Prospects for Hydro in the UK: Between a ROC and a Hard Place?

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ABSTRACT
The Renewables Obligation has set challenging targets for renewable energy in the UK. It requires electricity suppliers to source 10% of their energy from renewables by 2010 and imposes penalties where suppliers fail to meet their obligation. For every unit of electricity derived from a renewable generator suppliers are entitled to a purchase a Renewable Obligation Certificate (ROC), a form of 'Green' certificate which may count towards their obligation or may be traded in a ROC market. This mechanism means that generators gain additional revenues in order to encourage renewable development. New hydro developments and upgraded schemes below a certain capacity also qualify for ROCs which should stimulate increased activity. However, significant technical, economic and environmental difficulties remain for hydro developers. The mechanisms developed to assist hydro and other renewables following deregulation are considered with particular emphasis on the impact of the recent Renewables Obligation. Finally, it looks at the prospects for future hydro development to 2010.

INTRODUCTION
The UK Government has set a challenging long term aim of 60% cuts in carbon dioxide (CO_2) emissions by 2050 (DTI, 2003). On a shorter timeframe, the UK commitment to the Kyoto Protocol is for a 12.5% reduction below 1990 levels by 2008-2012 for a basket of greenhouse gases. The Government set a national target of 20% cuts in CO_2 to be achieved by 2010, although statements in December 2004 highlight that the Government anticipates that this target will be missed. The Government expects renewable energy to play a vital role in meeting these climate targets (DTI, 2003).

The European Union's Renewables Directive, which came into force in October 2001, requires Member States to adopt national targets for renewables that are consistent with reaching the overall EU target of 12% of energy and 22.1% of electricity supplied from renewables by 2010. The UK share of this target is that renewables sources eligible under the Directive should account for 10% of UK electricity consumption by 2010. While this in itself does not provide a means of achieving the targets, it places a legal obligation on the UK.

To this end, the UK has set a policy goal of achieving 10% of electricity from renewables (DTI, 2000). It has gone further, however, by defining an aspiration of 20% renewables by 2020 and a view of 30-40% by 2050 (DTI, 2003). Within the UK the picture is more complicated with the Scottish Executive committing itself to 18% by 2010 and 40% by 2020 (Scottish Executive, 2002a). The higher targets reflect the greater role of renewables – mainly large hydro – in Scotland as well as the Executive's desire to provide a lead to the UK.

Achieving these targets and aspirations will require a massive increase in capacity from all renewables including hydro. Whether they are achieved will depend very much on the mechanisms supporting renewables and on other factors at play within the electricity market.

SUPPORTING RENEWABLES IN THE UK
There have been a range of schemes to supporting UK renewables since the electricity industry was privatised in 1990. These include:

- the Non-Fossil Fuel Obligation
- the Climate Change Levy, and
- the Renewables Obligation.

NON-FOSSIL FUEL OBLIGATION
The Non-Fossil Fuel Obligation (NFFO) was introduced under the Electricity Act 1989 that privatised the industry. It was a competitive arrangement in England and Wales to encourage the establishment of non-fossil energy generation, including renewables and similar arrangements applied to Scotland (the Scottish Renewables Obligation, SRO) and Northern Ireland (NI-FFFO). Potential developers of renewable energy generating schemes bid a price, in p/kWh, at which they could construct their schemes with contracts awarded on the basis of this price. Successful bids would receive payment at the contracted amount for a set period with, for example, those from Orders 1 and 2 (1990/91) expiring at the end of 1998. NFFO was funded through a fossil-fuel levy paid by the supply licensees and ultimately passed on to consumers.

The renewable NFFO was a by-product of a mechanism designed primarily to support nuclear power which had proved impossible to privatise along with the rest of the industry in 1989 (Mitchell, 1995). Under EU competition rules the government needed to obtain permission from the European Commission (EC) to raise a levy to pay for nuclear power. Rather than take the politically risky approach of explicitly asking for a nuclear levy, they proposed a 'non-fossil generation' levy which was accepted on the basis that it could only run until 1998. While renewables were not explicitly mentioned it was accepted that they would be included in the levy (Mitchell, 1995). By virtue of the balance of production between the large nuclear generators and the significantly smaller renewable sector, the vast majority of the subsidy went to the nuclear industry. The short term nature of support implied by the 1998 cut-off created a range of problems and the Government agreed an extension of the NFFO for renewables only, given that by this time the nuclear generators had been privatised.

