ENERGY REVIEW RESPONSE

Client	**NFLA**
Contact	Pete Roche
Document No	11463/GR/01
Issue	B
Status	FINAL
Classification	Commercial in Confidence
Date	10 April 2006

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Published	:	Available to the general public

Revision History

Issue No:	Issue Date:	Summary
A	22.03.06	Draft
B	10.04.06	Final

Circulation:	Copy No:
NFLA(S)	1
GH Glasgow	2
GH Bristol	3

Copy No: _____

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1 INTRODUCTION

The Nuclear Free Local Authorities (Scotland), NFLA(S), has commissioned Garrad Hassan and Partners, GH, to provide material in support of a submission to the 2006 DTI Energy Review [1]. NFLA(S)'s brief seeks clarity on the extent to which renewables, and in particular grid-connected renewables, can contribute to a long-term, nuclear-free Scottish energy mix.

2 SCOTLAND ELECTRICITY – CURRENT PICTURE

Figures for Scottish electricity generation and consumption are published by the DTI and the Scottish Executive [2, 3]. In 2004 some 50,972 GWh were generated in Scotland, 5780 GWh of which was transferred to England, and 2,793 GWh transferred to Northern Ireland. Some 35,813 GWh was consumed in Scotland, with the remainder used by generators (including in pumped storage), or was attributed to losses.

A breakdown by capacity in Scotland is shown in Table 2.1. A breakdown by fuel for 2000-2004 is shown in Table 2.2 and graphically in Figure 2.1 (where the green line is Scottish consumption).

Generating plant	Capacity (MW)
Large hydro	1300
(Pumped storage)	(740)
Longannet	2304
Cockenzie	1152
Hunterston	1210
Torness	1280
Peterhead	1524
Wind	1060
CHP	275
Biomass	12
Total	**10,117**

Table 2.1 Installed Capacity in Scotland

Source	2000	2001	2002	2003	2004
Nuclear	16918	18052	15863	18394	18013
Coal	16624	15408	14826	14554	13054
Gas	8680	8523	11025	10025	11003
Oil	2604	2375	2186	2034	2262
Hydro natural flow	4665	3738	4458	2984	4546
Hydro pumped storage	613	534	622	670	786
Other renewables	306	465	643	834	1308
Total Generated	*50410*	*49095*	*49623*	*49495*	*50972*
Transferred	9600	8694	8034	8177	8573
Gen. cons. (incl. pump hydro), & losses	6070	6014	6229	6307	6586
Consumed in Scotland	*34740*	*34387*	*35360*	*35011*	*35813*

Table 2.2 Electricity production in Scotland 2000-04 (GWh)

