



An Examination of National Grid's *Future Energy Scenarios*

How much do the scenarios cost?

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Contents

.....	1
An Examination of National Grid's <i>Future Energy Scenarios</i>	1
1 Introduction.....	4
2 Method.....	4
2.1 Costing method.....	4
2.2 Variations to DECC parameters used in the present study.....	6
2.3 Capacity and Production data source.....	7
2.4 Division of Production between Coal and Gas generators of various types.....	7
2.5 Miscellaneous LCOE values also used in this study.....	9
2.6 Two comparison scenarios: Gone Gas and Gone Nuclear.....	9
2.7 Carbon dioxide emissions.....	10
3 Results.....	11
3.1 Results based on the values described in section 2.....	11
3.2 More realistic costs for offshore wind, nuclear, and gas.....	14
3.3 Carbon dioxide emissions of the various scenarios.....	18
4 Conclusions.....	19
References.....	22
Appendix.....	24
Abbreviated Capacity and Production Tables for the scenarios.....	24
Gone Green.....	24
Slow Progression.....	25
No Progression.....	26
Consumer Power.....	27
Gone gas.....	28
Gone nuclear.....	29

Summary

In a previous [paper](#) in this series, the authors analysed the National Grid's supply scenarios – presented in their Future Energy Scenarios (FES) document – in terms of their impact on security of supply. The current paper analyses the cost implications of these same scenarios.

Despite having installed more than 38GW of renewable energy generating capacity in the last decade, we have reached a capacity crisis. There is no hard evidence that this push for renewables has been an effective way to reduce CO₂ emissions, and the cost has certainly been very large. The analysis presented in these two papers makes a strong case for a radical review of energy policy from an engineering perspective, placing equal weight on cost, security and environmental impacts.

Although we hear that the cost of renewable energy is coming down and, in some cases, can reach parity with conventional sources, this is misleading since it relates purely to the cost of generation and takes no account of necessary additional costs, particularly transmission and backup.

The scenarios envisaged by National Grid necessarily inflate the cost of electricity, in part because the gas generating plant needed for backup (with the impending closure of coal-fired stations, the sole use of fossil fuel in the system) have to operate at very low efficiency. For comparison, we have included two further scenarios: Gone Gas and Gone Nuclear. Both of these result in significantly lower costs than the FES scenarios.

We looked at the cost figures used by DECC for building new wind and nuclear generating capacity against the costs currently reported elsewhere. These sources show that the official UK figures underestimate the cost of wind farms and overestimate the cost of nuclear capacity. To make the comparisons more realistic, we have used these alternative figures together with some other assumptions based on available evidence.

Both Gone Gas and Gone Nuclear would result in a smaller, more efficient generating fleet, producing electricity at a total cost of less than £100 per MWh, nearly half the cost of the Gone Green scenario and well below the other three FES scenarios. They would also provide security of supply.

Basing the future generating network on either of these proposed new scenarios would give a least-cost energy base for UK industry and minimise the risks of losing further jobs in energy-intensive industries, as has previously happened when the aluminium smelting sector closed.

Adopting either of these policies now would put the UK in an excellent position from which to proceed further towards a low-carbon future as appropriate technology becomes available.

1 Introduction

National Grid (NG) publish a Future Energy Scenarios (FES) document every year in which they map out, in considerable detail, a mix of possible energy delivery strategies for our future electricity system.

A national electricity generation system must provide three key components:

- i. Security of supply,
- ii. Electricity at prices that support the economic activity of the nation, and
- iii. Minimised impact upon the environment, by which most commentators mean reduced emissions of carbon dioxide.

All of these standards are important, yet only the third has clearly defined targets and is closely monitored. Security of Supply used to be the responsibility of the Central Electricity Generating Board who set standards and conducted regular reviews.

In a previous paper (1) we drew attention to the fact that the FES documents omitted any mention of security of supply, electricity generation costs, the impact on the generation and transmission infrastructure, and how attractive these future intentions would be not just to the generating plant owners, builders and operators, but also to the wider business audience.

The previous paper discussed the issue of security of supply. In this paper we attempt to cost the four scenarios, and compare NG's proposals against two of our own, which we term Gone Gas and Gone Nuclear.

2 Method

2.1 Costing method

Our objective is to assess the costs (not consumer or commercial electricity prices) of the scenarios described in National Grid's Future Energy Scenarios 2016 (FES) from the perspective of the customer.

We start, as is common practice, by evaluating the costs of generating for each mega-watt hour (MWh) of energy; we attempt to calculate the levelised cost of energy (LCOE). This is defined by the formula:

$$LCOE = \frac{\textit{Net Present Value of all costs of electricity generation}}{\textit{Net Present Value of all generation}}$$

LCOE is a view of energy costs restricted to the viewpoint of the owner/operator of the generating plant. DECC have carried out LCOE studies for a wide range of generation technologies (4). The technique requires gathering of historical data for plant planning, construction and commissioning, operational performance and maintenance costs, project financing (which includes investment borrowing mechanisms and debt placement during operation), charges for connection to the transmission system and rates and decommissioning. Discounted Cash Flow analysis is used at several stages, which will require a variety of debt and depreciation rates. Each generation technology requires a separate study.

This is not a simple task, but the results are far more meaningful than generation costs alone. The only way to provide an even more accurate picture is to estimate total system costs for various combinations of generating capacity. This is far more complex and beyond our present resources. Nevertheless, it is the approach that should be taken by government or whatever organisation may be responsible for the country's energy supply if we want the best decision making.

DECC provide summary data for each technology's costs for specified load factors, generation life, fuel costs and other parameters. But LCOE will vary with the achieved load factor that each generator (or technology type) experiences in each year of operation, which is largely dictated by the grid system operator. For this purpose, we have used an alternate LCOE analysis tool produced by IESIS (2) which allows user entry of parameters (including load factor) in order to determine costs.

We have compared the DECC and IESIS methods. In Tables 1 and 2 and we show

- i. Values for the parameters used in the LCOE studies, which were loaded into the IESIS calculator. The fuel prices are taken from DECC's 2013 study of fuel prices. In the IESIS calculator the renewables ageing factors were set to zero. (CCS denotes coal-fired carbon capture and storage).
- ii. Results from DECC and IESIS LCOE techniques. The CCGT and OCGT (Combined Cycle and Open Cycle Gas Turbine) DECC results are taken *before* the addition of carbon taxes.

	Technology							
	CCGT	OCGT	Biomass	Nuclear	CCS	Onshore Wind	Offshore Wind	Solar
Construction cost £/kW	610	320	2530	4,310	2,225	1,600	2,370	1,000
O&M £/MW/yr	30,830	14,300	111,515	89,403	69,102	44,625	115,802	22,400
Load factor %	93	7	65	91	93	28	38	11
Planning yrs	2	3	2	5	5	4	6	0
Construction yrs	3	5	1	6	5	2	3	1
Operation yrs	25	25	22	60	25	24	22	22
Fuel cost p/Therm	64	64	86	0	0	0	0	0
Discount rate %					10			

Table 1 Input parameters used in this study, derived from various tables in the DECC study of LCOE(4) and fuel prices from DECC's 2013 study (5)

	Technology							
	CCGT	OCGT	Biomass	Nuclear	CCS	Onshore Wind	Offshore Wind	Solar
DECC LCOE (Table 8)	62	165	123	89	116	100	113	122
IESIS LCOE	64	170	184	81	142	97	129	140
IESIS LCOE and system integration costs						154	178	200

Table 2 The LCOE results returned from the DECC levelised cost document (4) and IESIS LCOE calculator(2)

The differences between the two can be explained by observing:

- i. The Biomass LCOE is based on the capital cost of building new biomass plant, whereas the DECC figure is for biomass conversion.
- ii. The CCS IESIS calculation is based on the experience reported at the Boundary Dam Project in Canada.

The small differences that occur seem to coincide with the values that IESIS calculates for capital debt repayment.

IESIS have also attempted to cost system integration costs for renewable generation. The additional costs include services which renewables do not currently provide (such as frequency response, and operational reserve), protection against intermittency through the provision of a backup OCGT fleet, and extra costs of transmission since many renewable locations are located remote from traditional load centres. It is important that these costs are included in order to give a realistic assessment of renewable energy generation against conventional and nuclear generation. Table 2 shows the impact of these system integration charges.

2.2 Variations to DECC parameters used in the present study

We have updated the fuel prices used for the present study. We take gas to be priced at 47 p/therm, and coal at 16.4 p/therm in 2015, and then follow the annual variation of fuel prices predicted by DECC (6) in their 2015 study (Figure 1 and the unlabelled figure shown on table 16 therein).

The impact of ageing on load factor is calculated for all renewables. In the case of wind turbines we assume 1.7 % per annum, this being a central estimate found in a study by Stafell and Green (2013) (10); Hughes (11) found much higher values and reported 'The normalised load factor for UK onshore wind farms declines from a peak of about 24% at age 1 to 15% at age 10 and 11% at age 15'. But we have no way of selecting between these two and therefore take the more conservative approach.

In the case of solar ageing there is an exhaustive literature study of the subject by Jordan and Kurz 2012 (12), from which we take a central value of 1 % per annum.

2.3 Capacity and Production data source

National Grid provides a large data pack with their FES document. For each scenario they tabulate the capacity and production for every year between 2015 and 2040. The generation technologies studied are Storage, Biomass, CCS, CHP, Gas, Coal, Hydro, Interconnectors, Marine, Nuclear, Offshore Wind, Onshore Wind, Solar, Other Thermal, and Other Renewable. Appendix 1 gives a five-yearly overview of these capacity and production tables.

2.4 Division of Production between Coal and Gas generators of various types

Generation using gas as a fuel can employ a variety of technologies, the most common of which are Combined Cycle Gas Turbines (CCGTs) and Open Cycle Gas Turbines (OCGTs). CCGTs are probably the most efficient fossil fuel generators available (reaching 60% efficiency with the latest models) and thus have lowest emissions of any thermal generating technology other than nuclear. They are also cheap to build and can be constructed in about five years. However, CCGTs decline in efficiency when not used close to full power, and incur higher maintenance costs. To avoid these difficulties, OCGTs are used to provide top-up generation and deliver some of the UK's requirement for reserve and frequency response. OCGTs are cheaper to construct and have quicker delivery than CCGTs.

