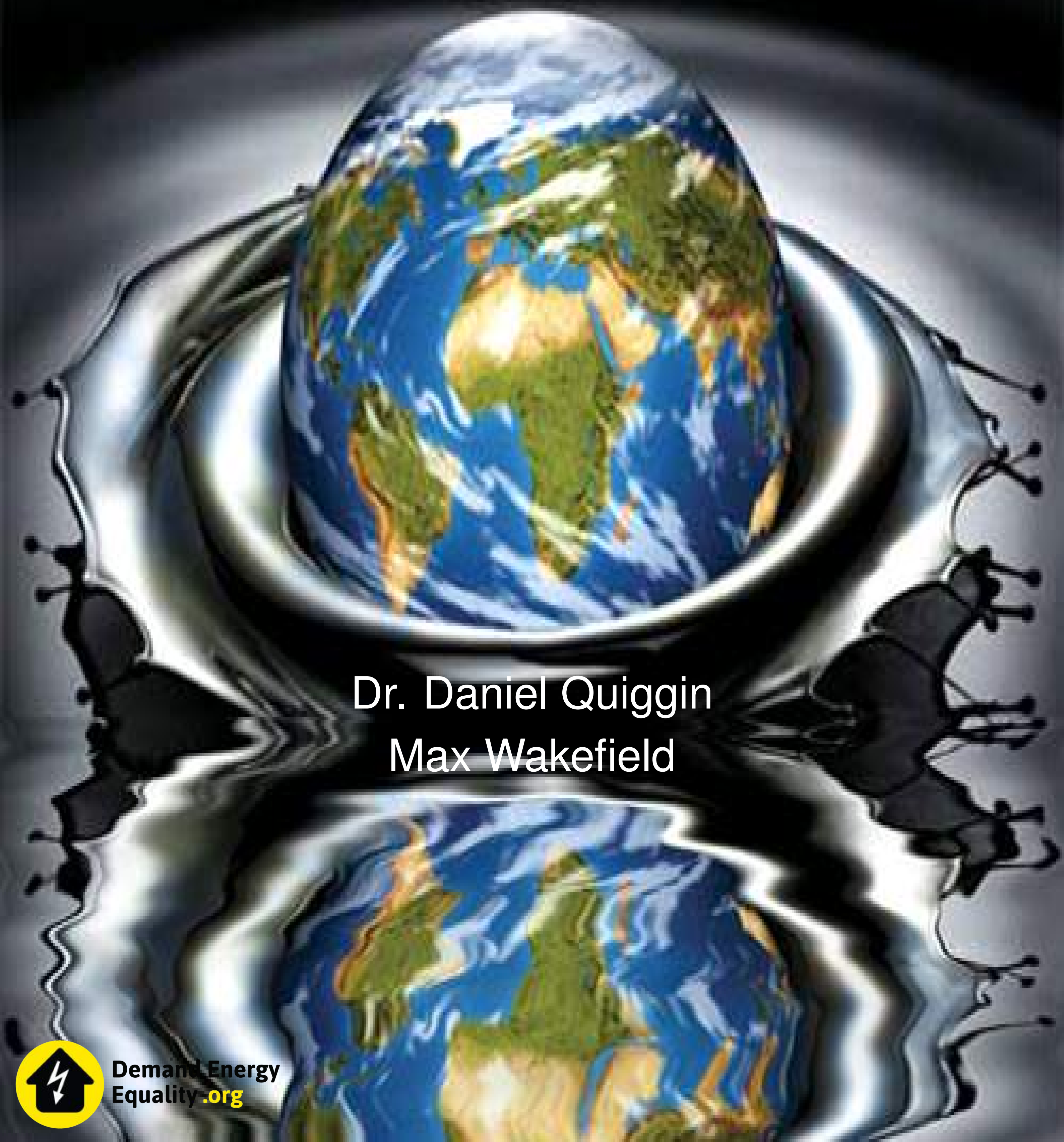
GREENPEACE

2030 Energy Scenarios



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Dr Daniel Quiggin has extensive knowledge and expertise in the analysis of the UK energy system,having modelled various UK Government energy scenarios during his PhD. This work included evaluating the impact of Demand Side Management requirements of those scenarios on household energy consumption patterns. Daniel is a director of Demand Energy Equality and a Research Associate at Loughborough University. Working on Hothouse; a 2-year research project that seeks to situate and understand domestic energy consumption within the context of families' everyday lives and routines. Daniel holds two 1st class Masters degrees, one in Physics and another in Earth System Science.

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This document and the research underpinning it has been reviewed by Prof David Infield (University of Strathclyde)

If you or your organisation would like similar work conducted on national supply-demand modelling, please contact us - info@dee.org.uk.
If you would like to use the SHED model online, please visit www.dee.org.uk/shed

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1. Executive Summary

1.1 Introduction

> "The UK's consumption [of energy] cannot continue to rise indefinitely.... if it is to make an effective contribution to a global reduction in greenhouse gas emission" (Energy and Climate Change Committee 2012)

This report is a direct response to the increasingly urgent need for industrialised countries to rapidly decrease their carbon emissions to prevent a worsening climate crisis.

It positions itself within the context of the UK's policy and legislation: we treat the Climate Change Act 2008 requirement for an 80% cut in emissions on 1990 levels by 2050 as a *starting point* for a more ambitious carbon reduction plan. This reflects the latest climate science published by the UNFCCC. The cumulative effect of carbon emissions guarantee that action taken sooner will have a far greater chance of avoiding the worst outcomes of a climate crisis; this report therefore concerns itself with *2030* targets.

Our report aims to make a significant contribution to enabling the Committee on Climate Change's (CCC) preference for a transition to a low carbon economy, spear-headed by *electrification* of demand traditionally delivered through other means; and *decarbonisation* of the power sector that provides electrical supply to meet such demand. Only through the former can the environmental benefits of the latter be extended to demand types currently delivered through the direct combustion of fossil fuels: whether the burning of gas in a domestic boiler, or of diesel in a family car. And only through that extension can a comprehensive decarbonisation of the overall UK economy be achieved.

This contribution takes the form of employing an advanced modelling process to design, test and iterate a 2030 energy scenario - in collaboration with Greenpeace UK - that can demonstrably overcome the specific technical, infrastructural and engineering problems associated with migrating to a radically decarbonised power sector. Indeed, a power sector that we know will have significant extra demands made on it in the future as a consequence of electrification and population growth.

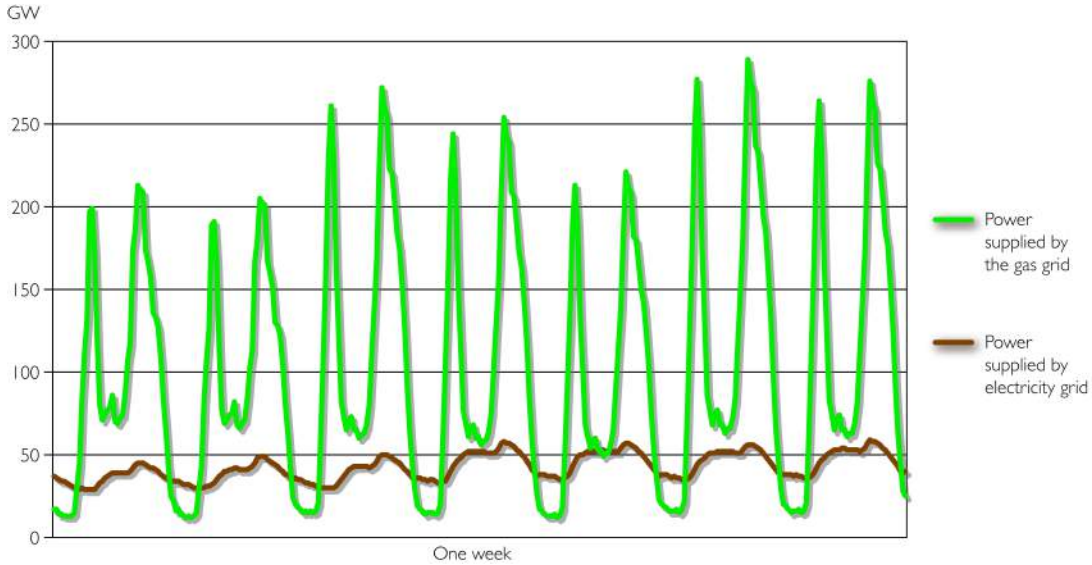


Figure 1.1: Power supplied by gas and electricity grid over one week in January. Source : Department of Energy and Climate Change (2012*b*).

1.1.1 The challenge

Both electrification and decarbonisation, as policy priorities, presents their own challenges. By unpacking each in turn we can see how, when combined, these challenges magnify one-another.

Electrification

Electrification refers to the intention to move substantial proportions of energy demand, primarily space heating and transport requirements, onto the electricity network by 2030 - with more to follow before 2050. The extent to which this is achieved has very significant knock-on effects for the *size* and *nature* of electrical demands that the National Grid will be expected to service.

Figure 1.1 shows the difference between the overall *total* UK electricity demand in comparison to the demand for gas, which is predominately used for space heating via gas boilers.

The size of the gas demand, in comparison to the total electricity demand, should make clear why electrification provides a problem. Even taking a proportion of this demand (this report will suppose 25 %) and transferring it onto the electricity network is a new and very sizeable challenge.

Furthermore, demand is not 'flat' (i.e. is not equally spread across each hour of a 24-hour cycle). This is particularly true in the case of domestic space heating which varies according to time of day, producing large peaks in demand in the mornings and evenings of, predominantly, winter days. Thus, by transferring a proportion of heating demand onto the electricity network, we also transfer a proportion of the associated peaks in demand onto the electricity network. These in turn combine with existing peaks driven by traditional electricity demand[1] (also generally in mornings and evenings) to

[1] Traditional electricity demand is the electrical demand from both domestic and non-domestic electricity consumers, with no contribution from electric vehicles, heat pumps or economy seven. It is the future electrical demand that is similar to current electrical demands, but with economy seven or resistive heating removed.

produce larger overall peak demands on the electricity network.

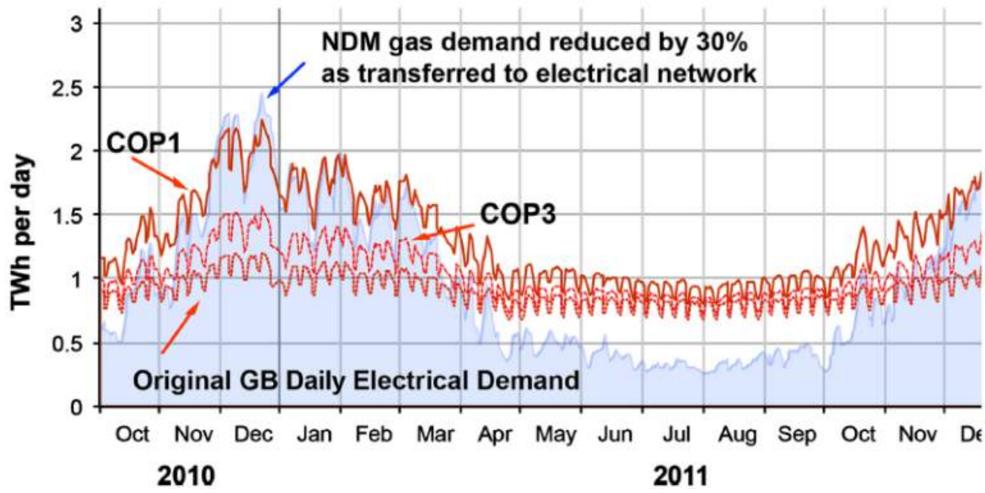


Figure 1.2: Transfer of heat and hot water demand from gas to electrical network. Source : Wilson et al. (2013).

Larger peaks in demand require larger reserves of generation capacity in order to met that demand - failure to do so results in blackouts or brownouts. The main consequence of electrification is the need to deal with increased demand peaks.

Figure 1.2 shows the changes to electrical demand with 30% of non-daily metered (NDM) heating transferred to either resistive heating technologies (COP1) or heat pumps (COP3), where the electrical demand is scaled by the coefficient of performance (COP) of those heat pumps. Wilson et al. (2013) find that if electrification of 30% of NDM heating demands were provided solely provided via heat pumps daily demand would increase by around 25%.

Key Information 1.1 Throughout this report a 2050 energy scenario developed by the DECC which is described by its strap line as; "Higher renewables, more energy efficiency", is utilised to compare the inputs and outputs of *GP:2030*. This DECC scenario is referred to as *DECC:2050:Renew* and it should be noted that it is a *2050* rather than 2030 scenario. *DECC:2050:Renew* was utilised as a comparator or benchmark as;

1. SHED has previously been used to model *DECC:2050:Renew*, hence the inputs and outputs are available to the authors.
2. *DECC:2050:Renew* is a scenario that is characterised by high renewable integration and comparable demand reduction.

Decarbonisation

Decarbonisation refers to the reduction to as close to zero as possible of the carbon intensity of energy delivery. The carbon intensity of certain energy uses is fixed by the *form* of delivery: the fuel burned in a car's internal combustion engine emits a certain amount of carbon when burnt. To decarbonise car travel, therefore, the form by which energy is delivered, fuel, must be substituted for electricity, which is able to be decarbonised. We are therefore concerned with the overall carbon intensity of electrical power delivered. The carbon intensity of the UK's power sector in 2015 is $\sim 500 g_{eq} CO_2/kWh$ - the CCC has identified a target of 50-100$g_{eq} CO_2/kWh$ by 2030. This report aims to reach as close to $50 g_{eq} CO_2/kWh$ by 2030, in light of worsening climate science and the clear benefits of mounting earlier action.

Decarbonisation, by a multiple of over 10, is no small task. Broadly, it involves the substitution for centralised, dirty, fossil fuel generators of cleaner, decentralised renewable generators, such as wind and solar. Depending on your method of analysis, renewables are either considered 'zero-carbon' (if life-cycle considerations are not made), or 'low carbon' (if they are). Figure 1.3 shows the relative life-cycle analysis (LCA) carbon densities of different electricity generation technologies.

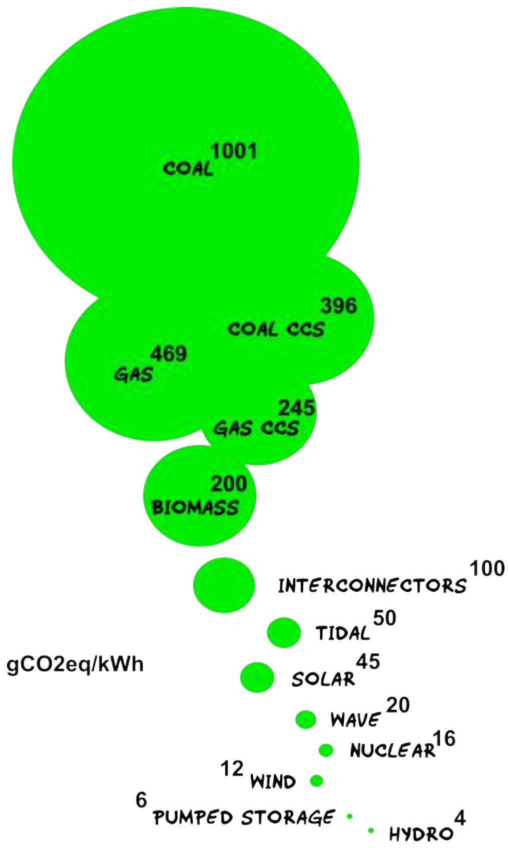


Figure 1.3: Emission factors per technology. Source : Intergovernmental Panel on Climate Change (2011)

Unless reliant on unproven carbon capture and storage technology (CCS)[2], or expensive and controversial nuclear power stations (which this report chooses not to consider for reasons elaborated on in Section 2.2.1), a future decarbonised electricity system will necessarily involve a high degree of renewables deployment. This, in turn, brings its own peculiar challenges - challenges which a "traditional" electricity system is protected from.

With a high level of renewables operational within a system the nature of supply - and control over, and expectation of, supply - changes. Under a traditional system, operators rely on the knowledge that, more or less, the full extent of the electricity network's generation capacity can be called on as and when needed to match demand. Under a renewables-dominated scenario this is no longer the case: supply varies depending on the weather (sunny, cloudy; windy, still) and time of day - supply is therefore "variable" or "intermittent", as opposed to "dispatachable"[3] There is no guarantee that peak supply will be simultaneous with peak demand; herein lies the problem.

Combining the two

Consider a future in which we continue to generate our electrical power in much the same way it is today but choose to electrify significant portions of heating and transport

[2] Carbon Capture and Storage (CCS); a technology currently being developed designed to be fitted to fossil fuel generators that *captures* CO_2 emissions from those generators in order to reduce the emission intensity factor of those generators. The captured carbon is then transported and *stored* to prevent emissions entering into the atmosphere.

[3] Dispatchable generator; an electrical generator capable of varying its output in accordance to the demand for electrical power, these are generally large scale centralised power stations.

demand. Such a choice would require the building of additional traditional, centralised and dispatachable generation capacity, ready to meet the increased demand peaks resulting from electrification.

Now consider a future in which we continue to demand electrical power in much the same way as we do today, i.e. do not electrify significant portions of heating and transport demand, but do decide to move to a predominantly renwewable power generation system. In this context the difficulties associated with balancing supply and demand using variable generation (renewables) would be mitigated partially by peak demands remaining at historical levels.

Nevertheless, both scenarios attempted alone would contain their own difficulties - but when combined the challenges inherent in each multiply those of the other: *electrification* increases the size of demand peaks on the electricity network; while *decarbonisation* (via renewables) in turn decreases the predictability of supply intended to meet those (now increased) peaks.

This is the dilemma facing the transformation of the UK's power infrastructure. It must be resolved in order for the UK to make good its obligation to rapidly decarbonise across the board. It is to this specific problem that this report turns its attention.

1.1.2 The model

The model used in this report, SHED ('Smart Household Energy Demand'), was built by Dr. Daniel Quiggin during his PhD in the Centre for Doctoral Research in Energy Demand, a joint collaboration between the Energy Institute at UCL and Loughborough University. SHED was built on previous research by Dr John Barton who created the Feasibility of Energy System Assessment Tool (FESA), utilised in the modelling of the Transition Pathways to a Low Carbon Economy project energy scenarios (Barton et al., 2013) and utilised in widely cited academic modelling of energy scenarios. SHED was developed initially to analyse three 2050 energy scenarios produced by the Department for Energy and Climate Change (DECC), and subsequently to meet gaps in the toolkit available to academics, energy planners and policy makers in designing future energy systems:

- **First, it implements new methods to accurately model heating demand**, enabling the implications of heat electrification to be far more accurately appreciated.
- **Second, it draws on *hourly* data for all demand inputs (including e.g traditional electricity demand), *and* on hourly weather data**. This enables it to match modelled hourly demand with renewable supply, which is determined using weather inputs.
- **Third, incorporates demand and supply data from a period of 11 years**, enabling rigorous testing of a given energy scenario's resilience.
- **Fourth, it enables the requirements of Demand Side Management (DSM) to be modelled at a national level, before being disaggregated to (and quantified at) the household level**. This enables the impact of flexibility in the demand-side of future energy scenarios, *assumed* in other modelling exercises, to be accurately assessed for its technical utility and likely social acceptability

By introducing each of these features into the modelling environment, SHED permits the following:

1. an accurate assessment of the ability of a modelled electricity system to enable **supply-demand balancing** over a period of over a decade
2. a measure of such a system's **carbon intensity**
3. the **requirements that would be placed upon households** to shift or reduce

their demand during given periods, depending on the priority given to DSM in an energy scenario

In doing so it can help to answer the question of what an *electrified* and *decarbonised* energy system will need to look like, and what our priorities should be in building it.

1.2 Greenpeace:2030

1.2.1 Design

GP:2030 was designed by Greenpeace UK and Demand Energy Equality with the following objectives:

1. **decarbonisation** within the CCC targeted 50 - $100 g_{eq}CO_2/kWh$ emission intensity factor, whilst;
2. achieving this figure in the **absence of carbon capture and storage** technology deployment, or the building of **new nuclear power stations**;
3. being **technically feasible**;
4. **electrifying** a substantial proportion of transport and heating to deliver emissions reductions in those sectors;
5. **balancing supply and demand** - ensuring the same, or an improved, guarantee of security of supply as is currently enjoyed in the UK;
6. ensuring the worst-case scenario impact of **demand-side management** on household consumption of energy is, nevertheless, likely technically and socially plausible, and;
7. being **economically feasible**

In creating *GP:2030* decisions were made regarding both the expected (and targeted) nature of demand in the scenario, and the make-up (and sequencing) of generation and balancing technologies - including DSM.

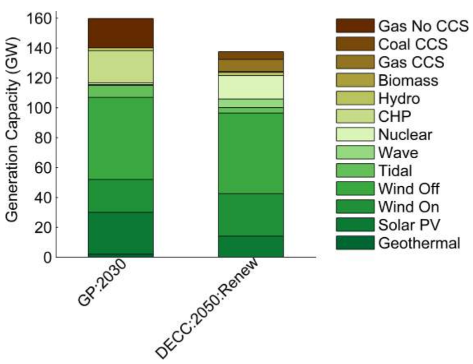
Figure 1.4(a) shows the annual demand for *GP:2030*, the Department for Energy & Climate Change (DECC) '2050 Renewables' scenario (*DECC:2050:Renew*), and historic demand over 11 years between 2001 - 2011. It demonstrates the major demand reductions assumed across both scenarios, particularly in domestic space heating. Grappling with the challenge of significant demand reduction in this area will hold great sway over the success or failure of a strategy of decarbonisation via electrification.

Figure 1.4(b) shows the generation capacities of *GP:2030* and *DECC:2050:Renew*, with the notable absence of *new* nuclear (some existing nuclear capacity is expected still to be operational in 2030) and CCS from the *GP:2030* scenario. *GP:2030*'s total generation capacity is roughly *double* that of current levels.

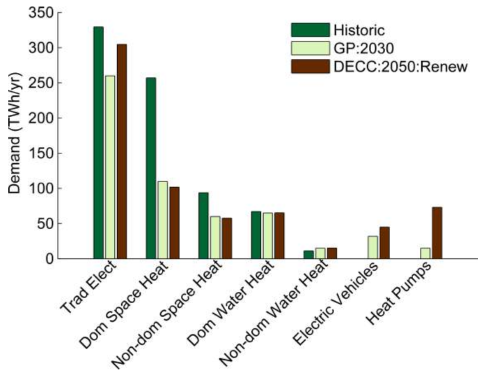
1.2.2 Findings

Using SHED to model *GP:2030*, we conclude that:

- **Radical decarbonisation of the power sector in the UK is possible**. *GP:2030* achieves either 77.9 $g_{eq}CO_2/kWh$ (Pragmatic) or 51.2 $g_{eq}CO_2/kWh$ (Climate driven), depending on the extent to which gas-fired power stations are called on to supply net demand after renewable supply and balancing mechanisms.
- **Achieving this by 2030 is technically feasible** - no significant assumptions are made about the *innovation* of new technologies in *GP:2030*; instead informed assumptions were made regarding the application of predominantly *developed* technologies.



(a) *GP:2030* generation capacity, compared to *DECC:2050:Renew*.



(b) Demand parameters from *GP:2030* and *DECC:2050:Renew*, compared to historic demands. Annual demand in TWh/yr.

Figure 1.4: Overview of supply & demand

- **Electrification of substantial proportions of transport and heating is possible**, while maintaining constant supply-demand balancing. ***GP:2030* experiences *no* periods of deficits (blackouts of brownouts)**.
- **Load factors on combined-cycle gas turbine (CCGT) generators are maintained at an economically viable level** of 23.6 % within the *pragmatic GP:2030* sub-scenario. In 2013 load factors for CCGTs fell to a record low of 28%.

In achieving such outcomes:

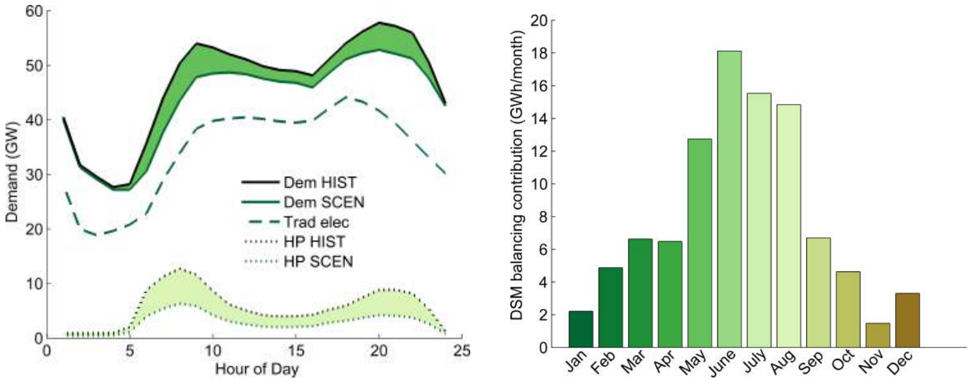
- **Ambitious domestic heating demand targets *must* be met**. Without a -57.2 % change in annual demand by 2030, supply-demand balancing will not be feasible and blackouts and brownouts will occur.
- **Domestic DSM plays a modest role in mitigating periods of deficit** . Fewer than 7 periods in which total demand shifting exceeds 3GW occur on average each year - however questions remain about the feasibility and social acceptability of DSM roll-out.

Figure 1.5(a) shows the increase in demand within *GP:2030* if heating targets are not met for January and February weekdays - in this case we would expect 47 hours of deficits over 11 years, totaling 141.9 GWh. Additionally, we would expect domestic DSM requirements to become onerous on households (and thus unworkable). This illustrates starkly the importance of meeting heating reduction targets.

Figure 1.5(b) shows total domestic contribution to balancing per month in GWh via DSM. We find that, in a scenario with significant combined heat and power (CHP)[4] supply (21.5GW), the periods with the most significant balancing requirements are in the summer months when CHP generation - following heat demand - is low.

Finally, by comparison with a fully costed high-renewables scenario developed by Poyry (2011) we indicate that *GP:2030* is economically feasible.

[4]Combined heat and power (CHP); a type of generator that produces heat simultaneously to electrical power, there are many forms of CHP units fuelled by different liquid or gas fuels.



(a) Increase in electricity demand due to a failure to meet heating targets in *GP:2030* for January/February weekdays through 2030, based on 2001:2011 data.

(b) Domestic DSM contribution towards balancing per month in GWh.

Figure 1.5: Overview of importance of meeting heating targets and monthly role of domestic DSM

1.3 Conclusion

We argue that building an ambitious power sector able to take up the gauntlet laid down by the urgency of decarbonising the UK's economy is certainly achievable. Renewable technologies, falling in price, are proven and deployable. Demand reductions, though testing of our often profligate use of energy, are realistic with sufficient political will and appropriate policy-making. Increased information flows throughout the grid can enable more rapid responses to fluctuations in demand and supply.

However, results indicate that scenarios (such as *GP:2030*) with a high degree of heat electrification, combined with intermittent renewable generation, are susceptible to additional supply-demand balancing requirements. In consequence, meeting heating demand targets is a prerequisite for achieving electrification targets: even modest levels of heat electrification result in large increases in peak electrical demand. The average electrical peak demand, across published energy scenarios treated in Quiggin (2014), rises by 15.3% when heating demand remains at historic levels, compared to when targets are met. Electrification and decarbonisation are not simple substitutions for existing energy forms. If electricity is the medium by which a reliable and clean energy future is to be delivered, then heating demand reduction must be achieved alongside heating electrification.

This report wishes to emphasise above all else, then, that our relationship with energy must change: at a national, organisational, household and personal level. In particular we must use less energy to heat our homes sufficiently for safety and comfort.

Failure to achieve this will deny us all the possibility of building a progressive and ambitious energy infrastructure we can rely on into the coming century. In this report we do not treat that as an option.

2. Introduction

2.1 Time for change

The UK's energy system is on the cusp of, arguably, its first real revolution since the inception of what was to become the National Grid in 1926. Its infrastructure, control, operation, governance, ownership, technologies and outcomes must - and will - change rapidly until, and beyond, 2030 if an energy system fit for the future is to be realised.

The immense complexity of securing this - and the overlapping technical, political, social and economic issues (and interests) such a task incorporates - ensure that no single pathway to an energy future is yet the subject of either political or public consensus. Perhaps this is unlikely to ever be the case. Yet, this is a crucial moment: the Paris UNFCCC COP21 climate talks will challenge world governments to commit themselves to the era-defining task of preventing the worst excesses of a climate crisis; while the UK is legally bound to meet its own 80% CO_2 reductions on 1990 levels by 2050 - a target already outdated by emergent climate science. Furthermore, public trust in the major UK traditional utilities - the "Big 6" - is at an all-time low, as consumer energy prices have continued to grow well in advance of inflation.

