THE WATER USE OF THE UK ELECTRICITY SECTOR AND ITS VULNERABILITY TO DROUGHT

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ABSTRACT

The majority (80%) of global electricity generation comes from thermal power stations, most of which use large volumes of water for cooling. Population growth and climate change are likely to increase water scarcity, whilst many countries are exploring pathways to low-carbon electricity systems. Thermal power stations, both with and without carbon capture and storage (CCS), are likely to continue using water for cooling where possible for the foreseeable future.

This thesis investigates the dependency on water for cooling of multiple low-carbon pathways for the UK put forward by Government and academia. An analytical framework that combines generation technologies, cooling systems and sources, water use factors and regional water availability is applied at national and regional scales. Whilst most decarbonisation pathways reduce freshwater use for a variety of reasons, high levels of CCS are likely to increase freshwater demands due to the increased water intensity of CCS generation. Furthermore, higher demands will be locally concentrated, given Government's strategy to cluster CCS facilities.

Subsequently, UKCP09 Weather Generator climate timeseries and a hydrological model of the River Trent are used to simulate the effects of hydroclimatic variability on licensed water availability. The impacts are tested on a CCS cluster operating with different cooling systems and under two Government-proposed abstraction regimes. Capacity availability is impacted by low flows, but this can be mitigated through increased use of hybrid cooling and prioritisation of more water-efficient capacity.

Other innovative solutions may reduce freshwater dependency, however these are not facilitated by the current policy and regulatory arrangements. In some cases, reducing water use and carbon emissions are in direct conflict. To ensure both energy and water security, this thesis proposes strategies that take into account the planning of CCS clusters, increasing competition for and scarcity of water, and the already challenging economics of CCS.

ACKNOWLEDGEMENTS

It was exciting to come back to the *alma mater* of my undergraduate degree, the School of Civil Engineering and Geosciences (CEG) at Newcastle University. With the encouragement of one of my favourite undergraduate lecturers, Dr Jaime Amezaga, I started work as a researcher for Prof Jim Hall in preparation for what was to become the Infrastructure Transitions Research Consortium (ITRC). Little did I imagine where this would take us. Jaime and Jim propositioned that I study for a PhD, but credit for convincing me is also largely due to my, *then* recently-acquainted, but *now* wife, Sam.

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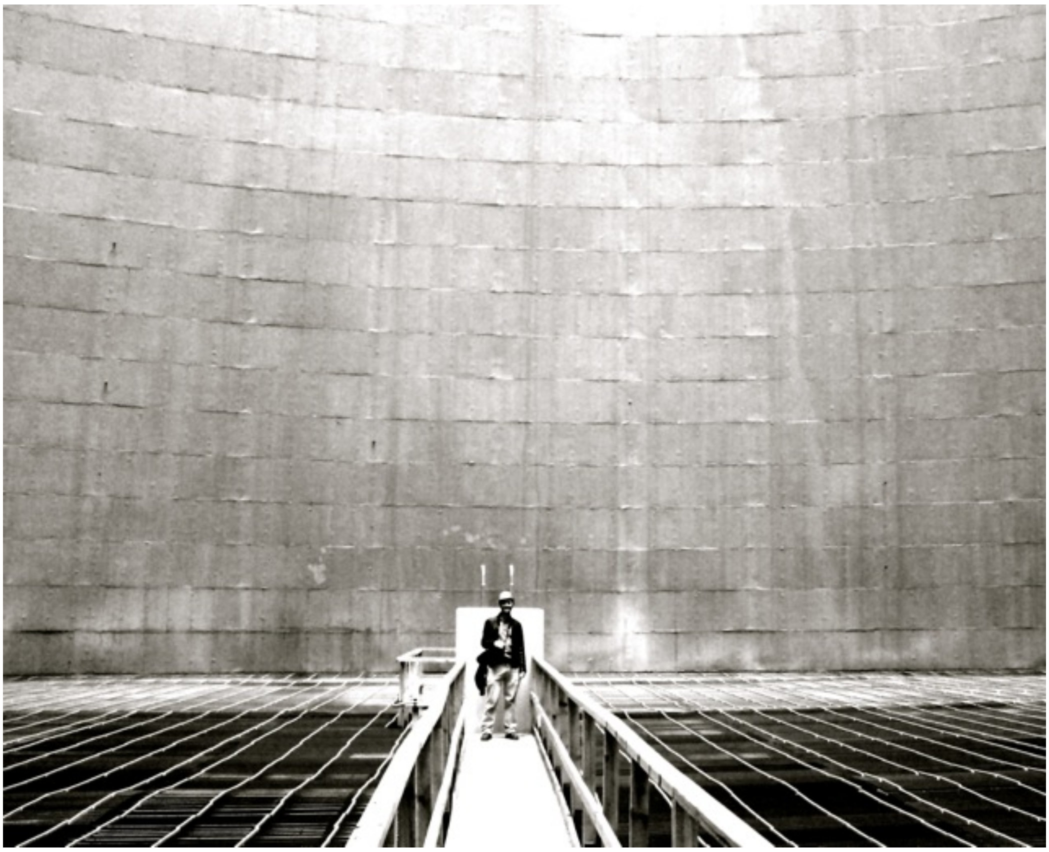
This work is dedicated to:

"The first generation to see the effects of climate change, and the last generation who can do anything about it" Mayor Michael McGinn (2013)



Myself in a natural draught wet cooling tower at Afşin Elbistan B coal power station, Kahramanmaraş, Turkey in October 2014.

STATEMENT OF CONTRIBUTIONS AND PUBLICATIONS

The following contributions to this thesis and publications, of both the author and others is acknowledged. The supervision and advice of Dr Jaime Amezaga and Prof Jim Hall was received throughout the duration of candidature and in preparation of this thesis.

Chapters 3 and 4

Chapters 3 and 4 are based on a publication, with further detail added to the methodology, discussion and conclusions.

- **Byers, E. A.**, Hall, J. W. and Amezaga, J. M. (2014) "Electricity generation and cooling water use: UK pathways to 2050," Global Environmental Change, 25, pp. 16–30. doi: 10.1016/j.gloenvcha.2014.01.005.

Chapter 5

The CGEN+ energy model and associated energy strategies were developed primarily by Prof Nick Jenkins, Dr Modassar Chaudry and Dr Meysam Qadrdan of Cardiff University for the ITRC programme of research. These outputs were received and processed by the author for the calculation of water use, as described.

Hydrological modelling outputs were developed by Prof Chris Kilsby and Alex Leathard of Newcastle University and used in the ITRC programme of research (Leathard and Kilsby, no date). These outputs were received and processed by the author for the calculation of water availability, as described. Description of the hydrological model is by Alex Leathard and the author. Assistance with data presentation from David Alderson in Figure 5-8, Figure 5-9 and Figure 5-10 is gratefully acknowledged.

- **Byers, E.A**., Qadrdan, M., Leathard, A., Alderson, D., Hall, J.W., Amezaga, J.M., Tran, M., Kilsby, C.G., Chaudry, M., 2015. Cooling water for Britain's future electricity supply. Proc. ICE - Energy In press. doi:doi.org/10.1680/ener.14.00028

Similar results for a wider range of five energy strategies are also presented in:

- Hall, J. W., Nicholls, R. J., Tran, M., Hickford, A. J. and Otto, A. (2015) *The Future of National Infrastructure: A System-of-Systems Approach*. Cambridge: Cambridge University Press.
- Tran, M., Hall, J., Hickford, A., Nicholls, R., Alderson, D., Barr, S., Baruah, P., Beaven, R., Birkin, M., Blainey, S., **Byers, E.**, Chaudry, M., Curtis, T., Ebrahimy, R., Eyre, N., Hiteva, R., Jenkins, N., Jones, C., Kilsby, C., Leathard, A., Manning, L., Otto, A., Oughton, E., Powrie, W., Preston, J., Qadrdan, M., Thoung, C., Tyler, P., Watson, J., Watson, G. and Zuo, C. (2014) *National infrastructure assessment: Analysis of options for infrastructure provision in Great Britain*.

Environmental Change Institute, University of Oxford, UK. Available at: http://www.itrc.org.uk/.

- Tran, M., Hall, J.W., Baruah, P., Blainey, S., **Byers, E.A.**, Chaudry, M., Qadrdan, M., Eyre, N., Jenkins, N., Kilsby, C., Preston, J., Alderson, D., Barr, S., Hickford, A., Nicholls, R., Otto, A., 2015. Managing interdependent low carbon infrastructure: energy, water and transport interactions. In review.

Chapter 6

The hydrological model was developed by Alex Leathard as part of his PhD research under the supervision of Prof Chris Kilsby of Newcastle University (Leathard and Kilsby, no date). Description of the hydrological model (section 6.2.1) was done jointly by the author, Dr Greg O'Donnell and Alex Leathard. The model structural uncertainty analysis and selection of parameter sets was performed by the author with the supervision of Dr Greg O'Donnell.

- **Byers, E.A.,** Hall, J.W., Amezaga, J.M., O'Donnell, G.M., Leathard, A., 2015. Water and Climate Risks to Power Generation with Carbon Capture and Storage. In Review.

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ABBREVIATIONS

ABSTAT	Environment Agency Abstraction Statistics Database
AC	Air-cooled
ACC	Air-cooled Condenser
ASB	Abstraction Sensitivity Band
BAT	Best Available Technique
BAU	Business As Usual
BREF	Best Reference Document
C	Closed-loop recirculating cooling
CAMS	Catchment Abstraction Management Strategy
CapEx	Capital Expenditure
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CCGT+CCS	Combined Cycle Gas Turbine + Carbon Capture and Storage
CCP	Carbon Capture Plant
CCR	Carbon Capture Readiness
CCS	Carbon Capture and Storage
CCS+	Carbon Capture and Storage Plus pathway
CCSA	Carbon Capture and Storage Association
CFD	Contracts for Difference
CGEN+	Combined Gas and Electricity Network model+
CHP	Combined Heat and Power
CMA	Competition and Markets Authority
CO2	Carbon Dioxide
Coal+CCS	Coal + Carbon Capture and Storage
CP1-REN	Carbon Plan 1 High Renewables pathway
CP2-NUC	Carbon Plan 2 High Nuclear pathway
CP3-CCS	Carbon Plan 3 High Carbon Capture and Storage pathway
DCLG	Department for Communities and Local Government
DECC	Department for Energy and Climate Change
Defra	Department for Environment, Food and Rural Affairs
DOE	Department of Energy (US)
DUKES	Digest of UK Energy Statistics
DW	Drinking Water
EA	Environment Agency
EC	European Commission
EC JRC	European Commission Joint Research Centre
ECC	House of Commons Energy and Climate Change Select Committee
EDF	Electricité de France
EEC	European Economic Commission
EFI	Environmental Flow Indicator
EHT	Electrified Heat and Transport
EHT-CCS	Electrified Heat and Transport with Carbon Capture and Storage
EHT-NUC	Electrified Heat and Transport with Nuclear
EHT-REN	Electrified Heat and Transport with Offshore Renewables
EIA	Environmental Impact Assessment
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Emissions Performance Standard
ESCO	Energy Service Company

EU	European Union
FAO	Food and Agricultural Organization
FDC	Flow Duration Curve
FGD	Flue Gas Desulphurisation
FOE	Friends of the Earth
FW	Freshwater
GCM	Global Climate Model / General Circulation Model
GEMA	Gas and Electricity Markets Authority
GES	Good Ecological Status
GHG	Greenhouse Gas
GIS	Geographical Information Systems
H	Hybrid cooling
H&C	Heating and Cooling
HHV	Higher Heating Value
Hig	High
HM	Her Majesty's
HMWB	Heavily Modified Waterbody
HOF	Hands off flow
HOF1	Hands off flow level 1
HOF2	Hands off flow level 2
HSE	Health and Safety Executive
IEA	International Energy Agency
IGCC	Integrated Gasification and Combined Cycle
IPPCD	Industrial Pollution Prevention and Control Directive
IRBM	Integrated River Basin Management
IRENA	International Renewable Energy Agency
ITRC	Infrastructure Transitions Research Consortium
IWRM	Integrated Water Resources Management
KGE	Kling-Gupta Efficiency
LAWA	Länder-Arbeitsgemeinschaft Wasser
LCOE	Levelised Cost of Electricity
LCPD	Large Combustion Plants Directive
LNG	Liquefied Natural Gas
lpd	litres per person per day
MB	Mass Balance
Med	Medium
mML	Million Mega Litres
MPI	Minimum Policy Intervention
MPI-CC	Minimum Policy Intervention with Carbon Cost
MPI-NoCC	Minimum Policy Intervention without Carbon Cost
MPP	Major Power Producer
MRF	Minimum Residual Flow
MSc	Masters of Science
NETL	National Energy Technologies Laboratory
NIEA	Northern Ireland Environment Agency
NPS	National Policy Statement
NREL	National Renewable Energy Laboratory
NRW	Natural Resources Wales
NSE	Nash-Sutcliffe Efficiency
NSElog	Natural log of the Nash-Sutcliffe Efficiency
NSIP	Nationally Significant Infrastructure Project
O	Open-loop / once-through direct cooling

OCGT	Open Cycle Gas Turbine
Ofgem	Office for Gas and Electricity Markets
Ofwat	The Water Services Regulation Authority
ONR	Office for Nuclear Regulation
ONS	Office for National Statistics
OpEx	Operational Expenditure
PB	Parsons Brinckerhoff
PBIAS	Percentage Bias
PET	Potential Evapo-transpiration
RBD	River Basin District
RCM	Regional Climate Model
SAAR	Seasonally Averaged Annual Rainfall
SCI	Shared CCS Infrastructure
SCR	Selective Catalytic Reduction
SEPA	Scottish Environmental Protection Agency
SRES	Special Report Emissions Scenarios
SW	Sea water
TW	Tidal water
UK	United Kingdom
UKCP09	UK Climate Projections 2009
UKM-326	UK MARKAL 3.26 pathway
UKM+	UK MARKAL 3.26 Plus pathway
UKTAG	UK Technical Advisory Group
US	United States of America
WBGU	German Advisory Council on Global Change
WEN	Water-energy nexus
WFD	Water Framework Directive
WG	Weather Generator

Chapter 1. INTRODUCTION

1.1 The water-energy nexus

The water-energy nexus (WEN) could be defined as the

> *"water use that results from the supply and use of energy, and the energy use that results from the supply and use of water".*

It describes the growing area and understanding of relationships between water and energy systems. Since the beginnings of civilisation humankind has attempted to harness the energy in naturally-flowing water to provide useful mechanical services. Now water is used in a variety of energy services from hydro-power, biofuel production and cooling of power plants. Energy is also increasingly used in our water systems to pump and move it, to treat and remove it (Figure 1-1).

The WEN fits within the wider are of the water-energy-food nexus. The existing poverty challenge, need to mitigate and adapt to climate change, 50% growth in global energy demand, 30% growth in global water demand, food shortages and population growth, will culminate in 2030 into what was described by Prof Sir John Beddington, then the UK Government's Chief Scientific Advisor, as "a perfect storm" (Beddington, 2009).

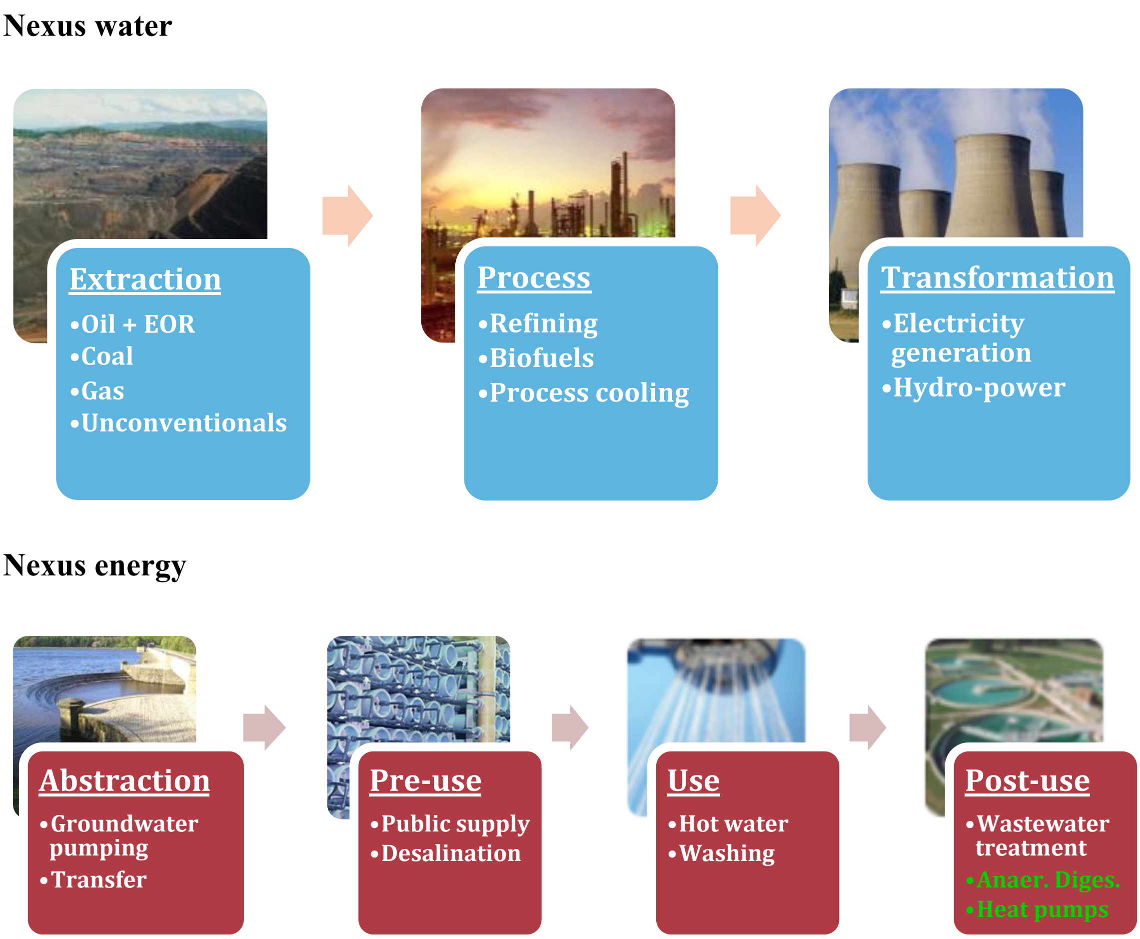

Figure 1-1. Nexus water and nexus energy. Respectively, examples of the use of water associated with the energy system, and the use of energy associated with the water system. EOR – Enhanced oil recovery. Anaer. Diges – Anaerobic digestion, which alongside heat pumps, offer the potential of energy recovery from the wastewater system. Source: Adapted from Byers, Amezaga and Hall (2012).

1.1.1 The UK context

Sir John Beddington's 'perfect storm' analogy is from a global perspective yet the issues will have impacts in the UK. Climate impacts between now and 2100 will bring warmer and wetter winters and hotter and drier summers (Murphy *et al.*, 2009). The population will grow 24% to approximately 76 million by 2050 and 86 million in the 2080s. This population is also ageing and increasingly living alone, consuming more per-capita resources.

This growth is increasing demands not only directly on water and energy infrastructure, but indirectly on all industries and economic sectors that also use energy and water. Furthermore, it is being increasingly recognised that the societal responses to one issue, have systemic rebound effects on another issue. For example, reducing dependency on imported fuels and food may increase local land competition. Alternative methods of water supply and higher water quality standards increases energy use. This PhD thesis focuses on the use of water for cooling power plants, which sits within the wider area of water-for-energy.

1.1.2 Water-for-energy

One half of the water-energy nexus is the use of water-for-energy (Figure 1-1, top panel). The use of water is prevalent throughout the energy value chain. Water is used in almost all forms of fossil fuel extraction, mining, processing and refinement. This is occurring in increasing quantities in recent years as high oil prices and growing demand have driven exploration of unconventional hydrocarbon reserves such as shale oil tar sands, hydraulic fracturing of shale gas plays and underground coal gasification. The extraction and refining of *unconventionals*, as well as traditionally-sourced fossil fuels also requires water inputs (McMahon, 2010). Lastly, water is typically used in a variety of electricity generation processes, such as at thermoelectric steam cycle plants, hydro-power and pumped storage, and even in the manufacture of generation equipment, from gas turbines to solar panels.

