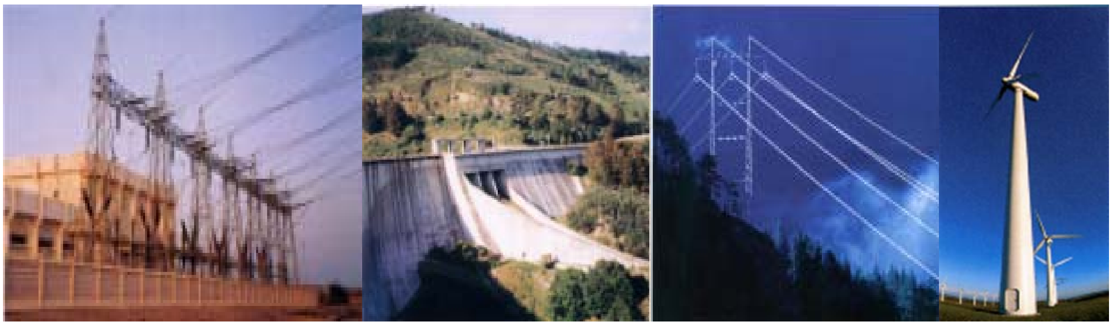
Great Britain Country Report



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 renewable generation within the GB (Great Britain) power markets. GB consists of England, Wales and Scotland.

1.1 Renewable Generation Capacity

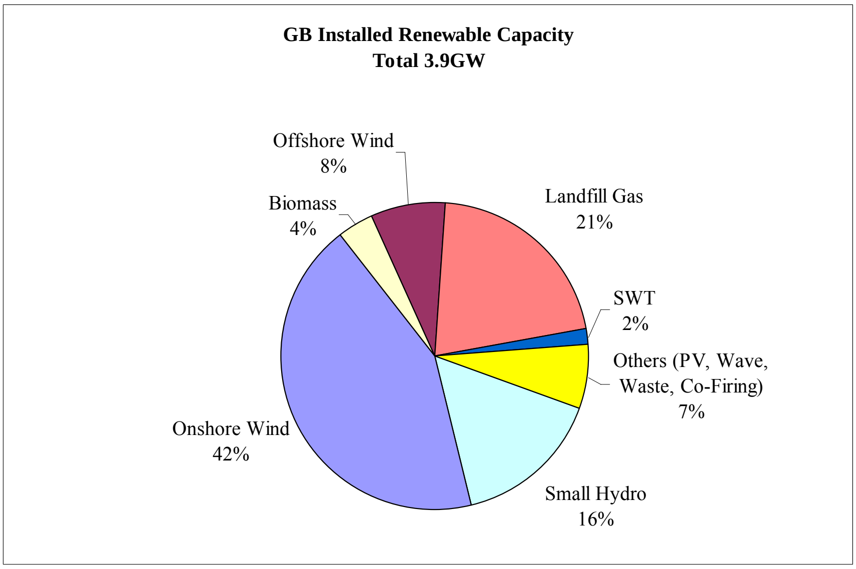
Great Britain has significant renewable resource potential with good on-shore wind speeds over significant areas of the country, as well as the potential for significant offshore wind, wave and tidal generation. Currently there is around 4GW of renewable generation capacity (plus 1GW of large hydro generation capacity) as shown in Figure 1, which represents approximately 4.6% of supplied power in GB in the financial year of 2006/7.

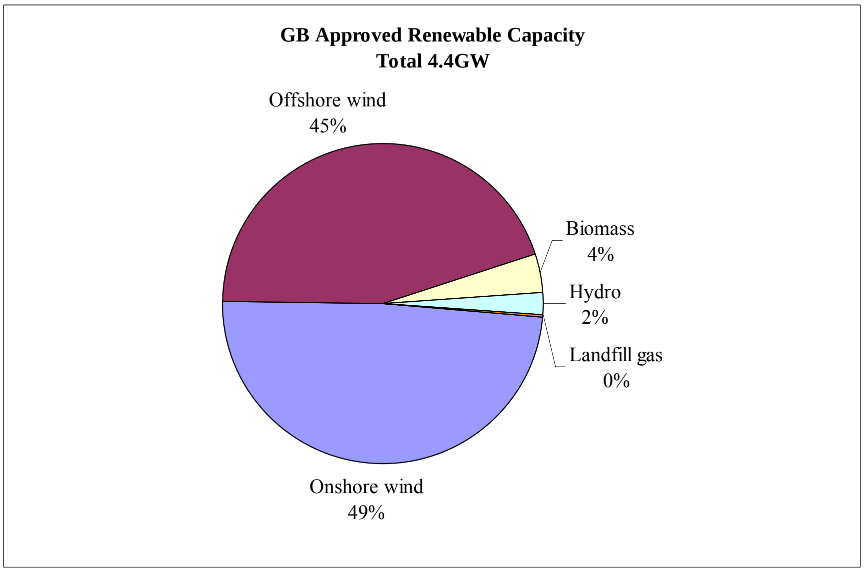
There is also a considerable volume of renewable generation capacity that has received consent for development (around 4.4GW that has planning consent approved), as well as a significant interest in developing renewable energy projects - around 28GW of projects at various stages of development - although it should be noted that it is unlikely that all of these projects would be progressed to construction.

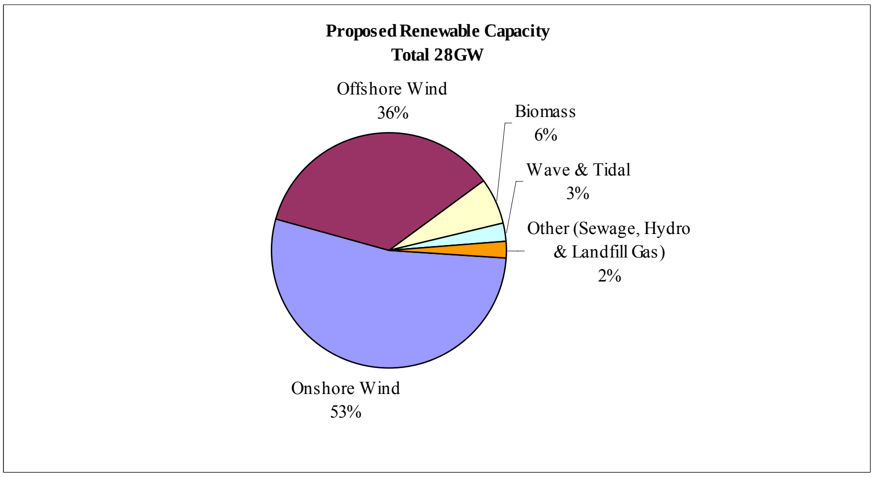
It can be seen in the figures below that onshore wind is the dominant technology, and on and offshore wind are likely to dominate renewable capacity in the future. The growth and demand for renewable energy projects is as a result of the Governments support mechanism - the Renewables Obligation – which has targets of 10.4% of supplied energy from renewable generation (excluding large scale hydro) in 2010 and 15.4% in 2015. In addition there are proposals to extend the targets to 20% by 2020.

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

Figure 1: GB Renewable Generation: Installed, Approved and Planned (~April 2007)







1.2 Renewable Generation Size

Generators of less than 100MW of capacity and connected to the distribution network do not require a generation licence. Additionally, they are not required to have a connection agreement with the transmission system and do not have to be registered directly within the main market arrangements. These "embedded" generators can for the purposes of the arrangements be treated as negative demand, effectively isolating them from many of the industry arrangements (and hence reducing their costs for participating in the market).

However, recent developments in regulatory arrangements and incentives to connect, particularly renewable generators, have meant that the traditional pattern of network usage has altered. One of the principal changes has been the increase in distributed generation connected to the network. It is likely that, if this trend continues, distribution networks will increasingly export power on to the transmission system at certain times rather than consistently taking power from it. As a result there is work currently being undertaken by the Regulator and System Operator (SO) to develop new arrangements for distributed generation, to take into account their effect in the transmission system.

The remainder of this document focuses on the arrangements for larger (>100MW) or transmission connected generation.

1.3 Renewable Generation and Power Markets

There are no special arrangements in the GB power markets for renewable generation, other than additional financial support available under the Renewable Obligation and Climate Change Levy. In other respects renewable generation is treated the same as conventional generation, and has to interact with and operate within the rules of the GB power markets.

A high level overview of the key principles governing the GB market is provided below and shown diagrammatically in Figure 2.

- Traded Market

  Counterparties can trade power either bi-laterally, through brokers or through exchanges. Non-physical players may also be involved in the traded market.

- Self despatch

  Counterparties (generators and suppliers) decide individually how much power they physically plan to inject and withdraw from the system.

