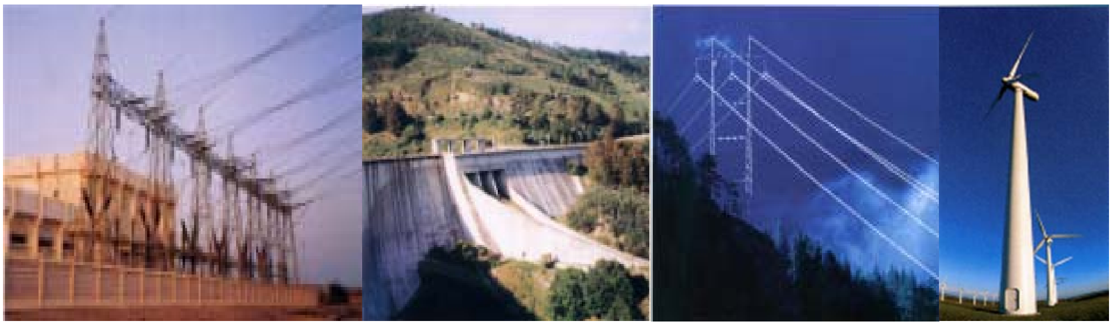
Ireland Country Report



Innovative Electricity Markets to Incorporate Variable Production

to

IEA – Renewable Energy Technology Deployment

May 2008

IPA Energy + Water Consulting **COWI A/S** **SGA Energy**

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1 MARKET MECHANISMS

This section provides an overview of the operation of variable renewable generation within the new Single Electricity Market (SEM), which is due to "go active" on 1 November 2007 and will unite the Northern Ireland (NI) and Ireland (Eire) electricity markets into a single all-island market.

1.1 Renewable Generation Capacity

The island of Ireland has significant renewable resource potential with good on-shore wind speeds over significant areas of the country, as well as the potential for significant offshore wind, wave and tidal generation. Currently there is approximately 0.9 GW of wind generation capacity across Ireland and NI.

There are different regulatory and legislative regimes across the island of Ireland:

- Ireland (Eire) is an independent state, and energy is the responsibility of the Department of Communications, Energy and Natural Resources (DCENR). The national currency is Euros (€).
- NI is part of the UK, although renewable energy is a devolved matter managed by the Northern Ireland Executive. The Department for Enterprise Trade and Investment (DETI) has responsibility for energy within NI. The national currency is pounds sterling (£).

Across all of Ireland the dominant renewable technology is currently biomass (particularly co-firing). Onshore wind is growing in significance and on and offshore wind is likely to dominate renewable capacity in the future. There are intentions to set an all-island energy target for 2020 during 2007.

There are, however, a number of obstacles associated with developing renewable energy projects most notably in obtaining planning consent for projects and limitations on transmission capacity (particularly in Eire), both of which are slowing the rate of development of renewable generation capacity.

1.1.1 Ireland (Eire)

Eire has a target to achieve 15% renewables by 2010 and 33% renewable energy generation by 2020. They also have a target to achieve 30% co-firing at the three state owned peat power generation stations by 2015. Renewables made up 5.2% of Eire gross electrical consumption in 2004 [1].

The largest growth in renewable energy contribution in Eire in recent years has come in the form of electricity generated from wind power. Wind generation output increased by 44% in 2004 and by a further 46% in 2005.

The total installed capacity of wind farms in Eire in December 2005 was 495 MWe [1].

According to Eirgrid in September 2007, there was 430 MW of distribution connected wind generation and 360 MW of transmission connected wind generation in Eire. In addition a further 440 MW was contracted to be connected and 1,300 MW was in the gate 2 process, which means it is queuing for connection [2].

Figure 1: Eire renewable generation capacity [1]

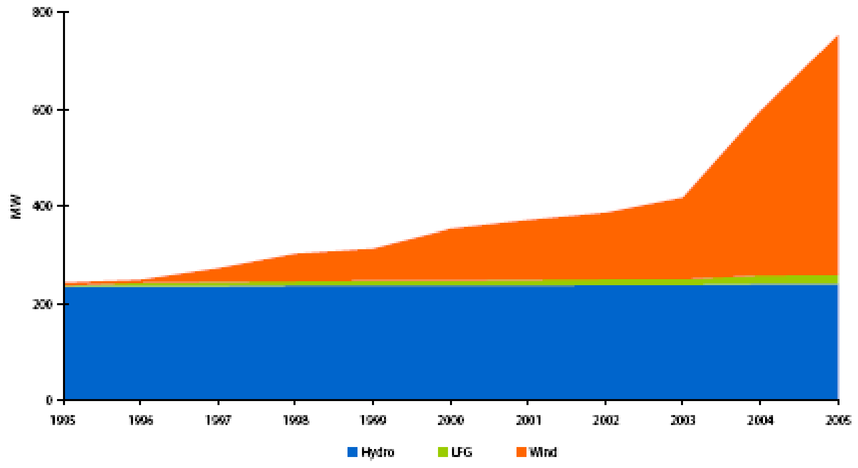
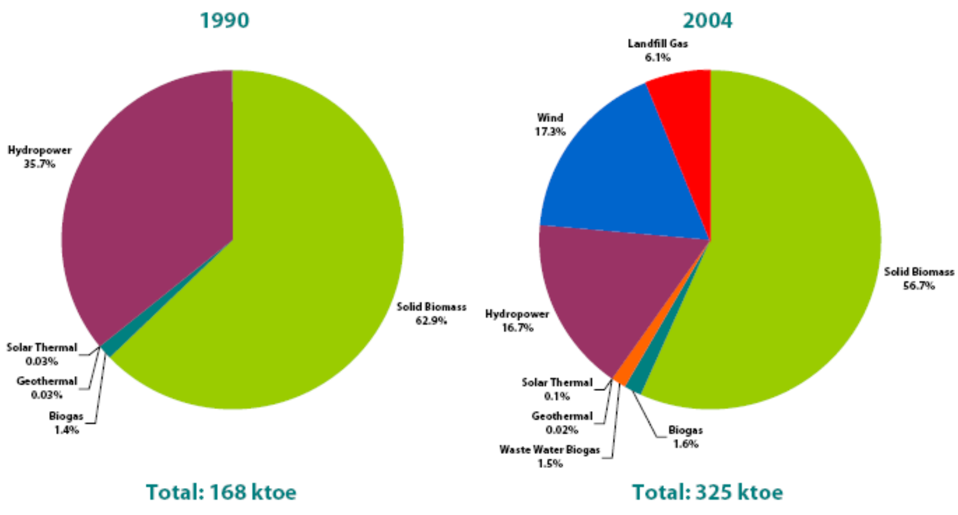


Figure 2: Eire generation from renewables [4]

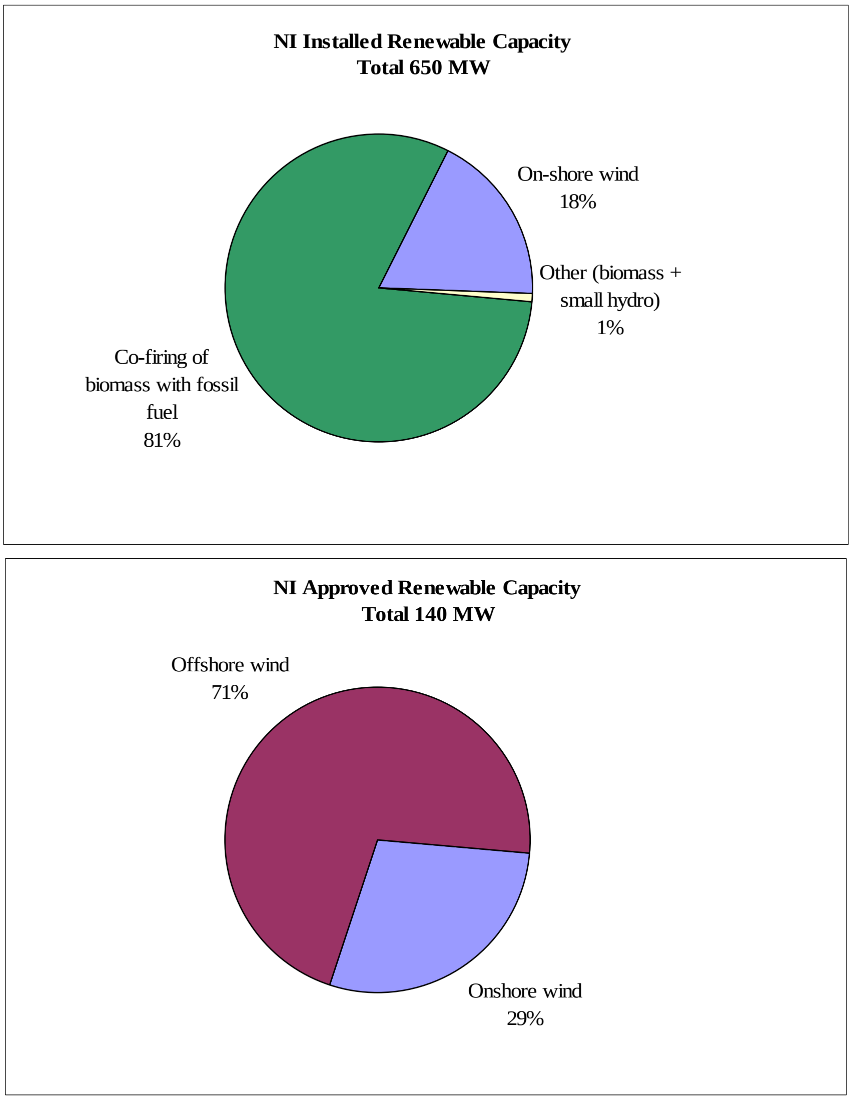


1.1.2 Northern Ireland

NI has a target of 6.3% renewables by 2012/13 through the renewables obligation – which is liked to the GB scheme. In September 2007, reference [3] specified that 3% of electricity consumed in NI is from renewable sources.

In 2004, Action Renewables commissioned a report on renewable potential in NI. This identified that there was 1,133 MW of undeveloped feasible RE resource. At the time there was just 31 MW of developed resource. Since then, the renewable capacity has risen to 650MW, largely through the introduction of the Renewables Obligation. The greatest resource identified was wind. Onshore wind resource was 565 MW in total (offshore wind resource was nominally set at 500 MW).