Across the industrialised world signs of a seismic shift in the way energy can be delivered is underway: the price of renewables, and solar in particular, continues to plummet; radically changing the traditional economics of energy generation.

> "The reason solar-power generation will increasingly dominate: it's a technology, not a fuel. As such, efficiency increases and prices fall as time goes on. The price of Earth's limited fossil fuels tends to go the other direction."
> (Bloomberg, 2014)

The implications are startling, and traditional centralised mega-utilities are unable to participate too keenly in the coming renewables surge without undermining their existing business models.

However - there is no silver switch. The technical implications alone of creating energy systems able to meet legally binding CO_2 reductions targets (and, indeed targets that necessarily go further) are significant, and will stretch our engineering and scientific expertise. Officially, the need to decarbonise the UK's power sector (leading the rest of the economy), is accepted across the political spectrum. Yet proposals for achieving this are often dependent on imperfect modelling exercises, unable to demonstrate strategies' competencies in delivering the reliability of supply the UK population expects, and that its economy requires. This is unsurprising: the size and quality of data sets, and model refinement, required is substantial, and evolving over time.

Without clear and rigorous assessments of the opportunities and tasks ahead neither the public, nor local campaigners, NGOs or Government will be able to campaign, plan or act for the changes we urgently need.

2.2 Framing the UK's challenge

Successful decarbonisation of the UK's economy, in-line with or in advance of stated targets, depends on the decarbonisation of the UK power sector - energy that is delivered to consumers through the national electricity grid. The majority of what scientists and society classify as "renewables" produce energy in the form of electricity, so the primary focus on the electricity system for the UK's decarbonisation is both logical and intuitive. However, it's role in decarbonisation becomes even more vital - and difficult - when the implications of decarbonising other elements of the UK's energy use, notably the heating of domestic and industrial properties and motorised transport are considered.

Currently, ~83% of UK homes are heated by gas boilers (Baker, n.d.), supplied through a national gas grid - and ~60% of the average UK household annual energy bill comprises paying for them. This is despite the fact that boilers are predominantly used to heat homes during the winter months. Burning gas in domestic boilers cannot be decarbonised - but homes must be heated. So a substitution for an alternative energy form, electricity, must eventually be achieved.

The largest delivered[1] domestic heating peaks reach ~160GW in the mornings and evenings of the coldest winter days (Quiggin, 2014). The UK's total electricity generation capacity in January 2015 stood at 85GW. Even accounting for the performance gains enabled by heat-pump technologies, to substitute electricity for gas as the principle energy form for domestic heating delivery requires over a *60%* increase in our entire electricity generation capacity. Given the majority of that capacity is fossil fueled and will need to be taken off-line to meet carbon reduction targets, this task is, in fact, more formidable than it first appears.

> **Key Information 2.1** The terms "dispatchable" and "non-dispatchable" generators are used throughout this report. So too are the terms "rampable" and "intermittent". A dispatchable generator is an electrical generator capable of varying or "ramping" its output in accordance to the demand for electrical power, these are generally large scale centralised power stations. A non-dispatchable generator is an electrical generator whose output is dependant on weather and climatic conditions, its output is referred to as "intermittent" or variable as these generators do not respond dynamically to electrical demand and their output varies in time with changes in the natural resource (e.g. wind speed or solar radiation intensity). ■

And this is true for more reasons than one. With the necessity to bring more and more renewables online comes the challenge of intermittency. While much of the UK's existing generation capacity lies in "disptachable"[2] or "rampable" centralised power

[1] "Delivered" energy; this is the energy demand at the point of use, rather than the energy in the fuel consumed.

[2] Dispatchable generator; an electrical generator capable of varying its output in accordance to the

stations, a future generation portfolio dominated by renewables will be subject to the whims of Britain's famously changeable weather. This provides the possibility for both under and over-supply of power into the grid depending on simultaneous demand. While over-supply is easier to deal with (notwithstanding economic consequences that will be considered later in this report), under-supply can lead to brownouts and blackouts[3] - a political non-starter and a serious economic disrupter.

2.2.1 Non-renewable alternatives

Several published energy scenarios (Electricity Networks Strategy Group, 2010; Department for Energy and Climate Change, 2009; Department of Energy and Climate Change, 2010; Ofgem, 2010*a*; Ault et al., 2008; Foxon, 2013; Department of Energy and Climate Change, 2010; Barnacle et al., 2013; Department of Energy and Climate Change, 2010) reserve large portions of electricity generation capacity for technologies that can supply power in a more traditional, predictable and dispatchable manner. In a low-carbon scenario the permissible technologies are nuclear or CCS fitted fossil fuel power stations. However, this report chooses to disregard both in designing future-proof ed energy supply systems due in part to Greenpeace policy (Greenpeace, 2008), but also because of substantial delivery risks that apply to both technologies. It should be noted that the UK currently intends to build at least one new nuclear power station at Hinkley Point in Somerset (see below), with the political consensus generally agreed that further nuclear capacity will need to be built also. In this respect this report assumes a major divergence from current political trajectories.

Carbon capture and storage

CCS is not, despite its regular inclusion in major party policy portfolios and industry narratives, a mature technology - and is not in commercial operation, at scale, anywhere worldwide to the authors' knowledge. Nor does this possibility appear to be something we can expect in the near future. Even if it were, putting its potential cost to one side, the carbon intensity reductions available through use of the technology are unimpressive. IPCC rate CCS gas at $245gCO_2eq/kWh$, compared to its unmitigated cousin's rating of 469gCO_2eq/kWh - under a 50% reduction (for coal, unsurprisingly, the figures worsen: for CCS fitted we find 396 CO_2eq/kWh, as compared to unfitted at 1001CO_2eq/kWh) (IPCC, 2012). Inclusion of an untested, uncosted and even *theoretically* under-performing technology in energy scenarios can only be justified in the absence of recourse to workable alternatives. Our findings suggest strongly this is not the case.

Nuclear

Nuclear, unlike CCS, is a mature technology: the first large scale power station was built in the UK in 1956. Analysed purely in terms of its carbon intensity, nuclear performs well at 16gCO_2eq/kWh (compared to solar's life-cycle carbon intensity of 45gCO_2eq/kWh, and wind's 12gCO_2eq/kWh). However, it remains an extremely contentious form of electricity generation, for several reasons.

First, it produces highly toxic, radioactive waste that presents a serious risk to human populations if mismanaged. Storage of this waste, while feasible within the lifetimes of those who benefit from the power that produced it, is nonetheless both expensive, and

demand for electrical power, these are generally large scale centralised power stations.

[3]Blackouts and brownouts; are regional or local losses of power due to demand exceeding supply resulting in automatic relays cutting off consumers

not morally insignificant when the burdens - financial and otherwise - placed on future generations (and far beyond) are considered. In 2012 the *yearly* spend on nuclear waste containment comprised 42% the DECC budget (The Guardian, 2012). While, with notable exceptions, the UK nuclear industry has demonstrated an ability to operate nuclear power generation without major disasters occurring - many believe the risk remains.

Second, nuclear is an extremely expensive technology to implement, with very long lead-in times. The most recent announcement, in October 2013, on new nuclear build in the UK - 3.2GW at Hinkley Point C, Somerset - revealed the government's commitment (on behalf of the taxpayer) to *guarantee* a "strike price" (minimum price) of £92.50/MWh (UK wholesale electricity prices at the time of announcement were £48/ MWh) to EDF, the French company proposing to build and operate the plant. The plant is not planned to open until 2023, and will cost an *estimated* £25bn to build (at time of writing). This does not include costs associated with decommissioning and ongoing waste management.

Third, while nuclear can provide a predictable base-load supply of electricity into the grid, it is not a technology designed to be ramped - and the cost-effectiveness of nuclear declines rapidly if it is regularly required to reduce or increase its production levels. In a scenario with a significant renewables contribution (even with the presence of CCS or nuclear), and increased peak magnitudes due to electrification of space heating, non-rampable centralised power technologies are less attractive.

Finally, the arguable relationship between the civil nuclear industry and the military nuclear industry provides another point of moral objection for many.

For these reasons this report similarly chooses to demonstrate that less problematic, risky and expensive alternatives to centralised nuclear power exist and are capable of meeting the UK's energy needs unaided by new nuclear capacity.

2.2.2 Opportunities: The falling cost of renewables

CCS and new nuclear have been excluded from this report's energy scenario on the basis of better - and feasible - alternatives. This is not an assessment that has been made solely on the basis of carbon intensity values, but also the economic and infrastructural implications of committing to given technologies in real economic, social and economic contexts.

There are clear trends in the the cost of renewables which are shifting the economics of future energy provision in favour of investment in solar, wind and other technologies previously thought to be too expensive and intermittent.

From the late 1970s, when solar first emerged as an applicable power source, its cost - according to Bloomberg - has fallen by 99%, from just under 50£/W to just under 0.50£/W (authors' currency conversion). In 2014 the cost of new wind power in the US had fallen to 2.5 cents/kWh - the cheapest of any new energy source in America (Shrubsole and Cameron, 2014).

As a case in point, the fall in the cost of wholesale electricity prices in Germany is causing serious problems for major utilities firms, which hold enormous fossil fuel assets. They are unable to embrace new technologies, for various reasons, as easily and with such overwhelming market dominance as they have been accustomed to (not least because doing so would undermine their existing, fossil fuel dependent, assets). The rapidly worsening economics of traditional electricity supply in Germany caused E.On to announce it would be splitting into two companies - one owning its old, fossil assets - the other focusing on power distribution and investments in renewables. This is likely a sign of things to come across the developed world - and a clear signal of the disruptive power of renewables when the appropriate policies are in place.

However, it should be noted that the cost of renewables technologies, and rapid decreases in them (most notably solar over the last 5 years) is not the complete picture. As renewables claim a greater share of overall generation capacity from traditional dispatchable generators the associated *grid* costs, required to integrate variable power production, also increase. As soon as renewables move beyond providing marginal power supply into the grid their variability begins to have a serious impact on supply-demand balancing. This requires investment in further technologies such as storage and smart grid ugrades. The costs of storage, though falling, are not falling as fast as the costs of, say, solar - and thus will have a negative impact on solar's total cost as long as it continues to be integrated into national grid infrastructures. The quest for low cost, high density storage technologies will continue as long as renewable shares of national generation portfolios are intended to increase.

Despite the economics of energy being vulnerable to the volatile global pricing of oil - which can spell death for both extraction projects on the carbon frontier *and* green investments alike - there are clear, and accelerating, trends towards the continued reduction in costs for widespread renewable deployment to the detriment of traditional forms of power generation. This report explicitly builds on the opportunities provided by the changing economics of power to build a scenario technically workable, economically defensible and socially desirable.

2.2.3 Making it work

In a scenario with significantly increased demand on the electricity network, due to heat and transport electrification, *and* an electricity supply system characterised by greater intermittency, the task of balancing supply and demand on a second-by-second basis year-round within politically, socially and economically acceptable boundaries takes on new meaning.

That we currently have access to such a secure supply of nationally delivered energy, notwithstanding inequalities in access to that system, is a staggering engineering achievement - but it is one aided by the availability of traditional, dispatchable, rampable power generation.

Making renewables-based systems work will require large reductions in energy demand for space heating to enable the transfer of a portion of space heating from gas to electrical heat pumps. The average figure for this required reduction across six prominent published energy scenarios is 47.5% within the domestic sector (Quiggin, 2014) - and even they are unable to demonstrate balanced supply and demand. Huge investment in energy saving programmes (such as adequate insulation in both new and old builds), improvement in technologies' operating efficiencies and - crucially - behaviour change will all be required to make any low carbon power system function acceptably.

According to The Economist;

> "Improvements in energy efficiency since the 1970s in 11 IEA member countries that keep the right kind of statistics (America, Australia, Britain, Denmark, Finland, France, Germany, Italy, Japan, the Netherlands and Sweden) saved the equivalent of 1.4 billion tonnes of oil in 2011, worth $743 billion. This saving amounted to more than their total final consumption in that year from gas, coal or any other single fuel. And lots of money is being invested in doing even better: an estimated $310-360 billion was put into energy efficiency measures worldwide in 2012, more than the supply-side

> investment in renewables or in generation from fossil fuels."
>
> (The Economist, 2015)

Demand Side Management

Demand side management (DSM, sometimes referred to as "demand side response", or DSR) has been popular within policy and academic circles for some time as a technological innovation able to mitigate some of the supply-demand balancing issues presented by highly electrified, highly renewable energy scenarios. Traditionally supply-demand balancing would have been achieved through simply managing *supply* up or down dependent on the nature of demand. Within a *dispatchable* scenario this would be (assuming sufficient overall generation capacity) predominantly enabled through the ability to ramp generators when needed and, at times of particular stress, invoking pumped storage held in reservoirs. Within a renewables-dominated scenario, the ability to manage supply upwards to meet peaks in demand is diminished significantly in an effort to reduce reliance on fossil fuelled power. Nor is the level of supply, and therefore extent of a possible deficit, able to be predicted as reliably given the intermittency of large portions of the generation mix. There are several possible responses to supply-demand imbalances within a renewables scenario (which will be addressed in turn in the report), but DSM is unique in that (instead of sourcing additional supply) it seeks to incentivise (or in extreme cases, oblige), reductions in demand at peak times from power consumers, whether domestic or industrial.

Industrial application of DSM is already in operation. Flexitricity is the first and largest UK provider of national supply-demand balancing services enabling access to the energy market for commercial clients and small generators. This is achieved via aggregation and smart two-way communication (*Flexitricity website*, 2011) such that "relatively small units down to individual pumps or compressors can participate". National scale balancing services interact via the National Grid Short Term Operating Reserve (STOR). Signals are passed to the Flexitricity Edinburgh based control room which communicates with generators and loads around the country (*Flexitricity website*, 2011). Fast load shedding is performed on a minutely basis utilising large commercial consumers who can temporarily shut down loads, such as air conditioning units and large freezers. In return Flexitricity clients earn money for reducing demand at particular times.

The technical, administrative and logistical feasibility of interacting with corporate and large scale power users in this way has not been matched, thus far, in a domestic setting. It should be clear why - the National Grid cannot negotiate contracts to provide demand reduction at peak times with every UK household, let alone communicate directly with each when needed. A process by which an entity aggregates the demands of many households and acts as a node for the National Grid (or another entity) to communicate with is needed instead.

This is enabled through new domestic DSM technologies: principally smart meters. A basic smart meter acts as a two-way communication device between the grid and a household unit: the grid is able to know the demand from a household, while the household is able to receive rapid (15 minute) price signals for electricity, reflecting the supply-demand balance on the grid in, almost, real-time. The assumption is that householders will move demand forward or backward in time in order to access a lower unit price. If enough households, aggregated, react in concert to price signals peak demands can be "smoothed", in turn reducing the amount of spare capacity, both renewable and non-renewable, needed to prevent shortages. Smart meter roll-out is already government policy by 2020. Future smart meters will be able to automatically manage demand from larger household appliances (e.g. fridge-freezers) in response to price signals.

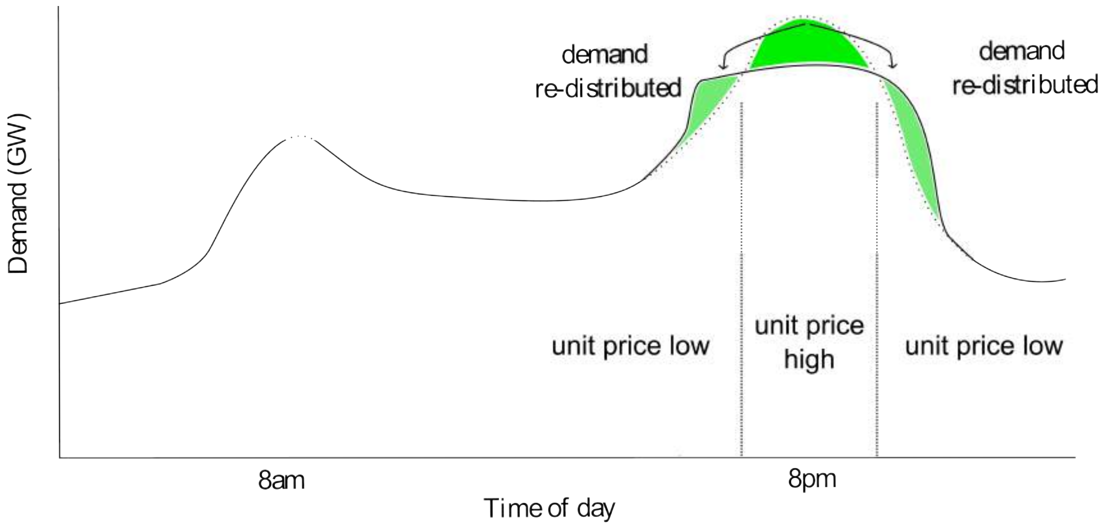


Figure 2.1: Illustration of national DSM facilitating reduced peak demand by shifting demand to off peak periods, achieved using variable tariff structures.

Figure 2.1 illustrates the principle of DSM where peak demand is shifted in time, forward or backwards, as consumers respond to a reduced electricity unit price either side of the peak period, which is relatively more expensive. These variable pricing tariffs are generally referred to as Time Of Use (TOU) tariffs. The illustration in Figure 2.1 is of the aggregate response from many households. Individual consumers will, of course, each respond differently in order to provide the aggregate response.

The Department of Energy and Climate Change (DECC) said in 2010:

> "The amount of flexible demand assumed in different 2050 analyses varies but the assumption used is generally between 20% and 30%."
> (Department of Energy and Climate Change, 2010)

This indicates they expect 20 - 30% of demand will be available for DSM. A number of questions arise in order to assess the likelihood households will respond positively to this new role, how to prepare households, and indeed if such expectations are even technically feasible:

- How regularly will DSM be required?
- Will particular times of the year be more onerous on households?
- Is this "20 - 30%" of demand in one particular hour or over several hours?
- What will DSM mean for individual households, of different socio-economic status?

In the existing published literature of energy scenarios, the above questions are not quantified and answered. SHED, and *GP:2030*, attempt to answer them. In doing so a more robust representation of the future electricity system is offered.

This is imperative, as it is unclear from current research how households are going to respond to the need to their change demand patterns, via DSM. Certain studies have shown that consumers who are made aware of consumption during peak times will shift demand to less expensive periods (Lindley, 2010). TOU tariffs via smart meters, in the Italian ENEL Telegestore project, have been shown to reduce consumption by

5-10% (Lindley, 2010). The Energy Demand Research Project (EDRP) trials of smart meters in the UK has shown up to 4% energy savings, with loads shifted in time via TOU tariffs by up to 10% (Ofgem, 2010*b*). Other studies that have investigated the effectiveness of feedback on demand have shown 5-15% reductions (Darby, 2006). Recent research also offers contrary evidence that there is a strong resistance by early adopter households to change behaviours based on information from smart meters (Hargreaves et al., 2010). Research by Hargreaves et al. (2010) on the EDRP, indicates that certain households found smart meters to create a sense of "fatalism, despondency, anxiety and even guilt". Untested at scale, DSM is the largest unknown of this energy scenario; despite being modelled beyond what is available in other published scenarios. Our approach to managing the risk of modelling such an unknown, to produce high-utility results, is treated in Section 3.3.2.

2.3 The question & the test

2.3.1 The question

The reality of constructing a radically decarbonised energy system in the UK, beginning with the power sector, thus presents many challenges. First, though, the task of *designing* that system must be addressed, with urgency.

While the complexity of a feasible energy system cannot be downplayed, we can ask three simple questions of any energy scenario purporting to hold the key to future energy demands:

1. "Given the necessity to electrify forms of energy delivery currently supplied otherwise, principally space heating, can the scenario be reasonably thought to balance supply and demand at the **tail end** of a January or February anti-cyclone?"
2. "Further to this; if combined heat and power (CHP) units are a major component of electrical supply, will summer months (when it is uneconomic to run CHP units), result in a scenario supply - demand imbalance?"
3. "Finally, is the scenario within 'politically, socially and economically acceptable' boundaries?"

Nevertheless, while the line of questioning can be simplified - beginning to respond it is a formidable exercise.

2.3.2 The test

Consider why: a model fit for the purpose must be able to:

- Incorporate a sufficient number of the ***many* inputs to both national supply *and* demand** - and do so with a **sufficient degree of accuracy**; to, in turn
- Assess the **supply-demand balancing outcomes of a theoretical future scenario** with **sufficient "temporal resolution"** (using data points close enough together in time) to accurately characterise the demand peaks and supply variations that form the crux of problem; *and*
- It must use a **sufficiently vast data-set**, representing several years of historical weather and demand values, to be a useful predictive tool for the purposes of designing such vital infrastructure.

Finally, a good model will be able to comment on the reality that workable scenarios entail for the people energy systems affect most - citizens - particularly in light of the inevitable introduction of domestic DSM.

Historically, energy models have struggled to meet the complexity of the task, while data sets of appropriate quality, relevance and size have often been unavailable. What makes this report significant is its presentation of results produced by a model that meets each of the criteria listed above.

For example, before privatisation in 1990, the Central Electricity Generating Board (CEGB) assumed that $\sim$85% of national generating capacity would be available during winter months. The CEGB required a 24% capacity margin[4] (calculated using equation 2.1), facilitating a Loss of Load Probability (LOLP) of 9%.

$$\text{capacity margin (\%)} = \frac{\text{total available capacity} - \text{peak demand}}{\text{peak demand}} \times 100 \tag{2.1}$$

Strbac et al. (2007) showed that to maintain reliability of supply at historic levels, with increased non-dispatchable generation, significant reserve generating capacity of dispatchable generators will be required. If the installed capacity of wind was 25GW, an minimum additional dispatchable reserve of 4.6GW would be required. This type of methodology underpins the way in which many energy scenarios calculate the generation capacity required to maintain reliability of supply.

Yet only recently has the electrification of heating been considered as having significant impacts on maintaining security of electrical supply (Wilson et al., 2013); consequently, it has not been considered simultaneously with an increase in non-dispatchable generation. Historic capacity margins used within much of the literature to determine reliability of supply are thus outdated: historically heating has *not* been electrified to the extent required to decarbonise the overall UK energy system. This report meets this problem head-on.

2.3.3 The SHED model

In this report we explore the outcomes of 2030 energy scenarios, designed by Greenpeace UK in a process facilitated by Demand Energy Equality, when subjected to rigorous testing using the Smart Household Energy Demand (SHED) model.

SHED was created by Dr Daniel Quiggin during his PhD at Loughborough University in the Centre for Doctoral Research in Energy Demand, based in the department of Civil and Building Engineering. The centre is a joint collaboration between the Energy Institute at UCL and Loughborough University, whose directors are Prof Kevin Lomas and Prof Bob Lowe.

Dr Quiggin was supervised by Dr Richard Buswell, with oversight from Prof Kevin Lomas. Dr Quiggin built on previous research by Dr John Barton who created the Feasibility of Energy System Assessment Tool (FESA). FESA was utilised in the modelling of the *Transition Pathways to a Low Carbon Economy* project energy scenarios (Barton et al., 2013), whose distinguished academics include; Prof Geoffrey Hammond, Prof Peter Pearson, Prof Goran Strac, Prof Simon Watson, Prof Graham Ault and Prof David Infield. In addition to the *Transition Pathways* scenarios, FESA was used in the modelling of the Centre for Alternative Technology's *Zero Carbon Britain* report (Centre

[4] The capacity margin of the electricity system is the percentage by which national available electricity generation capacity exceeds the maximum expected level of demand (peak demand)

For Alternative Technology, 2014) - indeed the *Zero Carbon Britain* team consulted Dr Quiggin on elements of their modelling process.

In creating SHED Dr Quiggin took FESA and built on the work by Dr Barton, expanding and improving on a model already held in high regard and utilised in widely cited academic modelling of energy scenarios. SHED was constructed to analyse, in particular, three 2050 energy scenarios produced by DECC. Dr Quiggin therefore has a detailed understanding of third party energy scenarios and the implications of using highly specialised modelling techniques to construct them.

Dr Quiggin received his PhD in December 2014 having passed his viva, which was examined by two highly distinguished academics; externally, Prof David Infield (University of Strathclyde) and, internally, Prof John Wright (Loughborough university).

Dr Quiggin completed a Masters in Physics at the University of Birmingham, and worked on the ATLAS detector at the particle physics laboratory at CERN before moving into the field of climate science, completing a second masters at the University of Bristol in Earth System Science.

SHED improves significantly on other energy scenario modelling tools by:

- **First, implementing new methods to accurately model heating demand**, enabling the implications of heat electrification to be far more accurately appreciated.
- **Second, drawing on *hourly* data for all demand inputs (including e.g traditional electricity demand), *and* on hourly weather data**. This enables it to match modelled hourly demand with renewable supply, which is determined using weather inputs.
- **Third, incorporating demand and supply data from a period of 11 years**, enabling rigorous testing of a given energy scenario's resilience.
- **Fourth, enabling the requirements of Demand Side Management (DSM) to be modelled at a national level, before being disaggregated to (and quantified at) the household level**. This enables the impact of flexibility in the demand-side of future energy scenarios, *assumed* in other modelling exercises, to be accurately assessed for its technical utility and likely social acceptability.

The report will demonstrate, using SHED, that a radically decarbonised energy system *is* possible by 2030 - not just possible to plan, but possible - with the right policies and political leadership - to fund and build; confident it will meet the strenuous demands placed on it by future populations.

This document and the research underpinning it has been reviewed by Prof David Infield (University of Strathclyde);

> "This is a useful report dealing with the complex issue of absorbing high penetrations of renewable power generation in line with achieving challenging reductions in carbon emissions." (Prof David infield)

Key Information 2.2 It should be noted that although an hourly time step model such as SHED is an improvement on the majority of energy scenario modelling, an hourly time step fails to capture variations in supply and demand at the sub hourly level. Covering variations within the hour will require some additional reserve margin and this will have some added economic and carbon costs unless met by additional storage or demand side management. SHED and modelling undertaken within GP:2030, is however, a significant improvement when compared to other published energy scenarios. ■

3. The Greenpeace 2030 Scenario

3.1 Aims & Objective of the Greenpeace 2030 scenario

The Greenpeace 2030 scenario (*GP:2030*) was designed with the set of precise aims of;

1. **Decarbonisation** within the CCC targeted 50 - 100$g_{eq}CO_2/kWh$ emission intensity factor, whilst;
2. Achieving this figure in the **absence of carbon capture and storage technology deployment**, or the **building of new nuclear power stations**;
3. Being **technically feasible**;
4. Electrifying a substantial proportion of transport and heating;
5. **Balancing supply and demand** - ensuring the proposal offered the same, or an improved, guarantee of security of supply as is currently enjoyed in the UK;
6. ensuring the worst-case scenario impact of **demand-side management** on household consumption of energy is, nevertheless, likely technically and socially plausible, and;
7. Being **economically feasible**

In this section, we explore the decisions that were made in creating *GP:2030*. These decisions apply not only to choices of energy generation technologies (such as offshore wind) - and the extent of their deployment - but also to the deployment of "balancing" technologies (such as battery storage) and to the ambition of demand reduction targets in areas such as traditional electricity[1] consumption and domestic space heating.

Of course, each decision in any area of a system has knock on effects for other elements - the process of refining these choices (or "model inputs") was one of iteration: making reasonable assessments and estimates, running the model, reassessing, and so forth.

The final inputs represent the result of a number of compromises - between ambition and cost; and between optimism and pragmatism.

[1] Traditional electricity demand is the electrical demand from both domestic and non-domestic electricity consumers, with no contribution from electric vehicles, heat pumps or economy seven. It is the future electrical demand that is similar to current electrical demands, but with economy seven or resistive heating removed.

3.2 The Dispatch Protocol

In considering the utility of *GP:2030* it is important to understand how the UK's electricity system would operate if the model were to be faithfully replicated in real life. This requires us to look at the dispatch protocol which defines the order technologies are deployed in, or processes initiated, as the system attempts to respond to a given demand level at a given time.