Currently, 80% of global electricity supply is provided by thermoelectric power plants fuelled by coal, gas, biomass, oil and nuclear (IEA, 2009). These power plants require cooling for safe and efficient operation. This cooling is normally provided by water and the bulk of generation capacity has been sited near water resources for this purpose. The volumes of water required for cooling can be substantial. Hence, power plants can both be vulnerable to, and also contribute to, water scarcity and hydrological risks.

1.2 Problems experienced in cooling of power stations

In some circumstances, power station operations have been compromised due to extremely warm air and water temperatures. Normally in these circumstances, the high temperatures have prevented adequate cooling of the plant, resulting in loss of efficiency and/or breach of environmental regulations. This sometimes results in ramping down or even complete shutdown of power plants.

Not all the cases are particularly well publicly documented as these situations can be commercially sensitive and may affect asset investments and company share prices. These situations normally come to light when safety or environmental regulations are at risk of being breached. Some of these cases are discussed below.

1.2.1 France

The French example is typically the most well known case due to the widespread impacts on nuclear power plants. During the European heat wave of 2003, 17 nuclear reactors were threatened with shut down for any one of the following three, largely interlinked, reasons;

- the intake cooling water temperature combined with ambient temperatures were too high to allow sufficient cooling at maximum power output;
- the output water temperature was too high (usually beyond 25 °C) contravening environmental regulations;
- insufficient flow in the rivers.

At the time, approximately 85% of France's electricity was provided by (thermoelectric) nuclear power (Poumadère *et al.*, 2005), with the second largest source coming from hydro-power, also in short supply during summer months. Nuclear capacity was reduced between 7% to 15% for five weeks whilst hydro output was reduced by 20% (Argonne National Laboratory, 2012) .The power company, Electricité de France (EDF), is Europe's largest power exporter yet had to cut its exports to the rest Europe by more than half (ASN, 2004). Widespread blackouts were only avoided due to generators being permitted to contravene environmental legislation by discharging cooling effluent above 25 °C. This also re-occurred in the 2006 heat wave although to a lesser extent.

1.2.2 The US

The heat waves and droughts across the US in the summer of 2012 had numerous impacts on hydro, coal and nuclear power plants (Krier, 2012; Rogers *et al.*, 2013; Spanger-Siegfried, 2013). Many of these occurred in the eastern half of the country (Figure 1-2). However, this figure perhaps does not tell the full story. The 2011 drought in Texas was the worst since records began in 1895, yet there is only one noted case on the map, whilst other reports suggest impacts were felt at numerous plants (see Stillwell (2013; pp. 15–16)).

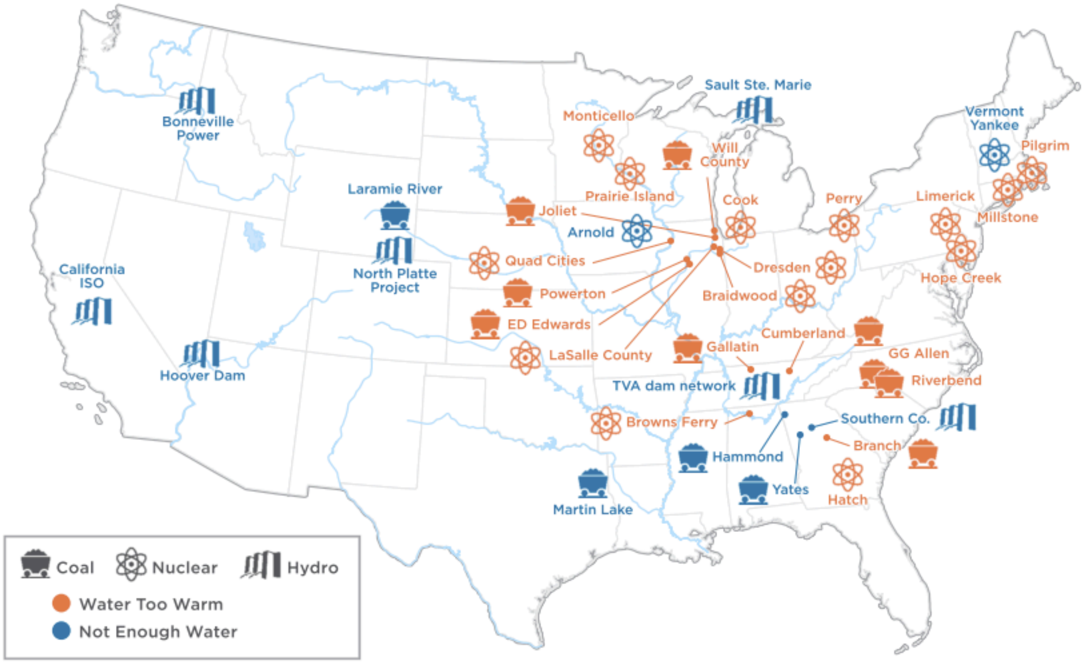

Figure 1-2. Examples of coal, nuclear and hydro power stations affected by water issues between 2006-2013. Source: Davis and Clemmer (2014), adapted from Rogers *et al.* (2013).

More recently, the drought in California has impacted on hydro capacity. Wider expected impacts on typically water-efficient gas-fired plants, reported by the California Energy Commission in July 2014 (Bloomberg Brief, 2014), seem not to have materialised in the media or literature. It is possible that individual cases affecting power plants were not reported on given that no blackouts occurred. The state, renowned for its water challenges, has been proactively working to reduce its electricity system exposure to water-related risks since about 2006 (California Energy Commission, 2014).

The US leads on research into water and climate impacts on electricity generation, with a number of research programmes being coordinated by the US Department of Energy over the past decade. In 2006 a Department of Energy Report to Congress identified that 39% of all freshwater abstractions were for thermoelectric generation for the year 2000 (US Department of Energy, 2006). However, adaptation in the sector is slow and it may not always be considered financially viable to upgrade cooling systems, amongst other resilience measures. In a number of exceptional cases where regulation on water temperatures would be breached, the environmental regulators have permitted operation without penalty, similar to the cases for France. Whilst this may be preferable in terms of energy supply security, without further pressure from regulators there is less incentive for companies to adapt. Nonetheless regulatory amendments to Section 316b of the Clean Water Act (Environmental Protection Agency, 2014) from the US Environmental Protection Agency (EPA) will reduce instances of this occurring as there will be fewer once-through cooled power plants.

1.2.3 China

The Chinese electricity system and industry is heavily dependent on coal, which meets approximately 80% of China's energy demand. Besides the cooling of power stations and industrial facilities, water is also used in the coal mining, processing and coal-to-chemical industries. In total it is estimated to account for a sixth of China's water abstractions. The large majority of abstractions related to coal are for electricity generation (87%) (Francis *et al.*, 2013). Severe shortages in the coming decades are expected (Chan, Knight and Robins, 2011; Chan, Robins and Knight, 2012; Yuan *et al.*, 2014).

Both the Chinese Government and electricity sector are engaged in water issues and are actively seeking to reduce water use through the five year plans. The government has set sectoral water-use targets, the latest being 2.85 (ML/GWh, l/kWh). More recently the *Three Red Lines* policy will establish ambitious targets to be met at river basin, provincial, city and county levels in 2020 and 2030. The targets correspond to total water use, productivity of water use linked to industrial added value and discharge of major pollutants in accordance with pollutant discharge capacity to be met at a 95% compliance level (Liu *et al.*, 2013). They result in substantial and challenging improvements compared to previous five year plans (Chan, Robins and Knight, 2012). Water use productivity should be at or close to the levels achieved in developed countries.

1.2.4 India

HSBC has reported multi-day power station shutdowns in 2012 due to lack of water resources (Singh, Knight and Mitchell, 2014). India faces considerable challenges that combine in the form of growing population and electricity demands, power production predominantly from coal power, huge agricultural demands for water (85%), very seasonal rainfall and a lack of storage capacity. Approximately 80% of annual rainfall occurs between June and September and per capita storage capacity is an order of magnitude smaller than comparable countries such as China, the US and Brazil.

1.2.5 Others

Numerous power plants across the world have also suffered similar predicaments during hot weather and drought, although registered cases can only be found on an ad-hoc basis, usually the media. Examples include Spain (Jowit and Espinoza, 2006), Romania (ICPDR, 2014) and Germany (Förster and Lilliestam, 2009) .

1.3 Notable results from the literature

The occurrence of the problems just described has led to studies investigating future dependency of the electricity sector on water. This work has taken a variety of perspectives, some of which described below. Others are also discussed in Chapter 2.

In the United States, the work by Macknick *et al.* (Macknick *et al.*, 2012b) shows substantial reductions (from 27% to 70%) in water abstraction for electricity across all four scenarios to 2050. All scenarios also reduce consumption besides scenario 3, the scenario with significant coal with carbon capture and storage (CCS) and nuclear, for which consumption increases beyond current levels past 2040. Scenario 4, with the most renewables (predominantly photovoltaic solar and wind), minimises both water abstraction and consumption. Water use in general is found to decrease due to use of closed-loop cooling over once-through cooling, as well as substitution of coal plants by more efficient natural gas CCGT plants. Where there are water use increases in some regions, this is primarily due to the use of nuclear power and coal+CCS. This work has important implications for showing how different national scale electricity pathways may impact differently on electricity sector water use.

In light of the work above, further work in the US by Tidwell *et al.* (2014) has simulated the costs of transitioning large numbers of thermal power plants to zero freshwater withdrawals. Median increases in the levelised costs of electricity are \$3.53/MWh indicating that many retrofits could be accomplished by adding less than 10% to current generation costs. Besides reducing system vulnerabilities, the impacts on wastewater and brackish water supply, as well as efficiency reductions from parasitic loads, are considered to be minimal.

The work of van Vliet *et al.* (2012) projected impacts of climate change on hydrological flows and streamflow temperature in Europe and the US. Climate impacts on 96 existing thermal power plants were quantified. The summertime average usable capacity for plants with once-through or combination cooling decreases 12-16% (US) and 13-19% (Europe) for the 2040s B1-A2 Special Report on Emissions Scenario (SRES)

(Nakicenovic and Swart, 2000). Larger reductions are experienced on a less frequent basis, shown using return period graphs for an example plant in each continent. Capacity reductions greater than 50% increase by a factor of 1.4 and by 2.8 for 90% capacity reductions, although modelling framework uncertainties for these more extreme events are acknowledged. Van Vliet, Vögele and Rübbelke (2013) have also shown considerable impacts on electricity prices for Europe using a similar modelling framework. Limited water availability is shown to have considerable impacts on countries with low production costs, such as Slovenia (12-15%), Bulgaria (21-23%) and Romania (31-32%) for 2031-2060.

The functions set out in Koch and Vögele (2009, 2013) describe the relationships between power plant water demand, electricity supply and the climate parameters: air temperature, water temperature and humidity. Two power stations are tested using current and 2050 climate conditions for the River Elbe basin (Germany), with costs calculated for water shortages and warm water temperatures. For power stations with closed-loop cooling systems, the effects of humidity and air and water temperatures are shown to be negligible. For once-through cooling systems, higher water temperatures require either higher water abstraction or output reduction. This work is further developed (2013) and comparable with Förster and Lilliestam (2009) using the same Krümmel nuclear power station. Similar work for the River Spree (Germany) includes multiple thermal and hydro power stations, finding that, despite declining water demands, streamflow reductions may cause potential impacts (from electricity purchases) of tens of millions of euros in more extreme years (Koch *et al.*, 2012). However, reductions that impact hydro power plants may be offset by optimisation and better management (Koch *et al.*, 2014b).

1.4 Background to the issue in the UK

In addition to the issues discussed above, this section explores the specific need for more detailed work on this area for the UK. Very little work has been done on the topic of electricity sector cooling water use in the UK and there is a considerable gap in data availability required to complete it. Climate change impacts for the UK have been studied in detail and the UK research community leads in this field. UK Government and business is also amongst the most proactive internationally, in terms of both mitigating and adapting to climate change. Finally, when considering the different scales at which both energy and water systems interact, there does not appear to have been any studies that examine this problem in an integrated fashion across the scales, from a national to a catchment level. Particularly in this respect, this thesis makes a significant novel contribution to the field.

1.4.1 US research efforts

It is incontestable that the United States leads this field in terms of knowledge and research. Significant research activities have been undertaken in this area since the early 2000s, most notably by the US Department of Energy (DOE) through the National Energy Technologies Laboratory (NETL) and the National Renewable Energy Laboratory (NREL). Much of this has resulted from new regulation adopted by the US Environmental Protection Agency regarding Section 316(b) of the Clean Water Act requiring best available technology for cooling water intake structures in 2001 and 2002, with the aim of minimising adverse environmental impacts. The US DOE Report to Congress *Energy Demands on Water Resources* (US Department of Energy, 2006) brought heightened attention to the issue which has picked up significantly in the past five years. Both laboratories continue to spearhead efforts under the US DOE Water Energy Tech Team (http://energy.gov/water-energy-tech-team), in addition to various research efforts taking place at the University of Colorado, University of Texas at Austin, University of California (various campii), the Massachusetts Institute of Technology and the Union of Concerned Scientists, amongst others. In the broader area of the *water energy nexus*, the majority of publications are from the United States (Figure 1-3).

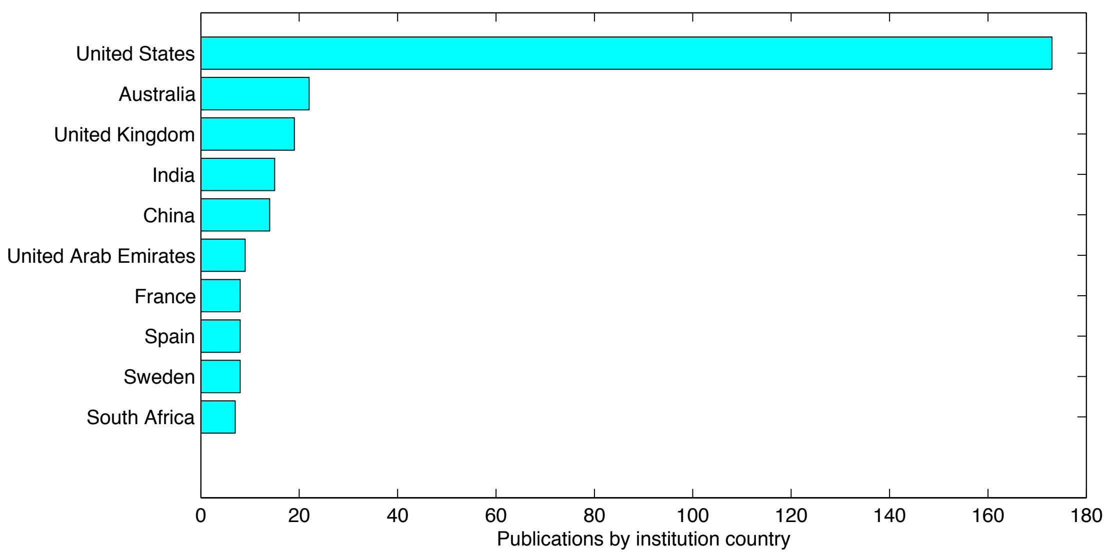

Figure 1-3. Number of publications by institution country using the keywords *'water energy nexus'* and searched within abstracts, titles and keywords from the Scopus database (November 2014).

1.4.2 Status of the UK knowledge in the field

Comparatively for the UK, very little has been done in this area. Schoonbaert (2012) and Smith (2012) projected UK electricity sector cooling water demands to 2050 although neither succeeded in validating current water use through lack of correct background data. A report commissioned by the Environment Agency (Turnpenny *et al.*, 2010) specifies in detail considerations for cooling of nuclear power plants but this is directed primarily to tidal and sea water use and their environmental impacts. There are also projections of future cooling water use in the updated *Case for Change Analysis* document to support the Abstraction Reform (Environment Agency and Natural Resources Wales, 2013), although details on the methodology and assumptions are lacking. Most recently, the Adaptation Sub-Committee of the Committee on Climate Change briefly covered[1] water scarcity risks to electricity generation in the report *Managing climate risks to well-being and the economy* (Adaptation Sub-Committee, 2014).

Water abstraction and cooling processes were also considered in the UK Climate Change Risk Assessment for the Electricity Sector (McColl, Angelini and Betts, 2012). Whilst the analysis considers changes in low flows at the Q_{95} level[2], there is little consideration for changing technologies and future demands. Water abstraction and cooling was also considered in the major power producer's Climate Change Adaptation Reports produced for Defra in 2011. Whilst widely calculated as one of the more severe and growing risks in the company adaptation reports, the information is fragmented across companies and lacks quantified details for further independent analysis.

1.4.3 The data-gap

The technical design and operation of thermoelectric power stations is well understood by the mechanical and power systems engineering community. When these systems use water, the volumes required for abstraction can be calculated for a range of design temperatures. Abstraction and use of water is closely monitored by power station operators given the drive to maximise efficiency within the conditions defined by regulation and the weather. This culture is sometimes known as *measure everything*.

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[1] Including reference to the work in Chapter 3 and 4, Byers, Hall and Amezaga (2014).

[2] Q_{95} is a commonly used flow statistic, referring to a flow level exceeded for 95% of the time of the historical flow record. It is the 5th percentile on flows, explained further in Chapters 5 and 6.

However it is difficult to obtain detailed design or operational performance from power plant equipment manufacturers and operators, especially data that combines air and water temperatures alongside thermal fuel inputs and electrical energy outputs.

Abstractors report water use annually to the Environment Agency in *abstraction returns,* which document the volumes of water used, on a monthly basis. This information is stored internally on a database. From this database, the EA generates basic summary reports of water abstractions for Defra called ABSTAT that are presented publicly. Until 2012, the most information publically available was the amount of water used by the whole electricity sector, for thermal and hydropower combined, on an annual basis, by region and water source. This led to the often misleading assertion that cooling water was responsible for approximately a third of freshwater abstractions,, similar to the US, shown to be incorrect in Chapter 3.

Whilst all the information held is technically available via a Freedom of Information request, obtaining data can be difficult due to the time taken to process it, subsequent processing charges, lack of automated system and a lack of information about all the data that is held. Hence what is made readily available is enough to be considered of the public interest. On a making a request to obtain some ABSTAT data summarised on a monthly basis (as opposed to annually), one reply received was:

> *"Undertaking such an exercise would also involve weeks worth of work. …To produce [data] for one year is likely to be more than 18 hours work".*
> (Environment Agency employee #1 Email, 2012) (Appendix D.1)

The absence of more detailed, publicly available data on cooling water use for the electricity sector drives two key motivations for this thesis:

1. That methods for analysis in this area that do not rely on extensive data would make a useful contribution, not only to the UK, but also for data-poor countries.
2. That the studies and results, whether successful or not, may be used as a starting point for further engagement and research on the topic with business and academia. This will also demonstrate the benefits of improved data availability.

1.4.4 Projected UK climate impacts

Research in the UK on climate change impacts is amongst the strongest internationally. Considerable efforts have been made to bring detailed information on expected climate impacts to a large number of stakeholders. Through the UK Climate Projections and UK

Climate Impacts Programmes (for both 2002 and 2009), amongst a variety of other initiatives, information on climate change impacts has not only cut through a variety of scientific disciplines, but has also permeated into business, civil society and government. UK Climate Projections 2009 (UKCP09) provides observed and downscaled climate projections for the UK at 25 km grid resolution using an ensemble of eleven variants of the HadRM3 model from the Met Office Hadley Centre (Murphy *et al.*, 2009). Climate projections are available for 30-year timeslices at decadal intervals from the 2020s (2010-2039) to the 2080s (2070-2099) for three SRES emissions scenarios, A1B, B1 and A1F1 for Low, Medium and High, respectively. Climate variables for land include a variety of temperature statistics (i.e. mean, daily maxima and minima, warmest and coolest days and nights), precipitation, air pressure, cloud cover and relative humidity. Additional projections are available for marine regions, storm surge trends, sea level rise and multi-level ocean simulations. A stochastic Weather Generator (WG) is also available for land-based projections that enables simulations that sample the full range of change factor vectors at a 5km gridsquare resolution.