- Notification

Counterparties have to notify their traded position and planned physical position to the market and system operator respectively at a specified point in time.

- Entry and Exit

  Counterparties must have rights to inject and withdraw power. The rights are granted at specific entry (and exit points). The system is based on the "ticket to ride" principle rather than point to point transportation.

- Balancing Settlement

  Counterparties are incentivised to balance their physical and contractual positions. Imbalances between these positions are subject to cash-out prices. There is a dual cash-out price depending on whether the counterparty is long or short (in relation to their physical and contractual position), with the prices typically being equal or at a premium to the spot market price.

- Balancing Market

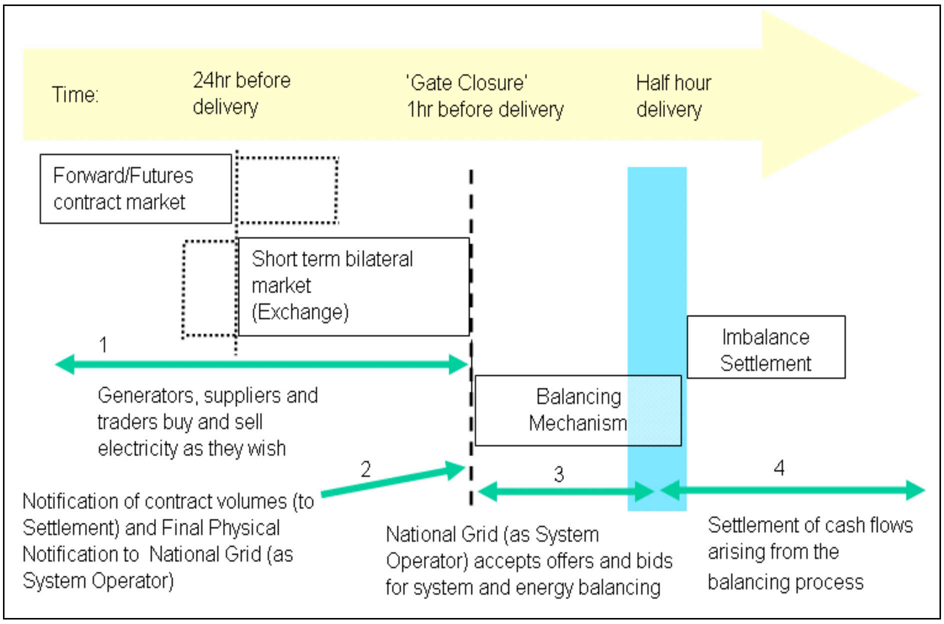
  There is a balancing market, in which counterparties can submit bids/offers to change their physical flows, allowing the system operator to balance the system in real time.

  The Balancing Market is very different from many of those in continental Europe, this reflects the different structures in the traded markets and the procurement of system services.

- Transmission Access & Charging

  Transmission Access is firm and charges are levied against a Transmission Entry Capacity. All generators connecting to the networks are required to meet the same standards, irrespective of the type of generation.

Figure 2: The Great Britain Power Markets[1]



1.4 Degree of Centralisation

There is no central agency within the GB 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 the responsibility of the operator. As a result renewable energy generators take the responsibility for the short and long term trading of their generation output.

1.5 Support Mechanisms

Renewable generation gets value for its output by selling power to other market participants. Projects may elect to enter into long term off-take contracts or to trade output in the power markets. Thus, renewable generation should achieve a price related to the power market price for its output. 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.

1.5.1 Renewable Obligation

The primary support mechanism for Renewable Energy in the UK is the Renewables Obligation (RO). Eligible renewable generation is credited

[1] Source: National Grid Seven Year Statement, May 2007 [1]

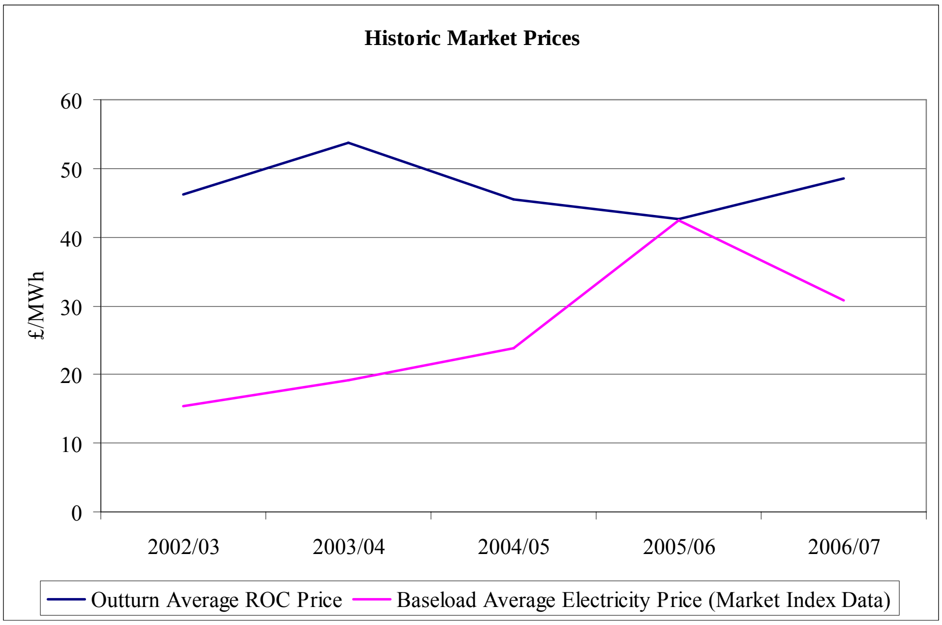
with a Renewable Obligation Certificate (ROC) for each unit of output (MWh) produced.

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 market for ROCs, and they can be traded separately from the electricity produced. The value of ROCs and power are shown over the last 5 years in Figure 3. It can be seen that ROC prices have typically been greater than power prices over the last 5 years, and so make a significant contribution to the economics of renewable generation projects.

Figure 3: ROC and Power Prices

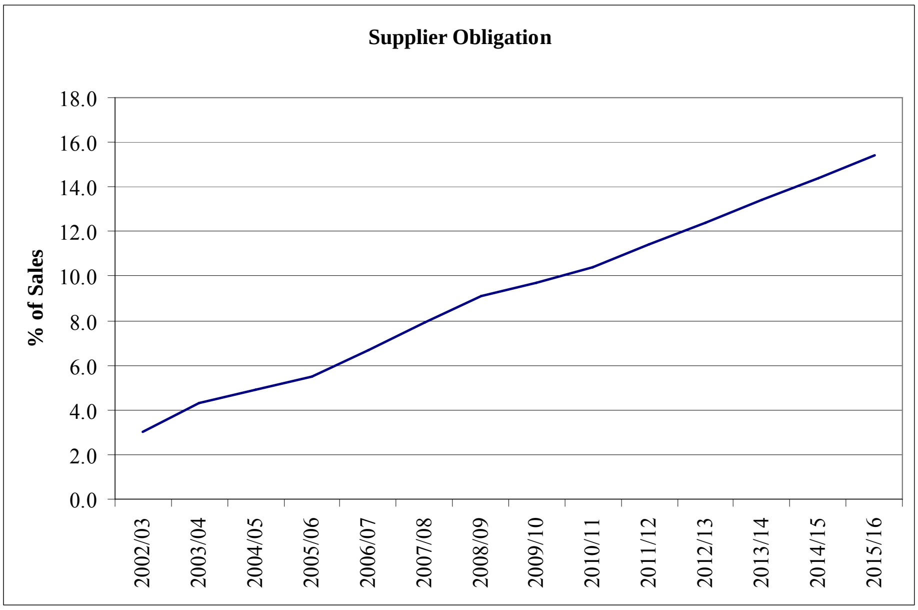


The obligation came into force in April 2002, with the level of the obligation increasing every year to 2015. The level of the Supplier Obligation is shown in Figure 4 to 2015, and there are proposals to extend the targets to 20% in 2020.

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 beween 0.25 ROCs per MWh awarded for the most economic technologies to 2 ROCs per MWh awarded for more expensive technologies.

Figure 4: Renewable Obligation on Suppliers



1.5.2 Climate Change Levy

The Climate Change Levy (CCL) is a tax on final energy use, set at £4.41/MWh for electricity (in 2007/08), 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.

1.5.3 Capital Grants

The Government has 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

The traded markets comprises both over the counter (OTC) and exchange based trading, which allows generators and suppliers to adjust their commercial positions ahead of real time down to a half hourly granularity. The GB power markets do not have a day-ahead auction, so all trading has to be undertaken through individual transactions.