The dispatch protocol, in this scenario, is broken down into five distinct phases:

- **Phase 1. Non-dispatchables:** Uncurtailed renewable generation, base-load nuclear (90% of capacity) and heat-led CHP
- **Phase 2. Non-fossil fuel dispatchables**: Geothermal and hydro
- **Phase 3. Balancing mechanisms (1)**: domestic DSM, pumped storage, emergency CHP (EmCHP), centralised battery storage and interconnectors (import)
- **Phase 4. Fossil & nuclear dispatchables**: combined-cycle gas turbines (CCGTs) and rampable nuclear[2] (10% capacity)
- **Phase 5. Balancing mechanisms (2)**: commercial DSM, decentralised battery storage (DBS), further domestic DSM and interconnectors (export)

The logic for this dispatch protocol should be, in the main, self-explanatory once the aims of *GP:2030* are revisited: by invoking all non-fossil fuel supply options, and certain balancing mechanisms, *before* calling on CCGTs to deliver extra power, the overall carbon intensity of the system is lowered. However, in order to maintain economically favourable load factors[3] for CCGTs (essentially the extent to which the turbines are actually used, and therefore the extent to which building them is attractive), Phase 3 only seeks to reduce net demand (after Phases 1 and 2) to as close to the generation capacity of the installed CCGTs as possible - 19.5 GW. In instances where this is not possible, Phase 5 is initiated to deal with residual demand (or, in the case of export interconnectors, residual surplus). For further discussion of load factor implications, please see 5.6.

3.2.1 Pragmatic & Climate driven sub-scenarios

This report will refer to two sub-scenarios within *GP:2030*: **"Pragmatic"** (*GP:2030:Pragmatic*) and **'Climate driven'** (*GP:2030:ClimateDriven*). In the former the dispatch protocol will follow the logic outlined above; in the latter Phase 3 will seek to reduce demand (after Phases 1 and 2) to the lowest value possible (i.e. potentially *under* the total generation capacity of installed CCGTs). This, in turn, reduces the loads placed upon CCGTs which has two effects:

1. A reduction in the overall carbon intensity of the power sector, but simultaneously;
2. A reduction in the average load factors for CCGTs.

The reduced load factors result in unfavourable economics for the operation of the CCGTs needed, reducing the chance of them being built (at least under traditional build arrangements). For this reason the sub-scenario is labeled "Climate driven". The comparison between the resultant load factors in each sub-scenario is covered in Section 3.4.

[2]see section 3.3.2 for discussion on the viability of ramping nuclear

[3]Load factor; is the average load placed on a dispatchable generator divided by the generation capacity of that generator

3.2.2 CHP and base-load nuclear

The position of CHP and base-load nuclear generation in the dispatch protocol should be noted. It may seem counter-intuitive to place such technologies alongside renewables as "non-dispatchables": however, this decision is determined by the economics of their operation. For CHP plants, it is uneconomical to run them following demand for electricity - instead CHP units follow *heat* demand (which is supplied directly through local heat networks). The electricity produced (effectively, following this logic, as a by-product) and fed into the grid then affects the size of the surplus or net demand of electrical power available at any given time, but cannot be called on to increase or decrease its production (except in "emergencies", see Section 3.3.2). CHP plants thus help to balance an electricity system servicing electrified heat demand twice over: first, by reducing the overall heat demand on the electricity system via direct heat network supply and, second, by contributing electrical power to meet the subsequent demand experienced by the electricity system.

Nuclear power stations *do* have the ability to ramp their production levels up and down, but doing so is expensive. For this reason, nuclear base-load runs at 90% of the installed capacity. The final 10% can be called on in a dispatchable manner, in Phase 4. For more information on the rampable nature of nuclear please see Section 3.3.2.

3.2.3 Surpluses

With a large capacity of renewable generation comes, as with deficit periods, increased periods of surplus power. As storage of electricity is challenging at scale, both technically and economically, careful thought within *GP:2030* has been given to how surplus periods are dealt with, as modelled under SHED, in a general sense. Precise details are given in the following sections, under the relevant technologies utilising surpluses, such as batteries. Surplus power can be stored in batteries (both centralised and de-centralised), used to supply demands that are shifted in time due to DSM, used to pump water uphill in pumped storage facilities to be used at a later time, or exported and sold to other countries via interconnectors. In *GP2030* exports only occur once any surpluses have been utilised to the greatest possible extent domestically.

3.3 Inputs

3.3.1 Demand

The inputs to the model, as already mentioned, do not solely pertain to supply and balancing elements. The first task of designing, and modelling, a future energy scenario is to model the *demand* the system will be expected to supply.

This depends on initial, predictive, estimations of the expected:

- Prevalence of and usage of **electric vehicles, heat pumps and solar thermal technologies** (due to solar thermal's impact on reducing heating demand);
- Annual **space heating demand** (or, rephrased, the expected or desired level of space heating demand reduction by 2030);
- Annual **water heating demand** (or, rephrased, the expected or desired level of water heating demand reduction by 2030);
- Increase or decrease in traditional annual electricity demand, and;
- Reisdual economy seven electricity demands.

SHED combines these input decisions with eleven years of hourly historical data. At a high level (and from a simplified perspective), these annualised demand inputs scale (up or down) the historic data such that eleven years of hourly *future* demands are modelled, representing eleven consecutive years of 2030. SHED also calculates the impact that, for example, solar thermal installations will have on the demand for heating.

The result is the predicted national hourly demands for a period of 11 years, against which the scenario's generation capacity and balancing mechanisms can be tested for their ability to deliver sufficient and reliable supply. For technical detail on the operation of the model, see Appendix A and Quiggin (2014).

Table 3.1 shows the values assumed in *GP:2030* for various demand inputs, and factors that impact on demand, alongside the values assumed in the DECC *2050* renewables (*DECC:2050:Renew*) energy scenario (which does not, tested with SHED, balance sufficiently):

Key Information 3.1 Throughout this report a 2050 energy scenario developed by the DECC which is described by its strap-line as; "Higher renewables, more energy efficiency", is utilised to compare the inputs and outputs of *GP:2030*. This DECC scenario is referred to as *DECC:2050:Renew* and it should be noted that it is a *2050* rather than 2030 scenario. When comparing demand parameters ti should also be noted that *DECC:2050:Renew* assumes 40 million households to *GP:2030*'s 30 million, meaning that energy use per household is significantly *higher* in *GP:2030*. *DECC:2050:Renew* was utilised as a comparator or benchmark because;

1. SHED[a], hence the inputs and outputs are available to the authors.
2. *DECC:2050:Renew* is a scenario that is characterised by high renewable integration and comparable demand reduction.

[a]Smart Household Energy Demand (SHED); the model used in this report to construct and test the Greenpeace 2030 energy scenarios. For detail please see 1.1.2

Demand Parameter	Historic	*DECC:2050:Renew*	*GP:2030* (%change on historic)
Traditional Electricity (TWh/yr)	329.4	304.5	260 (-21.1)
% households on economy 7 tariffs	5%	10%	0 (-)
Dom space heating (TWh/yr)	257	101.8	110 (-57.2)
Non-Dom space heating (TWh/yr)	93.9	57.8	60 (-36.1)
Dom water heating (TWh/yr)	67	65.3	65 (-3)
Non-Dom water heating (TWh/yr)	11.2	15.3	15 (34.2)
Electric Vehicles (TWh/yr)	-	45	32) (-)
% Heat supplied by Heat Pumps	-	90	25 (-)
Number Households (millions)	26	40	30 (15.4)

Table 3.1: Demand input parameters for *GP:2030* and *DECC:2050:Renew* and the change in demands relative to historic values. Note that heating values are delivered energy rather than the embodied energy within the fuel supplying that energy.

Key Information 3.2 It should be noted that throughout this report, including within Table 3.1 and Figure 3.1, space and water heating demand within the domestic and non-domestic sectors is defined in terms of "delivered" energy demands. This is the energy demand at the point of use, rather than the energy in the fuel consumed. Quantification of space and water heating in this sense is integral to calculating electrified heating demands as technologies, such as heat pumps, electrify the energy demand not the demand for fuel (such as gas). Hence the historic values quoted in Table 3.1 and Figure 3.1 may be lower than the reader would anticipate if the metric was to consider the fuel consumed.

Figure 3.1 focuses on annual demand values (over the 11 modelled years) divided between different demand types, and compares them to the averaged historical data (without any demand reduction assumptions) and the values chosen for the *DECC 2050 Renewables* scenario.

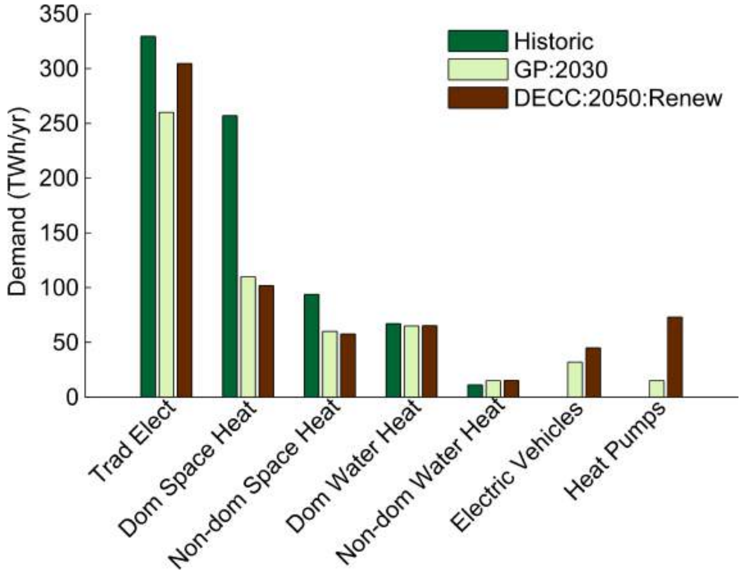


Figure 3.1: Demand parameters from each energy scenario. Annual demand in TWh/yr.

In both the *GP:2030* and *DECC:2050:Renew* scenarios significant average annual demand reductions are assumed in all categories, except non-domestic and domestic water heating. Each of the main demand categories are now explored in turn.

Space heating

Most notably, very significant reductions are assumed in domestic space heating where *GP:2030* envisages a -57.2 % change. This is in line with the average annual domestic space heating reduction figure for *DECC:2050:Renew* for 2050. Being a 2030 scenario, the *GP:2030* space heating targets are significantly more ambitious: but this report will repeatedly emphasise the enormous importance of reducing space heating demand - particularly in the domestic sector - as a pre-requisite for a workable decarbonised power sector when heat electrification is attempted in parallel.

The focus on non-domestic space heating demand is required due to the difficulty of shifting the *time* of such demand, and thus reducing peaks, using DSM: ultimately spaces need to be heated at certain times. If that fact cannot be substantially altered, then the demand occurring *at those times* must be reduced more so than when dealing with more mobile demand types. This explains why the space heating demand reduction assumed for the non-domestic sector is not as radical: this demand already occurs outside of the morning and evening peak periods.

Overall we argue that these national demand reduction assumptions must become priority national *targets* in the near future.

Water heating

GP:2030 assumes a very modest change of -3 % in domestic water heating demands, in line with *DECC:2050:Renew*. Domestic water heating demand is determined primarily through behavioural choices, such as the temperature of basin water and whether baths or showers are used for washing. Compounded by the fact that building characteristics do not significantly impact water heating demands, it is therefore unlikely that large reductions in domestic water heating demand will be made.

Heat pumps

The *GP:2030* scenario assumes, in contrast to *DECC:2050:Renew*, that the prevalence of heat pumps will be significantly lower: with 25 % of heat delivered via heat pumps compared to 90%. Even if achieving 90% of heat delivery from heat pumps by 2050 is feasible, 25% by 2030 is ambitious, given the relative infancy of the UK's heat pump industry. Skills and understanding in the supply chain, combined with improved public communication and project execution, will be key to overcoming consumer resistance. Thus our assessment is based on current (and fairly low) rates of deployment and the recognition of the cost and disruption currently associated with installation, as well as the challenges highlighted by the Energy Saving Trust's 2010 field study (EST, 2010). It is notable that the Renewable Heat Incentive (RHI) is currently unfunded beyond 2016; this will need to be addressed to ensure supply chain investor confidence. 24% of total 2030 heat demand in the 'medium abatement scenario' of the CCC's Fourth Carbon Budget is expected to be delivered via heat pumps (Committe on Climate Change, 2008), a target considered substantial but achievable with appropriate policy action by WWF in 2014 (WWF, 2014). In both *GP:2030* and *DECC:2050:Renew* it is assumed that ground or water, as opposed to air, sourced heat pumps are employed (to guarantee performance during winter) and that they provide $\sim$3 times as much heat as they consume electrical energy, in line with the literature. This factor of 3 is termed the 'coefficient of performance' and is modelled as stable over all seasons, for more information on the modelling of heat pumps see Appendix A and Quiggin (2014). No resistive heating is included in *GP:2030*, to which air-sourced heat pumps revert when they cannot function normally.

Traditional electricity demand

Traditional electricity demand is the electrical demand from both domestic and non-domestic electricity consumers, with no contribution from electric vehicles, heat pumps or economy seven[4]. For SHED's predictive purposes, future traditional electricity demand is similar to current electrical demands, but with economy seven and resistive heating[5] removed. Traditional electricity demand is the single largest energy demand category, within *GP:2030*, at 260 TWh/yr. Indeed *GP:2030* assumes a more optimistic outcome for demand reduction than *DECC:2050:Renew* based on increasing energy efficiency of appliances and increased awareness of consumption.

Modelled in SHED the higher *DECC:2050:Renew* traditional electricity demands contribute to deficits that cannot be closed, leading to supply - demand deficits. Hence it is integral to maintaining supply - demand balance that traditional electricity demand is reduced from current levels.

[4] Economy seven; is a differential tariff which is cheaper at night time - encouraging consumers to move demand to periods where demand is low. This type of tariff has been in operation since the 1980's in the UK

[5] Resistive heating; refers to heating provided by electricity, many *current* households on economy seven tariffs have storage resistive heaters

Electric Vehicles

Electric vehicles (EVs) will be a part of the future given the clear desire of the British public to have access to private transport. The precise extent of their roll-out will depend on improvements in technology, investment in national infrastructure (such as charging points) and price competitiveness vs. internal combustion engine vehicles (which in turn depends on battery development and the volatile price of oil). *GP:2030* EV demand is set at 32 TWh/yr, in line with *DECC:2050:Renew* which projects 45TWh/yr of EV demand by 2050. 32 TWh/yr equates, (based on CCC vehicle number projections (Committe, 2014); Government average mileage data (Department for Transport, 2014); and estimates of power usage from Tesla and the International Energy Agency (IEA, 2013)) to 12.6 million electric vehicles travelling 12,640km a year, using 0.2kWh/km. It has been assumed that EVs are not capable of providing power back to the grid, hence EVs are unable to provide balancing services, which many studies have suggested would be possible, but expensive (Kempton and Tomić, 2005). The driving and charging profile used to model hourly EV demands is a modified DSM profile, under which DSM has been accounted for (Acha et al., 2011). Hence the EV demand profile assumes EVs are charged overnight and during the day *between* morning and evening peak demand periods. EVs thus help to reduce or eliminate surpluses in the system more often than they contribute to net demands. If however a non-DSM charging profile is assumed within the modeling then the charging times would be more likely to coincide with times of supply-demand stresses.

Solar thermal

Although solar thermal units do not consume or produce electricity it is important to consider their impact on heating demands given these heating demands are later electrified via heat pumps. *GP:2030* is more optimistic about the potential for growth than *DECC:2050:Renew*. While the latter assumes that only 1 in 40 properties will have solar thermal installed by 2050, with an average installed power rating of 2kW, *GP:2030* assumes that 1 in 10 will have the technology installed. Under the RHI currently ∼4,000 properties have solar thermal installed, representing 1 in 6,500 households. It must be noted that physical limitations on the roll-out of solar thermal exist given the growth of solar PV: roof space already occupied by solar PV panels prevents installation of solar thermal in the future. In order for the growth of solar thermal to continue the RHI (or equivalent policy) must be continued beyond the end of 2016, when it is currently set to expire.

Number of households, build rates & energy efficiency

The UK is currently building between 125,000 - 130,000 new homes per year. These new homes are required under building regulations to have a much greater energy efficiency than the current building stock. Indeed, building regulations are under review and in 2016 it is likely that developers of new builds will be required to further improve heating efficiency standards. There has been discussion of incorporation of level 6 of the "The Code for Sustainable Homes" (CSH) within building regulations, which would mean new builds would be required to reduce CO_2 emissions to net zero. Hence space heating demands would necessarily be reduced substantially in all new builds. It is unlikely that by 2016 level 6 of the CSH will be implemented within the building regulations but a significant move in that direction is anticipated. The likely implementation of building regulations is that Fabric Energy Efficiency Standards (FEES) will be substantially increased.

With energy efficiency standards increasing for new build properties, a substantial component of the domestic space heating reduction targets of *GP:2030* could be achieved. Indeed *GP:2030* anticipates the number of households within the UK will rise from its current number of ∼26 million to 30 million, an increase of 15.4 %. This increase would require ∼267000 households to be built per year, assuming a constant yearly build rate. This build rate should be considered within the context of the current build rate (above), but also the UK Governments' aspiration for 300,000 per year, as announced by Business Secretary Vince Cable in May 2014. Hence the build rate required within *GP:2030* is within Government policy aspirations and indeed roughly double the current build rate. It should also be noted that within *DECC:2050:Renew* 40 million households are anticipated by 2050.

3.3.2 Supply & balancing mechanisms

With demand inputs specified, hourly demands are quantified for the eleven years of data within SHED, against which supply must be matched - enabling testing of the scenario's overall ability to balance supply and demand.

The supply profile is generated in SHED by combining hourly historical weather data for the period 2001 - 2011 (for more information on weather data and the modelling of renewables see Appendix A and B, as well as Quiggin (2014)) with decisions on:

- Generator capacities for all generation technologies;
- Pumped storage capacity;
- Other storage capacity (e.g. centralised or decentralised batteries);
- The dispatch protocol sequence, and;
- Demand side management

The hourly historic weather data enables us to predict the expected supply of uncurtailed, non-dispatchable, variable renewable power. Hourly capacity factors are generated from the historic weather data, regional resource constraints (such as sea bed depth for offshore wind) and technology technical characterisations (such as power curves for wind turbines, which define the wind turbine output at various wind speeds).

Key Information 3.3 The capacity factor for a given renewable generator is the ratio between its actual output over a given period of time, and its potential output if it were able to operate at rated nameplate generation capacity.

Detailed modelling descriptions of hourly capacity factors are not given within the report, for this information please see Quiggin (2014). However the mean capacity factor for each renewable generator, over the 11 years of historic data, is given below.
■

Depending on modelled demand, a net demand or surplus will be defined for any given hourly period. In the case of a net demand, the dispatch protocol is initiated, as detailed at the beginning of this section, until the net demand is reduced to zero. In the case of surplus, excess power is redirected to DSM, various forms of storage, exported and finally turned into hydrogen for hydrogen vehicles - according to the prioritisation of importance for surplus absorbers described above. This, amongst other things, defines the "state of charge" of storage (either pumped or battery), which in turn defines the ability of storage to reduce future net demands. This is why winter anti-cyclones provide such a challenge to renewable scenarios: if the wind doesn't blow for 5 days the ability of storage to reduce net demands driven by peaks in heating demand at the *end* of that period is severely diminished, in the absence of opportunities to re-charge.

Table 3.2 shows the input values for different categories of supply and balancing technologies for both *GP:2030:Pragmatic* and *GP:2030:ClimateDriven*, alongside *DECC:2050:Renew*. It should be noted that both the *GP:2030* sub-scenarios project the same installed capacities of generators and balancing mechanisms as well as identical demand targets. The difference between the two sub-scenarios arises from balancing mechanism alterations, as described in Section 3.2.1.

Key Information 3.4 It should be noted that all generators, be them renewable or CCGTs and nuclear power stations, are assigned an "availability factor". The availability factor is the amount of time that a generator is able to produce electricity over a certain period, divided by the amount of the time in the period. All renewables are assigned an availability factor of 85%, meaning that at any moment in time only 85% of the national capacity is available for generation, due to maintenance and equipment failure. The availability factors for each technology can be found in Quiggin (2014). In certain cases the availability factor is stated if the technology has a particularly low or high availability factor. It should be noted that the values in Table 3.2 and Figure 3.2 do not include availability factors. ■

Supply parameter	GP:2030	DECC:2050:Renew
Non-dispatchables (Phase 1)		
Nuclear (at 90% capacity)	1.2	15.7
CHP Biomass	4	0
CHP Gas	17.5	0
Wind Offshore	55	54
Wind Onshore	22	28.4
Solar PV	28	14.1
Tidal	8	3.6
Wave	0.5	5.8
Non-fossil dispatchables (Phase 2)		
Geothermal	2	0
Hydro	2	2.1
Balancing Mechanisms (1) (Phase 3)		
Domestic DSM	-	-
Pumped Storage	4 (27.8 GWh)	17.2 (400 GWh)
CHP emergency	-	-
Centralised Battery Storage (GWh)	3	0
Interconnectors (imports)	10	30
Dispatchables (Phase 4)		
CCGT no CCS	19.5	0
CCGT with CCS	0	8.1
Coal no CCS	0	0
Coal with CCS	0	5.1
Biomass	0	0.6
Nuclear (rampable 10%)	1.2	15.7
Balancing mechanisms (2) (Phase 5)		
Commercial DSM	-	-
Decentralised battery storage	1 in 10 households equivalent	-
Interconnectors (exports)	10	30

Table 3.2: Supply inputs, all in GW unless stated.

Figure 3.2 shows the total generation capacities of *GP:2030* and *DECC:2050:Renew*. *GP:2030* has a larger overall generation capacity than *DECC:2050:Renew* and a higher

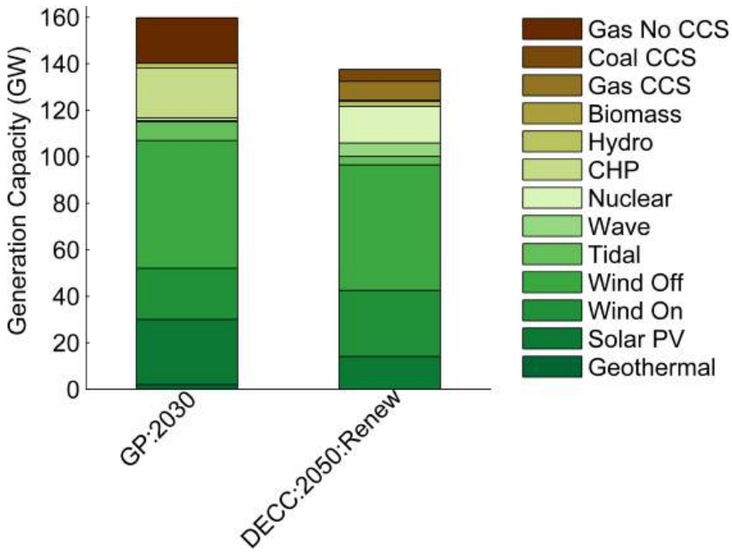


Figure 3.2: *GP:2030* generation capacity, compared to *DECC:2050:Renew*.

overall total of renewable generation capacity. It contains $\sim 1/3^{rd}$ more fossil fuel generation *capacity* (as distinguished from *use*), in the form of non-CCS CCGTs. In 2013, the total UK generation capacity was ~85GW, down 4.9% from the ~89.5GW at year-end 2012. Hence the total installed generation capacity in *GP:2030* of 159.7 GW is roughly double that of 2013. For comparison *DECC:2050:Renew* has a total installed capacity of 137.5 GW.

Demand Side Management (Domestic and Non-Domestic)

The potential for DSM has already been discussed at some length in Chapter 2, and is expected to be enabled by the installation in households of smart meters and, in some cases, intelligent appliances that can turn on or off in response to price signals from the grid. Here we discuss both domestic and non-domestic DSM specifically in terms of the modelling and input decisions to SHED.

While most "balancing mechanisms" - mechanisms for reducing the net demand that are not generation technologies (such as battery storage) - work by providing increased supply into the grid, DSM (either domestic or industrial), does so by *shifting* demand *away* from peaks. The decision where to place domestic and non-domestic DSM in the dispatch protocol defines to what extent technologies succeeding them are called on to provide extra supply, or reduce or shift demand.

There are two principle dimensions of the DSM algorithm that are defined by the scenario designers:

- the size of the "DSM window" - the time period either side of demand peaks into which it is deemed reasonable to expect consumers to shift their demand backwards or forwards in time;
- a lower limit, if implemented, below which DSM will not reduce net demand before calling on successive dispatchable generators, or additional balancing mechanisms.

Figure 3.3 is a diagrammatic representation of the national DSM algorithm used for both domestic and non-domestic DSM.

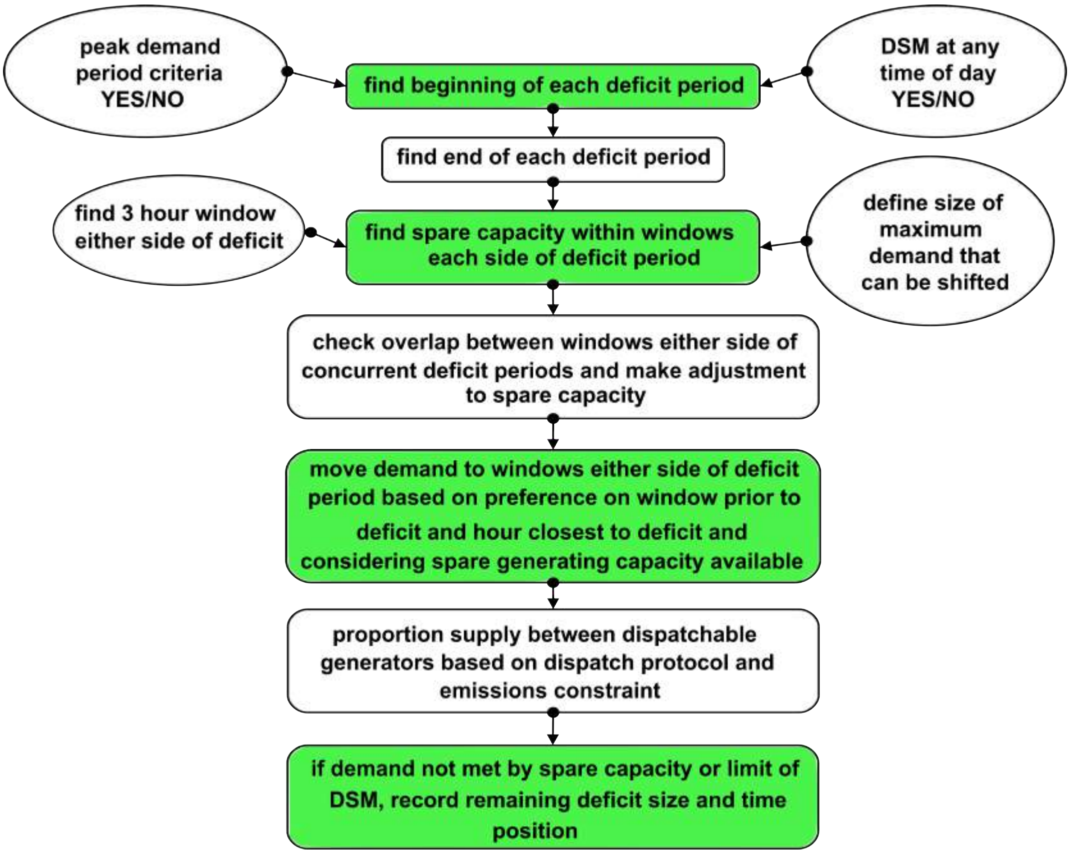


Figure 3.3: Representation of the generalised DSM algorithm for domestic and non-domestic consumers.

The domestic DSM algorithm allows participation during any hour of the day, with no maximum constraint. An Ofgem (2012) report has been used to define non-domestic DSM dynamics beyond the generalised algorithm in Figure 3.3. The extreme Ofgem non-domestic DSM scenario was followed in SHED, defining the winter week day load flexibility during peak demand as 4.4GW. It should be noted however that non-domestic DSM is one of the last components of the dispatch protocol and hence is called upon far less than domestic DSM.

In *GP:2030* the window within which demand must be moved in time to is kept to 3 hours pre and post the deficit periods for both domestic and non-domestic DSM. Obviously electrified heating demand can only be shifted forward in time with the aid of storage or highly heat efficient homes, whereas traditional electricity can be shifted forwards *or* backwards in time. Renewable surpluses or spare generating capacity within that window must exist to supply the demand. Demand is *only* shifted within the 3 hour window if there is sufficient supply *either side* of the the peak to absorb it. Thus the size of surpluses either side of peaks disciplines the degree to which demand can be shifted.