Although results are difficult to summarise across the whole of the UK, expected trends include:

- Warmer and wetter winters, with the changes approximately the same across the UK;
- Hotter and drier summers, with greater changes impacting the south and south eastern regions (Figure 1-4, Figure 1-5);
- Increased variance in temperatures and precipitation signifying a less predictable climate;
- Increasing spatial variability between impacts later in the century and for the high emissions scenario i.e. changes in the south will be more extreme than in the north, in the 2080s and high emissions scenarios.

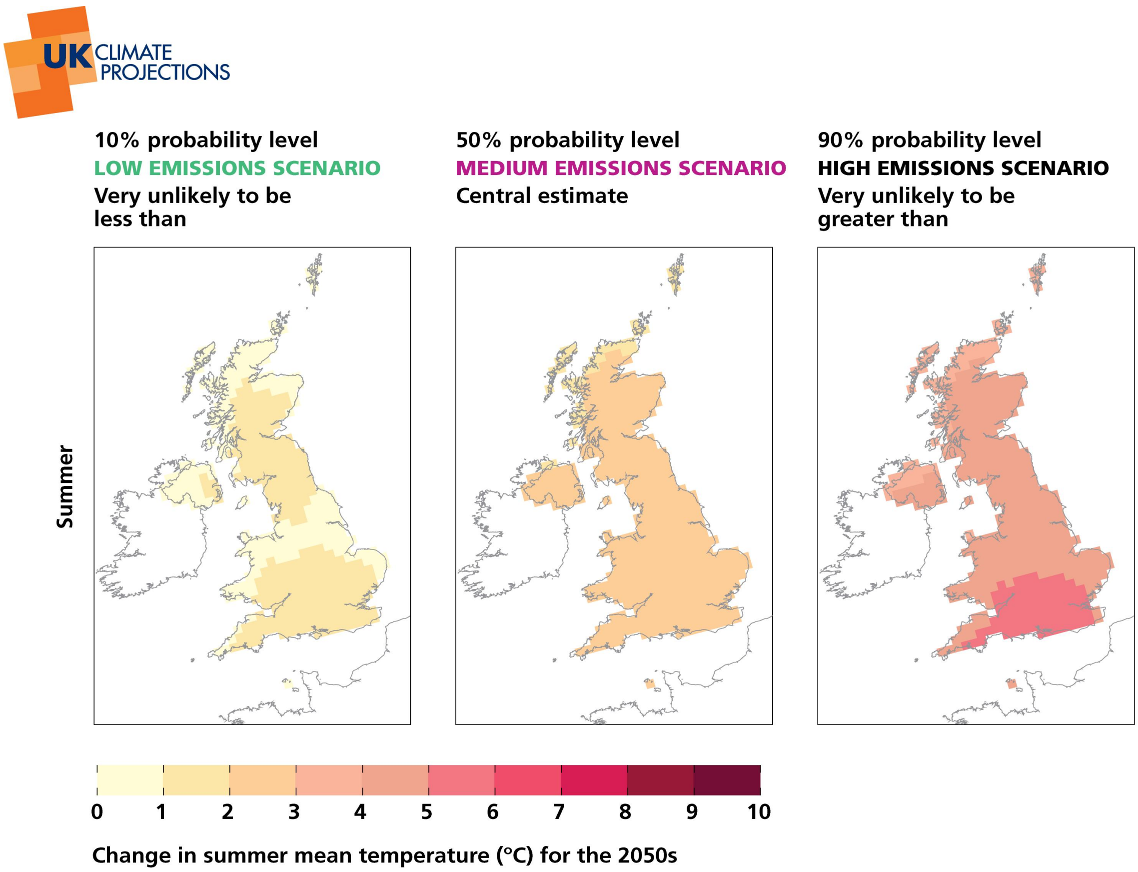


Figure 1-4. Example outputs from UKCP09 showing the change in summer mean temperature (°C) for the 2050s. It shows a large range of uncertainty between the very unlikely (10%) low estimate of the low emissions scenario to the very unlikely (90%) high estimate of the high emissions scenario. © UK Climate Projections 2009.

More recent work has used precipitation outputs from the regional climate models to drive hydrological models and estimate impacts on the UK's water resources. The Future Flows and Hydrology 2050 project simulated river flows and groundwater levels for a 2050s medium emissions climate scenario using an 11-member ensemble from the HadRM3-PPE climate model. Summer flows are largely expected to decrease falling within a range of +20% to -80% with greatest changes expected in the north and west (Prudhomme *et al.*, 2012, 2013). Some autumn flows are also expected to decrease by up to 80% in the south and east. Other national assessments similarly indicate the expectation of an increase in winter flows and reduction in summer flows (Wilby *et al.*, 2006; New *et al.*, 2007; Lopez *et al.*, 2009; Christierson, Vidal and Wade, 2012), as documented in the UK Climate Change Risk Assessment for the Water Sector (Rance *et al.*, 2012). Changes in water temperature expected with climate change alongside other socioeconomic changes are considered to be poorly understood and in much need to further research (Hannah and Garner, 2013).

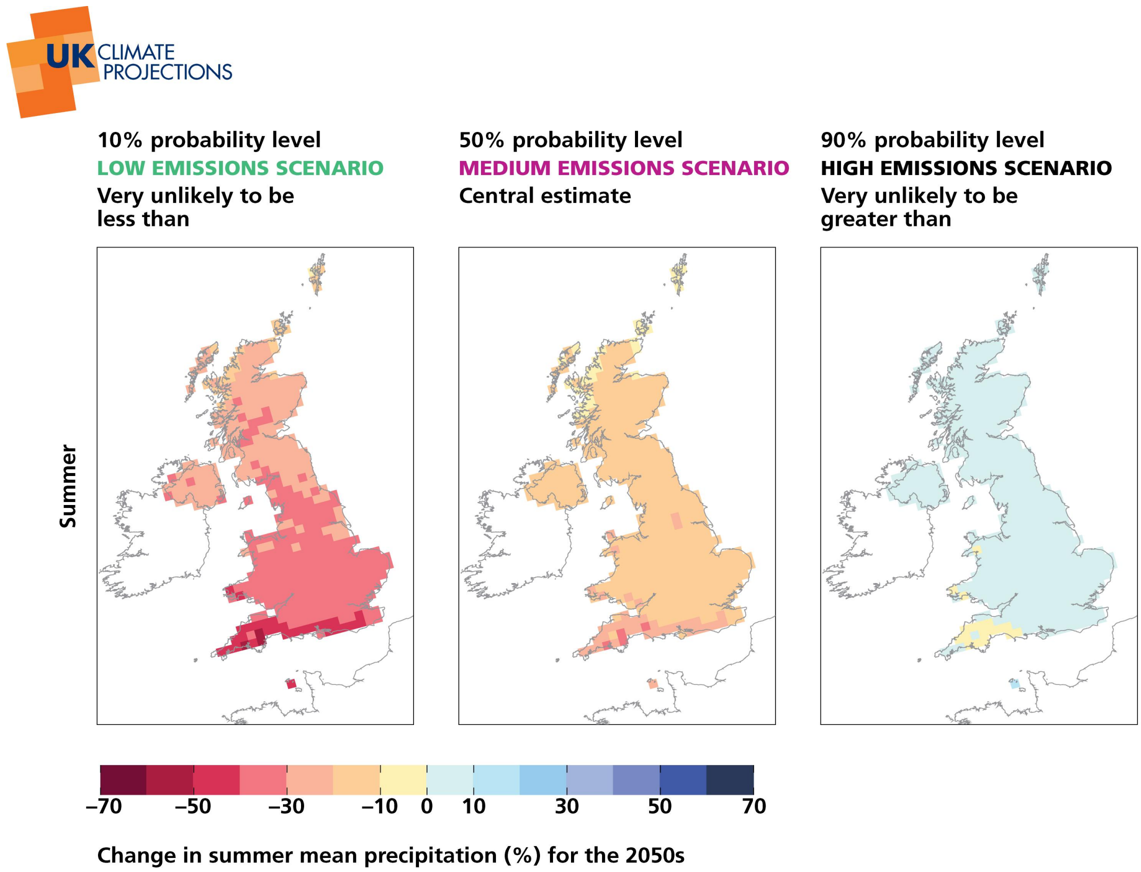


Figure 1-5. Example outputs from UKCP09 showing the change in summer mean precipitation (%) for the 2050s. It shows a large range of uncertainty between the very unlikely (10%) low estimate of the low emissions scenario to the very unlikely (90%) high estimate of the high emissions scenario. © UK Climate Projections 2009.

Overall, projected climate changes suggest that the impacts on the current electricity system would likely make operation of thermal power plants more challenging than the current climate. This is primarily due to low flows and warmer air and water temperatures, although increase in flooding and extreme rainfall, amongst other climate impacts (such as in McColl *et al.* (2012)) will also present challenges. How the climatic changes will impact on the future electricity system is discussed in the following sections.

1.4.5 Socio-economic conditions

The socio-economic prosperity of a nation are interdependent with the quality and performance of its infrastructure system. Infrastructure is said to define the boundaries of a nation's economic productivity and have critical implications for the environment (Hall *et al.*, 2013). Another distinguishing point made by Hall *et al.* is that it is the provision of infrastructure services that is important.

> *"We should not be concerned by infrastructure per se, but by the quality of the services it provides, in particular, in terms of reliability, cost, safety and environmental impact."* (Hall *et al.*, 2013)

In this respect, meeting future demands for infrastructure services within expected ranges of performance and quality is challenged by the changing socio-economic conditions of the nation that is interdependent with infrastructure. The notion of endless economic growth on a finite planet is widely contested between economists and ecologists. Influential theses by E. F. Schumacher (*Small is Beautiful: a study of economics as if people mattered*, (Schumacher, 1973)) and Tim Jackson (*Prosperity without growth: economics for a finite planet*, (Jackson, 2010) propose human prosperity as alternatives to the focus on economic growth. One argument by Jackson surrounds the decoupling 'myth' and differences between relative decoupling and the absolute decoupling, of prosperity from ecological inputs.

The energy sector's profits are currently coupled with selling volumes of energy. However, stakeholders across government, business and the research community (as cited in Hannon, Foxon and Gale (2013)) have identified that alternative service-provision models such as Energy Service Companies (ESCo), may be more economically and environmentally efficient models fulfilling society's energy needs. Societal needs are also changing. Despite considerable drives to improve efficiency of household appliances, the use of gadgets and electronic appliances means household electricity demands continue to grow (Energy Savings Trust, 2011).

The demographic structure of the UK is evolving. The population is ageing and the younger generation is increasingly affluent. Besides immigrant populations, household size is decreasing. Single occupancy households are expected to increase from the current 28% to as high as 40% by 2030 (ONS, DCLG), with resultant effects for infrastructure service demands. Single person households tend to use resources less efficiently, particularly for water and energy as spaces and activities are not shared. The understanding of this needs to be improved considerably. The Cave Review (Cave, 2009) reported that water consumption for single person households could be as much as 40% greater than multiple occupancy homes. The linkage to energy use could be particularly profound as many of the shared occupancy benefits are energy intensive hot water demands, such as dishwashing and clothes washing.

These examples illustrate a small part of the myriad of complexities and external forces of which infrastructure is a part. It is recognised, although not widely, that prediction and forecasting of infrastructure futures is problematic due to the long lifespan of many infrastructures, that can often last 50-100 years (Hall *et al.*, 2013). Decisions *lock-in* patterns of development and behaviour as well as prevent better technologies from entering the system and becoming the dominant technology (David, 1985; Arthur, 1989). Similarly it is difficult to predict or plan for disruptive, game-changing technologies, such as the steam engine, or the internet. There are now many well-established technologies for electricity provision and it is widely accepted that diverse portfolios of generation technologies bring greater security of supply (Bazilian and Roques, 2008; Skea, 2010). Hence, in the energy systems field and in line with general sustainability backcasting approaches, consideration of various diverse electricity generation portfolios is increasingly common and valued as a means for identifying sustainable societal transitions.

1.4.6 Energy policy in the UK

1.4.6.1 Objectives

The Department of Energy and Climate Change (DECC) is the lead ministerial department in the UK with responsibility for energy policy. Energy policy in the UK is governed by three overarching objectives, security of supply, affordability, and climate change (HM Government, 2009; MacKay, 2009; DECC, 2011f; Infrastructure UK, 2011). These policy objectives emerged as a paradigm since the early 2000s, before which the objectives were privatisation, liberalisation and competition (Helm, 2005). Security of supply is generally achieved through portfolio approach in terms of both technology and source when concerning imports. Affordability is targeted by the liberalised energy markets achieved in the 1980s and 1990s, which often involves squeezing of the marginal operating costs and sometimes reduced security of supply. The Gas and Electricity Markets Authority (GEMA) is the principle regulator for the electricity sector, whose primary duties are as an economic regulator with provisions to address the interested of both current and future generations. Day-to-day duties are carried out by Ofgem. Climate change objectives are met by economic instruments (such as a carbon tax) or by favouring certain technologies. Given the lack of experience with low-carbon technologies, some of which yet to be fully demonstrated, much of energy systems research of late has focussed on different low-carbon energy systems that also meet the other objectives. From 2011-2013 the Government published 12 National Policy Statements (NPS) for *Major Infrastructure* in the sectors of Energy, Transport and Water, Wastewater and Waste. EN-1 is the overarching NPS for energy whilst EN-2 to EN-6 cover fossil fuels, renewables, oil and gas supply and storage, electricity networks and nuclear power, respectively (DECC, 2011f).

1.4.6.2 Renewables and decarbonisation

The first Government incentives for low-carbon electricity were introduced in 1990 under the Non-Fossil Fuel Obligation, designed to support renewables as well as the state-owned nuclear power stations. This was later replaced by the Renewables Obligation in 2002 which obliged electricity suppliers to gradually increase the proportion from renewables. Whilst originally *technology neutral*, this has evolved to supporting different renewable technologies in bands according to maturity and market competitiveness, with regular price reviews.

The Climate Change Act 2008 committed in law the current and successive UK Governments to an 80% carbon emissions reduction on 1990 levels by 2050. This includes 5-year carbon budgets that must be met to ensure cumulative emissions in each period do not exceed prescribed levels. Much of the Government strategy and policy-scoping exercises carried out by the Government identified that achieving a low-carbon electricity supply was essential to meeting targets (HM Government, 2009, 2011; DECC, 2010). Electrification of other carbon-intensive sectors, such as transport, domestic heating and industry, facilitates simultaneous and economy-wide decarbonisation if the electricity supply is also low-carbon. The recently ascended Energy Act 2013 (HM Government, 2013a) further reshaped measures for *Electricity Market Reform* (EMR) (DECC, 2013b). Under the *Contracts for Difference* (CfD) system the incentives shift from renewables to low-carbon electricity generation that will include nuclear power and fossil fuel power stations with carbon capture and storage. An *Emissions Performance Standard* (EPS) also limits the CO_2 emissions from any plant exceeding 450 gCO_2/kWh effectively ruling out development or significant retrofit of unabated coal-fired generation. It does enable more efficient, yet still unabated, natural gas combined cycle gas turbines (CCGT) to be built. This is as intended by the *Capacity Market* mechanism which will ensure there is enough flexible capacity to cover peaks and intermittent renewables, thus ensuring security of supply.

1.4.6.3 Security of supply

Much of the attention surrounding security of supply in recent years has emerged from the closure of capacity from the EU Large Combustion Plant Directive (LCPD) and low levels of investment in baseload capacity in recent years. The LCPD will see the closure of approximately 12 GW_e of coal and oil-fired capacity by 2015, which will coincide with another 8.9 GW_e of nuclear capacity scheduled to closed between 2011 and 2023 (Energy UK, 2013). This led to Ofgem reporting a rapidly declining capacity margin expected to be only 4% in 2015/2016 (Ofgem, 2012) and the subsequent measures to address the capacity margin with the Capacity Mechanism.

1.4.6.4 Water in energy policy

Water is not considered within UK energy policy discussions as prominently as in other countries due to the low dependency on hydropower and general belief that the UK is a water-abundant country. Nonetheless water issues for thermal power stations have the potential to impact on the cost of electricity, its security of supply and its emissions, often in conflicting ways through the choice of cooling system. Policy information regarding Water Resources is provided as general information in NPS EN-1. Both EN-2 (fossil fuel generation) and EN-6 (nuclear power) have dedicated Water Resources sections but refer frequently to the information in EN-1.

The choice of cooling system is justified by the developer according to the European Commission Integrated Pollution Prevention and Control Directive (IPPCD) best reference (BREF) guidelines for applying *Best Available Techniques* (BAT) to Industrial Cooling Systems (EC JRC, 2001). The IPPCD BREF notes a number of environmental aspects to be considered in identifying BAT for applied cooling systems: energy consumption; water use; emissions of heat to surface water; emissions of substances into surface water; use of biocides; emissions to air; noise; risks (such as legionnaire's disease); and residues from cooling systems operation. The final BAT solution will be site-specific and will arise from an integrated approach to the assessment. At minimum, the efficiency of the cooling system must be maintained, or if an efficiency reduction is to occur this must be compared against positive environmental impacts.

Developers seek *Development Consent* by making application to the Secretary of State for Energy for approval under Section 36 of the Electricity Act 1989, a process now handled by the Planning Inspectorate. The Secretary of State will seek advice from the statutory consultees as to various aspects of the proposed design. The decision to consent need not follow the advice but must take into account legislation at both national and European level. Various issues and alleged contraventions of the EU Habitats Directive, amongst others, were identified at the Pembroke CCGT power station in Wales. It was recently constructed in a Special Area of Conservation in the

Milford Haven estuary and is discussed further in Chapter 4 (European Commission, 2012).

The importance of water in UK energy policy discussions is slowly growing, although unlikely to be particularly prominent given that for the most part, water use has been well managed by the sector. Discussions on future energy systems tend to consider water in more detail, whether it is biomass, CCS or unconventional fossil fuels such as tar sands and shale gas. The debates surrounding shale gas in the UK have been framed quite squarely on water issues, with concerns about both quantity and quality. Whilst the volumes consumed are unlikely to be substantial (Wood *et al.*, 2011), impacts on water quality are more serious, even though the risks are more likely derive from well integrity problems as opposed to the hydraulic fracturing process in itself (Royal Society and Royal Academy of Engineering, 2012). Nonetheless, linkages between energy and water are increasingly recognised and will continue to feature in the debates about the sustainability of future energy systems.

1.4.7 Water policy in the UK

1.4.7.1 Background

Policy Implementation of environmental policy in the UK is governed by the devolved environmental administrators, the Environment Agency (EA) for England (and formerly Wales), Natural Resources Wales (NRW), the Scottish Environmental Protection Agency (SEPA) and the Northern Ireland Environment Agency (NIEA). All are tasked with the implementation of key EU legislation, such as the Water Framework Directive (WFD) and the Drinking Water (DW) Directive. The regulators Ofwat and the Drinking Water Inspectorate have duties specifically for the water and wastewater industries which are primarily economic and service quality based.

Given that the very large majority of freshwater-based power stations are in England, this section will focus primarily on England and the EA perspective. Key to cooling water use for thermoelectric power stations is the availability of water resources for abstraction. The current water abstraction regime in England and Wales had its roots in the Water Resources Act 1963 that brought into place a system for abstraction licences for surface water and groundwater. Successive Water Resources Acts of 1968 and 1971 and the Water Act 1989 were brought together in the Water Resources Act 1991. Up until this point abstraction licences were issued to existing abstractors and based on previous volumes of abstraction, with little consideration of environmental impacts.

More recent legislation, the Water Acts of 2003 and 2014, have increasingly defined the governance of water abstraction, use and discharges to the environment.

As EU legislation has become increasingly stringent, a number of catchments have been identified as over-licenced and over-abstracted. De-regulation has seen the abolition of licences for abstractions of less than 20 m^3/day in order to focus efforts on larger abstractors. This has included the introduction of abstraction restrictions, such as Hands off Flow limits, seasonal licences and limited-duration licences. One cross-cutting issue is that the abstraction licensing regime is operated only a cost-recovery basis. Licences can in theory be traded, thus bringing in a market value, however the difficulty of this has meant that this rarely happens. Unless actors are able to trade licensed volumes with relative ease, there is little incentive to drive efficiency amongst the incumbent licensees.

