Recent Changes in the Electricity Markets in the UK

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ABSTRACT

In 1990 the Electricity Generation and Supply Industry in the UK was privatised and there followed a period of 11 years when only the Generating Companies bid into an Electricity Pool. The generators effectively set the price paid by the Supplier, and in turn the price paid by the consumer. During this period there was the need for a strong regulator to ensure price fixing did not take place. Deregulation of the supply side of electricity followed in stages and by late 1999 all consumers in England and Wales could purchase their electricity from any Supply Company, not just the regional supply company which had held a monopoly until that time.

Following privatisation, there was a period of general stability in the companies involved in generation and supply, but since 1995 there has been increasing activity with mergers and demergers. Some of these structural changes have seen companies specialising in one aspect of generation, distribution or supply, while others have seen vertical integration of companies. In 2001, the New Electricity Trading Arrangements (NETA) came into force, which involves both bilateral trading agreements and both generating and demand side bidding into the Balancing Mechanism Market which ensures security of supply. In the first year of trading the wholesale prices fell by 20%, which was on top of a 20% fall in the latter years of the Pool System. However, in the last 9 months since the middle of 2003, the prices have risen sharply in response to changing gas prices, and are now higher than at the onset of NETA.

Other changes in Electricity Supply have taken, or are currently taking, place which are also having an impact on the tariffs now paid. In particular the introduction of the Renewables Obligation and the recently announced Carbon Emission Trading are likely to impact on the future prices of electricity. This paper reviews these recent changes and expands on the general review of the last 20 years given in a similar paper last year (Tovey, 2003).

INTRODUCTION

For the last two decades, the total UK demand for electricity has been rising at 1.8% per annum, and in the last few years this rate has increased to over 2%. The net demand for the whole UK stands at 370 TWh per year (DTI, 2003). Of this figure, just under 50 TWh was generated in Scotland (Scottish Executive, 2003) with just under 20% transferred south of the border to England and Wales. Historically, the structure of the electricity supply industry in Scotland has always been different from that in England and Wales. In Scotland, both before privatisation on 1st April 1990 and since that time, there have been two vertically integrated companies, which have covered all aspects of electricity from generation, through transmission and distribution, to supply of electricity to customers. Initially, the companies were State Monopolies, covering specific regions of Scotland, and since that time there have been two privatised companies – Scottish Power and Scottish Hydro-Electric. The latter is now part of the Scottish and Southern Group.

Before privatisation there was a single Generating Company (Central Electricity Generating Board: CEGB) in England and Wales which generated and transmitted electricity but did not sell electricity to consumers. Instead the CEGB sold the electricity to 12 regional Electricity Boards who distributed and supplied electricity to consumers only within their region. The situation prior to privatisation is summarised in Fig. 1 while details of the different Regional Electricity Boards are shown in Fig. 2.

Historically there has always been a surplus of generation capacity in Scotland, which is transferred via inter-connectors to England and Wales. In 1990 8% of the electricity generated in Scotland was transferred to England and Wales, but this rose to 25% by 2000 (Scottish Executive, 2003). Until recently there has been no grid connection to Northern Ireland, although a 2000 MW DC link to France has been in operation since the mid 1980's. Currently, further inter-connectors to Norway rated at 1320 MW and to the Netherlands, also of 1320 MW, are under consideration.