Market participants can control balancing of their positions up to gate closure (1 hour ahead of the start of each half-hour settlement period), at which point all contracts have to have been notified to the market operator. In principle, it is possible to trade up to an hour ahead of real time, although in practice the power exchange, where most short term trades are undertaken, closes 1.5 hours ahead of real time.

There is limited liquidity across the different power markets, reflecting the vertically integrated nature of most of the major players. For instance approximately only 2% of electricity demand is traded as half hour products through the power exchange. Market liquidity can prove restrictive in terms of the ability of counterparties to use trading to balance their positions through the traded market. This is particularly true for renewable generators subject to output uncertainty such as wind generators, where traded positions need to continue to be adjusted approaching real time, as forecasts of output are updated.

In addition to the issues of limited liquidity, the brokered market works on a minimum lot size of 10MW – which could be relatively large for an independent renewable project. Although the lot sizes on the prompt and spot exchange are smaller at 1MW, the limited ability to trade small volumes of power can be restrictive for variable renewable projects.

The lack of a single gateway for trading means that counterparties typically have to maintain a number of different trading agreements and support these with appropriate credit, which can be a significant overhead for an independent generator. In addition maintaining a 24 hour trading operation requires a relatively large operation, which is unlikely to be viable for individual renewable generators.

In addition to trading power, renewable generators are able to trade ROCs, which is an extremely illiquid market. Also, the rules surrounding CCL mean that it is difficult for renewable generators to trade generator output and extract the value of the CCL exemption from different counterparties. Both of these provide additional barriers to renewable generators in terms of actively trading generation output in the power markets.

As a result of the complexities and overheads of trading, many independent renewable generators enter into long term off-take contracts with large utilities, avoiding the complexities of interacting with the traded market or the power market arrangements (such as notifications, imbalance etc).

In addition many independent renewable projects are project financed and so require some guarantees on future revenues streams (provided through long term off-take contracts) to support debt financing of the project. This is an additional factor that has led many independent renewable generation projects to enter into long term power off-take arrangements.

1.7 Despatch

Counterparties (generators and suppliers) decide individually how much power they physically plan to inject and withdraw from the system.

Generators typically have firm transmission access rights (see section 3.3.4), which means that renewable generators will typically plan to inject all available generation on to the system.

1.8 Notification

Generators have to submit physical and contractual notifications to the system operator (SO) and market operator respectively before gate closure, which is set at one hour before the start of each half hour settlement period.

The physical notification to the SO gives the continuous planned output of individual physical Balancing Mechanism Units (BMU). Notification is the expected power that will be injected/withdrawn at an individual BMU level. Generation BMUs are usually specified at individual generation set level, although individual wind turbines and other "smaller" generators at a single location would typically be grouped into one BMU. Parties have to follow their Final Physical Notification (FPN) positions. Any *intentional* fluctuation from FPN is a breach of the grid code, and as such a breach of the conditions of their licence. Clearly scope is provided to allow for the unpredictable nature of the output of many renewable generators.

Counterparties also have to provide notifications of contracts before gate closure. These are energy positions over each half-hour period. Contracts have to be notified to be taken account in the imbalance settlement processes.

1.9 Imbalance Settlement

Market participants have financial incentives to manage the balancing of their position, since they will be charged imbalance prices on any differences between their notified commercial position and physical output over each half hour period. There is a dual imbalance price system; counterparties are exposed to System Buy Price (SBP) when their account is short and System Sell Price (SSP) when their account is long. Both prices are derived as a function of Half Hourly Exchange market prices and system operator costs. The imbalance cost is simply the imbalance volume multiplied by the imbalance price.

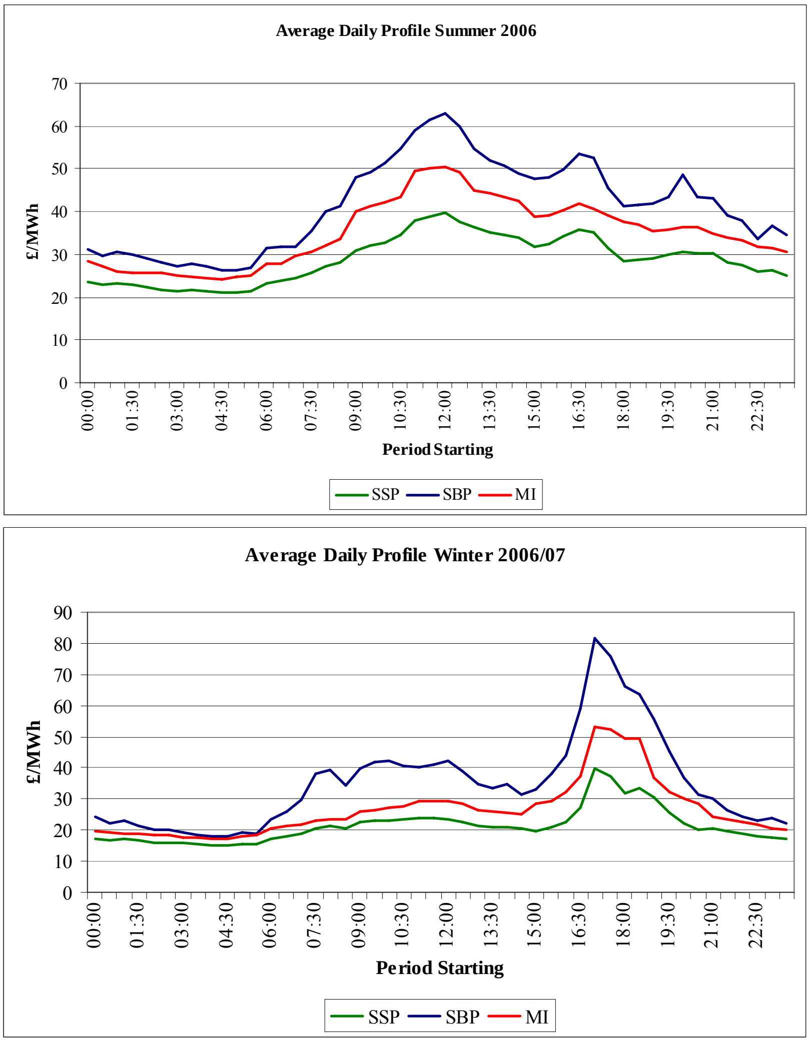
The methodology for calculating SBP and SSP varies dependent upon whether the system is long or short. There are two imbalance price methodologies, the main imbalance price (defined as a function of system operator costs) and the reverse imbalance price (defined as the Half Hourly exchange market price). When the system is long SSP is defined as the main imbalance price (and SBP is the reverse price), whereas when the system is short SBP is defined as the main imbalance price (and SSP is the reverse price).

Imbalance prices can be extremely volatile, and can be at a significant premium to the market price, this is especially true for SBP. The daily profiles of imbalance prices are compared to the market price in Figure 5.

Energy imbalances are calculated at an energy account level. Each market participant has a separate energy account for production (netting across all generation) and consumption (netting across all demand). However it is not possible to net imbalances between these two accounts. Thus, market participants are exposed separately to imbalances on both the generation and demand side. However, vertically integrated companies can meet their own demand using their own generation without trading through the market by notifying trades between their generation and consumption accounts, with volumes notified in both accounts before gate closure. Since portfolios can net balances across all of their generation (and separately demand) portfolio this naturally leads to some advantage due to averaging effects. In addition the ability of portfolios to trade between consumption and production accounts means that they are not as exposed to trading in relatively illiquid markets (especially approaching real time).

The variable and unpredictable nature of some forms of renewable generation (for example wind) means that they are particularly exposed to imbalance charges. Since imbalances are calculated at an energy account level this provides portfolio generators a considerable advantage compared to independent renewable projects. This is an additional factor that has influenced many generators to enter into long term off-take agreements with major utilities, passing them the imbalance exposure and allowing them to consolidate output from generation across the portfolio, reducing imbalance risks. The design of the markets allows for counterparties purely offering consolidation services, allowing generators to hedge imbalance exposure, but in practice use of this type of consolidation service is extremely limited.

Figure 5: Average Daily Imbalance Price Profiles[2]



1.10 System Balancing

The responsibility for balancing supply and demand is arguably split between the System Operator (SO) and market participants. The SO has responsibility for balancing the system between gate closure (1 hour ahead) and real time, but due to the issues associated with plant dynamics it may be necessary for the SO to take actions outside this timescale.