Figure 3: NI Renewable Generation: Installed and Approved (~April 2007)



1.2 Renewable Generation Size

Generators under 20 MW in Eire are normally connected to the Distribution System. In Northern Ireland the Transmission and Distribution codes are not yet unbundled, although they will be under SEM.

The remainder of this document focuses on the arrangements for larger transmission connected generation under SEM.

1.3 Renewable Generation and Power Markets

There are some special arrangements in SEM that allow for variable generation, to sell its output into the central pool. There is also additional financial support available to renewable generation, although the specific mechanisms vary between NI and Eire.

A high level overview of the key principles governing the new all-island market is provided below and shown diagrammatically in Figure 4.

- Market Operator

  Single Market Operator (SMO) will administer the new all-island market. The role of the SMO is to:

  - Administer daily generator bid/offer capture
  - Schedule the market and determine the System Marginal Price
  - Produce daily, weekly and monthly settlement and invoicing statements for market participants in relation to electricity, constraints, capacity payments and SMO charges
  - Execute weekly and monthly clearing services for these charges
  - Manage currency risk and market participants' credit requirements
  - Involved in the resolution of queries and disputes
  - Involved in market change
  - Provision of market information

- Traded Market

  Generators over 10 MW may only sell through a central pool. All generators that are despatched receive the System Marginal Price.

- Despatch

  The SMO decides on despatch based on generator bids, and will choose the optimum despatch based on cost and system constraints. Variable generators may choose to become Price Taking generators and get priority despatch.

- Notification

  Price Making generators submit bids into the system. Gate closure is 10 am the day before the trading day. The SMO will notify accepted bids at 11am the day before the trading day. There may also be adjustments up to and on the trading day.

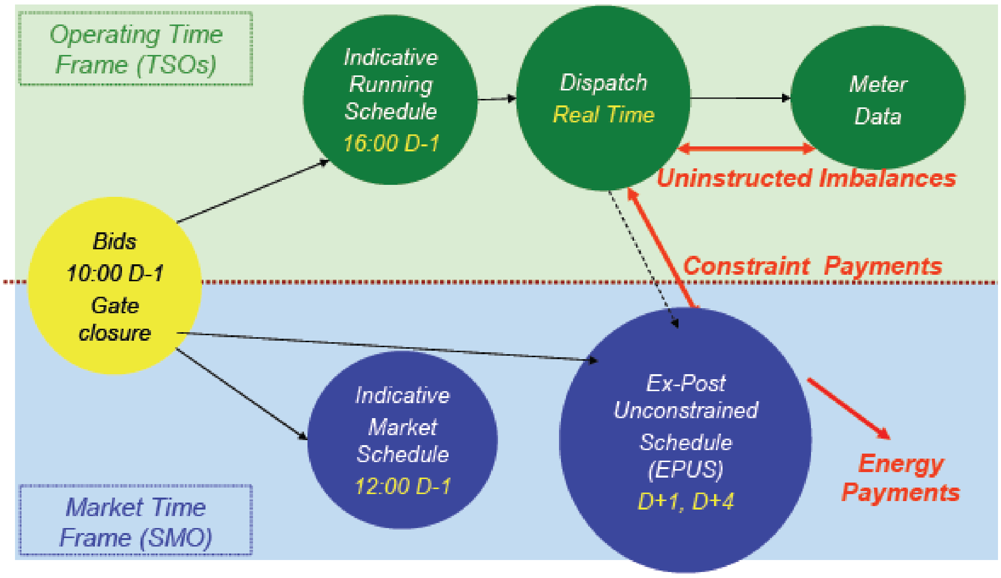
- Balancing Settlement

  The SMO balances the system. Imbalance charges apply when a generator generates above or below their scheduled amount.

- Transmission Access & Charging

  Transmission Access can be firm or non-firm. Constraint payments are made against the firm portion of the connection capacity.

Figure 4: The SEM Power Markets [5]



1.4 Degree of Centralisation

There will not be a central agency within the Ireland power markets managing the development, operation or marketing of renewable generation projects. It is the responsibility of individual private developers to identify suitable sites for renewable generation, obtain relevant approvals to allow construction and develop and operate the site.

The scheduling and trading of generation output is through a central pool and variable or autonomous wind generation can receive priority despatch. The value received for generation will be the pool price. Generation below 10 MW can decide whether to trade through the pool or through bilateral contracts with electricity suppliers.

1.5 Support Mechanisms

Renewable generation will get value for its output by selling power to the central pool (see section 1.6). In addition to the market value of the power produced there are a number of support mechanisms designed to increase the value of renewable generation. These vary between NI and Eire.

As we have seen, Eire and NI have separate renewable targets. However, they have indicated their intention to devise an all-island target in the future as the result of an All-Island Grid Study into the capacity for the secure incorporation of renewables in the network. It is unclear how much scope there is for combining the two renewable support mechanisms into a single all-island system. Whilst such a system may be more straightforward to operate, there is a difficulty in changing schemes without damaging investor confidence.

1.5.1 Eire REFIT

May 1st 2006 was the official launch of the Renewable Energy Feed In Tariff (REFIT) scheme. The programme provides support to renewable energy projects over a fifteen year period. Previously there was a competitive tender system for new renewables projects.

It is an unusual feature that the developer is obliged to negotiate with the electricity supplier to sell their output. The electricity supplier then receives a balancing payment from Government.

The first stage in the process is that the generator applies for a "letter of offer" from the Department of Communications, Marine and Natural Resources (DCMNR). To get the letter they must have must have planning permission and a grid connection offer for their project. The letter of offer confirms to any electricity supplier (licensed to supply in Eire) that in return for entering into a PPA with the generator for 15 years they will receive a "balancing payment" in accordance with the terms of the REFIT scheme.

Applicants in REFIT will be able to contract with any licensed electricity supplier up to the notified fixed prices, which are currently (2006/07):

REFIT Reference Prices:

- Large wind energy (over 5 MW) 5.7 Euro cents per kWh
- Small wind energy (under 5 MW) 5.9 cent per kWh
- Biomass (landfill gas) 7.0 cent per kWh
- Hydro and other biomass technologies 7.2 cent per kWh

These prices are linked to the consumer price index.

Suppliers will, in all cases, receive a base payment of 15% of the REFIT Reference Price for large wind per kWh.

In addition,

- If the annual published reference price for a Best New Entrant (BNE) plant is lower than the REFIT Reference Price for large wind then the supplier is paid the difference between the two prices.
- If the supplier has contracted with a generator a price greater than or equal to the REFIT Reference Price for that type of generation then the supplier will be paid the difference between the REFIT Reference Price for that type of generation and the REFIT Reference Price for large wind.
- If the supplier contracts with the generator at a price lower than the REFIT Reference Price for that type of generation but greater than the REFIT Reference Price for large wind they receive a payment based on the difference between the PPA price and the REFIT Reference Price for large wind.

The government will fund the money paid under REFIT through a levy on final electricity users. The levy will be based on the type of electricity connection (domestic, SME, large industrial etc.) [6]

The aim of the scheme is to provide support for "at least" 400 MW of capacity by 2010. However, it has been envisaged as providing up to 700 MW [6].

Contracts under REFIT are bilateral agreements between the supplier and the generator. Theoretically, under SEM bilateral PPAs are not generally valid as all energy must be bought and sold through the central pool. Existent contracts entered into prior to February 2007 may be converted into intermediary contracts whereby the supplier acts on behalf of the generator in the pool. Intermediary contracts are also allowed for generators below 10 MW [6]. Outside of this scope, contracts for difference may be an alternative approach.

At present there are no generators operating under SEM as state aid has only recently been granted. As of 23 October 2007, 60 generators had received conditional offers under REFIT with a combined capacity of 600MW.

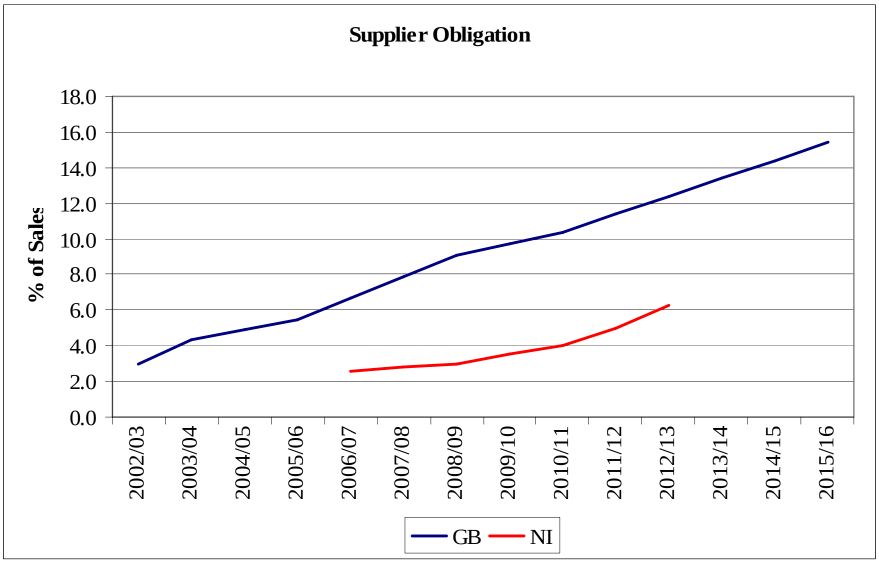
There is no clear, explicit requirement in the REFIT terms for generators based in Eire to deliver all their energy to Eire. However, generators claiming under REFIT will have to have a contract with an Eire supplier. This is foreseen by the DCMNR to require the energy to be delivered to Eire (at leas in a theoretical sense as pool energy is not currently tracked) [6]. If this is the case, then REFIT generators will not be able to claim LECs.

1.5.2 Northern Ireland Renewable Obligation

The primary support mechanism for Renewable Energy in NI is the Renewables Obligation (NIRO). This operates in tandem with similar obligations across the rest of the UK. Eligible renewable generation is credited with a Renewable Obligation Certificate (ROC) for each unit of output (MWh) produced.

The obligation came into force in April 2002 in Great Britain (GB), and was extended to NI in April 2005. The Northern Ireland Obligation is set lower than the GB obligation due to concerns about the impact of the RO on relatively high retail prices in NI. In addition NI has only committed to the RO until 2012/13, in contrast to 2015/16 across GB. The level of the NI Supplier Obligation is shown in Figure 5, including a comparison to the GB level.