Within the non-domestic DSM algorithm, demand is removed in equal proportions within the hours of the deficit period. This contrasts with the domestic DSM algorithm where the largest *instance* of deficit is given priority. Given the 4.4GW maximum demand constraint does not apply to domestic DSM, the only constraining factor to unlimited demand shifting is the spare CCGT capacity and surplus renewable supply, within the 3 hour window, either side of the deficit period.

Once defined, the algorithm runs as part of the supply-demand balance modelling. Results are obtained that show the frequency and size of DSM requirements within the scenario, at a national level, in order to maintain system balancing over the 11 modelled years. Later in this report we present the results of the disaggregated DSM requirements, enabling us to picture to what extent and frequency of demand shifting would be asked of individual households of different socio-economic types. For detailed information on this disaggregation process see Quiggin (2014), as a description of this methodology is beyond the scope of this report.

As outlined above, decisions affecting the type and extent of domestic DSM expectations, and its position in the dispatch protocol, affect the overall supply-demand balancing of the system.

Key Information 3.5 **DSM placement in dispatch protocol.** The placing of domestic DSM higher up the dispatch protocol may appear to place an unnecessary onerous burden on households, requiring them to be the first line of defence in balancing the national grid if there is still net demand after non-dispatchable and non-fossil dispatchable generation. However, this was decided by Greenpeace to enable:

1. The worst case scenario of domestic DSM to be quantified; modelling the most demanding scenario means that the *most* that might ever be reasonably expected of households is clearly defined. This enables *GP:2030* to place boundaries on what domestic DSM can be considered capable of
2. Reduce reliance on more expensive storage technologies, such as batteries and compressed air: if domestic DSM can be kept within reasonable boundaries despite being primary in the dispatch protocol's balancing mechanisms, *GP:2030* is overall less reliant on projected price movements of storage technologies explored below.

Hence domestic DSM occurs straight after renewable supply to reduce net demand (Phase 3), whilst non-domestic DSM occurs as the final balancing mechanism after CCGTs to soak up any residual net demand (Phase 5). During the iterative process of modelling *GP:2030* a second phase of domestic DSM was left within Phase 5 of the dispatch protocol - as the very last balancing mechanism, but as will be shown later is not called upon. ■

Wind

Wind power, both offshore and onshore, will provide the largest contribution to renewable supply into the grid. This expectation is reflected across all major energy scenarios in the literature: this is simply where the greatest opportunity lies to harvest energy from our surroundings in the UK.

Key Information 3.6 Across all eleven years of data, the mean hourly capacity factors modelled within SHED for onshore and offshore wind generation are 30.1% and 44.3% respectively. ■

In 2013 the installed capacity across the UK of onshore wind was $7,994MW$ across 4,804 turbines ($\sim 1.7MW$ average capacity), the offshore installed capacity was $4,049MW$ across 1,184 turbines (Renewable UK, 2013). Wind generation is expanding rapidly in the UK, currently there is a total of $5,651MW$ and $9,795MW$ of onshore and offshore wind projects with planning consent, respectively. There are

$1,322MW$ of onshore wind projects under construction and $1,005MW$ of offshore under construction (Renewable UK, 2013).

The total for offshore and onshore wind capacity in *GP:2030* is 77 GW; compared to the current total built, under construction and consented (offshore and onshore) at the time of writing of ~30GW - a 157% increase required by 2030.

Total onshore wind built, under construction or consented is ~15GW, requiring a ~47% increase (assuming all consented projects are built). This is a highly achievable target over the next 15 years. However, *offshore* capacity must be increased by around ~270% by 2030 (assuming all consented projects are built). This is then an ambitious, but necessary, target.

In calculating the total possible available resource for offshore wind, the constraints differ to onshore. There are no National Parks and cities to consider: but there are sites of special scientific interest, shipping lanes and protected areas. The main constraint, however, is the depth of sea bed (bathymetry) where the depth is required to be less than 40m, out to 30km. A detailed description of assumptions made in calculating various regional resource constraints can be found in the DTI (1998) report. Please see the maps of onshore and offshore wind weather stations used to determine wind capacity factors within Appendix B, further detailed descriptions of wind modelling can be found in Quiggin (2014).

The UK has the largest wind resource in Europe and urgent focus needs to be put on enabling its integration as the largest renewable contributor into a future power supply system; in particular onto the very rapid scaling up of offshore wind capacity. This is within our reach. Without it meeting carbon targets within reasonable timescales becomes very likely impossible.

Solar PV

There has been major growth in Solar PV installations since the introduction of the feed-in tariff in 2010, rising from ~80MW installed capacity at year end 2010 to ~5GW year end 2014 (Department of Energy and Climate Change, 2015*b*). These numbers reflect feed-in tariff subsidised installations as well as those installed under the Renewables Obligation (RO).

> **Key Information 3.7** Across all eleven years of data, the mean hourly capacity factor modelled within SHED for solar PV is 11.4%. ■

Though it cannot be assumed that growth achieved under a favourable subsidy regime will be matched year on year for the next 15, the UK Government predicted in 2012 that solar installation capacity could reach 22GW in 2020 located on 4 million households, on the basis of falling costs of fabrication and installation. The prospect of reaching 28 GW of installed capacity by 2030, as required by *GP:2030*, is therefore possible and achievable. Especially considering the projected installed capacity in *GP:2030* would require 1.5 GW per year for the next 15 years, and 1.2GW was installed in 2014 alone (Department of Energy and Climate Change, 2015*b*).

Combined heat & power

There are many forms of CHP units fueled by different liquid or gas fuels. In 2012 the technical potential of CHP was calculated by DECC to be $29.4GW$, rising to $33.8GW$ by 2030 (Ricardo-AEA, 2013). In 2011 the installed capacity of "Good Quality CHP" was $6.1GW$ (Ricardo-AEA, 2013). The *GP:2030* target of 21.5 GW is therefore 64% of DECC's technical potential estimate for 2030, and a 350% increase on 2011 installed

"Good Quality" capacity. It appears therefore well in line with official forecasts and expectation.

The approach taken here is that CHP units are treated as community scale heating systems, where power is produced simultaneously with heat (rather than many dispersed micro CHP units, due to the high capital costs (Lund et al., 2010)). There are several forms of district heating, from gas, biomass, biogas and geothermal plants - yet only 5% of installed CHP units in 2011 were fired by renewable fuel sources (Ricardo-AEA, 2013). Under *GP:2030* just under 23% of installed CHP would be renewably fueled, the remainder burning natural (fossil fuel) gas. While it would be theoretically possible to increase this proportion beyond 23% (to lower CHP's overall carbon intensity), doing so would require either turning over an unrealistic amount of UK agricultural land to biomass production; or importing vast quantities from abroad, which carries its own risks and emissions drawbacks.

In Phase 3, emergency CHP (EmCHP) is invoked after pumped storage. This simply enables the system to call on the full generation capacity (21.5GW) of installed CHP *regardless* of heat demand at that time. This doesn't however account for the availability factor for CHP, defined at 90%. Before Phase 3, heat demand drives the electrical output of CHP in *GP:2030*, which may not require it to operate at full capacity. However given the impact of space heating requirements on the electricity supply through deployment of heat pumps, it will often be, in fact, heat demand driving peaks - in which case Phase 1 CHP will be operating near or at capacity, and the ability of EmCHP to reduce those peaks will accordingly be impaired.

Tidal

Tidal patterns correlate to the motion of the moon, not to weather patterns, apart from during extreme storm surges. Tidal generation is calculated in a similar method to Mackay (2009), where output is proportional to the tidal stream velocity cubed, on a lunar cycle of 29.5 days, and generating power on both the ebb and flow tides. Hence the tidal stream energy, rather than lagoon or barrage types of tidal power is calculated.

> **Key Information 3.8** Across all eleven years of data, the mean hourly capacity factor modelled within SHED for tidal generation is 24.4%. ■

There is no aggregation over multiple independent sites to form a national capacity factor. Rather it is assumed there is one main scheme. This therefore results in four distinct peaks in generation per 25 hour period. The ratio between spring and neap tide capacity factors is just greater than 4. Within *GP:2030* 8 GW of tidal power is projected to be installed by 2030.

It should be noted that the current momentum behind tidal is focused on tidal lagoon facilities rather than tidal stream or barrage. There are currently no operating tidal lagoons known to the authors, and the supply profile of tidal lagoons will be different to tidal stream.

Hydro

In 2007 hydroelectric power stations in the UK generated 4TWh/yr, $\sim$1.4% of total electricity demand from 1.3GW of installed capacity. Within *GP:2030* a total generating capacity of 2 GW is projected to be installed, achieved though refurbishment of existing schemes and micro-hydro sites. Most renewable generators are given a 90% availability factor within SHED, hydro is given a lower 60% value due to the 2 GW of capacity being comprised of many micro-hydro sites. Hydro is useful as it can load follow and is classified as a dispatchable generator, Phase 2 in the dispatch protocol.

Wave

Being an immature technology, there is currently no commercial wave power in operation in the UK, hence the minor contribution the technology is assumed to make to the general energy mix, even by 2030.

> **Key Information 3.9** Across all eleven years of data, the mean hourly capacity factor modelled within SHED for wave generation is 21.1%.

While *GP:2030* only expects 0.5 GW of wave generation capacity to come online by 2030 this still represents a challenge, given the infancy of the technology at applied scale. As wave power generation systems are still under development in the UK, resulting in no clear technology leader, two systems were identified to produce power ratings and capacity factors in SHED; the Pelamis system (Henderson, 2006) and a generic system. The Pelamis system, was until recently, the closest to achieving commercial viability and its power curve can be found in Quiggin (2014). The generic device has an efficiency of 47% for all sea states, this modelling derives from the methodology developed in FESA (Barton et al., 2013). It should be noted that Pelamis went into administration in December 2014 (BBC, 2014*a*), during the modelling process for *GP:2030*.

Nuclear

The total nuclear installed capacity in *GP:2030* is simply the amount of current installed capacity due to be online in 2030, set at 1.2GW (i.e. Sizewell B). In *GP:2030* nuclear is assumed to run at 90% capacity, enabling only 10% of total capacity to be called on in peak periods. Being more ambitious with respect to the rampable portion of installed nuclear generation capacity relies on assumptions about what would be commercially acceptable (with or without Government subsidy), and involves additional engineering strain on critical components. The higher the reserved rampable portion of capacity, the less economical the station would be, meaning Government would likely need to *further* subsidise nuclear power operators.

Currently nuclear power stations provide base-load power to the electricity system with no dispatchable element, as ramping the generators puts large stresses on the reactor core causing expensive maintenance costs. Under current European Utilities Requirements nuclear power stations must be able to cycle daily between 50% and 100% of their rated power, with ramp rates of between 3-5%. As the OECD Nuclear Energy Agency points out (Nuclear Energy Agency OECD, 2011) the current lack of nuclear plant demand following is an economic rather than technical barrier.

GP:2030 does not include any new nuclear build (see Chapter 2 for more detail).

Geothermal power

The DECC has assessed the upper limit technical potential for geothermal within the UK to be 4GW (Department of Energy and Climate Change, 2011) by 2030. In a 2011 report for WWF the projected installed capacity of geothermal was 5GW (Garrad Hassan, 2011). Geothermal power has high utility as a renewable source of energy as it is dispatchable, hence it can follow demand, and it can act as base load in a similar way to nuclear power stations. Within *GP:2030* the siting of geothermal installations, be them in the UK or in Iceland with interconnection, is not defined.

Pumped storage

Pumped storage facilities pump water up a hill to a reservoir, increasing its gravitational potential energy, and releases the stored water, when required, through a turbine, generating electricity. Water is pumped up hill when electrical demand is low and released when required. Currently the UK has a total pumped storage capacity of 2.78GW with a storage capacity of ∼24.9GWh. The *DECC:2050:Renew* scenario forecasts significant increases in pumped storage generation capacity from 2.78GW to 17.2GW and storage capacity increases to 400GWh.

Proposals to build new pumped storage do currently exist. Scottish and Southern Energy are in negotiation over the Coire Glas 0.6GW facility (Scottish Canals, 2013) with further installations being considered at Sloy (0.06GW) and Bamacaan (up to 0.6GW) (Lannen, 2012), representing a significant increase in capacity. Within *GP:2030* the capacity of pumped storage is increased slightly to 4 GW and storage capacity to 27.8 GWh, in line with those sites that have already be identified.

Centralised battery storage

Electricity storage is currently expensive and technically challenging at scale. It is also very limited in terms of UK installed capacity, the majority of which is pumped storage. Nevertheless grid-level battery storage is assumed to be a useful part of a 2030 energy scenario, despite its omission from many scenarios in the literature. The largest battery in Europe (6MW/10MWh) was switched on at Leighton Buzzard, Bedfordshire in advance of a 2 year trial in December 2014 (BBC, 2014*b*). A major advantage of battery storage is its ability to provide power back into the grid almost instantaneously in order to reduce net demand. Pumped storage is limited in this respect by the the generation capacity of the hydro plants tasked with converting pumped water's gravitational potential energy back into electrical energy. For example, in *GP:2030* there is 27.8 GWh of pumped storage capacity proposed but the total associated disptach power is only 4 GWh, meaning that it would take a minimum of just under 7 hours to deliver the full stored energy capacity if called upon.

The levelised generation costs of power from CCGTs in 2012 was £80/MWh and £134/MWh for offshore wind DECC, 2012b. The cost of battery production has fallen and is predicted by many analysts to fall further in the near future. Within the next 7-8 years Citigroup estimates battery storage to fall to £149/MWh, based on technology cost reductions due to increased numbers of electric vehicles and policy and legislative changes within the EU (Pitt et al., 2015). *GP:2030* projects 3 GWh of grid-connected battery storage, less than the 5GWh that utility company Oncor is currently seeking investment for in Texas, USA.

It should be noted that although *GP:2030* projects 3 GWh of centralised battery storage, which sounds significant, net demand post renewables could often exceed 3 GW. In this case the store of power in the batteries would last only 60 minutes. Given that when net demands exists the duration of net demand often extends over many hours, this battery storage is limited in its capability of providing a high utility balancing function.

Interconnectors

There are currently three high voltage direct current (HVDC) links from the National Grid to France, Holland and Ireland. As an example, the UK-France interconnector is 70km in length with 45km of under-sea cable. The combined capacity of the current three interconnectors is 3.5GW and the National Grid is currently working on further interconnector projects with Belgium, Norway, Denmark and a second interconnector with France (National Grid Company, 2013). Of these projects the UK-Belgium interconnector is the most developed, with completion anticipated in 2018, adding 1GW of capacity (National Grid Company, 2013).

GP:2030 envisages just over a doubling in interconnector capacity between 2018 and 2030; not unreasonable taking into consideration other planned projects listed above. With the European Commission increasingly setting targets and legislation that encourages or mandates (CEC, 2008*a*,*b*,*c*,*d*) European countries to move towards renewable-heavy power supplies (therefore introducing intermittency issues) there is greater impetus for countries to be able to export surpluses and reduce net demands with imports. As will become clear the UK will, at times, produce power surpluses due to uncurtailed renewable supply (even after battery, pumped storage and EV charging) - in these instances interconnectors enabling power exports have the potential to provide economic benefits.

Supply-demand dynamics at the non-UK end of the interconnectors are not considered, thus no consideration is given to the power available to import or export via interconnectors at any given time; instead it is assumed that the maximum carrying capacity of the interconnectors can be called at any time. This is a limitation of SHED, but one that is reflected throughout the literature. Recent DECC and Ofgem analysis of reliable supply from interconnection has concluded that availability of supply from continental Europe is relatively high, although the specifics will depend on conditions in other countries, which gives confidence that firm supply of 10GW is not unreasonable (Department of Energy and Climate Change, 2015*a*).

Closed cycled gas turbines

In order to maintain an acceptably reliable power supply, in line with current official lower limits of loss of load probability (LOLP, see Chapter 2) some rampable CCGTs are included in *GP:2030*. They are not fitted with CCS technology, unlike the majority of fossil generation capacity in *DECC:2050:Renew*.

> **Key Information 3.10** In line with Greenpeace policy (Greenpeace, 2008), the CCGT generators projected within *GP:2030* are not fitted with CCS. This consequently results in higher emissions, but means the scenario is not reliant on unproven technology with potentially harmful effects. The emission intensity factor used for CCGT power stations originates from the IPCC, which estimates the life-cycle emissions from CCGTs to be 469gCO_2eq/kWh, rather than 245gCO_2eq/kWh for CCS fitted CCGTs (IPCC, 2012). ■

CCGTs are a mature technology, delivering a significant amount of the UK's current power supply. During non-ramping operation CCGTs are more efficient than open cycle gas turbines (OCGTs), but are less suitable for ramping rapidly during times of stress on supply than OCGTs. However, CCGTs are now the standard form of gas turbine due to significant investment in them over previous decades. Consequently, within SHED emission ramping penalties are applied: as generation from CCGTs varies more, emissions accounted for rise also. For more information on these ramping penalties see Quiggin (2014).

GP:2030 envisages a reduction in the current capacity of CCGTs to near the minimum level required (19.5 GW), in conjunction with non-fossil generation capacity and existing nuclear capacity, to ensure a reliable power supply.

Decentralised battery storage

Alongside an increase in the prevalence of battery storage at grid level, *GP:2030* envisages the proliferation of decentralised battery storage within household and commercial or public units. This follows the logic employed in assessing the potential for grid level storage: with battery costs declining and decentralised renewables on the rise it will likely become increasingly common to include storage alongside installations. Barclays estimates that battery costs have declined from $17,000 in 2009 to $3,700 in 2014 for a self-sufficient household system (Rob, 2014). Users will benefit from being able to reserve surplus power for use during peak periods, effectively being able to swap surplus prices for peak prices on certain occasions. The logic in favour of such investments increases under future energy conditions where electrical demand peaks are larger, supply more intermittent and batteries cheaper to install. *GP:2030* assumes that the equivalent of 1 in 10 households will have a single battery, of average 90*Ah* capacity, installed by 2030. Given the government expects 4 million households to host solar PV installations by 2020 (see Section 3.3.2), and *GP:2030* assumes there will be 30 million households in total by 2030; it would take only three quarters of those 4 million households to purchase batteries by 2030 (assuming no more solar PV was installed) in order for 1 in 10 to become a reality. While ostensibly ambitious, given the combination of factors encouraging household economic decision-making in this direction we consider it feasible. Furthermore, this assessment does not include battery storage investment by commercial or public sector organisations in combination with solar arrays, likely well before 2030 given similar economic calculations apply.

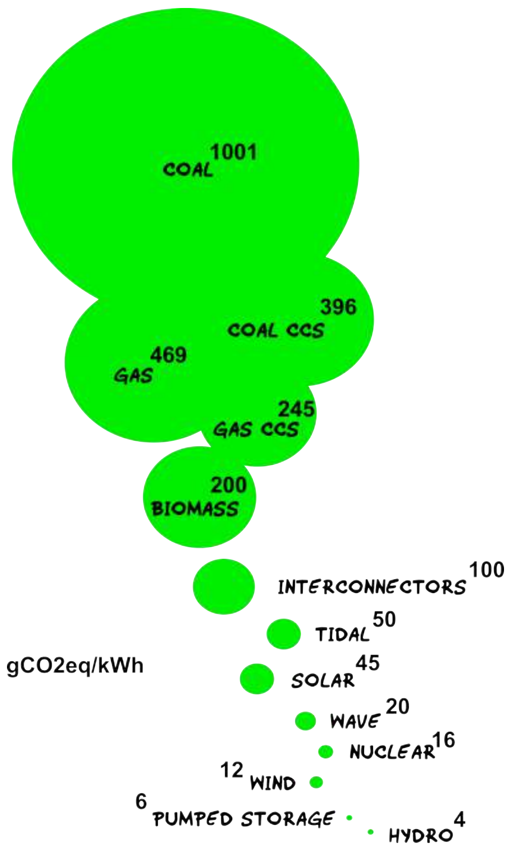


Figure 3.4: Emission factors per technology. Source : Intergovernmental Panel on Climate Change (2011)

3.3.3 Emissions

> "The UK's consumption [of energy] cannot continue to rise indefinitely.... if it is to make an effective contribution to a global reduction in greenhouse gas emission"
>
> (Energy and Climate Change Committee 2012)

The majority of emission intensity factors for generators are taken from the Intergovernmental Panel on Climate Change 2012 report on "Renewable Energy Sources and Climate Change Mitigation" (Intergovernmental Panel on Climate Change, 2011).

Where a better or more UK relevant source could be obtained, it has been. The emission intensity values taken as inputs to SHED are given in Figure 3.4(a). In relation to fossil fuel generators, the numbers quoted in Figure 3.4(a) do not include start up, part loaded, or ramping penalties which all increase emissions (Lew et al., 2012).

This is particularly true in the presence of high penetrations of renewables, resulting in a high frequency of load variation on those flexible fossil fuel generators. For CCGTs and coal power stations these penalties are a 15.6% and 5.1% increase respectively (Lew et al., 2012) (Note *GP:2030* does not project any coal capacity in 2030). These penalties are applied in SHED if the national generation from these generator types fall below 50% installed capacity.

Emission intensity calculation and Life-Cycle Analysis

The CCC's 50 - 100 $g_{eq}CO_2/kWh$ target by 2030 is based on *non* Life-Cycle Analysis (LCA) numbers for all generators except for those that burn fuel, including biomass. This means offshore and onshore wind, solar PV, wave, tidal, geothermal etc are assigned a zero value for emissions associated to those technologies. Although this methodology by the CCC is adequate it does mean that, as the electricity system moves from a fuel dominated emission paradigm to an *infrastructure* dominated future, LCA numbers will become increasingly important in assessing the UK economy's overall carbon intensity. The authors wish to state that CCC methodology therefore makes comparisons between present and future emission intensity factors challenging.

For completeness, emission intensity factors presented in Section 3.4 have been calculated using the full LCA numbers, shown in Figure 3.4, *and* using the CCC methodology with all but fuel burning generators' emissions intensity factors being set to zero.

3.4 Outputs & Results

The aim of this modelling process was to explore the possibility of reaching a 2030 electricity system which;

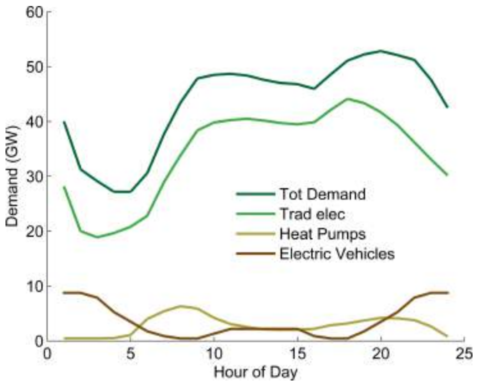
1. **Decarbonised** within the CCC targeted 50 - 100 $g_{eq}CO_2/kWh$ emission intensity factor, whilst;
2. achieving this figure in the **absence of carbon capture and storage technology deployment**, or the **building of new nuclear power stations**;
3. being **technically feasible**;
4. **electrifying** a substantial proportion of transport and heating to deliver emissions reductions in those sectors;
5. **balancing supply and demand** - ensuring the same, or an improved, guarantee of security of supply as is currently enjoyed in the UK;
6. ensuring the worst-case scenario impact of **demand-side management** on household consumption of energy is, nevertheless, likely technically and socially plausible, and;
7. being **economically feasible**

3.4.1 Emissions

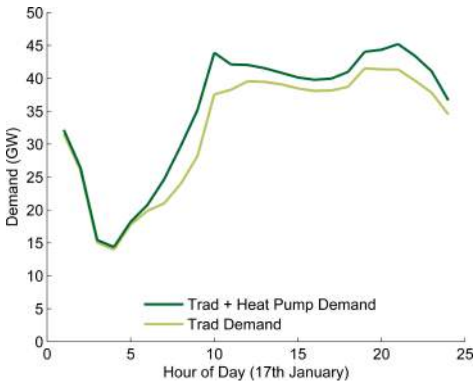
Of the listed objectives above, the objective of meeting the CCC's CO_2 targets has been achieved, reaching an emission intensity factor of 77.9 $g_{eq}CO_2/kWh$. We also considered the impact of balancing mechanisms working to further reduce emissions irrespective of the impact of balancing dispatch on CCGT load factors. This further reduced the emission intensity factor to 51.2 $g_{eq}CO_2/kWh$

3.4.2 Demand

Figure 3.5(a) illustrates the hourly *average* national daily demand profile during January/February weekdays of; traditional electricity, heat pump demand, electric vehicle demand and resistive heating. As is the case with current national electrical demand, traditional electricity demand peaks in the early evening, the profile shape resembling current demand profiles. The national demand profile changes with the higher morning electrified heating demand, resulting in national demand exhibiting two distinct peaks. The overriding change to total scenario demand, relative to historic demand, is the inclusion of the morning peak demand, almost equivalent in magnitude to the evening peak demand. This results in increased variability of demand, the morning peak period is $8-9am$ and the evening peak period $7-8pm$.



(a) Average electricity demand from traditional electricity, heat pumps and electric vehicles for January/February weekdays through 2030 based on 2001:2011 data.



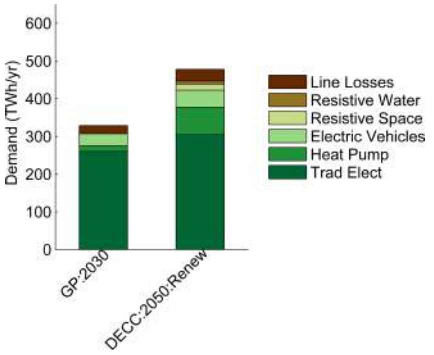
(b) Increase in electrical demand due to heat pumps during a typical January day.

Figure 3.5: *GP:2030* evolution of electrical demand due to heat and transport electrification.

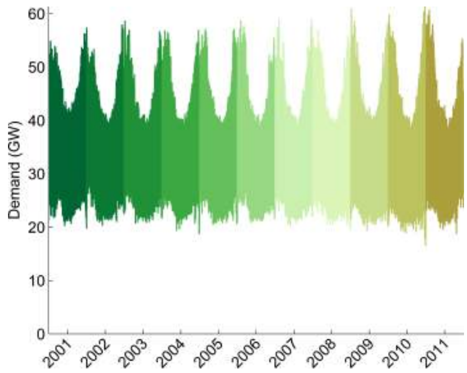
Figure 3.5(b) shows the increase in electrical demand during the 17^{th} January based on 2001 data. Whereas Figure 3.5(a) shows the average national electrical demands for January and February weekdays, Figure 3.5(b) illustrates the real time series results. The morning total demand can be seen to peak at $\sim 44GW$ and the evening peak at $\sim 45GW$, demonstrating the increased importance of the morning period as electrical demands increase due to heat electrification.

Figure 3.6(a) shows mean annual demands across the eleven years of SHED. Line losses amount to $21.5TWh/yr$, significantly less than the $31.3TWh/yr$ within *DECC:2050:Renew*. This is due to the lower level of heat electrification and traditional electricity demand within *GP:2030*.

GP:2030 projects 25% of heat to be delivered by heat pumps, whilst *DECC:2050:Renew* projects 90% (by 2050 rather than 2030), resulting in $15.1TWh/yr$ of heat pump electrical demand in *GP:2030* compared to $73.1TWh/yr$ within *DECC:2050:Renew*. It should be noted that *DECC:2050:Renew* forecasts 10% heating to be delivered by resistive heating, whereas *GP:2030* forecasts none. These factors combine to result in a *GP:2030* total annual demand of 328.6TWh/yr compared to 477.8TWh/yr within *DECC:2050:Renew*. Heat pump electrical demands therefore represent 4.9% of total annual demand within *GP:2030*, compared to 16.4% within *DECC:2050:Renew*. This, as will be discussed later, results in significantly more manageable supply - demand balancing as peak demands are not driven to the extreme levels of *DECC:2050:Renew*, by heat pumps.



(a) Mean *GP:2030* demands using forecast heating demands across the eleven years of data (2001:2011).



(b) Cyclical nature of traditional electricity demand within *GP:2030*, based on 2001:2011 data.

Figure 3.6: *GP:2030* evolution of electrical demand, annual and hourly breakdowns.

Figure 3.6(b) illustrates the modelled hourly national total electrical demand for all eleven years of data. As is expected, the cyclical nature of demand is apparent, with winter periods exhibiting the greatest demand values. Demand can be seen to peak at 62.3GW, which compares to a historic National Grid peak of 59.6GW over the same period from which the underlying data is drawn. *GP:2030* peak demands are comparable to historic levels, meaning that the reduction in traditional electricity demand has offset increased demand due to electrification of transport and heating - though only in the context of achieved heating reduction targets.