Each round of the Order saw the Government decide what volume of renewable energy it anticipated, split between several renewable types. The balance between technologies altered between each round dependent on judgements as to the most effective way of market development. Specific types were excluded as they were perceived to be approaching market competitiveness, e.g., sewage gas did not feature in later rounds. Over the five NFFO Orders three in Scotland and Northern Ireland, 1072 projects representing 4007 MW Declared Net Capacity (DNC) were awarded (DTI, 2004a). Difficulties with obtaining planning consent and with network connection costs have meant that only a fraction of projects were commissioned. By June 2004, only 512 projects contracted under the Orders had been commissioned and were generating electricity, with a capacity totalling 1271 MW DNC (DTI, 2004a).

The effectiveness of the mechanism could have been increased drastically, had two major problems been addressed (Mitchell and Connor, 2004):

- The maximum bid prices were generally too low. To be successful in gaining an NFFO contract, generators tended to bid low with optimistic project costs and project timings. The short term nature of support during early rounds meant that there was only a short period available to develop and achieve preferential energy prices; those for whom the economics turned out to be unfavourable did not proceed.
- There were no penalties for developers who were awarded contracts but who not take them up, reinforcing the tendency to bid unrealistically.

The NFFO scheme was replaced by the Renewables Obligation.

CLIMATE CHANGE LEVY

The Climate Change Levy (CCL) entered force in April 2001. The CCL taxes energy used in industry, commerce and the public sector according to the type of energy used. It was designed to encourage the use of environmentally friendly fuel sources to help the UK meet its emissions targets. The levy is financially-neutral to the UK Treasury with money collected from the levy returned via a number of initiatives including cuts in Employers National Insurance contributions for registered companies (HM Customs and Excise, 2002). A further feature is that in return for implementing agreed energy efficiency schemes, energy-intensive industries can see an 80% reduction in CCL rates (HM Customs and Excise, 2002).

The levy for electricity is set at 0.43p/kWh – equivalent to £31 per tonne of carbon. Only technologies which do not contribute to climate change are exempt from paying and are issued Levy Exemption Certificates (LECs). LECs can be sold, providing renewable generators with an additional revenue stream. Remarkably, electricity from hydro schemes larger than 10 MW as well as nuclear stations does not qualify for exemption. Officially this is to 'stimulate growth in the development of renewable sources of energy' as all the major large-scale hydroelectric schemes in the UK have already been developed (HM Customs and Excise, 2004). An alternative view would be that it was to avoid a potential windfall for Scottish and Southern Energy, owners of the large hydro schemes in the north of Scotland. The revenue received from the sale of the LEC is generally not at full value, with power purchase agreements typically offering 55% of face value in addition to energy revenues. Where these are sold to energy intensive consumers the LEC value may be as low as 20%. The LEC scheme is administered by the Office of Gas and Electricity Markets (Ofgem), the UK regulator via a fairly bureaucratic process as Figure 1 indicates.

Ultimately, the CCL is an energy tax, not a carbon tax and it has proven inefficient as a climate change mitigation measure given that fossil-fuel use by the electricity industry, the transport sector or households is not directly addressed (Royal Society, 2002).