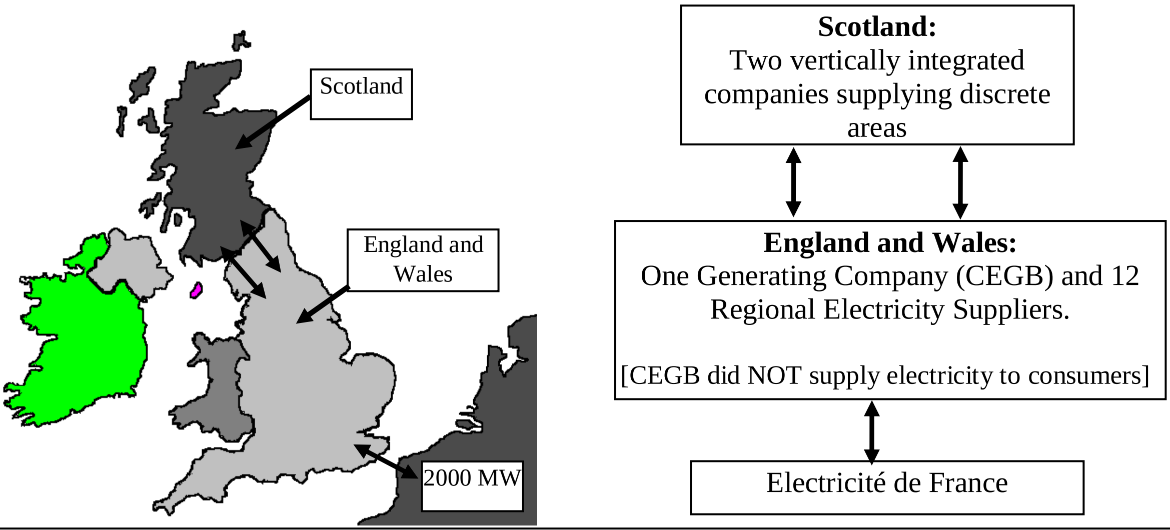


Fig. 1 Summary of Electricity Supply in UK before privatisation

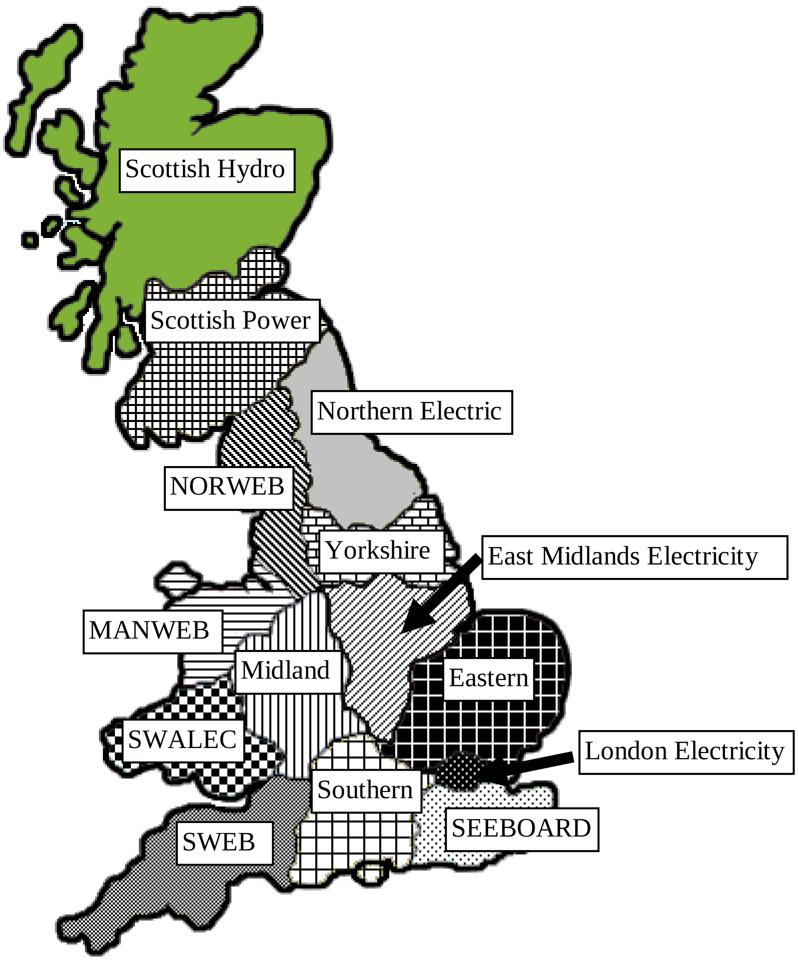


Fig. 2. The Regional Electricity Companies (REC) at the time of privatisation in 1990. Both Scottish Power and Scottish Hydro were vertically integrated with generation and supply. In England and Wales, the companies only supplied electricity, none generated electricity.

While there are normally major flows of electricity from Scotland to England and Wales, there are also significant flows of power south of the border. This is because the majority of the generation is in the north and most of the demand is in the south. Since 1990, when coal represented 65% of the generating capacity with oil at 11%, nuclear at 21% and gas less than 1%, the proportion of fuels used has changed significantly as shown in Table. 1. While the total nuclear generation in the UK is just over 20%, in Scotland it is over 40%. With 10% hydro generation in Scotland only 50% of electricity generation comes from fossil fuels.

Table 1. Fuel used in the generation of Electricity in the UK

	1990 (at privatisation)	2001 (at start of NETA)	2002	2003
Coal	62.9%	37.4%	35.4%	38.1%
Oil	10.6%	1.7%	1.5%	1.9%
Gas	0.7%	31.5%	33.6%	31.6%
Nuclear	20.5%	24.5%	24.3%	23.7%
Hydro	0.6%	0.4%	0.5%	0.3%
Other Renewables	1.1%	2.3%	2.5%	2.7%
Other Fuels		1.2%	1.3%	1.5%
Imports (France)	3.8%	1.1%	0.9%	0.2%

After a prolonged period of reduction in the use of coal, there was a significant shift in 2003 with an increase in the amount of coal burnt and a consequential reduction in gas burnt in the generation of electricity. At the same time the proportion of electricity obtained from France has declined and for the first time, the UK was a net exporter of electricity in the third quarter of 2003. The total generation of electricity from renewable resources was 3%, well short of the UK Government target of 4.3% for 2003.

During the 1990's, the UK was one of very few countries which saw a substantial drop in emissions from carbon dioxide. This was almost entirely due to the change in fuel mix for the generation of electricity. In the last few years, this trend has reversed and though emissions are still well below 1990 levels, the rises call into doubt the UK's ability to meet it's target reductions by 2010. Indeed in 2003, a rise of 5% occurred in the electricity supply industry. The UK National Allocation Plan published at the end of April 2004, will have severe impacts of the Electricity Supply Industry. The Plan allocates a 16.4% reduction in emission for this industry from 2002 levels, the largest reduction of any industry in the UK.

In the UK, unlike Russia, there is very little centralised combined heat and power (CHP), and none is associated with the major electricity companies. There is no infrastructure to deal with city-wide schemes for heat supply, nor is there any likelihood that large city wide schemes will now be built in the UK. There are, however, many small institutional CHP schemes in Universities, Hospitals etc, but these mostly have capacities less than 10 MW, with an average size of just 650 kW. Unlike Russia, there are no central heating facilities for towns and cities – each building generally has its own heating supply.

Unlike all other countries, the nuclear generation is provided by reactor types unique to the United Kingdom. With the exception of one pressurised water reactor (PWR), the nuclear reactors are all gas cooled and are either of the older MAGNOX variety or the new Advanced Gas Cooled Reactor (AGR). The MAGNOX reactors are now approaching 40 years in age, and most of these will be closed within the next 5 years. Currently there are no plans to build new nuclear reactors in the UK.

In the UK, the transmission and distribution of electricity are considered separately. In England and Wales, normally only transmission of electricity at a voltage of 275 kV or above is considered as transmission. Distribution represents the supply of electricity at voltages of 132 kV and below, and this is the responsibility of the relevant Distribution Network Operator (DNO). In the first five or so years of privatisation, the responsibility for distribution was identical to the Regional Electricity Company as shown in Fig. 2. (i.e. the REC and DNO were one and the same). Transmission was the responsibility of the System Operator, the National Grid Company. In Scotland, the two vertically integrated companies had the responsibility for both transmission and distribution, and the demarcation between transmission and distribution occurred at a voltage of 132 kV (rather than the 275kW in England and Wales.

PRIVATISATION AND THE POOL

The method by which the generating side of the Electricity Industry in the UK was privatised and the operation of the Electricity Pool, including some of the unusual aspects of the determination of the System Marginal Price (SMP) were described in detail by Tovey (2003). These aspects are summarised briefly here and in Fig. 3. The Pool only operated in England and Wales; two vertically integrated companies continued operation in Scotland.

