- enable producers of electricity from CHP to demonstrate that the electricity they sell is produced from cogeneration within the meaning of this Directive.

In the context of the Commission's duty to licence renewable/CHP suppliers and to monitor compliance with the 'balancing' obligation under Condition 20 of a supply licence[23], the operation of a mechanism for renewable/CHP accreditation within the new system will be explored. In particular, the use of CfDs in this context will be investigated.

***The Commission invites comments on the proposal to track the aggregate energy figures passing through the market on an annual basis, in order to comply with the obligation Article 3(6) of the Electricity Directive.***

***In addition, the Commission invites views on the most cost-effective means to put in place a system of renewable/CHP tracking under the new trading arrangements.***

[23] Condition 20 of a Licence to Supply Electricity, issued under Section 14(1)(c) and (d), requires that a green/CHP supplier balance the amount of green/CHP electricity that it sells to final customers with that which is available to it from a green/CHP source, on an annual basis, in accordance with criteria contained in the Code.