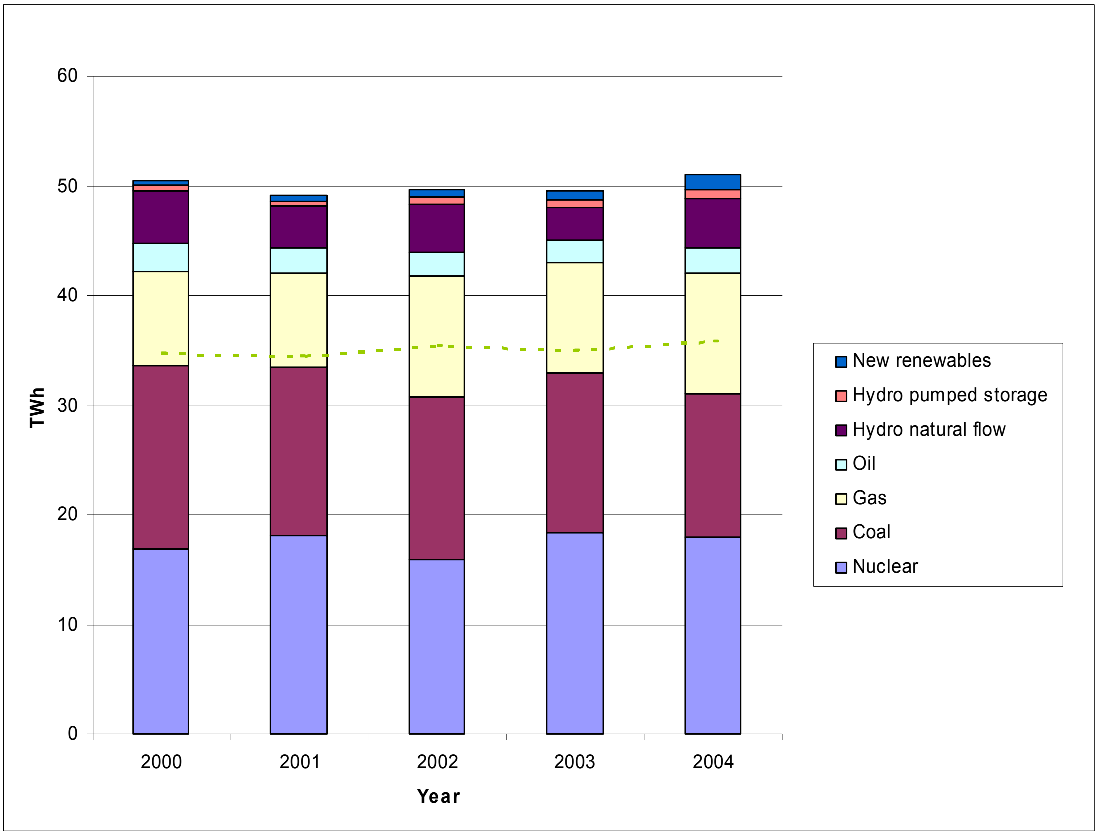

Figure 2.1 Electricity generated and consumed in Scotland

The following points should be noted:

- Nuclear generation accounted for some 35% of electricity generated in Scotland in 2004.
- The Moyle interconnector to Northern Ireland was commissioned in 2002, since when Scotland has exported to Northern Ireland as well as to England.
- Total exports from Scotland have fallen from approximately 10,000 GWh in the late 1990s to 8,500 GWh in 2004. Exports to England have nearly halved in the same period.
- Chapelcross nuclear power station closed in 2002. In the absence of grid reinforcement work, exports to England from Chapelcross cannot be wholly substituted by exports from elsewhere, which probably explains some of the reduction in exports to England.
- A Peterhead repowering project was completed in 2001, which included a capacity enhancement of approximately 1 GW. However the regulator refused an increase in Peterhead's authorised export capacity (there is strong competition for grid capacity in the North of Scotland).
- Some annual variation in hydro and coal output, and an increase in output from Peterhead.
- A substantial drop in nuclear output in 2002, stemming from mechanical problems at the Torness nuclear power station.

The traditional view of the electricity sector in Scotland is one of overcapacity in relatively low marginal cost generation. Cheap and plentiful generation has been the justification for protecting the electricity sector in Scotland from aspects of the privatisation regime introduced in England and Wales from 1988 onwards. It also contributed towards limiting the opportunities for new renewables plant in Scotland, as ministers were unwilling to promote new generation which would substantially impact upon existing plant and profitable exports to England.

At privatisation, so-called restructuring contracts were entered into which effectively allocated (contractually) the majority of generation plant to the two supply companies. The most well known was the Nuclear Energy Agreement (NEA) in which Scottish Power and Scottish Hydro-Electric had a must-take obligation until 2005 for the entire output from Torness and Hunterston. Access to the Scotland-England interconnector was also allocated to the two Scottish companies and British Nuclear Fuels Ltd (for Chapelcross).

Both ScottishPower and Scottish Hydro-electric have benefited from selling low marginal cost generation (principally coal, and some hydro) to the England and Wales market. Prior to April 2005 (when the new BETTA market was introduced in Scotland), exports were via the companies' historical rights to interconnector access. Claims of coal-generated exports are based more on contractual sales rather than the physical reality. Put another way, claims of nuclear power accounting for 50% of Scottish consumption is premised on allocating the entire Scottish nuclear output to Scottish consumers – in reality a proportion of nuclear-generated electricity does flow south.

Latterly, the accepted wisdom of Scottish overcapacity has undergone something of a U-turn, with public warnings of a looming energy gap. This is a situation which has been anticipated for some time within the energy sector, as it is precipitated by long-planned power station closure dates. But it is only relatively recently that it has been openly discussed as a situation which requires government action.

The longstanding background to Scotland's present energy outlook includes:

- The planned closure of Hunterston in 2011 and Torness in 2023.
- Emission limits imposed by European legislation which necessitate installation of Flue Gas Desulphurisation (FGD) equipment at Longannet and Cockenzie, or, plant closure.

Recent events over 2005-06 which contribute substantially to the long-term outlook include:

- An announcement by ScottishPower that Longannet will be fitted with FGD, extending its life to approximately 2025
- Plans by British Energy to seek a 10-year life extension for Hunterston to 2021
- Substantial rises in energy prices
- Following the new Renewables Obligation (RO) support mechanism, a sharp rise in installation rates of wind power in Scotland. Figure 2.2 shows annual installations in MW to 2005, and an estimated installation rate for 2006.