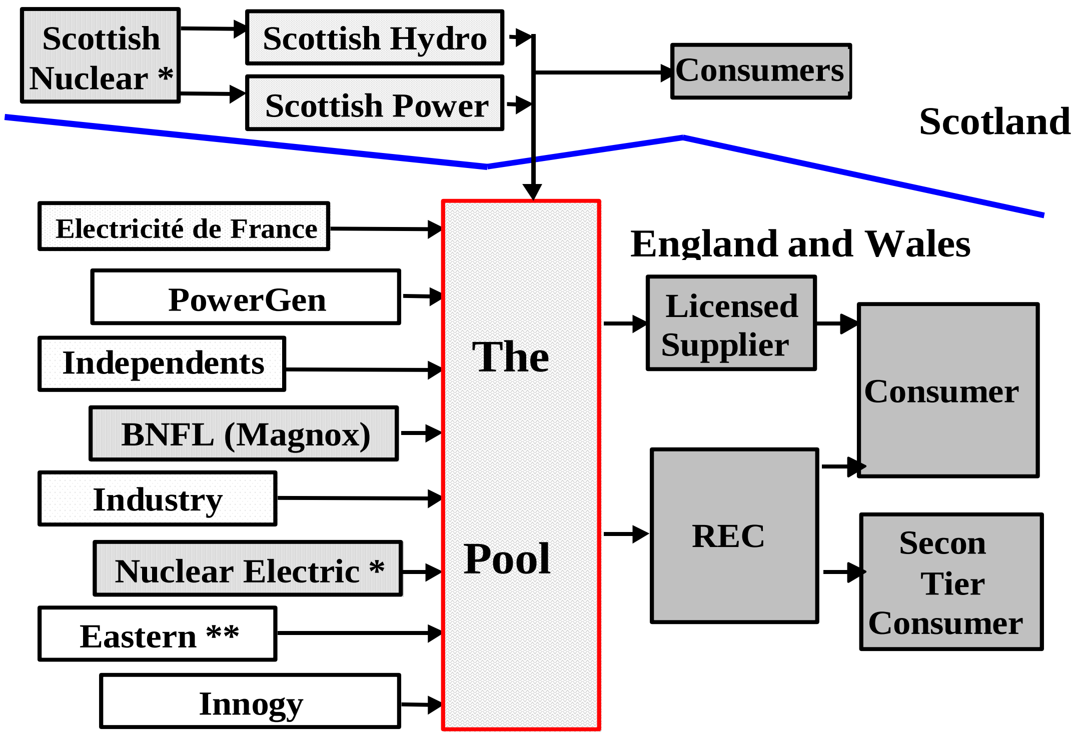


Fig. 3. A Schematic of the POOL in the UK in the late 1990s. The actual list of generators varied from year to year, the situation represents the position in about 1998.

In England and Wales a Pool system operated in which generator side bidding took place. While this was a major step forward, and ahead of deregulation in most other countries, there were deficiencies. Though many new independent generators entered the market, the original triopoly of PowerGen, National Power, and Nuclear Electric dominated the bidding, and there was evidence of price fixing. This caused the Regulator (initially OFFER, and later OFGEM) to step in an effectively fine the companies by requiring them to dispose of some of their generating capacity. As a result further players entered the market (Fig. 3). There were no effective controls, other than those imposed by the Regulator, on the System Operator (the National Grid Company) and thus there was no incentive to minimise costs through the optimum dispatch of electricity. The lack of demand side bidding into the Pool System was also another major weakness. As a result of these deficiencies, the New Electricity Trading Arrangements were introduced on 27th March 2001. Once again, these only applied to England and Wales, although there are discussions at an advanced stage with a view to including Scotland in an extended version of NETA in the so called British Transmission and Trading Arrangements (BETTA).

During much of the 1990's there were two separate Regulators: OFFER (Office of Electricity Regulation) and OFGAS (Office of Gas Regulation). Recognising the important link between Gas and Electricity, the two separate Regulators were merged into OFGEM (Office of Gas and Electricity Markets) in June 1999. At the same time, it was appreciated that there could be a conflict of interest between the duties of the Regulator and its responsibility in consumer protection. As a result a new body, ENERGYWATCH, was established as a result of the Utilities Act in 2000. Both OFGEM and ENERGYWATCH work closely together and their respective roles are defined in the "Memorandum of Understanding". In 2002 the electricity system operator, National Grid Company (NGC), merged with the corresponding gas operator (TRANSCO) to form National Grid Transco (NGT).

While the distribution charges varied from one region of England and Wales to another, the transmission charges were shared uniformly across the transmission network. This meant that customers in the north were effectively subsidising those in the south, while generators in the south were subsidising those in the north.

THE SUPPLY SIDE OF ELECTRICITY AFTER PRIVATISATION.

There have been two distinct stages in the supply of electricity since privatisation in 1990. Though large consumers (>1MW) were able to choose any licensed supplier from 1990, and medium consumers (> 100kW) from 1994, it was not until 1999 that domestic consumers could choose their supplier. Though a few changes in the structure of the supply companies took place before 1999, there have been substantial changes since that time. Some of the more notable changes which took place in the early years of privatisation were (i) the acquisition of East Midland Electricity by the generator PowerGen;, (ii) the take over of supply in the Merseyside and North Wales area (MANWEB) by Scottish Power; (iii) the merger of Scottish Hydro-Electric and Southern Electricity into the Scottish and Southern Group; (iv) the demerger of the generator National Power into International Power and Innogy, with the latter taking on responsibility of supply in the Midlands Electricity Area under the name of nPower. Finally in the NORWEB area there was an amalgamation of all utilities into the company United Utilities. The situation over ownership in the mid to late 1990s is shown in Fig 4, which should be compared with Fig. 2. It should be noted that the geographical areas remain the same.

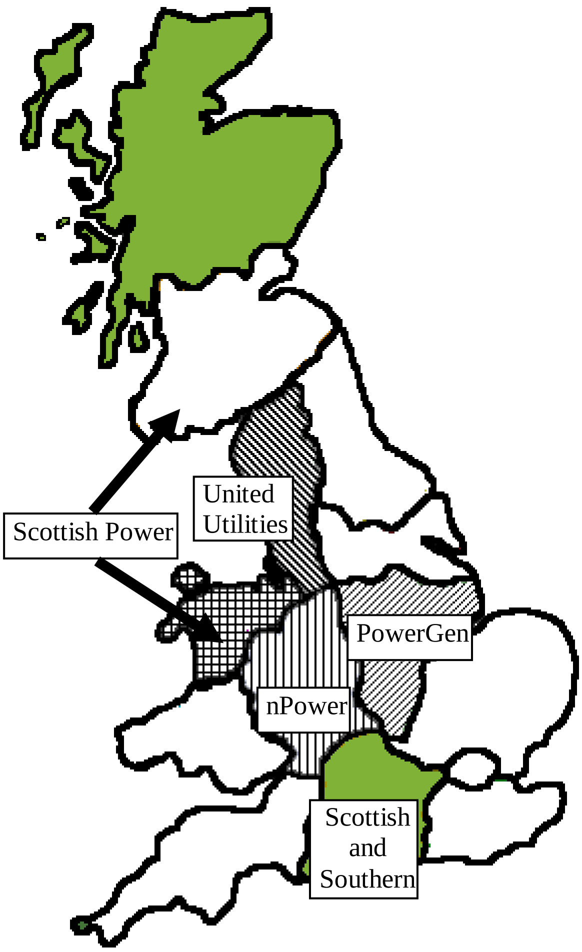


Fig. 4. Changes in the Distribution Companies during the 1990s. The white areas represent areas with no change.

Prior to Deregulation in 1999 the price charged for the domestic customers (which did not benefit from competition at the time) was regulated by the formula:

$$RPI - X + E + F,$$

where

RPI represents the Retail Price Index (i.e. a measure of the inflation from one year to the next),

X was a factor set by the regulator which initially was 5 – 8%, but reduced progressively,

E was the efficiency factor which companies were permitted to charge provided the income so received was transferred into an Energy Saving Trust for conservation measures.

