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THE REGIONAL ELECTRICITY GENERATION MIX IN SCOTLAND: A PORTFOLIO SELECTION APPROACH

BY

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The regional electricity generation mix in Scotland: A portfolio selection approach[1]

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Abstract

Standalone levelised cost assessments of electricity supply options miss an important contribution that renewable and non-fossil fuel technologies can make to the electricity portfolio: that of reducing the variability of electricity costs, and their potentially damaging impact upon economic activity. Portfolio theory applications to the electricity generation mix have shown that renewable technologies, their costs being largely uncorrelated with non-renewable technologies, can offer such benefits. We look at the existing Scottish generation mix and examine drivers of changes out to 2020. We assess recent scenarios for the Scottish generation mix in 2020 against mean-variance *efficient* portfolios of electricity-generating technologies. Each of the scenarios studied implies a portfolio cost of electricity that is between 22% and 38% higher than the portfolio cost of electricity in 2007. These scenarios prove to be "inefficient" in the sense that, for example, lower variance portfolios can be obtained without increasing portfolio costs, typically by expanding the share of renewables. As part of extensive sensitivity analysis, we find that Wave and Tidal technologies can contribute to lower risk electricity portfolios, while not increasing portfolio cost.

JEL code: D81, L94, R15

Keywords: Electricity generation mix, portfolio theory, regional energy policy

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1. Introduction

What technologies should comprise an effective electricity generation mix for Scotland? Recent attempts to answer this question have looked at future policy targets and drivers of change to the electricity generation mix. These studies produce scenarios for the generation mix in Scotland in order to inform current policy practice[2]. For example, these scenarios might identify whether specific targets for the proportion of generation from renewable sources will being met by the intended date. If these targets are not met then some additional policy would be required which will in turn cause the real outcome to differ from that imagined in the scenario.

In this paper, we use portfolio selection theory to provide an additional piece of evidence in the evaluation of alternative scenarios for the generation mix in Scotland. Portfolio selection theory was initially developed in financial economics to explain and prescribe methods for holding assets whose returns are uncertain. However, this approach has recently been carried over to applications in the energy and electricity generation field (e.g. Bazilian and Roques, 2008). More widely, it has found favour for the study of a number of research areas where outcomes (e.g. financial returns, or the cost of electricity) not only depend upon the characteristics of each of the individual options (e.g. technology costs or their variability), but also the interactions between the generation characteristics of each option (e.g. correlations between technology costs).

This paper differs in three ways from previous applications of portfolio selection theory to the electricity generation mix. First, we explicitly address the issue of the efficiency of electricity generation mix from a regional perspective. This is of interest given the distinctive energy policy emerging in Scotland as compared to the UK. This policy divergence is reflected in a set of more ambitious targets for renewable electricity and the ruling out of new nuclear power stations. We discuss these policy drivers for Scotland's electricity generation mix in Section 2.2[3].

[2] Some scenario work involves looking at individual technologies, e.g. FREDS:MEG (2009) but in this paper we are only concerned with scenarios for the electricity mix as a whole.

[3] The nature and rationale for energy policy distinctiveness in Scotland as compared to the UK is discussed in detail in Allan *et al* (2008). We do not add to this here. It is sufficient for our purposes to note that a distinctive

Second, we are able to examine the mean-variance efficiency of alternative electricity scenarios for Scotland in 2020. Assessing existing scenarios from an explicit portfolio selection approach provides complementary information that may be useful from a policy perspective. In fact, we find that none of the scenarios examined are mean-variance efficient. The implication is that there appear to exist opportunities to lower electricity costs for no greater risk, or reduce risks while incurring no additional costs, a result that presumably is, potentially at least, of considerable policy interest. However, a note of caution is required. In line with most other applications of portfolio theory in this field we assume zero transactions costs and do not incorporate current energy infrastructure as a constraint. Our results would therefore require further exploration before concluding that Pareto improvements are feasible[4]. Nonetheless, we believe our results provide a *prima facie* case for exploring alternative scenarios for the Scottish electricity generation mix.

Third, to our knowledge this is the first application of portfolio theory to include marine generation in electricity mixes. Our consideration of these Wave and Tidal technologies reflects the high marine renewable resource in Scotland, and the anticipated contribution of these technologies to the generation mix. Currently these technologies are largely in their development stages with limited commercial deployment and typically have higher standalone levelised costs than other renewable and non-renewable technologies (see Allan *et al*, 2009). However, our application of portfolio theory does offer support for the view that there is a potentially important role for marine technologies in future electricity mixes, even at existing cost levels. Allowing for learning rates further reinforces this view.

We begin in Section 2 with an historical perspective on the existing electricity generation mix in Scotland and examine the drivers of changes in the mix to 2020. We then discuss in some detail a number of recently published scenarios for the future generation mix in Scotland. In Section 3 we begin by outlining the rationale for examining these electricity generation mixes from a portfolio theory perspective, show how such analyses are conducted, and note the results of previous applications.

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focus on the electricity generation mix in Scotland motivates a separate appraisal of alternative electricity generation mixes at the regional level.

[4] Van Zon and Fuss (2008) relax the former assumption and Doherty *et al* (2008) relax the latter.

In Section 4 we report the results of our application to the Scottish electricity generation mix, before examining the impact of relaxing a number of (necessary) assumptions through detailed sensitivity analysis. We conclude in Section 5 with a discussion of the implications of our analysis for policy and suggest how the analysis can be refined in future research.

2 Scotland's electricity mix and historical basis for current position, plus factors affecting future generation mix

2.1 Development of the existing electricity generation mix in Scotland

Table 1a and 1b show the development of operational electricity generation capacity in Scotland. Reading along the rows for each technology in Table 1a, gives the decade in which the capacity (in MW) that is operational today was installed. Reading down the columns in this table shows us how much of the capacity operational today was installed in each decade. The same format is used in Table 1b but in this case each cell shows the number of separate facilities commissioned, by technology and decade. These two tables combine to allow us to identify a number of issues regarding the evolution of the existing operational generation mix in Scotland.

Table 1a: Capacity (in MW) of plants operational in Scotland in May 2009, by decade commissioned or first year of generation, and by technology

Capacity (in MW)	1920s	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s to 2008	**Total**
Hydro	17	186	-	792	174	300	2	-	119.7	**1590.7**
Diesel	-	-	9	109	-	10	-	2	3	**132.5**
Pumped storage	-	-	-	-	440	-	-	-	-	**440**
Coal	-	-	-	-	1152	2304	-	-	-	**3456**
Nuclear	-	-	-	-	-	860	1205	-	-	**2065**
Gas (including gas/oil)	-	-	-	-	-	-	1540	-	123	**1663**
Wind	-	-	-	-	-	-	-	63	1117	**1180**
Biomass (including poultry litter)	-	-	-	-	-	-	-	-	56	**56**
Total	**17**	**186**	**8.5**	**901**	**1766**	**3474**	**2747**	**65**	**1418.7**	**10583.2**

Source: BERR, Digest of United Kingdom Energy Statistics, accessed September 2009

Table 1b: Number of plants operational in Scotland in May 2009, by decade commissioned or first year of generation, and by technology

Number of projects	1920s	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s to 2008	**Total**
Hydro	2	7	-	39	14	1	1		7	**71**
Diesel	-	-	2	3	-	1	-	1	1	**8**
Pumped storage	-	-	-	-	1	-	-	-	-	**1**
Coal	-	-	-	-	1	1		-	-	**2**
Nuclear	-	-	-	-	-	1	1	-	-	**2**
Gas (including gas/oil)	-	-	-	-	-	-	1	-	1	**2**
Wind	-	-	-	-	-	-		4	34	**38**
Biomass (including poultry litter)	-	-	-	-	-	-		-	2	**2**
Total	**2**	**7**	**2**	**42**	**16**	**4**	**3**	**5**	**45**	**126**

Source: BERR, Digest of United Kingdom Energy Statistics, accessed September 2009

Table 1a shows the scale of the major periods of activity in terms of the existing generation mix in Scotland. Almost one-third of the installed capacity was commissioned in the 1970s, with over 75% of the existing capacity installed between the 1960s and 1980s. During the 1990s there was only a fraction of the investment compared to earlier decades. Only 65MW of new capacity were commissioned, 63MW of which came from wind generation. Table 1a shows that of the 1419MW of capacity commissioned since 2000, over 90% has come from renewable technologies, with most coming from onshore wind projects. During this time period 1117MW of onshore wind capacity and 34 renewables projects have been installed. This is a greater annual average level than occurred in the period of great investment in renewables generation capacity which followed the Second World War. That period saw the formation of the North Scotland Electricity Board with its plans to generate electricity from the glens of Scotland using hydroelectric technologies (Hannah, 1982). These investments in the 1950s led to 792MW of capacity installed across 39 projects. Each of these individual hydro schemes were part of larger schemes, such as the 262MW Sloy installation. The Sloy scheme began operation at different times from 1950 to 1963, with a total of ten separate facilities operating in this area. The Great Glen scheme was a similar proposal, with a total capacity of 225MW. Its constituent parts date from 1955 to the most recent addition of 100MW to this scheme which occurred in 2008.

Tables 1a and 1b also identify the development of major capacity in non-renewable facilities: the coal stations at Longannet and Cockenzie in the 1960s and 1970s, the gas station at Peterhead in the 1980s, and the nuclear facilities in the 1970s and 1980s. Since 1991, much of the new development, leaving aside any maintenance of existing plants which would have necessarily occurred, took place in renewables, with much of this occurring since the year 2000. We explore possible changes to the existing generation mix later in this section.

The amounts (GWh, rather than capacities) and share of electricity generation in Scotland coming from different technologies in 2007 is given in Table 2. 48,217 GWh was generated, with approximately 20% coming from renewable technologies[5]. For 2007, the most recent year for which data are available, coal, gas and nuclear each contributed more than 25% of the total amounts of electricity generated.

Table 2: Generation mix in Scotland in 2007 by technology, GWh

		GWh	% share
Coal / Pulverised fuel		13853	28.7
Gas		12595	26.1
Nuclear		12344	25.6
Total Renewables		**9424**	**19.5**
Of which:	Wind	2644	5.5
	Hydro	5895	12.2
	Biomass and landfill gas	885	1.8
Total, GWh		**48217**	**100.0**

Source: DTI Energy Trends, December 2008. Note: Totals may not sum due to rounding.

2.2 Factors affecting the future electricity generation mix in Scotland

Several interconnected factors are expected to produce significant changes in the future capacity and electricity generation mix in Scotland. These factors fall under two broad headings: technical and policy.