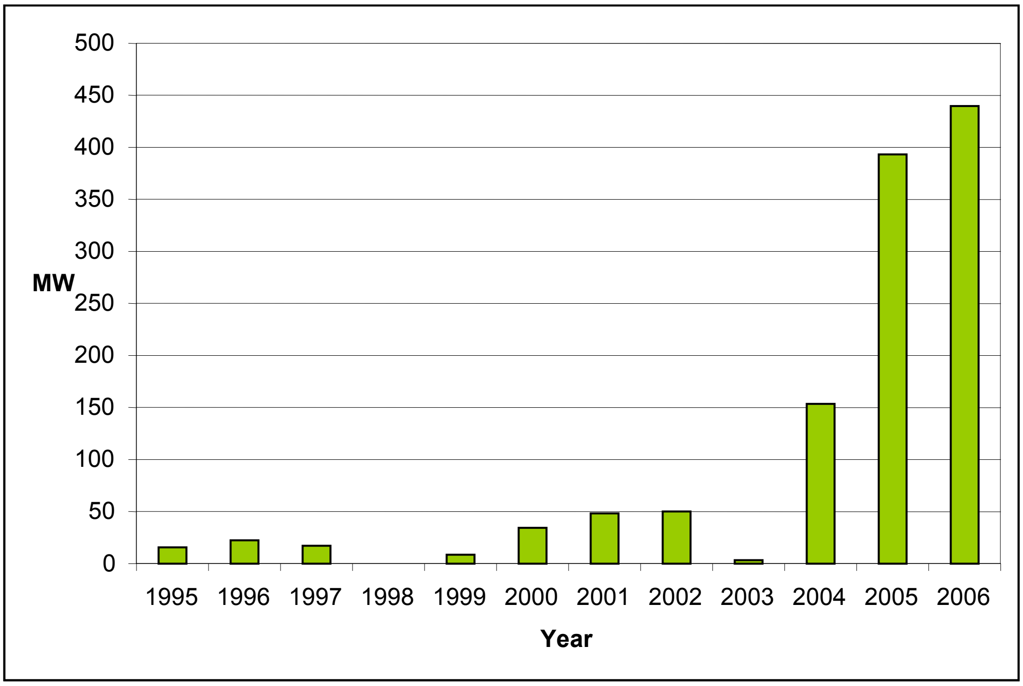

Figure 2.2 Annual wind power installations, Scotland

Events are often inter-dependent. For example rising energy prices has been a major factor in altering ScottishPower's economic evaluation of FGD (which was previously considered uneconomic).

3 OUTLOOK

At present, Hunterston is due to close in 2011, Cockenzie by 2015 and Torness in 2023. It is quite credible that life extensions will be sought for Hunterston and Torness. But, if these stations were all to close, Scotland's options for closing the energy gap, excluding new nuclear power, include:

- Energy efficiency
- Utilising extra gas-fired capacity at Peterhead
- Increasing the output from Longannet, which in 2004 ran at an approximate 48% capacity factor
- New renewables, (including micro-renewables)
- Reducing exports

By way of illustration, three nominal scenarios below show perturbations on these options.

3.1 Scenarios

(1)

- Energy demand grows at 1% per annum. (1% is a common assumption but, even before any substantial energy efficiency measures, average growth in the period 2000-04 was approximately 0.8% per annum.)
- Exports are increased in line with growth in energy demand at 1% per annum.

Figure 3.1 shows a possible response to this.