1.4.7.2 Abstraction reform

Various actors through consultation have identified both pressures that undermine the resilience of water resources as well as limitations in the current management system (Environment Agency and Ofwat, 2011). Of the former, these include: limited access to additional unused resources; climate change impacts; growing demands; and, environmental damage through unsustainable abstraction. Of the latter, limitations include: fixed allocations of water with little consideration for variability; difficulty in licence amendment; inequitable treatment of abstractors; no price signal in the way that licences are charged; majority of licenced water is unused; and, real and perceived barriers to licence trading. The Water Act 2014 legislated duties for the Secretary of State to report progress on reforming the management of water abstraction in England.

The Government is now leading a programme of abstraction reform with the aim of completion by 2020. Numerous consultation exercises and modelling studies are being performed in order to make the transition as fair as possible. A key aim of the new abstraction licensing regime is a system that is more flexible and dynamic; in terms of by whom and when abstractions are made, as well as to uncertain and variable hydroclimatic conditions brought on by climate change. The Government also aims to increase the economic value obtained from water resources and promote efficient and productive usage of water.

1.4.7.3 Energy in water policy

The electricity supply industry holds a very small proportion of the abstraction licenses (2.4%) yet is responsible for approximately 40% of abstraction volumes for non-tidal surface water in England and Wales. The majority of this volume is for non-consumptive hydro and pumped storage. For thermoelectric power stations, some licences are old and may relate volumes that correspond to when once-through cooling was more commonplace, even though closed-loop tower cooling is now used in almost all cases. The electricity sector also requires very high reliability and hold many of the *unconstrained* licences that do not have 'hands off flow' (HOF) conditions. HOF conditions on a licence restrict abstraction when the flow in a river falls beyond the specified level. These are used to both protect the environment and guarantee resource for other users with less stringent licence conditions (such as unconstrained users). In the proposed abstraction reform, all licences will have constraints that will set different levels of reliability for different users. Allocation trading will smooth out shortfalls and enable abstraction for the most economically productive users during times of relative scarcity.

The energy sector has raised a number of concerns in the abstraction reform consultation (Energy UK, 2014), although in general appears to be in favour of transition to either of the two regimes proposed. In particular, concerns include:

- The long lifetime and high investment value of energy assets, in the order of 30 years and £1 billion per power station (pp. 2, 17);
- The key link between water availability and electricity supply security;
- That understanding and representation of the electricity sector's water use in the reform process is oversimplified, noting that complexities and differences between the way water is used on freshwater and tidal sources, have been seemingly ignored (Energy UK, 2014; pp. 21–22).

Interestingly, Energy UK makes no mention of the increased cooling water demands of CCS, although does make note on several occasions of future changes such as retrofits and upgrades. The sector has also previously stated:

> *"nor is it appropriate to assume that once existing, river-based plant closes, new plant will automatically 'relocate' to coastal areas in order to gain 'unlimited' access to water… existing sites will be the primary candidates for future, new power station developments."* (Association of Electricity Producers, 2012; p. 4)

In combination with other statements regarding the 'significant' financial, efficiency and emissions benefits of using freshwater for cooling, it can be assumed that the electricity sector intends to continue its usage of freshwater resources in the UK for the foreseeable future. In light of the changing energy policy, this use must be scrutinised.

1.5 Problem statement

Climate change policy and legislation is a key driver in the changes currently occurring in the water and energy sectors. On the one hand the energy sector has been considering a wide range of policy options to mitigate greenhouse gas emissions and deliver a secure energy supply, particularly via the electricity sector. On the other hand, the water environment is under increasing pressure from population growth, economic growth and climate change. Thus the Government has sought to reform the way water is managed and used by all sectors. Competitive market conditions for low-carbon electricity generation have also been reviewed, although these may be more water-intensive (such as gas and coal with CCS). The electricity sector has also clearly stated its intention to continue its use of freshwater for cooling. Given the wide range of possible future energy scenarios under consideration, the electricity sector's cooling water use needs to be understood. The societal importance of water demands this, even if the sustainability of water use is not an energy policy objective in the UK. The regional disaggregation of this water use has implications for water resources, and in extreme circumstances, for the security of electricity supply. Systematic identification of where these conflicts may occur is required. Detailed simulation and analysis that explores the dynamics between electricity sector cooling water abstractions, hydroclimatic extremes and the performance of different abstraction regimes, will provide further insight into the sustainable management of water resources. This study of cooling water use at the national, regional and catchment levels brings a challenging but holistic approach to ensuring both water and energy security in an uncertain future.

1.6 Aim and objectives

The aim of this study is to analyse the use of water resources for cooling of UK power stations, under climate change, energy and water policy pressures, to ensure sustainability and security of the energy and water systems.

This study has five objectives that are met within the six chapters following this one.

a) Analysis of the current policy context, drivers of change and impacts of UK electricity sector cooling water use on energy and water security.

b) Develop a methodological framework for estimation of cooling water demands for electricity production on a national and regional basis.
c) Estimation of the current and future cooling water demands from electricity generation on national and regional scales, and identification on a regional basis of hot spots where cooling water demands may exceed availability under climate change.
d) Taking one catchment as a case study (identified in c.), simulate water availability for portfolios of future electricity generation capacity in a catchment with hydrology under the effects of climate change, and compare these interactions under different abstraction regimes.
e) Critique a variety of policy and regulatory approaches to effectively manage electricity sector cooling water abstractions taking into account both energy and water security.

How these objectives are met through the thesis are described following the methodological discussion in the next chapter.

Chapter 2. AIM AND METHODOLOGY

2.1 Introduction

Investigating the water-energy nexus for the UK in this study has had its roots in wider systems thinking and analysis of cross-sectoral demands between different infrastructure sectors. Both the energy and water systems are very different in their nature, scale and composition. They are also managed, operated and analysed in different ways. This results in quite different scales and perspectives from which analysis can be approached.

This chapter presents and discusses different methods and scales at which water-for-energy interactions can be analysed. It then describes the key principles of power station cooling and how these impact on water use. Besides cooling water use, study of these two systems also entails a wide range of uncertainties, such as electricity supply projections and hydrology, as well the policy environment that surrounds these sectors in the UK. The chapter finishes with presentation of the methods that address the objectives of this thesis in alignment with the chapters that follow.

2.2 The importance of scale and notable methodologies

In the past few years a body of research has emerged investigating future scenarios of water use by thermoelectric power. These normally involve energy projections and future water use, in some cases with climate change impacts on hydrological models. This work is summarised in order to build a picture of the different methods and approaches. All studies mentioned expect adverse impacts on power plant cooling due to hydrological or climatic variability. Some of the notable results have been described in Chapter 1.

Taking into account different scales is very important to both systems. The electricity and water systems are both operated and analysed at a variety of different scales. Electricity infrastructure tends to be sited according to demand centres and geographical features that may provide electricity (e.g. hydro or wind). Electricity infrastructure is typically organised into strata of components that make up the grid, such as generating units, various levels of high and medium voltage transmission networks that can be transnational in scale, transformers and substations, and low voltage distribution networks. Electricity infrastructure is typically analysed at the systems level of transmission infrastructure and generating assets, at the distribution network level, or at the generation asset level. The water system, in its more natural form, is most typically characterised at the river basin or catchment level. Aggregations of river basins at regional and national and transboundary level are also considered. The human interaction with the water system occurs and is analysed at the catchment scale taking into account human impacts on the natural environment and hydrological cycle, in addition to engineered water systems in urban environments. The following sections discuss scale in more detail alongside notable methodologies from the literature.

2.2.1 Energy systems level

At the international, national or regional level, we can calculate the water use of the electricity sector from an energy systems perspective. Typical questions would be, how much water does the sector currently use and how much will it use in the future depending on different configurations of the energy system? How will performance of the constituents (i.e. generating assets) of the electricity system change in time according to regulation, water availability or technological advances? How economically productive is the electricity sector in its use of water, compared to other sectors such as agriculture or manufacturing?

Using outputs from electricity supply projections, system-level models calculate water demands from portfolios of different supply technologies. Usually driven by electricity supply models, these are aggregated at national and regional levels. Water constraints on electricity supply are often not included in the electricity supply models and there is no feedback to the energy systems model.

Schoonbaert (2012) performed one of the first examples of this type of analysis for the UK using four electricity projections to 2050 at the national level. The work forms the foundation of the work in Chapters 3 and 4. The work in Chapters 3 and 4 builds on, formalises and improves the approach. Schoonbaert's work was not validated and the results for freshwater are shown to be incorrect, even though the approach was robust. Macknick *et al.* (Macknick *et al.*, 2012b) presents a similar piece of work for the US although the results are presented at a regional level over 17 hydrographic units. Water demands from all fuels have also been estimated on a global level (Hadian and Madani, 2013). In Pan *et al.* (2012) and Francis *et al.* (2013) water use by the Chinese coal sector is projected to 2030 using different scenarios, including use by coal-fired generation. Due to the studies' focus over the whole coal supply chain, the detail of the assumptions on future cooling water use are not well detailed and possibly underestimate future water consumption. Most recently, the study of Qin *et al.* (2015) on Chinese energy sector water demands found that the greatest pressures on China's "3 Red Lines" industrial water use policy would come from growing electricity demand and supply technology choices: namely inland coal and nuclear power.

2.2.2 River basin and catchment level

Analysis of electricity system at the basin and catchment scale is more in tune with the perspective of the water community. It is on these scales that water is geographically confined and distributed, thus its management on this level is usually considered most appropriate. This scale is widely adopted as *Integrated River Basin Management* (IRBM), and within the wider principles of *Integrated Water Resources Management* (IWRM). IWRM came to be known as the Dublin Principles and were formalised at the United Nations Conference on Environment and Development (the Earth Summit) in Rio de Janeiro, Brazil, as:

> *"a process which promotes the co-ordinated development and management of water, land and related resources, in order to maximize the resultant economic and social welfare in an equitable manner without compromising the sustainability of vital ecosystems."* (GWP TAC, 2000; Jønch-Clausen and Fugl, 2001)

However the origins of IRBM date back to as early as the 1960s (Watson, 2004). IRBM takes into account the different actors within the catchment, of which the energy sector is just one of them. There may be various energy actors within a catchment, in competition or cooperation with each other, and unlike some other actors like farmers, these actors are usually part of wider organisations active in various river basins. In this sense, from the energy sector perspective, IRBM is a bottom-up approach to managing water use of the energy sector whereas from the water sector perspective IRBM is more of an integrated cross-sector management approach. A number of studies, which whilst not traditionally IRBM, have been done at the basin and catchment scale and provide evidence about energy sector operations, that could contribute to a wider IRBM decision making.

Koch and Vögele have published several studies that investigate hydroclimatic impacts on electricity generation in Germany. Their approaches involve hydrological models driven by climate projections and the effects of water and air temperature on both thermoelectric and hydropower in the Elbe River basin and around Berlin (Koch and Vögele, 2009, 2013; Koch *et al.*, 2012, 2014b). Water demands are calculated using a physically-based cooling water model (section 2.4.1.1). Projections of electricity demand drive an electricity capacity model that expands capacity according to different economic scenarios. Cooling water demands are also adjusted according to hydroclimatic conditions such as air and water temperature. Water temperature is modelled using the logistic regression approach by Mohseni, Stefan and Erickson (1971). Monthly projections of water availability are compared against cooling water demands to establish the extent of electricity supply reductions and possible financial impacts. The simulations also include adaptation measures which are triggered for power plants if water constraints prevent operation. Once-through cooled plants may change to closed-loop tower cooling if certain conditions are met.

Förster and Lilliestam (2009) take a somewhat similar approach to model hydroclimatic variability and the constraints imposed by environmental legislation on the performance and electricity supply of a nuclear power plant in Germany. The study simulates performance of the plant using arbitrary water temperature increases and flow reductions. Electricity production is constrained by a number of constraints that correspond primarily to environmental legislation, but also the technical performance. Environmental constraints include the downstream mixed water temperature, the temperature difference between the two water flows being mixed, discharge temperature and a minimum discharge level. Furthermore, there is a limit to the volume abstracted due to electric pump capacity. The impacts on production and resultant costs are presented as results. This study is probably the most the most ambitious and well explained in terms of considering a wide range of regulatory constraints.

Lastly, Naughton, Darton and Fung (2012) consider projections of future water availability using flow duration curves against the current hands off flow limits that limit abstractions at low flows. The work considers abstraction demands from a proposed coal-fired CCS plant at both average and maximum load factors for the River Don in Yorkshire, UK.

Whilst these are useful from a water management perspective, they do not tell much about national-level energy policy where strategic decisions are made about the electricity system as a whole.

2.2.3 Multi-basin scale

The multi-basin scale given describes work between the energy systems level and the river basin level. The multi-basin scale covers the convergence of the two systems, taking into account the extent of the energy system and widely connected electricity grids over a landscape of contiguous river basins. Two types of studies seem to fit into this multi-basin category: studies to model long term electricity sector expansion taking into account water availability (Cohen *et al.*, 2014; Hall *et al.*, 2015); and, studies considering regional climate change impacts on electricity generation (Sieber, 2012; van Vliet, Vögele and Rübbelke, 2013), in some cases involving electricity grids and flows in power production, like the work of Rübbelke and Vögele (2011) and van Vliet, Vögele and Rübbelke (2013) for Europe.

Stillwell, Clayton and Webber (2011) consider 11 river basins in Texas for which cooling water availability is projected depending on whether water rights holders use their full allocations or only recent actual use. The analysis also considers four cases that show the potential reductions in water usage that could be achieved if power plants adopted more water-efficient cooling systems such as hybrid wet-dry and dry cooling. Other published work by Stillwell and Webber (2013) investigates impacts to power stations in the same river basins according to arbitrary changes in reservoir storage. The most recent work of Stillwell and Webber (2014) used least cost path GIS-based analysis to identify the feasibility of pipeline construction in order to use wastewater as a cooling water source. Further methods and results are presented in Stillwell's thesis (Stillwell, 2013).

It appears that only the work of van Vliet *et al.* (2012) has used macro-hydrological approaches to assess impacts at the continental scale for Europe and mainland U.S at a 0.5° x 0.5° spatial resolution. Using outputs from three global climate models (GCM) at two global SRES emissions scenarios, a coupled discharge and water temperature model projects changes in flows and water temperatures. Capacity reductions at 96 thermal power plants are calculated using the water demand model implemented by Vögele in Koch and Vögele (2009). Similar work by Rübbelke and Vögele (2011) and Vliet, Vögele and Rübbelke (2013) use similar approaches but only for Europe. In these cases, impacts consider the effects for the European electricity grid. The latter includes hydro and changes in electricity prices.

This scale of analysis, is potentially the perspective that most engages the interests of both water and energy communities. It also potentially presents the greatest challenges in bringing together modelling approaches over wide geographical scales whilst still eliciting useful results at finer resolutions.

2.2.4 The changing scale in this thesis

The methods in this thesis draw on a variety of approaches from both energy systems modelling and hydrological resource assessments. This work starts in Chapters 3 and 4 at a national level to make a high-level assessment of the dependency on water resources from energy systems level perspective. It covers not only quantities of water use but also evaluation of system performance metrics such as the water-use intensity of electricity supply. This methodology is developed further in Chapter 5 to consider the regional multi-basin scale. This brings the important perspective of regional water distribution without tying the analysis into uncertain details such as the exact locations of power plants that may or may not be constructed 40 years from now. Analysis at this intermediate landscape level brings together projections of energy supply and water demand against projections of water availability under climate change.

Having identified one specific region for further analysis, it is then necessary to assess different energy futures at the catchment scale. The work in Chapter 6 tests how different electricity portfolios fare under the localised management of reformed water abstraction regulation in a changing climate. Chapter 5 bridges the gap with a more balanced consideration of the electricity sector’s water demands against water availability under climate change. Lastly, policy considerations from the different scales are discussed and compared in Chapter 7. Considered all together, this thesis brings a new perspective and contribution to the field by making an assessment that changes scales through the analysis (Figure 2-1). This is markedly different from the theses of Stillwell (2013) and van Vliet (2012), for example, whose work has a more static scale.

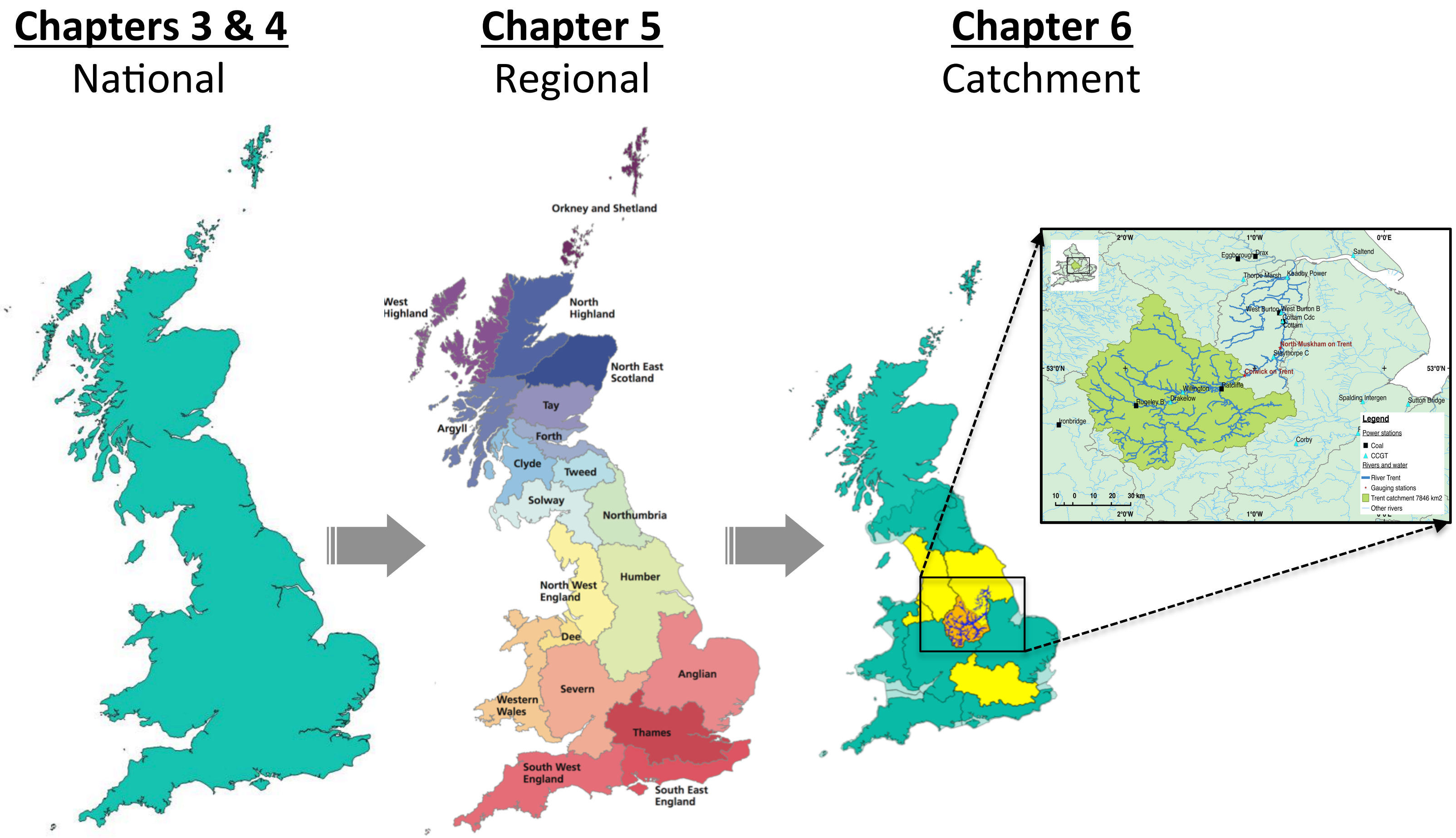


Figure 2-1. Changing scale and detail through the chapters in this thesis. *Centre GB map adapted from UKCP09 Met Office

2.3 Cooling of thermoelectric steam-cycle power generation

This section introduces the cooling of thermal power stations and associated water use. The detail supplied is not comprehensive, but the minimum required to understand this thesis.