Technical reasons for changes in the way in which electricity is generated in Scotland include, but are not limited to, the two points. These are: network and grid constraints and developments, and the remaining lifetimes of existing plant. We

[5] Note that this is significantly lower than renewables share of installed capacity in Scotland due to the lower capacity factors of these technologies.

attempt to summarise these issues here, beginning with the electricity transmission system. It has been acknowledged (RSE, 2006; FREDS:MEG, 2009) that significant reinvestment will be necessary over the next twenty years if renewable energy sources, typically located in areas away from major centres of demand, are to meet the levels of penetration envisioned (see ENSG, 2009, for details of the types of grid investments required under alternative scenarios). It has been estimated that a programme of network investment in the (UK) transmission grid totalling some £4.86 billion will be required (ENSG, 2009). Such grid enhancements include plans to increase the capacity of interconnection between Scotland and England through subsea HVDC cables to complement the existing onshore connection. Such transmission grid investments, however, require the permission of the networks regulator (OFGEM), which then allows the grid owner to recoup the costs of investment from generation customers who use the network (plus a (regulated) return on their investment). The regulator therefore predicts the extent to which network extensions would be used before it grants permission, but generators will not be willing to contract to site facilities in places served by the new grid until the new grid investment is made. This explains some of the delays in bringing forward additional generation in areas currently not served by the transmission network, and also emphasises the importance of developing an appropriate network for delivering Scotland and the UK's renewable energy goals.

The two major coal power stations in Scotland are coming under the European Union Large Combustion Plant Directive, so that from 2011 they will have 10,000 hours of operation remaining, or until 2015, whichever is sooner. Coal stations may remain in Scotland in the long term with the use of CCS technologies, such that the vast majority of their emissions are prevented from entering the atmosphere by being buried in previously depleted gas fields. Such storage capacity exists in the North Sea (Scottish Centre for Carbon Storage, 2009a) and it is hoped that CCS technologies might play a role in the future of coal generation in Scotland and the UK, although no full demonstration-scale plant has been completed. There are EU plans for 10-15 demonstration projects for CCS to be operational by 2015, although widespread deployment of CCS technologies is not expected to occur until 2020 (Scottish Centre for Carbon Storage, 2009b).

As identified in Table 1a and 1b, the current operational nuclear plants in Scotland were developed in the 1970s and 1980s. This means that they are now reaching the end of their design lives, and the two remaining stations, Hunterston B and Torness, are scheduled for closure in 2016 and 2023 respectively (RSE, 2006). In both cases, plant lifetime extensions are possible and would typically increase the working life of each plant by around 5 years. The recent report by a committee of members of the Scottish Parliament (Scottish Parliament, 2009) indicated that, while they did not see a new generation of nuclear facilities as necessary, "there will be a need to extend the operating lifetimes of the current generation of nuclear power stations in Scotland" (Scottish Parliament, 2009, paragraph 144). This is to avoid the perceived "energy gap" caused by the loss of existing coal and nuclear facilities.

As well as these environmental regulations, oil and gas generation will be affected significantly by the increasing level and volatility of fuel prices, which (as discussed in Section 3.3) typically make up the major element of the overall cost of these technologies. Indeed, in the case of both these technologies the marginal cost of production will be a function of the prevailing fuel price (subject to any fuel contracts). For the period to 2020 and beyond, fuel prices are expected to rise (van Ruijven and van Vuuren, 2009). This reflects current concerns about resource depletion (e.g. see de Almeida and Silva, 2009), reduced investment, greater demand (and uncertainty), and geopolitical risks. The range of fuel price forecasts is often huge and higher oil prices have been predicted before (for example, Saunders, 1984). Further, for specific fuels forecasts of more than a quarter ahead can offer no additional information than a one-quarter ahead forecast (Sanders *et al*, 2009). However, there appears to be a general consensus that over the long-term energy prices will rise.

The main factors affecting the shape of energy policy in Scotland have been discussed elsewhere (Allan *et al*, 2008). We summarise that discussion here, albeit briefly. Since devolution in 1999, policies concerning electricity generation in Scotland have increasingly come under the influence of the Scottish Government, despite energy being an issue that is reserved to Westminster. It has set ambitious targets for the share of Scottish electricity that comes from renewable sources (50% by 2020, compared to 20% in the UK by that time) and has stated that future applications for the building of new nuclear stations are likely to be rejected, a position backed in a vote in the Scottish Parliament[6].

Renewable electricity in the UK (including Scotland) is supported through the Renewables Obligation, which requires electricity supply companies to provide Renewables Obligations Certificates (ROCs) to the electricity regulator (OFGEM). The number of certificates that must be produced is currently equivalent to 9.7% of total supply (in year 2009/10), and this share will increase annually up to a maximum of 15.4% from 2016 to 2027. These certificates are earned by accredited generators using renewable energy sources for each MWh generated. They can be sold in the ROC market, with generators on the supply side, and electricity retail companies on the demand side. The price of ROCs in theory is restrained by the provision of an alternative method by which supply companies can meet their obligation, paying a buyout price, which began at £30 in 2001 and rises in line with the Retail Price Index every year. Monies received by OFGEM from supply companies paying the buyout price for any ROCs they are unable to produce are redistributed back to electricity supply companies, who receive a portion of the total buyout funds in proportion to their contribution to the total number of ROCs received. In practice, this has meant that since inception the annual value of a ROC has been between 20% and 50% higher than the buyout price, producing an important stimulus to renewable energy development (as seen from the growth in renewable capacity between 2000 and 2009 in Tables 1a and 1b).

From April 2009, the UK government introduced “banded” ROCs, whereby accredited renewable electricity generators receive different quantities of ROCs for each MWh they produce, based on the technology used to generate the MWh. In this way, the support for renewables is no longer “technology-blind”, but is intended to bring forward developments in generation technologies other than onshore wind. The

[6] Although, strictly, each application to build a new nuclear facility in Scotland would have to be considered by the Scottish Government on its own merits.

Scottish Government has introduced further differentiation, designed to favour new marine technologies.

Table 3 shows the capacity of renewable energy projects in Scotland, by technology, at stages prior to the operational stage (including projects without planning permission). Even assuming that not all projects are granted permission, there is demand from generators to install renewable energy capacity in Scotland. Almost 90% of the capacity of proposed projects are for Onshore wind, which are likely to provide the bulk of new renewable energy developments out to 2020. Thus, renewable electricity generation plans to date do not appear to suggest a balanced portfolio of technologies will be delivered by the market alone.

Table 3: Renewable energy developments in Scotland at stages prior to operation stage, as of end September 2009, MW

Technology	*Under construction*	*Resolution to consent*	*In planning*	*In appeal*	*In scoping*	*SRO outstanding*	**Total**
Hydro[a]	1.4	19.10	12.52	-	33.33	5.49	**71.84**
Onshore wind	624.05	2,490.98	3,377.18	894.60	2,738.21	4.31[b]	**10,129.33**
Offshore wind	180.00	-	-	-	115.00	4.31[b]	**299.31**
Energy from waste	0.23	18.30	4.27	-	5.80	40.46	**69.06**
Biomass electricity	13.70	41.60	84.00	-	406.00	12.90	**558.2**
Biomass heat	7.64	-	38.92	-	25.00	-	**71.56**
Wave	-	7.00	-	-	-	-	**7.00**
Tidal	-	-	-	-	62.00	-	**62.00**
Total	**827.02**	**2,576.98**	**3,516.89**	**894.60**	**3,385.34**	**67.47**	**11268.3**

Notes: a = excludes pumped hydro, b = total wind capacity with SRO outstanding is 8.62MW, but no disaggregation by On- or Offshore are provided in source. We have split this between On- and Offshore wind 50:50. Totals for this column include this figure, but it is not included into the row totals for both wind technologies, meaning that the sum of the column totals is different from the sum of the row totals.

Source: Scottish Renewables (2009)

Under "banding" of ROCs, onshore wind will continue to receive 1 ROC per MWh, while "post demonstration" technologies such as offshore wind and regular biomass will receive 1.5 ROCs per MWh. The "emerging" class of technologies, including marine, solar photovoltaics and geothermal, will receive 2 ROCs per MWh under Westminster proposals. The Scottish Government has gone further, bringing forward proposals that Wave and Tidal generators in Scottish waters should receive 5 ROCs per MWh and 3 ROCs per MWh respectively. This, combined with other government funding in place for marine, including the EMEC testing site on Orkney, the £13 million Wave and Tidal Energy Scheme[7] (WATES) providing testing funding for devices in Scottish waters, and the £10 million Saltire Prize challenge[8], underlines the Scottish Government's support for marine technologies, but also serves to show that it is the intention of Scottish Government policy that renewables development in the next ten years is not limited to as narrow a range of technologies as has been the case in the years since the RO mechanism was introduced.

2.3 Scenarios for Scotland's future electricity generating mix

We study three projections of the future Scottish electricity generation mix for Scotland in 2020. Two of these are produced by the private sector (SCDI, 2008; Murray, 2009[9]), while the third comes primarily from a recent Scottish Government document "Scottish Energy Study" (AEA Technology, 2008). In this third study there are two alternative scenarios, corresponding to "Central" and "High" alternative assumptions regarding the future of primary energy prices, so in total we have four scenarios for the Scottish generation mix in 2020. For ease of exposition, we label these four scenarios the following: SCDI, GH, and SES1 and SES2, respectively.

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[7] As of September 2009, £2.946 million had been spent on WATES projects and their associated infrastructure for testing. It is anticipated that all the £13 million will be spent by March 2011.

[8] The details of the prize are the following. "£10 million will be awarded to the team that can demonstrate in Scottish waters a commercially viable wave or tidal energy technology that achieves a minimum electrical output of 100 GWh over a continuous 2 year period using only the power of the sea and is judged to be the best overall technology after consideration of cost, environmental sustainability and safety" (Scottish Government, 2008). The prize is intended to be awarded in Spring 2015, following the assessment of qualifying marine generation between January 2010 and December 2014.

[9] The private sector study (Murray, 2009) was based on research prepared by Garrad Hassan, so we label this scenario "GH".