Market participants can only manage system balancing (at a portfolio level) up to gate closure, since at this point they must declare the physical operation of plant through the submission of FPNs. Market participant balancing can only be undertaken through the bilateral traded market (OTC and exchange trading) as there is no day ahead auction or other centralised Balancing Market mechanism. Limited market liquidity has been seen as a problem especially in the prompt

[2] MI – Market Index

markets, and may be one of the drivers for consolidation of the industry into a number of vertically integrated portfolios (generation and supply). However, the ability to trade up to gate-closure ensures that at least in theory the market should allow economic scheduling across the industry close to real time.

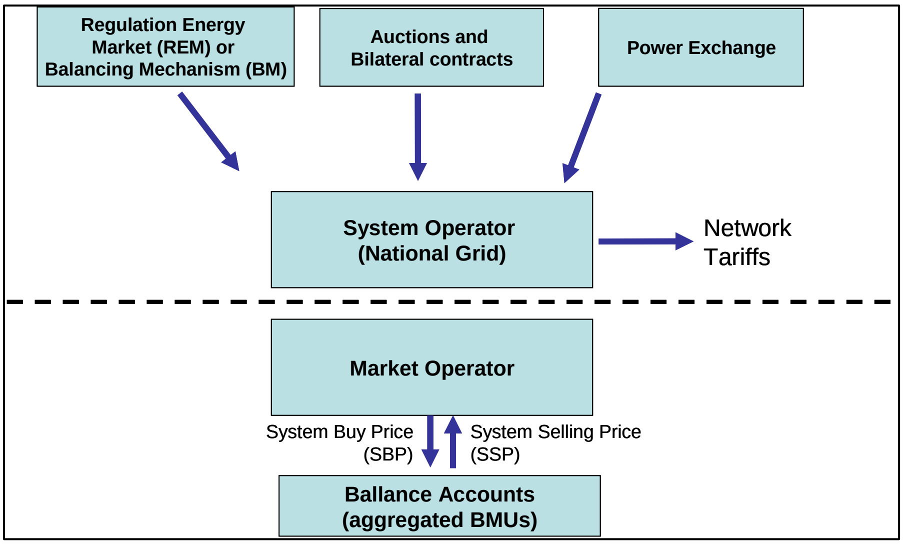
The GB SO (there is only one control area within the GB power market) has sole responsibility for balancing the system after gate closure. The system operator is responsible for residual energy balancing. This means that the system operator is responsible for resolving any energy balancing, required as a result of differences between demand and generation FPNs, as well as any imbalances due to demand or generation fluctuations and unplanned outages that result in imbalances occurring after gate closure (differences between physical output and FPN). In addition the System Operator is responsible for system balancing – maintaining supply quality (stable voltage and frequency) and supply security (transmission constraints). The system operator has a number of tools for system and energy balancing. These include accepting bids or offers in the Balancing Mechanism, entering into contracts with market participants for energy or ancillary services, and energy trading in the power markets.

The Balancing Mechanism (BM) is the market that exists between gate closure and real time. The BM is a monopsony market with the SO as the sole counterparty. Market participants (predominantly generators, but also large controllable loads) can submit bids/offers to decrease/increase their output from their notified FPN level. The BM is a pay as bid market. Whilst the BM is used as a Balancing Market, it is also used for the delivery of other system operator actions such as Ancillary Services.

Although some flexible plant can derive significant revenues from the provision of ancillary services, and the provision of flexibility to the SO through Balancing Mechanism Bids/Offers, variable renewable generation are unlikely to provide any significant BM participation.

An overview of the Balancing Power Market is provided in Figure 6 below.

Figure 6: Overview of the Balancing Power Market in Great Britain



2 CROSS BORDER TRADING

GB currently has the ability to import/export between two different electricity markets – France and Northern Ireland. In May 2007, National Grid also announced that it would be proceeding with the BritNed interconnector between GB and the Netherlands. This is a joint venture with Dutch TSO TenneT and is expected to be completed by late 2010.

Ireland can only currently import/export to GB.

2.1 Current Cross Border Flows

2.1.1 England-France (Interconnector France-Angleterre – IFA)

Capacity:	England to France	2,000 MW
	France to England	2,000 MW
Owned by:	National Grid and Réseau de Transport d'Electricité (RTE)	
Availability:	97%	

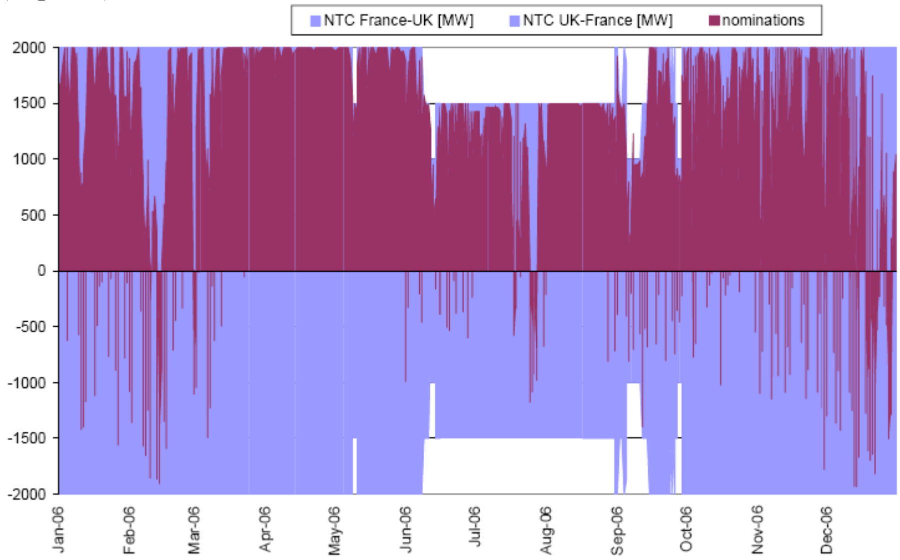
The England-France Interconnector is a high voltage direct current (HVDC) link between the French and British transmission systems. The interconnector is approximately 70km in length with 45km of subsea cable. The availability has consistently exceeded 97% per year.

National Grid Interconnectors Ltd jointly own and operate the Interconnexion France Angleterre (IFA) with RTE SA (the French transmission system operator).

- ***Interconnector Nominations***

  Inteconnector capacity nominations for 2006 are shown in **Figure 7**. It is clear that flow on the interconnector is predominantly from France to GB.

Figure 7: Net Transfer Capacity and Cross Border Capacity Nominations in 2006 (MW), flows from France to UK (positive) and from UK to France (negative)[3]



2.1.2 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 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.

[3] Tradewind Report [2]

2.2 Cross Border Capacity Mechanisms

2.2.1 England-France Interconnector (IFA)

Time blocks sold:	Year, season (summer/winter), quarter, weekend and day
Volume constraints:	1 MW blocks
Method of initial sale:	Normally Auction (tender also possible)
Reserve price:	Variable
On-sale allowed?	Yes – re-sell or sub-let
Restrictions:	Max change of 750 MW between two settlement periods "Use it or lose it" principle applied

- ***Purchasing Capacity***
  - Capacity may be offered for sale by tender.
  - Auctions are held each business day for daily capacity (subject to outages) and periodic auctions are held for capacity on the following basis: year, season (summer/winter), quarter, weekend and day. Capacity is offered in tranches of 1MW (units) and users can bid up to the maximum offered in each auction.
  - Any capacity that remains unallocated after an auction or tender may be offered as capacity available for shorter duration.
  - Purchased capacity can be resold or sub-let. Reassignment must be notified to NG and RTE before 17.00 on the day before the daily auction for the day concerned.
  - Purchased capacity in blocks of a month or more can be reallocated – users can ask NG and RTE to resell it at auction and will receive the proceeds (less a fee).
- ***Superposition***

  Superposition capacity is not currently being made available.
- ***Capacity Rights: "use it or lose it"***

  Capacity rights are subject to a "use it or lose it" rule. By 06.00 hours on the day of the auction for each contract day, users with units longer that a contract day will need to give the Operators notice of their intended level of use of the Interconnector on the forthcoming contract day. To the extent that users indicate that capacity will be unused the Operators will make the capacity available in the daily auction. The original user will still be required to pay for the capacity and will not receive any proceeds from the auction. This ensures that a capacity holder is incentivised to on-sell or sub-let unwanted capacity.

It is also interesting to note that the IFA Access rules do not include any provisions intended to ensure that actual use reflects the notified level of use. This position, however, could change if it were felt for example that capacity was being blocked.

2.2.2 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, SONI (the System Operator in Northern Ireland) 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.

2.2.3 Potential Future Interconnector Capacity

- ***BritNed link to the Netherlands***

  In May 2007, National Grid announced that it would be proceeding with the BritNed interconnector between the UK and the Netherlands. This is a joint venture with Dutch TSO TenneT and is expected to be completed by late 2010.