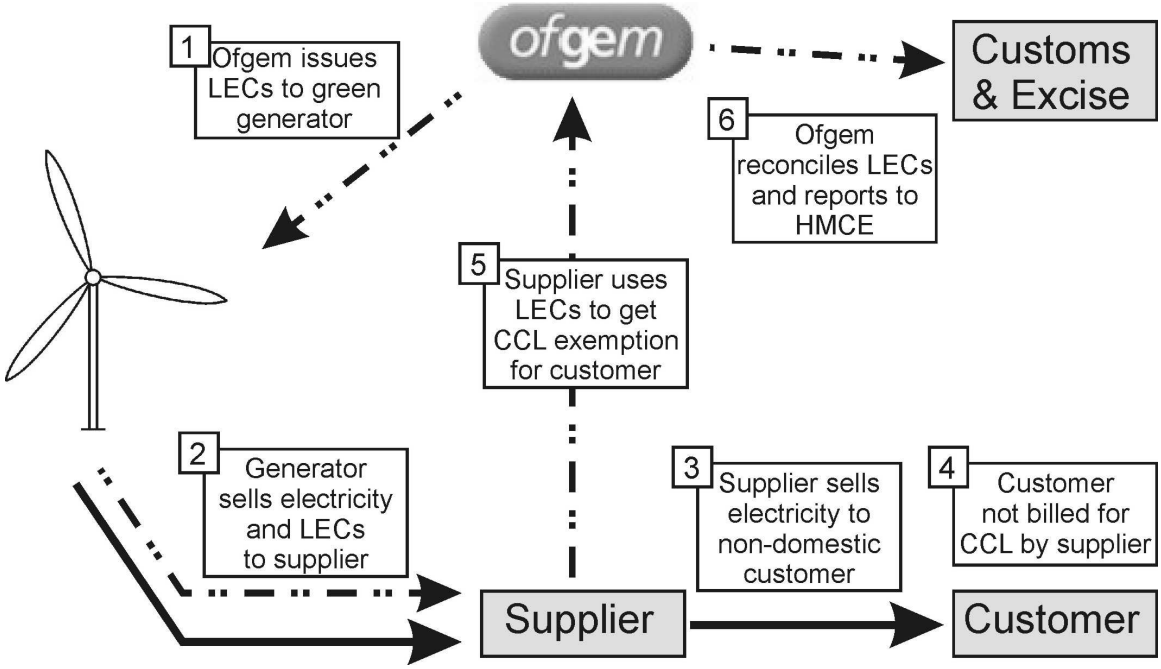

Figure 1. Flows of electricity (solid) and LECs (broken) within the climate change levy

RENEWABLES OBLIGATION

The Renewables Obligation (DTI, 2002) replaced the NFFO as the main renewables support mechanism in April 2002. The Obligation requires all licensed electricity suppliers in England and Wales to supply a specific proportion of their electricity from renewables. In order to provide a stable and long-term market for renewable energy the Obligation will remain in place until 2027. The annual obligations were originally specified up to 2010/11, rising incrementally from 3.4% in 2002/03 to 10.4%; in response to several concerns (examined later) this has recently been extended through to 2015/16 when a target of 15.4% will apply. The Scottish equivalent, the Renewables Obligation Scotland (Scottish Executive, 2002b), operates on the same basis albeit with raised percentage obligations of up to 17.8% by 2010/11 as a result of the larger base level of renewables from the large hydro schemes.

Technology neutral, the obligation makes provisions for electricity from a wide range of sources including hydropower. However the eligibility of hydro defined by capacity:

- Micro hydro (i.e. capacity less than 1.25 MW DNC) is eligible.
- Small hydro (i.e. capacity less than 20 MW DNC) is eligible if it has been commissioned or refurbished since 1st January 1990
- Large hydro (>20 MW DNC) is ineligible unless it is a new scheme commissioned after 1st April 2002 or where additional capability can be gained by refurbishing existing plant to raise efficiency.

The Renewables Obligation is administered by Ofgem and, once again, is based on a complex set of procedures for compliance (Figure 2). Ofgem accredits qualifying renewable generators and issues Renewables Obligation Certificates (ROCs) to generators on the basis of 1 ROC per 1 MWh of metered production. The onus is on the supplier to acquire the necessary number of ROCs and periodically demonstrate their compliance with the Obligation. Suppliers can obtain ROCs in a number of ways:

- by buying both energy and ROC from renewable generators
- by buying the ROC alone from renewable generators, or
- by buying the ROC in a trading market.

Should suppliers be unable to purchase sufficient renewable energy to meet their obligation, they must pay a 'buy-out' penalty. For every MWh the supplier is short of their obligation, they must pay £30.51 (in 2003/04, rising with inflation) into the buy-out fund administered by Ofgem. The fund is then recycled to compliant suppliers with their share of the fund equal to their proportion of the total ROCs submitted. The payment is referred to as the 'buy-out' or 'recycle' premium and serves to raise the value of the green energy above the minimum buyout value.