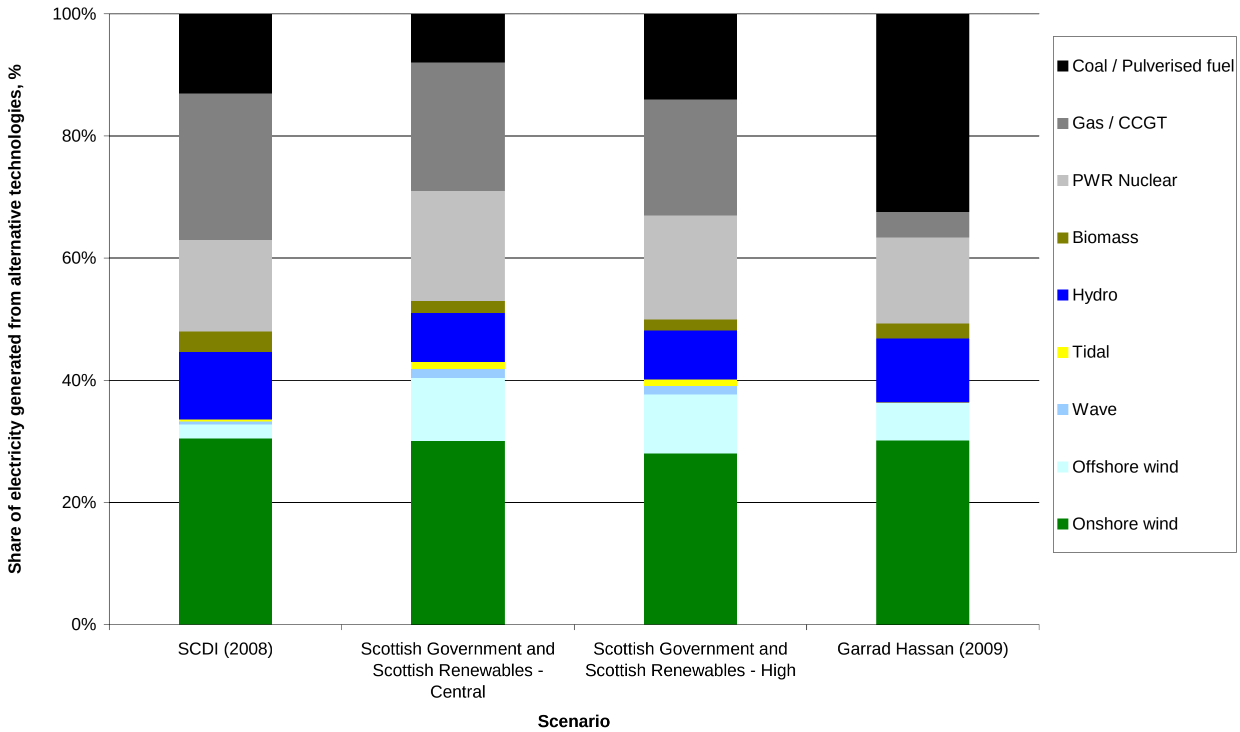
All four scenarios share the same year, 2020, and have a number of other similarities. First, the total of Scottish electricity demands are broadly similar across all the scenarios. The SCDI scenario predicts annual increases between 2008 and 2014 of 0.9%, reduced to 0.4% p.a. for 2016 to 2020. The annual consumption in Scotland in their scenario is 45.9TWh, 9% higher than demand in 2008. GH follow the assumptions in SCDI. However having been published six months later, this report is able to reflect the experiences of early 2009 when economic output and energy consumption fell in Scotland. This study assumes no growth in electricity demand between 2008 and 2009, then the same pattern of demand growth as SCDI between 2009 and 2020. This gives total Scottish electricity demand in 2020 of 45.4TWh in 2020. Total demand for electricity (including losses and own use) in Scotland according to AEA Technology (2008) will be 41.5TWh in the SES1 scenario, and 42.5TWh in the SES2 scenario. These are both actually slightly lower than demand in 2005 and are therefore around 9% lower than the other scenarios.

Second, given the significant uncertainty surrounding some of the anticipated developments discussed in Section 2.1, it is perhaps somewhat surprising that the installed capacity and total amount of electricity generated in Scotland in 2020 remains broadly the same across the four scenarios. The SCDI scenario predicts generation of 53.4TWh in 2020, coming from an installed capacity of 15.9GW. The GH report predicts a slightly higher level of generation of 58.0TWh with a correspondingly higher installed capacity of 16.5GW. As with consumption, total generation is lower in both of the AEA Technology scenarios. The SES1 and SES2 scenarios, have total generation of 50.3TWh and 54.3TWh respectively. While there are no capacity figures given for the SES1 and SES2 scenarios, both see large increases in the extent to which renewable generation technologies provide electricity to the generation mix. There is also the continuation of some nuclear (at least through 2010), a move towards "clean coal" and the replacement of some new gas capacity. These figures suggest that the total capacity for generation in Scotland would be significantly higher than current levels, particularly given the lower capacity factors expected for onshore wind, which other commentators expect to produce much of the growth in renewables.

We can see from the projected levels of generation and demand in Scotland in 2020 that in all four scenarios Scotland is forecast to remain, as now, a large net exporter of electricity to the rest of the UK (i.e. its local consumption is significantly less than its local generation).

Each of the scenarios anticipates a different development path for generation technologies, which give us four alternative generation mixes for Scotland in 2020. These generation mixes are displayed in Figure 1. These mixes represent the portfolios that we study using portfolio theory in Sections 3 and 4.

Figure 1: Generation mixes in each of the four scenarios



Consider firstly the share from renewable technologies. In each of the scenarios there is a significant increase in generation from renewable sources for the reasons described above. The lowest renewable share in generation comes from the SCDI scenario with 48%, while the highest share comes from SES1 scenario is 53%. Within renewable technologies, and this is the same across all four scenarios, Onshore wind provides most of the renewable generation (and around 30% of the total generation), while Hydro provides around 10% of total generation. The remainder of renewable generation is assumed to come from a range of Biomass, Offshore wind and Wave and Tidal technologies. Offshore wind contributes, in all scenarios apart from SCDI (where biomass provides 3.4%), the third highest share of renewable generation.

It is in non-renewable technologies that the largest differences are seen across the scenarios, although this observation does not apply to nuclear where there is little variability in its share. Typically nuclear is expected to provide between 14% and 18% of total generation. The share of coal and gas in the total generation mix does differ, particularly so in the GH scenario where the mix is heavily in favour of coal generation, rather than gas, while in the other scenarios the opposite is the case. We examine the efficiency of these alternative scenarios for the Scottish generation mix in Section 4, whilst in Section 3 we describe the portfolio theory method and its application to the electricity generation mix.

3. Portfolio theory and applications to electricity generation mix

3.1 Method

The genesis of mean-variance portfolio theory is credited to papers by Markowitz (1952) and Roy (1952). This work made key contributions to both the normative and positive study of selecting portfolios of financial assets. Previous work, such as Williams (1928) argued that investors would and should invest in the assets offering the greatest return. As Rubenstein (2002, p. 1042) notes: "the most important aspect of Markowitz's work was to show that it is not a security's own risk that is important to an investor, but rather the contribution the security makes to the variance of his entire portfolio – and this was primarily a question of its covariance with all the other securities in his portfolio".

This method has been applied to a number of alternative areas, including the optimal industrial structure for an economy (Conroy, 1975; Chandra, 2002) and the optimal mix of electricity supply options, which is the focus of this paper (e.g. Bazilian and Roques, 2008a). In applications to electricity supply options, it is most common for a measure of the unit cost for each technology (normally the levelised cost in p/kWh) to replace asset return, while the measure of risk used is the year-to-year variation in each technology's generating cost. With electricity generating technologies, the standard deviation of holding period returns for future cost streams for each technology are used in the measure of portfolio risk, where holding period returns measures the range of change in the cost streams from one period to the next[10].

In a simple two-technology example[11], the expected cost of the electricity portfolio ($E(r_P)$) is a weighted average of the expected cost of each technology i ($E(r_i)$), where the weights (X_i) are the proportion of each technology i in the portfolio, ($\sum_{i=1}^{n} X_i = 1$) i.e.:

$$E(r_P) = X_1 E(r_1) + X_2 E(r_2)$$

However, portfolio risk (σ_P) is not simply the weighted average of the individual technology risks, but includes the correlation coefficient between the technology returns. In the two-technology case[12]:

$$\sigma_P = \sqrt{X_1^2\sigma_1^2 + X_2^2\sigma_2^2 + 2X_1X_2\rho_{12}\sigma_1\sigma_2}$$

where ρ_{12} is the correlation coefficient between the returns of technologies i and j, and σ_i is the standard deviation in the year to year costs of technology i.

Bazilian and Roques (2008b) argue that portfolio theory assists the electricity supply decision in two ways. First, it reduces the decision of what technologies, and their shares, should be in portfolios to an examination of the small subset of the total of such portfolios which are *efficient* in terms of their risk-return characteristics. An

[10] Bazilian and Roques (2008b) for example use annually reported values.
[11] This section follows the hypothetical example as described in Bazilian and Roques (2008b, p. 65-68) where a social planner is assumed to be making the decision about the optimal mix of electricity generation technologies.
[12] This reflects the formula for the variance of a linear combination of random variables.

efficient portfolio is one in which the cost is lowest for any given level of risk, or alternatively, the risk is lowest for any given level of portfolio cost. Sub-optimal (i.e. inefficient) portfolios can be identified and ignored (so long as efficient portfolios acknowledge any technological or other constraints on the portfolio choice). Second, we can measure the impact of additional technologies in terms of their contribution to *portfolio* costs and risks. A fossil-fuel-only portfolio therefore might have least cost, but adding non-fossil fuel technologies into such a portfolio might realise the triple benefits of increasing the diversity of the electricity mix, reducing the portfolio risk – due to their costs being uncorrelated to fossil price – while not increasing portfolio cost. This is the "portfolio effect", by which researchers examining electricity portfolios have found that (typically) renewable technologies, which tend to have greater levelised costs than non-renewable options, can help to decrease portfolio risk for a given level of portfolio cost, in large part, due to their zero correlation with fossil fuel prices. We illustrate the portfolio effect for a simple two-technology case in Appendix I.

3.2 Applications to electricity mix

Applications of mean variance portfolio theory to energy and electricity generation issues have grown rapidly, following the work of Shimon Awerbuch (e.g.2005a, b) and others. Bazilian and Roques, 2008a, provide an excellent summary. This modern literature acknowledges the earlier applications of, among others, Bar-Levy and Katz (1976) and Humphreys and McLain (1998), who were the first to analyse energy mixes using portfolio theory.

The literature to date has identified certain issues to be considered when MVPT is being applied to the case of electricity generation mixes (Roques *et al.*, 2006; Awerbuch and Berger, 2003). Such issues typically concern the applicability of MVPT to electricity (and energy) portfolios, and can be grouped into three main areas: the characteristics of the generating technologies as assets, the comparability of measures of return, and the comparability of measures of risk to the financial assets for which MVPT was initially designed.

On the characteristics of assets, MVPT typically assumes that assets are infinitely divisible. Investments in new generation capacity on the other hand, and the types of technologies invested at particular times (as we saw in Table 2), are typically lumpy, and perhaps very lumpy, as in the case of the construction of a new nuclear power station. Secondly, conventional MVPT will not consider costs of moving from current (inefficient) to future (efficient) portfolios. These are important for electricity generation portfolios where there might be significant salvage and decommissioning costs for existing technologies. The levelised cost of decommissioning each technology might be included in the measure of technology cost, but the costs of shifting from one portfolio to another are not explicitly addressed. Further, electricity assets might also not be perfectly fungible: two identical technologies may not share characteristics of return and risk if their location or fuel availability is different (Awerbuch and Berger, 2003).

On the measurement of return, MVPT theory assumes that the holding period returns of assets are normally distributed. The results of electricity applications rest on the assumption that variables are also normally distributed. Returns on financial assets are also dimensionless – i.e. expressed in terms of (£) return per (£) investment. Levelised costs as a measure of asset return do not have this property. On the measurement of risk, MVP theory uses past volatility as a guide to the future. Probabilistic approaches do not capture the extremes that could cause significant disruption to the electricity system (Roques *et al.*, 2006).