3.4.3 Supply

Figure 3.7 illustrates the average monthly output from all non-dispatchable renewable generators. As hydro and geothermal are dispatchable they are not shown here. The residual inflexible (90%) nuclear generation of Sizewell B, anticipated to still be open in 2030, can be seen to generate a small amount of base-load power, at the very bottom of the graph. The greatest seasonal variation in generation originates from CHP, dipping to a summer low when following heating demands.

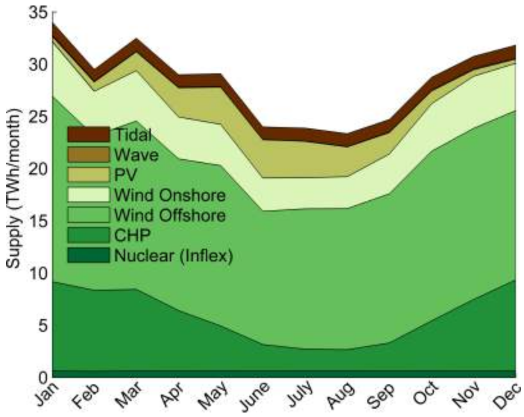
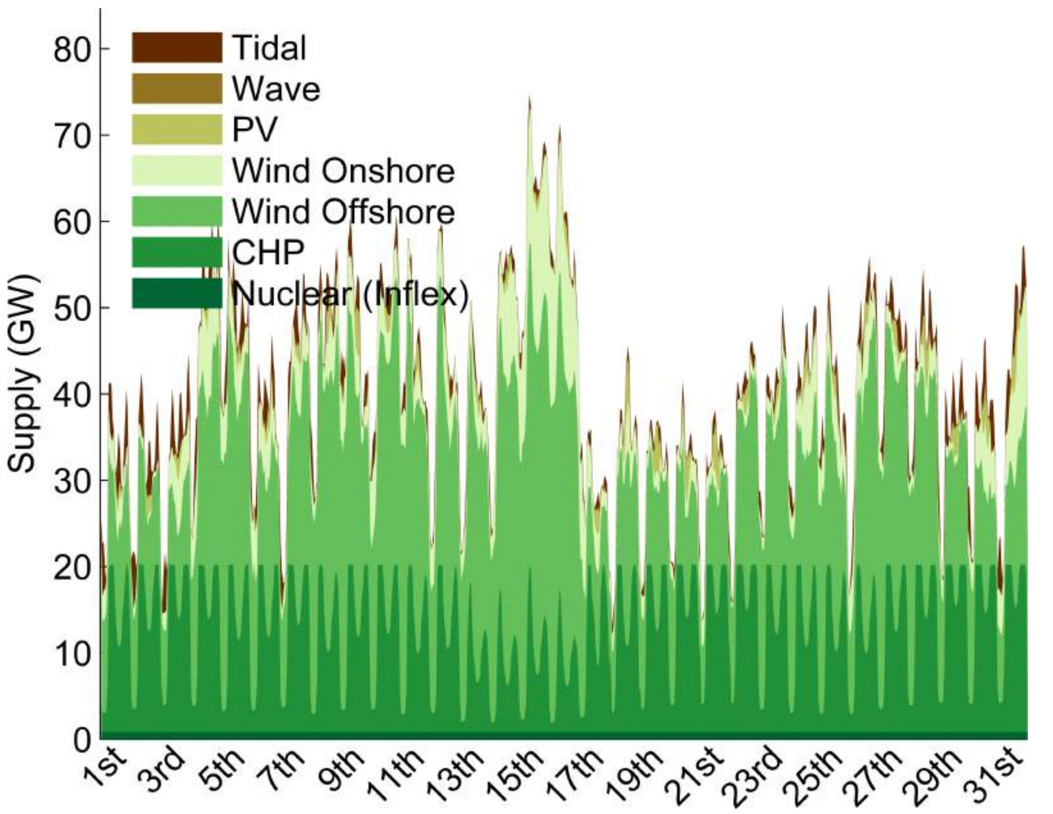


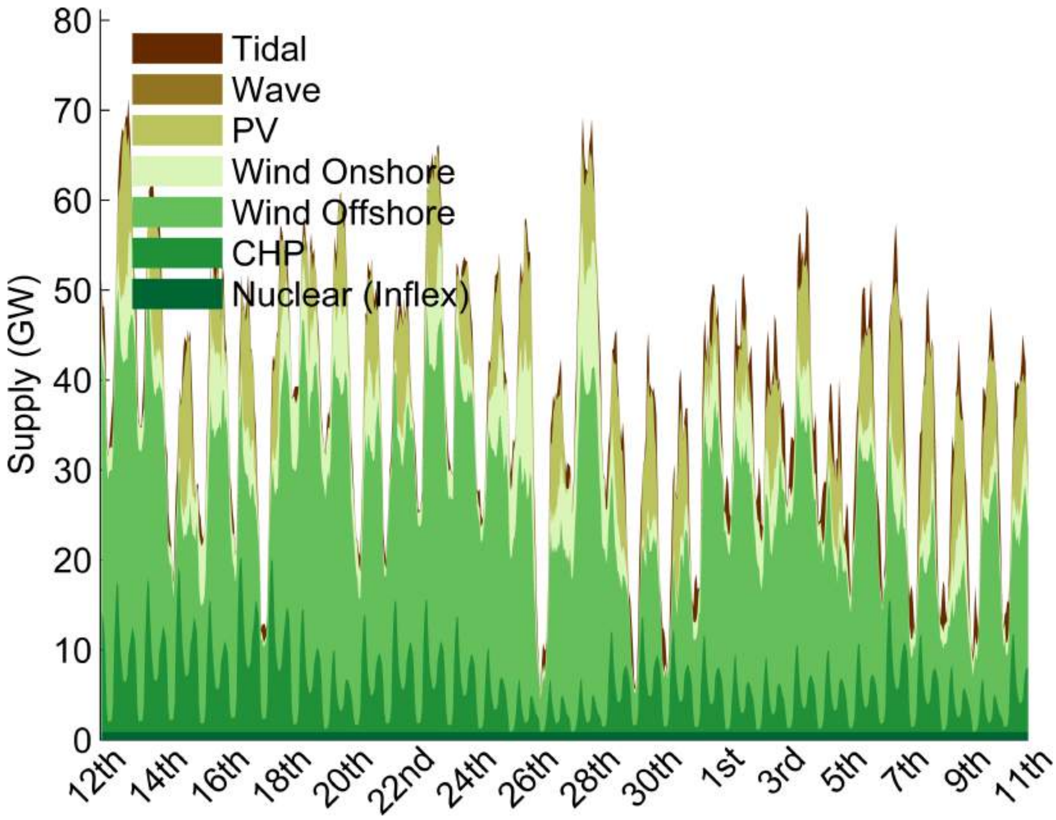
Figure 3.7: Non-dispatchable monthly supply through 2030 (mean across all years of data)

Seasonal variations

Figure 3.8(a & b) illustrate hourly generation for non-dispatchable generators for January (based on 2001) (Figure 3.8(a)), and a May - June period (Figure 3.8(b)). The summer period has been selected on the basis that the nighttime of May 26^{th}, into the early hours of May 27^{th} (2005 data), represents the minimum renewable generation output of all the 11 years modelled. This period is the most challenging for supply - demand balancing and therefore the most onerous domestic DSM is experienced during this period (explored further in Section 3.4.5). CHP has a biomass and gas fired combined capacity of $19.4GW$, which takes into account their availability, set at 90%. Within the winter period (Figure 3.8(a)) CHP generation regularly reaches it maximum output as heat demands are high, however in the summer this is not the case and inter-day CHP generation varies much more. In the late night period of May 26^{th} the combined output of all renewables drops to $\sim 5.5GW$, compared to a $\sim 13.2GW$ minimum in the January winter period. The other major contributor to this fall in renewable output is offshore wind, whose output during this summer low drops to $\sim 3.5GW$. The mean and variation in output in the summer and winter are comparable, but the summer minimum forces the total renewable generation to problematic lows.



(a) January (2001 data).



(b) May - June (2005 data).

Figure 3.8: Non-dispatchable *GP:2030* supply during particular periods of the year.

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Balancing mechanisms

Figure 3.9 illustrates how dispatchable CCGT power stations and the balancing mechanisms of domestic DSM, pumped storage, batteries and interconnectors (IC) and so on respond to net demand post renewable supply. The legend of Figure 3.9 follows the order of dispatch within SHED. As can be seen interconnectors and batteries (both centralised grid connected and decentralised low-voltage network connected), do not provide power back to the network to aide balancing in this particular instance (Figure 3.9 late May (2005 data)). This is due to dispatch order in which these balancing mechanisms have been modelled.

After renewable supply from both intermittent non-dispatchable and dispatchable renewable generators (hydro and geothermal) the first balancing mechanism to be initiated is domestic DSM, which in the first instance shifts demand to periods where excess renewable supply would otherwise become surplus supply. In *GP:2030:Pragmatic* this is only initiated if the CCGT generators would otherwise not be able to meet net demand, preventing uneconomical low load factors on CCGTs. Pumped storage, then centralised batteries and then interconnectors follow the first phase of domestic DSM, which are also only initiated if CCGTs would otherwise fail to meet net demand. Hence by the point that batteries would be called upon (in this instance - Figure 3.9 late May (2005 data)) the net demand has been reduced to a level that can be supplied by the CCGTs and as such batteries and interconnectors do not play a role.

This methodology, sequentially speaking (see Section 3.2), prioritises domestic DSM over other storage and balancing mechanisms (though which is actually relied on most over an annual period is not necessarily determined by this hierarchy). This approach was taken as large scale electricity storage, either in the form of batteries, compressed air or hydrogen-electrolysis processes, are not currently cost effective and is yet to be proven economically at scale (despite the expectations indicated in Section 3.3.2). Indeed the extra pumped storage of $2.9GWh$ with a capacity of $1.2GW$ is at the limit of current appropriate sites for pumped storage. By ensuring that the level of domestic DSM is manageable, even with households playing the greatest role they would ever have to play, it is possible to treat this *GP:2030* scenario as practically achievable without having to rely heavily on unproven large scale electricity storage, or interconnectors.

From Figure 3.9 it is possible to observe that the challenging period of late evening of May 26^{th} into the early morning of May 27^{th} both pumped storage and domestic DSM play a critical role in maintaining supply - demand balance. The contribution of domestic DSM to balancing peaks at $\sim 4.8GW$, and pumped storage $\sim 4GW$ during this period. Further to the net demand periods, Figure 3.9 also shows periods of excess or surplus supply when renewable supply exceeds demand. This excess power is utilised within the first instance of domestic DSM as power to supply the demand that is shifted away from net demand periods, and secondly to charge the store of energy within storage facilities such as pumped storage and batteries. In Section 3.4.6 further attention will be given to the surplus supply.

As can be seen, when a substantial amount of CHP capacity is envisaged - in order to help reduce heating demand on the electricity supply - the most challenging periods for supply-demand balancing actually occurs in the *summer*, when CHP generation is low, following seasonally reduced heating demands. Critics of renewable based systems often focus on the dangers of the lights going out because of winter anticyclones. In practice, as we have shown it is summer periods that provide the biggest difficulties, in *GP:2030*. Winter anti-cyclones are not unproblematic, nonetheless. System man-

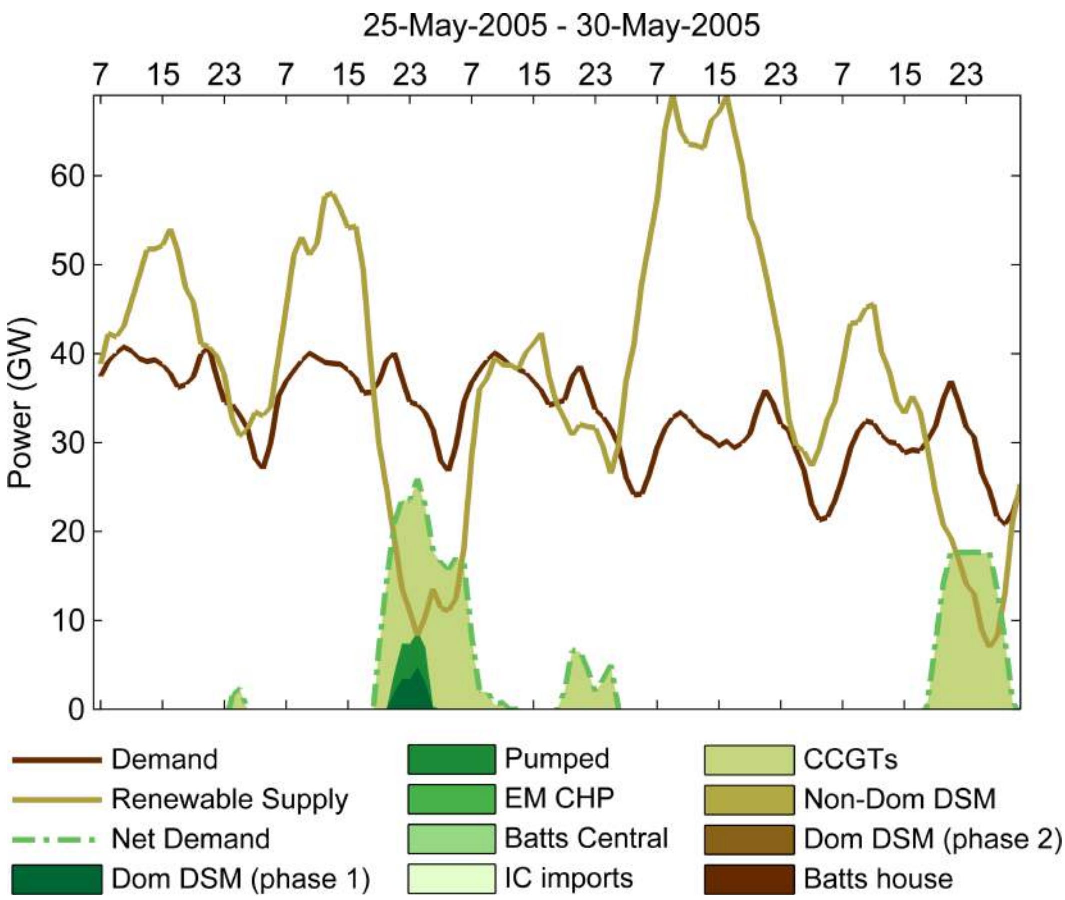


Figure 3.9: Non-dispatchable *GP:2030* net demand post renewables and the balancing mechanisms and CCGTs that fill that net demand during the summer minimum in renewable supply.

agement during those periods relies, within *GP:2030*, on the effective combination of all balancing mechanisms; DSM, storage and fossil fuel generators working in concert. As such, a solution in one area of the scenario creates problems, though not insurmountable, elsewhere.

3.4.4 Load Factors

In 2013, with power generation from CCGTs at its lowest level since 1996, load factors for CCGTs fell to a record low of 28%. In 2008 CCGT load factors were at an eight year high of of 71.0% per cent. The fall was due to an increase in power generation from coal fired power stations, whose load factors reached 58% in 2013. In *GP:2030* CCGTs without CCS are the only dispatchable centralised fossil fuel generators, with an average load factor of 23.6 %.

Climate driven sub-scenario

Turning to *GP:2030:ClimateDriven*, where the balancing mechanisms work to minimise deficits and CO_2 emissions, without consideration of maintaining reasonable load factors on the CCGTs. The load factor is found to fall by an order of magnitude to 2.1 %.

3.4.5 Balancing

Figure 3.10 shows the annual average contribution from all balancing mechanisms. The order of the balancing mechanisms from left to right in Figure 3.10 follows the order of the dispatch protocol within SHED. For comparison, offshore wind supplies on average $\sim 181.3TWh/yr$ and CCGTs $\sim 36.3TWh/yr$. Pumped storage is the largest contributor to balancing at $\sim 0.7TWh/yr$ with emergency CHP the second most vital balancing mechanism at $\sim 0.6TWh/yr$. Imports from interconnectors are also critical to balancing, supplying $\sim 0.1TWh/yr$. The contribution from domestic DSM and grid connected batteries is significantly lower at $\sim 0.1TWh/yr$ and $\sim 0.01TWh/yr$ respectively. Household batteries supply even less at $\sim 0.4GWh/yr$, thats giga-watts rather than the tera-watt units of the previous balancing mechanisms. Non-domestic DSM supplies a similar amount of balancing to household batteries at $\sim 0.4GWh/yr$.

So although the first phase of domestic DSM sequentially occurs prior to pumped storage and interconnector imports; the requirement for surplus renewable power within a 3 hour window of the net demand period prevents domestic DSM playing a greater role. It should be noted that although domestic DSM has been included in a second phase, occurring after CCGT dispatch, this second round of domestic DSM is not required within *GP:2030*. During periods when this second phase of domestic DSM would have been required CCGTs were running at maximum capacity, i.e. there was no spare renewable capacity either side of the peaks in question for net demand to be shifted to. In eventuality, all domestic DSM in *GP:2030* occurs as a result of shifting demand away from periods where CCGTs are unable to supply all of net demand to periods where there *is* excess renewable supply.

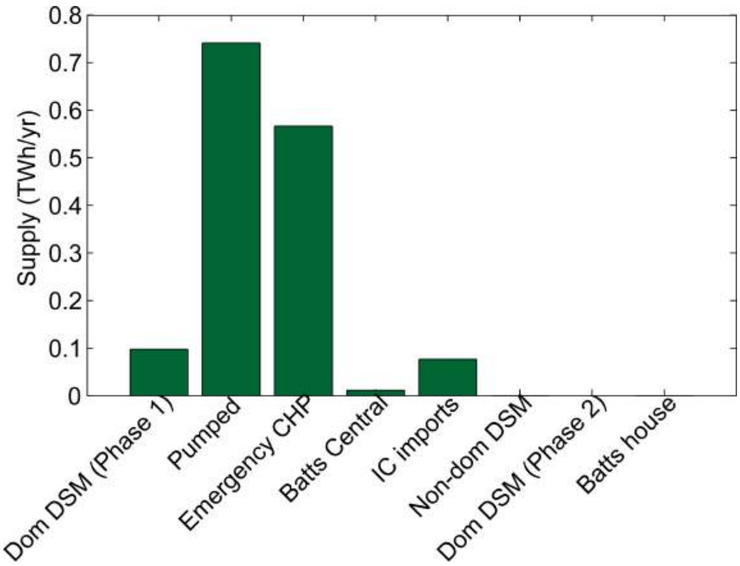


Figure 3.10: Annual average energy supply from balancing mechanisms

In order to assess the viability of these balancing mechanisms contributing to the annual contributions shown in Figure 3.10, historic data was obtained for pumped storage, interconnectors and non-domestic DSM. In 2014 pumped storage contributed $\sim 3TWh/yr$ back into the National Grid (Department of Energy and Climate Change, 2014), significantly more than the $\sim 0.7TWh/yr$ utilised within *GP:2030*. In the real world balancing mechanisms are used not only during periods when fossil fuel generators are unable to supply power due to capacity constraints, but also when it is economically viable and profitable, thus the large difference. As pumped storage is able to react efficiently and quickly to surges in demand, the facilities tend to supply peak power even if fossil fuel generators could, as it is cheaper. Also in 2014, interconnectors to the continent supplied $\sim 16.6TWh/yr$ into the UK, $\sim 10.3TWh$ from France and $\sim 6.3TWh$ from the Netherlands. This is again a much greater supply of energy than the $\sim 0.1TWh/yr$ found by SHED under *GP:2030*, for the same reasons as were highlighted for pumped storage.

Finally it is worth considering the current amount of energy shifted in time due to DSM within the non-domestic sector, where demand-side mechanisms do currently operate. As the development of non-domestic DSM services is a recent addition to balancing mechanisms the National Grid can call upon, data is difficult to obtain. The National Grid classifies different contracts with balancing services, depending on the response time from the service provider, into "Frequency Response", "Fast Reserve" and "Short Term Operating Reserve (STOR)". The National Grid states;

> STOR in particular has seen strong recent volume growth on the demand side. However significant volumes of those STOR Services are in fact delivered by back-up generators depressing demand, rather than "true" load reduction.

Focusing on STOR, where the strongest demand-side balancing growth has been witnessed, the total STOR capacity utilised over 2013 was $167.2GWh$ (The National Grid Company, 2014). The authors have been unable to obtain a breakdown of the fraction of this which is non-domestic DSM - however $\sim 4\%$ of the instantaneous capacity is non-domestic DSM. This is $\sim 4\%$ of the capacity of STOR that is available at any given time, akin to a power rating. Making the assumption that this $\sim 4\%$ translates from instantaneous capacity into annual supply, we can assume $\sim 6.7GWh$ was supplied in 2013, again significantly greater than the $\sim 0.4GWh/yr$ within *GP:2030*.

Domestic DSM

Although domestic DSM plays a significantly smaller role in balancing than pumped storage, emergency CHP or interconnectors the complexities of householders attitudes and responses to DSM means careful attention should be paid to its expected role. Whereas the other balancing mechanisms face technical and economic barriers to their implementation, domestic DSM faces social and psychological barriers. It has been shown by numerous studies (Darby, 2010; Lindley, 2010; Ofgem, 2010*b*; Hargreaves et al., 2010; The Commission for Energy Regulation, 2011) that households are likely to respond negatively to frequent requests for DSM above 10% of demand. Other technical and feasibility studies into the integration of high penetration of renewables, such as Poyry (2011), have assessed the technical and economic feasibility of balancing mechanisms. A unique aspect of SHED is its ability to assess domestic DSM down to the household level. For a detailed description of how SHED disaggregates national domestic DSM dynamics and requirements to the household level see Quiggin (2014), as the methodology is extensive and beyond the limitations of this report.

Figure 3.11 illustrates the average occurrence of domestic DSM at a national level in one year, across different levels of demand shifting. As can be seen the majority of these occurrences are below $0.2GW$, occurring on average 77 times per year, across the eleven years of data that SHED runs over. Figure 3.11 also demonstrates that the requirement for balancing from domestic DSM declines exponentially as the requirement increases. Hence the number of occurrences where the requirement is $\geq 3GW$ is on average only 6.8 instances per year.

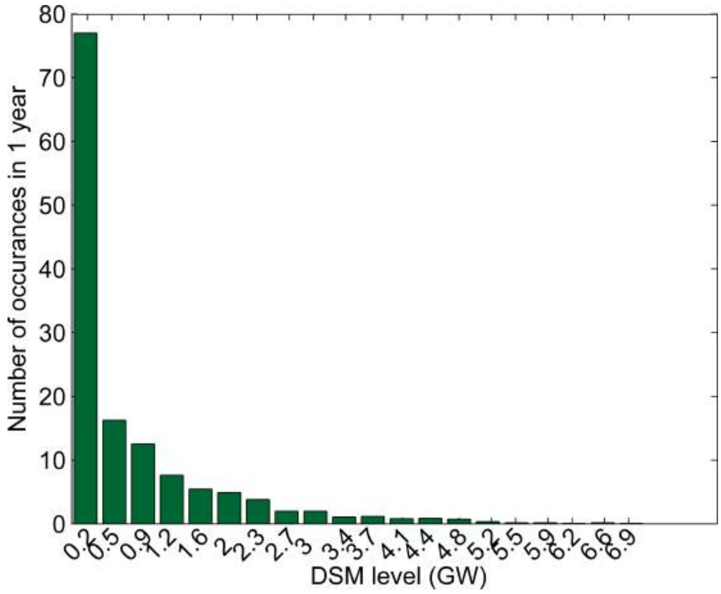


Figure 3.11: Number of required domestic DSM occurrences in one year across different levels of DSM

Figure 3.12 shows that the requirement of domestic DSM falls predominantly within summer months. As was discussed in Section 3.4.3, this is mainly as a result of lowered CHP power output, following heating demand, during summer months. Consequently, the following analysis will focus on summer months in interpreting the impact DSM will have on individual households.

Impacts on individual households

As previously indicated, the methodology used to disaggregate the national DSM dynamics to the household level can be found within Quiggin (2014). Broadly the methodology:

- Takes real hourly household heating and electricity consumption, and;
- Forms a pool of 1000 households from which an aggregate demand profile can be built, before;
- Passing a proportion of the *national* DSM requirement to this aggregate pool of households based on its hourly consumption, before;
- Assuming each individual household participates on an equal basis in shifting its demand to fulfill the aggregate requirement.

Households are protected from reducing demand below 100 watts and are not required to reduced their demand by more than 80%. In essence this means those households that are consuming more power within a given period will be required to shift more of their electrical demand.

When considering the impacts of the *required* DSM, the differential response across household socio-economic groups is important, particularly as studies have shown households respond in different ways to smart meters (Hargreaves et al., 2010). Identifying households within in the aggregate pool that are typical of particular socio-economic

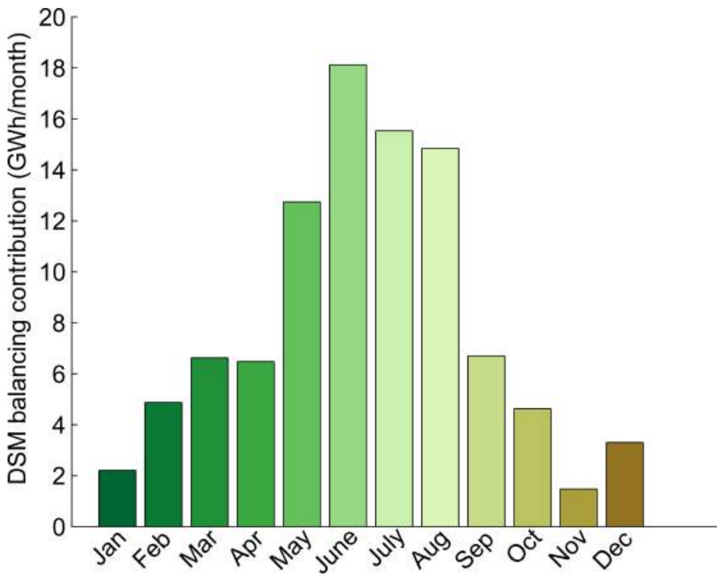


Figure 3.12: Domestic DSM contribution towards balancing per month in GWh

groups aids in defining how different households will be required to participate in DSM. Work by Druckman and Jackson (2008) has been used to define the characteristics of these "typical" households. Druckman and Jackson (2008) identified "typical" households by utilising UK National Output Area Classifications (OAC) to segment households into seven "supergroups"[6] which exhibit different socio-demographic characteristics (Office for National Statistics, 2005; Vickers and Rees, 2007). Within SHED the selected supergroups are; *Constrained by Circumstance*, *Typical Traits* and *Prospering Suburbs*. Further information on the specifics of each supergroup can be found in Vickers et al. (2005).

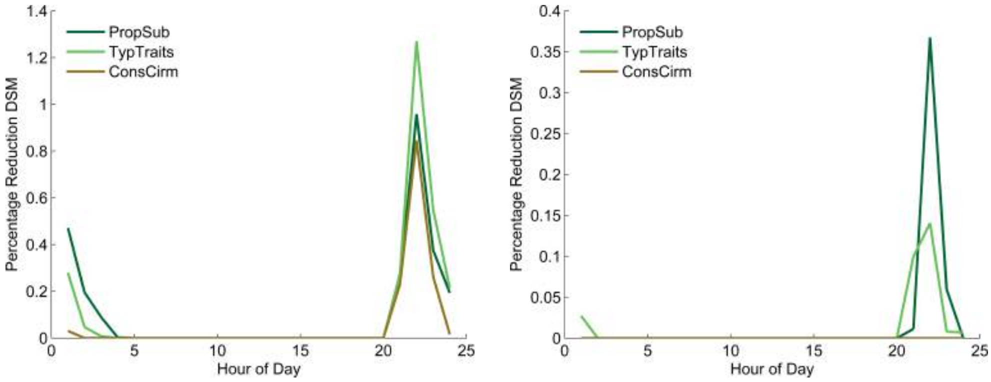
The *Prospering Suburb* household is a detached mortgaged property consuming on average $18,500kWh/yr$ of gas and $5,000kWh/yr$ of electricity, both of which are above the national average. The property is 30-75 years old with two adults aged between 46-55 with no children and one adult at home during the day. The 'lead participant' is employed earning more than £75,000 per year.

The *Constrained by Circumstance* household is a local authority rented flat consuming on average $7,100kWh/yr$ of gas and $1,200kWh/yr$ electricity, both of which are below the national average. The house is 10-30 years old with two bedrooms. The lone occupant is retired within an income of less than £15,000 and is at home during the day.