Conventional coal fired plants (all of our coal fleet falls into this category) are best used close to full power, so again, there is a need to split some of the production allocation for coal onto OCGTs.

Before the surge in operating, variable and intermittent renewable plant, it was a simple grid system operation to ensure that both coal and CCGT plants had spell of continuous, high powered-operation. It was the most economical way to operate the grid. In the FES proposals we now see that the gas plants have a very poor loading factor (Figure 1).

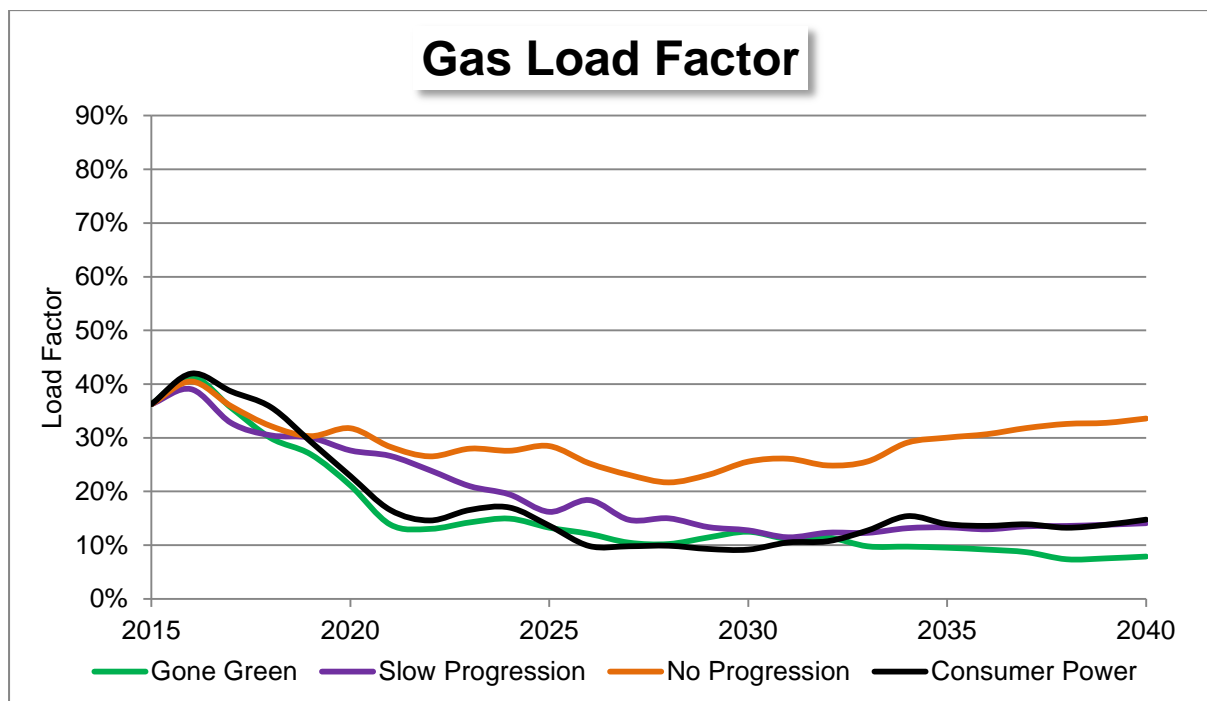


Figure 1 The gas loading factors for the four scenarios

Worse still, the baseload of the grid has been significantly affected by the 'must run' regime of renewable generation. Thus efficient scheduling of CCGTs and coal plants has become very difficult.

(see Figure 2 (a) and (b)). In our analysis we have assumed that the grid system operator is able to allocate close to 80% of the gas and coal production to discrete numbers of plants operating at 600 MW sent out (i.e. 660 MW sets operating at 90 % load and thus achieving high efficiency and being able to contribute to the response and reserve market). Unallocated production and capacity, spilled from this process, is then passed to the OCGT fleet. This division of plant allocation adds little or nothing to the costs of each scenario, but the CCGT plant will run at 90% load factor in every scenario.

In the paper analysing the risk of loss of supply (1) we identified the additional capacity required to achieve a risk level of 4% with various amounts of load reduction. In our costing exercise we add sufficient OCGT plant to reduce the risk of loss of supply for all the scenarios to 4% throughout the study period. This will make the loading factor for the OCGTs low and does increase the scenario costs, but OCGTs are very cheap to build and this, again, is a small increase. (OCGTs added to the scenario capacity to reduce risk have a capital cost as low as £320,000/MW according to the DECC LCOE study. Ideally, they will never run: there will never be a supply crisis, so they will seldom be called upon to generate. To construct 10 GW of such plant would cost £3.6bn. The smart metering programme is set to cost £11bn (7). This hardly seems good value for money.)

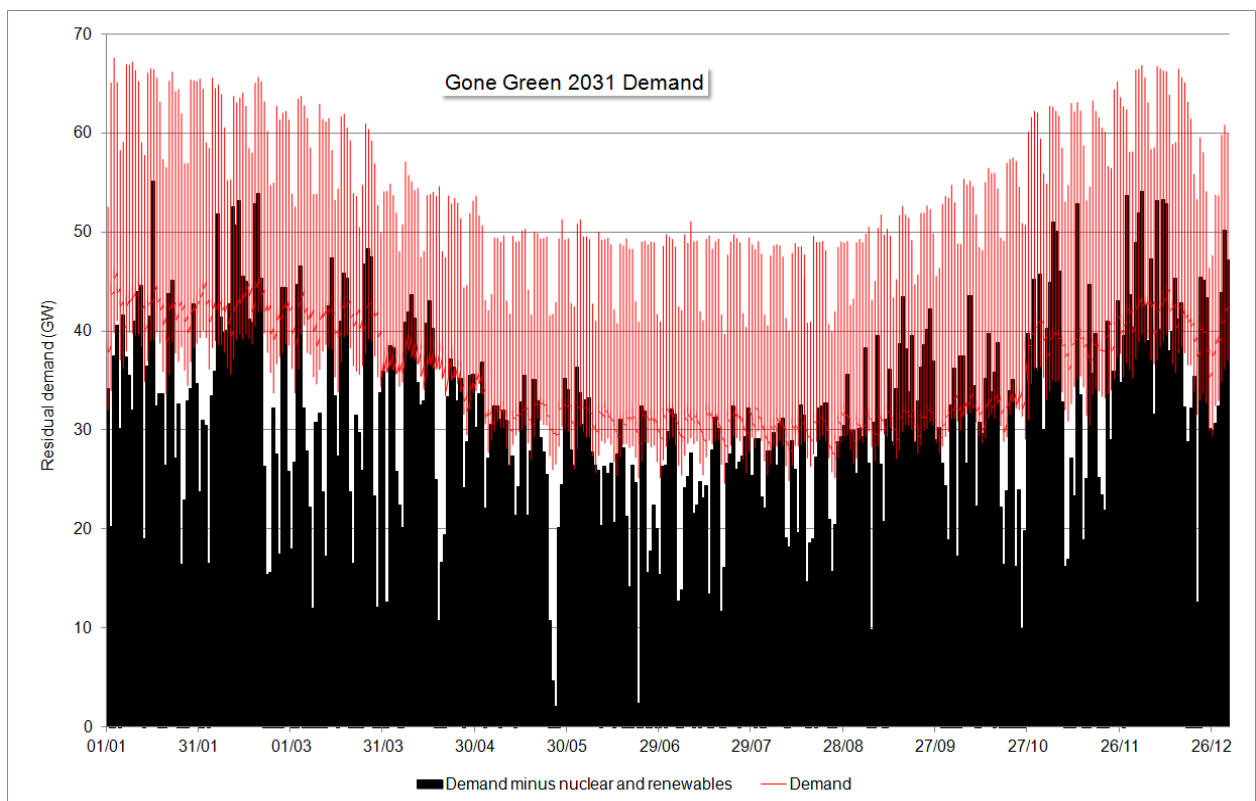


Figure 2a Typical annual demand profiles. The black represents the demand available after subtraction of wind, solar and nuclear, and must be shared amongst all the remaining generation technologies (data taken from FES2015). Data for renewable generation obtained from (8),(9).

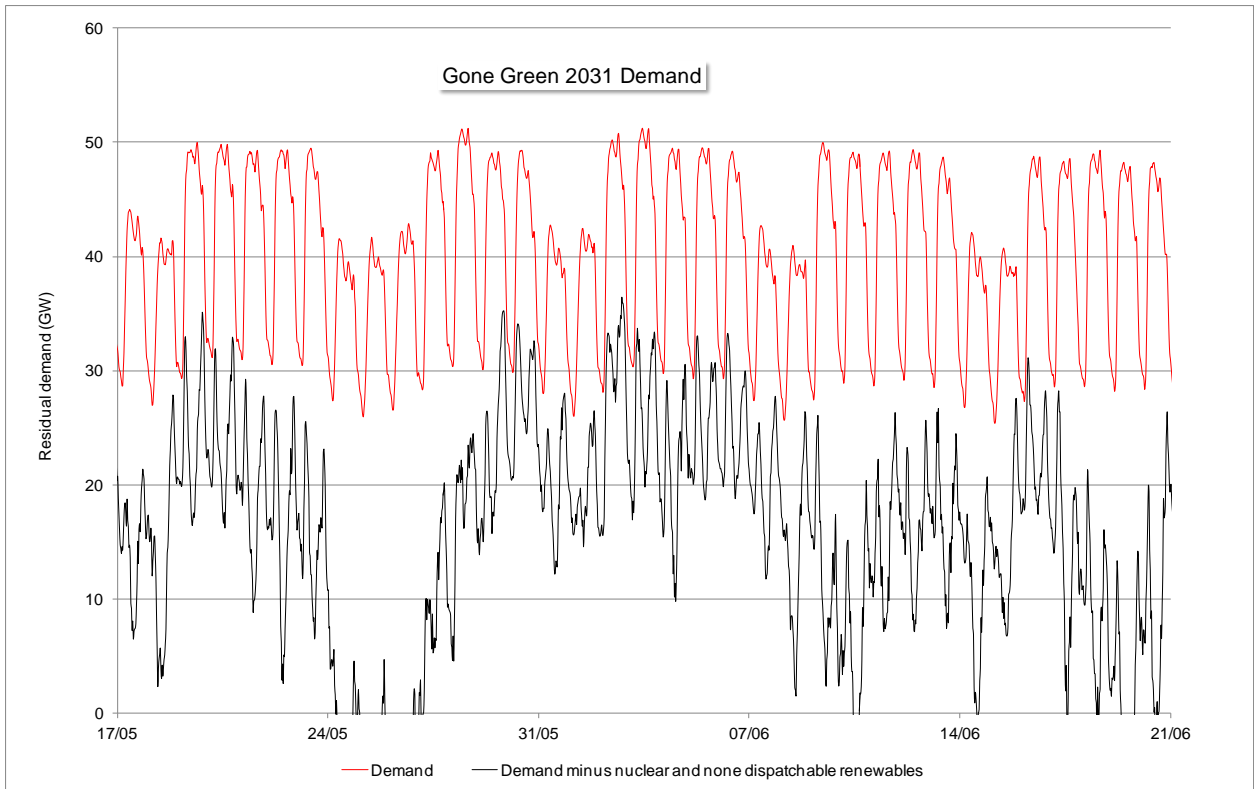


Figure 2b A portion of Figure 3a. Note the periods when there is no requirement for *any* other generation other than renewables and nuclear.