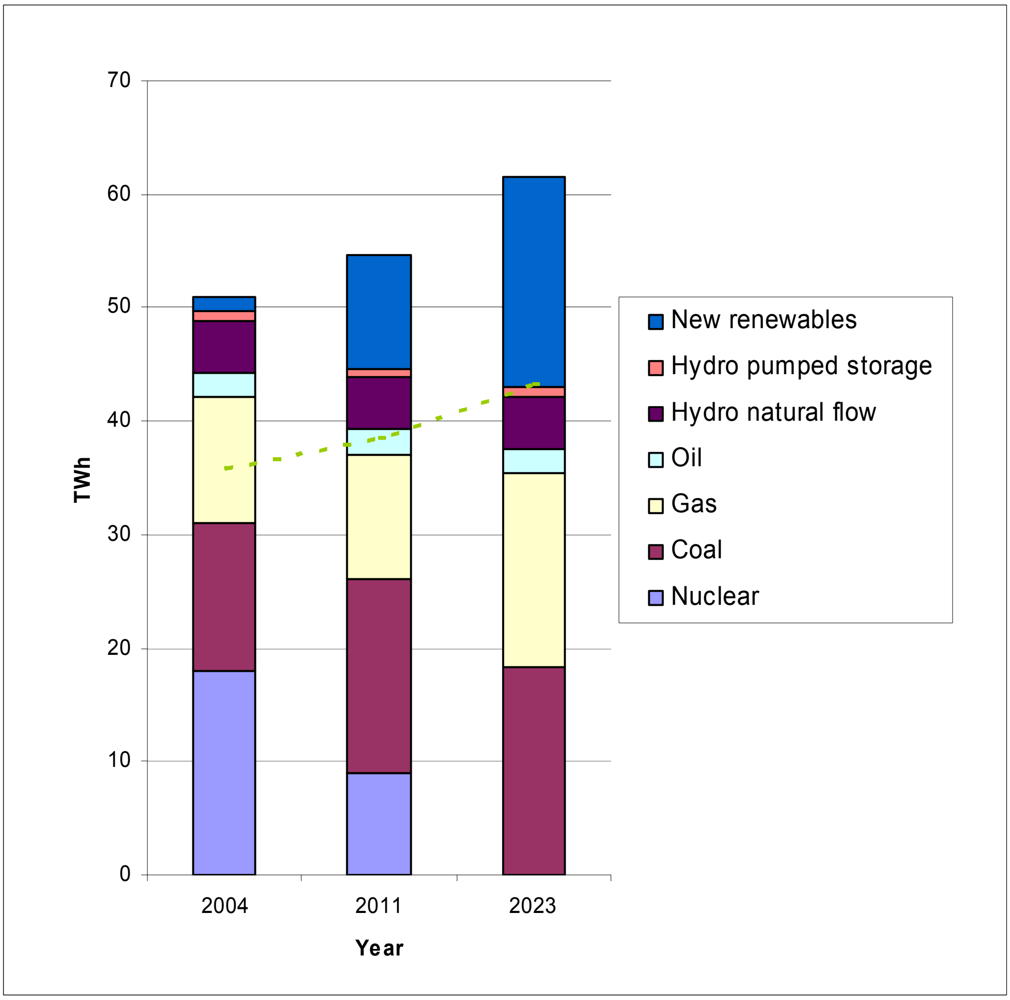

Figure 3.1 Scenario (1) Outlook

By 2011,

- It is assumed that gas output is not able to increase due to grid constraints in the Peterhead area.
- Coal output has increased by 30% or nearly 4TWh.
- New renewables have increased their output from 2004 to 2011 by just under 34% a year, (a total of 8.7 TWh) with an installed capacity of approximately 2.9 GW in 2010 and 3.9 GW in 2011. By comparison, the BWEA[1] expects Scotland to deliver in onshore wind alone 3.5-4.4 GW by 2010, depending on planning approval rates, and in the absence of north of Scotland grid upgrades.

By 2023,

- Cockenzie is shut and Longannet is generating at a 90% capacity factor
- Authorised output from Peterhead has been increased by 900MW

[1] BWEA: British Wind Energy Association

- The Scottish Executive's target of 40% of renewables by 2020 is met with a growth rate of just over 2% per year in new renewables from 2011, after which growth accelerates to 15% for the three years 2023.

(2)

- Energy demand grows at 0.5% per annum
- Exports are increased in line with this demand growth.

Figure 3.2 shows a possible response to this scenario.