F represented the fossil fuel levy, which was initially set at over 10%, but reduced to around 2% by the late 1990s and then was phased out fully. This levy was initially (until 1998) used to subsidise nuclear power, but the reduced levy in later years was used to promote renewable energy resources. As a result of the F factor, the prices of electricity immediately after privatisation rose slightly, but by Deregulation in 1998, prices were cheaper to the domestic customer in real terms despite the imposition despite the addition of VAT (Value added Tax) in 1994.

Since deregulation, the above formula was progressively relaxed during a transition period.

DEREGULATION OF ELECTRICITY SUPPLY

The Electricity Supply in the UK was deregulated for all 20 million domestic customers over a period of nine months from 5th September 1998. After Deregulation, all customers had the choice as to from whom they could purchase the electricity. In many cases, the alternative suppliers were other Regional Electricity Companies, although there emerged an increasing number of independent companies for whom there was no historic geographical base. Many of these new companies have suffered in an increasingly competitive market and some have gone into receivership such as the recent case of Atlantic Electricity and Gas.

Switching suppliers in the early years did result in significant savings. For example, the following illustrates the changes as experienced by the author. In mid 1998 he was paying 7.48 p per kWh for his electricity (about 3.7 roubles). In April 2003, the price was 5.62p (about 2.8 roubles). However, this magnitude of reduction was only achieved by those customers who changed suppliers. Those who were reluctant to change, or could not be bothered to change, have seen only limited savings. In late 2003 and early 2004, many suppliers have increased their prices in response to significantly increased gas prices, but the unit price is still well below those paid in 1998.

A large number of tariffs are available and many companies are targeting a niche market. Thus some companies supply electricity with a relatively high fixed charge and a lower unit rate, while others supply electricity with no fixed charge and a relatively higher rate. Clearly the latter tariff favours the low consumer while the former favours the larger consumer. Thus in any one area, there is generally no one single company which is best for all consumers. Some tariffs are termed “Green Tariffs” as these are designed to promote renewable electricity. In many cases these tariffs are at a slightly higher price than the normal standard tariff. Some companies encourage payment by the internet by having reduced tariffs, while some of the newer non-geographic companies only trade over the internet.

Within a consumers bill there are effectively three component parts, but the separate information is not indicated on the bills sent to customers. This lack of transparency as to the composition of charges is probably a defect in the UK system. Although some also argue that most domestic customers are not interested in anything but the total price. These three components are:-

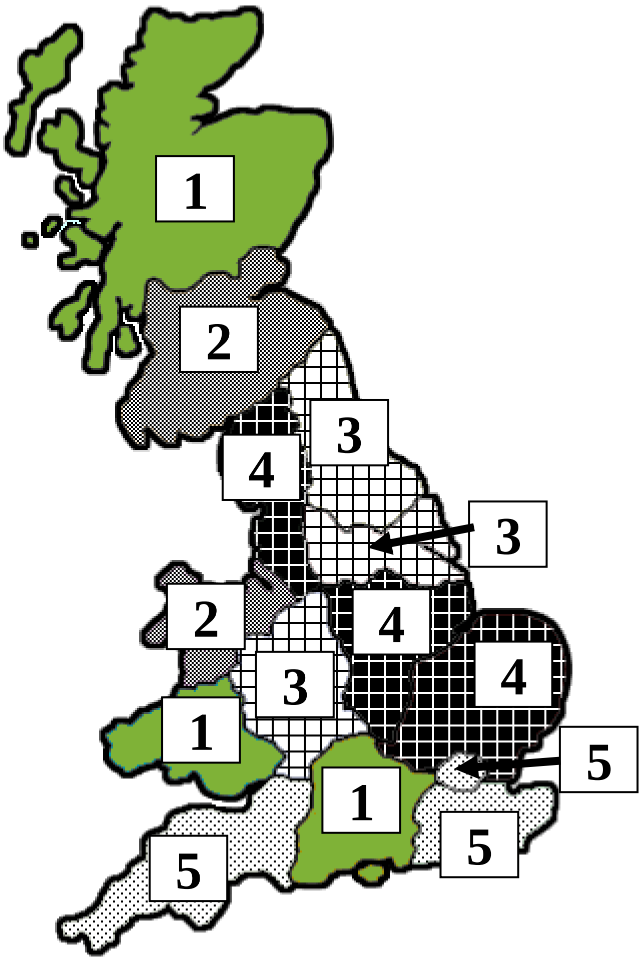
i) an actual charge for the units used,
ii) a charge for use of the local distribution network. This charge will be the same for all customers within one regional area. The charge is also the same for all electricity suppliers in that area,
iii) a charge for the meter reading.

Until deregulation, all three of the components were charges by the local Regional Electricity Company, but in the last 5 years there have been substantial changes. Thus there has been the emergence of specialist meter reading companies with one company, Siemens Metering representing 50% of the total Meter Reading Market.

In the last few years there has been a significant change in ownership in many of the supply companies. Increasingly there has been involvement from overseas companies from France, Germany, and the United States. One of the earlier such changes was the take over of the Eastern group with its supply base in the East of England by the American firm TXU. During the privatisation period, the Eastern Group had become more vertically integrated with the purchase of several coal fired power stations from PowerGen and National Power. However, most of these stations were amongst the oldest such stations and consequently the least efficient. With the onset of the New Electricity Trading Arrangements (NETA – see below), and an increasingly competitive market, the wholesale price of electricity fell to 40% below the 1998 level. This caused significant trading difficulties to many generators, and partly for this reason TXU ceased trading. While its supply business was taken over by PowerGen, as was one coal fired station, the distribution network operations were taken over by the London Electricity Group, who by that time had become part of Electricité de France.

Other mergers and take-overs took place in the supply industry with Electricité de France becoming the parent company of both SEEBOARD and SWEB in addition to London Electricity. PowerGen further increased its supply geographical base by taking over the supply business of United Utilities (formerly NORWEB). At the same time, nPower (the supplier in the Midlands Area), took over the geographical supply base in the former Yorkshire and Northern Electricity areas, while Scottish and Southern (formed originally from the merger of Scottish Hydro and Southern Electricity) also became responsible for SWALEC (the company in South Wales). The current situation in 2004 is represented by Fig. 5.

While distribution charges have always taken account of regional differences, differential transmission charges are also now in place as indicated below. However, the transmission charge for demand is the same throughout any one of the geographic areas, which remain the same as they were prior to privatisation. It should be noted that though there is a dominant company in each area, all the groups have customers in most of the different regions. Usually it is found that customers who are with companies other than their geographic company pay less than those who have tariffs with their local company.