2.5 Miscellaneous LCOE values also used in this study

The IESIS study does not include an analysis of costs for all technologies. Since, for the most part, these do not vary across the scenarios, their comparative impact on costs is small. We have therefore used cost constants extracted from the DECC LCOE study, as shown in Table 3.

Technology	LCOE (£/MWh)
Storage	108
CHP	90
Hydro	130
Interconnectors	80

Table 3 Additional LCOE values

2.6 Two comparison scenarios: Gone Gas and Gone Nuclear

For comparison we have created two further scenarios: Gone Gas and Gone Nuclear. Both match the production profile of Gone Green, but whereas Gone Green grows the installed capacity to 186 GW, the others grow to 122 GW; this results in a growth in the productivity of the generation plant not seen in any of the other scenarios, see Figure 3. The progress of each scenario is as follows:

- i. No new renewables are built after 2016. The existing renewable plant continues to the end of its useful life.

- ii. Gone Gas and Gone nuclear are nearly identical until 2026, the earliest date when new nuclear power can be added to the grid.
- iii. Both new scenarios see a large expansion of gas plant up to 2025. NG discusses such an expansion in the FES 2016 document. It is assumed that this expansion is driven by the imperative of the loss of all the UK's coal (17 GW) and AGR (4 GW) capacity, and a need to address concerns over security of supply. It is a challenging objective, but no more so than the other scenarios. For example, the expansion of solar capacity to 42 GW envisaged in the Consumer Power scenario would cover an area of over 1,000 sq kilometre—just less than the area of Bedfordshire!
- iv. Neither employs CCS plant.
- v. Neither has significant expansion of interconnector capacity.
- vi. Both Gone Gas and Gone Nuclear have low risk of loss of supply beyond 2025.

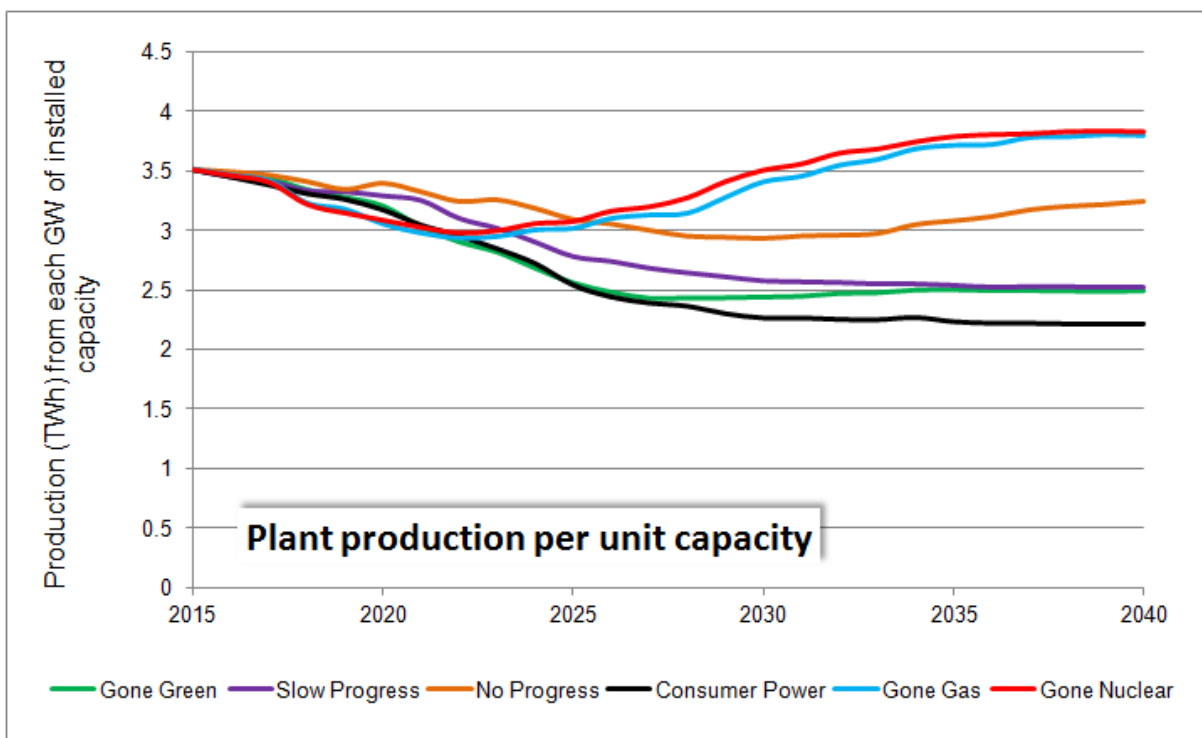


Figure 3 Scenario plant productivity TWh/GW installed. (A generator operating at 100 % load factor would achieve a value of 8.76).

2.7 Carbon dioxide emissions

The scale of carbon dioxide emissions associated with electricity generation has dominated selection criteria for obtaining new generation capacity for the last ten years to the near eclipse of considerations of cost or generation security. NG provide carbon dioxide emission rates (g CO₂/kWh) for their four scenarios every five years but do not indicate how these values are calculated. To calculate the CO₂ emissions from thermal plant we would have to know their various rate of emission over the full operational range of load factors, and also at times when they are running up and down in load. Operating at or near full load we know the emission rates of CCGTs, OCGTs, and coal-fired stations, but at low loads there is little information available.

Rather than neglect this subject we have estimated carbon dioxide emissions rates for each year and scenario based on the following assumptions:

- i. Generation from offshore wind, onshore wind, solar, marine, hydro, storage and nuclear are all assumed to be at zero rate, thus neglecting any allowance we should make for construction emissions.
- ii. Coal, and CCGT generation has been forced to operate at 90% load factor in all the costing calculations and are taken to have emission rates of 800 and 350 g CO₂/kWh respectively.
- iii. CHP is taken to be the same as CCGT
- iv. CCS is assumed to be coal fired, and emits at 20% of the rate of normal coal generation
- v. Biomass generation is dominated by burning wood in large power stations such as Drax and is therefore taken as 15% the rate of normal coal generation. 'Other renewable is' taken to be the same as biomass generation.
- vi. For interconnection production we assume that other countries have achieved generation at a rate of 100 g CO₂/kWh.
- vii. Operating OCGTs close to full power can achieve emission rates of 560 g CO₂/kWh. OCGTs operate with a wide range of load factors. Their emission rates will be higher at lower loads but we have no data to support a competent calculation of emissions. We therefore assume the full load rate for all OCGT operation. This is certainly a significant source of error in the calculations. 'Other thermal' is taken to be the same as OCGT.
- viii. No attempt is made to estimate carbon dioxide emissions generated during loading and unloading thermal plant, a significant source of error.

All of calculations will under-estimate carbon dioxide emissions, more so in those scenarios with a high proportion of renewables since they underestimate the emissions of OCGTs (see notes vii and viii above) the most. They should be viewed with caution but they do provide a reasonable comparison of performance between the scenarios. The scenarios mainly change their relative scale of renewables, CCGT and nuclear plant (CCS only appears in Gone Green from 2030 onwards and all coal generation disappears after 2022) while the other generation types remain very much the same.

3 Results

3.1 Results based on the values described in section 2

Figure 4 shows the LCOE calculations for the six scenarios using the conditions laid out in sections 2.1 and 2.2