Figure 5: RO – Comparison of GB and NI Obligation

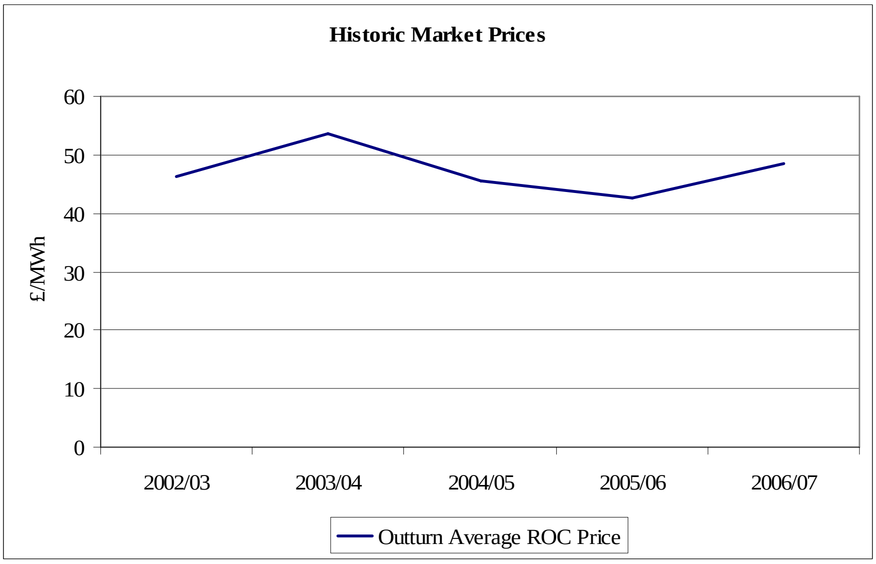


The RO places an obligation on licensed electricity suppliers to present a number of ROCs equivalent to a percentage of the electricity they have supplied, or pay a "buy-out" price for any shortfall. The buy-out price was originally set at £30/MWh in 2002/03, and is indexed linked. Funds accumulated from the buy-out are then "recycled" back to those suppliers based on the number of certificates presented. Thus, the value of a ROC is the buy-out price + recycle price.

This mechanism means that the market price for ROCs is set by supply of renewable generation and demand (as defined by the obligation).

There is a UK market for ROCs, and they can be traded separately from the electricity produced. The value of ROCs in the UK is shown over the last 5 years in Figure 6. ROCs can be traded between different jurisdictions, for example a ROC generated in NI can be redeemed in England.

Figure 6: ROC Prices



Although the Renewable Obligation has provided renewable generation with a significant additional income stream, the future income from ROCs is subject to both market and political risk.

There are current proposals which could significantly change the operation of the RO. The most significant change would be to move from the RO being technology neutral (1 ROC is awarded for each MWh of eligible renewable output) to a system where the number of ROCs awarded would be technology dependent with between 0.25 ROCs per MWh awarded for the most economic technologies to 2 ROCs per MWh awarded for more expensive technologies.

The introduction of SEM causes some complications under the RO as to qualify for a ROC generation must be used in the UK, however the centralised pool comprises both UK (NI) and non-UK (Eire) demand.

Currently the DETI intends to resolve these difficulties by amending the legislation to require any generator who wishes to claim ROCs to have a "relevant arrangement" with a Northern Ireland electricity supplier [7]. This arrangement would state that the supplier undertakes to purchase from the SEM pool and supply to customers in Northern Ireland an amount of electricity that is equal to or greater than the amount of electricity generated by the renewable generator and sold to the SEM pool.

It is possible, indeed likely, that any such relevant arrangement may be combined with a contract, either for the sale of ROCs or possibly a hedging contract (Contract for Difference, CfD). A potential disadvantage of such a requirement is that there are only a limited number of suppliers in Northern Ireland and any renewable generator would be obliged to come to an arrangement with one of these suppliers.

1.5.3 Northern Ireland Climate Change Levy

The Climate Change Levy (CCL) is a tax on final energy use for non-domestic customers, set at £4.41/MWh (2007/08) for electricity, and is currently index linked. Electricity supplied from renewables or good quality CHP are exempt from CCL, effectively increasing the value of electricity supplied form these sources.

The value of CCL is set by Treasury each year, and so is not guaranteed over the lifetime of a renewable generation project. Thus, there is some political risk associated with the additional revenue achieved by a renewable generator through CCL.

Unlike ROCs the value of the CCL cannot be traded separately from the electricity with which it was supplied.

As with ROCs, there are potential issues related to LECs under SEM as to qualify for a LEC generation must be used in the UK, however the centralised pool comprises both UK (NI) and non-UK (Eire) demand. In addition, a LEC must be traded with the renewable electricity to which it relates.

DETI have indicted [7] that Her Majesty's Revenue and Customs (HMRC) anticipate that a "relevant arrangement" similar to that proposed for ROCs would in their opinion be sufficient evidence under existing legislation that power had been used by a Northern Ireland supplier to supply customers in Northern Ireland.

1.5.4 Eire Guarantees of Origin

Eire has not yet introduced a traceable certificate system. At some stage they intend to introduce Fuel Mix disclosure. DCMNR have indicated informally that this process is likely to be agreed with Northern Ireland when it does take place. It is possible that this will operate in conjunction with the REFIT scheme, whereby a supplier is credited with the "green" component for any REFIT contracts that they have entered into and the remainder of their disclosed generation mix will be the residual pool mix [6].

1.5.5 Northern Ireland Renewable Energy Guarantees of Origin

In Northern Ireland, renewable energy is eligible for Renewable Energy Guarantees of Origin (REGOs)[1]. These have no intrinsic value, but they allow electricity suppliers to market such electricity as "green" and are declared as part of a supplier's fuel mix.

[1] Introduced by [8]

REGOs are part of a European-wide system for tracing electricity, collectively known as Guarantees of Origin or GoOs required by EU directive on the promotion of electricity produced from renewable energy sources in the internal electricity market (2001/77/EC).

No requests for issue of REGOs have yet been made in NI.

1.5.6 Capital Grants

The Government of Ireland and the UK Government in NI have each provided capital grants for nascent technologies such as offshore wind, tidal and marine generation projects. These have been allocated on a project specific basis to support the development of these technologies.

1.6 Trading

SEM will establish a single centralised or gross mandatory pool market for the whole of Ireland, with electricity being bought and sold through the pool under a market clearing mechanism. The market will operate in both Sterling and Euros. There will be no opportunities for bilateral physical power transactions outside the pool. The SEM market rules are set out in the Trading and Settlement Code (the TSC) [9]. Generators 10MW or above must participate in the pool. Generators under 10 MW can opt to trade bilaterally or through the pool.

The SEM will establish a single electricity transmission system for Ireland, operated by a Single Market Operator (SMO). The role of the SMO is to [9]:

- Administer daily generator bid/offer capture
- Schedule the market and determine the System Marginal Price
- Produce daily, weekly and monthly settlement and invoicing statements for market participants in relation to electricity, constraints, capacity payments and SMO charges
- Execute weekly and monthly clearing services for these charges
- Manage currency risk and market participants’ credit requirements
- Involved in the resolution of queries and disputes
- Involved in market change
- Provision of market information

The model is suitable for the participation of renewable and CHP generators, since all energy can be sold directly to the pool and off-take contracts are not a prerequisite to market entry.

Generators receive the following payments [9]:

- **System Marginal Price** (SMP) for their scheduled despatch quantities
- **Capacity Payments** for their actual availability
- **Constraint Payments** for changes in the market schedule due to system constraints

1.6.1 Entering the Market

There are two fees that a participant must pay to enter the new market. Both these charges are irrespective of size.

- ***Accession Fee***

  The accession fee will be a fee paid to the SMO by each applicant for accession to the TSC, to cover the SMO's costs incurred in assessing the application [9].

- ***Participation Fee***

  The participation fee is defined as "the fee payable with an application to register and become a Participant in respect of any Unit".

1.6.2 System Marginal Price (€/MWh)

The SMO charges suppliers for electricity purchased from the pool and pays generators for electricity sold into the pool. The single System Marginal Price (SMP) per MWh is set by the engine responsible for settling the market [9].

The SMP is set based on an ex-post optimised schedule for the whole trading day. This will be based on bids received from generators (see Section 1.8 "Notification"). The ex-post SMP for each half hour trading period will therefore be based on an unconstrained stack of available generation, taking account of the plant on the system at the end of the previous trading day, the actual demand and renewable generation (other than price making renewable generation) which occurred during that trading day [10].

Additionally, generators may seek price and cash flow certainty. These generators may enter into contracts for differences (CfDs) with another party. These contracts set a strike price, which is generally the forecasted annual average SMP. When the SMP is below the strike price, the generator is paid the difference by the counterparty. When the SMP is above the strike price, the generator pays the additional monies to the counterparty.

CfDs between suppliers and generators allow both parties to hedge their position and stabilize their costs/income.

1.6.3 Capacity Payment (€/MW)

The Capacity Payment Mechanism (CPM) is a fixed revenue capacity mechanism.

- ***Calculating the Annual Capacity Payment Sum (ACPS)***

  A formula establishes a fixed amount of revenue (the ACPS) that will be paid out in capacity payments throughout the year [11]. This is published at least 4 months prior to the start of the relevant year, at the end of August [11].

  ACPS = Best New Entrant Price × Capacity Requirement

  - **Best New Entrant (BNE) Price:** calculated as the annualized fixed costs (financial, investment, operational) of a BNE peaking plant. For 2007 this is €64.73/kW.
  - **Capacity Requirement:** calculated through a database of generator availabilities accounting for both Scheduled Outage Durations and Forced Outage Probabilities over which the demand forecast is superimposed. This enables a Loss of Load Expectation to be derived to establish the quantity of capacity required to meet the adequacy standard [12].

  The total capacity pot for 2007 is ~ €450.5 million.

- ***Calculating the monthly Capacity Period Payment Sum***

  For each month the specific pot is calculated based on a formula which ensures that most payment is made in the months with highest demand [13].

- ***Payment to generators***

  Out of the monthly pot a payment is made to generators based on:

  - **30% fixed payment** (calculated in advance and provides certainty)
  - **40% variable payment calculated in advance** based on forecasted availability
  - **30% ex post payment** based on actual availability

  Payment to a given unit will be calculated based on a formula. At its simplest level this can be expressed as:

  Payment = Factor × Availability × (Variable + Fixed + Ex-post component of price)

- **Availability:** is normally the loss adjusted eligible available capacity. However, there are a number of exceptions. In particular variable generators (such as wind) will receive a value based on their actual output. If a wind generator is constrained down it receives a capacity payment based on wind speed data at the location.
- **"Factor":** a formula to ensure that payments go to generators that offer energy at a price below the Value of Lost Load (VOLL), which is the expected price if load is lost.