Electricity Supply Areas in 2004

1. Scottish and Southern Group: now supplies in following geographic areas:
   - Scottish Hydro Electric
   - Southern Electric
   - South Wales (SWALEC)

2. Scottish Power Group: now supplies in following geographic areas:
   - Scottish Power
   - MANWEB

3. nPower: now supplies in following geographic areas:
   - Midlands
   - Yorkshire
   - Northern

4. PowerGen: now supplies in following geographic areas:
   - East Midlands
   - Eastern
   - NORWEB

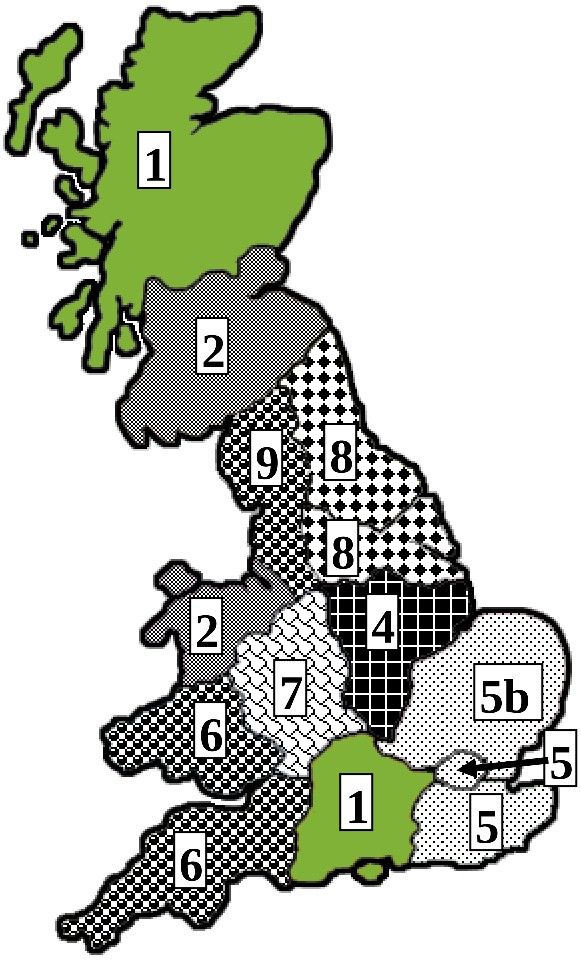
5. Electricité de France: now supplies in following geographic areas:
   - London
   - SEEBOARD
   - SWEB

Fig. 5. The situation in 2004 with regard to geographic supply areas. This figure should be compared with figures 2 and 4 to see changes in the last 14 years. The companies in areas 1 and 2 are UK owned while the parent companies for areas 3 and 4 are both German owned, and the parent company for areas 5 is French.

Some of the recently formed non-geographically based companies have been taken over by the geographically based companies. In a few cases this has been because of financial difficulties experienced by these companies – for instance, Atlantic Electricity and Power recently went into receivership and its operations were taken over by the Scottish and Southern Group.

CHANGES IN DISTRIBUTION NETWORK OPERATION

A further significant change has also taken place in respect of the distribution of electricity as shown in Fig. 6. Whereas it was the norm for the regional supply company to also be the Distributed Network Operator (DNO) until the late 1990s, it is clear that in many areas supply companies are concentrating on core business and disposing of the network operations. It is noteworthy that now only seven of the fourteen areas have the same company for both supply and distribution. Some companies like PowerGen are the network operator in one of their areas, but not in others.



Distribution Network Operators 2004: Note the numbers are the same as the groupings in Fig. 5.

1. Scottish and Southern: note the SWALEC area is operated by Western Power (6)

2. Scottish Power

4. PowerGen only in East Midlands area. The Eastern area network is operated by EDF (5b), while their NORWEB area is operated by PPL

5. Electricité de France (EDF). The London and SEEBOARD areas are the same as the supplier areas. However, the SWEB area network is operated by PPL, and EDF are also the network operator for region 5b

6. Western Power Distribution: PPL – an American based company operating the networks in the SWEB, SWALEC, and NORWEB areas.

7. Aquila: an American based company operating the Midlands area network.

8. Northern Electric and Yorkshire Electric Distribution: both owned by Mid American Energy.

9. United Utilities: a UK company

Fig. 6. The Distribution Network Operators (2004). Note the significant changes compared to Figs. 2, 4, and 5. Only 50% of the areas now have the same geographic supplier and network operator.

THE NEW ELECTRICITY TRADING ARRANGEMENTS

The New Electricity Trading Arrangements (NETA) came into force on 27th March 2001 and represented a major change in the way electricity was traded in England and Wales but not Scotland. Tovey, (2003) gave an in depth review of the operation of NETA, while much technical information about specific operational detail may by found in a series of papers from the Regulator (e.g. OFGEM, 2000). The following is a brief summary of how NETA works.

Under the new arrangements, and unlike the POOL mechanism, most electricity is traded outside the NETA Balancing Mechanism. Both generating and demand side bidding takes place and this effectively prevents some of the price fixing problems which arose in the POOL. NETA favours those generators and suppliers who can guarantee specific levels of generation or supply in advance. It also favours those generators and suppliers who can guarantee agreed flexibility in output / demand at short notice. Conversely, those generators or suppliers who cannot guarantee specific levels of generation /

demand suffer financially. Situations such as equipment failure etc. can lead to substantial losses for the companies involved. System Security is maintained by the Balancing Mechanism. On the other hand the majority of electricity (> 95%) is traded outside this Balancing Mechanism through bilateral agreements or trades through a broker. The System Operator (National Grid Transco. NGT) is not involved in these transactions but it is a requirement that the volume of trade (not the price) is notified to NGT. Trading may be done for any time period in the future and it is not unusual to see the volume of electricity traded for a particular half hour period take place several times over.

Trading takes place in half-hour blocks for each day of the year for each Balancing Mechanism (BM) unit. A generation BM unit will typically be a single generating set in a power station. Small generating sets can be consolidated into a single BM unit. On the demand side, a BM unit might be a single large customer or a collection of smaller customers. The final trading position of each BM unit must be declared by 1 hour before the start of the actual half hour period in question. Prior to June 12th 2002, this period was 3.5 hours. This cut-off time is known as "***Gate Closure***". Thus Gate Closure for the half hour period from 12:30 – 13:00 will be at 11:30. The final trading position is known as the Final Physical Notification (***FPN***).