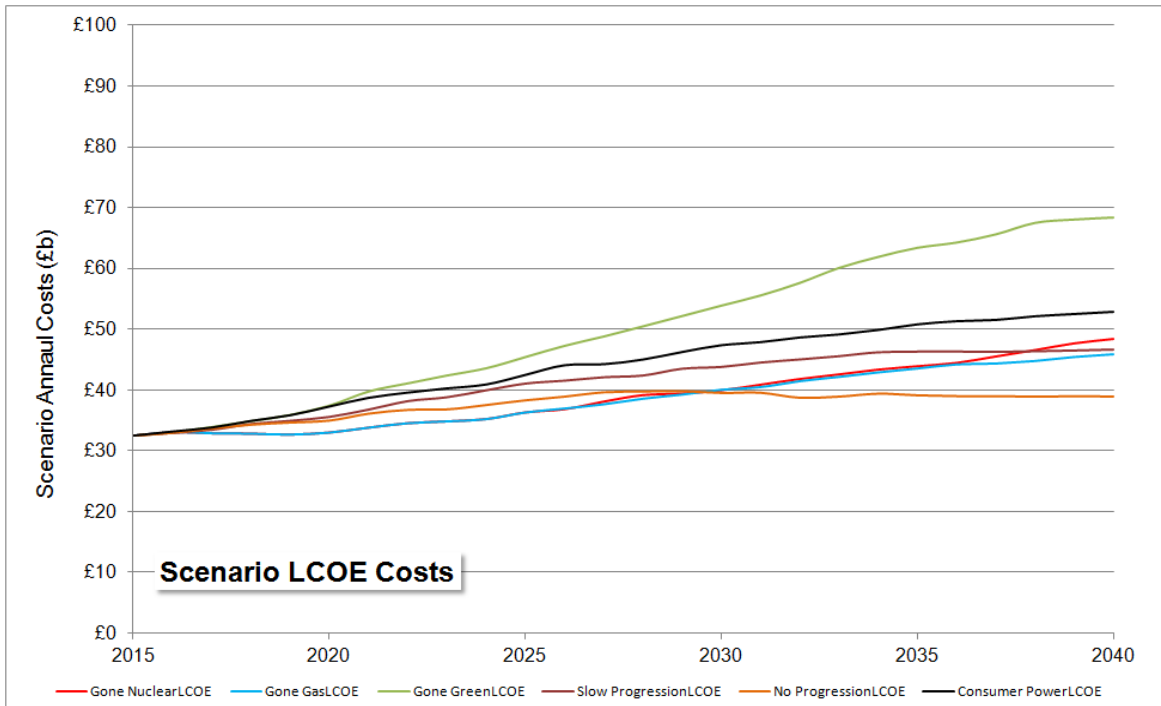


Figure 4 Total annual LCOE values for the 6 scenarios

Figure 5 shows the total system costs for the six scenarios

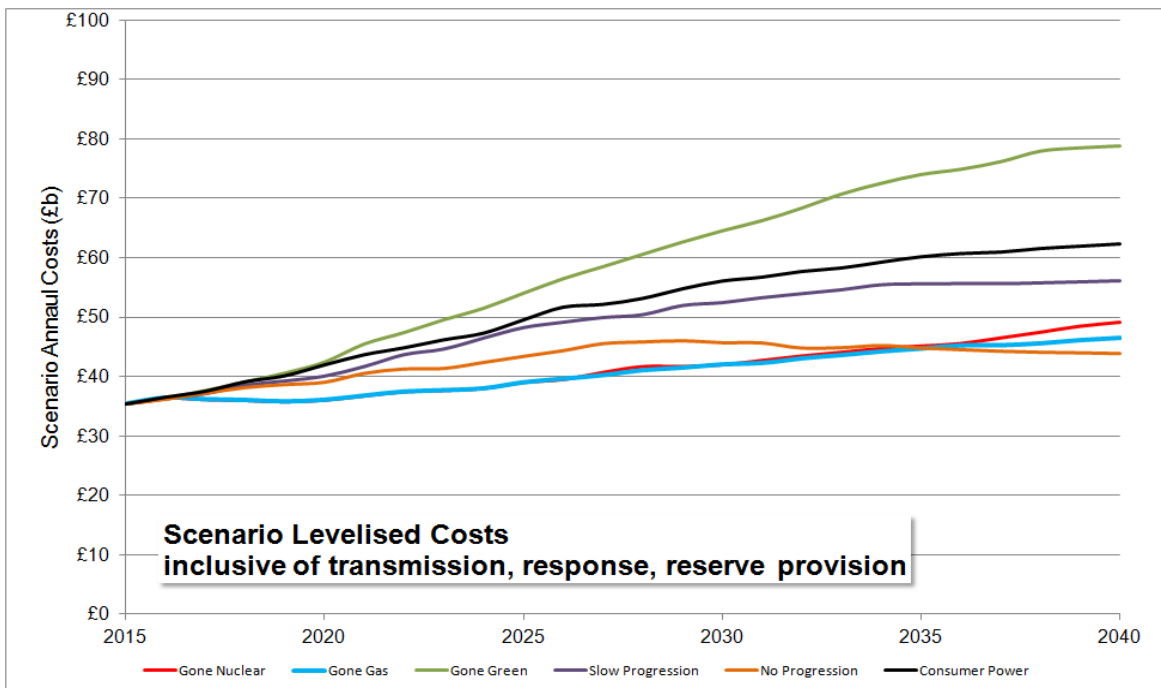


Figure 5 Total annual system costs for the six scenarios

Clearly, the total system costs are higher than the LCOE values, especially in those scenarios which have the most renewables (Gone Green and Consumer Power). The difference between total system costs and LCOE costs in the Gone Green scenario of 2040 is £10.4bn per annum. The Climate Change Committee (CCC) have identified the scale of system integration costs in their report *The Case For and Against Onshore Wind Energy in the UK (2012)*; it is worth quoting extensively from it:

The most recent official assessment of transmission requirements associated with renewables has been carried out by the Electricity Network Strategy Group. **The total investment cost of transmission consistent with the provision of 30 per cent of electricity from renewable sources by 2020 (including about 32,000 MW from onshore and offshore wind) was estimated to be £8.8 billion (ENSG, 2012), or roughly £1 billion as an annual average if costs are spread evenly each year from now to 2020.** As the benefits of the investment will accrue over the lifetime of the assets, which will be several decades, it makes sense to annuitize it over a longer period. This has been done by the Committee on Climate Change (2011b), which estimated that transmission costs will be around 20 per cent of the total annualised costs of accommodating 30 to 64 per cent of electricity from renewable sources by 2030.

Besides transmission, the costs related to the increased intermittency of electricity sources also need to be taken into account. These include the costs of distribution interconnection, bulk storage, smart grids and additional conventional generation (to ensure balancing and reliability). **Overall, the Committee on Climate Change estimated that the combined costs of transmission upgrades and other flexibility measures related to a 30 to 64 per cent share of electricity from renewables by 2030 would be between £5 and £5.9 billion per year (CCC, 2011b; Pöyry, 2011).**

In 2040 Gone Green includes 46 % of renewable capacity (16% offshore wind, 10%, onshore wind and 20% of solar) so the CCC report would imply system integrations costs of approximately £6b, compared to the value calculated here (£10.4b)

The scenarios do not deliver the same amount of annual production; in 2040 Gone Green and No Progress are scaled to deliver 465 TWh and 352 TWh respectively. For better comparison of the scenarios we calculate the generation costs for each MWh and show these in Figures 6 and 7.

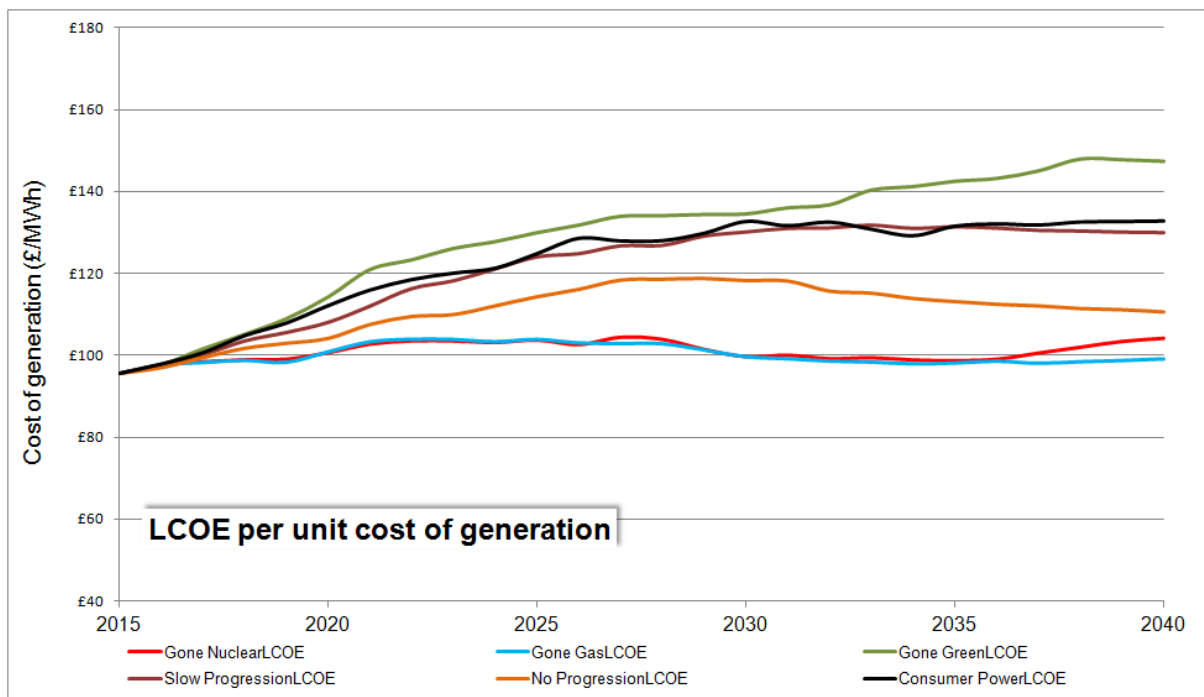


Figure 6 Per unit LCOE cost of electricity

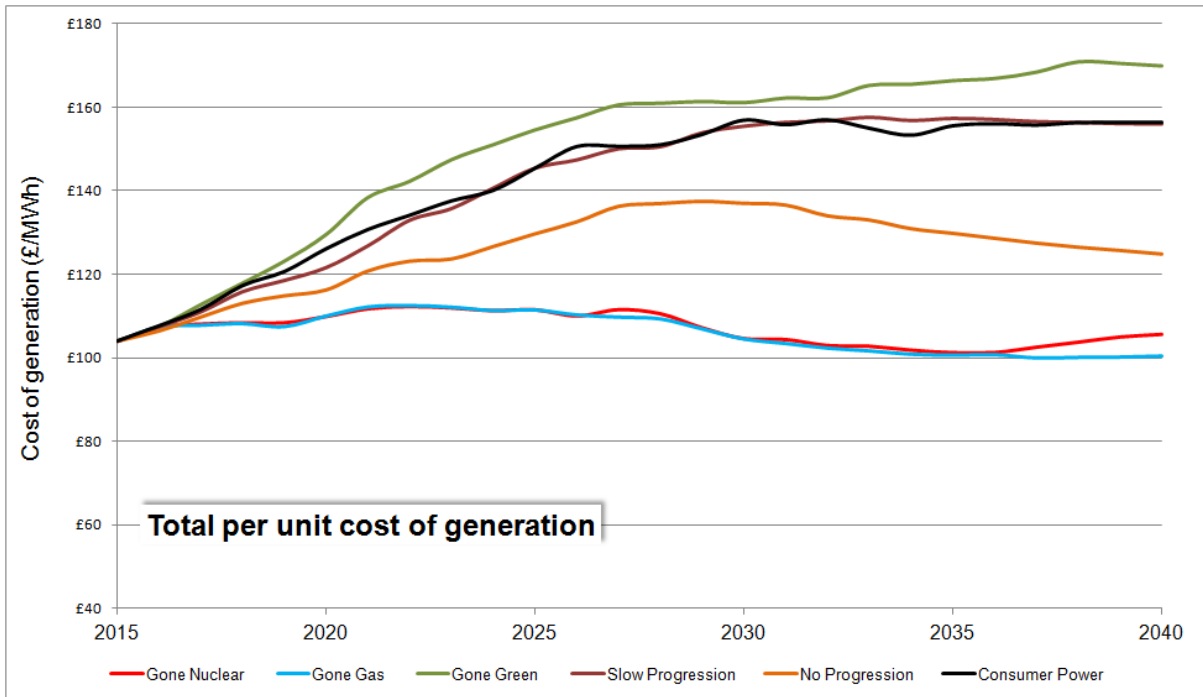


Figure 7 Total system cost of electricity production

Now the cost benefits of the Gone Gas and Gone Nuclear scenarios can be clearly seen. The two scenarios are very similar in cost because nuclear and gas have very similar LCOE values.