Despite these limitations, there have been a number of applications of MVPT to electricity generation systems following the approach of Awerbuch and Berger (2003). These have been carried out at regional level for, for example, Scotland (Awerbuch, 2008; Pajot, 2008) and California (Bates White LLC, 2007) and at the national level, e.g. for the UK (Awerbuch *et al.*, 2005a), the Netherlands (Jansen and Beurskens, 2008), Ireland (Doherty *et al*, 2008) and for developed and developing countries (Awerbuch *et al.*, 2005b). A common feature of most of these applications is the comparison of scenarios for the electricity generating mix for the region of interest with efficient generation portfolios. In each case, the focus is on the possible contributions that renewable technologies might make within such portfolios. In our conclusions in Section 5 we return to the issues raised by these applications, and examine some recent extensions to the portfolio theory method for electricity generation.

3.3 Implementation

3.3.1 Technologies and levelised costs

We begin by detailing the unit costs of electricity (in p/kWh) from each of the technologies to be considered. We estimate the "levelised costs" of electricity (see Allan *et al*, 2009) for 11 technologies, which correspond to those technology groups considered in the scenarios for Scotland. These provide an estimate of the cost of generating a unit of electricity from a range of alternative technologies. We use the discounting approach for estimating levelised costs (Gross *et al*, 2006) where all costs and all electrical outputs are discounted to a present value. Dividing the present value of all costs by the present value of all electrical output (in physical units, i.e. kWh), gives the levelised costs for each technology. We include only "private" costs – i.e. those costs which would be paid by the developer of the technology over its lifetime – and so include costs of pre-development, construction, operation and maintenance, fuel costs and any decommissioning costs[13]. External costs, such as the cost of emissions or system costs of incorporating additional variable generation are not included. The eleven technologies, and their estimated levelised costs, are shown in Figure 2.

[13] We take the levelised cost method from Allan *et al* (2009) for all technologies. Only the Nuclear technology is assumed to have decommissioning costs.

Figure 2: Levelised costs of eleven electricity technologies included in study

Several points can be noted from this figure. First, we include five non-renewable technologies – Nuclear, Combined Cycle Gas Turbine (CCGT) (Gas), Pulverised fuel (Coal) and CCGT with Carbon Capture and Storage (CCS) and Pulverised fuel with CCS – and six renewable technologies – On- and Off-shore Wind, Hydroelectric, Biomass, Wave and Tidal. These cover the technologies which are included in scenarios for the Scottish electricity generation mix in 2020. As shown in Table 2, the generation mix as of 2007 was dominated by large-scale coal, gas and nuclear. However some renewable technologies did make a significant contribution to electricity generation in Scotland.

Second, we can use the levelised costs of electricity to compare the standalone costs of electricity generation for each technology. This has been used as an indicator of the amount of financial support required, or the cost reductions necessary, for renewable technologies to become "competitive" against non-renewable technologies. From this perspective, the standalone cost of gas or coal, plus any subsidy to renewable generation, is typically taken to be the cost at which renewable technologies become competitive (e.g. Carbon Trust, 2006). A key insight which portfolio theory gives is that a comparison on levelised cost alone neglects the potentially important role that technologies with higher standalone costs can play in reducing the risk of electricity portfolios. We start from a position where the levelised cost of Wave and Tidal electricity generation, for instance, is greater than non-renewable options. We intend to examine what role renewable technologies, including Wave and Tidal, might play in future electricity portfolios for Scotland. To conduct such an analysis, we require information on the cost variability of all technologies (termed "risk" in portfolio applications) and on the correlations among the costs of each technology.

3.3.2 Technology risks and correlations between costs

Technology risks are typically taken from recent work applying portfolio theory to the European electricity mix (Awerbuch and Yang, 2008). Technology risk in applications of portfolio theory to costs of alternative electricity technologies is defined as "the standard deviations of the holding-period returns based on historical data for each cost component" [of the costs included within each technology] (Awerbuch and Yang, 2008, p. 90). As the holding period returns measure the year-to-year fluctuations in the cost stream, the standard deviation of these cost streams is expressed as a percentage. Each cost component (e.g. construction, fuel, etc.) can, in principle, have a different standard deviation for its holding-period return than that same cost component for other technologies. As Awerbuch and Yang (2008) make clear, identifying appropriate values requires a search of the literature. Awerbuch and Yang (2008) use estimates of the standard deviation of holding-period returns for the construction cost component of non-renewable technologies can be, as one example, taken from a study conducted for the World Bank (Bacon *et al*, 1996). This World Bank study found that the standard deviation of construction period outlays for thermal plants varied across technologies, with large Hydroelectric projects having the greatest annual cost variability (38%)[14].

[14] These estimates are described in Bacon et al (1996, p. 29). We note that the Bacon *et al* (1996) database covered developing countries thermal and hydroelectric projects between 1965 and 1986, and as such an updated survey of the cost variance, covering developed and developing countries and a wider range of technologies (including renewables) would be a useful piece of research. It is perhaps surprising that this reference remains current in the portfolio literature, but we follow the Awerbuch and Yang (2008) application here, including the estimates of construction cost variability which are taken from Bacon *et al* (1996). It is likely that these cost variability for both thermal and hydroelectric plants are towards the upper end of estimates which would be seen for Scotland.

In this paper, we follow Awerbuch and Yang (2008) in taking the values as derived in Bacon *et al* (1996) for construction risk for Thermal (i.e. Coal (including CCS) and nuclear) and Hydroelectric generation, and we take the values for the construction risk of other technologies (including renewables), from Awerbuch and Yang (2008). Awerbuch and Yang (2008) derive their estimates of the fuel cost standard deviation from an International Energy Agency database of fossil fuel import prices from 1980-2005. This allows them to calculate the annual variability in the cost stream for each fuel type. There are thus differences across technologies due to different fuels being used across the (non-renewable) technologies. Clearly, renewable technologies will have zero fuel inputs. The assumed cost variability for each of the cost components for each technology is given in Table 4. Where cost components are inapplicable to specific technologies (for instance, fuel for renewable technologies) this is indicated with a dash. Overall risk for each technology is calculated as the weighted average of these estimates for each cost component, where weights are that component's share in the levelised cost for each technology[15].

[15] Thus, we follow Jansen and Beurskens (2008) in assuming that the cost components themselves for each technology are uncorrelated.

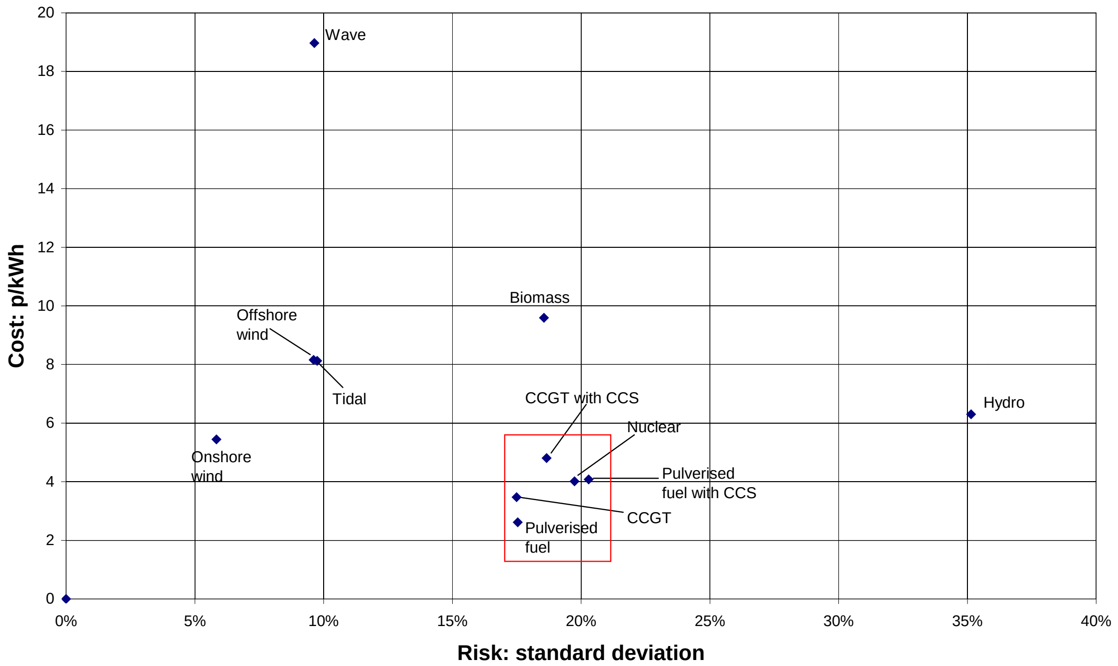
Table 4: Cost stream holding-period returns standard deviation for each of the twelve electricity generation technologies considered

Technology	*Construction*	*Fuel*	*Fixed O&M*	*Variable O&M*[b]	*Pre-development cost*[d]	*Fuel delivery*[e]	*Waste fund and decommissioning*[f]	*Storage*[f]
Wave[g]	10%	-	8%	8%	10%	-	-	-
Tidal[g]	10%	-	8%	8%	10%	-	-	-
Onshore wind	5%[a]	-	8%[a]	8%	5%	-	-	-
Offshore wind	10%[a]	-	8%[a]	8%	10%	-	-	-
Nuclear	23%[a]	24%[a]	5.5%[a]	5.5%	23%	-	10%	-
CCGT	15%[a]	19%[a]	10.5%[a]	10.5%	-	19%	-	-
Pulverised fuel	23%[a]	14%[a]	5.4%[a]	5.4%	-	14%	-	-
Hydroelectric	38%[a]	-	15.3%[a]	15.3%	-	-	-	-
Biomass	20%[a]	18%[a]	10.8%[a]	10.8%	-	-	-	-
Pulverised fuel with CCS[c]	23%	14%	5.4%[a]	5.4%	-	14%	-	40%
CCGT with CCS[c]	15%	19%	10.5%	10.5%	-	19%	-	40%

Notes: [a] indicates that component variability is taken from the same technology category in Awerbuch and Yang (2008). [b] indicates cost components which are not separately identified in Awerbuch and Yang (2008), and indicates where values for "Fixed O&M" component have been used for "Variable O&M". [c] indicates that for CCS technologies, holding period standard deviations are taken to be the same as the non-CCS version of the same technology, i.e. Pulverised fuel and Pulverised fuel with CCS, and CCGT and CCGT with CCS. [d] indicates that pre-development cost standard deviations are taken to be the same as the Construction cost standard deviation for that technology (predevelopment costs are included within Construction costs in the estimates of Bacon *et al*, 1996). [e] indicates that Fuel delivery cost standard deviations are taken to be the same as Fuel cost standard deviations. [f] indicates values which are assumed, but are not based on evidence in the literature. [g] indicates technologies for which we have assumed their component costs have the same holding-period standard deviations as for Offshore Wind.