This is the initial market mechanism that has been adopted. However, the Regulatory Authorities have indicated that the treatment of wind and other intermittent sources of energy in relation to capacity payments in the SEM will be reviewed. Any recommendations for change will not be implemented until after November 2007 [12].

1.6.4 Constraint Payment (€/MWh)

Despatch of plant in the SEM will initially be determined on the basis of an unconstrained merit order of all available plants. However, this unconstrained merit order may not be physically feasible for a number of reasons, one of which is transmission constraints. Transmission constraints arise when there is insufficient capacity in the transmission network to accept all the generation that wishes to produce and export (and is in the merit order) in a given area.

Plants that are constrained down as a result of transmission constraints will receive the difference between their offer price and the single market price (SMP), i.e. their opportunity profit. Plants that are constrained up as a result of transmission constraints will receive the SMP price and the difference between the SMP price and their offer price for the portion of their bid that is outside the merit order [10]. Plants that are regularly constrained either up or down will be subject to scrutiny to ensure they are not deliberately setting their price in order to profit from the constraint. Bids are required to reflect the marginal cost of operating the plant.

1.6.5 Market Operator Charge

The TSC states that the Market Operator Charge consists of [9]:

- Fixed Market Operator Generator Charge.
- Fixed Market Operator Supplier Charge.
- Variable Market Operator Charge applicable to all Participants in respect of their Supplier Units, expressed in €/MWh.

The majority of costs, 95%, will be recovered through the variable charge in order to avoid barriers to entry, which could be caused by high fixed charges to generator and supplier units.

The €1.75m [9] caused by energy imbalances will be recovered through the variable charge. This will essentially ensure that suppliers cover any difference between their energy payments to the SMO and the SMO's energy payments to generators [9].

For the initial tariff period from November 2007 the charges are [9]:

- Variable charge of €0.628 / MWh;
- Fixed charge to generators of €116 / MW installed capacity; and,
- Fixed charge to suppliers of €543 / supplier Unit.

1.7 Despatch

Despatch of plant in the SEM will initially be determined on the basis of an unconstrained merit order of all available plants. However, as this is an unconstrained merit order it may not be physically feasible for a number of reasons, one of which is transmission constraints. Under SEM, it is possible that large volumes of intermittent generation may become connected to the system. The SMO has indicated that large volumes of intermittent generation may force SMO to constrain off such plant for non-transmission system security reasons.

Plants may be **constrained off** or **constrained on.** This means they can either be obliged to switch on when they are outside the merit order or switch off when they are in the merit order. In either case, they will receive a Constraint Payment (see section 1.6.4).

Renewable generators are entitled to priority despatch subject to system security considerations. Some generation will not be "despatchable" (they don't have the ability to turn on or off at the TSO's instruction). This wind generation is described as **Autonomous** and is effectively always despatched. This definition applies to all wind or run of river hydro generation below 5MW.

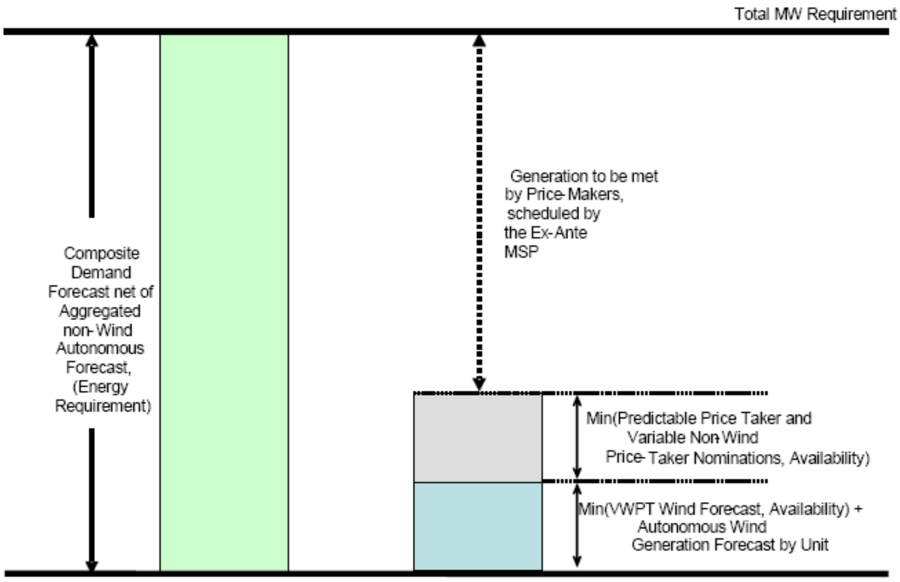
Non-autonomous renewable generation in the SEM can receive priority despatch. Regardless of size, renewable generation will have the option of acting as Price Making or Price Taking generation [10].

- **Price Making** renewable generators (subject to relevant commissioning tests) will submit offers to the SMO and will be despatched in a similar way to other generators. Price Making generators run the risk of not being despatched if their offer price is too high.
- **Price Taking** generators will have standing offers in place which may be set at their short run marginal price, zero or that of the lowest offer received by the SMO which will ensure they are always despatched, subject to

system security constraints [10]. (All autonomous generators are effectively price takers).

Wind and run-of-river hydro is described as **Variable Generation** and has this choice between price making and price taking.

Figure 7: Meeting generation requirement [15]



1.8 Notification

Price Making generators wishing to sell energy through the pool will be required to submit bids to the SMO [10]. The technical and economic parameters submitted in these offers are expected to encourage generators to submit bids that accurately reflect their Short Run Marginal Costs (SRMC) under normal circumstances [14].

Generators below a de minimis level are not required to submit offers to the market (they are not precluded from submitting offers, but have the option not to). De minimis generators not submitting offers become Price Takers in the market [10].

1.9 Imbalance Settlement

The calculation of an efficient despatch schedule in the SEM will be dependent on generators submitting generation offers. Central commitment involves a long gate closure the day before the trading day. The SMO is responsible for ensuring the balancing of the system and optimizes generation over a 24 hour period taking account of plant on the system at the end of the previous trading day [10].

There is incentive for generators to be available through the **capacity payment** (see section 1.6.3). This incentive is higher during peak demand.

1.9.1 Uninstructed Imbalances

Uninstructed imbalances apply to Price Makers and Price Takers (relative to their nominations) but not Autonomous Generators.

Tolerance band

A tolerance band for uninstructed imbalances will be set annually ex-ante. Within that tolerance:

- If a generator generates <u>below scheduled generation</u> it will make a repayment back to the market at the maximum of either the SMP or the bid price.
- If a generator generates <u>above scheduled generation</u> they will receive a payment for the imbalance at the minimum of the SMP or the bid price.

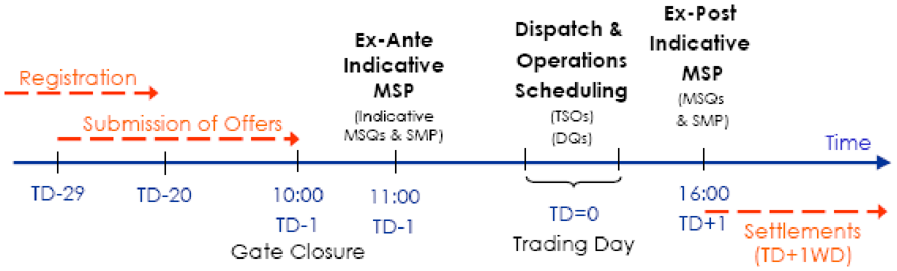
Imbalance outside the tolerance band

- For <u>over-generation above the tolerance band</u>, the payment received will have an over-generation discount factor applied to it.
- For <u>under-generation below the tolerance band</u>, the repayment to the market from the generator will have an under generation premium factor applied.

1.10 System Balancing

Generators (subject to a de minimis level) will submit offers to the SMO prior to gate closure every trading day. Gate closure time is 10am day in advance of real time to allow the SMO to determine an indicative despatch and to allow participants time to plan based on indicative despatch.

Figure 8: The SEM Power Markets [5]



The indicative SEM despatch schedule will be calculated taking account of generator and load offers, as well as start up costs, heat rates and other technical factors. This schedule will use the most accurate demand forecast, wind generation forecast, reserve requirements, transmission constraints and generator availability information.

The indicative despatch will be devised to minimise system costs over a 24 hour period, having due regard to the balance of start-up and running costs.

2 CROSS BORDER TRADING

The island of Ireland currently only has the ability to import/export to GB via the Moyle Interconnector.

2.1 Current Cross Border Flows

2.1.1 Scotland-Northern Ireland Interconnector (Moyle)

Capacity:	Scotland to Northern Ireland	400 MW*
	Northern Ireland to Scotland	80 MW*
Owned by:	Moyle Interconnector Ltd, subsidiary of Northern Ireland Energy Holdings	
Availability:	99.4% (2007 Annual Report and Accounts)	

* Limited by system constraints

There is a 500MW interconnection between the synchronous zones of GB and the island of Ireland.

The available transfer capacity (ATC) of the Moyle Interconnector for the trading of electricity between the electricity markets of Ireland and Great Britain is 400MW for east-west trades, limited by system considerations. The ATC for west-east trades is 80MW at present, limited by Moyle's agreements for access to the GB transmission system.

125MW of the east-west capacity is contracted until October 2007 to Northern Ireland Electricity plc (NIE) under a priority contract which was part of the original arrangements under which the interconnector was built. The remainder of the ATC is available to the market for third party access.

2.2 Cross Border Capacity Mechanisms

2.2.1 Scotland-Northern Ireland Interconnector (Moyle)

Time blocks sold:	Monthly, annual, two and three year basis
Volume constraints:	5 MW
Method of initial sale:	Auction
Reserve price:	Flexible, subject to cap
On-sale allowed?	Yes
Restrictions:	Notional 40% cap figure for capacity gained at auction

- *Purchasing Capacity*

  After the introduction of Single Electricity Market (SEM) in Ireland, the System Operator in Northern Ireland, SONI, will continue to manage auctions on behalf of Moyle.

- A weekly product is planned for some time during 2008. In the future daily capacity products may be offered.
- Capacity unsold at any auction will be made available in the shorter term auctions for the relevant period.
- Auctions have a pay-as-bid, sealed envelope format. An electronic auction process may be introduced if a weekly product is made available.
- Capacity holders can take advantage of secondary trading.