Finally the *Typical Traits* household is a terrace privately rented property consuming on average $15,400kWh/yr$ of gas, and $4,900kWh/yr$ of electricity, both of which are roughly equivalent to the national average. The house is 5-10 years old with three bedrooms. There are two adults and one child living at the property, none of whom are at home during the day. The lead participant is 36-45 of age, employed earning £$30-50,000$ per year.

Figure 3.13 illustrates the average DSM percentage demand reduction, each hour of the day, during July/August weekdays for traditional electricity and heat pump DSM.

[6]The Supergroups were designed for the Office for National Statistics (ONS)



(a) Traditional Electricity. (b) Heat Pump.

Figure 3.13: Typical households average percentage reduction in demand due to DSM during Jul/Aug weekdays

		Trad			HP	
	ProsSub	TypTrait	ConCirm	ProsSub	TypTrait	ConCirm
% DSM	22	23	16.2	3.9	4.1	0
% DSM$\leq$10	17.2	16.4	10.9	3.1	3.3	0
% DSM$>$10	4.7	6.6	5.3	0.8	0.8	0

Table 3.3: Probability of DSM participation requirement during the evening peak (9pm - 11pm) demand periods, and of those DSM periods which are greater or less than 10% of demand for each typical household, in Jul/Aug weekdays.

Table 3.3 shows that the majority of DSM reduction periods for *traditional electricity* demand are below 10% of demand for all three typical households. Figures 3.13 (a & b) shows the mean reduction is between 0.9 – 1.3% for the three typical households. To put this in context; the *Prospering Suburbs* and *Typical Traits* households consume on average $\sim$600 watts of power during these DSM periods. A 10% DSM demand reduction would therefore equate to 60 watts of power, this is equivalent to a higher power consumption laptop. Given that consecutive periods of DSM $\geq$ 10% of demand can last up to 1.4 hours in *GP:2030* scenario this would mean unplugging a laptop up to that maximum time period, which households may be unwilling to do. Alternatively a household could turn off a typical $A{+}{+}$ rated fridge freezer for 30 minutes with no impact on the items inside the fridge or freezer EA Technology (2011) and save $\sim$30 watts of the total 60 watts required. This can be achieved with simple smart appliance control, with no engagement from the household required.

It should be noted that within Table 3.3 the *Constrained by Circumstance* household is not required to participate in heating DSM as its heating demand is very low during these periods, and is hence protected from participation due to the rules of the DSM algorithm.

The maximum period of time a household would be required to participate in DSM where that DSM reduction is $\geq$ 10% of demand is shown in Figure 3.14, where the DSM reduction peaks at $\sim$35.7% for the *Typical Traits* household and lasts for 5 hours.

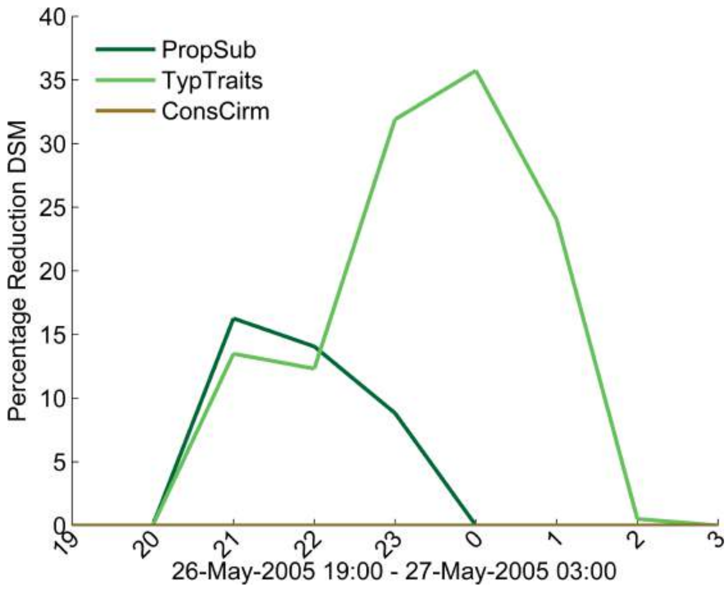


Figure 3.14: Most Challenging DSM period

It should be noted that the period of DSM represented in Figure 3.14 occurs only once in the 11 years that SHED runs over. Indeed out of the 96408 hours of the 11 years of SHED, there are only 132 instances of traditional electricity DSM demand reduction exceeding 10% for the *Prospering Suburbs* household, 152 for the *Typical Traits* household and 108 for the *Constrained by Circumstance* household. As was found at the national level, as the DSM demand reduction requirement increases the number of occurrences falls off exponentially. As such the number of instances exceeding 30% (as is the case in Figure 3.14) is only 12, 17 and 6 for the *Prospering Suburbs*, *Typical Traits* and *Constrained by Circumstance* households, respectively. Of the 17 instances of $\geq$30% DSM demand reduction for the *Typical Traits* household, 2 of those hours are shown in Figure 3.14 and the rest occur where the duration of the DSM requirement is either a singular hour or two hours, but not the consecutive 5 hours duration as in Figure 3.14. It is this duration and magnitude in combination that makes this late May period the most challenging.

It should also be noted that although Figure 3.14 peaks at $\sim$35.7%, this could be achieved by simply delaying, for example, the washing or tumble dryer cycle. This can be achieved automatically, using smart control interfaces between the washing machine and the household's smart meter. This would not require the household to be consciously aware of any interruption of their daily patterns of behaviour.

However, on careful inspection of the energy being consumed by the two households during this period it was found that the mean energy demands were $\sim 450Wh$ and $\sim 290Wh$ for the *Prospering Suburbs* and *Typical Traits* households, respectively. This level of demand is suggestive of minimal activity within the household at this time, with perhaps some lighting on and devices charging. Consequently, turning off a washing machine or tumble dryer would not be an option: in this extreme case the household would be required to turn off all non essential appliances.

Although this sounds extremely onerous, requiring households to turn off lighting and non-essential loads, this occurrence is, as previously mentioned, very rare occurring only once in 11 years. Further to this it should be noted that the dispatch protocol within *GP:2030* has been designed with the intention of exploring the most onerous DSM requirement on households. By placing domestic DSM at the top of the dispatch protocol households are therefore required to participate much more than if they were placed at the bottom. These results can be thought of therefore as the *worst case scenario* for domestic DSM. If other balancing mechanisms within Figure 3.10 were to increase their role in balancing then the role households play would be lessened.

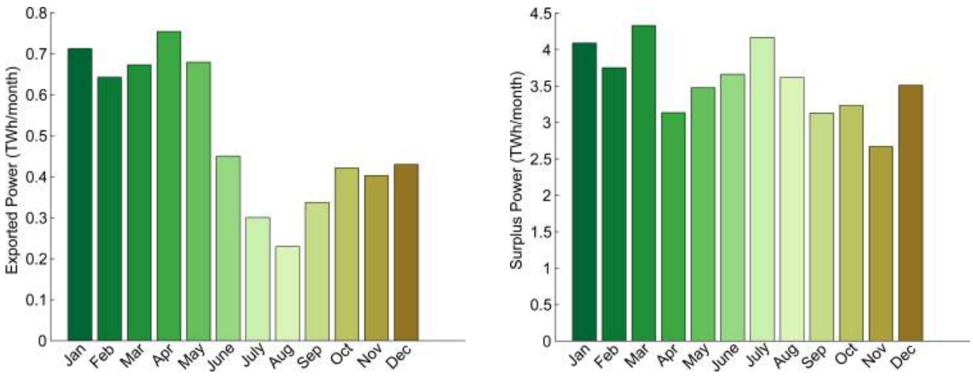
Key Information 3.11 As was highlighted in Section 3.4.5 the balancing mechanisms of pumped storage, non-domestic DSM and interconnectors supply within *GP:2030*, on an annual basis, far less than currently. For instance in 2014 interconnectors to the continent supplied $\sim 16.6TWh/yr$ into the UK, $\sim 10.3TWh$ from France and $\sim 6.3TWh$ from the Netherlands. Much greater than the $\sim 0.1TWh/yr$ found by SHED under *GP:2030*. This is due to the following reasons;

1. Domestic DSM is placed higher up the dispatch protocol in order to asses the worse case scenario that households will be confronted with, in doing so domestic DSM takes a greater burden of balancing responsibility.
2. Currently all balancing mechanisms respond to market price signals, under SHED it is the net demand each mechanism responds to.
3. The dispatch protocol was designed to minimise CO2 emissions.

The authors have assessed that domestic DSM quantified within *GP:2030* are within achievable levels, however these other balancing mechanisms could remove some of the balancing responsibility from domestic DSM.

3.4.6 Surplus power

Figure 3.15(a) illustrates the average energy exported via the interconnectors over the eleven years of SHED. The monthly exported power drops to a summer low in August, again due to the reduction in CHP output following lower heating demands in the summer. Once power has been exported up to the capacity limit of the interconnectors the remaining power is surplus to requirements within the electricity system. Figure 3.15(b) illustrates this surplus energy per month. Within *GP:2030* this surplus energy is assumed to be available for hydrogen production for transport. There are other uses for this surplus power, other than hydrogen production, such as the production of methane. It is beyond the scope of SHED and this report to detail the conversion type and use thereafter of this surplus power. However due to the greater conversion efficiencies, both straight to the gas type and back to electricity, it is assumed hydrogen production would be preferred to methane. Following through with the assumption that electrical surpluses are used for hydrogen production and that hydrogen is used for hydrogen vehicles, a current typical car-driver uses $\sim 40kWh$ of energy per day (Mackay, 2009). If we now assume pessimistic conversion efficiencies in order to give conservative estimates, the wheel-to-wheel efficiency of hydrogen is set at 24% (Bossel, 2006), and the efficiency of electricity to hydrogen at 60%. Then taking the average monthly production of surplus energy from Figure 3.15 as $3.5TWh$, this equates to supplying $\sim 438,000$ hydrogen cars with a continuous daily supply. This would be expensive to achieve due to the high costs of electrolysis, hence these numbers should be treated as possibilities rather than specifications.



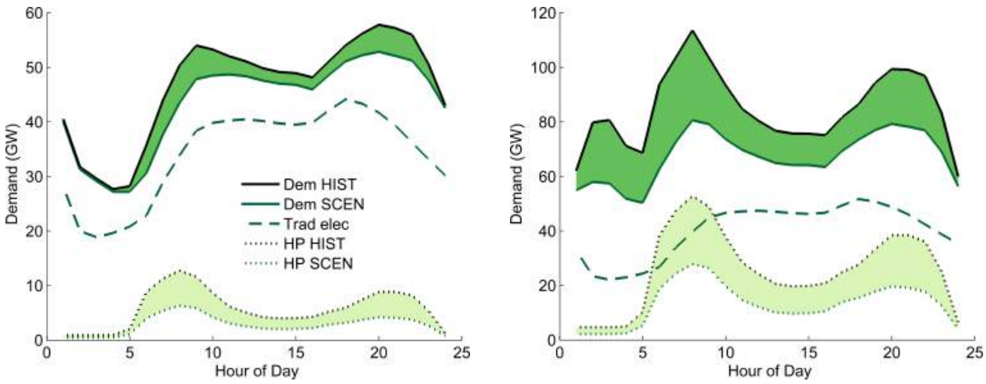
(a) Exported Power.

(b) Surplus electrical power for hydrogen production.

Figure 3.15: Monthly power exported and surplus power.

3.4.7 Importance of heating targets

A failure to meet heating reduction targets will have significant impacts on electricity demand. Figure 3.16(a & b) illustrates changes in the demand profile during January/February weekdays due to heating demands remaining at *historic levels*, for both *GP:2030* and *DECC:2050:Renew*. Heat pump electrical demand becomes more pronounced, with morning and evening peaks now more dominant. This is exemplified within *DECC:2050:Renew* due to high heat pump electrification, ambitious reduction targets and 10% of heat being delivered by resistive heating. A failure to meet heating targets results in morning peak electrical demand dominated by heat pumps rather than traditional electricity demand, which further emphasises the double diurnal demand peaks.



(a) Greenpeace.

(b) DECC Renewable.

Figure 3.16: Increase in electricity demand due to a failure to meet heating targets for January/February weekdays through 2030, based on 2001:2011 data. Note difference in scale for Y axis between graphs.

Key Information 3.12 In *GP:2030* there are no deficit periods, meaning that reliability of supply is consistently maintained and blackouts and brown outs are totally avoided. If heating targets are not met then over the course of eleven years there would be 47 hours of deficits totaling 141.9 GWh. Further to this domestic DSM would increase to onerous levels for households, further illustrating the importance of meeting heating reduction targets. ■

4. Economics

4.1 Costs of similar scenarios

It is beyond the scope of this analysis and report to investigate detailed costing of the *GP:2030* scenario. Consideration has, however, been given to the cost implications by drawing on published work by the CCC. In The Renewable Energy Review (CCC, 2011) the CCC draws on analysis by Poyry (2011) regarding the cost implications for an electricity network with a high penetration of renewable generators and electrification of heating and transport. A comparison of the *GP:2030* scenario and that of Poyry's "very high 2030" scenario is given in Table 4.1, in which comparable generation capacities of renewable generators between *GP:2030* and *Poyry:2030* are evident.

Poyry's analysis shows that up to a 65% (2030) and 80% (2050) share of generation from renewables results in additional intermittency costs to consumers of 1 pence per kWh. The *GP:2030* scenario projects $\sim$76% penetration of renewables, whilst the *Poyry:2030* scenario contains $\sim$68%. As the CCC acknowledges, there is considerable uncertainty over the future costs and investment required to manifest any scenario, mainly due to the uncertainty of future costs of any particular technology (Committee on Climate Change, 2011). The CCC expect that with a 65% renewables share, the average electricity generation cost in 2030 would be $\sim 8.2-13.8p/kWh$, requiring $\sim 126-227bn$ of investment.

4.2 Scenario divergences

There are clearly differences between the *Poyry:2030* "very high" renewable scenario and *GP:2030*. Table 4.1 shows total electricity demand within the Poyry scenario is $409TWh/yr$, compared to *GP:2030* of $327TWh/yr$. As was discussed in Chapter 3 electricity demand is necessarily low to enable robust balancing of supply - demand when domestic heating is electrified, which drives peak electrical demand due to diurnal heating peaks.

Levels of renewable generation are comparable between the two scenarios (Table 4.1); an additional $8GW$ of offshore wind is projected under *GP:2030* whilst onshore wind and solar PV remain at comparable levels. "Marine" generation is set at $8GW$ in *Poyry:2030* which is comparable to the $8.5GW$ of tidal and wave combined in *GP:2030*.

The capacity of balancing mechanisms is very similar between the two scenarios (pumped storage is precisely the same), whilst the Poyry scenario projects an additional 5GW of interconnectors and *GP:2030* an additional 3GW of centralised battery storage. There is a significant divergence in the two scenarios when it comes to nuclear, CHP, coal and CCGT's. The Poyry scenario projects 35GW of CCGT's; *GP:2030* only 19.5GW. The *GP:2030* scenario also projects no new build of nuclear (remaining at 1.2GW as Sizewell B remains open) whilst *Poyry:2030* projects 11GW of nuclear capacity. Further to this *Poyry:2030* projects 4GW of unabated coal power stations to be open in 2030, whilst *GP:2030* predicts none. These three scenario divergences result in *Poyry:2030* projecting an additional 29.3GW of centralised generation in the form of nuclear, unabated coal and CCGT's compared to *GP:2030*. This is however roughly balanced against *GP:2030* projecting an additional 21.5GW of CHP (gas and biomass).

	GP:2030	Poyry:2030 (Very High)
Total Electrical Demand (TWh/yr)	327	409
Non-dispatchables (Phase 1)		
Nuclear	1.2	11
CHP Biomass	4	Not stated
CHP Gas	17.5	Not stated
Wind Offshore	55	47
Wind Onshore	22	21
Solar PV	28	25
Marine		8
Tidal	8	-
Wave	0.5	-
Non-fossil dispatchable (Phase 2)		
Geothermal	2	Not stated
Hydro	2	Not stated
Balancing Mechanisms (1) (Phase 3)		
General Extra Storage	-	1.2 (2.9 GWh)
Additional Pumped Storage	1.2 (2.9 GWh)	1.2 (2.9 GWh)
Centralised Battery Storage (GWh)	3	Not stated
Interconnectors	10	15
Dispatchables (Phase 4)		
CCGT no CCS	19.5	35
CCGT with CCS	0	0
Coal no CCS	0	0
Coal with CCS	0	4

Table 4.1: Comparison of *GP:2030* to *Poyry:2030*. Source : (Poyry, 2011)

In summary, while the costs of *GP:2030* are not modelled within SHED, by comparison with a fully costed scenario of similar dimensions we are able to estimate the order of magnitude of costs, and impacts on average electricity generation cost. Two things should be borne in mind, nevertheless: first, accurately predicting future average prices for any given scenario is fraught with difficulty. Second, revolutionising the UK's energy infrastructure is, naturally, a highly expensive enterprise. Nevertheless, costs must be borne, whether or not our existing infrastructure is replicated (if climate change science were ignored) - the question is to what extent the right investments now will avoid spiralling future costs as a result of ecological damage and resource scarcities.

5. Discussion

In any model of the real world, especially one such as SHED which looks into the future, assumptions must be made. The implications of some of the assumptions made within SHED and the decisions made within *GP:2030* are discussed here, alongside some of the relevant important outputs of *GP:2030*.

5.1 Electrification of heating

5.1.1 The role of traditional electricity demand reduction

Many published energy scenarios foresee a rise in traditional electricity consumption in the coming decades. Within *GP:2030* a change of -21.1 % is projected as the electrification of 25 % of heating, as well as 32 TWh/yr from EVs, requires demand reductions within traditional electricity consumption as well as reductions in heat demand. In the absence of such reductions, supply-demand balancing would fail to achieve reliability of supply.

5.1.2 Post 2030

If further decarbonisation of the UK energy system is to be achieved post 2030, which is necessary from a climate change perspective, this is likely to take the form of increased electrification of heating. In order to maintain reliability of supply with increased electrification there are a number of options:

1. Increase the capacity of fossil fuel generators, which will lead to a rise in emissions.
2. Increase the capacity of renewables in conjunction with increased storage and DSM.
3. A greater emphasis on heating demand reductions, via increased heating efficiency and behaviour change. This too will be challenging, but ultimately confronts the problem at its root cause: the demand for heating in our poorly insulated housing stock.

The authors favour a further reduction in heating demand as the preferable solution to the incorporation of more electrified heating into the electricity network, in order to maintain reliability of supply.

5.1.3 Importance of meeting space heating targets

As was discussed in Section 3.4.7, if *GP:2030* heating demand reduction targets are not met then peak demands increase resulting in 47 hours of deficits across the 11 years of the model, with domestic DSM becoming more onerous. This would likely result in a negative feedback loop where households, too regularly required to participate in DSM in order to prevent blackouts, begin to respond negatively to price signals (to the extent that clusters of households stop participating), further compounding the 47 hours of deficits. For these reasons it is imperative that any 2030 scenario, such as *GP:2030*, ensures that heating demand reduction is prioritised in equal measure to renewables integration.

5.2 Domestic DSM

Domestic DSM within *GP:2030* was intentionally placed early on in the dispatch protocol. This choice was made for a number of reasons, principally due to a need to investigate the most conceivably onerous requirement on households; and to manage that accordingly. The outputs show that summer months (due to the reliance on CHP units following heating loads) are the most challenging, but have been kept within manageable levels. By this we mean that households are *not* expected to participate above the 10% of demand level too often. The level at which households are likely to respond negatively (Darby, 2010; Lindley, 2010; Ofgem, 2010*b*; Hargreaves et al., 2010; The Commission for Energy Regulation, 2011). It is the *Prospering Suburbs* household which experiences the most onerous DSM, being required to participate at ≥10% on 4.7 % of July/August weekdays, with a further 17.2 % of those days requiring ≤10% of demand to be shifted in time. Considering the studies cited in this regard this degree of demand shifting is not considered unreasonable.

As a consequence of domestic DSM being initiated immediately after non-dispatchable renewables within the dispatch protocol, the results represent the worst case scenario for households. This requirement from households could be reduced with non-domestic DSM, as well as storage, playing a larger role.

The most vulnerable household is the *Constrained by Circumstance* household, where the lone occupant's income is £15,000, is at home during the day, retired, and living in a a local authority rented property. The age of the occupier, and the occupation of the property during the daytime, makes this household vulnerable to lulls in internal temperature, and the income and tenure indicates this household is less likely to be able to implement interventions to help automate or shift demand, in response to DSM requirements. This household is required to participate less often in DSM and their heating isn't impacted at all during the challenging summer months.

Looking further at the OAC supergroup classifications (Vickers et al., 2005) it is possible to identify areas of the UK that these typical households represent. The *Prospering Suburbs* household could be found across England with concentrations in the North-West, the Midlands and around London. The *Constrained by Circumstance* household is associated with city areas, and the *Typical Traits* household can be found across the whole of the UK. For further details on the distributions of these household classifications across the UK see Quiggin (2014).

Despite *GP:2030*'s success in maintaining a reasonable level of *quantified* reliance domestic DSM for system balancing, it should be remembered that the deployment of this technology is not comparable to building wind turbines or installing solar panels - it only works if deemed socially acceptable by households and citizens. Given this, questions of fairness as to *whom* is required to shift *what* and *when* are highly relevant. It is beyond the scope of this report to comment more here, except to say that this can be seen not only as a problem for technological implementation - but perhaps instead as an opportunity for addressing distributive questions within the context of energy access.

5.3 Decentralisation

GP:2030 is a highly decentralised energy scenario; not only do renewables represent $\sim$ 76% of generation capacity but 4 GW of biomass and 17.5 GW of gas fired district CHP units are projected to be installed by 2030. In 2011 the installed capacity of "Good Quality CHP" was 6.1GW (Ricardo-AEA, 2013), however other scenarios also project high levels of CHP, such as 52.5GW under *Transition Pathways Thousand Flowers* (Barton et al., 2013).

Decentralisation in turn provides new questions, and opportunities, regarding the future operation and ownership of an electricity system, which will need to be incorporated into any policies designed to realise it.

5.3.1 Summer CHP & emergency CHP

With high levels of installed CHP it is important to note that as SHED models CHP following heating demands, this results in the summer net demand periods that domestic DSM is then forced to close. As previously mentioned it is costly to run CHP units without the heat they generate being utilised. Hence emergency CHP follows domestic DSM and pumped storage in the dispatch protocol, see Section 3.2.

5.4 Batteries

Both centralised and decentralised battery storage have been modelled as playing a role in balancing within *GP:2030*. Although the economics of large scale battery storage is expected to improve in the short term, it remains a relatively expensive option; and has been placed low down in the dispatch protocol. Hence although 3 GWh of centralised battery storage is forecast by *GP:2030*, only $\sim$0.01 TWh/yr is supplied back into the grid for balancing purposes. As the economics of batteries improve greater proportions of the role domestic DSM currently plays in *GP:2030* in balancing can be moved onto battery capacity. While battery costs remain high it would be unwise to rely too heavily on expensive batteries in modelling exercises.

5.5 Interconnectors

5.5.1 SHED shortcoming

It should be highlighted that SHED does not model the availability of power from the non UK end of the 10 GW of interconnectors projected under *GP:2030*. This is a modelling limitation, which is difficult to overcome as the whole European electricity system would need to be considered and modelled to quantify the availability of power at the non UK end of each interconnector. To the authors' knowledge there is currently no European wide electricity system model that achieves this. It should however be noted that *GP:2030* places interconnectors low down in the dispatch protocol and hence only $\sim$0.1 TWh/yr is imported through those interconnectors, compared to $\sim$0.7 TWh/yr from pumped storage. In 2014, interconnectors to the continent supplied $\sim$ 16.6TWh/yr

into the UK, $\sim 10.3TWh$ from France and $\sim 6.3TWh$ from the Netherlands. This is a much greater supply of energy than found by SHED under *GP:2030*, this is due to interconnectors under SHED supplying periods of net demand post other balancing mechanisms rather than those periods that are economically profitable to do so, as is the case within the current electricity market.

5.5.2 Exports & surpluses

Whilst imported energy via interconnectors averages ~0.1 TWh/yr, exported power averages ~12.2 TWh/yr. Hence the UK becomes a net, large, exporter of power. It should be noted that this exported power is only exported once all UK demands are met and storage facilities are at capacity. Even once the maximum amount of power (determined by the interconnector capacity) has been exported the UK is able to utilise the rest of the monthly surplus for hydrogen production for transport, totaling on average ~42.8 TWh/yr. As was discussion in Section 3.4.6 this equates to supplying $\sim 438,000$ hydrogen cars with a continuous daily supply. Detailed considerations of surplus power utilisation are beyond the scope of this report, hence this hydrogen production and use should be treated as a guide to the possibilities, rather than a specification.

5.6 Pragmatic & climate driven sub-scenarios

Two sub-scenarios have been modelled, *GP:2030:Pragmatic* and *GP:2030:ClimateDriven*, both of which have the same demand and supply inputs. Under *GP:2030:Pragmatic* all balancing mechanisms work in collaboration with CCGTs to maintain an economically favourable average load factor on CCGT generators of 23.6 %. Under *GP:2030:ClimateDriven* the balancing mechanisms work to reduce net demand *as much as possible* prior to CCGTs to maximise CO_2 reductions, hence the load factors drop to 2.1 %. Although *GP:2030:ClimateDriven* reduces emissions further, the low load factors would be unlikely (without additional subsidy) to result in investment in new CCGTs. However, a substantial portion (PROBABLY NEED A NUMBER OFF DOUG HERE) of the projected 19.5GW gas CCGT capacity in *GP:2030* has already been built. Additionally, the advent of the Government's Capacity Market, though less than perfect, means that fixed costs associated with new CCGTs can be met by capacity payments, as well as commercial returns via the energy market. Still, the authors consider *GP:2030:ClimateDriven* predominantly as a useful guide until the scale of reduction in average load factors has been taken into account within future plans for the Capacity Market, or other subsidy and public finance mechanisms.

5.7 Dispatch Protocol

Currently generators bid into the energy market on various time scales based on supply-demand forecasts, the price of fuel and many other factors. The dispatch protocol modelled here assumes the overriding objective governing generator dispatch is the minimisation of CO_2 emissions, particularly within *GP:2030:ClimateDriven*. In either case, this would require the energy market to be reformed and preference given to those generators with the lowest associated CO_2 emissions (as is done with solar in Germany), which are generally non-dispatchable. This therefore assumes that by 2030 the UK government will reform the energy market in order to achieve such an outcome, which in turn produces the issues identified above regarding load factors on CCGT gas turbines.

5.8 Limitations of hourly time-steps

Despite SHED utilising a large and relatively high-resolution data set in order to model energy scenario outcomes it is, like any model, imperfect. One significant area for improvement will be the reduction of hourly time-steps to smaller periods enabling variations within the hour steps to be identified and modelled. Ensuring (currently hidden) demand variations within the hour steps are met with sufficient demand will require some additional reserve margin, unless met by additional storage or demand side management, and this will have some added economic and carbon costs.

5.9 A final note

Due to electricity being a high grade form of energy enabling the use of new delivery technologies, together with the principles and interpretation of mainstream economics, policy makers and politicians have been guided towards utilising and planning for an electric future. The interpretation of decoupling principles suggest that by substitution for other energy forms, electricity could bring about both lowered emissions and increased energy security. This substitution may not be straightforward, with challenges in supply-demand balancing likely to become an increasing problem in the short term. This is important to remember when published energy scenarios visioning the energy systems of the future forecast the aforementioned electrification and decarbonisation of the energy system.

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6. Conclusions

The stated aims of *GP:2030* were:

1. **Decarbonisation** within the CCC targeted 50 - 100$g_{eq}CO_2/kWh$ emission intensity factor, whilst;
2. achieving this figure in the **absence of carbon capture and storage** technology deployment, or the building of **new nuclear power stations**;
3. being **technically feasible**;
4. **electrifying** a substantial proportion of transport and heating to deliver emissions reductions in those sectors;
5. **balancing supply and demand** - ensuring the same, or an improved, guarantee of security of supply as is currently enjoyed in the UK;
6. ensuring the worst-case scenario impact of **demand-side management** on household consumption of energy is, nevertheless, likely technically and socially plausible, and;
7. being **economically feasible**

Each of these aims has been achieved, as demonstrated in Section 3.4 and Chapter 4.