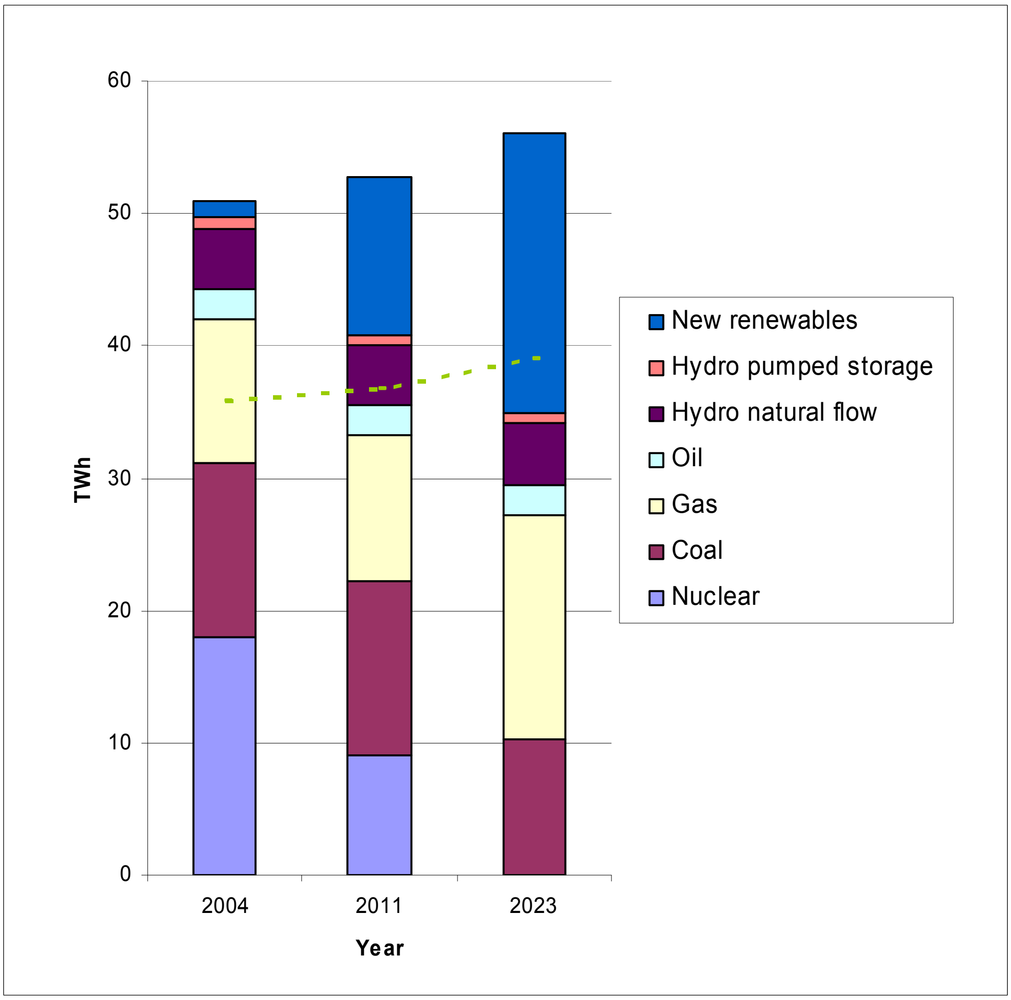

Figure 3.2 Scenario (2) Outlook

By 2011,

- Coal output is unchanged from 2004
- New renewables output has increased its output from 2004 to 2011 by just over 37% per year to 2011 (a total of 10.7 TWh), culminating in an installed capacity of approximately 4.5GW in 2011.

By 2023,

- Coal output is reduced from 2011 levels by 2.9TWh (22%) and Longannet is generating at a 51% capacity factor
- Authorised output from Peterhead has been increased by 900MW
- Renewables are generating 42% of generation by 2020, which is enough to meet the Scottish Executive's target with excess for allocation to targets in England and Wales. By 2023 renewables are generating 46% of generation. This is achieved at an annual growth rate of just under 5%, from 2011.

(3)

As (2), but with the elimination of exports.

Figure 3.3 shows a possible response to this scenario.