There is no set fixed level of maximum capacity which any bidder may acquire. In the event of an over subscribed annual auction (held for capacity for periods of one or more years) a notional 40% cap figure applies. If this 40% cap figure is reached by any bidder at the annual auctions then this triggers an analysis of the impact on the market environment of the auction outcomes. This does not mean that any one participant's holding would be limited to 40%.

Prior to the introduction of SEM market participants could only access somewhat less than the full capacity of the Moyle Interconnector. Restrictions on import capacity below 410MW (400MW at N Ireland entry point) have been due to system restrictions. However, one of the principles of the SEM is that such system restrictions on the island of Ireland should not affect market participants' trading volumes or prices within the central market system.

Consequently, in the future Moyle will make its capacity available to market participants up to the values contained in its connection agreements:

- Maximum Import (Scotland to NI) - 450MW in the winter and 410MW during the summer period (April – October inclusive)
- Maximum Export (NI to Scotland) - 80MW at all times.

- ***Reserve Price***

  The maximum reserve price is set at £2,010/MW/month (2007/08) (£1,971/MW/month inflated from Oct 06 to March 07).

  Moyle may set a lower reserve price for any auction or type of product at a time when interest in using Moyle is low. This is intended to encourage use of the interconnector.

- ***Superposition***

  Superposition capacity is not currently being made available.

2.2.2 Potential Future Interconnector Capacity

- ***Ireland-GB Interconnector ("East-West Interconnector")***

  The Irish Governments plans in the 2007 Energy White Paper include a new 500MW Interconnection to Wales. The connection to GB has been heavily promoted by wind energy proponents who claim that the increased security of supply would allow the Irish system to accommodate greater levels of wind without high balancing costs.

  This is planned to be constructed between 2009 and 2012.

2.3 Cross Border Trading

2.3.1 Scotland-Northern Ireland

Capacity firm or non-firm:	Non-Firm	
Latest auction:	Minimum of D-5 days at present	
Notification of available capacity:	9.30 D-2**	
User nomination:	11.00 D-1	
Notification to market system operator/TSO	Scotland	11.00 D-1
	Ireland	Users submit bids into SEM by 10.00 D-1 SMO indicates despatch by 11.00 D-1
Imbalance penalties apply:	Scotland to Northern Ireland	Yes
	Northern Ireland to Scotland	Yes
TNUOS charges apply:	Scottish side	Full
	Irish side	None

* Capacity payments under SEM based on flows not on availability
** Normally limited by grid constraints rather than interconnector constraints

- ***Timing of Auction***

  Auctions may be annual, monthly or weekly. In addition, the system operator may choose to trade surplus capacity within day.

- ***Curtailment***

  Capacity holders have effectively purchased the right to use a specified amount of the capacity of the interconnector for a specified duration, subject to any physical outages on the interconnector. In the event of change to the Available Transfer Capacity (ATC) of the interconnector, capacity holders are notified of the restriction, and their capacity holding is revised down on a pro-rata basis for the duration of the outage.

However, under SEM the right to capacity does not give a user the right to despatch, see the section below on the interface with the SEM.

- ***Consistency between GB and Irish markets***

  At present the flow of electricity is primarily from GB to Ireland, and this is expected to continue.

  From November, Ireland will have a highly liquid mandatory central pool market. The UK has a relatively illiquid spot market and most trades are carried out through bilateral contracts.

- ***Interface with SEM (Ireland)***

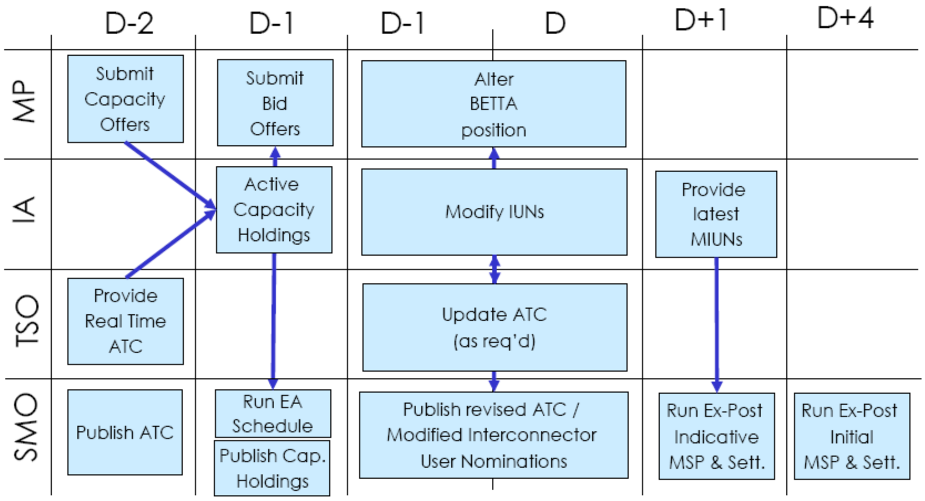
  The SEM is a centralised wholesale electricity market in which all electricity must be bought and sold via a gross mandatory pool. Dispatch is merit-order and is based upon generator or despatchable demand price/quantity data subject to system constraints, losses, transmission congestion, system security and reserves.

  The principle of economic dispatch will also apply to all energy entering the market via interconnection irrespective of capacity rights on the interconnector.

  In Ireland, Interconnector units are treated as Predictable Price Makers. Interconnector Units are “virtual”, in that the unit is not registered as such. Instead, the Participant is registered as an interconnector user.

  Before gate closure at 10.00 on D-1, Interconnector Users submit bids to the Market Operator. The Market Operator will schedule all generating units (including Interconnector Units) to meet scheduled demand according to the merit order. The process is outlined in Figure 9.

Figure 9: Interconnector in the SEM



SMO = Single Market Operator
TSO = Transmission System Operator
IA = Interconnector Administrator
MP = Market Participant
IUN = Interconnector User Notification
MIUN = Modified Interconnector User Notification
ATC = Available Transmission Capacity
EA = Ex Ante
MSP = Market Scheduling and Pricing

- ***Interface with BETTA (GB)***

BETTA uses a thirty minute trading period, and gate closure is one hour ahead. Under BETTA, each interconnector capacity holding is treated as a pair (production and consumption) of Balancing Mechanism Units (BM Units). Physical Notifications (PNs) are calculated and submitted to the BETTA market by the Interconnector Administrator (IA) on behalf of Interconnector Users.

SONI is currently the IA for the Moyle interconnector. Under the existing system, the interconnector agent provides a fixed schedule to the GB Market Operator for a 24 hour period from 06.00 to 06.00 at 11.00 on the previous day. Thus, irrespective of the within day operations on SEM or BETTA, the gate has effectively closed on the interconnector at 11.00 on the previous day. Under SEM, the schedule provided to BETTA may be based on the first indicative dispatch provided by the MO/SO after gate closure.

However, while the BETTA element of the schedule would not be expected to change, the SEM element, and therefore the actual running of the interconnector, may vary with real time dispatch. This potentially opens the interconnector (via the IEA) to an imbalance between the scheduled flow and the actual flow.

Under SEM, the procurement of power from BETTA via a bilateral contract remains unchanged. However, now the means by which the SEM participant ensures that he pays only the price at which he procured the power (as opposed to the pool price) must be provided through an appropriate financial contract hedging against the pool price.

- ***Ancillary Services***

  The current rules on the interconnector do not allow generators to offer ancillary services (balancing/reserve power) in GB. The Interconnector gate closure is day-ahead, whilst BETTA gate closure is 1 hour ahead.

  Under SEM, after gate closure the System Operator is entitled to make SO Interconnector Trades across the relevant Interconnector in either direction, using any available Interconnector capacity which is not allocated to Interconnector Users. This could allow them to purchase and despatch power on the spot market.

  There is no evidence of arrangements between the two TSOs (National Grid and SONI/Eirgrid) to provide or share reserve capacity through the interconnector.

2.4 Renewable Support Mechanisms

2.4.1 UK – Renewables Obligation

To be eligible for the Renewables Obligation electricity has to be both generated and consumed in the UK. This means electricity generated outside the UK and imported over an interconnector does not qualify. Furthermore, renewable electricity generated in the UK and then exported will also not be eligible.

2.4.2 UK – Climate Change Levy

To qualify for a LEC generation must be used in the UK and a LEC must be traded with the renewable electricity to which it relates.

It is possible for electricity generated outside the UK to be eligible for LECs provided it can be demonstrated that the electricity has been consumed in the UK (including sufficient capacity being booked on the interconnector).

2.4.3 Eire - REFIT

REFIT is intended to ensure that electricity funded through the REFIT tariffs will count towards Eire’s RES target. It allows the import of electricity from other member states to qualify provided it does not count towards that member state’s RES target and counts towards Eire’s target instead for the 15 year duration of the feed in tariff.

2.4.4 Overview

- ***Export from the supporting country***

  Of the renewable support mechanisms available in the supporting countries, the only support mechanism which allows export is the Northern Ireland Renewables Obligation. However, this only has limited export possibilities with renewable electricity generated in Northern Ireland and exported to GB, and consumed within GB, eligible to receive ROCs.

- ***Import to the supporting country***

  In a similar manner to exporting from Northern Ireland to GB, renewable electricity generated in GB and exported to Northern Ireland, and consumed within Northern Ireland, is eligible to receive ROCs.

  In addition, the REFIT scheme in Eire and the CCL scheme in the UK will allow renewable energy entering from another member state to benefit. The terms require that it counts towards the receiving country's RES target and not to any other member state's target. In the case of Eire this must be for the full 15 year duration of the project.

  A generator exporting from GB to Eire would need to be confident of sufficient interconnector capacity for the 15 year lifetime of the support. It means all of its electricity would have to go to Eire, as it would not be eligible for support in GB under the Renewables Obligation or CCL as the guarantee of origin for all generation would have to count towards Eire's RES target.

  Essentially, this means support is on an "all or nothing" basis. This prevents wind generators from receiving support through REFIT for selling surplus generation over the interconnector, for example when wind speeds are high.

  Generators exporting from Ireland to GB can benefit from the value of the LEC, but not the ROC.

2.5 Utilisation for Variable Generation

There is no evidence that wind or other variable generation makes use of the GB-Ireland interconnector to any significant extent.

2.6 Summary

Overall, the trade in variable renewable generation into and out of the island of Ireland is limited by various market parameters.

2.6.1 Renewable Component

Perhaps the most significant factor affecting renewable energy transport across borders is the nature of the renewable support mechanisms. These are designed in such a way that import or export of renewable generation affects its eligibility.