6.1 Decarbonisation

In *GP:2030*, we modelled two sub-scenarios. The first, *GP:2030:Pragmatic*, only sought to reduce net demand after renewable supply, via balancing mechanisms, to the level of the maximum capacity of fossil fuel dispatchable generators (see Section 3.2). These were then called on to meet as much of net demand as possible at this point. As explained, this sequence was designed to balance the economics of power station operation with the imperative to reduce the grid's carbon intensity. *GP:2030:Pragmatic* achieves a carbon intensity of **77.9** $g_{eq}CO_2/kWh$, falling from the 1990 level of 770$g_{eq}CO_2/kWh$ and from a contemporary level of around 500$g_{eq}CO_2/kWh$.

The second sub-scenario, named 'climate driven', differed *only* insofar as balancing mechanisms were not prevented from reducing net demand after renewable supply below the maximum capacity of fossil fuel dispatchable generators (i.e. they were allowed to reduce net demand at this point by as much as possible, see Section 3.2). This arrangement prioritised maximum decarbonisation over economic considerations of power station operation. *GP:2030:ClimateDriven* achieves a carbon intensity of **51.2** $g_{eq}CO_2/kWh$.

As stated in Section 3.3.3, non-Life Cycle Analysis values are used to calculate the carbon intensity values stated above. It is worth noting for completeness that, using LCA values, the carbon intensity of *GP:2030:Pragmatic* rises to **89.9** $g_{eq}CO_2/kWh$, while that of *GP:2030:ClimateDriven* rises to **63.4** $g_{eq}CO_2/kWh$. Both still remain within the target range of 50-100$g_{eq}CO_2/kWh$.

6.2 CCS, nuclear and technical feasibility

As is evident from Table 3.1, no *new* nuclear, or CCS fitted, generation is included in *GP:2030*, for reasons relating to maturity, performance, risk and cost outlined in more detail in Chapter 2. Otherwise, efforts have been made to restrain the technical requirements of *GP:2030* with a focus on mature technologies, or those operating in some form already prior to being scaled: *GP:2030* does not rely on the expectation of major technological innovation, or invention, to be successful. It does however expect the costs of certain existing technologies, such as batteries, to fall in order to help enable the transformation it envisages - though such technologies have been de-prioritised versus those where no such expectation is required, e.g. pumped storage. The success of *GP:2030* from a supply-demand balancing perspective helps vindicate the logic for omitting costly or problematic technologies, such as CCS and nuclear, in the initial stages.

6.3 Electrification

Ambitious but achievable decisions were made about the required electrification of heat and transport - a vital component of the UK's broader decarbonisation.

As discussed in Section 3.3.1, 25 of space heating is expected to be electrified, via heat pumps, by 2030. This then equates, in SHED, to moving 25 % of domestic space heating demand onto the electricity system. Given the size of the UK's annual domestic heating demand, this is a very substantial shift.

Electric vehicles are expected to create an additional annual demand of 32 TWh/yr.

Combined, these expectations mean *GP:2030* achieves a significant level of electrification of demand currently supplied through direct combustion of fossil fuels. The crucial role of the power sector in the UK's overall decarbonisation program depends on being able to move demand onto the electricity network in this fashion.

6.4 Balancing supply & demand

Decarbonisation of the UK's economy via electrification of heating and transport demands is only available if the newly decarbonised power sector can absorb additional demand while maintaining security of supply in a context of increased intermittency. In *(*GP:2030) $\sim$ 76% of installed generation capacity is composed of non-dispatchable renewable generators.

As is outlined in Chapter 2, it is to the question of balancing supply and demand in this new world of energy supply and consumption that this report turned its full attention.

As stated in Section 3.4 *GP:2030* experiences no black or brownouts for the 11 years of data, thus achieving a 'loss of load probability' of 0. Given the imperfection of modelling such complex future outcomes, the authors of this report do not wish to claim that *GP:2030* would be unable to experience brown or blackouts if built. For example, we assume that the modelled domestic DSM requirements are in fact realised. However it is clear that *despite* the electrification of heating and transport within the scenario, and the hugely increased deployment of non-dispatchable renewable supply, *GP:2030* achieves a supply that is *at least* as secure as is presently mandated. The Secretary of State currently requires a LOLP of 9%, i.e. 9 instances of deficit over 100 years.

The majority of balancing is enabled by storage technologies, such as pumped storage and batteries at both grid and household level. Storage of electricity is therefore critical to maintaining a balanced system; however *GP:2030* assumes storage levels that are within reasonable expectations and does not rely on technologies not already in operation.

6.4.1 The importance of heating demand reduction targets

It is one of the principle concerns of this report to reiterate the enormous importance of meeting heating demand reduction targets in order to maintain supply-demand balancing in a highly-renewable and electrified energy scenario. *GP:2030* requires a -57.2 % change in annual space heating demand by 2030. This is more ambitious than the average of 47.5% reduction required across six prominent 2050 scenarios in the literature (Quiggin, 2014). However, it should be noted that those scenarios do not achieve acceptable levels of security of supply when tested in SHED, principally because their heating demand reduction targets are insufficient and electrification levels extremely high. Hence annual heating demands result in much greater peak electrical demands driven by electrified heating. *GP:2030* avoids these pitfalls by emphasising heating reductions and containing heat electrification at lower, more manageable levels.

If heating targets are *not* met in *GP:2030*, and annual heating demands remain at historic levels, then over the course of 11 years there would be 47 hours of deficits totaling 141.9 GWh.

6.5 Domestic demand side management (DSM)

GP:2030 performs very well in balancing supply and demand, and is further strengthened by its demonstrable, quantified and reasonable reliance on domestic DSM to do so. This is extremely important for two reasons. First; previous models have only been able to assume a given flexibility in the demand-side of modelLed energy scenarios without, for example, investigating whether there is sufficient supply either side of a peak period to allow demand to be shifted. Second; domestic DSM, though technically feasible, is as yet untested at scale and is therefore an unknown quantity given it relies on human behaviour change and thus social conditions. A heavy, and un-modelLed, reliance on domestic DSM within any energy scenario is consequently problematic because it both expects much from an untested technology *and* fails to specify *exactly what* it actually expects.

In *GP:2030* domestic DSM is kept within reasonable limits, preventing onerous responsibility on households to provide demand side balancing to the electricity system. The majority of instances where households are required to shift their demand are below 0.2GW (at a national level), occurring on average 77$/yr$ across the eleven years of data that SHED runs over. There are only 6.8 instances per year where $\geq 3GW$ is required at a national level from domestic DSM. The majority of balancing in *GP:2030* is enabled by storage mechanisms, as DSM requires conditions in which there is sufficient supply within a 3 hour window on either side of a problematic demand peak - this is not always the case.

6.6 Economic feasibility

6.6.1 Cost

In order to assess the economic feasibility of *GP:2030* this report has chosen to compare it to a full costed high-renewables scenario produced by Poyry in 2011 for the Committee on Climate Change. It can be seen in Chapter 4 that the two scenarios are technically similar enough to draw reasonable comparisons between, regarding potential costs. Poyry's analysis shows that up to a 65% (2030) and 80% (2050) share of generation from renewables results in additional intermittency costs to the consumers of 1 pence per kWh. As stated above, *GP:2030* assumes a 76% share by 2030. The CCC expect that with 65% of renewables penetration, the average electricity generation cost in 2030 to be $\sim 8.2 - 13.8 p/kWh$, requiring $\sim 126 - 227 bn$ of investment, roughly equivalent to between one and two times the annual NHS budget, but spread over 15 years.

6.6.2 Dispatchable generator load factors

A key element of the *operational* economic feasibility of the power sector is the average load factor for dispatchable fossil fuel generators called on to reduce net demand after renewable supply and balancing mechanisms have been invoked. In order for the building of power stations to be economically favourable, traditionally average load factors must be maintained at levels that do not obscure the possibility of recouping initial capital investment.

In 2013, with power generation from CCGTs at its lowest level since 1996, load factors for CCGTs fell to a record low of 28%. In 2008 CCGT load factors were at an eight year high of of 71.0% per cent. The intervening fall was due to an increase in power generation from coal fired power stations, whose load factors reached 58% in 2013.

In *GP:2030:Pragmatic* mean load factors on CCGT generators are maintained at an economically favourable level of 23.6 %. Within *GP:2030:ClimateDriven* this falls substantially to 2.1 %. It should be clear from this that serious consideration was given in the modelling process to this element - it is for consideration of the reader that each sub-scenario with its attendant carbon intensities and load factors is presented.

It should be noted that dispatchable generation is a necessary component of an electricity system that is required to balance each second of each day of each year. The extent to which it is required is influenced by the overall demand peak values and how far balancing mechanisms are enabled to reduce net demand after non-dispatchable supply. If achieving the lowest technically feasible carbon intensity for the power sector is the over-riding priority for the design of an energy scenario, consideration must be given to how to fund, or incentivise the building of, economically unrewarding CCGT power stations (or how to reduce demand in advance of *GP:2030*'s projections). The UK's newly inaugurated electricity capacity market is an initial, if uncertain step, in addressing this issue and must be updated within the context of conclusions drawn from modelling exercises such as this which project heavily reduced average load factors.

6.7 The possibility & the imperative

What *GP:2030* shows is the real possibility of an ambitious carbon reduction plan for the UK's power sector - and thus its economy more broadly - eschewing new nuclear and CCS technology dependence in favour of non-dispatchable, highly renewable and increasingly decentralised supply.

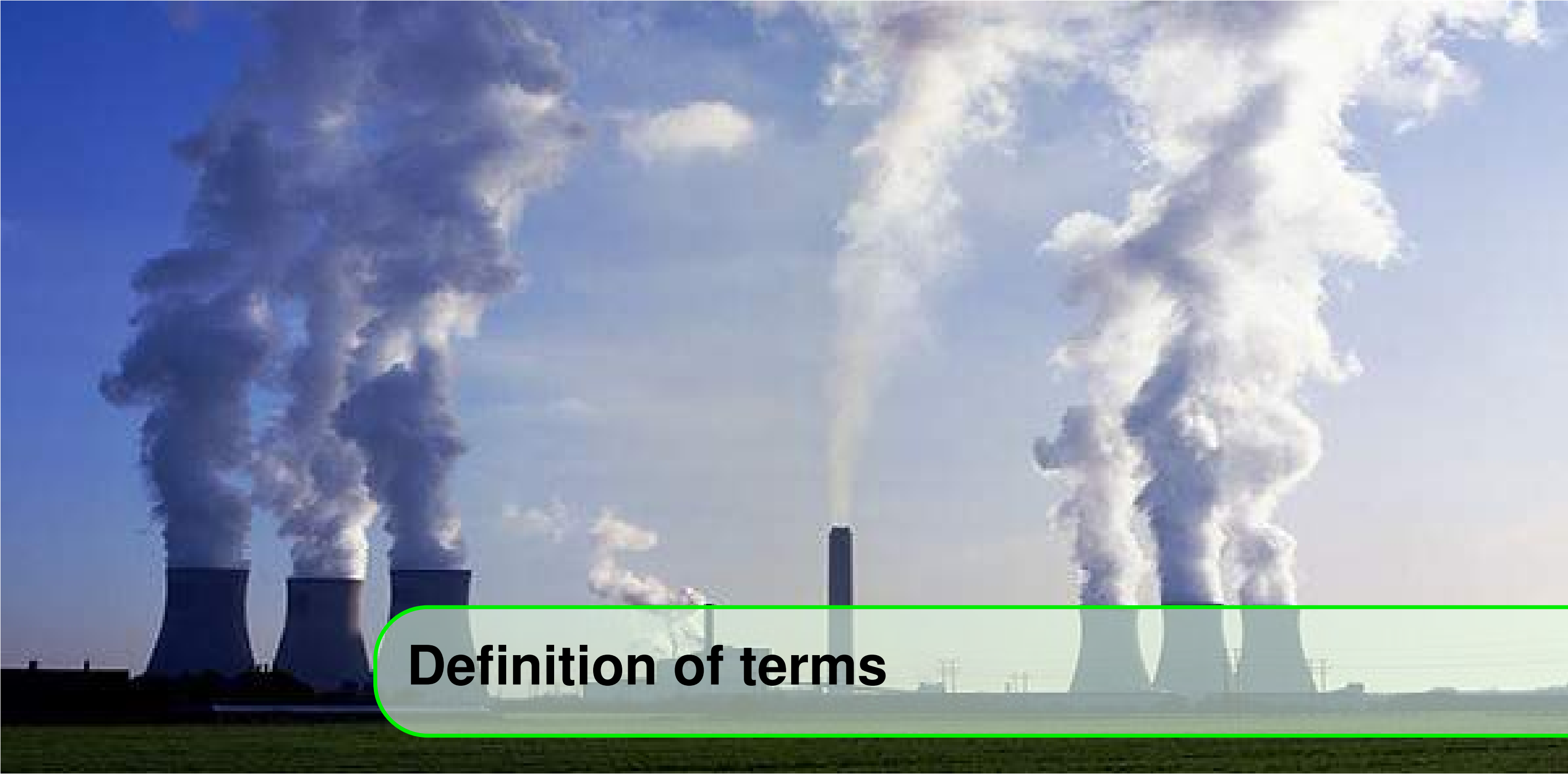
The huge scale of such a transformation ensures that its success will rely, amongst other factors, on far-sighted political leadership. The replacement of the majority of the UK's current electricity generation capacity, the roll-out of new, and relatively untested, technologies into households, the rewriting of the electricity market's rulebook and shifts in public attitudes and behaviour are but some of the prerequisites for a workable energy future.

But what other choices are there? There will be choices between different national energy plans, but the central themes of this report - the dilemma of increased electrical demand peaks *and* increased supply intermittency - will affect any proposal that is serious about taking responsibility for the UK's role in precipitating a climate crisis. We either continue as normal, or we get serious about reducing space heating demand rapidly; scaling up and innovating key technologies; and changing our relationships up and down the scale with the production and consumption of energy.

Such systemic flux also presents exciting opportunities: far greater domestic energy sufficiency, homes that are better insulated and cheaper to live in and community and citizen ownership of national energy infrastructure - to name a few.

The authors wish to end this report by reiterating the urgency of the need to take action on climate change. Even *with* a global temperature rise limited to 2C - the current political consensus - the earth's ecosystem will enter unknown territory, risking global society in an unprecedented manner. As a nation it is the UK's responsibility to act within the best of its knowledge and abilities, for the sake of every global citizen, to prevent such unthinkable outcomes.

This requires enacting the most ambitious carbon reduction plans we think achievable. The *Greenpeace:2030* report is dedicated to such an effort.

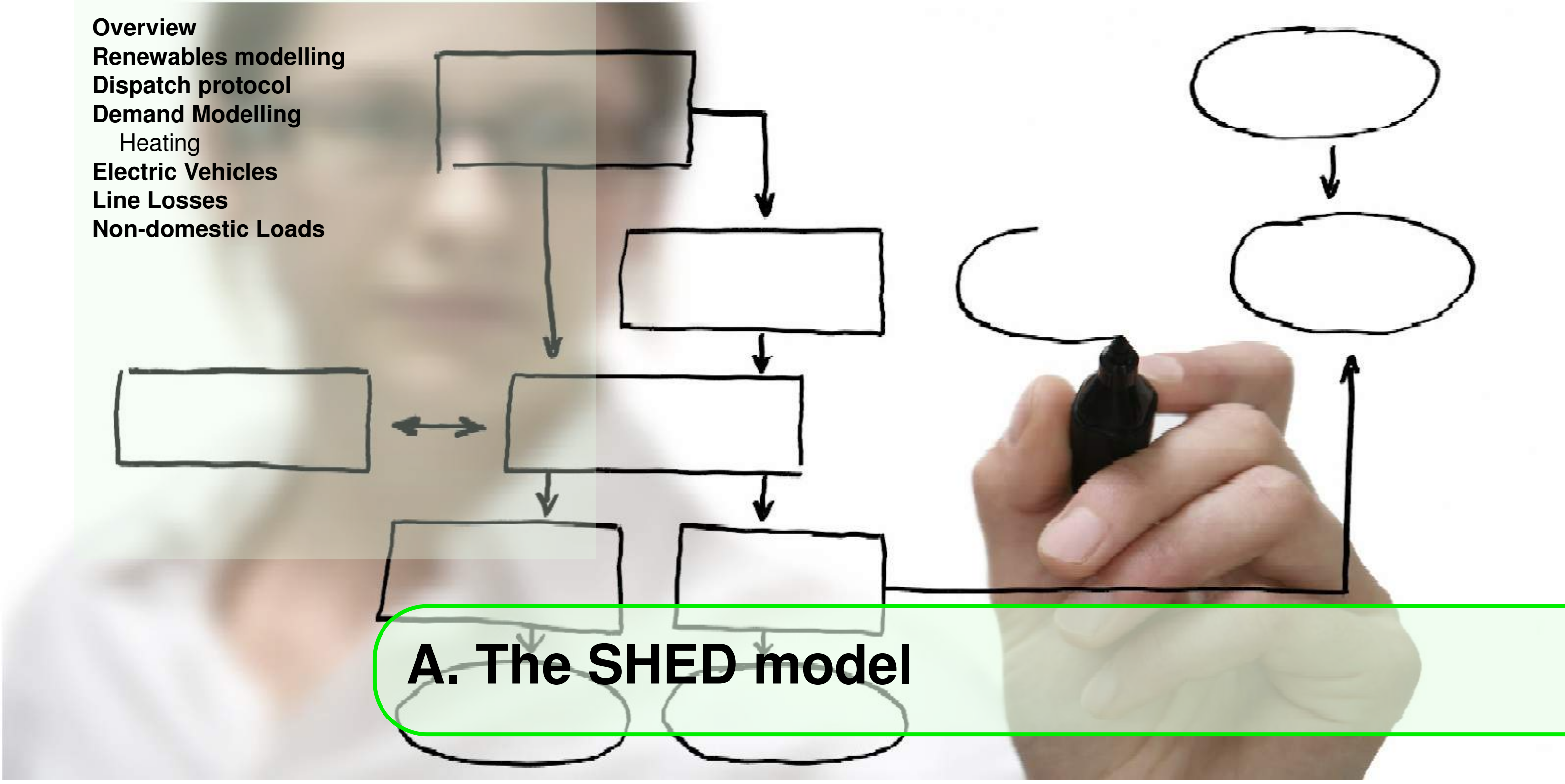


Definition of terms

Here terms that are used regularly throughout the document are defined;

- **Dispatchable generator**; an electrical generator capable of varying its output in accordance to the demand for electrical power, these are generally large scale centralised power stations.
- **Non-dispatchable generator**; an electrical generator whose output is dependant on weather and climatic conditions, its output is referred to as intermittent or variable as these generators do not respond dynamically to electrical demand
- **Capacity factor**; the ratio between an electrical generators actual output over a given period of time, to the potential output of that generator if it were able to operate at its rated nameplate generation capacity. Capacity factors can be calculated for both dispatchable and non-dispatchable generators.
- **Load factor**; is the average load placed on a dispatchable generator divided by the generation capacity of that generator
- **Availability factor**; is the amount of time that a generator is able to produce electricity over a certain period, divided by the amount of the time in the period.
- **Combined heat and power (CHP)**; a type of generator that produces heat simultaneously to electrical power, there are many forms of CHP units fuelled by different liquid or gas fuels.
- **Traditional electricity**; the electrical demand from both domestic and non-domestic electricity consumers, with no contribution from either electric vehicles or heat pumps
- **Carbon capture and storage (CCS)**; a technology currently being developed designed to be fitted to fossil fuel generators that *captures* CO_2 emissions from those generators in order to reduce the emission intensity factor of those generators. The captured carbon is then transported and *stored* to prevent emissions entering into the atmosphere.
- **Smart meter**; is an energy (gas or electric) meter that records consumption of energy in intervals of an hour or less communicating that information back to the energy supplier for monitoring and billing purposes. Smart meters enable two-way communication between the meter and the central system.
- **Time of Use tariffs (TOU)**; a type of metering and billing that employs smart

meters which are programmed to determine energy consumption at intervals throughout the day, allowing energy suppliers to changes rates and charges based supply and demand.



A. The SHED model

A.1 Overview

Here an overview of SHED is presented with further detailed descriptions given in the following sections. This overview is designed to give a contextual understanding of how the modelling components fit together. SHED is a hybrid top-down national supply-demand model with a bottom-up household demand and DSM model, here an overview of the top-down modelling methodology is presented, for a full description please see Quiggin (2014). The top-down modelling is comprised of hourly historic weather patterns, demand data and installed generator capacities. Supply-demand modelling methodologies developed within the FESA model (Barton et al., 2013) have been utilised and adapted.

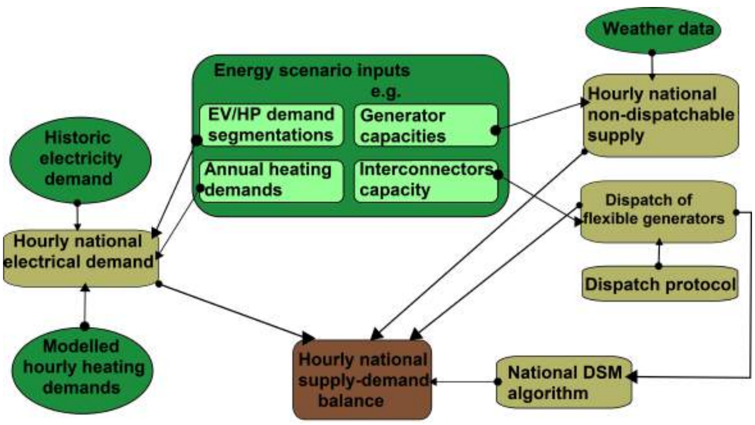


Figure A.1: High level schematic of SHED modelling components. HP = heat pump, EV = electric vehicle, DSM = demand side management

A.2 Renewables modelling

The renewables modelled include; wave, solar PV, tidal stream, onshore and offshore wind. Hourly renewable supply is composed of historic weather data, the specific technology characteristics and sub-division of the country into weighted regions, to form hourly national capacity factors[1] for each renewable technology. The scenario specific national generator capacities are combined with these capacity factors to form scenario specific hourly renewable generation. The weightings between sub regions are based on the total possible available resource, which originate from UK government estimates (DTI (1998)). Hourly weather data, to model renewable generation, was obtained from the British Atmospheric Data Centre (BADC) (UK Meteorological Office, 2011) with the exception of wave data, which the Met Office (UK Meteorological Office, 2013) supplied. SHED utilises eleven years of data enabling a variety of weather patterns and variations in demand to be represented, those years being 2001 – 2011.

A.3 Dispatch protocol

Currently electricity generators bid into the market on various time scales based on demand forecasts, the price of fuel and many other factors. The simplified dispatch protocol within SHED assumes the overriding objective governing generator dispatch is the minimisation of CO_2 emissions. This would require the energy market to be reformed and preference given to those generators with the lowest associated CO_2 emissions. Under this methodology renewable generators are left to generate uncurtailed. So too are CHP generators, which are modelled as following heat demands.

A.4 Demand Modelling

Figure A.2 illustrates the demand model components, these components are described in further detail in the following sections. Historic national half hourly electricity demand data from ELEXON (The NETA Web Site, 2013) forms the basis of deriving traditional electricity demands. *Traditional* electricity demand is the electrical demand from both domestic and non-domestic electricity consumers, with no contribution from electric vehicles, heat pumps or economy seven. It is the future electrical demand that is similar to current electrical demands, but as energy scenarios specify the level economy seven or resistive heating this is removed and re-introduced later. The ELEXON data encompasses all national domestic and non-domestic loads, as well as economy seven water and space heating. This data is scaled by each scenarios annual demand projections once economy seven water and space heating are removed. Historic hourly temperature data from three Met Office Integrated Data Archive System (MIDAS) weather stations form the basis of calculating the number of Heating Degree Hours (HDH), which are scaled by the national annual delivered space heating demands[2] (DSHD) data, to give hourly DSHD. Alongside hourly DSHD, hourly delivered water heating demands are calculated enabling hourly heat pump electricity demands to be found, along with solar thermal and CHP outputs. The approach taken within SHED is to model solar thermal water heating demands first, such that heat pumps follow a reduced net heating demand. Electric vehicle (EV) charging profiles (Acha et al., 2011)

[1] Capacity factor; the ratio between an electrical generators actual output over a given period of time, to the potential output of that generator if it were able to operate at its rated nameplate generation capacity.

[2] Delivered space heating demand is the energy demand at the point of use, rather than the energy in the fuel consumed

are utilised to derive the scenario specific EV hourly demands. Finally the resistive heating demands are calculated utilising current economy seven water and space heating profiles.

The final hourly electricity demand is, at a high level perspective, the sum of traditional electricity, electrical vehicle, heat pump, resistive heating and resistive heating demands.

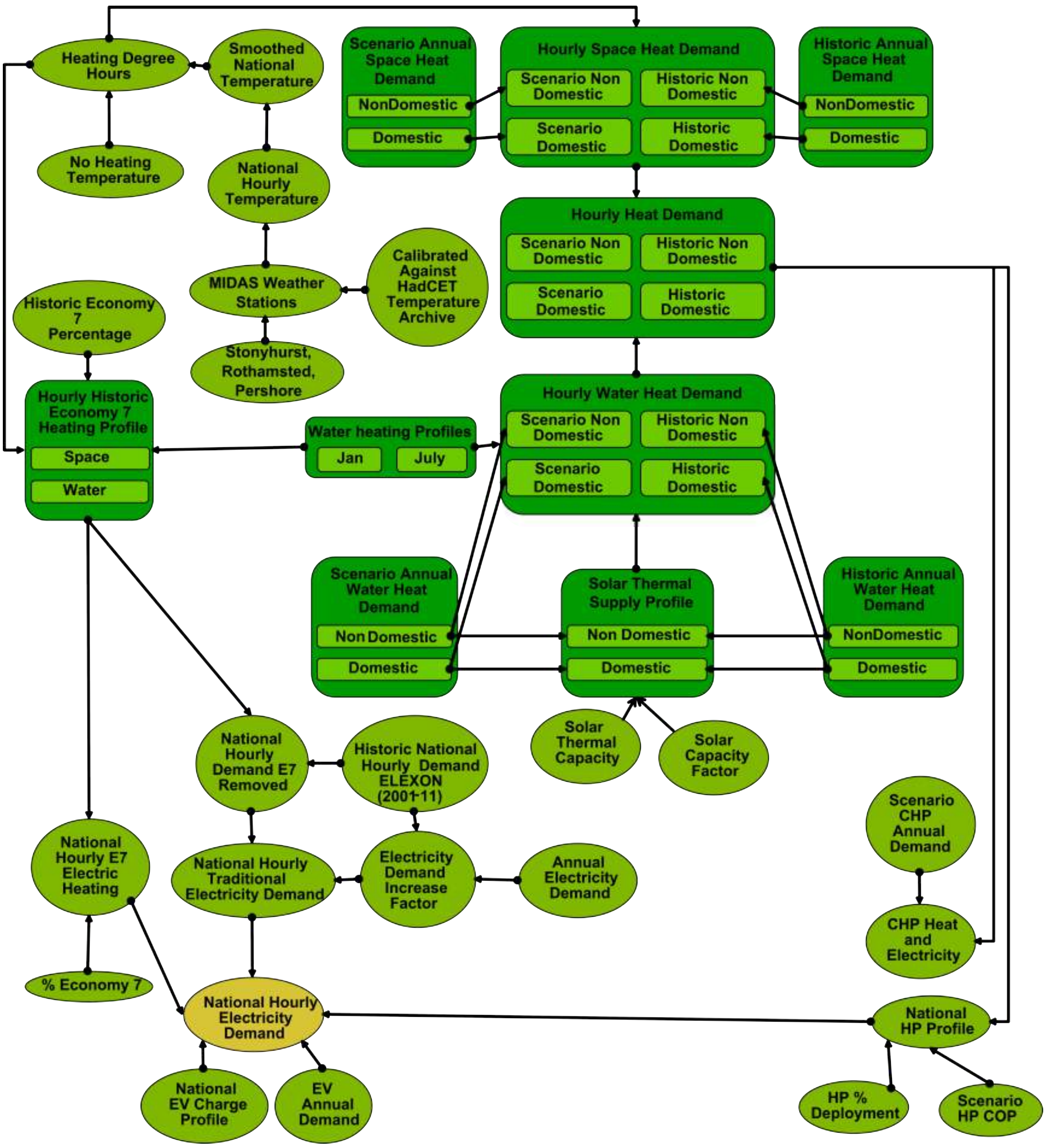


Figure A.2: Detailed representation of the components of the demand model elements of SHED. Target output highlighted in yellow. HP = heat pump, EV = electric vehicle, E7 = economy seven

A.4.1 Heating

Only recently in publications by Sansom and Strbac (2012) and Wilson et al. (2013) has the electrification of heating been considered to drive peak electrical demands to levels

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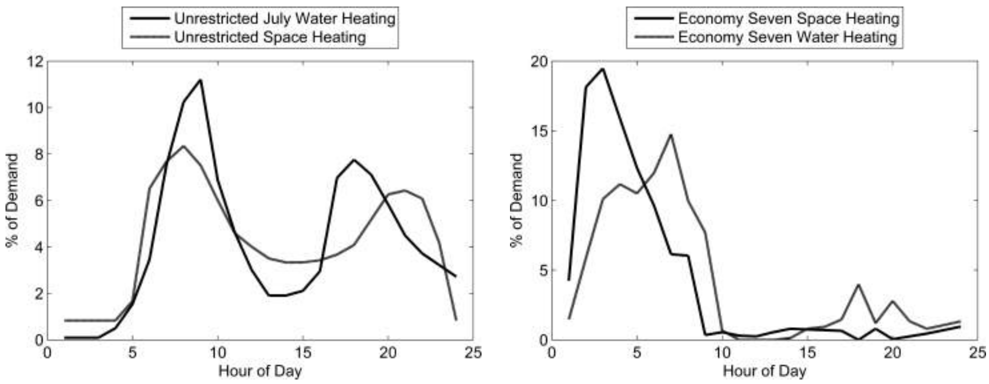
where reliability of supply is potentially compromised. Wilson et al. (2013) quantified daily demands, whilst Sansom and Strbac (2012) utilised half hourly gas demands to derive heating demands.