If a generator or supplier deviate from the agreed ***FPN*** level, they will be charged by the System Operator for this imbalance. If a generator produces more than the agreed amount of electricity, or a supplier has a demand less than the agreed amount, then the imbalance is charged at the System Sell Price. If the generator fall short in his commitment, or a supplier has too much demand, then they are charged at the System Buy Price. In the early days of operation of NETA, the system Buy Price was high and reached over £100 per MWh while the System Sell Price was relatively low. In the three years since NETA began the two prices have converged as shown in Fig. 7. Since the System Buy Price is normally noticeably higher than the System Sell Price, most generators and suppliers tend to err on the side of having too much electricity on the system.

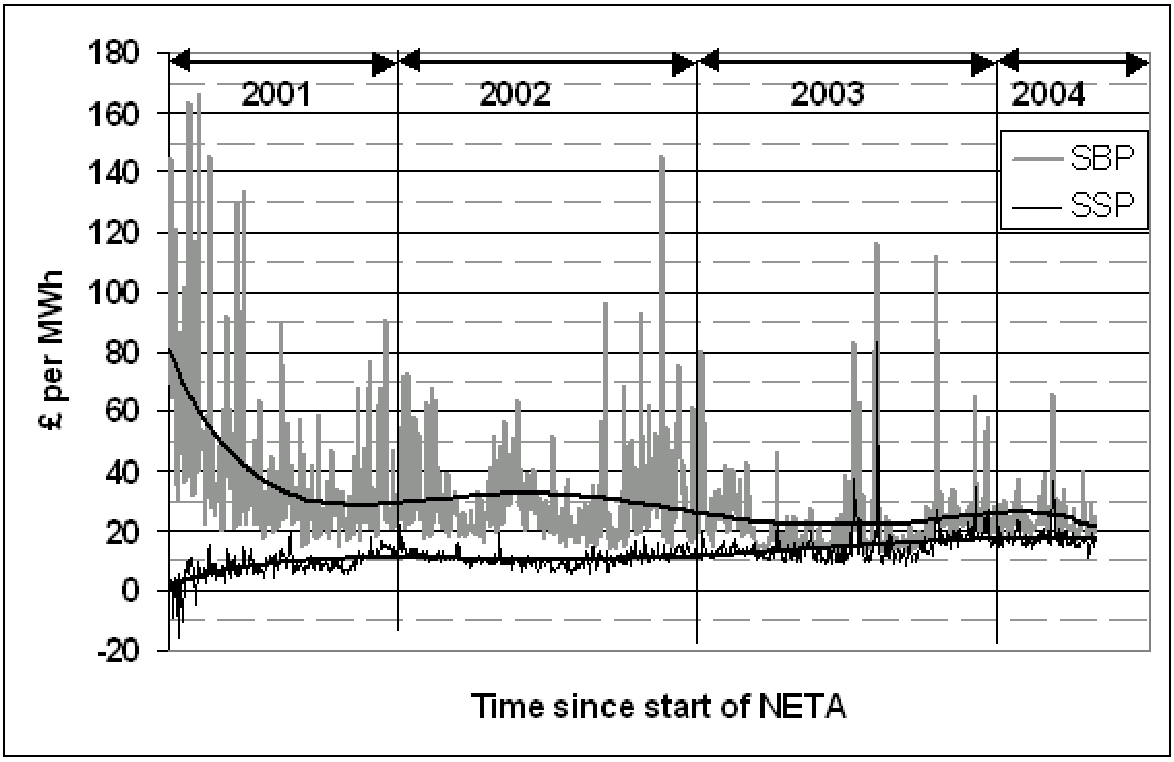


Fig. 7. The average daily System Buy Price (SBP) and System Sell Prices (SSP) since the start of NETA. There has been significant convergence of the two prices, although there are still days when the two prices differ significantly. The last data points on the right refer to 3rd May 2004. Data from Elexon (2004).

To ensure system stability, the System Operator requires the flexibility to adjust the availability of electricity to account for unexpected changes in demand (from weather changes, unexpected events such as popular television programs, unexpected equipment failures, or interruption to the transmission network). This is achieved by inviting the BM units to modify their ***FPN*** level to either increase or reduce the amount of electricity on the system. To increase the amount of electricity on the system involves an ***OFFER*** to provide this increase. This may be done by either increasing the generation output or by reducing the demand. Any changes made under such an ***OFFER*** will result in the relevant BM Unit being paid for the change. Conversely if the amount of electricity on the system is to be reduced, the BM Units can make a ***BID***. For a generating BM Unit this will mean a ***BID*** to reduce generation, whereas for a demand BM Unit this will represent a ***BID*** to increase demand. Agreements for such ***BID***s will result in the relevant BM Units paying for this modification of level to the ***FPN*** level.

In many cases, a generator or supplier may ***BID*** or ***OFFER*** different prices for ranges of deviation from ***FPN***. Thus a ***BID*** to deviate by say 25 MW might be £30 per MWh, but a deviation between 25 and 50MW might be £40 per MWh. Normally the National Grid Transco will accept the cheapest ***OFFER*** or ***BID*** so as to keep prices down, but sometimes system constraints may prevent this. There is no obligation for a BM unit to participate in the Balancing Mechanism, but some companies specialise in providing BM Services and can make 25% or more by this means. Details of how these ***BID***s and ***OFFER***s work (including graphical explanations) may be found in Tovey (2003).

Once an ***OFFER*** or ***BID*** has been agreed between the National Grid Company and the relevant BM Units, it cannot be cancelled. Instead there is provision for ***UNDO BID***s to cancel an ***OFFER***, and ***UNDO OFFER***s to cancel a ***BID***. This is illustrated in Fig. 10 where it is noticed that ***any UNDO OFFER*** or ***UNDO BID*** will not be at the same as the original ***BID*** or ***OFFER*** and thus this will be a net benefit to the BM Unit concerned and a penalty on National Grid Transco. In this way there is a control on the operation of the System Operator which was not present in the POOL.

The ***OFFER***s and corresponding ***UNDO BID***s and the ***BID***s and ***UNDO OFFER***s, are normally submitted in pairs and agreed as ***BID – OFFER*** Acceptances or ***BOA***s (Fig. 8).