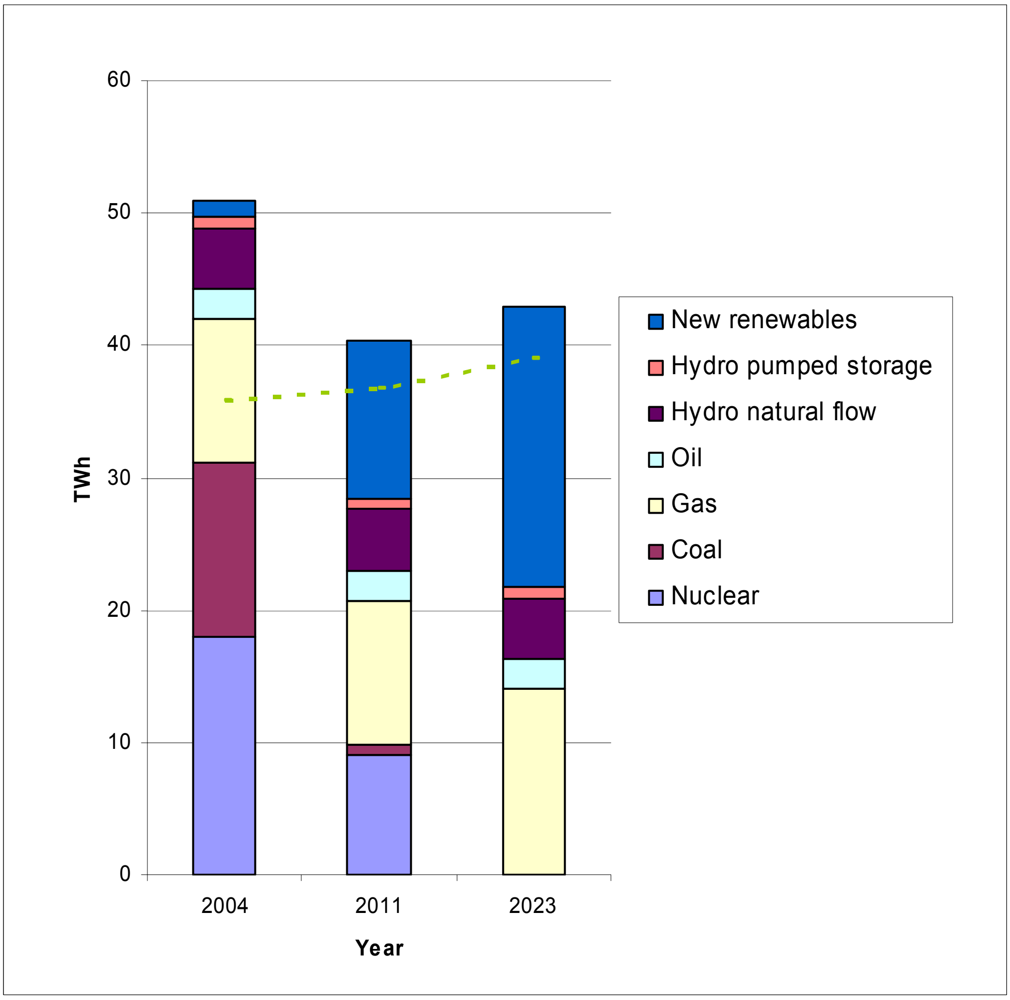

Figure 3.3 Scenario (3) outlook

Under this scenario, renewables levels are kept the same as under achievable, which results in relatively higher penetration levels (41% of generation in 2011 and 60% in 2023). Coal output is reduced to a minimum by 2011 and eliminated by 2023 when gas replaces coal as the marginal plant on the system.

3.2 Analysis

The scenarios above are for illustrative purposes, but serve well in demonstrating that:

- There are a number of options available for meeting Scotland's energy gap, without new nuclear power.
- It is only through a combination of measures that optimal outcomes are achieved
- Doing nothing is not an option
- Even if a decision to build nuclear plant is taken, it will not be operational for the 2011 scenario and possibly not even by 2023. Thus strong and decisive action on energy efficiency and renewables is essential now if carbon emissions are to drop in the next decade.

The scenarios major on the contributions possible from growth in new renewables. Some of the higher levels shown may seem ambitious, but are demonstrably achievable.

The renewable **resource** is plentiful in Scotland. The maximum contribution of new renewables in the scenarios is some 21 TWh in 2023. In research for the Scottish Executive, it has been estimated that the Scottish resource (wind, wave, tidal, biomass and landfill gas) totals approximately 215 TWh [4].

The highest **percentage penetration** of renewables (including large hydro) is some 60% of generation. By contrast Norway generates nearly all of its electricity from hydro power. Denmark secures its entire electricity supply from large and small Combined Heat and Power plant and wind energy. In the West of Denmark (which is electrically separate from the East but connected to Sweden to the North and Germany to the South), wind energy penetration alone is already over 20%. By the end of 2004, Schleswig Holstein, a region of Northern Germany, had a wind energy penetration of 34%. This is before future growth of renewables planned for all of these countries.

Since the early 1990's, wind energy has grown world-wide in installed capacity at a consistent annual rate of approximately 30%. Individual markets such as Germany and Spain have far exceeded these **growth rates**. Between 1999 and 2005 Germany installed 15.6 GW of wind energy – the lowest annual installation being 1.6 GW and the highest 3.2 GW. The experience of wind energy shows the possibilities for the less mature technologies such as wave and tidal as they too approach maturity.

Alternatives to these large contributions in grid-connected renewables include micro-renewables, which can contribute substantially to reducing the need for grid-supplied electricity. Demand for oil in the generation of electricity would be reduced through enhanced renewables development on the islands.