We present levelised costs and technology risks for eleven electricity supply options for Scotland in cost-risk space in Figure 3. As in previous applications, we show technology risk on the horizontal axis and technology cost (here in p/kWh) on the vertical axis. We can identify a distinct grouping of the non-renewable technologies at between 2 and 6 p/kWh, with technology risks between 17 and 21%. Renewable technologies vary not only in terms of the levelised cost of units of electricity generated (shown by the distance up the vertical axis) ranging from Onshore wind to Wave, but also in terms of their technology risk, ranging from Onshore wind to Hydro (as noted in the notes to Table 4 and footnote 13 above, this value is taken directly from the study by Bacon et al, and could be taken to be at the high end of the standard deviation of construction costs for Hydroelectric developments in Scotland).[16]

Figure 3: Eleven electricity supply options for Scotland in cost-risk space



The final element required is for us to determine the correlation between the costs of each of the technologies. Following the literature, we estimate the correlation between technologies' costs as being based on two elements: the correlation between fuel costs, and between O&M costs. In the case of O&M costs, we use estimates of the

[16] We repeat that risk refers to the year-to-year variability in cost for each technology. Were we to consider the attitude of commercial investors to risk, then the limited state of development in the marine sector would make these risks more difficult to quantify.

appropriate correlation between technologies' O&M costs for Europe (taken from Awerbuch and Yang, 2008, p. 115). Fuel cost correlations are not initially taken from this literature in our central simulation. Rather, we base these on estimated correlations between fuel costs for Coal, Gas and Uranium taken from fuel cost series for the UK. These are based on quarterly series for each fuel, and taken from BERR's Quarterly Energy Prices publication in the case of Coal and Gas (starting in 1990), and from Eurotom's Price series for Uranium (beginning from 1980). The estimated fuel cost correlations are give in Table 5a, while the O&M cost correlations are given in Table 5b. In both tables, the correlation matrix is symmetric about the diagonal.

Table 5a: Correlations between fuel holding period returns for eleven technologies

	Wave	Tidal	Onshore wind	Offshore wind	Nuclear	CCGT	Pulverised fuel	Hydroelectric	Biomass	Pulveris-ed fuel with CCS	CCGT with CCS
Wave	1.000	-	-	-	-	-	-	-	-	-	-
Tidal		1.000	-	-	-	-	-	-	-	-	-
Onshore wind			1.000	-	-	-	-	-	-	-	-
Offshore wind				1.000	-	-	-	-	-	-	-
Nuclear					1.000	0.649[a]	0.591[a]	-	-0.220[b]	0.591[a]	0.649[a]
CCGT						1.000	0.757[a]	-	-0.440[b]	0.757[a]	1.000
Pulverised fuel							1.000	-	-0.380[b]	1.000	0.757[a]
Hydroelectric								1.000	-	-	-
Biomass									1.000	-0.380[b]	-0.440[b]
Pulverised fuel with CCS										1.000	0.757[a]
CCGT with CCS											1.000

[a] indicates that these are estimated from UK fuel price series as detailed in the text. [b] indicates that these are taken from Awerbuch and Yang (2008) for Europe in the absence of appropriate data series for the UK.

Table 5b: Correlation between operation and maintenance costs for eleven technologies

	Wave	Tidal	Onshore wind	Offshore wind	Nuclear	CCGT	Pulverised fuel	Hydroelectric	Biomass	Pulverised fuel with CCS	CCGT with CCS
Wave	1.00	0.00	0.00	0.00	-0.07	0.00	-0.22	0.00	0.00	-0.22	0.00
Tidal		1.00	0.00	0.00	-0.07	0.00	-0.22	0.00	0.00	-0.22	0.00
Onshore wind			1.00	1.00	-0.07	0.00	-0.22	0.29	-0.18	-0.22	0.00
Offshore wind				1.00	-0.07	0.00	-0.22	0.29	-0.18	-0.22	0.00
Nuclear					1.00	0.24	0.00	-0.41	0.65	0.00	0.24
CCGT						1.00	0.25	-0.04	0.32	0.25	1.00
Pulverised fuel							1.00	0.30	0.18	1.00	0.25
Hydroelectric								1.00	-0.18	0.03	-0.04
Biomass									1.00	0.18	0.32
Pulverised fuel with CCS										1.00	0.25
CCGT with CCS											1.00

Source: Correlations taken from Awerbuch and Yang (2008) for the EU.

We note that our estimates of the correlation coefficients between fuel costs are all more strongly positive (i.e. closer to one) than those typical in the literature. This may be due to the inclusion of more recent years' data, in which there has been a significant upward trend across all fossil fuel prices. Further, some researchers have found negative correlations between the fuel costs of nuclear and fossil fuels, while our estimates are positive and significant in scale. We explore the impact of changing the assumed correlation between these fuel costs in sensitivity analysis in Section 4.2.

3.3.3 Technologies' shares in future electricity portfolios

One major difference between the illustrative results from portfolio theory applications to electricity supply mixes and conventional applications to finance is that in the former case bounds (maxima and minima) are typically imposed on the share that each asset can constitute in optimal portfolios. In finance full specialisation is possible and investors can hold negative shares in assets through short-selling. The setting of an upper bound for each technology is typically driven by the energy resource constraint, or the extractable energy potential, in the case of renewable energy options or the maximum attainable deployment levels for each technology in the case of non-renewables (Awerbuch and Yang, 2008). We follow Awerbuch and Yang (2008) in considering a "central case", in which we specify the upper and lower bounds on each asset in the electricity portfolio. Upper and lower bounds for each technology include the shares observed for each technology in scenarios for Scotland in 2020, and these are given in Table 6. We vary the upper bounds for Nuclear and marine technologies in sensitivity analysis in Section 4.2, but our "central case" results use the upper and lower constraints on each technology given in Table 6. The rationale for each of these upper and lower bounds for each technology is given in Appendix II.

Table 6: Minimum and maximum supply limits in 2020, plus share in 2007 generation mix (% of total Scottish electricity generation in 2020 for each technology)

	2007 shares in generation (%)	*Minimum (%)*	*Maximum (%)*
Wave	0	0	10.5
Tidal	-	0	5
Onshore wind	5.5	5	35
Offshore wind	0	2	15
Nuclear	25.6	0	20
CCGT	26.2	0	25
Pulverised fuel	28.7	0	35
Hydroelectric	12.2	0	15
Biomass	1.8	0	5
Pulverised fuel with CCS	-	0	35
CCGT with CCS	-	0	25

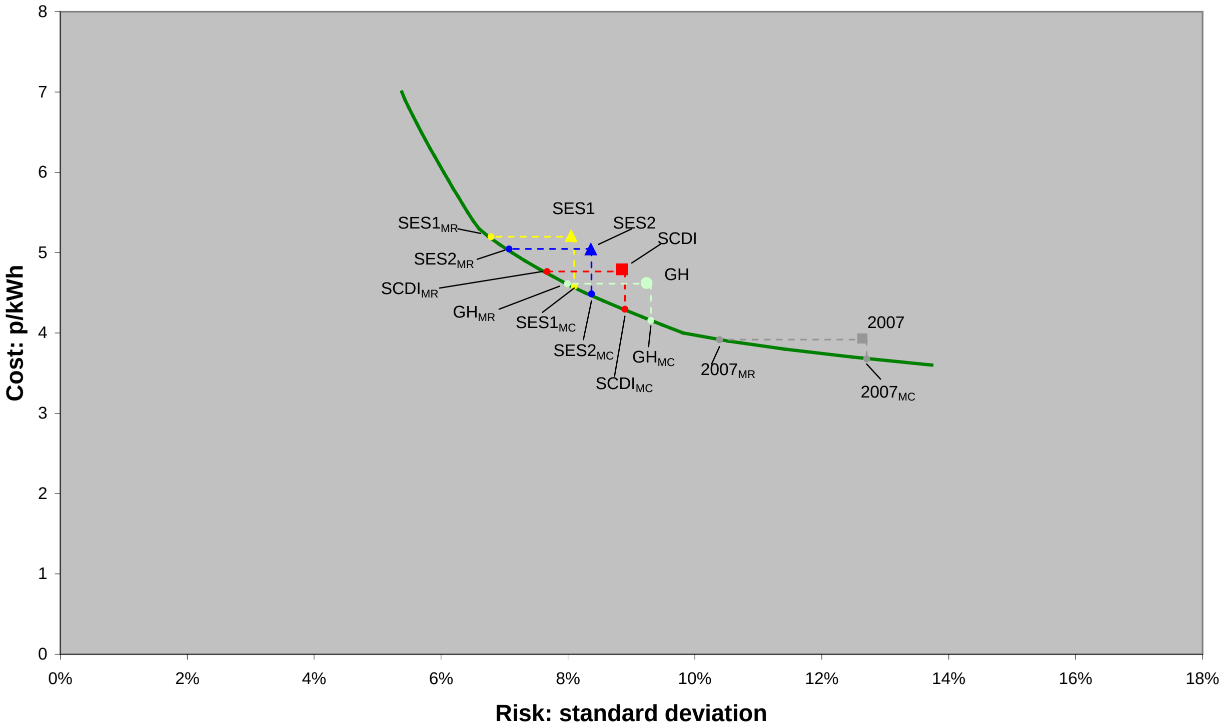
4. Results

4.1 Central results: comparison of scenarios to efficient portfolios

Using these four scenarios for electricity generation in Scotland we can evaluate the efficiency of the generating mixes from the perspective of their risk-cost performance. Firstly, we solve the model to generate the efficient frontier – the set of portfolios which give the lowest level of portfolio risk for a given portfolio cost (and lowest portfolio cost for a given portfolio risk). We can then compare cost-risk profiles of the four scenarios to this frontier and discuss the efficiency of these scenarios.

The cost-risks for these four portfolios are shown in Figure 4 together with the locus of efficient portfolios. The four scenarios are ordered along a cost-risk frontier: ordering the scenarios by cost gives a reverse ranking on risk for these four scenarios. All four scenarios, however, are within the *efficient* frontier. Also in Figure 4, we show the points where alternative portfolios exist with the same cost or risk as the four scenarios, but lie on the efficient frontier. The clear implication is that it is possible to improve on each of the four scenarios in terms of lower costs, lower risks or some combination of the two. We label these comparator portfolios for each scenario as Minimum Risk (MR) and Minimum Cost (MC) portfolios, and show where these are found along the efficient frontier for each scenario by adding MR or MC as a subscript to the abbreviation of each of the four scenarios identified above. The GH scenario, for instance, has a portfolio cost and portfolio risk of 4.61 p/kWh and 9.23% respectively. The MR portfolio with the same portfolio cost as the GH scenario is given by the point on the efficient frontier marked GH_{MR}. The distance from GH to GH_{MR} shows the inefficiency of the GH scenario portfolio, measured in terms of the potential for risk reduction. The distance from GH to GH_{MC} indicates the scale of inefficiency expressed in terms of the potential for cost reduction.

Figure 4: Cost-risk space showing efficient frontier and four scenarios, plus 2007 generation mix, and Minimum Risk and Minimum Cost (efficient) variants of each scenario



Note: See text for definition and explanation of each of the four scenarios – GH, SCDI, SES1 and SES2. "2007" represents the portfolio of the generation mix as of 2007.