The renewable generator may sell to any supplier or trader although it is common for the ROC to be bought in addition to energy through a power purchase agreement. The value placed on the ROC can be agreed fixed or can

be linked to current trading prices with the ROC market. The market value clearly varies with the balance of supply and demand and, with demand currently exceeding supply, ROC values are in excess of the buyout value. The difference between the buyout price and the market price is the value of the recycle premium. Several organisations track or predict ROC prices (Ofgem, 2004a). The Non-Fossil Purchasing Agency (NFPA) publishes the prices obtained from auctions of ROCs issued to generators contracted under the NFFO scheme; an auction from October 2004 indicated a ROC price of £46.12/MWh, while ROCs at a similar auction in July 2004 were valued at £52.07. Platts Power UK publishes predicted ROC prices on its website (www.platts.com); ROC prices for 2004/05 are predicted to be between £44 and £48/MWh depending on the rate of build of renewable plant.

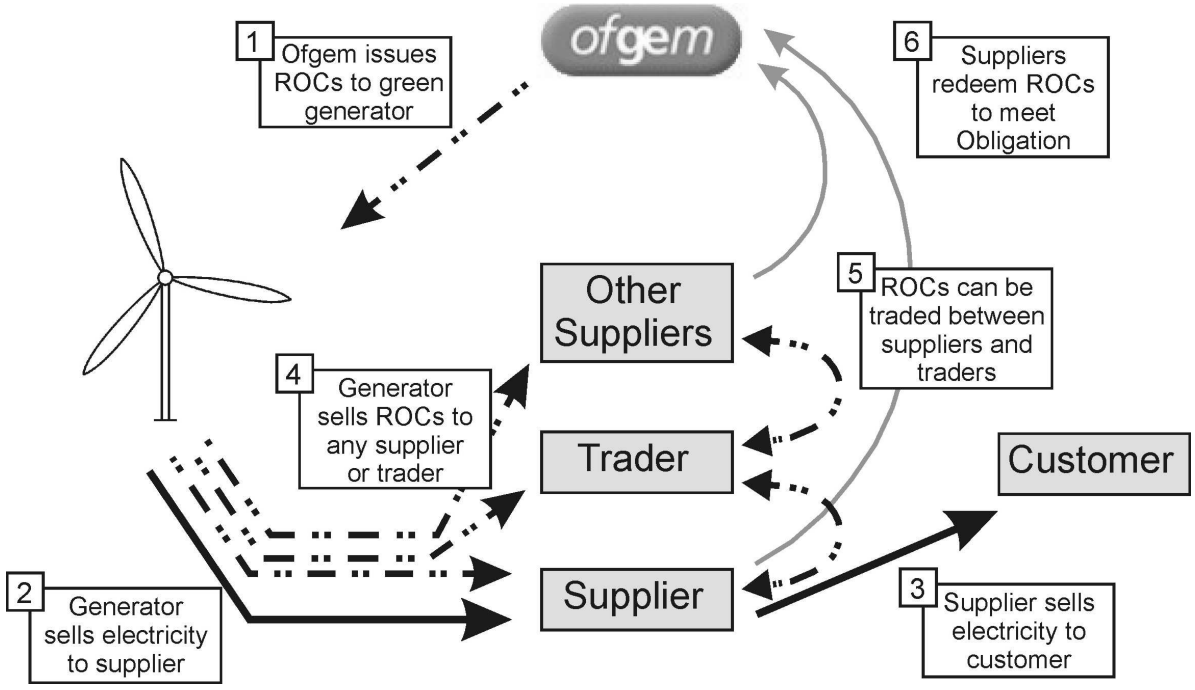

Figure 2. Flows of electricity (solid) and ROCs (broken) in meeting Obligation (grey)

Overall, the market value of renewable energy is set by the base ROC value, the current wholesale electricity price, the LEC and the recycle premium as Table 1 indicates. In essence the combination of support mechanisms raises the revenue to renewable generators by several times that received in the wholesale energy market.