  BritNed will have a capacity of 1,000MW and will be 260km long. The link will run beneath the North Sea between the Isle of Grain in Kent to Maasvlakte, near Rotterdam. It will transmit power in both directions, and has been identified as a 'priority' project in the European power market.

  BritNed will be a commercial interconnector, funded and operated independently from National Grid and TenneT's regulated businesses. Customers will have open access to the capacity via a combination of 'implicit' auctions facilitated by APX and short term 'explicit' auctions.

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

  The Irish Government's 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.

- ***Norway-GB Interconnector***

  In 2003, National Grid and Statnett (the Norwegian grid operator) obtained environmental permits for a 1,200 MW interconnector between Easington, County Durham, and Suldal in Rogaland County. At the time it was not possible to find a commercial structure that satisfied the requirements of National Grid, Statnett and the Norwegian Government. National Grid and Statnett are continuing to study alternative structures that would make the construction of this project possible.

2.3 Cross Border Trading

2.3.1 England-France

Capacity firm or non-firm:	Non-firm	
Latest auction:	7.15 – 8.45 on D-1 (business days only)	
Notification of available capacity:	7.00 on D-1	
User nominates capacity:	6.00 on D-1	
Notification to market system operator/TSO:	GB France	11.00 D-1 Six intra-day gates T-3hs
Imbalance penalties apply:	England to France France to England	Yes Yes
TNUOS charges apply:	English side French side	Full Export Fr – UK: Free Import UK – Fr: €1/MWh

- ***Notification of Capacity Limitations***

  The actual capacity available can change on a daily basis and the capacity offered in daily auctions reflects the Interconnector capacity available on that day. The amount of available Interconnector capacity for contract day D is published by 07.00 hours on the day before the auction (D-1).

- ***Curtailment***

  Capacity is sold on a non-firm basis. Users are therefore directly responsible for any trading consequences as a result of changes to Interconnector capability. For example, during outages all users have their rights to use interconnector capacity curtailed to the extent of any capacity shortage, pro rata with all other users. The user will therefore be liable to imbalance charges (positive or negative) under the BSC and the RTE Settlement Arrangements.

- ***Consistency between GB and French markets***

  Both markets trade primarily through bilateral contracts, therefore the interaction between participants is relatively straightforward. However, in both countries the spot market is relatively illiquid.

  Both markets are traded and balanced on a half hourly basis.

- ***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.

  The interconnector agent provides a fixed schedule to the GB Market Operator at 11.00 on the previous day. Thus, irrespective of the within day operations, the gate has effectively closed on the interconnector at 11.00.

- ***Interface with French Market***

  As well as the day ahead notification, RTE allows interconnection users to obtain rights for imports and exports at different times (called "Gates"). Six gates apply for IFA :

  - 20.00 on D-1 for application 4 hours later (19.00 British time)
  - 03.00 (02.00 British time), 08.00 (07.00 British time), 11.00 (10.00 British time), 14.00 (13.00 British time) and 17.00 (16.00 British time) on D for application 3 hours later.

  When total demand exceeds available capacity, RTE partially accepts the demands by curtailing them according to a prorata algorithm.

- ***Ancillary Services***

  Rules on the Interconnector do not facilitate participation in the Balancing Mechanism in Britain or 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.

  Bids on the day ahead French balancing mechanism have been possible since November 2004. The French Balancing Mechanism allows RTE to accept bids and offers for trading day D from 15:00hrs on D-1 to the last Interconnector Gate Closure on the day (there are 6 intra-day gate closures as shown in Figure 8). The User must ensure that a revised notification is submitted to National Grid.

Figure 8: Intra-day gate closures on IFA [3]

Intra-day Gate Number	Time	Period From	Period To
1	19:00 D-1	23:00 D-1	23:00 D
2	02:00 D	05:00 D	23:00 D
3	07:00 D	10:00 D	23:00 D
4	10:00 D	13:00 D	23:00 D
5	13:00 D	16:00 D	23:00 D
6	16:00 D	19:00 D	23:00 D

If RTE has accepted a bid or an offer from a User who is participating to French Balancing Mechanism, this User must submit Intra-day Nominations.

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

2.3.2 Scotland-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 Ireland	Yes
	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***

Figure 9: Proposed timings for auction

Capacity Product	Auction timing prior to relevant capacity period "CP"	
	Latest Time	Earliest Time
Annual or 2/3 Year	CP- 4 weeks	CP – 5 months
Monthly	CP- 5 days	CP - 1 month
Weekly	CP- 2 days	CP – 1 month

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.

  Since November 2007, Ireland has 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 dispatchable demand price/quantity data subject to system constraints, losses, transmission congestion, system security and reserves.

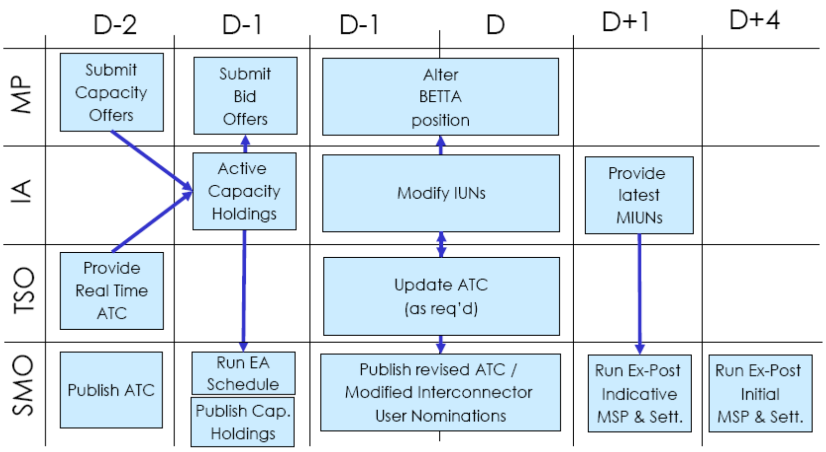
  The principle of economic dispatch will also apply to all energy entering the market via interconnection irrespective of capacity rights on the interconnector.

  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 10**.

Figure 10: 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 France – Feed in Tariff

To qualify for the feed in tariff, a renewable generator must be in France and must sell to the French TSO. Therefore the electricity must be both generated and consumed in France.

2.4.4 France – Tender

To qualify for the tender process a renewable generator must be in France and must sell to French TSO. Therefore the electricity must be both generated and consumed in France.

2.4.5 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.

2.4.6 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 Renewables Obligation. However, this only has limited export possibilities with renewable electricity generated in GB and exported to Northern Ireland, and consumed within Northern Ireland, eligible to receive ROCs.

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

  In a similar manner to exporting from GB to NI, renewable electricity generated in NI and exported to GB, and consumed within GB, 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 France or 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 either the GB-France or the GB-Ireland interconnectors to any significant extent.

2.6 Summary

Overall, the trade in variable renewable generation into and out of GB 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-France Market Constraints

Transport is sold in blocks of capacity, with the smallest "block" being 1 MW for a day. The low load factors and variability of wind generation would make this an inefficient way to transport electricity, as either there would be excess capacity or transport would be curtailed. In addition, any deviation from the nominated position would be subject to imbalance charges in GB or France. This effectively restricts the extent to which variable generation is likely to choose to use the interconnector.

2.6.3 GB-Ireland Market Constraints

The interconnector between GB and Ireland has even greater restrictions on its usefulness for variable generation due to the larger 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.

Increasing the amount of renewable generation contributing to meet the electricity demand in GB is a critical part of achieving Government's energy policy goals. There is currently around 120GW of generation capacity that is either connected (c80GW), or is seeking connection by 2017 (c40GW), excluding any potential new nuclear generation. Of this there is currently 11GW of new, mainly renewable generation seeking connection to the transmission system in Scotland, over 9GW of new connections in Wales including a significant amount of renewables, plus, for offshore wind generation, current plans to develop 8GW in UK territorial waters and an objective of achieving up to an additional 25GW by 2020.

The current framework for grid investment is proving to be insufficient to cope with this requirement for new renewable connections, with significant delays occurring to connect significant volumes (predominantly wind) of renewable generation. As a result the Government together with the regulator are undertaking a review on the best framework for the delivery of new transmission infrastructure and the management of the grid to ensure that they remain fit for purpose as the proportion of renewable generation grows. The review is expected to report its findings in May 2008.

3.1 Grid Investment

Within the GB market there are 3 different transmission owners (TO). This includes National Grid Electricity Transmission (NGET), who look after the high voltage network in England & Wales, Scottish Hydro Electric Transmission (SHETL), who manage the high voltage network in North Scotland and Scottish Power Transmission (SPTL) who manage the high voltage network in South Scotland.