From Figure 4, we can see that some of the four scenarios lie closer to the efficient frontier than others. The 2007 generation mix, for instance, has a portfolio cost which is significantly below those implied by any of the four scenarios we consider for 2020. This results largely from the higher share of (relatively) cheaper non-renewable technology used in this portfolio. The GH scenario, with 49% of electricity from renewables, has a cost of 4.61p/kWh, which is 22% greater than the cost of electricity in the 2007 portfolio mix (where generation from renewables technologies is around 19.5%). This is towards the lower end of anticipated increases in electricity prices for households and industrial users as projected to occur from measures intended to tackle climate change, such as those described in Section 2.2 (see Bellingham (2008) for more details on this point). As might be expected the scenarios for 2020, which have significantly greater shares of generation from renewable technologies, all have appreciably lower portfolio risk than the generation mix for 2007.

While the GH scenario has the lowest cost of the four scenarios for 2020 considered, it lies well to the right of the minimum risk portfolio for its level of portfolio cost: the distance from GH_{MR} to GH in Figure 4 is substantial. This result indicates that portfolio risk could be reduced by 1.26% without incurring a greater portfolio cost. This distance is greatest (in absolute terms) for the SES2 scenario, where the minimum risk portfolio has 1.33% less year to year volatility than the SES2 scenario portfolio. SES1 has the lowest portfolio risk, but it has the highest portfolio cost, while the GH scenario has the highest portfolio risk and the lowest portfolio cost.

Table 7 shows the generation mix for each of the four scenarios for Scotland in 2020, plus the 2007 mix. It also shows the efficient portfolios with the same cost but the minimum risk, or the same risk but minimum cost, as the four scenarios. The first five columns show the mix for 2007 and then each of the four scenarios in turn. The portfolio risk and cost for each scenario is given towards the bottom of each column. We can see that each of these four scenarios for 2020 feature a mix of renewable technologies; there is not one renewable technology which dominates. The total share of electricity from renewable technologies under each scenario is given in the second last row of the table, and we can see that the renewable share is between 48% and 53%. The next eight columns show, in turn for each of the four 2020 scenarios, the Minimum Cost and Minimum Risk portfolios which can be constructed with the same level of risks and costs respectively as each scenario.

Table 7: 2007 mix and four scenarios for Scottish mix in 2020, plus Minimum Risk and Minimum Cost variants of each scenario

	Technology mix under 2007 mix and each scenario					Minimum Risk versions of each scenario					Minimum Cost versions of each scenario				
Technologies	2007	SCDI	SES1	SES2	GH	2007_{MR}	$SCDI_{MR}$	$SES1_{MR}$	$SES2_{MR}$	GH_{MR}	2007_{MC}	$SCDI_{MR}$	$SES1_{MC}$	$SES2_{MC}$	GH_{MC}
Coal	28.7	13.0	8.0	14.0	32.4	35.0	29.7	24.2	26.4	31.9	35.0	35.0	32.4	35.0	35.0
Coal CCS	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	0.0	0.0
Gas	26.2	24.0	21.0	19.0	4.2	25.0	11.4	9.2	10.1	12.3	25.0	14.5	12.5	12.0	16.4
Gas CCS	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	25.6	15.0	18.0	17.0	14.1	6.0	7.5	7.1	7.2	7.6	20.0	7.9	7.7	7.1	8.5
Hydro	12.2	11.0[a]	8.0	8.0	10.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore wind	5.5	30.5	30.1	28.1	30.2	32.0	35.0	35.0	35.0	35.0	14.8	35.0	35.0	35.0	35.0
Offshore wind	-	2.3	10.4	9.7	6.1	2.0	6.5	14.5	11.2	3.2	2.0	2.0	2.5	2.0	2.0
Biowaste	1.8	3.4	2.0	1.8	2.4	0.0	5.0	5.0	5.0	5.0	0.0	3.0	5.0	4.0	2.1
Tidal	-	0.4	1.2	1.1	0.1	0.0	5.0	5.0	5.0	5.0	0.0	2.6	5.0	4.9	1.0
Wave	-	0.5	1.4	1.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total (%)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Portfolio risk	12.64%	8.85%	8.05%	8.36%	9.24%	10.28%	7.56%	6.73%	7.04%	7.96%	12.64%	8.85%	8.05%	8.36%	9.24%
Portfolio cost	3.93	4.79	5.21	5.04	4.62	3.93	4.79	5.21	5.04	4.62	3.69	4.30	4.58	4.47	4.18
Renewables (%)	19.5	48.0	53.0	50.0	49.3	34.0	51.5	59.5	56.2	48.2	16.8	42.6	47.5	45.9	40.1
Direction (and size) of renewable share relative to scenario	-	-	-	-	-	Pos. (14.5)	Pos. (3.5)	Pos. (6.5)	Pos. (6.2)	Neg. (1.1)	Neg. (2.7)	Neg. (5.4)	Neg. (5.5)	Neg. (4.1)	Neg. (9.2)

Note: [a] This include pumped storage hydro.

A number of things can be seen from the results for the Minimum Cost and Minimum Risk portfolios given for each scenario in the last eight columns of Table 7. Firstly, for all the scenarios for Scotland's electricity generation mix in 2020 detailed above in Section 2.2, we can construct portfolios which have the same risk *or* cost profile, but which are more efficient in that portfolio cost is reduced for that level of risk, or their risk is reduced for that level of portfolio cost. Secondly, with the exception of the GH scenario which already has over 49% of electricity coming from renewables, in each cases the Minimum Risk portfolio for each scenario has a greater share of electricity from renewables than the scenario mix (this is given by the final row of Table 7). As an example, the efficient portfolio with the same level of cost as the SCDI scenario, but the minimum level of risk has 50.8% of electricity supplied from renewable technologies, compared to 48.0% in the SCDI scenario itself. There is also significantly more electricity from renewables in the Minimum Risk portfolio of the SES1 and SES2 scenarios. We can see therefore, that increasing the share of electricity from renewables from those given by the scenarios would decrease the risk inherent in the electricity portfolio[17].

Thirdly, there are several points specifically relating to marine energy technologies, both Wave and Tidal. Generation from Tidal technologies are at their limit (5%) in all of the minimum risk portfolios for each scenario, despite the highest share of Tidal in any of the four scenarios being 1.2%. This underlines the role that this form of technology might play in future Scottish electricity portfolios by reducing portfolio risk. This increased share for Tidal does not affect the portfolio cost. However, Wave does not feature in any of the efficient portfolios for any of the four scenarios. This is likely to be due, in part, to the high levelised cost for this technology which is likely to fall as it moves towards full-commercial development and deployment. The adoption of Wave technology is also affected by the assumed upper limits on the maximum shares of other technologies permitted in the electricity portfolios. We might find, for instance, that Wave energy contributes to efficient portfolios when the upper limit on Onshore wind, for example, is reduced. It would prove useful to investigate the impact of assumed changes in the levelised costs of Wave generation technologies in sensitivity analysis, especially given the

[17] Recall that risk measure here relates to the year-to-year variability in technology costs.

new proposals for banded Renewable Obligation Certificates (ROCs) for renewable technologies in Scotland and UK, but we do not explore this further in this paper.

4.2.1 Sensitivity: Alternative correlations

The fuel cost correlations are potentially important for the results obtained in Section 4.1 above. We carry out sensitivity analysis in this section, by repeating the calculation of the efficient frontier but using fuel cost correlations taken from the recent portfolio theory application for the EU (Awerbuch and Yang, 2008). As mentioned above, the fuel cost correlations estimated from UK data are higher than have typically been used in portfolio studies. The EU figures used in this sensitivity are thus lower. This is likely to affect our earlier results in two areas. First, the risk measure for any given technology mix will be reduced (see Appendix A). Second, mixes along the efficient frontier will change. Previously inefficient portfolios will now be efficient. The new estimated efficient frontier is shown in Figure 5.

Figure 5: Efficient frontier sensitivity analysis – alternative fuel cost correlations

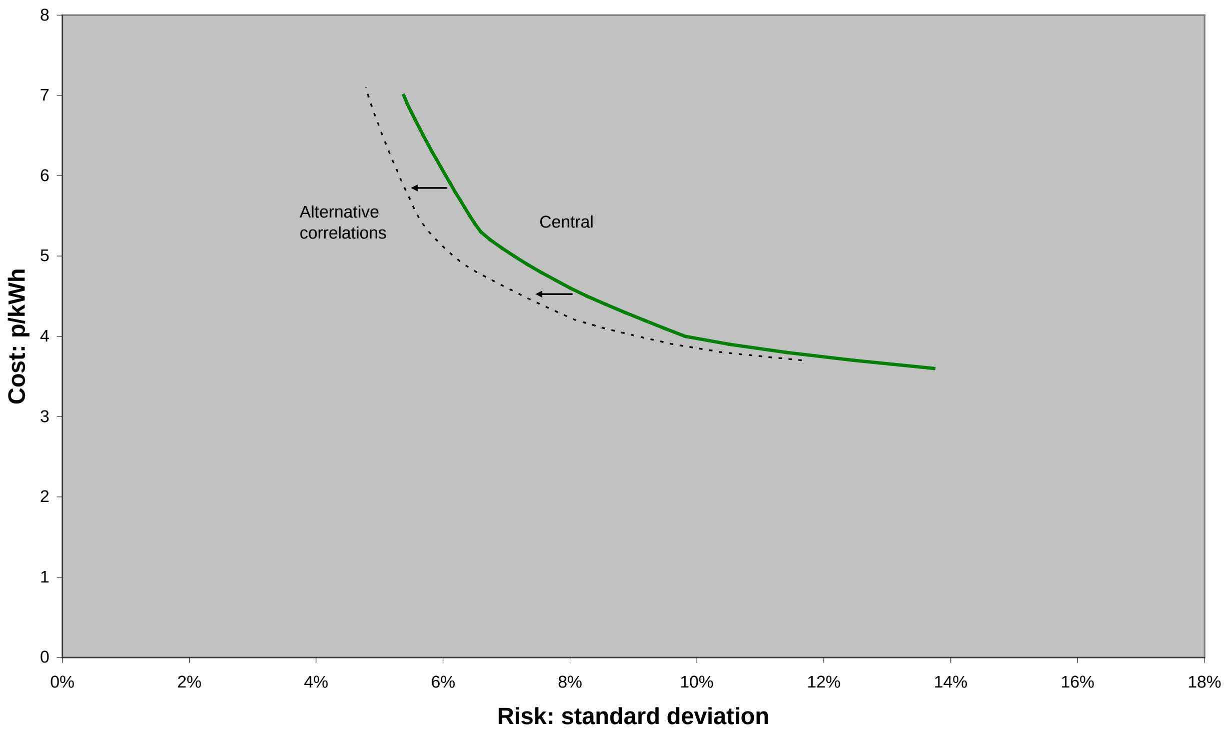


Figure 5 shows that using the EU correlations produces an efficient frontier of portfolios that dominates the frontier generated using the UK correlations. Portfolios on this new efficient frontier are therefore superior to those on the efficient frontier in the central case, in that portfolios with the same cost can be constructed, but that these have lower portfolio risk.