It seems unlikely that wind or other variable renewable generation will be transported regularly over borders unless it is able to receive a similar level of the renewable support in the country it is being exported to.

2.6.2 GB-Ireland Market Constraints

The interconnector between GB and Ireland has restrictions on its usefulness for variable generation due to the large bundles of capacity sold – the lowest "block" is currently 5 MW for a month. This means there is little chance of a generator being able to use wind forecasts to forecast their output in advance.

Again, any deviation from the nominated position would be penalised. Variable generation would not benefit from the "variable price taker" option that it could normally benefit from in Ireland to receive priority despatch. If a generator is not in the merit order it will not be despatched.

3 GRID PLANNING

This section investigates some of the issues associated with integrating renewables within the transmission and distribution grid.

3.1 Grid Investment

3.1.1 Responsibility

EirGrid in Eire and SONI in Northern Ireland are the Transmission System Operators (TSO). EirGrid plans the Eire transmission system, and these plans are approved by the regulator CER. SONI is a wholly owned subsidiary of NIE. SONI plans the NI transmission and distribution system and plans are approved by Ofreg.

There is co-operation between the North and South of Ireland on the overall grid outlook, with the TSOs taking a shared view of the longer term requirements of the all-island transmission system. This will be developed based on connection activity, discussions with the Regulatory Authorities, users and other interested parties, and by consideration of legislative developments and government policies.

The design of new connections and the development of the medium term transmission plan will be monitored against this 'joint strategic outlook'.

3.1.2 Grid Planning

There is co-operation between the North and South of Ireland on grid planning.

- **Development Planning:** is driven by general load-related network developments in each jurisdiction, such as demand growth, generation retirals, generation and demand patterns, as well as network modifications required by the age, condition and performance of system assets.
- **New connections:** each transmission system operator will be responsible for managing the connection offer process for physical connections to the transmission system in its jurisdiction. Where contingent reinforcement works are identified as potentially being required to the transmission system in the other transmission system operator's jurisdiction, both transmission system operators will liaise to ensure all necessary information is shared so as to enable a connection offer, reflecting the schedule of overall works that needs to be carried out, to be made within the required timeframe.

The standards used by EirGrid in the Republic of Ireland and by NIE in Northern Ireland are separate and different. Under industry practice, extreme generation positions are explored to gain an understanding of the robustness of the network. This means assuming that generation in a given zone will be at a maximum when demand is at a minimum.

3.1.3 Priorities

- ***EirGrid***

  EirGrid revises and publishes its plans for the next five years each year. These plans are required to take into account:

  - Existing and planned generation, transmission, distribution and supply;
  - Forecast statements;
  - Interconnections with other systems; and
  - National and regional government development objectives

  According to their Transmission Planning criteria, the **primary** aim is the maintenance of the integrity of the bulk transmission system for any eventuality. The adequacy and security of supply to any particular load or area is **secondary**. The technical considerations are mitigated by economic considerations and other factors that various stakeholders in the transmission system would consider significant.

  These plans are subject to public consultation and are reviewed by the regulator CER.

- ***SONI***

  SONI's primary responsibility is to ensure the safe, secure and economic operation of the transmission system in Northern Ireland which includes the dispatch of generating plant, management of outages, operation of settlements, managing Moyle and North-South interconnector flows and maintenance of operational security standards to meet Northern Ireland's demand for electricity.

  A Transmission Statement on System Capacity is prepared by the TSO to cover each of the seven succeeding financial years and revised at least once per year. This shows future circuit capacity forecast power flows and loading on the NI System and fault levels for each network node covered by the statement.

3.1.4 Offshore Regime

The island of Ireland potentially has a large offshore wind resource. The East Coast in particular has good sea bed conditions.

- ***Eire***

  For permitting offshore wind farms in Ireland a “foreshore license”. allocates exclusive rights to a single developer to allow in-depth site assessment. In a second step a foreshore lease can be granted that assigns exclusive site development rights to a developer.

  Licences are awarded on a first-come-first-served basis. This allows a large number of developers the opportunity to move further into the process before projects are selected through the planning system.

  The connection process for offshore wind is currently very similar to onshore generators. Wind applications would be part of the gate process (see below) [16].

  Ireland currently has one offshore Windfarm. In January 2002 Airtricity obtained a foreshore lease to develop a 520MW offshore wind farm on the Arklow Bank. The first phase (25.2MW) was completed in June 2004 in co-development with GE Energy. Further phases were put on hold because the REFIT support for offshore wind was insufficient to make the scheme viable.

- ***Northern Ireland***

  The permitting process is different in Northern Ireland as planning permission is required initially. Currently, Article 39 consents are required to construct, extend or operate a generating station (both on and offshore) whose capacity exceeds 10 MW. DETI is proposing to reduce this threshold from 10MW to 1MW for all offshore wind and water driven generating stations. This amendment would bring the threshold in the NI offshore area into line with the position in the rest of the UK. The threshold for onshore electricity stations requiring Article 39 consent will remain at 10MW.

3.2 Planning & Security Standards

The relatively small size of the island of Ireland means that even fairly small developments can have a large impact on the network.

Figure 10: Size of system by various parameters [17]

	Ireland	All-Ireland	England/Wales
Winter Peak	4.4GW	6.2GW	50GW
Summer Night Valley	1.6GW	2.1GW	18GW
Wind farm Min. size for which Grid Code requirements apply	>5MW	>5MW	>50MW
Min. Size relative to Summer Night Valley	0.3%	0.24%	0.27%
Min. Size relative to Winter Peak	0.11%	0.08%	0.10%
50MW compared to each system	3.1% *(11 times)*	2.4% *(9 times)*	0.27%

This implies that on a combined Ireland system (in normal running mode), a 5MW wind farm would have a similar effect to a 45MW wind farm on the England/Wales system.

3.2.1 EirGrid

EirGrid plans the Eire transmission system according to the planning standards that are approved by CER. ESB is responsible for carrying out this planned work as the asset owner (it also owns the distribution network assets).

The system is planned to be able to withstand a number of more probable contingencies and more severe less probable contingencies.

Figure 11: Contingency Performance Tests (ESB National Grid)

Disturbance	Analysis	Criteria	Allowable Remedial Actions
Base Case			
None	Steady-state load flow	Normal limits Capacitor switching voltage step	Tap-changing, Phase angle regulators, Switched shunts, Busbar Sectionalising
	Short-circuit analysis	Allowable short circuit levels	None
More Probable Contingencies			
Single Contingency (N-1)			
– line – transformer – generator – SVC, reactor or capacitor	Dynamic simulation	Transient stability, voltage and frequency fluctuation range	None
	Steady-state load flow	No voltage collapse, cascading outages; voltage step; emergency limits	None
	Steady-state load flow	Normal limits	Tap-changing, Phase angle regulators, Generation redispatch, Switched shunts, Network Switching
Overlapping Single Contingency and Generator Outage (N-G-1)			
– generator + line – generator + transformer – two generators – generator + (SVC, reactor or capacitor)	Dynamic simulation	Transient stability, voltage and frequency fluctuation range	None
	Steady-state load flow	No voltage collapse, cascading outages; voltage step; emergency limits	None
	Steady-state load flow	Normal limits	Tap-changing, Phase angle regulators, Generation redispatch, Switched shunts, Network Switching
Trip – Maintenance (N-1-1)			
– two lines – line + transformer – line + power conditioning unit – two transformers – transformer + (SVC, reactor or capacitor) – (SVC, reactor or capacitor) + (SVC, reactor or capacitor)	Dynamic simulation	Transient stability, voltage and frequency fluctuation range	None
	Steady-state load flow	No voltage collapse, cascading outages	None
		Emergency limits	Load Shed 15MW
	Steady-state load flow	Normal limits	Tap-changing, Phase angle regulators, Generation redispatch, Switched shunts, Network Switching, Load Shed 15MW
Less Probable Contingencies			
Busbar fault, busbar coupler fault, breaker failure, protection failure, loss of double circuit	Steady-state load flow	No voltage collapse, cascading outages	None

In [18] EirGrid have forecast that from 2007 to 2011 electricity peak demand will increase by 20%.

In terms of system development, in some cases for renewable generation EirGrid has accelerated network development (socialised through TNUoS) in order to be able to connect the new plant more rapidly. All renewable generation currently planned to be connected directly to the transmission system is wind. At present the next stage of development is planned under "gate 2", and the main area for development is the South West. Two new CCGTs are also planned for the South West, so considerable grid reinforcements will be required to cope with large net flows from the South West to the North East.

Geographically, most proposed wind developments are distant from demand centres. Also the only way to control the dispatch is to constrain down. This means the system must both be able to accept large amounts of wind generation and also to be able to accept large amounts of balancing power when wind generation is low.

Further development of the network is required to keep pace with these significant changes and to select optimum reinforcement projects where necessary.

Under the various test scenarios considered, large scale wind generators are modelled like any other generating system. However, because of its low load factor, no part of the system can depend on wind generation.

3.2.2 NI

SONI plans the NI transmission and distribution system and their plans are approved by Ofreg. The SONI Planning Code forms part of the Grid Code and provides generally for the supply of certain information by users of the system in order that the planning and development of the NI System may be undertaken.

The construction, extension or operation of any generating station over 10 MW, requires the Department of Enterprise Trade and Investment's consent under Article 39 of the Electricity (Northern Ireland) Order 1992.

3.2.3 All Island Grid Study

In July 2005 the Governments of Ireland (Eire) and Northern Ireland jointly issued a consultation paper on an all-island '2020 Vision' for renewable energy. One of the outcomes for this process was to recommend an "All Island Grid Study" [17]. This was published in January 2008 and examines:

- Range of generation portfolios for Ireland,
- Ability of the power system to manage electricity from renewable sources,
- Investment required, and
- Climate change and security of supply benefits.

The All-Island Grid Study [17] conducted a simplified assessment of the amount of transmission grid reinforcement required for an increased renewable energy share in the total portfolio.

The study considers a range of scenarios from a base case with 2,000 MW wind, 4,000 MW wind combined with various thermal plant, 6,000 MW wind and 8,000 MW wind. It was found that 8,000 MW wind was not possible to reinforce the existing system and a complete re-design would be required. The study also incorporates various other variable and baseload renewables to a lesser extent (i.e. biomass, hydro, wave and tidal). This showed that the difference in reinforcement costs between a 16% renewable energy share (2,000 MW wind) and a 42% share (6,000 MW wind) was only 7%.