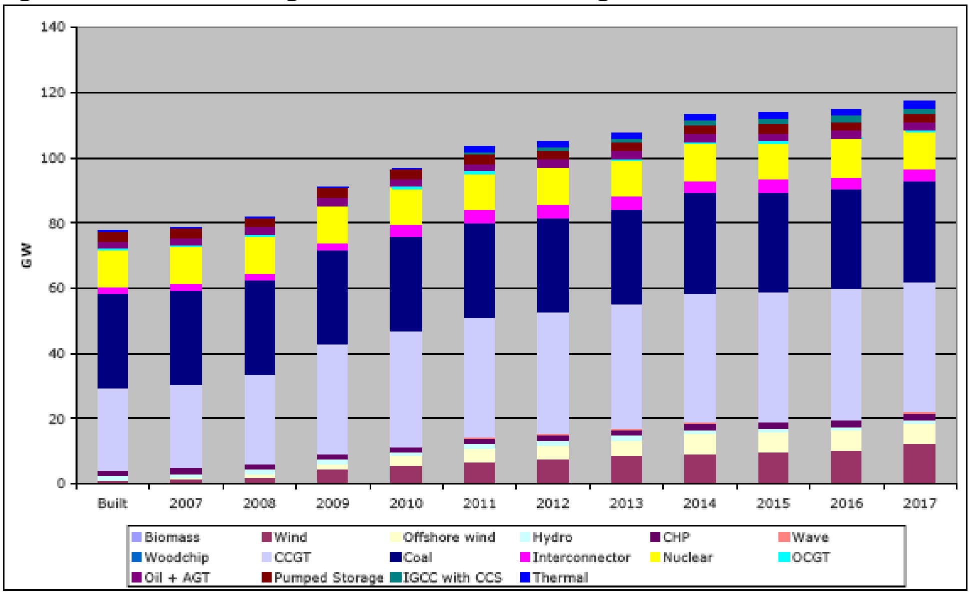
Due to their monopolistic nature they are subject to transmission price control reviews every 5 years. The regulator, Ofgem, is responsible for reviewing the price controls and determining the amount of capital expenditure over the period. The principle method of the price control is “RPI-X”, which encourages the network provider to increase their efficiency, with the gains shared between the company and their customers over time.

In the previous price control period (to 2007), responding to the wave of new renewable generation connection applications in Scotland, Ofgem published its proposals for providing funding for investment in transmission capacity to meet this demand. This provided funding for £560 million of investment to connect additional renewable generation in Scotland, and to reinforce the transmission system to accommodate flows from Scotland to England. More recently, Ofgem’s Transmission Price Control Review (TPCR) provided regulatory funding for an unprecedented £4 billion of investment in the transmission system in the period between 2007 and 2012 for connecting new generation as well as maintaining or replacing existing assets. The TPCR allowances also included a system of revenue drivers which provide flexible funding should more generation materialise than was assumed in the baseline allowances. The associated TPCR revenue allowances were accepted by transmission licensees who are now responsible for carrying out efficient investment on generation connections in the period between 2007 and 2012.

In terms of the operation of the grid system, this is managed by the National Grid, acting as the System Operator. National Grid plans the system on the basis of the contracted generation background. The contracted background includes all generation that is connected to and has applied to join the system. The volume of generation projects that are likely to come forward out of the contracted background and use the system is uncertain because not all projects will connect and incumbent generators may disconnect with limited notice.

As we move forwards towards 2020, National Grid's contracted generation background as at October 2007, including offshore wind connections, indicates that the total generation may be around 120GW in the coming decade compared to 77GW at present, as shown in Figure 11[4].

Figure 11: National Grid generation contracted background [4]



It is important to recognise that whilst there is a large volume of generation contracted to connect to the transmission system, it is difficult to assess the effect without a detailed understanding of the quantity and timing of generating capacity leaving the system - therefore the above chart overstates potential connected capacity. Under the current arrangements, information in relation to generators' intentions to leave the transmission system is inadequate, with users only needing to provide a minimum 5 days' notice to reduce their transmission entry capacity (TEC). This does not help in creating an accurate picture of the challenges that the transmission system is facing.

[4] National Grid uses 2017 as a proxy for all projects after 2016

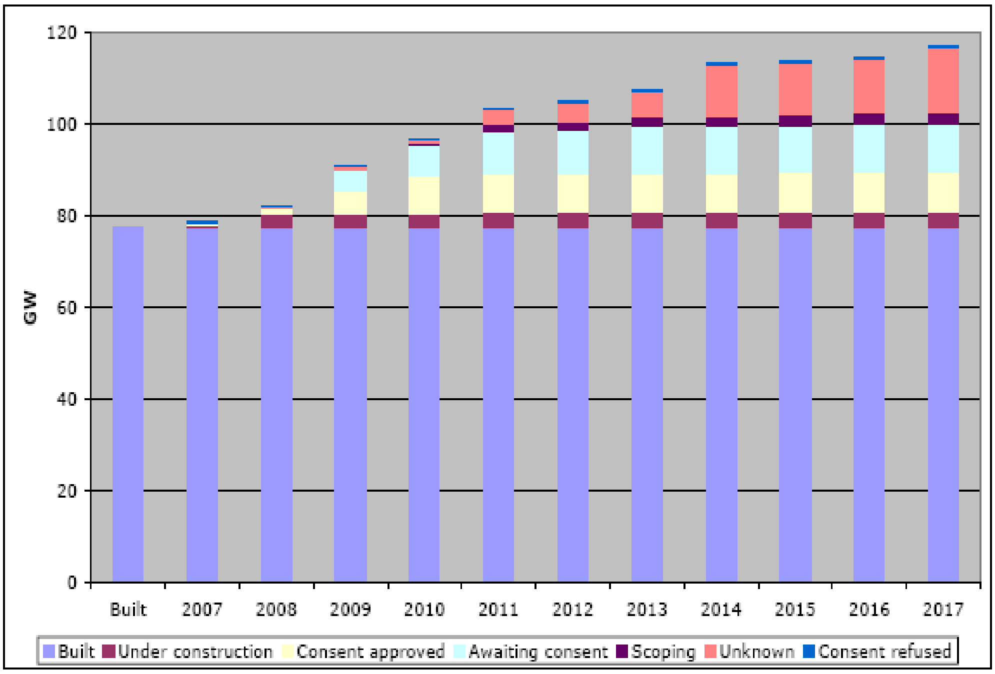
The challenge presented in building transmission for large volumes of new connections is substantial. As Figure 11 above shows, the GB contracted background implies that the transmission system will need to accommodate around 120GW of generation capacity in the coming decade. The main difficulty with planning and building against the contracted background is that various assumptions need to be made because of the lack of information about future commitment to use the transmission system.

The three transmission licensees plan and build their transmission systems recognising that a proportion of the projects that have entered the connection application process will not proceed to completion. This is because at present there is no real commitment required from generators to use the system until their transmission construction works begin. The cost of an application for a connection agreement is low, and has arguably contributed to the large queue of generation on the system.

The transmission licensees also have to build and manage their transmission systems with almost no notice of closures. This creates a situation whereby either more transmission reinforcement than necessary could be built or additional balancing actions need to be taken that could otherwise have been avoided.

To illustrate the size of the problem, the contracted background in Scotland is mostly comprised of projects that have not yet received consents, are in scoping or are unknown. Taking the case of 2009, Figure 12 shows that there is around 1GW of new generation that is due to be built in that year which has not yet even received its consents. Given the time required between projects gaining planning consent and the completion of its construction works, it is likely that the majority of this 1GW of new generation will not be built on time, and therefore the infrastructure requirements would be different to that needed to accommodate the full amount of generation.

Figure 12: Existing and future developments in GB



Stronger user commitment may allow transmission infrastructure to be built more quickly and efficiently with less risk of asset stranding. It may also be the case that transmission reinforcements under the existing approach are progressed sequentially by the licensees, could be built in parallel, thereby reducing the overall build time.

Whilst there has been significant resources allocated to building and upgrading new infrastructure, the current transmission access regime is still causing delays for renewables (and others) wishing to connect as the growth in generation capacity is exceeding the pace with which the necessary reinforcements can be built, in addition to the reasons identified above. These delays have arisen for several reasons:

- Given the scale of demand for new generator connections, the current "queue" of projects seeking to connect does not reflect the likely order that projects will be ready to connect. The current first-come-first-served approach taken by National Grid to connecting generation does not assess or reflect the status of generating projects in the queue. Resolving this issue is key in improving prospects for faster connection. In particular, new generators are often unable to get connection dates that match their project development timescales.
- Although construction times for new generation and transmission capacity are similar it can take years for planning permission to be granted to allow construction to begin on major transmission infrastructure. This has been cited by the TO's as the largest problem they face in connecting new generation.