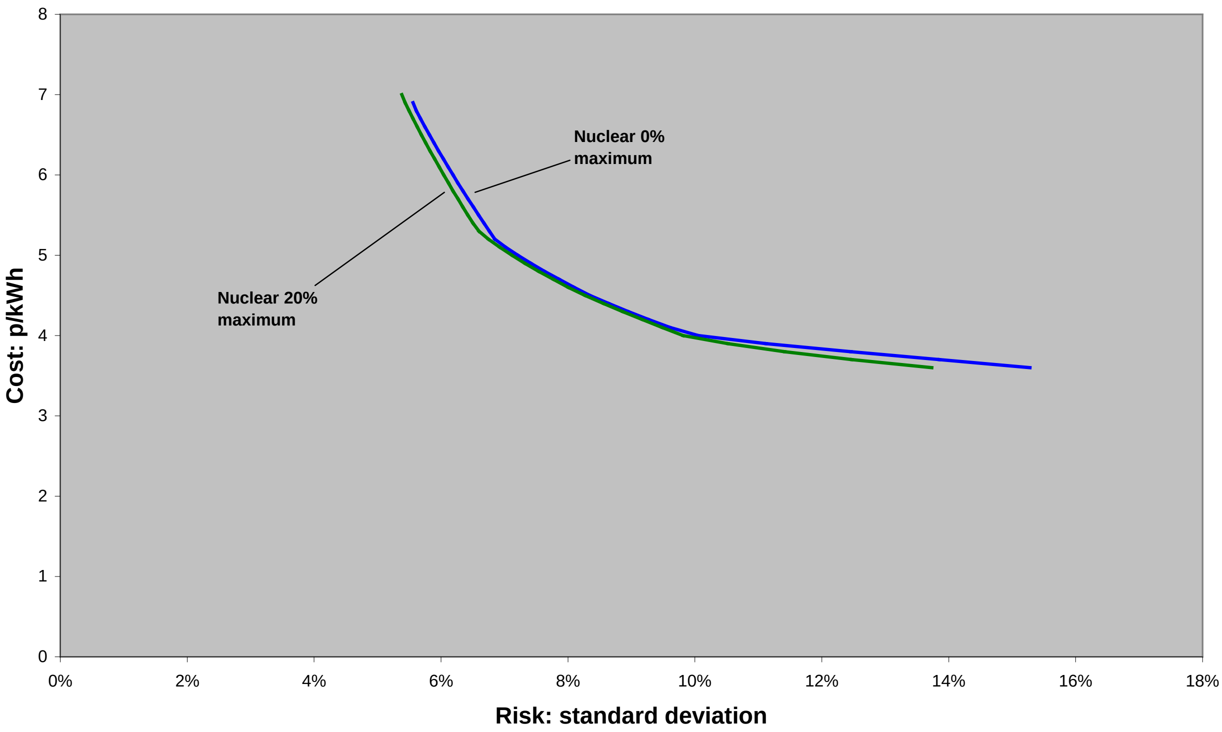
4.2.2 Sensitivity: No nuclear and higher maximum shares for marine

Two specific values in Table 4 are the focus of sensitivity simulations in this section. First, as acknowledged in the introduction, the future role of nuclear generation in the electricity mix in Scotland is highly uncertain and affected by technical (i.e. plant life-time) and political factors. Most importantly, the current minority Scottish National Party Government has ruled out the construction of new nuclear power stations in Scotland. We therefore examine the impact on the portfolio selection of removing nuclear as an option in the generation mix (i.e. constraining its upper bound to zero). Secondly, we are interested in the extent to which the maximum shares on marine technologies limits the formation of efficient portfolios, and the benefits of relaxing the upper bounds on marine technology into the Scottish generation mix. As noted in the introduction, Scotland has some of the most significant marine energy resources in the world. It also generates some of the most advanced private sector and academic research into electricity generation from waves and tides, and has specific government mechanisms designed to stimulate development of these technologies in Scotland.

No nuclear

Figure 6 shows the impact on the efficient frontier in cost-risk space where we vary the maximum share of nuclear in the generation mix. We compare in our central case, which incorporates an upper limit of 20%, to the case where nuclear is not permitted to be selected as one of the technologies employed (i.e. where the upper limit on this technology's share in the generation mix is set at zero). We can see that having nuclear available as an option offers generation portfolios which are always superior to those without nuclear as a possibility. This is an argument for maintaining a nuclear option in Scotland. Howver, the benefits of this option, in terms of risk reduction for different levels of portfolio cost, is small for all portfolio costs.

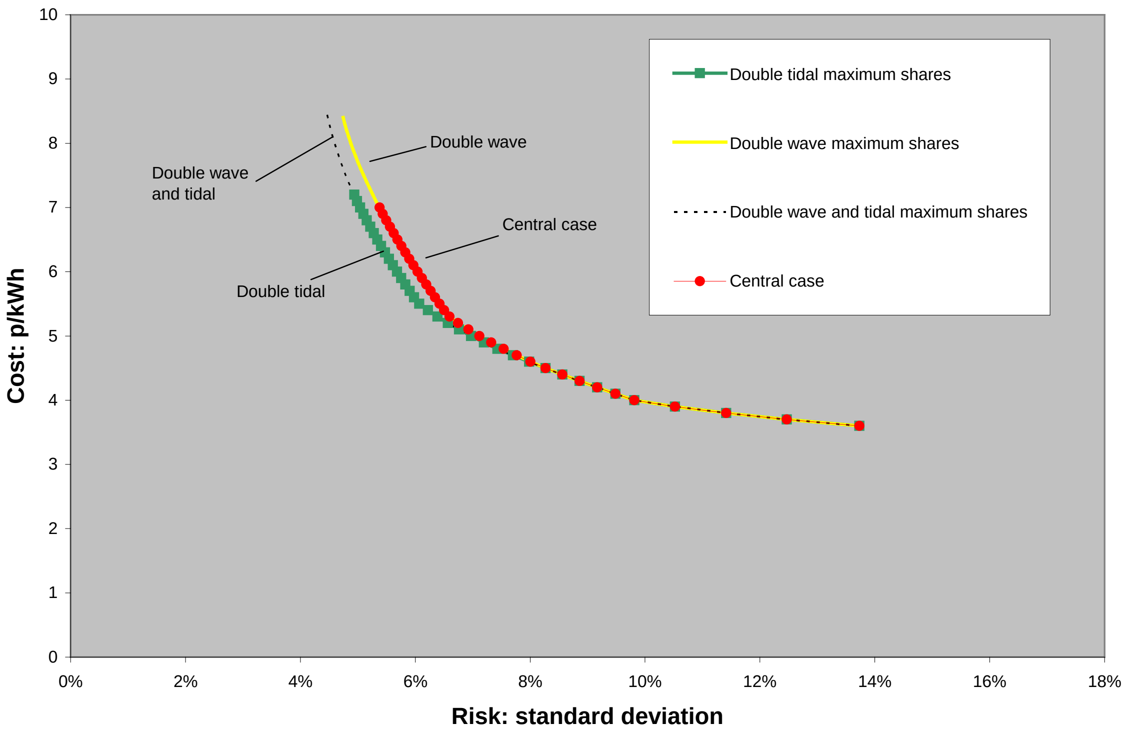
Figure 6: Efficient frontier sensitivity analysis – removing nuclear technology as an option in the Scottish electricity mix



Varying the maximum portfolio shares for Wave and Tidal

Figure 7 shows the impact on the efficient frontier of changing the maximum shares for Tidal and/or Wave technologies in the Scottish generation mix. We show three cases in this diagram: doubling the limits on Wave and Tidal separately, and then doubling the limit on each technology together. Doubling the maximum share of Tidal in the Scottish mix from 5%, the figure assumed in the central case, to 10%, causes the efficient frontier to move to the left (i.e. superior to the central efficient frontier) for costs higher than 3.7p/kWh, reducing the risk of efficient portfolios (for higher portfolio costs). Without changing the upper limits for Wave generation, efficient portfolios with a portfolio cost greater than 7.1p/kWh cannot be constructed, and which, other things being equal as portfolio cost increases so portfolio risk reduces. When the maximum share of Wave power is increased, the efficient frontier is extended upwards, decreasing risk for increases in portfolio costs. Thus, increasing the possible contribution that Wave technologies can make offers the possibility of reducing the portfolio risk of the Scottish electricity generating mix.

Figure 7: Efficient frontiers under alternative assumptions about maximum shares of Wave and Tidal in Scottish electricity generating mix



5. Conclusions

The mix of electricity generation in Scotland has traditionally reflected a combination of natural resource, economic, political and technical developments and challenges. It is likely that the next twenty years will see significant change in the technologies used to generate electricity in Scotland. Technologies which have served to meet electricity demands over the last twenty years will reach the end of their design life or become uneconomic. Simultaneously, policy interventions will stimulate the renewable energy sector. The distinctive approach to energy policy in Scotland *vis-à-vis* the rest of the UK serves to motivate a focus on regional electricity supply, although this might not be appropriate for all UK regions. This paper examines some recently published scenarios for the Scottish generation mix from the perspectives of portfolio selection theory. This approach augments the evidence-base that is relevant for Scottish energy policy formulation.

In this paper we provide a portfolio analysis of four alternative scenarios for Scotland's electricity generating mix in 2020. We find that the generation portfolios associated with each of these scenarios are not mean-variance efficient. Since the scenarios were developed with modelling methods other than portfolio theory, this result is not particularly surprising. However, our approach enables us to quantify the likely scale of inefficiencies, which appear to be non-trivial, whether assessed in terms of "excess risk" or "excess cost" when measured relative to generating mixes that lie on the feasible efficient frontier of portfolios. The policy implications are potentially important, since our results imply that the same portfolio risks can be obtained at lower cost, or lower risk can be secured at the same cost, or some combination of the two. In general, therefore, there appears to be an opportunity for a Pareto improvement or what Awerbuch (2008) terms a "no regrets" policy adjustment relative to these four scenarios for Scotland.

Our analysis offers support for a number of key observations made by others who have applied the portfolio approach to electricity generating portfolios (e.g. Awerbuch and Yang, 2008, p111). First, the approach clearly demonstrates the potential major inefficiencies involved in selecting generating mixes on the basis of levelised costs alone. It is important to assess new technologies appropriately, i.e. based on their contribution to the electricity generating portfolio rather than on a standalone basis. Second, the benefit of any "portfolio effect" of new technologies does not necessarily accrue to the private developers responsible for their introduction. (Nor are negative effects borne by those responsible for the investments.) From a single-technology private perspective, the "portfolio effect" is an externality, and perhaps ROCs – especially in their new "banded" form – reflect at least a partial attempt to officially recognise this. If electricity generation firms are engaged with more than one type of generation technology, however, then the "portfolio effect" will benefit them directly through lower risk variation.

This latter point serves as a reminder of the perspective of our application of portfolio theory: namely that of the planner or policy maker (though this is an incomplete perspective in that we do not incorporate carbon costs separately into our analysis). In fact, in liberalised energy markets decisions on investments are made by private transactors who are motivated by profits. Extension to accommodate this is possible (e.g. Roques *et al*, 2009). However, it remains important that those responsible for the formulation of energy policy appreciate the importance of the portfolio perspective for informing decisions on what constitutes desirable optimal generation portfolios.