2.3.1 Power station cooling systems

Power stations were originally sited on rivers such that the water could be used as the cooling source as well as for other processes. The thermoelectric steam cycle is the most common form of electricity production and derives from the Rankine cycle. The Rankine cycle is the thermodynamic cycle of a heat engine used to convert heat into mechanical work. In a thermoelectric plant, heat from fuel combustion or nuclear fission is used to generate steam. The flow of steam through a steam turbine is transformed into mechanical work, which is converted to electricity using a generator. The steam is condensed upon exiting the cooler end of the turbine and returned to the boiler where it is reheated again (Figure 2-2).

The greater the difference in temperature between the hot and cold ends of the steam turbine, the greater the mechanical work that can be extracted. Since the working fluid is usually water, unless supercritical steam is achieved, the turbine entry temperature is approximately 565°C and the turbine exit temperatures at the condenser is around 25°C. The cooling system maintains the temperature at the condenser as low as economically possible and this may be achieved in a variety of ways. The aim of the cooling system is to remove heat from the condenser at the exit of the steam turbine in order to maintain a low *backpressure*. A low backpressure helps the steam turbine extract the maximum amount of work from the steam.

Since the first power stations sited on rivers, a variety of cooling systems have been developed for different ambient and environmental conditions. Heat is removed from the condenser in either an open or a closed-loop. Cooling systems are introduced in the sections that follow, with more detailed operational details found in the literature (EC JRC, 2001; NETL, 2009b; Turnpenny *et al.*, 2010; Macknick *et al.*, 2011; Rutberg, 2012; Delgado, 2014). This study introduces four primary categories of cooling systems: once-through (also known as open-loop); closed-loop wet tower (natural and mechanical draught); hybrid; and air cooled (both dry towers and air cooled condensers).

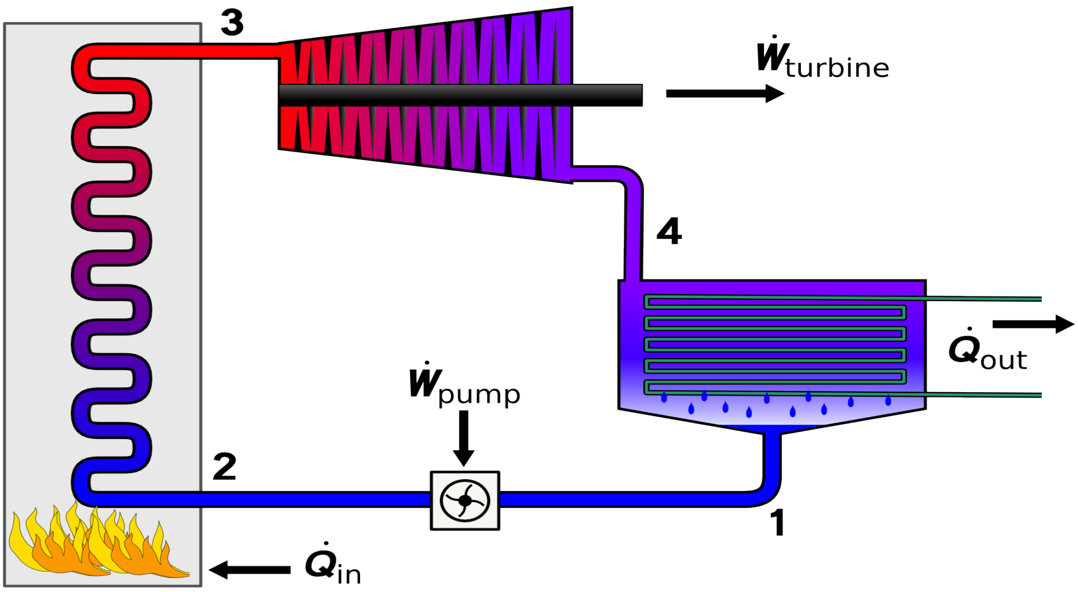


Figure 2-2. Schematic layout of a Rankine cycle. 1. Working fluid (usually and henceforth water) is fed to a boiler, possibly requiring energy for a pump (W_{pump}). 2. Water is heated in a boiler from a thermal input (Q_{in}) such as fossil fuel combustion or nuclear fission. 3. Steam passes through a turbine to produce mechanical work ($W_{turbine}$). 4. The steam is condensed and heat removed (Q_{out}) via a cooling system. Source: Ainsworth (2007).

2.3.2 Heat rejection and cooling demand

The thermal efficiency of the power plant is the driver of the requirement for cooling. A more thermally efficient power plant needs to reject less heat and hence the cooling demand is lower. This requires a smaller capacity cooling system. Whilst efficiency does itself depend on the cooling system, higher steam temperatures result in more efficient electricity production. See Carnot (1824) for the theoretical basis or descriptions by Delgado (2012, 2014) and Dincer and Zamfirescu (2014) for more practical explanations applied to electricity generation.

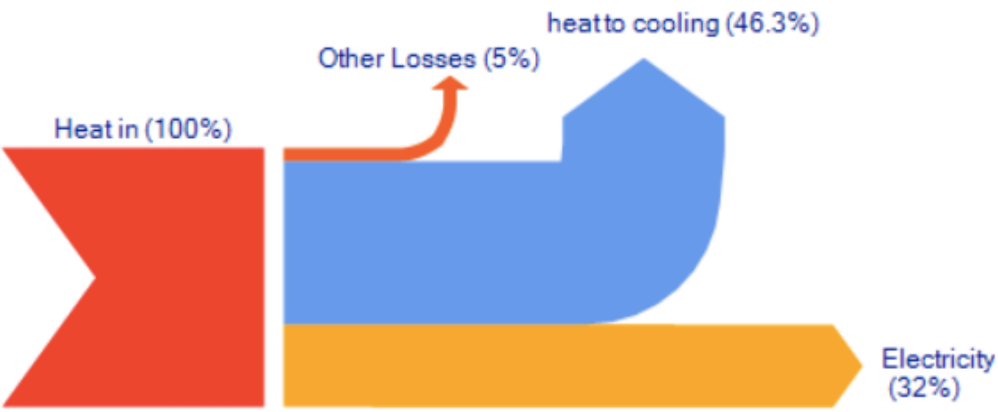


Figure 2-3. Heat balance diagram for a power plant of 32% efficiency, in this case a nuclear power plant. Source: Delgado (2012).

Figure 2-3 and Figure 2-4 show heat balance diagrams for two different power plants of different thermal efficiencies and processes. The difference between the two can be seen in the heat load (MW_{th}) that requires cooling. As power plants of different types (i.e. gas CCGT, nuclear, pulverised coal) have different efficiencies, their cooling loads vary and hence the association that power plants of different fuel types have different cooling water requirements. This is true to some extent, in the fact that cooling demand of different plants with the same cooling system will depend on the thermal efficiency. But the primary determinant of cooling water use is the cooling system type, not the efficiency of the plant, explained well by Delgado (2014).

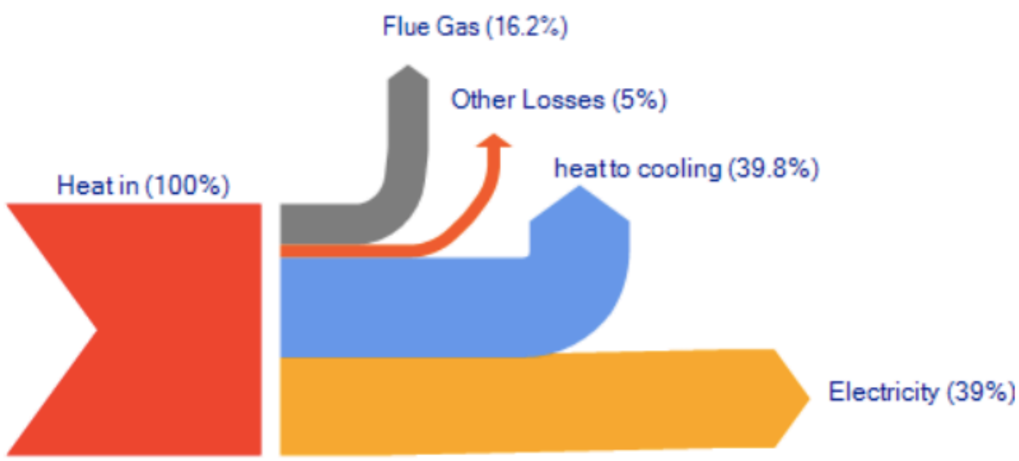


Figure 2-4. Heat balance diagram for a power plant of 39.8% efficiency, in this case IGCC coal power plant. Source: Delgado (2012).

2.3.3 Water use at the power plant

In a power station, water is used for a variety purposes, split into process water and cooling water. Process water includes the boiler feedwater, flue gas de-sulphurisation (FGD) and ash-handling, amongst other processes. Depending on the system used, cooling water use can vary substantially and may be at least an order of magnitude higher than process water use, if not more.

Table 2-1. Summary of water use at a thermoelectric power plant. Sources: Zhai, Rubin and Versteeg (2011); Rutberg (2012).

	Water use litres/kWh, ML/GWh	Applies to	Consumptive or returned/re-used
Boiler feedwater	~0.2-0.35	All steam cycle	Reusable
FGD	~0.2-0.35	Coal only	Consumed
Ash-handling	~0.1	Coal only	Reusable
Cooling systems			
- Once-through	100-150	All steam cycle	Returned
- Closed-loop wet tower	0.9-4.4		Consumed (mostly)

Water use varies according to cooling system and power plant type so whilst a few of these variables and ranges are summarised in Table 2-1, more definitive figures for a range of technologies and processes should be sourced from the literature, e.g. (NETL, 2009b; Zhai and Rubin, 2010; Zhai, Rubin and Versteeg, 2011; Parsons Brinckerhoff, 2012; Rutberg, 2012). Given that cooling system water use is usually by far the most significant water use at a power plant, it is described in more detail in the following section.

2.3.4 Abstraction and consumption

Abstraction is the total volume of water withdrawn from the water source. These are termed *withdrawals* in the US. *Consumption* is the volume of water lost; that which is not returned to the water source.

Consumptive water use is effectively a proportion of the total abstraction, and may depend on a number of factors. Two seemingly similar plants may have different water use due to design, operational or environmental conditions. In once-through systems, consumption occurs mostly due to the elevated temperatures of the discharge water, which contributes to evaporation losses from the water body. The evaporation will depend on the temperature differentials between the discharge water, the receiving body of water, fluid mixing and air temperatures. If an operator is required to keep discharge temperatures below a certain level, a greater throughput of water is required.

In hybrid and closed-loop cooling systems, the proportion consumed depends primarily on the amount of cycles that the abstracted water is recirculated through the towers. Each time water is circulated through the towers, some water is lost to evaporation whilst the remainder rises in temperature. This is replenished with makeup water. The rate of evaporation and temperature elevation depends on variety of relationships between the air, water, humidity and plant operating conditions. Thus, replenishment of recirculating water may change, and can also be determined to some extent by the plant operator. Despite the above issues leading to variable operation, power plants operate to maximise commercial gain through efficient operation and will operate at the limits permitted by environmental regulation.

2.3.5 Cooling system descriptions

2.3.5.1 Once-through cooling systems

In an open-loop once-through system, a continuous flow of cool water extracts heat through specific heat transfer and is discharged to a heat sink such as a river, lake or the sea (Figure 2-5). This is known as once-through (or open-loop) cooling and requires the abstraction (or withdrawal) or large volumes of water. This is generally the most efficient form of cooling due to the low temperatures of the cooling fluid. However, it may be susceptible to warm water temperatures during heat waves with subsequent reductions in efficiency if water is not abstracted at a higher rate. Once-through cooling systems may also have negative impacts on aquatic ecology through the impingement and entrainment of biota against screens and through cooling systems. Furthermore, the thermal discharges may have negative impacts of aquatic ecology (Turnpenny *et al.*, 2010). Once-through cooling systems are particularly common with nuclear power stations due to high reliability. These systems are sometimes operated in conjunction with a cooling tower that is used to cool either the abstracted or the discharged water in locations where the water body temperatures may be high.

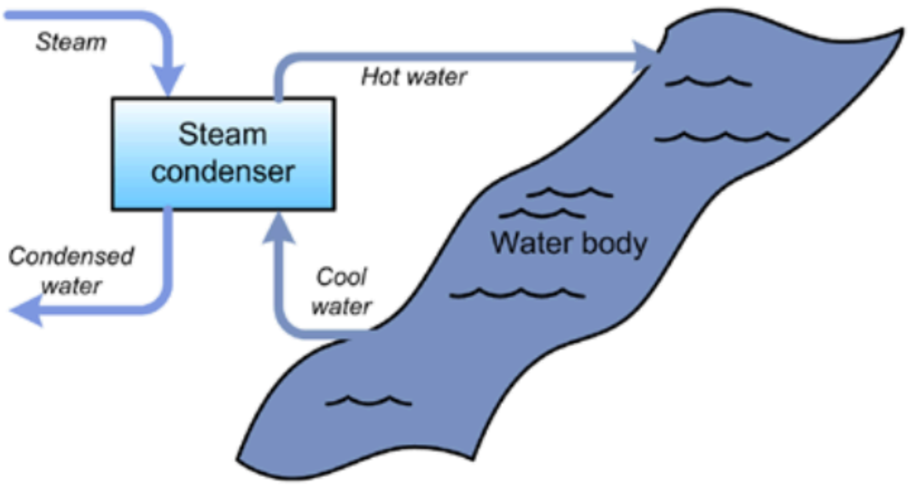


Figure 2-5. Once-through cooling system. Source: Delgado (2012).

2.3.5.2 Closed cycle wet cooling systems

Closed cycle cooling systems keep the cooling fluid in a cycle that recirculates, with the fluid passing through heating and cooling phases. The cooling is usually provided by a cooling tower, but may also be a pond, for example. In either case, the majority of cooling is provided by latent heat transfer by evaporation, from the warm water to the air. In wet cooling towers, the cooling water is sprayed from the middle of the tower whilst air travels up through the tower. A large proportion of this may be evaporated (between 30-80%) depending on the operating conditions. The cooler water that is not evaporated is recirculated through the steam condenser again for another cycle. Water that is evaporated is replaced by makeup water. Abstractions for closed cycle cooling systems are two orders of magnitude lower than for once-through systems. However, the consumption (evaporative losses) is usually a little higher than once-through systems. The cooling towers may be either natural draught or mechanically assisted by fans.

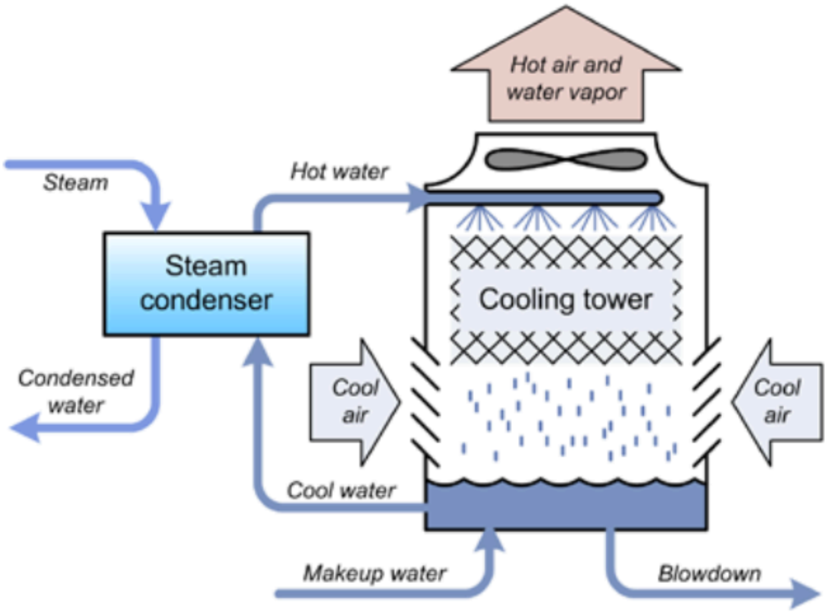


Figure 2-6. A closed cycle cooling tower. In this case a mechanical draft tower assisted by a fan. Source: Delgado (2012).

The water that is lost is replenished by *makeup water*. Due to the evaporation the cooling water becomes concentrated by mineral deposits and salts.. This concentrated water is discharged as *blowdown* to prevent fouling and scaling.

Figure 2-7. Closed-loop wet cooling towers: natural draught (left) at Afsin B power plant, Turkey, and mechanical draught (right) at Soma power plant, Turkey.

2.3.5.3 Air cooled systems

Air cooled systems can be either via dry cooling towers or via air cooled condensers (ACC). Cooling occurs via convective heat transfer. In ACC the steam is cooled in condenser tubes directly that act like large radiators. In dry cooling towers, a closed cycle cooling loop with recirculating water is cooled via radiators within either a natural or mechanically draught cooling tower. Dry cooling systems are suitable in dry environments with little water availability. However, they have reduced cooling efficiency, particularly in hot weather.

2.3.5.4 Hybrid cooling systems

Hybrid cooling systems and not specifically a technological configuration and is more a term used to conceptually describe systems that combine aspects of wet and dry cooling for the desired performance. Some hybrid systems are engineered for plume abatement whilst others reduce water use.

Of those for reducing water use, some are designed to be mostly air-cooled, besides in very hot air temperatures when water is used for additional cooling to maintain power plant efficiency. Water use on an average basis is low, but high during warm weather. Conversely, other low-water hybrid systems can be designed to use water when it is available and reduce water use when it is scarce by using more mechanical air draught, albeit with efficiency reductions at high air temperatures. The performance depends very much on both the design of the cooling system, but also designed operating conditions of the power plant.

The latter is the basis on which hybrid cooling systems are considered for this study. For Chapters 4, 5 and 6 we consider the water use of hybrid cooling to average over a year at 65% of that of conventional closed-loop wet tower cooling, although this amount could vary through the year. For Chapter 7, which includes daily simulation of water availability, we consider hybrid cooling with flexible operation that operates in modes between 100% and 60% of closed-loop wet tower water demand.

2.3.6 Cost considerations

Cooling systems are a fundamentally important part of a power station and result in costs that range between 2-6% of the capital cost of a power plant. The capital cost can vary considerably between gas CCGT and less efficient coal plants, as well as between different cooling systems. Closed-loop wet tower cooling systems cost about 40% more than once-through cooling, whilst both hybrid and dry cooling systems cost three to four times that of wet tower cooling systems (NETL, 2009a; Fowles, 2014). Dry, hybrid, pond and tower cooling systems also require large amounts of space. Operational costs related to the cooling system are also a significant component and may considerably outweigh the capital costs over the lifetime of the plant.

Operational costs may be considered in two ways: as a thermal efficiency loss if the cooling system does not cool as much as a once-through system, or as mechanical losses resulting from parasitic electricity demands to run water pumps and fans in the cooling system to provide the same level of cooling. In reality, the pumps and fans have fixed operational ranges and efficiency losses occur around these operating points depending on ambient conditions. If ambient conditions such as air and water temperatures begin to rise, mechanical losses are normally increased (i.e. fans and pumps operating at maximum) in order to maximise electrical output. If the cooling system is operating at maximum design load, warming temperatures subsequently result in marginally reduced electrical output. This occurs because the cooling system cannot maintain the same turbine exit temperature, hence the turbine backpressure is reduced and mechanical work extracted from the steam by the turbine, decreases.

2.3.7 CCS parasitic loads and cooling water use

As defined by the Carbon Capture & Storage Association (CCSA, 2014), carbon capture and storage (CCS)

> *"uses established technologies to capture, transport and store carbon dioxide emissions from large point sources, such as power stations."*

The addition, or integration of CCS equipment to fossil-fuelled power generation enables most (80-90%) of the carbon dioxide (CO_2) emissions to be captured from the plant thus providing a low-carbon source of electricity. There are currently three main methods of carbon capture, split predominantly in reference to the fuel combustion stage, that are in varying stages of development for different types of thermoelectric power plants (CCSA, 2014).

- Pre-combustion capture converts the fuel into a mixture of hydrogen and carbon dioxide using a process such as gasification or reforming. In power generation, it is likely to be used with coal-fired Integrated Gasification Combined Cycle (IGCC) plants.
- Post-combustion captures the CO_2 using a solvent from which it is then separated for transport. In power generation, it is likely to be used with existing power plants, particularly coal.