- Existing generators have limited incentives to release or sell transmission capacity in the short-term, given uncertainty over whether they will be able to acquire it again in the future. Generators are required to give only very limited notice of their intention to close and/or disconnect from the system making it harder for the system operator to reallocate capacity quickly to other generators.
- In addition to the practical problems of the existing regime in delivering new capacity there are some process difficulties that need addressing. Recent efforts by National Grid and the industry to amend the access arrangements through changes to the industry codes have been relatively slow.
- A further problem is the quality of information regarding infrastructure plans made available between transmission licensees and generators is limited, and may result in poor or costly decisions to locate plant on the system given limited knowledge of cost and timing implications resulting from transmission factors.

Offshore Transmission Networks

The UK has significant offshore renewable resource (wind, wave & tidal). In order to connect this resource an offshore electricity transmission regulatory regime needs to be implemented in order to allow renewable generation located in the sea outside the territorial waters of Great Britain to connect to the existing onshore network.

Currently, there are plans for about 6-7GW of electricity (which represents just under 10 per cent of current generating capacity) to be developed in the sea around Great Britain, primarily from wind resources.

The Government has announced that transmission networks offshore will be subject to price controls, which will be set and reviewed by the regulator Ofgem. The new regulatory arrangements are expected to be in place in 2008.

Currently there is very little transmission network offshore, and the Government and Ofgem believe that allowing companies to compete for the right to build this infrastructure will be the best solution for both consumers and generators by encouraging efficient construction and technical innovation. Ofgem will be responsible for running a competitive tendering process to select an Offshore transmission owner who will be responsible for designing, building, financing and maintaining the transmission network.

In running the tenders Ofgem will be (subject to legislation):

- Allowed to recover its costs of running tenders from those participating in the tender process and enable Ofgem to require a financial commitment in the form of deposits and financial security from those parties; and
- able to make a property transfer to ensure that property, rights and liabilities are transferred from the developer to the successful OFTO. Ofgem will only have the power to make a scheme in certain circumstances

and upon application (which it is envisaged will arise when commercial negotiations fail, in order to ensure that property is transferred from the developer to the successful Offshore Transmission Owner in a fair, timely and effective manner).

Whilst the regulation and rules have not yet been finalised and work is still ongoing a number of guiding principles have already been established:

- The regulated revenue stream is fixed for a period of 20 years, with the revenue stream subject to performance incentives which would include capacity delivery, availability and incentives for losses.
- It is proposed after the end of the licence term, that the licence will be re-tendered out. However, in cases where this is not suitable (e.g. the generator continues to operate for a short number of years only) a review on a case by case basis will be undertaken.
- Additional incremental investment of up to 20% of the initial capital cost can be undertaken without re-tendering (post-construction). The revenues for the recovery of costs associated with the increment would not be subject to the price control.
- A licence will be required to transport electricity generated in offshore waters to onshore. The offshore transmission operator should also be established as a separate legal entity.
- Generators would establish the specification for the offshore transmission assets. This may vary above the security standards.
- Risks relating to transmission assets would be shared amongst the transmission owner, generator and consumers. Users of the network would provide payment security via the GB System Operator.

3.2 Planning & Security Standards

The GB transmission systems is planned, developed and operated in accordance with the GBSQSS (Security and Quality of Supply Standard) as specified in the transmission licences. The GBSQSS sets out the criteria that the transmission licensees are required to apply when planning investment in their networks and operating the transmission system. The standard was established for a power system predominately supplied by conventional generation.

For the planning stage, the GBSQSS defines the range of system conditions including the demand and generation background to be assessed and the events for which the transmission system is required to be secure. These conditions must be applied when designing transmission network infrastructure and connections to it. Similarly, the operational criteria in the GBSQSS define the range of system conditions to be assessed and the events for which the transmission system is required to be secure. The operational criteria are closely related to the planning criteria but also provide additional flexibility to manage actual system conditions approaching and during real time operation of the transmission system (e.g. to accommodate planned or forced outages on the transmission system or on plant or systems connected to the transmission system).

The rules defining the system conditions and events to be secured in both planning and operational criteria are deterministic in nature. More specifically, the events that are secured generally involve two pieces of primary transmission equipment being out of service. Therefore, the GBSQSS is commonly known to be based on N-2 deterministic criteria in planning and N'-D deterministic criteria in operation, where N denotes an intact network with all transmission equipment in service, N' denotes a network with prior outages of transmission equipment due to maintenance or faults, and D denotes a narrower definition of outage of two circuits, i.e. that of two overhead line circuits strung on the same towers.

National Grid's security standard had been subject to a thorough review in the mid 90's, where alternative criteria such as N-1/N'-1 instead of N-2/N'-D, or probabilistic instead of deterministic, were considered but rejected due to potential concerns regarding higher risk of security and reliability of supply, and/or complexity and uncertainty in application.

A major question, and one that is currently being asked, is whether the existing standards remain fit for purpose in a world with a high volume of intermittent generation connecting in remote parts of the network. As a result the 3 transmission owners are undertaking a review of the current security and quality standards and whether they are applicable to variable renewables. They are expected to report their findings at the end of March 2008. A number of different (5) approaches are being investigated. This includes:

- **Approach one - Current GB SQSS Approach.**

  The calculation of the required transmission capability is based on two components, namely; the 'planned transfer' and the 'interconnection allowance'. Capabilities are determined for N–1 and N–2 outage conditions to ensure system robustness against credible contingencies. Transmission capability requirements are specified on a boundary basis where a boundary can be drawn anywhere on the system, provided it divides the transmission system into two contiguous parts and the minimum ACS (average cold spell) peak demand on either side of the boundary is 1500MW. The latter condition relates to the application of the interconnection allowance. For N–1 outage conditions the required boundary capability is defined as the sum of the planned transfer and the full interconnected allowance. For N–2 outage conditions the required boundary capability is defined as the sum of the planned transfer and half the interconnection allowance.

  Wind generation is treated like any other generation except that a lower availability factor is used. To date, most of the transmission-connected wind generation has been in Scotland and the transmission licensees have determined an availability factor (AF) of 72% for wind to be used for the calculation of planned transfer in the GB SQSS. This availability factor translates to a wind generation output of around 60% in the planned transfer condition. The availability factor for conventional generation has been traditionally taken to be 100%, leading to an output of around 83% in the planned transfer. This approach is supplemented by cost benefit analysis to cover cases where transmission capabilities greater than those required solely for demand security are needed for economic reasons.

- **Approach two - Security approach supplemented by cost benefit analysis (most favoured approach – currently)**

  Studies have been conducted to investigate the security driven component of transmission capability requirements. The fundamental premise is that transmission should not unduly restrict generation from contributing to demand security during the time of peak demand. This is also an underlying principle of the GB SQSS. Starting with a given risk that there would not be sufficient generation available on the entire system to meet demand during the time of winter peak, transmission capability requirements are determined so as not to significantly increase the risk of failing to meet demand beyond that due to generation unavailability. This approach is supplemented by cost benefit analysis to cover cases where transmission capabilities greater than those required solely for demand security are needed for economic reasons.

- **Approach three - Membrane approach supplemented by cost benefit analysis**

  This is a security approach based on transmission requirements for demand security supplemented by cost benefit analysis. The development of the security approach is based on a two-step process of benchmarking and characterisation of the required boundary capabilities. Benchmarking involves determining the performance of the GB SQSS for a system with very little wind to establish a benchmark index, determined in this case as the demand reduction probability.

  For future scenarios with wind generation of varying penetrations; the transmission capability requirements are determined so as to maintain the same benchmark indices. Characterisation of the required capabilities is performed with respect to known quantities like installed conventional wind and conventional generation capacities, wind penetration, demand, etc.

- **Approach four - Generation equal access supplemented by cost benefit analysis**

  Approaches Two and Three are founded on the principle that the sole purpose of the interconnected transmission system security standard is to achieve a certain level of demand security. As a consequence, these approaches are seen to deliver a lower requirement out of small-to-medium sized exporting groups than the current standard. This fits with the observation that the original circle diagram is symmetric between demand and generation. For example, it requires the same level of transmission capability out of an exporting group of 20% national generation and 10% national demand, as it does into an importing group of 10% national generation and 20% national demand.