3.2 More realistic costs for offshore wind, nuclear, and gas

Capital costs dominate the LCOE for all renewables. We consider the capital cost of offshore wind that DECC used in their study (£2.37m/MW) to be too low. Figure 8 shows the rise in reported costs for UK offshore wind farms (wind fleets on the North Sea coasts of Holland, Denmark and Germany are similar). We use a capital cost of £3.5m/MW for offshore wind; with that cost, and assuming a 45 % capacity factor, the maintenance costs would need to be close to zero to achieve an LCOE of

£100/MWh

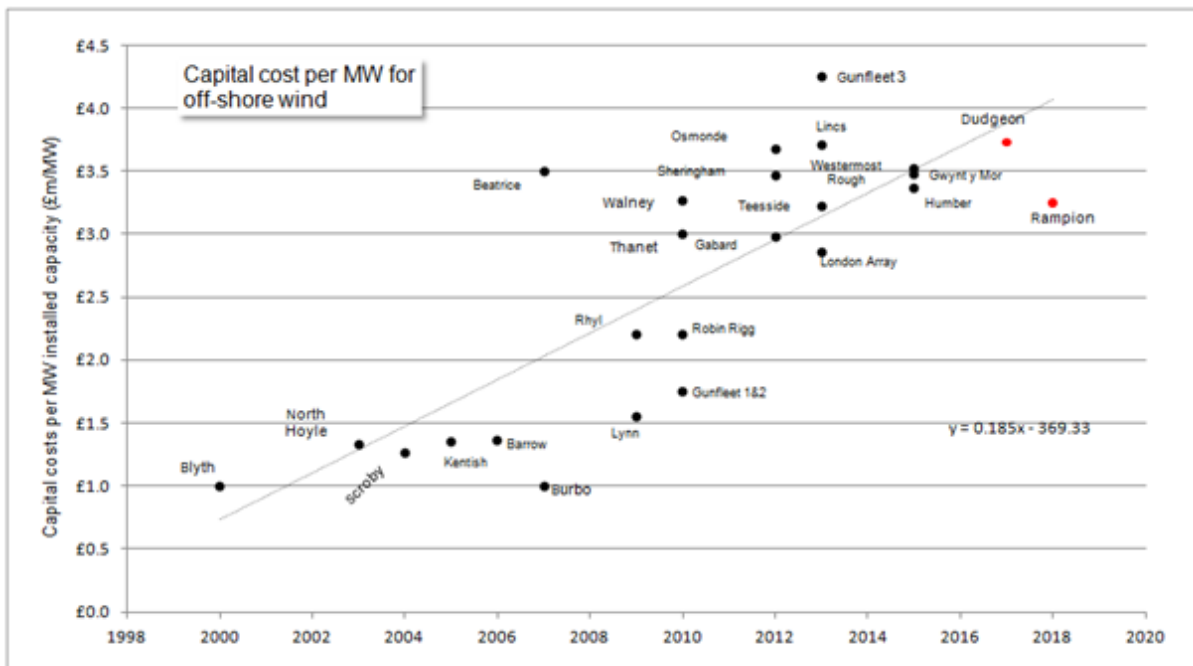


Figure 8 Capital cost of UK offshore windfarms (13).

The capital cost of nuclear that DECC uses is too high. The *price* of energy (with escalation) from Hinckley Point is unusually high and is likely to drive public opinion away from nuclear power. But costs elsewhere in the world, and in the UK are much lower. The Moorside proposal, using Westinghouse AP1000s (globally 18 AP1000s are being built or planned) gives a cost of £2.9m per MW. We use this figure instead of the £4.3m/MW figure of DECC.

The gas spot market price recently fell to 26p/Therm and has recovered to just over 30p/Therm. DECC are obviously predicting an average of forward prices stretching over periods that may vary over a few years to a few decades, but a central 2015 price of 47p/Therm seems high. We therefore assume that gas prices only achieve 85% of the DECC predictions.

Given the above three observations, we re-run the calculations, and the results are shown below in Figures 9-12.