Everyone agrees that energy efficiency is desirable. However, discussions as part of the current Energy Review suggest that government is struggling to implement meaningful energy efficiency measures. Energy efficiency is not the subject of this paper – however it is difficult to comprehend why, for instance, a programme of ambitious energy efficiency measures with mandatory targets and / or stepped pricing to ensure real reductions in energy use, is apparently more daunting than building new nuclear power stations of a new design, with no prospect of ever guaranteeing the safe storage of dangerous nuclear waste, in the context of public opposition, increasing climate instability and terrorist threats to global security.

4 FUTURE CHALLENGES

Factors which are often cited as constraints to realising renewables potential are discussed briefly here.

4.1 Grid Infrastructure

The topology of the current grid infrastructure in the UK is not ideally suited to an electricity system supplied from renewables. Naturally, this is because the existing system is designed for existing generation plant. There are a number of options for moving forward:

- Alter the grid topology, which involves extending the grid to high resource areas.
- Develop micro-renewables at the point of consumption
- Use a storage medium such as hydrogen, and, like natural gas, transport the hydrogen to an alternative point of use

All three of these options are being pursued at the present time.

Grid extensions offer the nearest-term solution. In Scotland, the 2010 target of 18% of generation supplied by renewables will be met without any major grid reinforcement. The 2020 target of 40% of consumption will require some reinforcement work, which at present is proposed to comprise the Beauly Denny upgrade and strengthening of the interconnections between Scotland and England.

4.2 Variability

Renewables such as wind energy which rely on naturally fluctuating resources are characterised by variable output. Up to a certain penetration, the level of which is dependent on the system in question, renewables variability is “lost” in the existing fluctuations of demand and generation. At some point, the system operator will need to respond to renewables variability – either through application of existing practices for managing the system or through adoption of new tools.

The effects of renewables variability can be mitigated at the wind farm – for instance through control functions of wind turbines, power conditioning, or through the use of storage technologies in combination with renewables plant. Variability is also amenable to prediction, which helps considerably in managing variability. At the system operator level, operators with high penetrations of wind energy are pioneering new practices such as forecasting and control strategies.

The main point to note is that variability does not pose an absolute limit on penetration levels. But, increasing penetration levels do pose challenges which require the adoption of new practices and which, because this is a change from existing practices, incurs costs.

The GB system operator, National Grid Company (NGC) states that:

“*The output of some renewable technologies, such as wind, wave, solar and even some CHP, is naturally subject to fluctuation and unpredictability relative to the more traditional generation technologies. However, based on recent analysis of the incidence and variation of wind speed, the expected intermittency of wind does not appear to pose major problems for stability, which cannot be adequately managed.*” And that “*It is a property of the* *interconnected transmission system that individual and local independent fluctuations in output are diversified and averaged out across the system*."

Furthermore, "*Current levels of frequency response and short term reserve are believed to be sufficient, even if the Government's 2010 goal of 10 per cent of electricity supplies sourced from renewable fuels were all to be met by, say, wind technologies. In any event, should more response and reserve services be required, then ancillary service market arrangements should encourage their cost effective provision. So although there could be an increase in operational costs, significant technical problems arising from accommodating the Government's targets for renewables and CHP by 2010 are not foreseen*." [5]

A new report on variability by the UK Energy Research Centre reviews some 200 international studies on the impacts and costs of variable renewables [6]. The report's principal author, Robert Goss, states that:

"*The output of wind, wave and other renewables fluctuates and cannot fully be controlled. The extent to which this is likely to create problems, costs or even lead to black-outs is the subject of a long-running debate. Reports that suggest it is highly costly, or restricts the role of renewables, are out of step with the majority of expert analysis, reflect regional problems that the UK can avoid, or both*." [7]

4.3 Costs

A thorough comparison of future unit energy generation costs, with an explanation of their derivation, are presented in a UK Government Office report, as part of the 2003 Energy Review [8]. These are reproduced in Table 4.1.