There are a number of limitations to the study. In particular, it assumes a co-ordinated approach to grid reinforcement – with the grid being reinforced speculatively in advance, rather than waiting for plant to apply for connection. The study also used a less robust approach to the level of grid security required than the TSO would normally apply. It considers an n-1 security of the grid, but does not consider the implications when lines are out of service for maintenance.

The All-Island Grid Study [17] discusses the option of wind energy curtailment as an alternative to network reinforcement and suggests the need for further research in this area.

3.2.4 Interconnections

Ireland is a relatively small market, and so attempts have been made to increase the capacity for trade across interconnectors. The Irish Government's plans include a new 500MW Interconnection to Wales. The connection to GB has been heavily promoted by wind energy proponents who claim that the increased security of supply would allow the Irish system to accommodate greater levels of wind.

3.2.5 Grid Code Requirements

- ***Eire: Grid Code for Wind***

  All Generators connecting to the Transmission System are required to comply with the Grid Code. Grid Code was originally developed with synchronous generators in mind. Since Wind Turbine Generators do not have the same characteristics as synchronous generators, it was considered appropriate to develop a new set of Grid Code provisions specifically for Controllable Wind Farm Power Stations. The Commission for Energy Regulation (CER) approved the proposed Wind Grid Code on 1st July 2004.

  These requirements are stricter than in most other countries. Taking into account that the Irish synchronous zone contains only a generation capacity of 7 GW the reason for the requirement of wind turbines to participate in frequency control is evident.

Figure 12: Grid Code Requirements for Wind Turbines

Requirement	***Scale***
Fault Ride-Through: A windfarm must remain connected to the system for voltage dips on any or all phases, where the voltage measured at the HV terminals of the grid-connected transformer remains above a defined level.	>5MW
Frequency:	
• Tolerance over the Frequency Range	All
• Participation in High Frequency Control	>5MW
• Participation in Low Frequency Control	>10MW
• Adherence to Ramp Rates	>5MW
• MW Curtailment	>5MW
Voltage:	
• Tolerance over Voltage Range (directly transmission connected only)	>5MW
• Participation in Voltage Control (transmission connected or connected at a distribution voltage to a dedicated transmission station)	>5MW
• Reactive Power Range (transmission connected or connected at a distribution voltage to a dedicated transmission station)	>5MW
Signals from Wind Farms to TSO:	
• first Signals List for wind farms connected to transmission connected wind farms or distribution connected wind farms fed from a 110kV substation	>5MW
• Second Signals List for distribution connected wind farms	>5MW
Wind Farm Meteorological Data: provide the TSO with meteorological data from wind farms.	>10MW
Control Signal-MW Curtailment: wind farms may be subject to curtailment by the TSO.	>5MW
Black Start Disconnection: to allow for disconnection of Wind Farms and to prevent reconnection in case of Black Start.	>5MW
Responsible Operator: requirements include responding within 15 minutes, being onsite within an hour and being available 24 hours a day, every day.	All
Declarations: whenever changes in availability occur or are predicted to occur.	>30MW

MW Forecasts	>30MW

To offset any perverse incentive for developers to split their windfarm site into <5MW "parts" to avoid meeting the Wind Grid Code requirements, the Wind Grid Code requirements apply to:

- 5MW or above Wind Farms
- Below 5MW Wind Farms on a "contiguous"[2] Wind Farm site where the development of the Wind Farm results in the total installed capacity on the combined sites exceeding 5MW.

Wind developers view the grid code requirements as unduly onerous. They were applied retrospectively on existing generators and required them to comply or be shut down. IWEA estimates the extra cost incurred by developers to date at ~ €100,000,000 [19].

According to the IWEA, at present there are numerous generator performance derogations for non-wind in Ireland and not enough incentives to perform as required by the Grid Code in Ireland. Generators must comply or be removed from the system. Alternative incentive mechanisms are required to encourage improved Grid Code performance and remove deliberate excursions from the Grid Code.

Similarly, Northern Ireland also has separate requirements for wind generation under the Grid Code [16].

3.3 Transmission Access & Charging

3.3.1 Transmission Connection

For generation projects typically under 20 MW total capacity at a single location, a distribution connection will normally be investigated first. EirGrid is responsible for issuing a connection offer in Eire and SONI in Northern Ireland.

EirGrid and NIE have taken different approaches to connection. EirGrid adopts a "cluster" approach through a gating process. NIE has historically insisted that projects have planning permission before an offer is made. They are now considering a cluster approach, which in some cases may require investment prior to planning permission being granted to all generation.

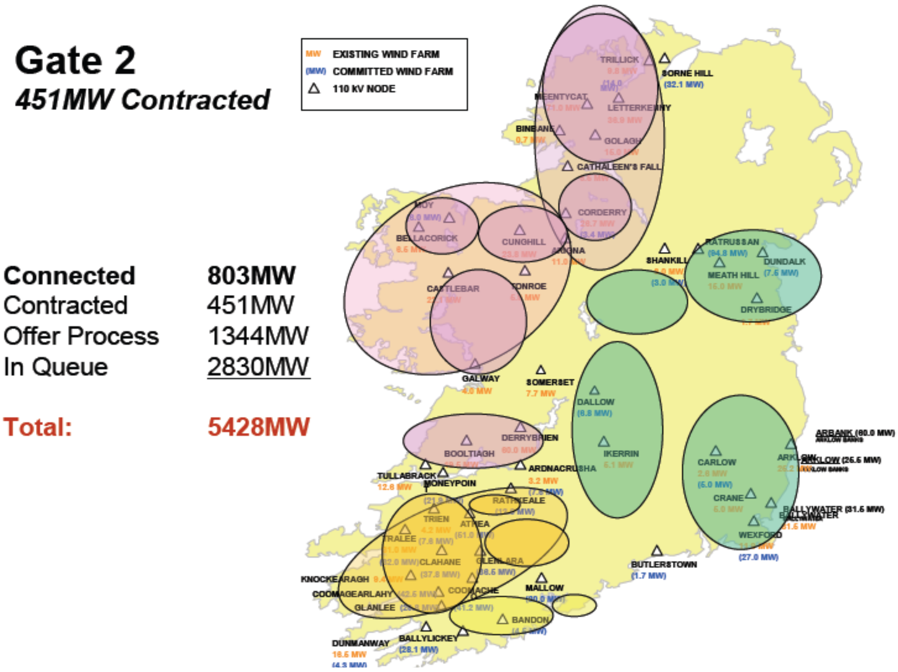
There have been challenges regarding connection of wind generation to the grid in Eire due to the recent large growth in capacity. ESBNG raised concerns about the capacity of the grid to absorb the rapid growth in wind

[2] A Contiguous Wind Farm Site is defined as: "An area containing more than one contracted Wind Farm where each contracted Wind Farm's site is adjacent to at least one other contracted Wind Farm".

power from 2003. This led to a moratorium on grid connections for wind generation put in place by CER in 2003.

Representatives of the wind energy sector and others raised concerns about the effects of this moratorium on the sector and called for an acceleration of the process to develop a grid code for wind connections. CER developed new grid codes at transmission and distribution level. The moratorium was lifted in December 2004, and a group processing approach for grid connection applications was put in place. EirGrid has now made grid connection offers to all applicants under Gate 1. The Gate 2 process contains applications that were made subsequent to the imposition of the moratorium in 2003. Applications in Gate 2 are still being processed; some applicants have received offers while many are still waiting. Wind developers have expressed frustration at the length of time it takes to receive connection under this system.

Figure 13: Gate 2 Progress (EirGrid, October 2007)



Once a grid connection offer has been made, developers may be subject to further delays. Transmission connections are contestable and can be awarded to other parties, however Distribution connections are non-contestable. According to IWEA, the ESB has typically taken 2 years from the date of the actual grid connection offer to complete a connection.

The long connection process for wind can cause a number of related issues. In particular, planning consents in Eire generally have a 5 year "window". If the project does not receive a connection offer within this time, they may have to reapply for planning consent. Additionally, this makes the process of ordering turbines more difficult. Given the global shortage of turbine parts, this can cause further project delays. IWEA would advocate a swifter gate processing system, with a clearly defined offer (or refusal) to connect [16].

Generation transmission connection processes in Eire and NI will be harmonized from 1 January 2008. Variable wind generation will be connected through a group processing system similar to that currently in place in Eire. This is likely to mean that it continues to take a comparatively take a long time for wind generators to receive any grid connection offer. However, the rules in this area are still in development. They will be informed by the All Island Grid Study [17].

A project jointly funded by NIE and wind developers is currently studying the possibility of a correlation between high wind speeds and wind cooling on overhead distribution power lines to explore dynamic rating for power lines to allow more flexible ratings.

3.3.2 Connection Charging

On 7th December 2007, the Regulatory Authorities, on behalf of the SEM Committee published a consultation paper inviting views on transmission connection charging policies under the SEM

A shallow transmission connection policy is adopted in the SEM, with a "deep" reinforcement timeframe made known to the generator as part of the connection offer. Connection charges are based on the shallow connection cost [9].

There are Guiding Principles for identifying the connections assets chargeable to specific connections as opposed to through general Transmission Use of System (TUoS) charges. These charges are for the minimum technically acceptable solution to connect a new user to the existing transmission system.

As a corollary of shallow connection charges, generators pay a locational charge as part of their TUoS – i.e. they should pay more to contribute to the cost of the deep reinforcement which their shallow connection has caused [9].

It is possible for generators to contest connection charges. However, this cannot be done until after a connection offer has been made. In the case of connections under gate processing, this can take an indefinite period.

- ***Reserve costs***

  Reserve costs are those costs associated with the need for reserve generation capacity due to the possibility of lower than expected generation or higher than expected demand. Under SEM, reserve costs will be passed on to customers through a socialised charge.

  Whenever a new plant applies for connection to the system, a study will be conducted by the System Operators to determine whether the reserve requirement for the system as a whole has increased as a result. The reserve requirement for the system might increase, for example, in the case of a very large plant, or in the case of plant for which variable production is highly correlated with the production of other plant (as is the case with wind). If it is shown that the connection of that new plant will increase the reserve requirement for the system, then that new plant may be required to pay a reserve causation charge upon connection [11].

3.3.3 Transmission Access

- ***Physical Access to Transmission Network***

  Physical access to the transmission system will be permitted in certain circumstances at the date of shallow connection and prior to completion of deep reinforcements. The provision of access to the transmission system at shallow connection is subject to the transmission system being able to take the generation export [10].