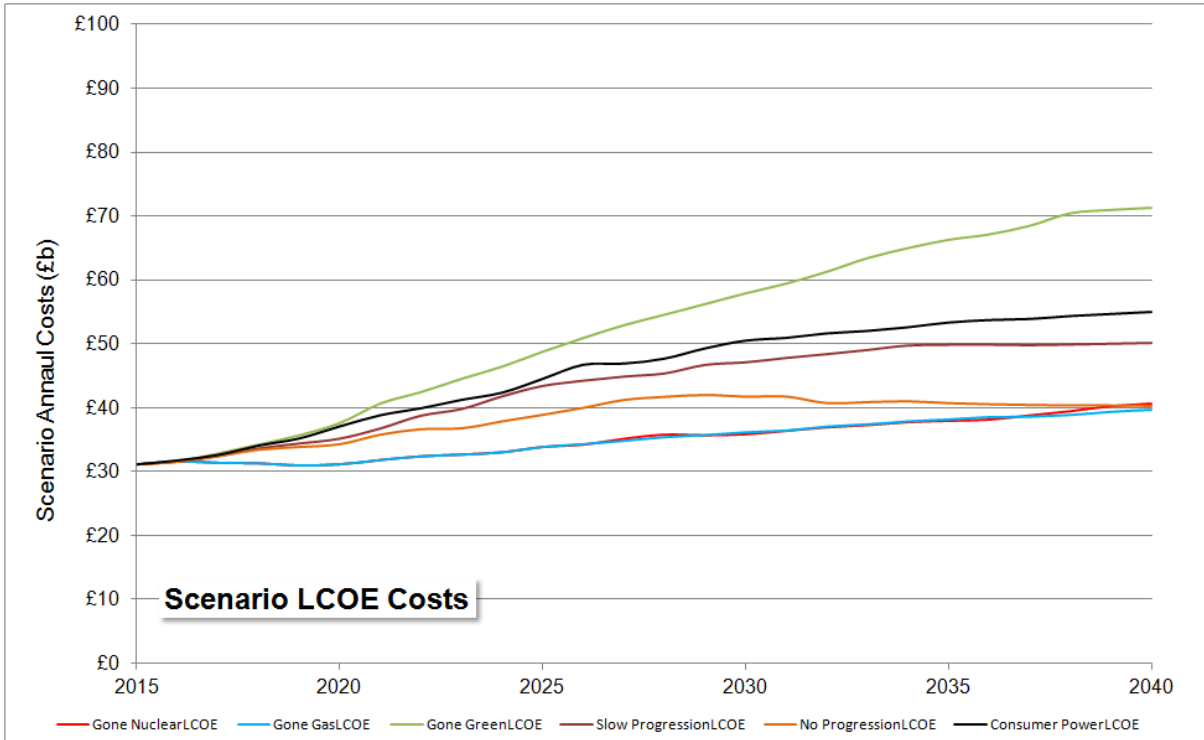


Figure 9 Total annual LCOE values for the 6 scenarios with 2016 cost data

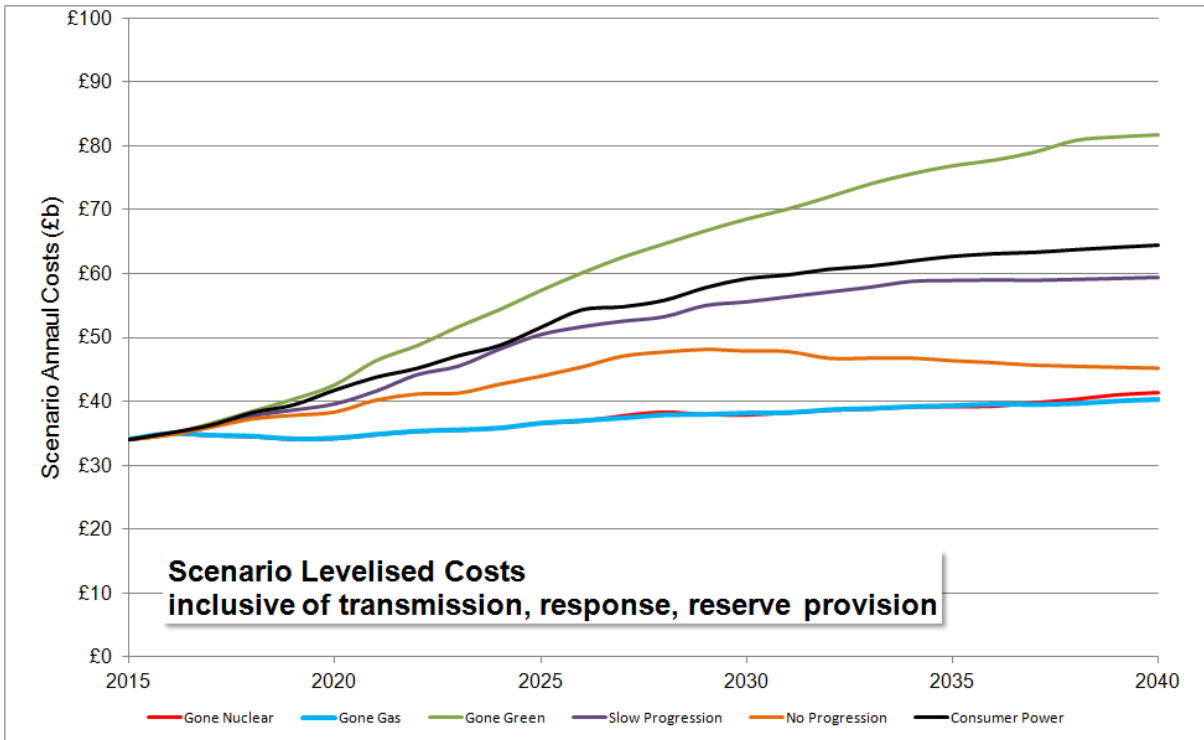


Figure 10 Total annual system costs for the six scenarios with 2016 cost data

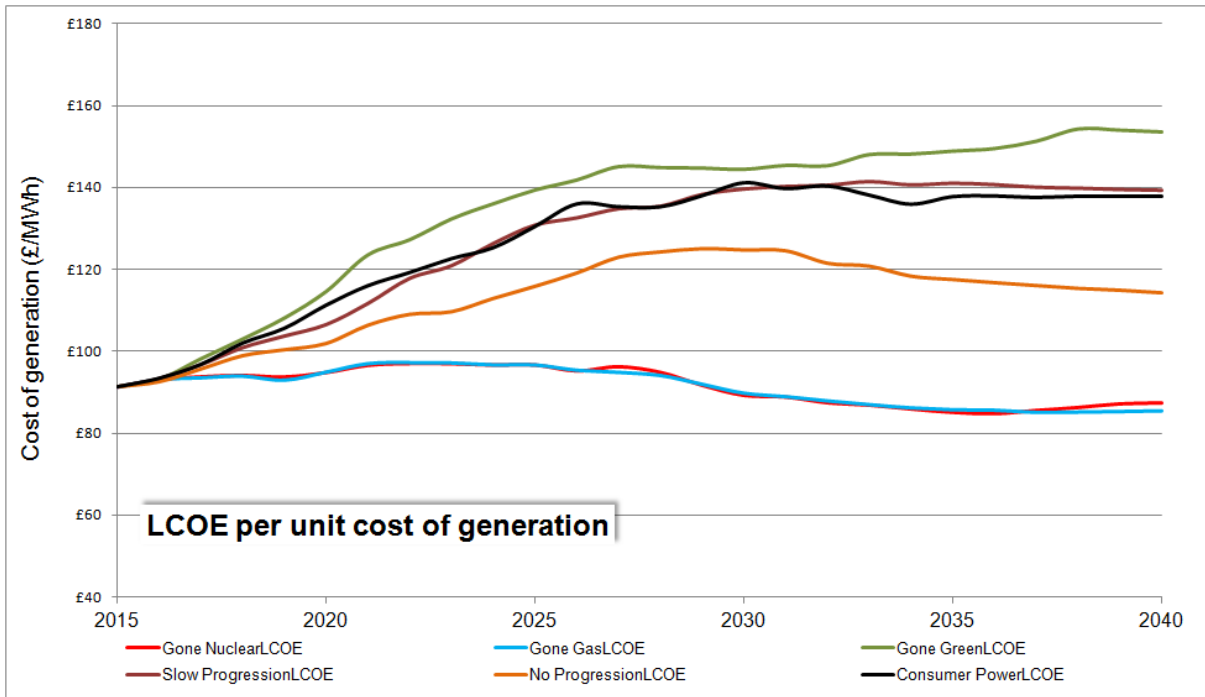


Figure 11 Per unit LCOE cost of electricity with 2016 cost data

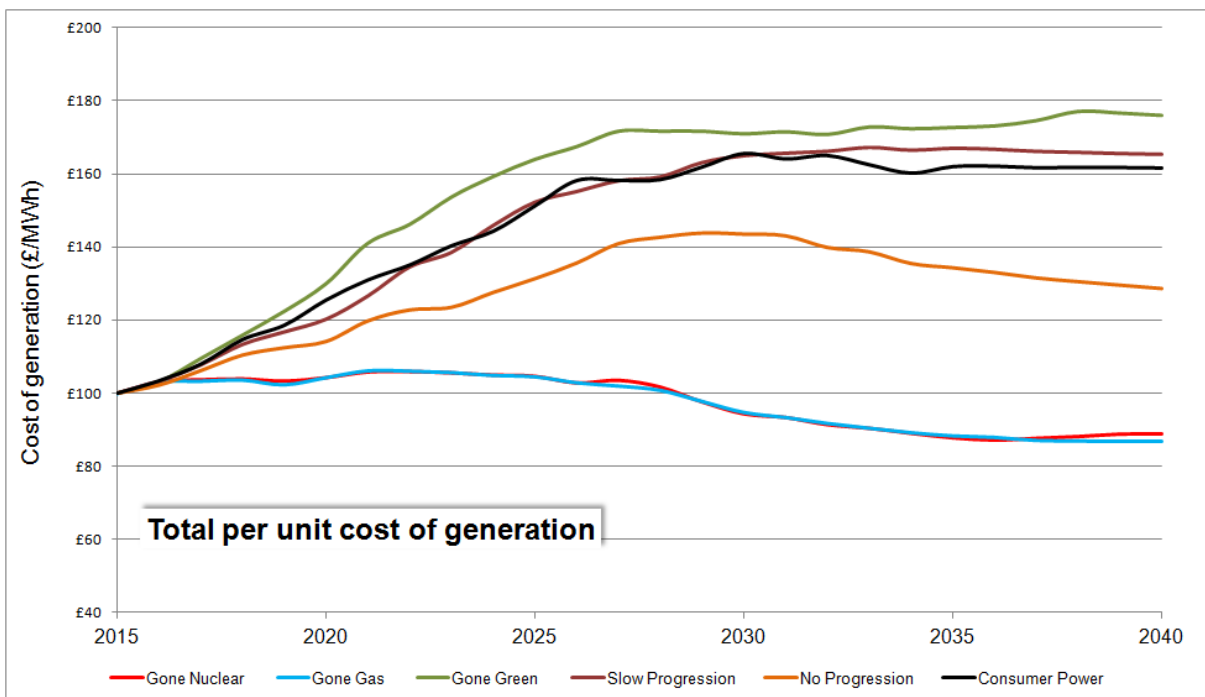
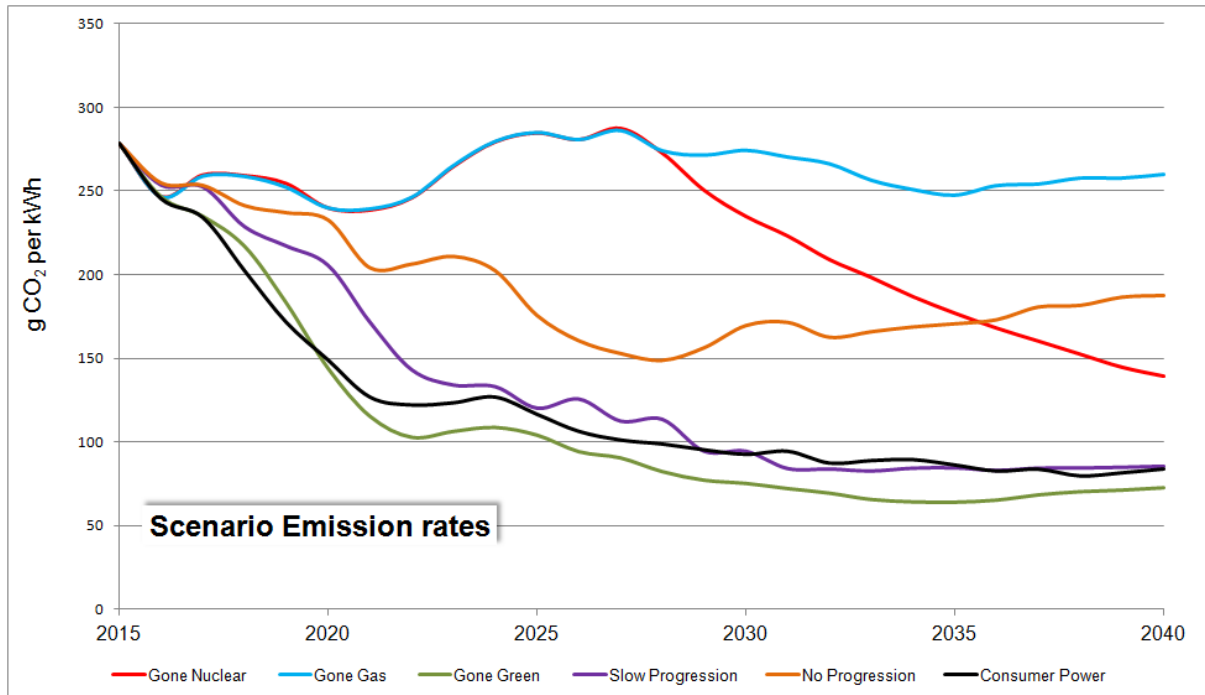


Figure 12 Total system cost of electricity production with 2016 cost data

3.3 Carbon dioxide emissions of the various scenarios

Figure 13 shows the calculated emission rates for the scenarios



4 Conclusions

Gone Green, Consumer Power and Slow Progression will nearly double the cost of UK electricity compared to today. The costs of the Gone Gas and Gone Nuclear scenarios are very similar to costs today. Present electricity prices have already influenced the closure of the UK's aluminium smelting industry, and are similarly involved currently with the steel industry. If prices are related to costs then these three NG scenarios may well reduce significantly the UK's manufacturing sector well before 2040.

It should not be supposed that any of the scenarios, as shown in the total system cost graphs 10 and 12, have any intermittency problem. The IESIS calculator 'solves' this issue by 'building' an adequate fleet of OCGT stations to be used in the event of any loss of production from wind and solar. The size of this fleet is slightly less than the sum of the capacities for wind and solar. Including these 'intermittency OCGT' fleets, the installed UK generation capacity will be close to triple the present size. Not only will there be extensive areas of the countryside covered with solar panels, and littered with wind turbines, but a requirement for new transmission plant connecting renewable plants remote from the load centres. The transmission network will be at least double the present size, owned by National Grid on a regulatory asset cost basis. In a fully competitive market, these costs would be charged to the renewables developer and become a charge on its shareholders. Currently, they are a charge spread over all customers.