- Oxy-fuel combustion systems removes the nitrogen from air prior to combustion resulting in a concentrated (90% dry basis) flue stream of CO_2, which may either be directly stored or further purified to remove remnant pollutants (The Global CCS Institute, 2012). It is less common for power generation amongst the current demonstration projects (The Global CCS Institute, 2013), although the CO_2 capture level is likely to be the highest.

In either case, these systems require considerable amounts of energy to operate, in the form of both heat and electricity, known as *parasitic load*. Both can be taken from the power plant. However, whilst the use of waste heat reduces cooling demand of the plant, the use of electricity increases it, as this electricity is not supplied to the grid. Overall, cooling demands are marginally decreased at the plant, but substantially increased for the carbon capture system, resulting in a significant increase in cooling demand per unit of electricity generated. Where the cooling system uses water, water use is increased accordingly. Water demands are also increased at the boiler, selective catalytic reduction (SCR) and flue-gas desulphurisation (FGD) stages. Breakdowns of the water use for a super-critical pulverised coal plant with post-combustion CCS, with closed-loop wet tower cooling, are reproduced below from Zhai, Rubin and Versteeg (2011) in Figure 2-8. It is worth noting how the aforementioned reduction in steam-cycle cooling demand, plus slightly increased demands from boiler, SCR and FGD, result in similar plant-level water demands (~2,400 ML/GWh), until cooling of the CCS system is taken into account.

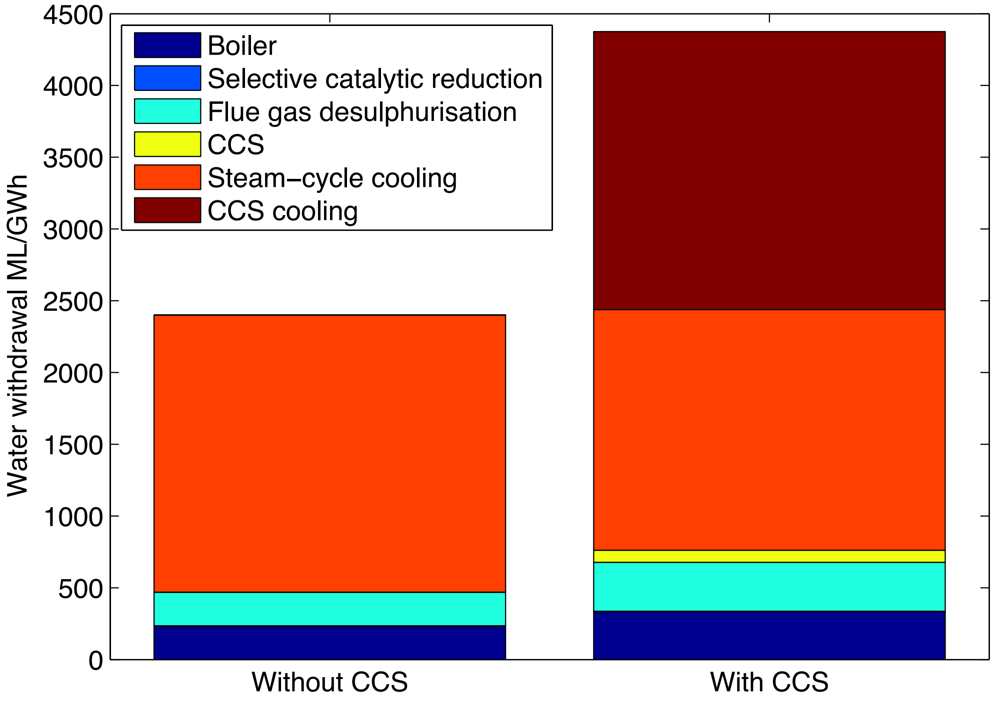


Figure 2-8. Water withdrawal compared between a super-critical pulverised coal power plant with and without post-combustion carbon capture and storage. Figures for consumptive water use are approximately and proportionally smaller, by about 30%. Adapted with permission from data in Table 4 in Zhai, Rubin and Versteeg (2011). Copyright (2011) American Chemical Society.

In terms of fuel inputs against useful outputs, the efficiency of power plants with CCS is reduced, hence the CCS system's term of a parasitic load. This increases fuel inputs and subsequent costs. In the theoretical case studied by Zhai, Rubin and Versteeg (2011), the net plant efficiency (higher heating value HHV) decreases from 38.3% to 26.4%, with subsequent 19% increase in cooling demand for only 69% of the electrical output, per unit of fuel input. Overall, for a closed-loop wet tower cooling system, abstraction and consumption of water increases by 83%, on a unit of electricity basis.

The description of Zhai's work serves to illustrate the impacts of a CCS system. Nonetheless with a variety of both generation and CCS technologies, estimates for cooling demands are wide-ranging, but all increasing.

Another report by Parsons Brinckerhoff (PB) (2012), commissioned by the Environment Agency, details some of the other literature estimates before comparing its own modelling results for various types of CCS plants and cooling systems. Compared to international empirical estimates the figures are low, even for unabated capacity. This is probably due to the figures being for mechanical draft wet tower cooling as opposed to natural draft, as well as the thermal efficiencies of the new plants being higher than the current stock. The assumptions on plant, cooling system and environmental conditions and parameters also have an effect on performance. Some of these results for cooling water abstraction and consumption rates are summarised and compared below.

Table 2-2. Cooling water use factors for different types of power plants with CCS, adapted from data in the report by Parsons Brinckerhoff (2012).

	No CCS		With CCS						
Cooling water use ML/GWh[a]	Closed-loop hybrid cooling		Once-through (seawater)		Closed-loop wet tower mechanical draught		Closed-loop hybrid cooling		Hybrid example % increase
Plant + CCS type	Abs.	Cons.[b]	Abs.	Cons.[c]	Abs.	Cons.	Abs.	Cons.	
CCGT + post	0.57	0.45	87.36	0.87	1.14	0.91	1.01	0.81	77%
CCGT + post + FGR	0.57	0.46	90.56	0.91	1.18	0.94	1.05	0.84	84%
Coal + post	1.19	0.95	165.13	1.65	2.15	1.72	1.91	1.53	61%
Coal + oxy	1.17	0.93	175.30	1.75	2.28	1.83	2.03	1.62	74%
IGCC + pre	0.76	0.61	94.50	0.95	1.23	0.98	1.09	0.87	43%
Biomass + post	1.17	0.94	243.35	2.43	3.17	2.53	2.81	2.25	140%

[a] Also equivalent to litres/kWh
[b] Consumption calculated as the same proportion of abstraction as "with CCS". ~80%
[c] Consumption assumed to be 1% of abstraction

The estimates of Zhai, Rubin and Versteeg (2011) are significantly higher that the PB report, even when considering only cooling water use. A key difference between the modelling assumptions is the cycles of concentration, which is affected by the dissolved solids in the water that are concentrated when water is evaporated. Regulatory limits on discharges and the water treatment procedures in operation will affect the cycles of concentration in operation at the plant. Zhai, Rubin and Versteeg (2011) assume 4, whilst PB have assumed 5, indicating more water-efficient operation due to cleaner water or better water treatment procedures. As acknowledged, use of sea or estuarine water would entail fewer cycles of concentration and subsequently higher rates of abstraction, more in line with those presented by Zhai, Rubin and Versteeg.

The meta-analysis of Macknick *et al.* (Macknick *et al.*, 2012a) reports figures for four different CCS plants with data derived from the US National Energy Technology Laboratory (NETL, 2010a, 2010c). All of the figures are considerably above those in the PB report and more in line with Zhai, Rubin and Versteeg (2011).

In conclusion, all the best sources of literature agree that water use, including cooling water, will increase substantially for forthcoming CCS plants. The scale of the increases is also generally agreed upon, in the approximate range of a 40% to 90% increase for unabated coal and gas plants. Whilst the PB figures were supposedly done with the UK in mind, the figures are considerably below those of other estimates, due to the low initial figures for unabated capacity. With no other UK water use figures available, it is difficult to compare. Consequently, figures from the US peer reviewed literature are used.

2.4 Uncertainties in water-for-electricity studies

The variety of topics covered by this work alongside various methods and data sources requires a structured discussion on the uncertainties of this work. Where possible, the best available information is used, although it should be noted that this is not always the best information that exists. As described in more detail in section 1.4.3, power companies and regulators are known to have useful data, but are unable or unwilling to provide it, due to the time needed for processing and concerns about commercial confidentiality. The following sections briefly discuss key points about methods and general uncertainties in future electricity supply projections, cooling water use factors, cooling method and source allocations, climate change projections and impacts, hydrological modelling and future water and energy regulation.

2.4.1 Methods for obtaining cooling water use factors

The majority of uncertainty concerning cooling water use factors was discussed in section 2.4.1. This thesis uses empirical datasets that introduce parametric uncertainty into the modelling of this work. The wide range of performance between different cooling systems and power generation types ultimately means that the use certain cooling systems dictates the uncertainty in cooling water use factors.

Cooling systems which use once-through cooling abstract approximately two orders of magnitude more water than an equivalent power station using a closed-loop wet tower system. Thus, when calculating water use from electricity supply projections, correctly establishing the correct capacity of plants using once-through and closed-loop cooling systems is significantly more important than worrying about whether a cooling water use factor should be 20% higher or lower.

It is worth examining the different theoretical and empirical ways in which we may calculate cooling water use at a power station and by the sector. As discussed in Chapter 1, the need for cooling is a fundamental aspect of the Rankine cycle and water is most commonly used as the cooling medium that removes heat to perpetuate the cycle.

The thermodynamic processes that occur in the cooling are a function of natural-physical properties, such as the temperature of the water or air and the specific heat capacity of water, as well as human-engineered variables, such as the flow of water through heat exchangers and the desired temperature rise of the volume of discharge water. This can be approximated theoretically by defining objective parameters that constrain an otherwise wide range of possibilities. Theoretical calculations are used in the "Front End Engineering Design" of power stations and their respective cooling systems as well as in research applications that explore thermodynamic performance under different conditions, whether operational, hydroclimatic or regulatory and economic.

Empirical methods observe the water use at power stations, which happens on a continuous basis, hence the potential for very high quality and useful data if combined with other performance data such as fuel input, electrical output and hydroclimatic data. Empirical approaches are typically used in assessing the performance of existing assets against both other assets and theoretical approximations. However, usually on the grounds of commercial sensitivity, only the lowest level of water use statistics (i.e. annual or unitised) tend to ever be made public, if at all. Furthermore, as noted by Rutberg (2012), empirical datasets that collate information from various water users, such as those done by regulators, may be subject to poor quality assurance and methodological disparities between different survey responders.

2.4.1.1 Theoretical approximations

Various theoretical formulations for calculating water use have been presented in the literature and are generally very similar (Maulbetsch, 2004; Olsson, 2012; Rutberg, 2012). Koch and Vögele (2009) present a formula originally from the German Federal / State Working Group on Water (Länder-Arbeitsgemeinschaft Wasser (LAWA), 1983) for the calculation of water demand for power plants with once-through cooling:

$$\boldsymbol{Q = \mathrm{KW} \cdot \mathrm{h} \cdot 3.6 \cdot \frac{1 - \eta_{total}}{\eta_{elec}} \cdot (1 - \alpha) \cdot \frac{1}{\vartheta \cdot c \cdot AS}} \tag{1}$$

where Q is the cooling water demand (m^3), KW is the installed capacity (kW), h is the operation hours, 3.6 converts kWh into megajoules, η_{total} is the total efficiency of the power plant, η_{elec} is the electric efficiency (%), α is the share of waste heat not discharged by cooling water (%), ϑ is the density of water (t/m^3), c is the specific heat capacity of water (MJ/t °C) and AS is the permissible temperature increase of the cooling water (°C).

For a closed loop wet cooling tower, as most commonly used on freshwater in the UK, the formula is modified to take into account the heat that is discharged through evaporative (latent) heat transfer and the subsequent water loss, in addition to makeup water to prevent the build up of minerals and sediments. Rearranging equation 6 from Koch and Vögele (2009), the maximum water abstraction (m^3/s) required, Q_{max}

$$Q_{max}^{F} = \frac{\mathrm{KW}_{max} \cdot \mathrm{h} \cdot 3.6 \cdot \frac{1-\eta_{total}}{\eta_{elec}} \cdot (1-\alpha) \cdot \lambda \cdot (1-\beta) \cdot \omega \cdot EZ}{\vartheta \cdot c \cdot AS} \quad (2)$$

where KW_{max} is the maximum output (kW), λ is a correction factor to account for efficiency changes, β is the share of waste heat released to the air (%), ω is a correction factor accounting for the effects of changes in air temperature and humidity over a year (dimensionless) and usually between 0.75 and 1.25, EZ is the densification factor, otherwise known as cycles of concentration (usually between 1and 4).

Whilst calculating the water requirements in this way across portfolios of power stations is feasible, structural and parametric uncertainty of this model should be noted. Unfortunately there is no mention of either in Koch and Vögele (2009), and the literature source cited (Länder-Arbeitsgemeinschaft Wasser (LAWA), 1983) that probably derived equations 1 and 2 is difficult to obtain.

The model also requires good quality data or assumptions of certain parameters for each power plant that are not readily available for the UK. The net electrical efficiency η_{elec} would be required for all the power stations and is currently not available from DECC. Whilst these could be assumed, they also depend in part on the loading operation of the power plant. Further plant-specific factors λ and EZ, would also be needed and are subject to variation with time. Given the lack of availability of such information in the majority of cases, this method does not necessarily offer advantages over empirically-based data due to the structural and parametric uncertainty that would arise.

2.4.1.2 Empirical methods

The majority of researchers have used methods that use empirical water use factors from operational plants that are categorised by a typology sorted by generation type and cooling method. These water use factors prescribe volumes of water per unit of electricity generated and are hence easily applied to large and diverse generation portfolios, especially those that are changing through time. Water use factors of this type can be obtained either directly through the operators or via regulatory reporting mechanisms that require operators to disclose water use and electricity generation. Understanding the different types of empirical sources and their limitations is important.

Individual data request to power plant operators

- Although potentially time-consuming, individual requests theoretically can offer the best information. However, different formats of data may be received, with variable quality. It may not be possible to obtain a complete dataset covering all generation types and cooling technologies. Suited best for small studies of only a few plants.

Data request via industry body

- If data is available through industry bodies, it can potentially be a powerful resource. Bodies and constituent members may need to be convinced of the benefits of providing data, however, introducing this trusted mediating party may facilitate the process. Methodological procedure and statistical measures used in producing figures (i.e. sample size) should be made clear in order to understand the limitations of the dataset. Most suitable for studies considering many power plants on large scales. Also suitable in smaller studies if taking into account the fact that the figures are industry averages.

Literature meta-analyses

- Meta-analyses potentially offer useful figures for large studies of numerous facilities for which industry-wide insights are desired. Such datasets should be used with caution, however. Sample sizes may vary across the dataset, and meta-analyses may combine both theoretical and empirical factors. Nonetheless these offer potentially the most reliable figures for regional and national scale studies, hence they are most commonly used.

In these cases, water use is normally reported per unit of electricity generated. The water abstraction factor, A, is

$$\boldsymbol{A} = \frac{\boldsymbol{W_A}}{\boldsymbol{G}} \tag{3}$$

where W_A is the volume of water abstracted (m^3) and G is the electricity generated (kWh) over a set period of time (in this case an hour).

Similarly, the consumption factor C is

$$\boldsymbol{C} = \frac{\boldsymbol{W_C}}{\boldsymbol{G}} \tag{4}$$

where W_C is the volume of water consumed (m^3) and G is the electricity generated (kWh) over a set period of time (in this case an hour).

To date, research in the United States has been most comprehensive in specifying water use factors for the electricity generation. The National Energy Technology Laboratory *2007 Coal Power Plant Database* (NETL, 2007a) contains information on more than 1700 generating units, including water use. Studies by other US national laboratories, such as the National Renewables Energy Laboratory, Sandia, Argonne and the Department of Energy have provided a mixture of theoretical and empirical factors within a variety of reports (Torcellini, Long and Judkoff, 2003; US Department of Energy, 2006; NETL, 2007b, 2009b, 2010b; Veil, 2007; Macknick *et al.*, 2011; Cohen *et al.*, 2014). The meta-analyses by Macknick *et al.* (Macknick *et al.*, 2011, 2012a) collected water use factors from published primary literature for both non-renewable and renewable generation technologies and is the most extensive peer-reviewed record to date. One of Macknick's major sources was the Coal Power Plant Database, however it was noted (in conversation) that in many cases the cooling system type was not recorded. Whilst Macknick *et al.* (Macknick *et al.*, 2012a) opens the discussion noting that methodological differences exist, there is no distinction of different methods and how datasets should be treated. The majority of data points within Macknick's analysis do not state whether the water use factors are theoretical or empirical, although analysis of the underlying documents suggest that most are empirically based. The data is predominantly for the US, however its application to power stations in other countries is valid, certainly in the absence of better data.

Nothing similar exists for Europe, let alone the UK, even though the current regulatory reporting mechanisms currently in place would permit such a database to be compiled without much difficulty. The main caveat of this is that the data for water abstraction and electricity generation, at least for the UK, is collected by separate authorities thus complicating the procedure. For this work, attempts to obtain all the licensed abstraction records for the electricity sector from the Environment Agency in England and Wales have thus far been unsuccessful, due to the extensive amount of time required to collate the individual records held in the database. However, growing interest in the topic area in recent years, including from within the EA (Environment Agency, no date c; Parsons

Brinckerhoff, 2012), may result in the EA reconsidering the value of such a dataset for public use.

2.4.1.3 Conclusion and methodological choice

In this thesis, empirical water use factors are used through Chapters 3, 4, 5 and 6. The ease of application combined with the expectation that a comprehensive dataset of water use factors for the UK will emerge in due course, is a primary motivation. Whilst the work in Chapter 6 would probably be better using the physics-based approach, ensuring methodological consistency through the chapters is also preferable. Further caveats and uncertainties associated with the method are discussed in more detail in Chapter 4.

The water use factors used are fully presented in Table 3-3 of Chapter 3. The majority of these are based on the median values reported by Macknick *et al.* (2012a), who also presents the minimum and maximum values recorded from the meta-analysis. A snapshot of this data is reproduced to give a sense of the uncertainty in the water use factors (Table 2-3). Variance is not particularly high, but the number of datapoints (*n*) is also quite low. Reasons for variation include plant age, design and efficiency, local hydroclimatic conditions (air and water temperatures) and regulatory conditions on abstraction, and discharge volumes and temperatures.

Table 2-3. Summarised snapshot of the data presented by Macknick et al (2012a) give a sense of the uncertainty in the water use factors.

ML/GWh	**Abstraction**			**Consumption**			
	Minimum	Median	Maximum	Minimum	Median	Maximum	*n*
			Closed loop wet tower				
Coal Subcritical	1.75	2.22	2.70	1.49	1.81	2.51	8
Coal Subcritical with CCS	4.16	4.34	4.38	3.09	3.20	3.43	4
Coal Super critical	2.20	2.40	2.54	1.68	1.87	2.25	9
Coal Super critical with CCS	1.84	1.92	2.06	1.43	1.49	1.54	3
CCGT	0.57	0.97	1.07	0.49	0.78	1.14	6

2.4.2 Electricity supply projections

The key dimensions of change in electricity supply are the demands that need to be met and the different supply mix used to meet that demand. Ultimately, the scale of supply and demand drives the total quantity of water used. These two dimensions are not distinct, as the cost of supply as well as other exogenous factors may go some way towards regulating the scale of demand. This thesis uses three different types of electricity supply projections, within which there are a number of different supply mixes.

Chapter 4 uses six supply projections that derive primarily from the DECC 2050s Pathways Analysis (DECC, 2010) although with origins from modelling done on the UK MARKAL model system at University College London and the UK Energy Research Centre (Kannan *et al.*, 2007). Chapter 5 uses five regional supply projections from the CGEN+ model used for the Infrastructure Transitions Research Consortium (Hall *et al.*, 2012a, 2015; Chaudry *et al.*, 2014; Tran *et al.*, 2014). Chapter 6 uses five author-derived supply projections based on current and planned capacity as well as projected demand for the Trent catchment.