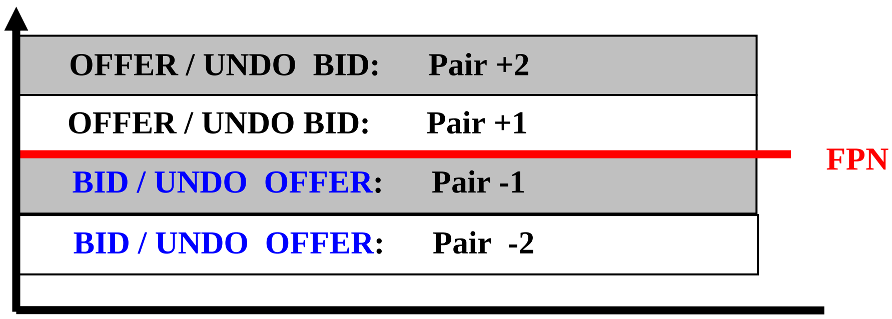


Fig. 8. Examples of ***BID / OFFER*** Pairs

IMPACT of NEW ELECTRICITY TRADING ARRANGEMENTS on COMPANIES

During the 1990s there was a substantial investment in new combined cycle gas turbine generation (see Table 1) and consequently there is now considerable over-capacity of generation. The consequence of this has been that the true costs of generation have been exposed to full market forces and several companies have experienced difficulties. At the onset of NETA, the wholesale prices for electricity were already 20% below the levels in 1998, and a further 20% fall occurred in the first year of NETA (Fig.9). Prices remained at low levels for the next 12 months (Fig. 9). As a result, in September 2002, British Energy (the company which operates the more modern nuclear stations (i.e. the Advanced Gas Cooled Reactors and the Pressurised Water Reactor) experienced difficulties and required Government assistance to continue trading. Equally, TXU became insolvent and other companies such as AES (a generating company) have also experienced acute difficulties. Those companies which have become vertically integrated have to some extent been cushioned, but even they have found it necessary to mothball relatively new (<8 years old) generating plant.

Fig. 9. Wholesale prices of electricity since the start of NETA. The rise in late 2003 reflected the changes in the price of gas.

In the summer of 2003, National Grid Transco expressed concern over the magnitude of the capacity reserve for the winter of 2003-2004. This had fallen to 16%, well below the normal level of 20 – 24%, and experience in the past has indicated that when this falls below 20%, problems occur in guaranteeing supply. Following this warning, and the rise in wholesale prices, several mothballed plants were recommisioned and the level of reserve now stands at just over 20%. It is clear that market signals alone are not sufficient to ensure adequate capacity.

THE FUTURE OF NETA – MOVING TOWARDS A BETTA SYSTEM.

While consumers in England and Wales have benefited from Deregulation, the markets in Scotland have yet to benefit fully. Discussions have been held for a number of years to extend the basic mechanisms of NETA into Scotland as the British Electricity Transmission and Trading Arrangements (BETTA). These discussions are now at an advanced stage and it is hoped that a system covering England, Wales and Scotland will be implemented in the spring of 2005 with the role of the System Operator becoming the GB wide System Operator. Several important reasons for the delay may be cited, including:

(i) the differences in definition of the boundary between transmission and distribution as noted above,

(ii) the incorporation of the England Scotland Inter-connectors into the system – the charges for the use of these facilities is different from normal transmission,

(iii) the need to address issues related to renewable power generation, particularly as much future development will be at the peripheral margins, and there are EU directives in place to minimise the impact of excessive transmission charges on renewables.

FUTURE CHANGES LIKELY TO AFFECT THE UK ELECTRICITY MARKET.

In addition to the introduction of BETTA next year, there are two separate aspects which are likely to affect the Electricity Markets in the UK. These are the Renewables Obligation and Carbon Emission Trading. The Renewables Obligation was introduced on 1st April 2002 and attempts to increase the proportion of UK electricity generated from renewable energy sources in the next decade or so. More recently the Carbon Emission Trading Nation Allocation Plans have been published . These have the intention of developing a Carbon Trading Market in the EU, initially for the three year period 2005 - 2007, but later in a second phase for the period 2008 – 2012.

The Renewable Obligation is described in full in DTI (2001), and reinforced in the Energy White Paper (UK Government, 2003). It sets targets for the proportion of electricity that each supplier must provide in each year. The target percentage increases each year up to 2010. Recently it has been announced that the target will continue to rise to 15% by 2015 with an expectation that further targets at higher levels covering the period beyond 2015 will be announced. The target values are shown in Table, 2 while information on which renewable technologies qualify is provided in Table 3.

TABLE 2. The Renewable Obligation Targets (DTI 2004)

Period	Estimated Total Electricity Available (TWh)	Electricity from Licensed Suppliers (TWh)	Renewable Obligation Target (%)	Renewable Obligation (TWh)
2002/03	358.2	313.6	3.0	9.4
2003/04	360.6	316.2	4.3	13.5
2004/05	363.1	318.7	4.9	15.6
2005/06	365.6	320.6	5.5	17.7
2006/07	368.5	321.4	6.7	21.5
2007/08	371.4	322.2	7.9	25.4
2008/09	374.3	323.0	9.1	29.4
2009/10	377.3	323.8	9.7	31.5
2010/11	380.3	324.3	10.4	33.6

The differences between the Total Electricity Available and that sold includes the auto-generation of electricity and losses in the system. The increase in demand for electricity is running at a much higher rate than the Government figures above and by 2003 had already exceeded the estimated available electricity for the year 2005/06

TABLE 3. Eligible Renewable Sources for the Renewables Obligation.

Landfill Gas	yes	Sewage Gas	Yes
Onshore Wind	yes	Offshore Wind	Yes
Geothermal	Yes	Tidal and Tidal Stream	Yes
Wave	Yes	Photovoltaics	Yes
Energy Crops	Yes	Forestry and agricultural waste	Yes
Energy from Waste	Only non-fossil derived energy will be eligible. Incineration of mixed waste will not be eligible. Energy from non-fossil derived element of mixed waste will be eligible if advanced technologies are used		
Cofiring of biomass	Eligible until 31st March 2011 for up to 25% of obligation. At least 75% of biomass to be energy crops from 1st April 2006.		
Hydro < 20MW	Eligible		
Hydro > 20MW	Only stations commissioned after 1st April 2002.		

The total renewable percentage in 2003, including ineligible large scale hydro, was around 3%, well below the target level of 4.3%. To ensure that suppliers conform to the targets there is a procedure of Renewable Obligation Certificates (ROCs) which suppliers must hold or are otherwise fined for any shortfall. The Renewable Obligation Certificates can themselves be traded and currently are trading at a premium of 50% or more over their face value. Not only that, but there are several other incentives for those holding Renewable Obligation Certificates. The procedure is illustrated in Fig. 10.