To calculate hourly electrified heating demands, hourly delivered heating demands are required and are comprised of both domestic and non-domestic water and space heating. Daily demand profiles for unrestricted space and water heating originate from heat flow measurements within a district heating scheme of a social housing complex (Woods and Dickson, 2004). The normalised profiles are shown in Figure A.3. Hourly water heating demands are derived from the 24 hour July unrestricted heating profile and scaled by the annualised national delivered water heating demand. For space heating ($p_{sp}(t)$) it is assumed there is no demand during high summer (July and August). These profiles are normalised across the 24 hours of the day such that, for instance, 8.4% of the total daily space heating load occurs at 8am (see Figure A.3). Hourly temperature data forms the basis of calculating the number of HDH which are scaled by the annual delivered space heating demands and unrestricted profile of Figure A.3, to derived hourly DSHD.



(a) Unrestricted heat demand profiles. Source : Woods and Dickson (2004).

(b) Economy seven heat demand profiles.

Figure A.3: Heat demand profiles: percentage of demand occurring each hour of a typical day.

A degree hour is the number of degrees Celsius by which the hourly average outside temperature is below a *no heating* temperature. The no heating temperature, T_{NH}, is the temperature at which no heating is required to maintain sufficient inside temperature, and is dependent on; building characteristics, heating equipment used, number of occupants and their behaviour, $T_{NH} = 15.5^oC$. The smoothed temperature, T_s, given by the moving average temperature of Equation A.1 is taken as the outside ambient temperature from which the number of degree hours, D_H, is found (Equation A.2). This is the difference between the smoothed temperature, T_s, and the no heating temperature, T_{NH}, where D_H is zero if T_s is greater than T_{NH}.

$$T_s(t) = \sum_{t-23}^{t} \frac{T(t)}{24} \tag{A.1}$$

where; $T(t)$ is the hourly outside ambient temperature

$$D_H(t) = \begin{cases} T_{NH} - T_s(t) & \text{if } T_{NH} > T_s(t) \\ 0 & \text{if } T_{NH} \leq T_s(t) \end{cases} \tag{A.2}$$

The majority of UK housing, commerce, and industry is located in England. The method of using an area enclosing the majority of the building stock is common within representative temperature measurements (Parker et al., 1992). The *daily* Hadley Centre Central England Temperature (HadCET) record is representative of a triangular area enclosed by Lancashire, London and Bristol (Parker et al., 1992). As hourly, rather than daily mean temperatures are required, HadCET is insufficient for the purposes of SHED. FESA utilised the Rutherford Appleton Laboratory (RAL) dataset in Oxfordshire to derive hourly values, and calibrated the data against HadCET. The HadCET daily mean temperatures are derived from three equally weighted weather stations (Parker and Horton, 2005); Rothamsted near London, Pershore on the boarder of south Wales and Stonyhurst just north of Blackburn in Lancashire. The MIDAS dataset contains hundreds of land based weather stations, so hourly temperatures were obtained from weather stations as close to the HadCET stations as possible.

Hourly DSHD, $S(t)$, is the product of the annual DSHD (S) and the HDH, normalised by the total number of HDH in the year to give an effective degree hour capacity factor, shown in Equation A.3. Equation A.3 gives the hourly flat DSHD with the unrestricted profile (Figure A.3(a)) not accounted for.

$$S(t) = S.\frac{D_H(t)}{\sum_1^n D_H(t)} \tag{A.3}$$

where; $S(t)$ is the hourly flat DSHD;
S is the annual delivered space heating annual demand;
$D_H(t)$ is the number of degree hours; and,
n is the number of hours in the year.

To account for the daily unrestricted heating profile the total flat DSHD each day is proportioned across the 24 hours by the unrestricted profile. The resulting unrestricted demand profile is given by Equation A.4. The hourly flat (or restricted) DSHD is used to determine non-domestic hourly heating demands.

$$S^p(t) = \sum_{1}^{24} S(t).\frac{p_{sp}(t)}{\sum_1^{24} p_{sp}(t)} \tag{A.4}$$

where; $S^p(t)$ is the hourly *unrestricted* DSHD;
p_{sp} is the space heating demand profile of Figure A.3; and,
$S(t)$ is the hourly flat DSHD of Equation A.3.

Heat pumps

Heat pump electricity demand ($E_{sc}^{HP}(t)$) has been modelled as following hourly delivered space and water heating demands. The scenario defined fraction of heat supplied by heat pumps (f^{HP}) and the coefficient of performance of the heat pumps (COP^{HP}), give Equation A.5.

$$E_{sc}^{HP}(t) = \left(S_{sc}(t) + W_{sc}(t)\right).f^{HP}/COP^{HP} \tag{A.5}$$

A.5 Electric Vehicles

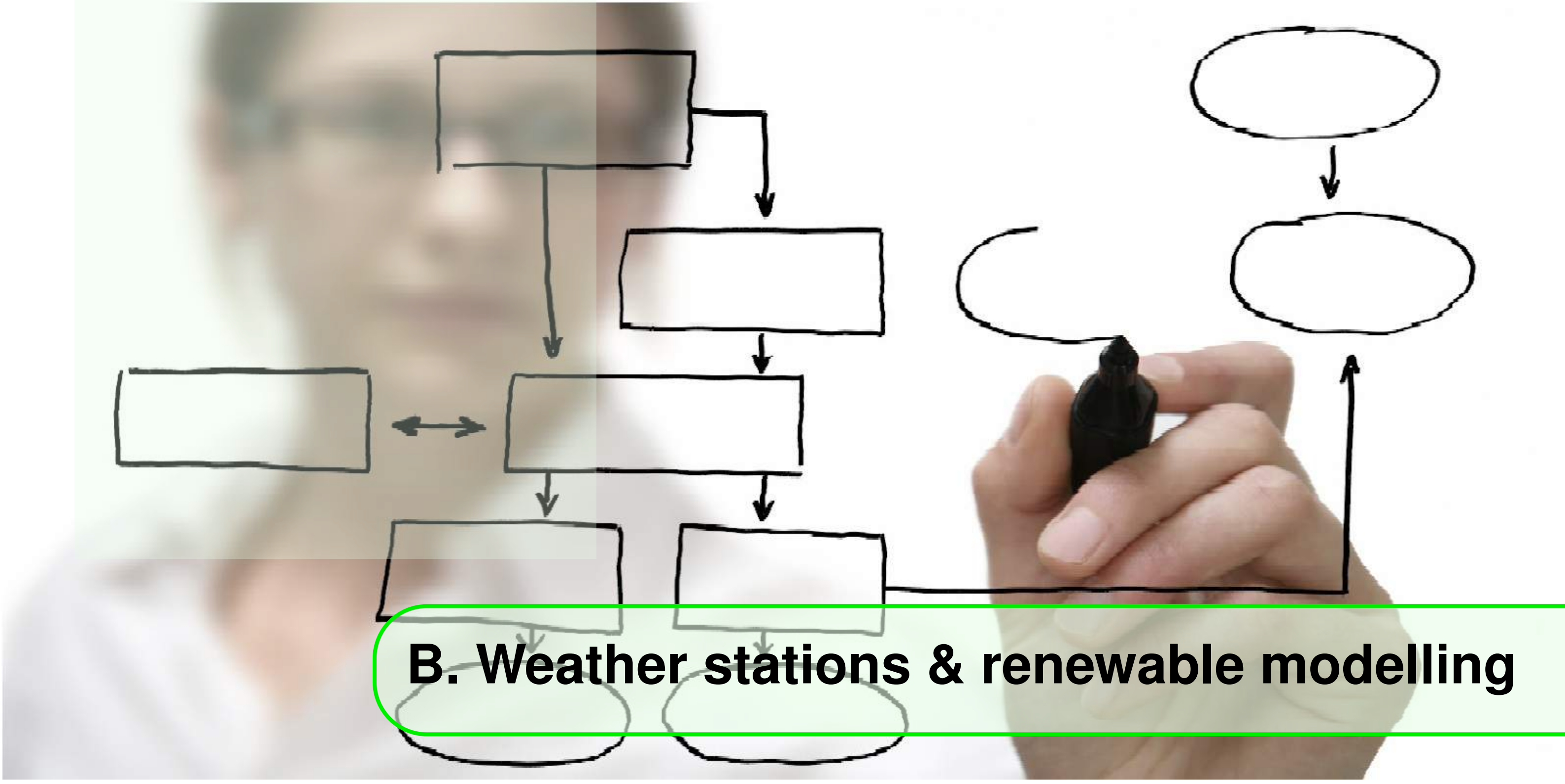
It has been assumed that EVs are not capable of providing power back to the grid, hence EVs are unable to provide a balancing services to the grid, which many studies have suggested would be possible but expensive (Kempton and Tomić, 2005). The driving and charging profile used to model hourly EV demands is a modified DSM profile (found in Quiggin (2014)), under which DSM has been accounted for (Acha et al. (2011)).

A.6 Line Losses

The electricity system is considered as a single node, as such transmission and distribution losses are accounted for by a simple increase of 7%, regardless of local generation levels but assuming a small increased efficiency of the electrical network by 2030. These losses are applied to the total electrical demands. Typical historic transmission losses as recorded by the National Grid Company are less than 2% (National Grid, 2009). In 2000/01 the average losses reported to Ofgem across all 14 Distribution Network Operators was 7%, with a range between 5.4% to 9.1% (Ofgem, 2003).

A.7 Non-domestic Loads

The traditional electricity loads of both domestic and non-domestic are treated together under the scaled Elexon data. Electrified space and water heating are treated in a similar way to domestic demands, but a daily flat (or restricted) heating profile is applied rather than the unrestricted profile. The non-domestic DSM dynamics are treated separately to domestic DSM, for further information see Quiggin (2014)



B. Weather stations & renewable modelling

For a full description of renewable modelling methodologies applied within *GP:2030* please see Quiggin (2014).

Figure B.1 shows the location of those weather bouys, three of which are located off the south west and Wales coastline; Turbot Bank, Seven Stones and Aberporth and two are situated off the west coast of Scotland and Ireland; K4 and K5. The country was then subdivided into two regions; North and South West based on the resource assumptions given in the DTI Marine Resource Atlas DTI, 2011 (Thorpe, 1999), such that variation in generation across the country was accounted for. This resulted in a North region weighting of 0.77 and consequently a South West weighting of 0.23.

Capacity factors for solar PV are calculated using hourly global irradiation data from 32 Met Office weather stations (UK Meteorological Office, 2011). Due to data quality across the eleven years many potential weather stations had to be discarded. It is assumed the majority of installations are roof mounted, which follows the methodology of the DTI (1998) report. As such UK sub regions are weighted by building and, more accurately, urban area distributions, for which statistics were obtained from the Department for the Environment Food and Rural Affairs (2003) and The Office for the Deputy Prime Minister (2004) (ODPM). As was found by Forrester (2005) 73% of the roof mounted solar resource is situated in England, which is then divided into 9 sub-regions. Scotland, Wales and Northern Ireland are classified as individual sub-regions resulting in a total of 12 regions. These subregions can be seen along with corresponding weather stations in Figure B.1. The weightings between regions, along with the raw data, can be found in Quiggin (2014). In essence the weightings can be thought of as a percentage of the total UK buildings that each region contains.

For onshore and offshore regional weightings, and capacity factors, to be calculated the available resource and associated constraints are required. Assumptions and methodology from the DTI (1998) are again utilised. The breakdown of onshore subregions can be seen in Figure B.2, with the total available resource and weightings given in Quiggin (2014). England and Wales constitute one region as does Northern Ireland, with fourteen subregions in Scotland. The breakdown of offshore subregions can be seen in Figure B.3, with one square representing a 1GW wind farm. The total available resource and weightings per region are given in Quiggin (2014). For onshore

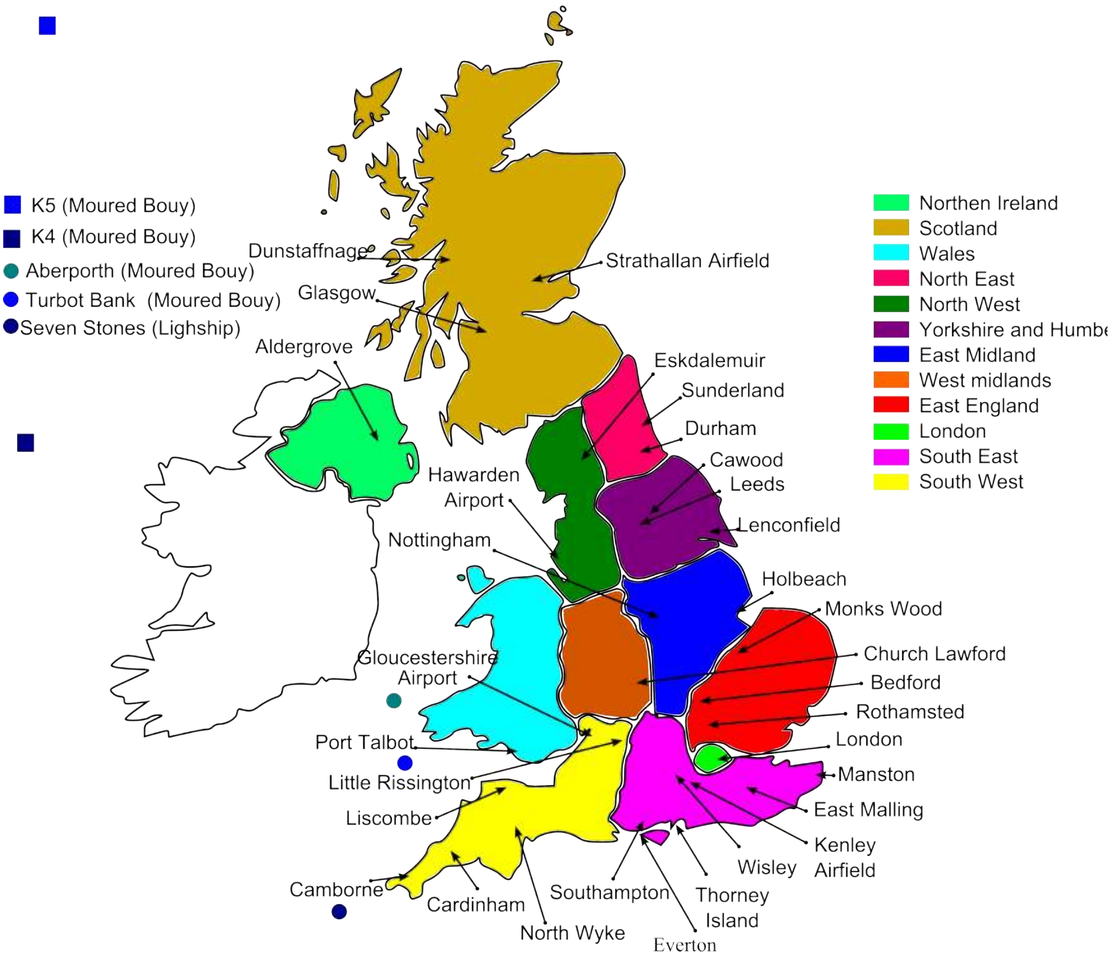


Figure B.1: Location of wave buoys and solar irradiation weather stations.

resource allocations, the variables within the DTI (1998) report include socio-economic factors, along with size and spacing of the onshore sites. Also included are protected areas such as National Parks and green-belt land as well as the location of urban areas, agricultural land and lakes, and other geographic constraints. The DTI (1998) report utilised wind atlases to determine those areas with annual mean wind speeds (AMWS) of $7ms^{-1}$ or more. This is the minimum mean wind speed at which wind generation becomes economically viable with modern wind turbines. With the majority of the wind resource contained within Scotland, this region was subdivided into further smaller regions, with consequently more weather stations found for these areas.

In calculating the total possible available resource for offshore wind, the constraints differ to onshore. There are no National Parks and cities to consider but there are sites of special scientific interest, shipping lanes and protected areas. The main constraint, however, is the depth of sea bed or bathymetry where the depth is required to be less than 40m out to 30km. Again a detailed description of assumptions made in calculating the regional resource can be found in the DTI (1998) report. The practical available resource including all constraints was calculated to be $100TWh/y$, whereas the total possible available resource with no constraints other than sea bed depth, utilised within SHED in calculating the capacity factors, is cited within the DTI (1998) report as 2851TWh/y. This no constraint total resource was used rather than constrained resource. As the wind speeds at hub heights of the 2MW and 5MW turbines meet the required AMWS of 7ms^{-1} in nearly all regions of the UK coastline, the main constraint is simply the bathymetry. This then means the map shown in Figure B.3 broadly represents the sea bed depth, rather than any constraints from shipping lanes etc.

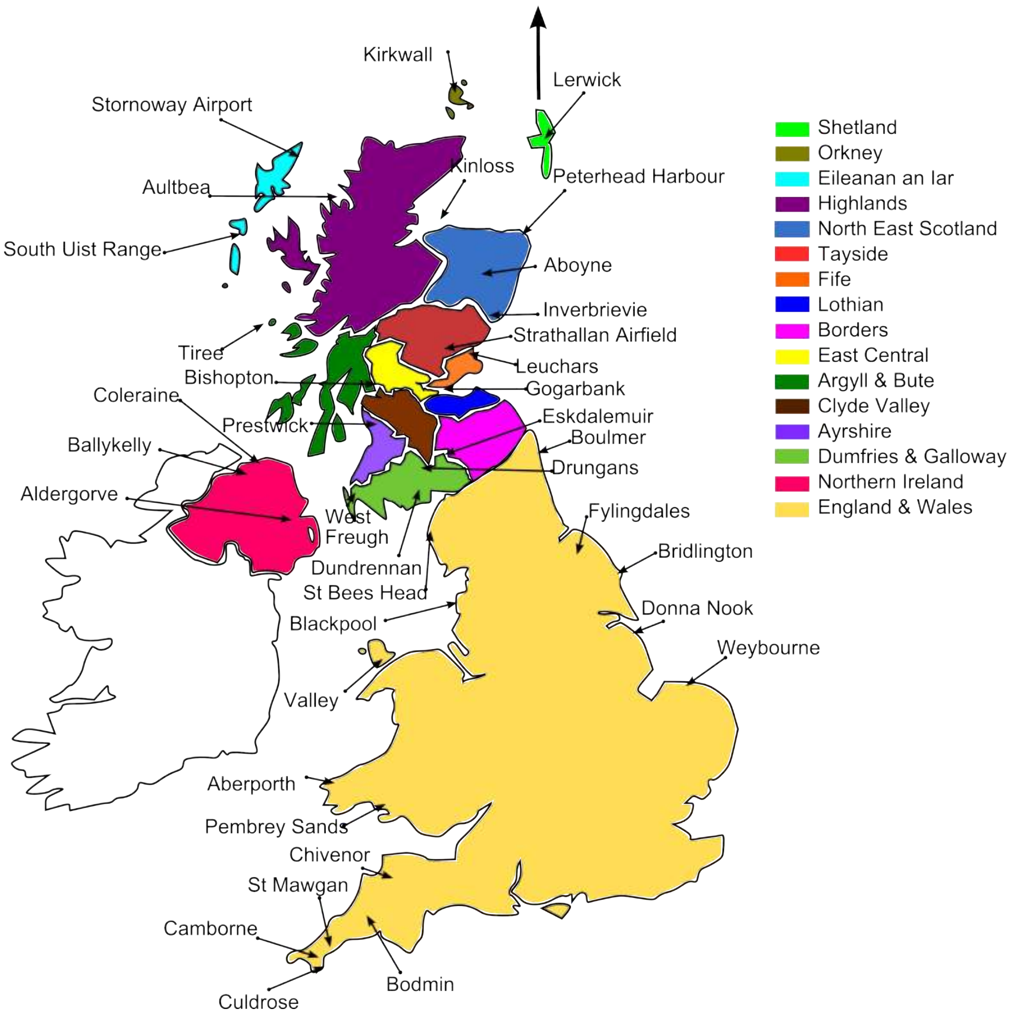


Figure B.2: Location of wind weather stations.

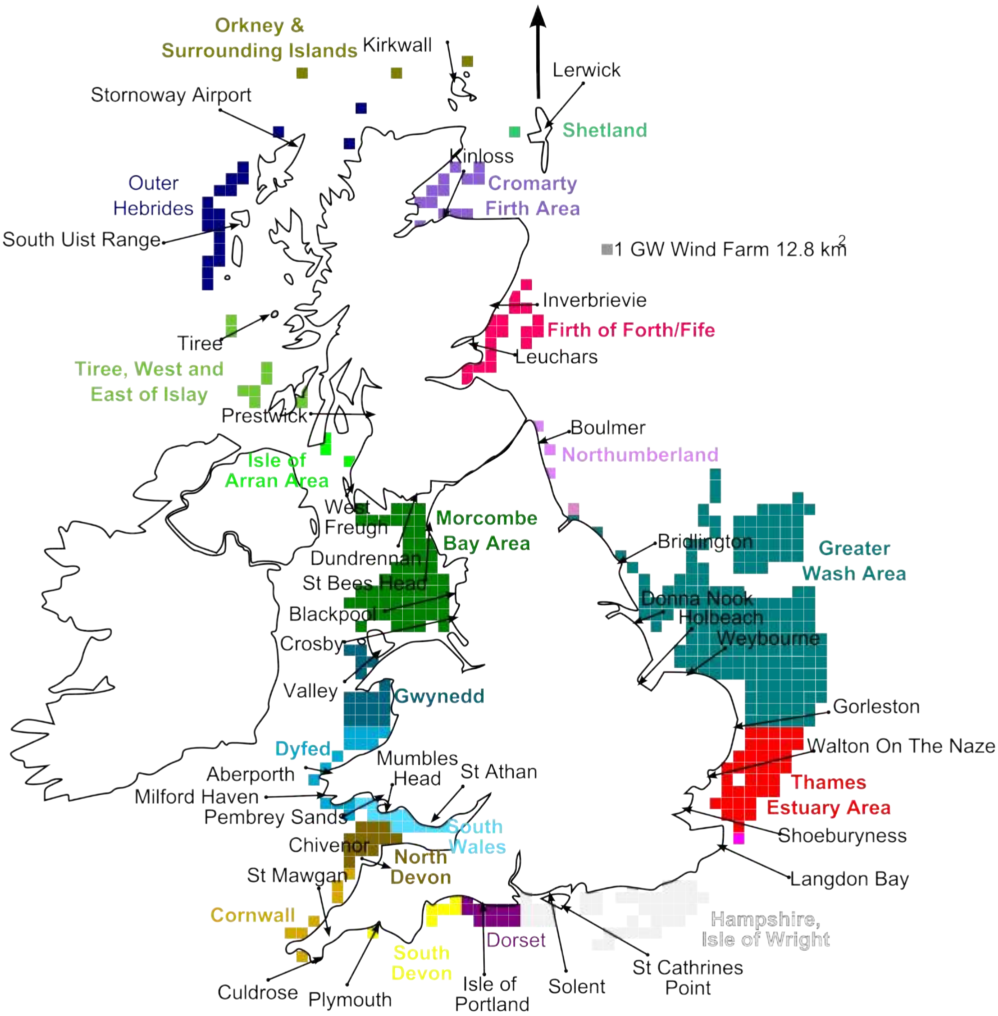
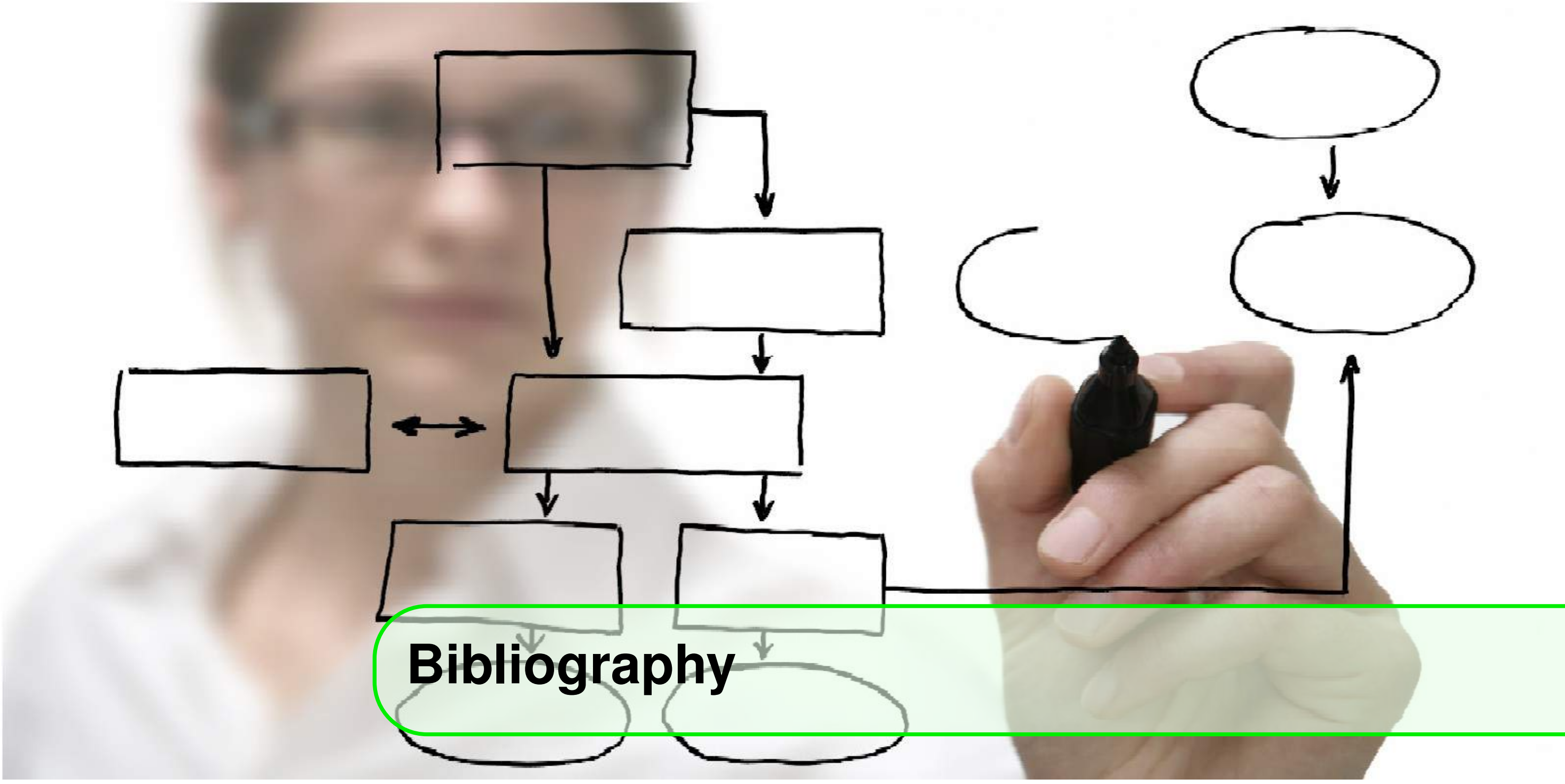


Figure B.3: Location of offshore wind weather stations.



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