Key to the supply projections used in Chapters 4 and 5 is that each projection consists of a different supply mix, but also results in a different electricity demands. This means that results reported for water use, have been modelled to reflect the energy system as a whole and not merely different mixes in electricity supply. This means that overall results are more scenario-based but with the caveat that the potential for analysis of some parameters, such as the scale of electricity demand met, is reduced. Conversely, the electricity supply projections in Chapter 6 all feature the same level of capacity and electricity generation. The intention is to facilitate better analysis of the effects of different supply mixes and different assumptions on cooling system types, whilst keeping the level of electricity supply constant. Given that the level of demand to be generated in the Trent catchment may indeed depend on the quantity of water available, keeping the baseline supply level constant and testing its sensitivity across projections is important. Many further uncertainties exist into how electricity supply projections can be modelled, in particular regarding demand elasticities, fuel prices, regulation and technology learning curves but these are outside the scope of this thesis.

2.4.3 Cooling water source and cooling method allocation

Cooling water source and cooling methods allocations are distributions that describe the cooling methods and sources used by an electricity mix at a particular point in time. These distributions may change with time according to the capacity mix and regulation governing water use.

In this thesis, the number of cooling sources and cooling methods have been limited and exclude a few other potential alternatives that are considered less likely from the UK perspective (Table 2-4). Groundwater resources in the UK are limited, particularly in the south and are generally protected for some public water supply use. Currently there is no groundwater use for the cooling of thermoelectric power plants, although groundwater is used for boiler feedwater in a few instances. The potential of using industrial or municipal wastewater as a cooling source is technically feasible and employed at well over 50 locations in the US (Veil, 2007), amongst other countries. The only known case of wastewater re-use in the UK is at Uskmouth CCGT power plant although this is for the boiler feedwater, not cooling water purposes. Whilst it is thought that there is considerable potential for this option in the UK, it is excluded from this analysis as it requires detailed contextual study on a case-by-case basis. It is hence recommended as further research and discussed in Chapter 7.

Table 2-4. Cooling sources and methods that are included and excluded from this analysis.

	Cooling source	Cooling method
Included	Freshwater Tidal water Sea water Air-cooled	Once-through direct cooling Wet tower closed-loop evaporative cooling Low-water hybrid cooling Dry cooling (either air-cooled condenser or dry tower cooled)
Excluded	Groundwater Wastewater re-use (industrial or municipal)	Once-through tower cooled Other hybrid variants

There are variety of cooling methods, many of which combine similar principles. They are broadly categorised as above however. Once-through tower cooling is typically used at sites where there is sufficient water available for once-through cooling, but the water is warm and thus requires either pre or post-cooling. There are no known sites using this method in the UK. All sites with cooling towers appear to be of the closed-loop configuration and it is thought unlikely that future plants will use once-through tower cooling due to insufficiently high freshwater flows. Other hybrid variants of cooling exist, such as those for extremely hot temperatures and also for plume abatement. This study chooses one variant of hybrid cooling, designed for reduced water use, as is the main interest of this study.

The sensitivity of assumptions regarding cooling water sources and cooling methods is considered throughout Chapters 4, 5 and 6. These are shown to be critical determinants in the overall water use by the electricity sector and thus attention to these assumptions is warranted when interpreting the results.

2.4.4 Climate change projections

Climate change projections are used in Chapters 5 and 6 as inputs to the hydrological model. Climate change projections have come from the UK Climate Projections 2009 (UKCP09). UKCP09 uses climate projections from the Met Office Hadley Centre HadCM3 Global Circulation Model (GCM) (Murphy *et al.*, 2009) used to reproduce weather variables across different regions of the world. The Met Office regional climate model (RCM) downscaled the global climate projections to the 25km grid scale used in UKCP09. In this thesis, the UKCP09 Weather Generator has been used to stochastically generate synthetic climate timeseries at a 5km grid scale consistent with the downscaled UKCP09 projections.

Three main causes of uncertainty arise from the UKCP09 climate modelling work, as noted in Murphy *et al.* (2009):

1. *natural climate variability, both internal external;*
2. *incomplete understanding of the Earth System processes and their imperfect representation in climate models (modelling uncertainty)*
3. *uncertainty in future emissions.*

Exploring the natural climate variability can be done by running multiple stochastic realisations of the Weather Generator, such as in Borgomeo *et al.* (2014). This is particularly resource-intensive, not so well supported in the UKCP09 WG user interface and considered beyond the scope of this work. Nonetheless, the climate model structural and parametric uncertainty is covered by UKCP09's use of multimodel and perturbed physics ensembles. This results in the different probabilistic projections, also present in the Weather Generator simulations if the full range of change factor vectors is used. Uncertainty in future emissions (3) has been segregated such that different emissions scenarios can be tested. These are based on the SRES (Nakicenovic and Swart, 2000) B1, A1B, and A1F1 marker scenarios that correspond to low, medium and high emissions pathways, respectively, based on aggregate greenhouse gas emissions by 2100. This enables greater insight in to the effects of different emissions scenarios that are ultimately a result of societal activities. Thus decision makers may better understand the effectiveness and impacts of different emissions pathways.

In Chapter 5 only the medium emissions scenario (A1B) is used in the hydrological model, whereas in Chapter 6, all three emissions scenarios are used in order to cover a wider range of uncertainty. This also enables greater comparison of the relative effects of different emissions scenarios against, for example, different demands or abstraction regimes.

2.4.5 Hydrological modelling

A few uncertainties stem from the hydrological modelling work in Chapters 5 and 6 besides the uncertainties that also stem from the climate projections which are used as inputs to the hydrological model. Structural model uncertainty exists around the representation of the physical hydrological processes. The choice of parameters used in the hydrological model has been selected to improve model performance at low flows, which impacts on the model performance at other parts of the flow regime. The choice of parameter set is also subjectively based on the choice of objective function. Different objective functions would identify different parameter sets identified as the most appropriate parameter set. Model uncertainty is discussed further and shown in Chapter 6. Other uncertainties such as for the estimate of Potential Evapotranspiration (PET), land use changes and observed climate and hydrological timeseries such as temperature and river flow, are not addressed in order to keep the study focussed on the key variables.

2.4.6 Water, energy and climate regulation

Regulatory and policy responses have significant impacts on infrastructure, both from the capacity that is developed as well as the way that it is operated. The Climate Change Act 2008 and the Energy Act 2013 are currently the key drivers of the energy sector to be considered in this work. The former drives emissions reductions and limits most future electricity capacity to low-carbon. This subsequently precludes, for example, the use of unabated coal-fired capacity in any of the future electricity projections. The latter stimulates the development of low-carbon generation such as coal and gas with carbon capture and storage (CCS) as well as unabated gas (CCGT) capacity. Power plants built in the next decade will have a lifespan beyond 2050 and are unlikely to be stranded in the near term as a result of further abrupt legislative changes.

Water regulation will have impacts on the water availability to the electricity sector and subsequently the cooling systems used. The current water abstraction regime is being reformed and due to be *transitioned* by 2020. In Chapter 6 we consider both the current and proposed abstraction regimes to investigate impacts on power plant operations. The proposed regime will change the way that volumes are allocated according to flow, as well as improve the way that water allocations can be traded. This work only considers the impacts of the way that available water is allocated.

Other environmental regulation such as from the EU Water Framework Directive has implications particularly for water body ecology and chemical quality, as described in Chapter 7 and by Förster and Lilliestam (2009). Specific regulations apply to streamflow and cooling water discharge temperatures, however these impact primarily on power plants with once-through cooling, not closed-loop cooling towers systems because the discharge volumes, if any, are comparatively very small. The current approach of water temperature regulation is one of limiting the extent of extreme temperature changes, as opposed to specified absolute values that must not be passed. However, some species are sensitive to absolute values and it is unclear exactly how fast they can adapt. With climate change and the expectation of rising streamflow temperatures due to both hotter summers and low flows (van Vliet *et al.*, 2013), it is likely that regulation based on absolute values will be breached for frequently unless it is adjusted.

Further regulation on the environmental impacts of water use for thermal power generation, such as air and water quality, are not considered in the modelling work, but are discussed throughout the text.

2.5 Introduction to the methods used in the Objectives and Chapters

In its ambition this work brings together some of the best methods and approaches from the discussions above and applies them to the UK context. This study transverses scale between the energy and water systems in order to apply the most appropriate techniques.

As described in the Problem Statement, the use of cooling water by power stations in the UK is not particularly well understood from both energy systems and water resources perspectives. This is particularly the case considering the relative expertise of the United States in this area and, the attention given to other issues concerning climate change in both energy systems and water resources.

This section introduces some of the methods and the perspective of analysis for the forthcoming chapters. It proposes the suitability of the methods and how these will meet the objectives, in addition to their contribution to the overall aim of the thesis. Figure 2-9 maps out which objectives are tackled in the corresponding chapters.

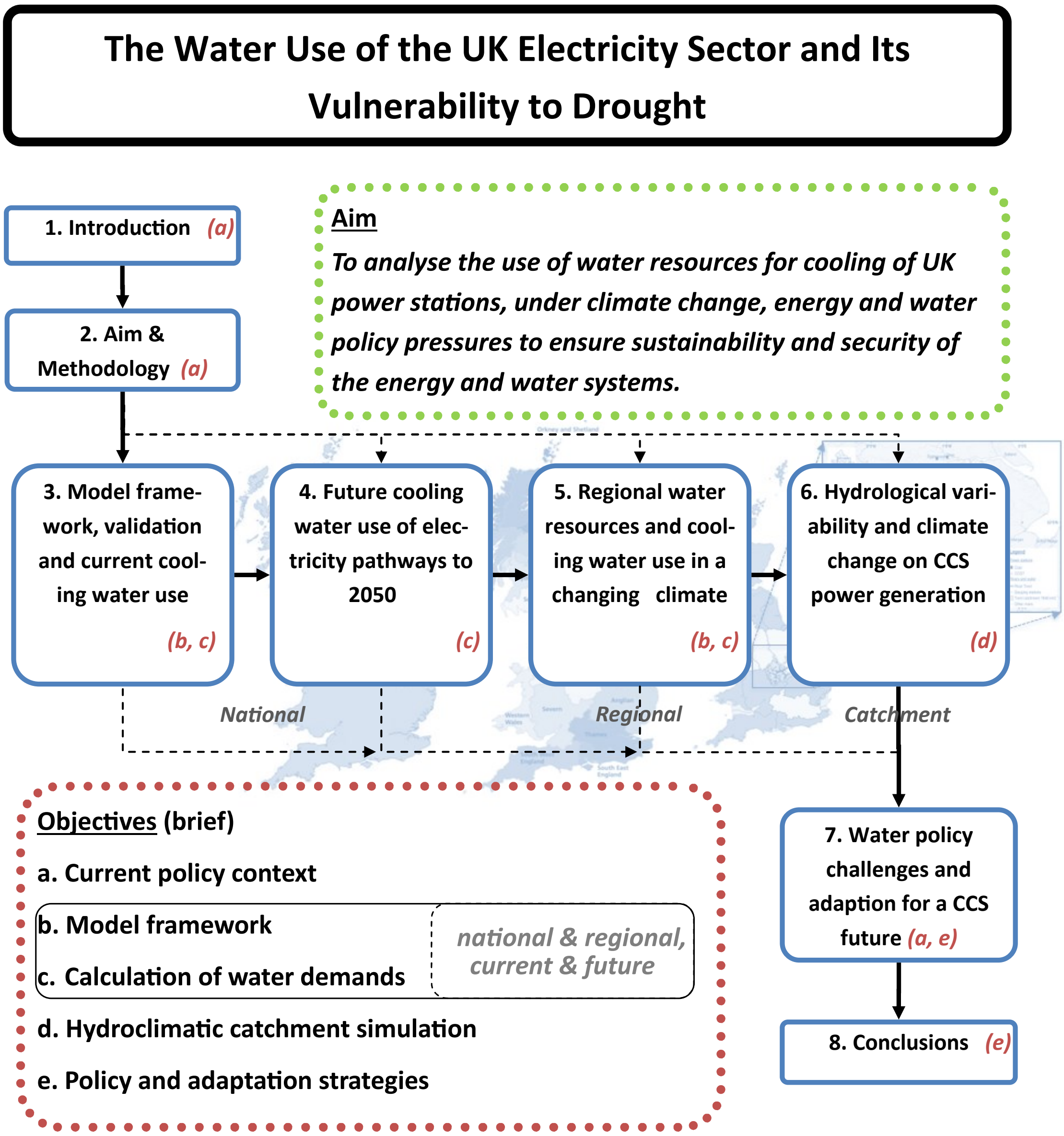


Figure 2-9. Schematic map of the chapters, aim and objectives of this thesis.

2.5.1 Objective a) Current policy context

a) *Analysis of the current policy context, drivers of change and impacts of UK electricity sector cooling water use on energy and water security.*

Understanding the current governance and policy arrangements of the UK is critical to ensuring that the results of this thesis extend beyond academic applications. Chapters 1 and 2 introduce and discuss some of the key current policy, governance and regulation surrounding the energy and water sectors, with a focus on water for electricity production. This is done primarily through an overview of the policy and regulatory landscape.

Understanding the policy context and range of drivers is key to defining the methodology for this study, hence its discussion within these first two chapters. Whilst a variety of EU Directives and legislation have quite specific impacts on the way that water is used for cooling at power plants, this study will focus primarily on the volumes of water used, and not thermal discharges or use of biocides in cooling systems. Further details are covered in the following chapters, where appropriate, and offer more detailed insight into how policy has been considered within the studies. For example, the energy scenarios used in Chapters 3 and 4 are directly derived from the Government's Carbon Plan (HM Government, 2011) in order to achieve explicit policy relevance. The same applies to the abstraction regimes simulated in Chapter 6.

In Chapter 7 we bring together key policy and governance insights and conflicts that have been identified through the studies in Chapters 3 to 6. Crucially this integrates policy perspectives that have been learnt through studying the water-for-electricity nexus at different scales. This is discussed further in section 2.5.5.

2.5.2 Objective b) Framework for demands at national and regional scales

b) *Develop a methodological framework for estimation of cooling water demands for electricity production on a national and regional basis.*

National scale water demands can be calculated using electricity system-scale figures for current and projected electricity generation. Chapter 3 formalises a framework for undertaking this type of assessment based on generation technology, cooling methods and cooling sources. Whilst the former is usually an energy model output, cooling sources and cooling methods need to be investigated and presumed. Detailed information about cooling characteristic rarely exist but this is important for validation. This method follows broadly the approaches used by Schoonbaert (2012) for the UK and Macknick *et al.* (Macknick *et al.*, 2012b) for the US, even though implementation and presentation of results is quite different.

The ambition is to formalise a model framework that is scalable, such that it can be employed at regional or continental scales with little adaptation. The framework should also be employable at a variety of temporal scales. The framework, based around the key inputs of generation technologies, distributions of cooling methods and sources, and water use factors, enables more comprehensive analysis of the uncertainties surrounding the input data and assumptions, especially if implemented into a mathematical programming software such as Matlab or R.

Chapter 3, most crucially, validates the model and baseline dataset against recent levels of freshwater and tidal water use reported by the Environment Agency over the past five years. This is an important advance from the work of Schoonbaert whose results appear to overestimate the level of electricity sector freshwater use by a factor of approximately four.

Chapters 4 and 5 builds on the framework presented in Chapter 3 to calculate water use for different sets of electricity generation pathways. Chapter 5 develops the framework of Chapter 3 by calculating cooling water demands on a regional basis. For this, electricity generation pathways with regional disaggregation are required.

2.5.3 Objective c) Future demands at national and regional scales

c) *Estimation of the current and future cooling water demands from electricity generation on national and regional scales, and identification on a regional basis of hot spots where cooling water demands may exceed availability under climate change.*

This objective tests the flexibility of the framework to calculate water use on different temporal and spatial scales. The aim is to do this on national and regional scales using two different energy models. Chapter 4 builds on the validated model by calculating water use, for all sources, on an annual timestep from 2007 to 2050 for a selection of national electricity pathways, derived from the Carbon Plan (HM Government, 2011). Indicators are used give an idea of the sectoral performance through time. This chapter also explores the sensitivity of the cooling method and cooling source assumptions, something that has not been done in similar studies.

For Chapter 5, the pathways are derived from the CGEN+ model that combines electricity and gas networks on a regional scale (Chaudry *et al.*, 2014). Regional water demands are more appropriately assessed against water availability, thus demands are quantified on an annual and instantaneous basis. Using outputs from a hydrological model, this chapter develops an approach for regional assessment of cooling water availability to the electricity sector.

Regional water availability is derived from a water resources model also developed for ITRC. This model is used to calculate the volumes of low flows in a medium emissions climate. A series of calculations based on current abstraction licensing practices is used to estimate the proportion of low flows available to the electricity sector. This assessment of water resource availability to the sector alongside the regionalised demands is a new high level assessment aimed at identifying regional water availability constraints for further detailed catchment scale analysis. Besides this method of assessment, this approach bridges the two more common scales of assessment in water-for-electricity studies.

2.5.4 Objective d) Hydroclimatic catchment simulation

d) *Taking one catchment as a case study (identified in c.), simulate water availability for portfolios of future electricity generation capacity in a catchment with hydrology under the effects of climate change, and compare these interactions under different abstraction regimes.*

Informed by the analysis in Chapter 5 and Objective b), a critical region and catchment for cooling water supply is to be identified for a catchment scale analysis. The aim is to assess hydrological and climate impacts on future thermal generation capacity in the catchment.

The study in Chapter 6 makes reference to methods employed by Naughton, Darton and Fung (2012), Koch and Vögele (2009), and Förster and Lillestam (2009). This work employs a lumped conceptual hydrological model of the River Trent with UKCP09 Weather Generator timeseries as inputs to explore a wide range of future climates at decadal timeslices to 2080 and for three emissions scenarios. The main focus of the hydrological model to assess the frequency and severity of low flows and droughts.

The performance of five CCS power capacity portfolios are tested against probabilistic projections of water availability from the hydrological model, similar to approaches described by Hall *et al.* (2012b) and Borgomeo *et al*. (2014). The capacity portfolios comprise a range of cooling technologies and generation mixes of CCGT, CCGT+CCS and Coal+CCS. Finally, an algorithm is developed to prioritise the most water-efficient capacity and identify differences in capacity availability between the current and proposed abstraction regimes during periods of low flows.

The study covers a wide range of uncertainties with the intention of identifying differences between the current and proposed abstraction regime. Testing a wide range of possibilities is one step towards identifying an abstraction regime that is robust. The study aims to present methods and results that may assist both the electricity sector and those involved in water abstraction licensing and reform. The simulation framework also enables differentiation between mean and extreme changes in water availability.

2.5.5 *Objective e) Policy and adaptation strategies*

e) *Critique a variety of policy and regulatory approaches to effectively manage electricity sector cooling water abstractions taking into account both energy and water security.*

This chapter brings together a variety of policy insights and implications identified during the work of the preceding chapters. In this case, CCS is identified as an aspect most needing attention. The chapter starts with an overview of the governance arrangements to give a notion of the regulatory challenge. It investigates whether the current abstraction licensing arrangements are compatible with Government policy on CCS, given that consents for *carbon capture ready* power plants are already being made. In light of some concerns raised in previous chapters, a number of innovative technological adaptations for power stations are put forward. The chapter finishes with a critical evaluation of CCS, energy policy, climate change and the challenges that lie ahead, depending on whether CCS becomes a mainstream technology.

2.6 Conclusions

Undertaking this detailed investigation of cooling water use in UK electricity generation requires the application of a variety of methods from both energy systems analysis and water resources research. In some cases, particularly in Chapters 5 and 6, methods from both fields need to be combined in novel ways. However this brings insight from a variety of perspectives. As discussed comprehensively, this study transforms from an energy systems high level perspective at national and regional scales to focus on the catchment scale most familiar to the water community. As a whole, the methodology progresses in a logical way that bridges traditional methods and perspectives from the energy and water research communities. This integrated approach that comprehensively covers different scales through the thesis is a novel contribution to the field of water-for-electricity studies.

A key component of this analysis has been the thorough discussion of the trade-offs between the main methods for calculating water use factors. Rarely scrutinised or questioned, it may assist others embarking on water-for-electricity analysis. Each method has its advantages for particular applications, although other circumstances such as data availability, also dictate the methodological choice.