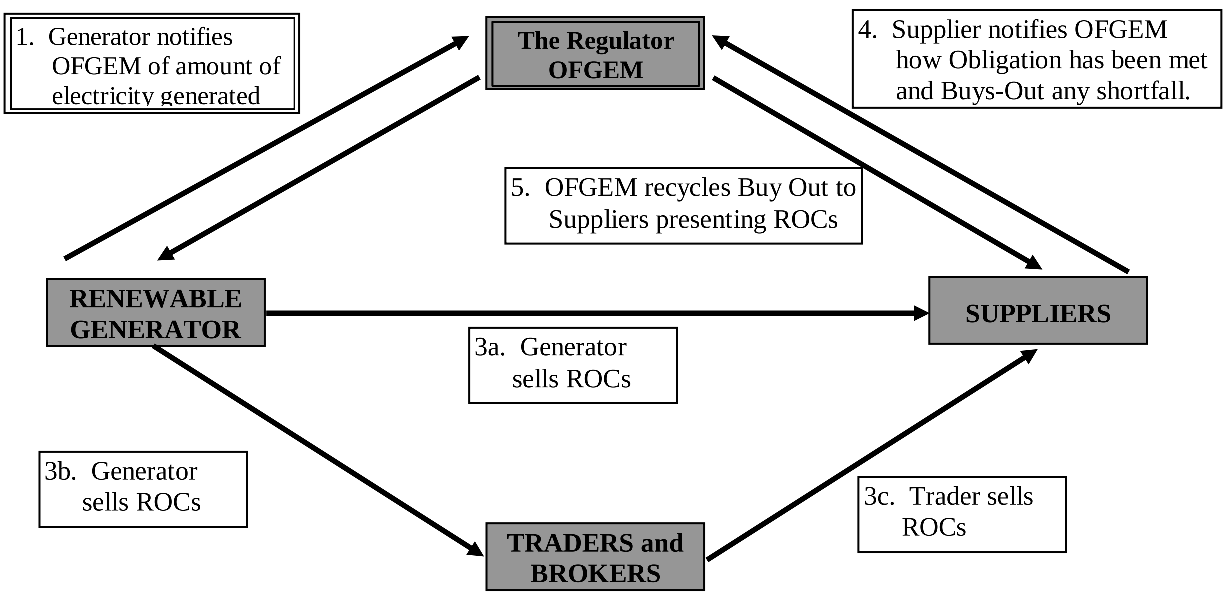


Fig. 10 Schematic of allocation, trading and redemption of Renewable Obligation Certificates

In the first stage, the Renewable Generator, sends proof of his generation in terms of MWh output to OFGEM who allocate ROCs in proportion to the output. The generator may then either sell the electricity along with the ROCs to a supplier (stage 3a). Alternatively the generator may trade his ROCs into a Trading Pool. Periodically, auctions are held in which suppliers who have a shortfall in the number of ROCs can purchase additional certificates. At the end of the relevant period the supplier then transfers his ROCs to OFGEM, and if he fails to comply with the required target percentage, pays the Buy-Out price to OFGEM. Finally in the last stage, OFGEM recycle the Buy-Out income to the suppliers in proportion to the number of certificates originally held.

Because the Buy-Out fines are recycled, the value of the ROCs actually held will be above their face value whenever there is a shortfall in the amount of renewable electricity generated, such as at the present time. The Buy-Out price was originally set by OFGEM at £ 30 per MWh in April 2002. This is being increased in line with inflation such that it was £30.51 per MWh in April 2003, and recently (April 2004) it was raised again to £31.39 per MWh. As a result of the current shortfall in certificates, they are currently trading at prices ranging from £45 - £48 per MWh. The value of renewable generation is significantly above the current wholesale NETA price of around £20 per MWh. The components of the value are:

The NETA wholesale price	£20 - £22
Face Value of ROC (April 2004)	£31.39
Exemption from the Climatic Change Levy	£4.30
Embedded benefits (reducing transmission/distribution charges)	£1.50
Benefits from recycled Buy-Outs	£12 - £18
Less the imbalance risk under NETA	-£2
Net benefit	£56 - £75

At these prices some of the renewable technologies such as onshore wind are very cost effective. Others such as photovoltaics are still far from cost effective, although capital grants are available for schemes such as these.

At the end of April 2004, the UK Government announced the carbon emission allocations as required by the European Union commitment to reduce carbon dioxide emissions. Unlike countries such as Italy which have allocated emission levels 8% above 2000 levels, the UK has established a cut of 15.2%, with the electricity generation sector taking a cut of 16.3%. The basis of the UK allocation was to take the actual emissions in the five year period (1998 – 2002) discounting the year with the lowest emission. The actual allocations for each year 2005 – 2007 were then allocated as a percentage below the historic level – this percentage varies from sector to sector. The UK has also decided to have exactly the same allocation in each of the three years. While these allocations have been made, there is still a period of consultation where some adjustment in individual installation or individual sector allocations may be made. Some potential anomalies exist where generating stations with exactly the same capacity and fuel have currently been given different allocations. There is concern that the historic baseline may disguise historic inefficiency and reward such plants at the expense of those who have already invested in more efficient technology.

If the carbon allocation had been solely within the UK, there would have been a significant shortfall in the allocations. There would need to be significant purchase of allocations at the Buy-Out price of 40 Euros per tonne, which in turn would result in not insignificant prise rises, particularly in the electricity sector. Currently trading on the European market is at price much lower than this ceiling largely as a result of the very generous allocations by countries such as Italy. Once all National Allocation Plans have been received, the European Commission will review the plans and may require a tightening of allocations in some countries. It is too early to assess the likely impact of these emission trading arrangements which are due to come into force on 1st January 2005. It is almost certain that there will be rises in the price of electricity which will inevitably be passed on to the consumer.

CONCLUSIONS

The privatisation of the UK Electricity Markets have seen many changes over the last 14 years, and there continue to be further changes. Some of the key points are summarised as:

1. While wholesale prices of electricity fell by 20% in the latter years of operation of the POOL, and a further 20% in the first year of operation of NETA, whole sale prices have now risen and are comparable with those at the onset of NETA.
2. The difference between the system BUY and SELL prices associated with the Balancing Mechanism under NETA has narrowed considerably as the market has matured.
3. The recent rises in wholesale prices have followed the trend in gas prices and these have encouraged the re-commissioning of mothballed generating sets. The consequence of this is that there is an improved security margin of capacity (at over 20% compared to 16% 12 months ago).
4. There continues to be significant activity in the structure of companies. The number of geographically based companies has reduced from 14 at privatisation in 1990 to 5 in 2004. All these companies now control two or three different areas.
5. Discussions on the implementation of the British Electricity Transmission and Trading Arrangements are now at an advanced stage and are planned for implementation in the spring of 2005. This will include Scotland within an effective extension of NETA. One of the critical area of discussion has been the different ways in which transmission and distribution have been viewed in Scotland as opposed to England and Wales.
6. The Renewable Obligation is providing an incentive for generation of electricity from renewable resources. At the same time a trading market has been established with the Renewable Obligation Certificates, which are currently trading at a premium of 50% over their face value, reflecting the significant shortfall in the actual renewable generation as opposed to the set targets.
7. The recently announced National Allocation Plans for Carbon Emission Trading could cause significant rises in the cost of electricity.

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