Breakdown	**Value (p/kWh)**
ROC, (as long as demand exceeds supply)	3
Wholesale energy price (mid 2003 levels)	1.5–1.8
Levy exemption certificate (20% of CCL)	0.086
Recycle premium (as demand currently exceeds supply)	1.5
Total	6 – 7

Table 1: Renewable electricity value, adapted from Mitchell and Connor (2004)

CHALLENGES FOR RENEWABLES

Despite this obvious financial incentive in producing green energy there are still challenges to meeting the UK renewables targets. These are listed below with several elaborated on in later sections:

- Financing of projects
- Size
- Renewables Obligation itself
- Network issues
- UK electricity market
- Planning issues

FINANCING

With the supply and demand for renewables defining the values of the ROC and buy-out premium, there is no guarantee over prices and revenues from these sources. As supply moves closer to demand, the value of the buy-out premium will fall, becoming zero once it exceeds the annual demand. An additional effect will be that once supply exceeds demand, suppliers can choose which generators to buy from. This will result in some generators being unable to contract to sell ROCs and the market value of ROCs will likely decrease (Mitchell and Connor, 2004). These effects have led to difficulties gaining project financing for renewable projects as lenders apply significant mark downs in ROC value, often near zero when assessing coverage ratios (Goode, 2003). A key means of making ROCs more palatable to lenders is to offload the ROC risk to another party through, for example, power purchase agreements (Goode, 2003). This will, however, tend to lower the overall revenue to the generator.

An additional issue is with the timeframe of the Obligation. With the original targets specified until 2010/11 this offered a relatively short timeframe within which to receive enhanced revenues. With lenders preferring 15 year maturity for project finance deals the time constraint was limiting the availability of lending funds to developers. The Government accepted this view and this was one of the main reasons why the Obligation target was raised and extended to 15% by 2015/16.

SIZE

The difficulties associated with project financing mean that the Renewables Obligation has generally only been beneficial to large firms than can finance developments from their balance sheets. It is anticipated that some of the changes to the Obligation will have eased these difficulties. Size was also relevant for participation in the Obligation as until 2003, ROCs were only available to generators producing more than 0.5 MWh/month. Following consultation, an April 2004 amendment to the Obligation will allow generators to accumulate output over the course of the year and make a claim for certificates on the basis of the annual generation. This would allow small-scale generation, previously ineligible for ROCs, to fall within the Obligation.

RENEWABLES OBLIGATION

A significant feature of the Obligation is the incentive given by the buy-out premium, which unfortunately, is such that there is a strong collective incentive to undershoot the Obligation target in order maintain ROC value and maximise returns from existing generation. The buyout fund and accordingly the ROC value is vulnerable to non-compliant suppliers failing to pay the buyout penalty, either through supply company collapse (e.g. TXU) or through late payment. As there was no mechanism for dealing with late payments or failures the buyout fund was lower than expected (Mitchell and Connor, 2004). While the buyout fund issues are likely to be resolved following consultation, the tendency to undershoot the target will remain.

NETWORK ISSUES

The UK electricity transmission network has flows that are predominately from Scotland and the north of England to the demand centres in the South East. The exploitation of renewable resources including hydropower will tend to accentuate the flow patterns. Unfortunately the transmission network is already constrained and significant and expensive upgrades will be required to ship the (mostly wind) power south. A £1.5 billion series of upgrades are planned within Scotland and northern England to expand the transmission capacity (RETS, 2003). While the transmission issues are relevant for large scale generation, the vast majority of renewable schemes are expected to connect to the distribution network. The networks were not designed to accommodate generation and, as a result, there are a range of technical and economic impacts that tend to make connections expensive (Harrison et al, 2002). With new incentives for UK Distribution Network Operators to connect smaller scale generation (Ofgem, 2004b) connection issues should, to an extent lessen, through more empathetic connection planning or through the use of intelligence in the network to create so called ‘active networks’ that can accommodate additional capacity.