  The demand security approaches do not pick up this aspect of the current GB SQSS, and the current standard embodies an aspect, that part of its purpose is to provide sufficient transmission to enable remote generation to access the transmission system. This access for remote generation is in some sense equal with that for more central generation.

- **Economic Approach**

  The working group did not propose to carry out a full economic appraisal. That would be an onerous exercise, requiring extensive transmission studies to determine boundary capabilities, both of the planned system and of a suitably reinforced system, and also extensive economic studies of the year-round running of the entire generation fleet, to determine constraint estimates. Instead, the much simpler model was developed which illustrates the principles arising in practical economic studies.

  The model was run with boundary capabilities derived from the different candidate approaches to determine the level of constraints and ultimately constraint costs, which were then compared against transmission reinforcement costs. It was concluded that the purely economic approach is unsuitable for the main approach to transmission planning due to the sensitivity of the cost benefit to a large number of input parameters. However, it is clear that the costs of transmission are generally relatively cheap compared to the costs of constraints. When the fraction of wind capacity being used in Approach One is considered against the constraint cost, the economic range for this fraction is of order 70-80%.

3.3 Transmission Access & Charging

It is recognised that there are a number of limitations associated with the current transmission access arrangements, and as a result the Government together with the energy regulator is currently undertaking a review, with an emphasis on how to increase the proportion of variable renewable generation connecting to the electricity networks to enable the Governments' renewable energy targets to be met.

Historically, the transmission system has been planned and developed using a system of "invest then connect", which means that if the connection of a new generator leads to the need for investment in the wider network, the generator is not allowed to export power onto the system until this reinforcement work is complete. As a consequence, there can be circumstances where generators are physically able to export onto the system, but delays to wider reinforcements prevent them from doing so.

The discussion below describes the current status of transmission access and charging arrangements.

3.3.1 Grid Code Requirements

Connection to the transmission system requires meeting grid code requirements. Although there can be derogations from some of the requirements, there are not class derogations for renewable generation. This means that renewable generation may have to be designed to meet grid code requirements such as the capability to provide mandatory levels of frequency response.

3.3.2 Transmission Connection

The GBSO has a licence obligation to provide a customer with an offer of connection within a defined timescale, this is dependent upon the type of agreement the customer has applied for and whether any works are needed to facilitate the connection. The connection date that will be offered to a customer will be dependent on the location and the types of works that will be needed to facilitate the connection.

A significant amount of transmission reinforcement is required to allow access to much of GB's renewable resource base, and so the availability of transmission is proving a significant delay to the development of renewable generation projects.

Renewable generation is not treated differently to conventional generation, and so does not get preferential treatment in terms of grid access or connection dates. In addition there are broadly the same security standards required for connection of renewable generation, as conventional generation, despite the fact that the output profile of projects such as wind could be very different from that of conventional generation. However, there are ongoing discussions on how security standards for renewable generation could be developed to avoid them being more rigorous than reasonably required.

3.3.3 Connection Charging

The capital costs, operation and maintenance associated with the connection assets are charged to the generator via an annual fee. This only covers the shallow connection, with any transmission reinforcement costs (deep connection costs) socialised and recovered from all market participants through Transmission Charges (see section 3.3.5).

However, once a generator has entered into a connection agreement with the GBSO it may be required to provide financial security against the deep transmission system reinforcement works identified in its bilateral agreement. The financial security regime is designed to provide the transmission owner some protection from the risk of stranded assets if the project does not go ahead.

The shallow connection regime provides renewable generators significant protection against being exposed to the costs of significant deep transmission reinforcement work, which in practice is likely to be shared over a number of renewable generation projects. However, the financial security required by the transmission owner has in some cases been significant which has been problematic especially for relatively smaller generation projects. However, there is ongoing work to further develop the financial security regime, which could reduce the financial requirements on generation projects.

3.3.4 Transmission Access

Transmission Entry Capacity (TEC) provides a generator firm access to the transmission system. A generator cannot export more than their TEC. TEC is technology neutral and so variable generators who may only achieve their TEC at certain times in the year will be charged their full TEC value irrespective of whether they are able or how often they are able to achieve TEC. A generator has to pay transmission charges based upon their TEC, but as long as they maintain payments then they are guaranteed to maintain their right to TEC.

A generator can reduce TEC levels (thereby reducing transmission charges), but would not be guaranteed to be able to increase TEC in the future. Recently a short term firm access Short Term Transmission Entry Capacity (STTEC, 1-2 weeks) and Limited Duration Transmission Entry Capacity (LDTEC, 7-45 weeks) access products have been introduced.

However, broadly renewable generators are likely to have to reserve and pay for firm access to the transmission system based upon their maximum generation export. This can place a significant financial burden on variable generation such as wind.

- **Temporary TEC exchanges**

  A modification to the way in which TEC can be treated was recently made. It allows existing users to trade their capacity on a temporary, within year basis for variable periods of time as defined in a bilateral agreement, subject to an appropriate exchange rate being determined by NGET. This capacity leasing may allow any unused or underused capacity to be transferred between existing users and maximise the use of the transmission system.

  This flexibility may allow both generators and the wider market to respond to unanticipated events, such as a plant breakdown, in a more efficient manner. Whilst the modification is mainly based for large generators being off-line for a period of months it could, in principle at least, be used for higher granularity trades.

3.3.5 Transmission Charging

Transmission Network Use of System is the transmission owner charge for the transmission assets. Generators have to pay TNUoS based upon their TEC (normally generation capacity). TNUoS is charged on a zonal basis, with Great Britain being divided into 14 zones for the purpose of demand TNUoS charging, and 20 zones for generation TNUoS charging. It is possible for generation charging zones to change each year. Demand charging zones do not change. Each year National Grid calculates a TNUoS tariff for each generation and demand zone. These tariffs vary across Great Britain and are designed to encourage demand and generation to locate in a manner that reduces peak power flows on the transmission system. This means that the tariffs will vary year by year as the configuration of demand and generation in Great Britain changes. For example, because peak power flows tend to be from north to south, generation TNUoS is highest in Scotland and lowest in the South of England. The converse holds for demand TNUoS.

The locational differences in Generation TNUoS are significant ranging from -£8.56/kW to £21.59/kW for the period from 22nd June 2007 to 31st March 2008 (a negative value indicating that generators are paid TNUoS). A significant amount of the renewable resource is located in the more expensive TNUoS regions, increasing the costs associated with renewable generation.

ANNEX A – ABBREVIATIONS

Acronym	Definition
ACS	Average Cold Spell
AF	Availability Factor
ATC	Available Transfer Capacity
BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
CCL	Climate Change Levy
CHP	Combined Heat and Power
EC	European Commission
EU	European Union
FPN	Final Physical Notification
GB	Great Britain: includes England, Scotland and Wales
GB SQSS	Great Britain Security and Quality of Supply Standard
GW	Gigawatt = 1,000,000 kW (unit of power/ capacity)
IA	Interconnector Administrator
IEA	International Energy Agency
IFA	Interconnexion France Angleterre
kW	Kilowatt = 1,000 Watts (unit of power/ capacity)
kWh	Kilowatt hour = 1,000 Watt hours (unit of energy)
LDTEC	Limited Duration Transmission Entry Capacity
LEC	Levy Exemption Certificate (exemption from the Climate Change Levy)
MI	Market Index
MO	Market Operator
MW	Megawatt = 1,000 kW (unit of power/ capacity)
MWh	Megawatt hour = 1,000 kWh (unit of energy)
NG	National Grid
NGET	National Grid Electricity Transmission
NI	Northern Ireland
OTC	Over The Counter
PN	Physical Notification
REFIT	Renewable Energy Feed In Tariff (Eire)

RES	Renewable Energy System
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
RTE	Resaeu de Transport d'Electricite
SEM	Single Electricity Market
SHETL	Scottish Hydro Electricity Transmission Ltd
SMO	Single Market Operator (in the all-island market)
SO	System Operator
SONI	System Operator of Northern Ireland
SPTL	Scottish Power Transmission Ltd
SBP	System Buy Price
SSP	System Sell Price
STTEC	Short Term Transmission Entry Capacity
TEC	Transmission Entry Capacity
TPCR	Transmission Price Control Review
TNUoS	Transmission Network Use of System
TSO	Transmission System Operator
UK	United Kingdom: Includes England, Scotland, Wales and Northern Ireland

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.
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)
Superposition	Superposition is a mechanism which nets trades in either direction of an interconnector. It is a congestion management tool, which allows the commercial capacity of the interconnector to exceed its physical capacity.
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
"Use it or lose it"	Any capacity that users indicate will be unused, the interconnector operator will make available. The original user will still be required to pay for the capacity and will not receive any proceeds from the auction.
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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