  - Where deep reinforcements are not completed, the generator's access shall have an amount of capacity which is deemed physically firm and an amount deemed physically non-firm. The generator will then receive Firm Physical Access and constraint off payments for the portion of their plant with Firm Physical Access. They will receive non-firm physical access for the remainder of the capacity and no off constraint payments until deep reinforcements are complete [10].
  - When deep reinforcements are completed the plant has firm physical access and receives constraint payments against any of its capacity that is constrained.

  Although constraint payments are only made against the firm portion, capacity payments are based on the full available capacity.

- ***Constraint and Curtailment***

  Constraint arises out of inadequacies in the grid infrastructure to accommodate generation capacity. Curtailment is a constraint that arises when there is an imbalance between generation and electricity demand or in situations where it is unlikely that variable generation capacity can respond to changes in demand.

  Both affect the ex post wind generation capacity factor, which can compromise the financial viability of wind development.

  - **Curtailment**

    Prior to SEM, curtailment was used by EirGrid for wind generation. It has emerged in Ireland due to the particular circumstances of a relatively high level of wind penetration in an electricity market with insufficient interconnector capacity.

Some suggestions have been made that curtailment without compensation could be used as a mechanism to include higher levels of wind generation in the future. It is possible this could be done on a "last on, first off" basis, but is not clear if this will mean reduced transmission charging for the affected developments

- **Constraint payments**

  Constraint payments are made for network constraints, but not for curtailment. Although constraint payments are only made against the firm portion, capacity payments are based on the full available capacity.

  - Where deep reinforcements are not completed, the generator's access shall have an amount of capacity which is deemed physically firm and an amount deemed physically non-firm. The generator will then receive Firm Physical Access and constraint off payments for the portion of their plant with Firm Physical Access. They will receive non-firm physical access for the remainder of the capacity and no off constraint payments until deep reinforcements are complete [10].
  - When deep reinforcements are completed the plant has firm physical access and receives constraint payments against any of its capacity that is constrained.

  For wind, the level of constraint payments is set at the level that they could have produced at the time rather than being set at the level of actual capacity. Similarly, capacity payments are set at the level of energy that they actually produce or could have produced (if constrained).

3.3.4 Generator Transmission Charging

In the future, the transmission system operators will develop a common methodology to calculate All-Island tariffs for TUoS generation. The Regulatory Authorities have decided to defer the introduction of all-island locational TUoS generator tariffs until October 1st 2008. The precise values of the TUoS charges are not currently determined. They will be based on €/kW/yr.

All distribution and transmission connected generators over 10 MW installed capacity will be subject to locational generation Transmission Use of System (TUoS) charges (for embedded generators below 10MW these charges are set to zero). The charging system is based on the system previously used in Eire by EirGrid. This involves determining the maximum cost of transporting from a given generator under a number of scenarios on a reverse MW-mile basis.

- ***Reverse MW Mile***

  The methodology consists of:

  - Defining a number of scenarios which represent the operating conditions considered in investment planning. For wind this involves assuming 100% load factors at summer minimum and 0% load factors at Winter peak.
  - In each scenario, calculating the MW flow on each transmission circuit resulting from the presence of each generator.
  - Applying a cost for each transmission circuit
  - Calculating a cost for each circuit used, and hence an aggregate cost across the entire network, for each generator.
  - Select the highest (most positive) cost for each generator.
  - Divide by the capacity of the generator to get a value in €/kW/yr.
  - The cost per generator is shifted to give the overall return allowed.

  Negative tariffs for wind generators are set to zero, on the grounds that intermittent generation cannot be relied upon to defray transmission system investment and hence it is inappropriate that they should actually receive payment.

3.3.5 Transmission Losses

Transmission losses in the SEM will be accounted for by applying locational loss factors to the outputs of each generator. These loss factors are calculated on the single combined transmission system and are set annually in advance. On 7th December 2007, the Regulatory Authorities on behalf of the SEM Committee published the all-island Transmission Loss Adjustment Factors for 2007 (November to December) and for 2008. The loss factors vary monthly and by time of day (day/night).

ANNEX A – ABBREVIATIONS

Acronym	Definition
ACPS	Annual Capacity Payment Sum
ATC	Available Transfer Capacity
BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Mechanism
BNE	Best New Entrant
CCL	Climate Change Levy
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation
CfD	Contract for Differences
CHP	Combined Heat and Power
DCENR	Department of Communications, Energy and Natural Resources
DCMNR	Department of Communications, Marine and Natural Resources
DETI	Department of Enterprise, Trade and Investment
EC	European Commission
ESBNG	ESB National Grid (the Transmission System Operator for Ireland)
EU	European Union
GB	Great Britain: includes England, Scotland and Wales
GoO	Guarantee of Origin
GW	Gigawatt = 1,000,000 kW (unit of power/ capacity)
HMRC	Her Majesty Revenue & Customs
IA	Interconnector Administrator
IEA	International Energy Agency
IWEA	Irish Wind Energy Association
ktoe	Kilo tonnes of oil equivalent
kW	Kilowatt = 1,000 Watts (unit of power/ capacity)
kWh	Kilowatt hour = 1,000 Watt hours (unit of energy)
LEC	Levy Exemption Certificate (exemption from the Climate Change Levy)
MW	Megawatt = 1,000 kW (unit of power/ capacity)
MWh	Megawatt hour = 1,000 kWh (unit of energy)
NI	Northern Ireland
NIE	Northern Ireland Electricity

Acronym	Definition
NIRO	Northern Ireland Renewables Obligation
PPA	Power Purchase Agreement
REFIT	Renewable Energy Feed In Tariff (Eire)
REGO	Renewable Energy Guarantee of Origin
RES	Renewable Energy System
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
SEI	Sustainable Energy Ireland
SEM	Single Electricity Market
SME	Small to Medium Sized Enterprise
SMO	Single Market Operator (in the all-island market)
SMP	System Marginal Price
SO	System Operator
SONI	System Operator for Northern Ireland
SRMC	Short Run Marginal Cost
TNUoS	Transmission Network Use of System
TSC	Trading and Settlement Code
TSO	Transmission System Operator
UK	United Kingdom: Includes England, Scotland, Wales and Northern Ireland
VoLL	Value of Lost Load

ANNEX B – GLOSSARY

Term	Definition
Bilateral	Trades or other contracts between two participants, for example a generator and supplier.
Capacity	Cf. Energy, Power. The maximum ability of a generating station to generate an amount of electricity in a given time. Measured in units of power (kW). The actual energy generated is dependant on the load factor.
Clip Size	The minimum size of interconnection capacity contracts.
Credit Cover	The cash or other financial security that must be provided.
Day Ahead	The day prior to the day that is being traded for or balanced.
Deep Connection Costs	Cf. Shallow Connection Costs. The costs of reinforcing and upgrading the wider network to enable additional generation or demand to be connected.
Energy	Cf. Power, Capacity. Formally defined as the ability for a system to do work. In the case of an electrical energy this is measured in kWh. Energy cannot be stored in the transmission network, so at any given time the total energy generated must equal the total energy demand and total losses (due to heating of wires etc.) This is known as balancing the system.
Gate Closure	The last time at which energy can be traded before the markets are closed. Balancing trades may take place closer to real time on a separate balancing market.
Great Britain	England, Scotland and Wales (excludes Northern Ireland)
Group Processing	This means that the grid operator puts applicants into a queue and groups them into areas or zones. Reinforcement is then carried out on selected zones to accommodate the applicants in that zone. There is no guaranteed timescale for connection.
Intraday	Within the day that is being traded for or balanced.
Ireland	The term Ireland refers to the state of Ireland (Eire), which excludes Northern Ireland. Within this document we have usually referred to "the island of Ireland" or "all-island" to include both Eire and Northern Ireland. For clarity, the state of Ireland is referred to as Eire throughout.
Load Factor	Also may be known as a capacity factor. The ratio of the actual energy output of a power plant over a period of time and its energy output if it had operated a full capacity of that time period. For example, an onshore wind farm might have a load factor of 30-40%. This means that on average it generates at 35% of its capacity, although at any given time it may be generating anywhere between 0% and 100% of its total capacity.
Locational	Cf. Postage Stamp. Differentiated by geographical location. For example, in the case of transmission charging, this typically will mean higher charges further from demand centres.

Term	Definition
Long	Cf. Short. Where a participant has more generation than is required to balance their demand (including losses where applicable)
Main Price	Cf. Reverse Price. The balancing price where a participant is out of balance in the same direction as the market, for example a participant that is "short" when the market is "short".
Merit Order	The order that a system operator will place generators in based on the costs to deliver a certain quantity of generation. Those generators that will allow the forecast demand to be met at the lowest costs (subject to system constraints) are described as being in the merit order and are despatched.
Postage Stamp	Cf. Locational. Uniform, equal throughout the network.
Power	Cf. Energy, Capacity. Power is the ability to create energy in a given time, and can be expressed in the following equation: $Power(kW) = \frac{Energy(kWh)}{Time(h)}$
Price Maker	Cf. Price Taker. In the context of an electricity pool, a price making generator will submit a number of bids/offers indicating how much electricity they would be prepared to despatch at a given price. The system operator will place the generators in order of cost to determine which plants will be despatched.
Price Taker	Cf. Price Maker. In the context of an electricity pool, a price taking generator will not submit a bid or will submit a bid at zero. This means it will always be despatched (subject to system constraints) and will receive the pool price. Price taking generators include variable generators with low marginal costs, such as wind.
Real Time	The actual time period that energy is being traded for or balanced.
Reverse Price	Cf. Main Price. The balancing price where a participant is out of balance in the opposite direction to the market, for example a participant that is "short" when the market is "long".
Shallow Connection Costs	Cf. Deep Connection Costs. The costs of physically connecting a generator to the nearest appropriate point in the transmission network, this may typically be the closest substation. This does not include costs associated with any required reinforcements to the wider transmission network.
Short	Cf. Long. Where a participant has less generation than is required to balance their demand (including losses where applicable)
Supplier	Normally used to describe a retail electricity supplier that sells electricity to final consumers, this can include domestic, commercial and industrial consumers
United Kingdom	Includes England, Scotland, Wales and Northern Ireland
Vertical Integration	Vertical integration is the degree to which a firm owns its upstream suppliers and its downstream buyers. For example, within the electricity industry this can be used to describe the situation where a parent company owns both an electricity retail supplier and generator.

ANNEX C – REFERENCES

Number	Reference
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