THE ELECTRICITY MARKET

At privatisation in 1990, the England and Wales electricity market was based around a single price wholesale pool and capacity payments to encourage availability. While smaller generators were exempt from participation in the pool, there were significant problems with market power and a new approach was sought by Ofgem. This resulted in the introduction of the New Electricity Trading Arrangements (NETA) in March 2001. NETA aimed to be a commodity market and relied on a Balancing Mechanism to ensure effective system operation. A major outcome is that where a generator is short on output in a given period, they must pay the market rate to cover their shortfall. In essence, this penalises intermittent or less controllable generation like renewables and makes it less valuable (Mitchell and Connor, 2004). A significant problem for pumped storage hydro is the lack of capacity payment. This means that the fast response plant can only begin to cover its significant fixed costs by producing at high price periods and by operating in the Balancing Mechanism to cover short term imbalances. From April 2005 NETA will

apply to Scotland as well under the guise of BETTA (British Electricity Trading and Transmission Arrangements) which appears likely to spread the difficulty for renewables given that most of the resource lies in Scotland.

PROSPECTS FOR UK HYDRO DEVELOPMENT

Hydropower accounts for around 1% of UK electricity generation, the majority of which comes from the large hydro schemes in Scotland (DTI, 2004b). Current installed capacity is over 4,200 MW of which two-thirds is in pumped storage schemes (Table 2). This compares to an overall UK generation capacity of 78.5 GW (DTI, 2004b). The heyday of UK hydro construction was in the 1950s and early 1960s with the North of Scotland Hydro-Electric Board efforts in the Highlands. The last large scheme developed was the Dinorwig pumped storage scheme commissioned in 1984. Since then only relatively small capacity generation has been developed.

Country	Large Hydro (> 20 MW)	Small Hydro (1-20 MW)	Micro Hydro (< 1 MW)	Total	Pumped Storage	Total Capacity
England	0	10	9	20		20
Scotland	824	434	27	1,286	699	1,985
Wales	83	58	7	148	2,088	2,236
N Ireland			3	3		3
Total	907	503	46	1,468	2,788	4,256

Table 2. Current UK installed hydropower capacity (MW) by country, size and type (Williams, 2004)

The vast majority of the UK's large hydro potential has been developed and with the apparent labelling of large hydro as a social and environmental 'bad' new build is not widely expected. One exception to this is the 100 MW Glendoe scheme proposed by Scottish and Southern Energy for a site near Loch Ness in the Scottish Highlands.

While the large scale potential may be limited, there is significant potential for smaller plant. This is particularly true in Scotland where it is estimated that a potential 300 MW of small hydro could produce energy at less than 7p/kWh (Garrad Hassan, 2001). Part of Mott MacDonald's work for the Renewables Advisory Board study (RAB, 2003) identified 123 potential small hydro projects with a combined capacity of 205 MW. Of these, 43 MW were in progress or highly likely to go ahead by 2010, with a further 28 MW classed as likely, i.e. with a 50% chance of progressing. Overall, between 90 and 135 MW of additional small hydro was expected by 2010 although a failure to deal with planning, financing and network issues could see that capacity fall. The encouraging developments on the network side should allow hydro developers to take advantage of the 'firmer' power production characteristics (relative to other renewables) in providing security of supply benefits to the network as well as using the continued preference for the more controllable synchronous generator to integrate with the 'active network'.

The development of micro-scale renewables and combined heat and power is an increasingly significant component of Government policy. There are now a series of incentive schemes for households and communities to develop them and there have been recent changes to regulations (Electricity Association, 2003) permitting less onerous specifications for connecting micro-scale generators.

CONCLUSIONS

The UK has a 14 year history in supporting renewables within a liberalised electricity system, albeit in some cases as a by-product of subsidising nuclear power. The flagship policy, the Renewables Obligation has set challenging targets for renewable energy and operates through Renewable Obligation Certificates (ROCs), a form of 'green' certificate. While there are signs that the Obligation is stimulating the necessary investment in the renewable sector there are a range of difficulties with the Obligation itself as well as financial and technical issues that are acting as a constraint on development. Although with exceptions, the era of large hydro schemes in the UK is long passed but there appears to be scope for further development of smaller scale schemes.

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