Storage of electrical energy will have little prospect of solving the intermittency problem for the foreseeable future and is not considered in this paper. The amounts of storage required are vast. Ignoring the seasonal intermittency of solar, in Gone Green a drop below 10 % capacity factor for wind (instead of an average 27%) lasting a week would cause a production loss of approximately 500 GWh; the pumped storage capacity of Dinorwig is 10 GWh, and another 'Dinorwig' would cost about £1b (1990 prices). Battery storage is more expensive but has dropped to between \$0.5 and \$2/kWh. At best, we are still at 25p/kWh for battery storage – double that paid with typical domestic tariffs.

It has been claimed by some that the costs of renewables are falling. There is an initiative to reduce the LCOE for offshore wind below £100/MWh. There is a long way to go. The official cost shown in Table 2 suggests that only a small decrease is required (£13/MWh according to DECC (3)). But Figure 8 shows that the actual 2013 capital cost was closer to £3.5 m/MW, not the £2.37 m/MW used by DECC. And the capital cost continues to increase, as it has done since 2002, at a rate of 18 % per annum.

The trend with onshore wind capital costs is also upward (see Figure 13) but here the rate is a modest 3.8 %. (Data for this Figure gathered from newspaper reports).

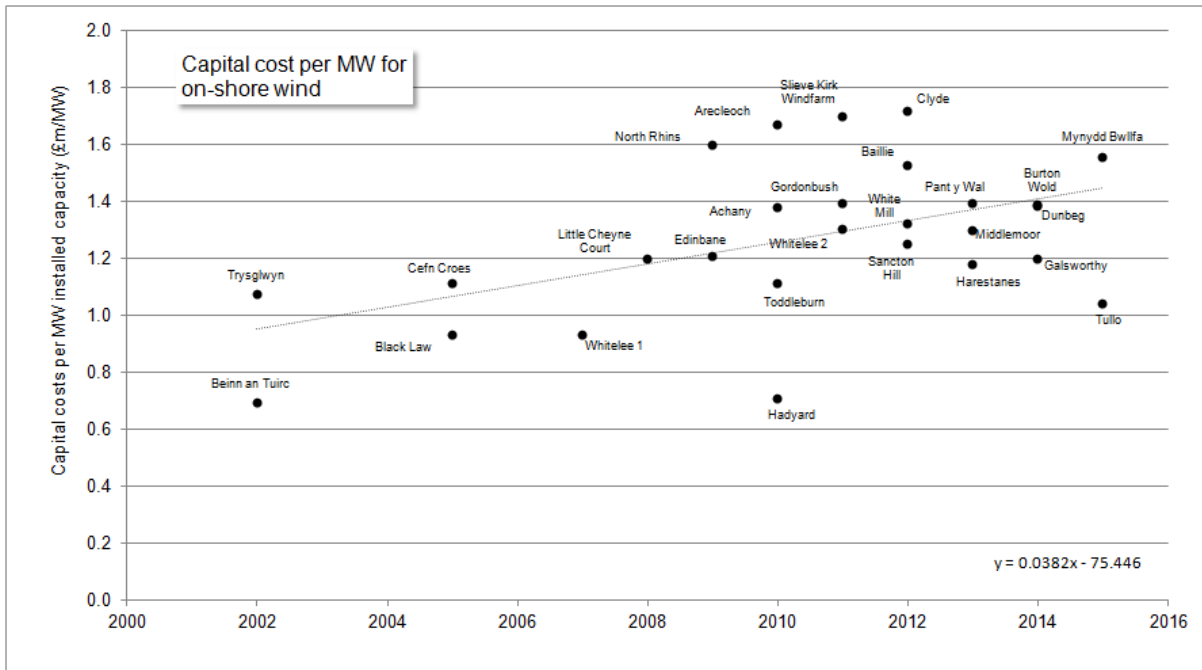


Figure 13 The capital cost of UK onshore wind

Solar capital costs are reported to be falling. Prices seem to have tracked the downward trend of FITs tariff rates. It seems doubtful they will fall much further unless a new form of cost-effective manufacture emerges since their manufacture is energy intensive. There may be potential for improved efficiency, either through improved optical performance or by moving toward multi-energy gap absorber materials, but both improvements will increase capital costs.

Given little prospect of renewable costs falling, it would seem sensible for National Grid to study scenarios such as Gone Gas and Gone Nuclear. Both Gone Gas and Gone Nuclear would reduce costs and give secure supplies. They would provide a cost effective energy platform for UK manufacturing. The present day transmission network would suffice with modest extension and improvement, the landscape of the UK would look much the same as today, and 100 sq km of agricultural land earmarked for sola would remain available for farming. No doubt there would be a reaction from bodies not altogether disinterested but, with regard to the 'public good', both scenarios would deliver significantly lower costs and better Security of Supply, thus providing an ideal platform for further improvements that cut carbon dioxide emissions below those already achieved by 2040.

Neither Gone Gas nor Gone Nuclear match the emissions performance of Gone Green, Consumer Power or Slow Progression. However, Gone Nuclear emissions are falling steeply by 2040 and would achieve parity by 2045 with further expansion of nuclear generation.

The UK needs to establish new standards or targets for both electricity Security of Supply and generation costs. The generation planning system is now in need of fundamental review. -The public and industry (particular generation plant owners, constructors and operators) need confidence that both these issues are being addressed. This can only be accomplished through a process of audit and review carried out on a regular basis. This will require a complete re-structuring of the

responsibilities and processes used to achieve an acceptable level risk and an optimum cost of generation.

One possible structure would be to set up a Standing Commission of Parliament. The Head of the Commission would be responsible for achieving a Standard set by Parliament. This new Standard would take account of the reliance of modern society on the electricity system. The Commission would have the authority to tender for long - term contracts for both capacity to be delivered at times of peak demands, and for energy with appropriate escalation clauses. This would allow the Commission to accept a combination of the tender offers that satisfied the Risk Standard at the minimum cost. [More detail is contained in Gibson's submission to the House of Lords' inquiry (2014-15) on behalf of REF.(14)] The Commission could also take on board the requirement for an Independent Grid System Operator. In this event, we would strongly advocate that the functions of System Design and Asset Management, being closely related to System Operation, also move to the Commission.

This brief study has focussed entirely on future energy scenarios. We have built over 38 GW of renewable generation over the last ten years, perhaps the highest build rate of generation capacity ever seen in the UK. This has been accompanied by considerable expansion of the transmission grid network. In spite of this we seem to have a capacity crisis (1). We begin to see that we have increased the price of electricity to the point where heavy industry is leaving the UK. We have no real evidence that the fall of carbon dioxide emissions that has been calculated for this period can be attributed to electricity generation or simply a fall in energy demand following production activity. Surely it is time for this strategy of building renewables to be recognised as not fit for purpose?

The excellent agreement between the IESIS spreadsheets (publically available, and easily modified as required) and the DECC 2013 study data serve to establish the IESIS work as a benchmark tool for this form of analysis. The agreement between IESIS and the CCC in calculating total system costs further confirms this quality.

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Appendix

Abbreviated Capacity and Production Tables for the scenarios

Gone Green

Fuel Type	Installed capacity (GW)					
	2015	2020	2025	2030	2035	2040
Storage	2.74	4.23	5.51	8.12	9.33	11.41
Biomass	2.53	3.21	3.84	3.65	3.65	3.65
CCS	0.00	0.00	0.00	1.80	7.42	11.17
CHP	5.32	6.12	6.22	5.40	5.65	5.83
Gas	28.30	25.44	27.76	24.39	16.41	14.73
Coal	17.28	1.93	0.00	0.00	0.00	0.00
Hydro	1.59	1.67	1.77	1.83	1.87	1.89
Interconnectors	3.95	7.55	19.36	23.26	23.26	23.26
Marine	0.04	0.09	0.88	2.70	3.72	5.22
Nuclear	8.99	8.99	4.72	10.16	18.55	18.55
Offshore wind	4.87	9.91	21.68	28.98	28.98	28.98
Onshore wind	8.22	12.30	17.33	18.35	19.10	19.60
Solar	9.59	16.23	22.90	30.58	34.55	36.83
Other thermal	1.44	2.12	2.15	2.18	2.14	1.74
Other renewable	2.08	2.59	2.99	3.44	3.88	3.90
TOTAL GW	96.96	102.36	137.12	164.83	178.51	186.77

Fuel Type	Production TWh p.a.					
	2015	2020	2025	2030	2035	2040
Storage	2.67	3.77	4.88	7.21	7.91	10.46
Biomass	16.43	20.09	19.89	12.22	5.61	2.45
CCS	0.00	0.00	0.00	8.82	40.65	79.67
CHP	26.18	29.86	31.19	26.48	27.83	28.74
Gas	89.92	47.06	32.23	26.71	13.69	10.17
Coal	57.71	10.97	0.00	0.00	0.00	0.00
Hydro	4.66	4.97	5.33	5.58	5.74	5.82
Interconnectors	23.98	58.89	72.19	51.51	38.43	38.43
Marine	0.01	0.14	1.72	5.37	7.35	10.24
Nuclear	61.95	54.53	21.18	61.20	117.81	118.96
Offshore wind	16.69	36.39	82.34	110.89	89.40	70.77
Onshore wind	20.12	30.85	38.71	33.93	32.89	28.03
Solar	10.06	16.96	23.64	31.46	35.42	37.65
Other thermal	0.01	0.03	0.03	0.03	0.03	0.03
Other renewable	10.32	13.70	16.77	19.85	22.80	23.26
TOTAL (TWh)	340.72	328.20	350.11	401.25	445.57	464.67

Slow Progression

Installed capacity (GW)						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.74	3.06	3.25	3.58	4.87	6.35
Biomass	2.53	2.92	3.21	2.98	2.91	2.50
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	5.32	6.14	6.22	4.95	5.15	5.20
Gas	28.30	27.78	30.14	28.22	24.40	24.48
Coal	17.28	5.90	0.00	0.00	0.00	0.00
Hydro	1.59	1.62	1.64	1.70	1.71	1.72
Interconnectors	3.95	4.15	13.46	14.86	16.06	16.06
Marine	0.04	0.06	0.48	0.89	2.49	2.49
Nuclear	8.99	8.99	4.72	5.69	7.36	7.36
Offshore wind	4.87	8.23	17.13	22.18	24.18	24.18
Onshore wind	8.22	11.74	15.22	16.13	16.52	16.81
Solar	9.59	14.88	18.80	24.49	28.10	30.09
Other thermal	1.44	2.35	2.48	2.69	2.61	2.64
Other renewable	2.08	2.37	2.58	2.73	2.93	2.88
TOTAL GW	96.96	100.19	119.33	131.08	139.27	142.75