Technology	2020 unit cost, 5-15% discount rate (p/kWh)	Confidence in estimate
PV	10-16	High
Onshore wind	1.5-2.5	High
Offshore wind	2-3	Moderate
Energy crops	2.5-4	Moderate
Wave	3-6	Low
Fossil with CO_2 Capture & Sequestration	3-4.5	Moderate
Nuclear	3-4	Moderate
CCGT	2-2.3	High
Coal (IGCC)	3-3.5	Moderate

Table 4.1 UK Performance and Innovation Unit cost estimates

The Review noted that "*support for renewables will induce innovation and "learning", bringing down the longer-term unit costs of the various technologies as volumes increase and experience is gained. In this way, today's investment buys the option of a much cheaper technology tomorrow*." The follow-on White Paper states that "*specific measures are needed to stimulate the growth in renewable energy that will allow it to achieve the economies of scale and maturity that will significantly reduce its costs.*"

High energy prices are cited in the present energy review when it states that "*[high] prices will incentivise reduced and more efficient consumption*" but that "*policies designed to reduce* *emissions may prove unpopular if they add further to prices that are already high*." And on nuclear power it states that "*The 2003 Energy White Paper recognised that replacement nuclear build might be necessary if we are to meet our carbon targets, but concluded that its then current economics made it unattractive…..The [present] Review will examine whether recent changes in energy prices have changed that assessment*."

Underpinning the current Energy Review there are arguably two conflicting objectives on energy prices. One is the implied need for high prices to justify investment in new and / or expensive technologies, the other is the desire to reduce prices for consumers. The electricity system will in any event require substantial investment over the coming years to replace ageing plant and infrastructure, and to meet rising demand. There are uncertainties associated with any choices made now which will set the scene for the future makeup of the industry.

Two years ago the PIU had a "high" confidence in gas-fired generation costs and yet international politics have prompted gas prices to rise since, in the absence of any material change to the UK's gas supply prospects in that time. Nuclear power has had 60 years of unprecedented levels of investment, with no solution to storing waste safely for the thousands of years it remains dangerous, and no fail-safe against accidents or terrorist activity. There is no design consensus, with the latest proposals centred on largely unproven designs. And burning fossil fuels causes climate change.

In these circumstances, investment in wind energy – powered by free *in situ* fuel, modular, proven, fast to construct and removable with minimal lasting impact on the surroundings – looks very attractive. Investment in less mature technologies such as wave and tidal may initially be more expensive than conventional power but has to be, in the longer-term, the better, less risky and in the long-term lower-cost choice. Ultimately, it is the only choice, it is just a matter of how much damage we choose to inflict in the meantime.

4.4 An imperative

In the context of a perceived overcapacity, growth in renewables in Scotland was slow. Challenges were presented as problems and there was a general resistance to change. A new market mechanism and positive government support have dramatically changed that situation. An emerging energy gap poses twofold implications for renewables:

- The former resistance to renewables on the grounds that they detract from the benefits of running existing low cost plant has more or less disappeared, and is replaced by those same detractors now entering into the business of building wind farms and investing in longer-term marine technologies. The main financial driver to-date has been the RO but there are signs of a longer-term, mainstream confidence in renewables as it becomes clear that it could have a future as a major energy supplier. This is a positive boost for renewables which have in the past been constrained by vested interests.
- A belief, held by some, that renewables cannot fill the energy gap, and that as such a programme of new conventional plant is required. The extent to which such a decision would impact upon renewables would very much depend on the circumstances. But it would remove at least some of the drive created by an "imperative" for renewables and of course divert substantial money that could otherwise have gone towards renewables.

The first and second largest markets in the world for wind power are Germany and Spain. Both are in the context of political decisions on no new nuclear build. Sweden also has a nuclear moratorium and has announced a long-term plan to break its dependence on fossil fuels by 2020 through substantial investments in renewable energy and energy efficiency [9].

5 CONCLUSIONS

Key conclusions from this analysis are:

- There are a number of options available for meeting Scotland's energy gap, without new nuclear power
- Even if a decision to build nuclear plant is taken, it will not be operational in time to meet the gap left by the first major plant closure planned for 2011. Thus strong and decisive action on energy efficiency and renewables is essential in any event if carbon emissions are to drop in the next decade.
- Changes to the grid's topology are inevitable for accessing Scotland's most energetic sites for renewables. At the same time, longer-term options such as hydrogen as an energy carrier should be pursued.
- The natural variability of some renewables does not pose an absolute limit on penetration levels. This point has most recently been reiterated through a comprehensive review of some 200 international studies on the subject.
- Investment in wind energy – powered by free *in situ* fuel, modular, proven, fast to construct and removable with minimal lasting impact on the surroundings – already looks attractive. Investment in less mature technologies such as wave and tidal may initially be more expensive than conventional power but has to be, in the longer-term, the better, less risky and in the long-term lower-cost choice.
- A decision in favour of a programme of new conventional plant would remove at least some of the drive created by an "imperative" for renewables and of course divert substantial money that could otherwise have gone towards renewables.

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