However, it is important to keep in mind the limitations of our analysis that may be result in an overstatement of the gains that can actually be secured in practice. First, we have abstracted from the transactions costs associated with altering generation mixes. In practice these might be minimised by gradual adjustment through plant retrials and new investments. The system we employ suggests an undoubtedly unrealistic degree of flexibility (although it is tied to those changes which may occur out to 2020). Future work could consider incorporating adjustment costs, and perhaps explicitly include multi-period extensions. Second, the portfolios considered here are not tested for feasibility given the existing energy system's infrastructure. It may be that some of the portfolios identified here as "efficient" may in fact not actually prove feasible, although the timescales under consideration suggest that non-feasibility is unlikely to be a barrier. However, the costs of ensuring feasibility may be a real barrier, particularly given the scale of renewables contributions to the low risk generating mixes. There appears to be substantial scope here for combining the portfolio selection approach with other energy system models, in an attempt to determine whether apparent "no regret" policies really are feasible. Future research should address this question that is certainly worthy of further investigation.

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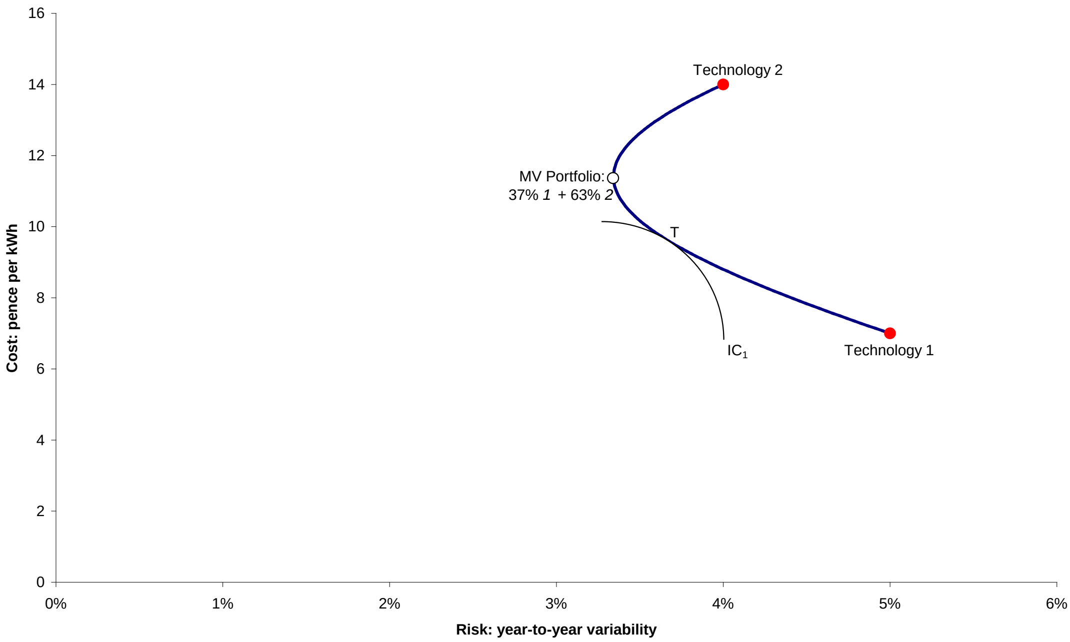
Appendix I: The portfolio effect for a two-technology example

The gains from diversification of an electricity portfolio from a two-technology hypothetical case are apparent from Figure AI.1. In this example, technology 1 has a levelised cost of 7p/kWh with a year to year variability of standard deviation of 5%, while technology 2 has a levelised cost of 14p/kWh with a standard deviation of 3%. The correlation coefficient between these two hypothetical technologies is assumed to be 0.15.

At each end of the line shown in Figure AI.1. is the risk/cost combination from an electricity portfolio consisting solely of technology 1 and technology 2 respectively. A portfolio consisting solely of technology 2 would not be rational, since by increasing the share of technology 1 in the portfolio, a social planner choosing the electricity mix could achieve a portfolio with lower cost return and less risk (thus, moving us along the line segment down from Technology 2). Once we have a portfolio containing 63% of technology 2 and 37% of technology 1 we reach the minimum variance (MV) portfolio where risk is minimised. Increasing the share of technology 1 above 37% lowers the portfolio expected cost but increases the portfolio risk. Portfolios along the line between MV and a portfolio consisting entirely of technology 1 are therefore efficient, as portfolio costs are minimised for given levels of portfolio risk (and vice versa). Portfolios between MV and a portfolio consisting entirely of technology 2 are not efficient as portfolios could be found which offer significantly lower cost for the same level of risk. We can thus address our focus solely on efficient portfolios.

Figure AI.1: Hypothetical example of a two-technology portfolio demonstrating the "portfolio effect"



The preference of rational planners in choosing between efficient portfolios can be shown using indifference curves, showing the combinations of risk and return for which utility is constant. Greater utility would be derived from lower cost for a given risk level, so indifference curves to the south-west in Figure AI.1 are preferred. Point T shows the tangency point between an investor with indifference curve IC_1 and gives the expected return and risk for this (optimal) portfolio.

Appendix II: Rationale for upper and lower bounds for each technology share in 2020 mix

The selection of upper and lower bounds for the twelve technologies shares' in the Scottish electricity generation mix are necessarily subjective, and as such can be debated and discussed. In selecting the values shown in Table 6 for the maximum and minimum shares for each technology we had the first criteria that the maximum share should cover the highest figure seen across the four scenarios used in our analysis (which we labelled SCDI, SES1, SES2 and GH, and show in Table 7). The minimum shares we set at zero, so that we were in effect assuming that all of the output of each technology could be removed from the electricity network in Scotland, as would happen for planned outages at thermal stations, or periods of zero renewable energy resource, for instance.

Wave and tidal – the Scottish marine resource has been estimated at 79.2TWh/year (Scotland's Renewable Resource, 2001). This is greater than the likely total electricity demands from Scotland in 2020, and includes all wave and tidal resources. The actual amount of marine energy which can be extracted from the seas around Scotland is likely to be far smaller than this, given economic considerations; such as the additional grid infrastructure required to extract all of this power; the inhospitable environments in which devices would necessarily be based for all this energy to be extracted making costs higher; and the requirements for environmental obligations and the interests other sea-using groups, such as the fishing industry.

The Marine Energy Group within the Scottish Government's Forum for Renewable Energy Development in Scotland stated in 2004 (FREDS:MEG, 2004) that wave energy capacity in Scotland could reach 1300MW by 2020. Assuming a capacity factor of 30%, this equates to a total annual electrical output of 3416.4GWh, which is approximately 7.1% of the total electricity generated in Scotland in 2007. Recently, the Carbon Trust (2006) reported that the offshore wave potential in the UK is approximately 50TWh/year, which is about one-seventh of current electricity consumption. Nearshore wave devices around the UK have the potential to provide 7.8TWh, which is approximately 16.2% of total electricity generated in Scotland. We use a maximum share for wave which lies between that estimated by the FREDS:MEG (2004) and the Carbon Trust (2006), and assume that the maximum share for wave energy in Scottish scenarios for 2020 is 10% of total Scottish electricity generation. As noted below, we undertake sensitivity analysis around this figure to show the importance of this assumption for the results and conclusions reached in the paper.

Tidal – the Scottish tidal resource has been estimated at 33.5TWh (FREDS:MEG, 2004), but, as above, this will include those resources which are not extractable for a number of economic, technical and environmental reasons. FREDS (2004) reported that the extractable tidal capacity at five locations around Scotland by 2020 – Pentland Firth, Orkney, Shetland, West Highlands and South West Scotland – could be as much as 2336MW, producing 6138GWh. This would equate to roughly 14.3% of Scottish generation in 2007 (see Table 2). The Carbon Trust (2005) reported that the UK technically extractable tidal energy resource was around 22TWh/year, around 6% of total UK electricity demand, but notes that this is around an upper limit, and may be optimistic and require revision downwards. We decided on a conservative maximum share of tidal energy in our portfolio for the Scottish electricity generation mix in 2020, and chose a realisable maximum of 5% by 2020.

As noted in the text above, and in the main paper, the possible size of each technologies share in a Scottish electricity generation future is open to question and highly speculative. For this paper, the crucial question is whether changing these maximum constraints impacts on the feasibility of superior portfolios. This is a natural place where sensitivity analysis is important, and we report the results of this in the text. In Section 4.2.2 we explore the implications for the results of relaxing the maximum shares for both wave and tidal, where we double these maximum shares independently and then simultaneously.

Onshore wind – the highest share for Onshore wind in any of the four scenarios is 30.5 (SCDI). There is low variability around this share across the other scenarios, with a range from 28.1% to 30.5%. We assume a maximum share for onshore wind of 35.0%.

Offshore wind – the higher share for Offshore wind in any of the four scenarios is 10.4% (SES1). There is some variability across the other scenarios, where this share ranges from 2.3 to 10.4%. We assume a maximum share for offshore wind of 15.0%, which is slightly higher than the highest share for this technology across the four scenarios.

Nuclear – as discussed in the Introduction, the future role for Nuclear technologies in the Scottish generation mix is highly uncertain due to political (i.e. the SNP minority government's stance on new nuclear build) and economic (i.e. the lifetimes of the two existing nuclear facilities running out between 2015 and 2023). As with the assumptions for the maximum shares for wave and tidal we explore the importance of Nuclear technology to the construction of efficient portfolios in sensitivity analysis. In our central case, we assume a maximum share of 20%, which is slightly lower than the share of Nuclear in the generation mix for 2007. Nuclear generation's share of total electricity generated in the four scenarios for the Scottish generation mix in 2020 varies between 14.1% and 18.0%, and so within a maximum share of 20%. In sensitivity analysis in Section 4.2.2 we explore the impact of constraining the maximum share to the same as the minimum share – zero per cent.

CCGT (including CCGT with CCS) – we assume a maximum share of 25% for both CCGT technologies – with and without CCS. This is consistent with the four scenarios for the generation mix in Scotland predicting a share for this technology of a maximum of 24.0%. As with the other thermal technologies, the minimum share that we assume these technologies could provide in 2020 is zero per cent.

Pulverised fuel (including pulverised fuel with CCS) – we assume a maximum share of 35.0% for coal power generation in Scotland in 2020 – with and without CCS. This is consistent with the four scenarios for the generation mix in Scotland, predicting a maximum share for this technology of 32.4%. As with CCGT, the range of the shares for this technology across the four scenarios varies considerably – the GH scenario is unique from these four in assuming that there will be more generation from coal than gas in Scotland in 2020.

Hydroelectric – we assume that Hydroelectric sources, which provided 12.2% of electricity generated in Scotland in 2007 would be constrained at a maximum share of 15% in 2020. This was slightly higher than the highest share seen for this technology across the four scenarios (11.0%) but consistent with some increases both in the capacity of Hydroelectric plants and a greater use of these technologies for meeting baseload electricity supply.

Biomass – we assume that Biomass sources, which provided 1.8% of electricity generated in Scotland in 2007, would be constrained at a maximum share of 5% in 2020. This is higher than that forecast in the four scenarios for 2020, where the highest share is 3.4%.