Production TWh p.a.						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.67	2.82	2.96	3.26	4.28	5.31
Biomass	16.43	19.89	18.03	13.23	11.77	10.19
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	26.18	29.92	31.22	23.95	25.03	25.30
Gas	89.92	67.27	42.79	31.54	28.47	30.21
Coal	57.71	31.50	0.00	0.00	0.00	0.00
Hydro	4.66	4.79	4.90	5.08	5.16	5.20
Interconnectors	23.98	29.03	71.53	67.45	61.69	61.69
Marine	0.01	0.06	0.90	1.83	4.95	4.95
Nuclear	61.95	57.19	24.77	34.18	46.13	46.64
Offshore wind	16.69	29.87	64.57	83.29	84.79	86.61
Onshore wind	20.12	29.45	36.27	32.65	35.09	35.70
Solar	10.06	15.65	19.69	25.59	29.18	31.13
Other thermal	0.01	0.06	0.03	0.04	0.04	0.04
Other renewable	10.32	12.38	13.84	14.99	16.48	16.48
TOTAL (TWh)	340.72	329.89	331.50	337.07	353.04	359.46

No Progression

Installed capacity (GW)						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.74	3.06	3.10	3.45	3.53	3.60
Biomass	2.53	2.82	2.74	2.51	0.53	0.51
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	5.32	6.04	6.50	6.78	6.69	6.59
Gas	28.30	29.80	36.77	37.57	36.04	38.38
Coal	17.28	7.47	0.00	0.00	0.00	0.00
Hydro	1.59	1.59	1.59	1.59	1.60	1.60
Interconnectors	3.95	4.15	9.96	11.36	13.96	13.96
Marine	0.04	0.05	0.05	0.05	0.05	0.05
Nuclear	8.99	7.78	4.72	1.22	4.56	4.56
Offshore wind	4.87	7.01	11.97	17.10	17.10	17.10
Onshore wind	8.22	11.58	11.46	11.53	9.35	5.47
Solar	9.59	12.80	14.15	14.71	12.41	10.26
Other thermal	1.44	2.42	2.85	3.38	3.62	3.66
Other renewable	2.08	2.32	2.48	2.61	2.77	2.69
TOTAL GW	96.96	98.88	108.34	113.85	112.19	108.41

Production TWh p.a.						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.67	2.82	2.91	3.19	3.25	3.31
Biomass	16.43	19.28	18.37	11.81	1.26	1.27
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	26.18	29.35	31.95	33.31	33.27	32.70
Gas	89.92	82.94	91.66	84.13	94.80	112.93
Coal	57.71	36.02	0.00	0.00	0.00	0.00
Hydro	4.66	4.71	4.76	4.80	4.85	4.89
Interconnectors	23.98	29.62	52.41	64.82	60.34	60.34
Marine	0.01	0.04	0.04	0.13	0.13	0.13
Nuclear	61.95	51.30	30.86	7.90	30.53	30.86
Offshore wind	16.69	25.47	45.12	65.98	66.11	66.44
Onshore wind	20.12	29.13	28.99	28.39	23.14	13.69
Solar	10.06	13.46	14.87	15.42	12.82	10.42
Other thermal	0.01	0.04	0.04	0.05	0.06	0.06
Other renewable	10.32	11.94	13.07	13.94	15.16	14.89
TOTAL (TWh)	340.72	336.12	335.05	333.86	345.72	351.93

Consumer Power

Installed capacity (GW)						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.74	3.73	4.91	10.69	16.36	18.26
Biomass	2.53	2.92	3.21	1.07	1.00	0.31
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	5.32	6.25	6.72	6.80	6.07	6.13
Gas	28.30	27.50	30.91	27.91	26.06	24.82
Coal	17.28	2.92	0.00	0.00	0.00	0.00
Hydro	1.59	1.69	1.78	1.87	1.93	1.97
Interconnectors	3.95	8.55	20.06	23.26	23.26	23.26
Marine	0.04	0.06	0.58	0.70	0.75	0.75
Nuclear	8.99	8.99	4.72	7.36	11.28	14.08
Offshore wind	4.87	8.27	15.44	21.68	22.68	22.68
Onshore wind	8.22	12.10	14.48	15.45	16.21	16.70
Solar	9.59	16.75	25.10	33.62	39.10	42.33
Other thermal	1.44	2.38	2.71	3.03	3.31	3.32
Other renewable	2.08	2.73	3.25	3.97	4.62	4.77
TOTAL GW	96.96	104.85	133.85	157.39	172.63	179.37

Production TWh p.a.						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.67	2.99	3.75	7.95	11.63	13.42
Biomass	16.43	18.56	17.31	4.05	3.12	1.69
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	26.18	30.82	33.37	33.61	28.99	29.01
Gas	89.92	55.08	36.89	22.43	31.77	32.08
Coal	57.71	7.39	0.00	0.00	0.00	0.00
Hydro	4.66	5.03	5.38	5.70	5.93	6.06
Interconnectors	23.98	65.55	82.87	90.48	66.48	66.48
Marine	0.01	0.06	1.10	1.48	1.61	1.61
Nuclear	61.95	55.26	23.78	35.30	68.53	83.01
Offshore wind	16.69	29.88	57.84	74.12	71.51	63.22
Onshore wind	20.12	30.25	33.93	24.22	29.27	29.55
Solar	10.06	17.53	26.03	34.80	40.39	43.65
Other thermal	0.01	0.03	0.04	0.05	0.06	0.06
Other renewable	10.32	14.50	18.37	22.97	27.20	28.37
TOTAL (TWh)	340.72	332.95	340.66	357.17	386.48	398.21

Gone gas

Installed capacity (GW)						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.74	4.23	5.51	8.12	9.33	11.41
Biomass	2.53	3.21	3.84	3.65	3.65	3.65
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	5.32	6.12	6.22	5.40	5.65	5.83
Gas	28.30	44.72	61.52	61.52	57.92	57.92
Coal	17.28	3.92	0.00	0.00	0.00	0.00
Hydro	1.59	1.67	1.77	1.83	1.87	1.89
Interconnectors	3.95	5.15	5.15	5.15	5.15	5.15
Marine	0.04	0.05	0.05	0.05	0.05	0.05
Nuclear	8.99	8.99	4.72	10.16	20.00	25.60
Offshore wind	4.87	3.97	3.07	2.38	1.84	1.42
Onshore wind	8.22	9.41	8.95	6.21	2.76	1.22
Solar	9.59	11.30	10.22	8.16	5.65	2.51
Other thermal	1.44	2.12	2.15	2.18	2.14	1.74
Other renewable	2.08	2.59	2.99	3.44	3.88	3.90
TOTAL GW	96.96	107.43	116.16	118.24	119.88	122.29

Production TWh p.a.						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.67	3.77	4.88	7.21	7.91	10.46
Biomass	16.43	20.09	19.89	12.22	5.61	2.45
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	26.18	29.86	31.19	26.48	27.83	28.74
Gas	89.92	135.00	204.00	235.00	237.00	261.00
Coal	57.71	10.97	0.00	0.00	0.00	0.00
Hydro	4.66	4.97	5.33	5.58	5.74	5.82
Interconnectors	23.98	10.00	10.00	10.00	10.00	10.00
Marine	0.01	0.14	1.72	5.37	7.35	10.24
Nuclear	61.95	54.53	21.18	61.20	117.81	118.96
Offshore wind	16.69	13.71	10.61	8.21	6.35	4.91
Onshore wind	20.12	23.16	22.02	15.28	6.78	3.01
Solar	10.06	11.89	10.75	8.58	5.94	2.64
Other thermal	0.01	0.03	0.03	0.03	0.03	0.03
Other renewable	10.32	9.80	8.63	7.61	6.70	5.91
TOTAL (TWh)	340.72	327.91	350.23	402.77	445.06	464.16

Gone nuclear

Installed capacity (GW)						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.74	3.07	3.07	3.07	3.07	3.07
Biomass	2.53	3.21	3.84	3.65	3.65	3.65
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	5.32	6.12	6.22	5.40	5.65	5.83
Gas	28.30	44.72	61.52	57.92	51.92	45.92
Coal	17.28	3.92	0.00	0.00	0.00	0.00
Hydro	1.59	1.67	1.77	1.83	1.87	1.89
Interconnectors	3.95	5.15	5.15	5.15	5.15	5.15
Marine	0.04	0.05	0.05	0.05	0.05	0.05
Nuclear	8.99	8.99	4.72	14.92	29.92	44.92
Offshore wind	4.87	3.97	3.07	2.38	1.84	1.42
Onshore wind	8.22	9.41	8.95	6.21	2.76	1.22
Solar	9.59	11.30	10.22	8.16	5.65	2.51
Other thermal	1.44	2.12	2.15	2.18	2.14	1.74
Other renewable	2.08	2.59	2.99	3.44	3.88	3.90
TOTAL GW	96.96	106.28	113.72	114.35	117.53	121.27

Production TWh p.a.						
Fuel Type	2015	2020	2025	2030	2035	2040
Storage	2.67	3.77	4.88	6.37	6.37	6.37
Biomass	16.43	20.09	19.89	12.22	5.61	2.45
CCS	0.00	0.00	0.00	0.00	0.00	0.00
CHP	26.18	29.86	31.19	26.48	27.83	28.74
Gas	89.92	135.00	204.00	195.70	160.20	124.70
Coal	57.71	10.97	0.00	0.00	0.00	0.00
Hydro	4.66	4.97	5.33	5.58	5.74	5.82
Interconnectors	23.98	10.00	10.00	10.00	10.00	10.00
Marine	0.01	0.14	1.72	5.37	7.35	10.24
Nuclear	61.95	54.53	21.18	91.00	182.00	265.00
Offshore wind	16.69	13.71	10.61	8.21	6.35	4.91
Onshore wind	20.12	23.16	22.02	15.28	6.78	3.01
Solar	10.06	11.89	10.75	8.58	5.94	2.64
Other thermal	0.01	0.03	0.03	0.03	0.03	0.03
Other renewable	10.32	9.80	8.63	7.61	6.70	5.91
TOTAL (TWh)	340.72	328.20	350.11	401.25	445.57	464.67