Chapter 3. MODEL FRAMEWORK, VALIDATION AND CALCULATION OF COOLING WATER USE FROM ELECTRICITY PATHWAYS

3.1 Introduction

The water use from a power station can be calculated by multiplying the electricity generation over a period of time (GWh) by a water use factor (MegaLitres/GWh). However, estimation of the water use across a sector consisting of many assets of different technologies, ages, modes of operation and locations, quickly becomes complicated. There are different ways to calculate water use as discussed in Chapter 2, although here only one of those methods is presented, as previously justified.

The first section of this chapter presents the framework for a model developed to estimate current and future abstraction and consumption of cooling water from the electricity sector. The second section discusses the implementation of this model for the UK, describing in detail the collection of data and model validation. The third section presents and discusses results of modelling the current electricity sector's cooling water use in the UK for 2010. The chapter concludes with a discussion on methodology and the contribution that this makes to analysis of both current and future electricity pathways. Some of this information is reproduced with permission from Byers, Hall and Amezaga (2014).

3.2 Model framework for deriving water usage from current and future electricity pathways

The model presented here quantifies current water use of the UK electricity sector distributed by generation type, cooling method and cooling source. This is done by using recent data of electricity generation and by defining characteristics of the current generation capacity. By establishing a validated model of current use, implementation of future electricity pathways is facilitated, primarily due to the fact that future assumptions will be based on the current situation, which must be known to be an accurate representation of the system.

In Chapter 4, the same model framework is similarly used to test six decarbonisation pathways for the UK by combining projections of cooling methods and cooling sources for future thermoelectric generation to estimate water use for the desired timeframe (Figure 3-1). The first timestep in calculation of future water use is the current situation and it is essential that this is as accurate as possible, discussed later in section 3.5.2.

For both current and future studies, water use is calculated by:

1. multiplying the electricity output from a generation technology by the abstraction and consumption factors for that technology and chosen cooling method,
2. Attributing that water demand to a cooling source.

In order to do this, the following datasets are normally needed:

1. Electricity generation by fuel type; (section 3.3.1)
2. The distribution of the generation by fuel type across different sources and cooling technologies, most easily determined by using datasets of installed capacity; (section 3.3.2.2-3.3.2.5)
3. Water use factors for each cooling system and fuel/technology; (section 3.3.2.6).

When all the electricity generation from all technologies is aggregated through time, we have an electricity pathway.

We can define an electricity generation pathway with an $n_t \times n_g$ matrix $\boldsymbol{G}$ whose elements $g_{t,j} : t = 1,\ldots n_t, j = 1,\ldots n_g$ define the amount of electricity generated (in TWh) by generation technology j in year t. Subsequently, the $n_t \times n_g \times n_m \times n_w$ array $\boldsymbol{S}$ defines for each generation technology the percentage split across $m = 1,\ldots n_m$ cooling methods and $w = 1,\ldots n_w$ cooling sources for specified timestep $t = 1,\ldots, n_t$. The first timestep is an observation of the current distribution amongst cooling sources and cooling methods whilst assumptions are made about future distributions. The matrices $\boldsymbol{A}$ and $\boldsymbol{C}$, of size $n_m \times n_g$, specify respectively abstraction and consumption factors for water use per unit of electricity generated (in ML/TWh) corresponding to the n_m cooling methods that are available to the n_g generation technologies. Abstraction and consumption for any combination of generation technology and cooling method is obtained by element-wise multiplication of ***A*** and ***C***, respectively, with ***G*** and ***S*** to give ***GAS*** and ***GCS***. Thus the abstraction *a* or consumption *c* for pathway ***G*** on cooling source *w* in year *t* is equal to the sum of water use for all generation classes in ***G*** multiplied by the cooling methods and source distributions in ***S***:

$$\boldsymbol{a_{t,w}} = \sum_{j=1}^{n_g} \boldsymbol{g_{t,j} a_{j,m} s_{t,m,w}} \tag{1}$$

$$c_{t,w} = \sum_{j=1}^{n_g} g_{t,j} c_{j,m} s_{t,m,w} \tag{2}$$

The modelling work presented is also described by Figure 3-1 and has:

- n_g = 7 generation technologies: nuclear, gas open cycle gas turbine (OCGT), gas combined cycle gas turbine (CCGT), oil, sub-critical coal/biomass, gas CCGT with carbon capture and storage, super-critical coal with carbon capture and storage.
- n_w = 4 cooling sources: non-tidal surface water (FW), tidal surface water (TW), sea water (SW) and air-cooled (AC). The water nomenclature refers to the categories used by the Environment Agency, although for brevity we refer to “non-tidal surface water” as freshwater (FW).
- n_t = 13 timesteps: 2007:2011, 2015:5:2050. Results are interpolated linearly on an annual basis for graphical reproduction
- n_m = 4 cooling methods: open-loop (O), closed-loop (C), hybrid (H), air-cooled (A).

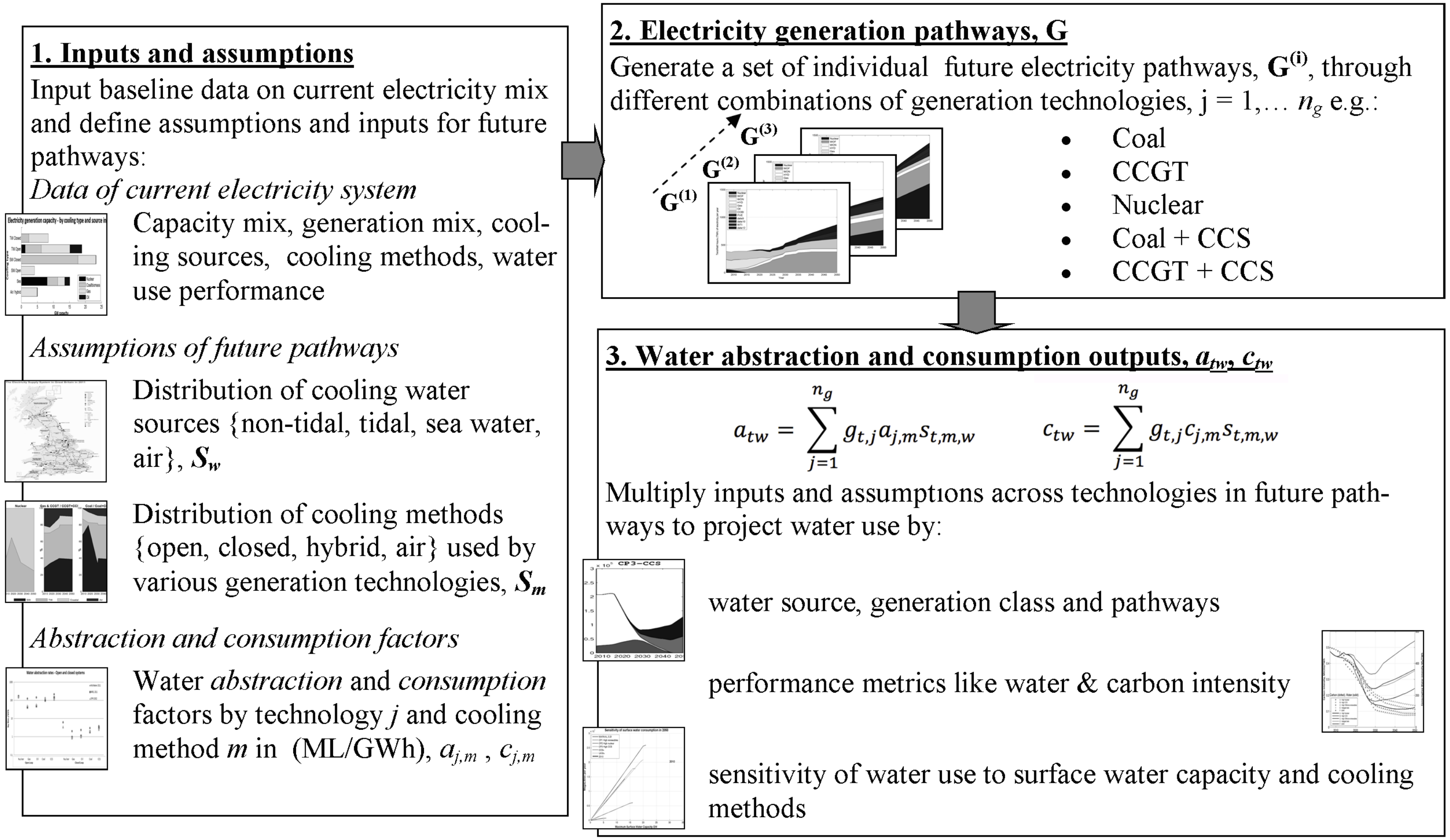


Figure 3-1. Model framework diagram for estimating water use from electricity generation pathways. With an abundance of generation pathways being developed, the greatest challenge lies in acquiring data for the use and distribution of water sources, especially needed for validation. Source: Byers, Hall and Amezaga (2014) (CC-BY).

3.3 Model configuration to assess the current water use in the UK

3.3.1 Current electricity generation

The current state of electricity generation in the UK was introduced in Chapters 1 and 2. It is important to reiterate at this point that thermoelectric generation contributes 90% of the 380 TWh of electricity generated annually in the UK (DECC, 2012b). The majority of these power stations are cooled by water abstractions from the environment.

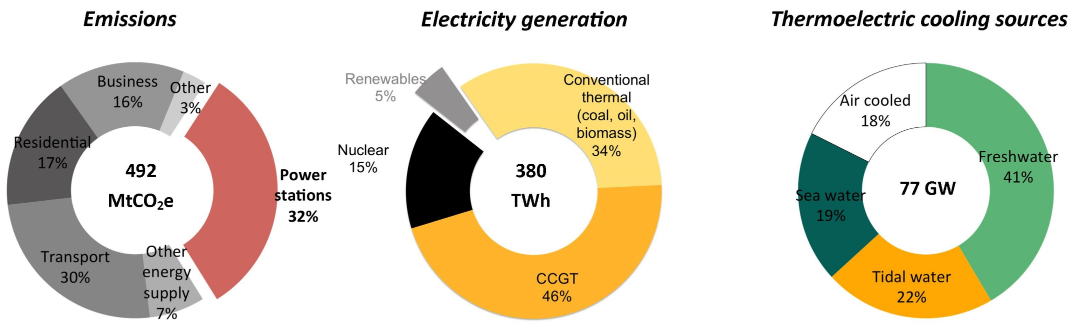


Figure 3-2. The UK energy sector in 2010. Figure source: Byers, Hall and Amezaga (2014). Data from the left and centre pie charts is from DECC (2011b).

In order to obtain the most accurate and consistent data and information of the UK electricity system, the Digest of UK Energy Statistics (DUKES) was referred to extensively. Published annually by the Department for Energy & Climate Change, DUKES contains comprehensive coverage of the UK energy system, Chapter 5 of which is exclusively for electricity generation. Electricity generation is categorised in detail by generation capacity type, quantities of fuel used, capacity factors, location, end-users and many other permutations thus providing consistent and sufficient detail for this type of analysis. For the recent figures of electricity generation, Tables 5.6 and 5.7 of the Digest of UK Energy Statistics (DUKES) were used for each fuel/capacity type, for the years 2007-2011 (DECC, 2011b, 2012b).

Table 3-1. Summary of electricity generation by capacity type for 2006 to 2011, summarised and adapted from DUKES (DECC, 2011b, 2012b).

TWh/year	2006	2007	2008	2009	2010	2011
Nuclear	69.2	63.0	52.5	69.1	62.1	69.0
Onshore wind	0.0	0.0	0	0	0	0
Offshore wind	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	4.6	5.1	5.1	5.3	3.6	5.7
Gas	140.8	165.8	176.2	165.5	175.7	146.8
Oil	5.9	5.0	5.7	4.4	4.8	3.7
Coal/ Biomass	162.5	148.7	138.2	116.9	122.2	124.0
Other (wind, wave, solar)	4.2	5.3	7.1	9.3	10.2	15.8
Pumped-hydro	3.7	3.9	4.1	3.7	3.2	2.9
Gas+CCS	0.0	0.0	0.0	0.0	0.0	0.0
Coal+CCS	0.0	0.0	0.0	0.0	0.0	0.0
Total	391.1	396.8	389.0	374.2	381.8	367.8

For the database of current electricity generation capacity, DUKES table 5.11 was filtered to include all thermoelectric capacity in the UK above 17 MW_e (Figure 3-3). Detailed in Appendix A.1, this table has been modified such that more information about power plant cooling method and the cooling water source could be added. Whilst the very best efforts have been made to ensure the veracity of the data, including independent verification by an employee of the Environment Agency, this data is presented openly for scrutiny by the community in Appendix A.1.

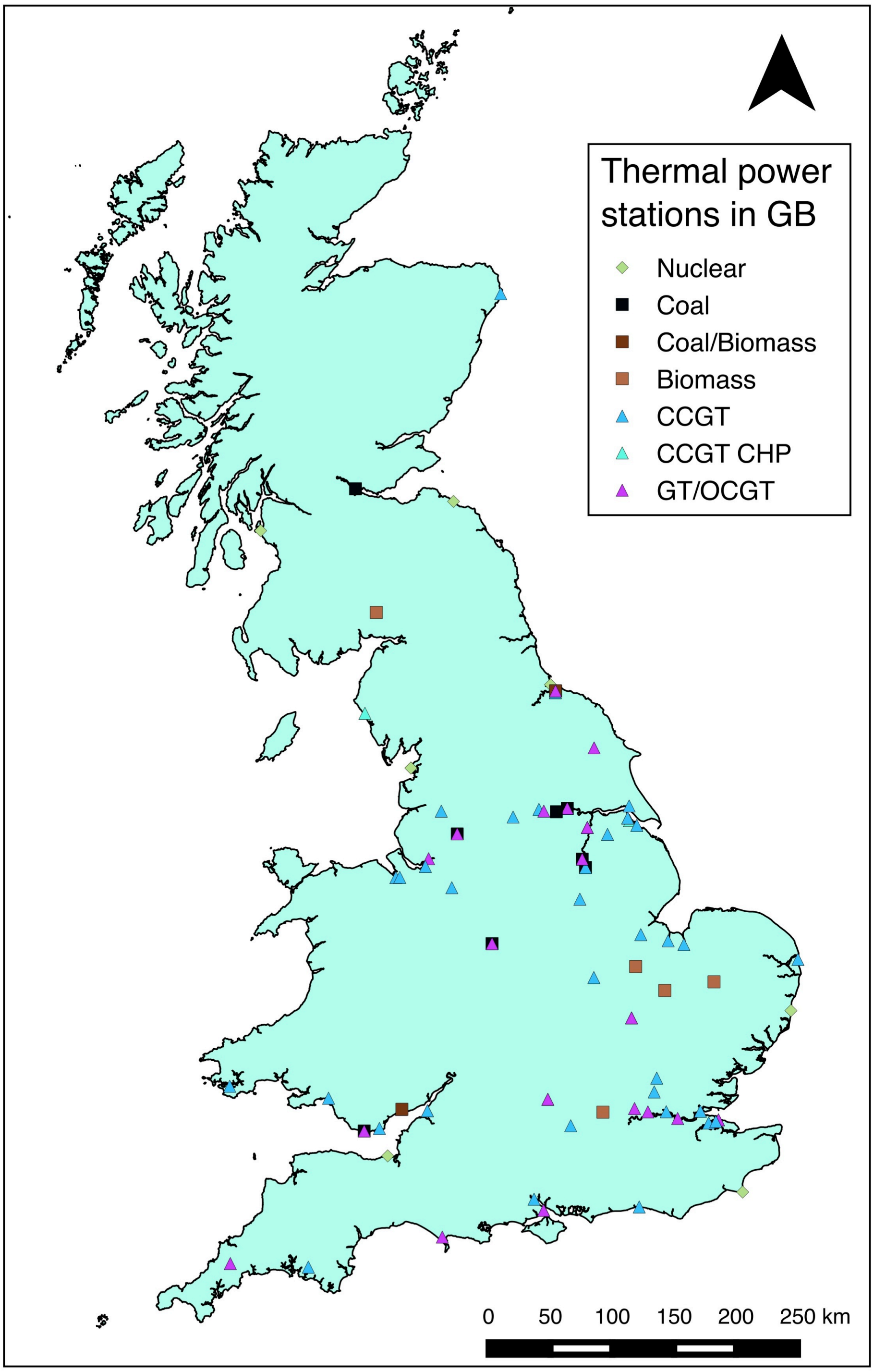


Figure 3-3. Map of thermal power stations in Great Britain by power station type. Power station database from DECC (2011b) Table 5-11, whilst locations are from Enipedia (Davis *et al.*, 2014) and the author's own research on Google Maps.

3.3.2 Current and historical abstractions of water

The Environment Agency (EA) is responsible for licensing water abstractions in England and Wales, including to the electricity sector. The EA has reported estimated abstractions from various sectors from 1995, of which "Electricity Supply" is one of the categories. These figures are estimated on the basis of metered abstractions reported by licence holders on an annual basis. For both non-tidal surface water and tidal surface water, the electricity supply industry is responsible for a large proportion of overall abstractions (Figure 3-4, Figure 3-5).

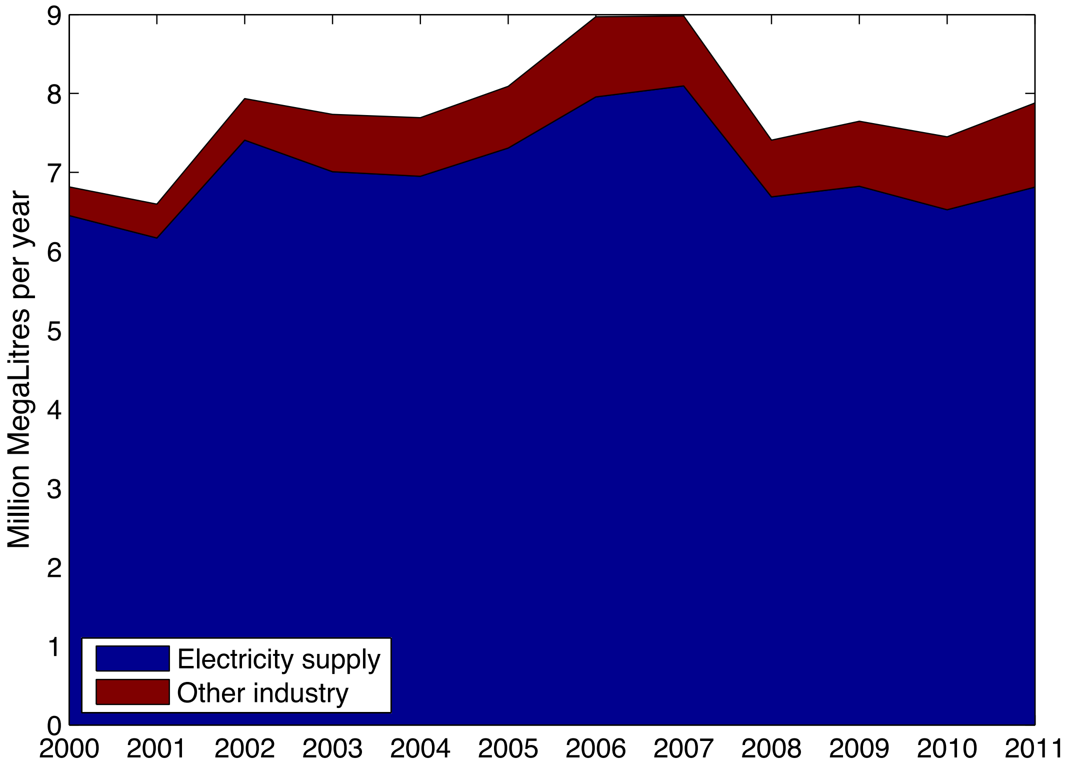


Figure 3-4. Estimated tidal surface water abstractions for England and Wales. Data source: Environment Agency (2012a).

The ABSTAT datasets are generated automatically to compile the abstraction returns of almost 50,000 licence holders thus more detailed interrogation of the data, by EA employees, let alone the public, is difficult.

3.3.2.1 Identifying abstractions from electricity generation

The category "electricity supply" includes abstractions from hydro-electric power and pumped storage hydro. Thus when validating the model it is necessary to remove these abstractions in order to account only for thermoelectric generation. The Environment Agency does not publish figures exclusively for hydropower and pumped storage although the EA have provided estimate figures of the hydro/pumped contribution for each region. Thus for the validation these contributions were excluded.

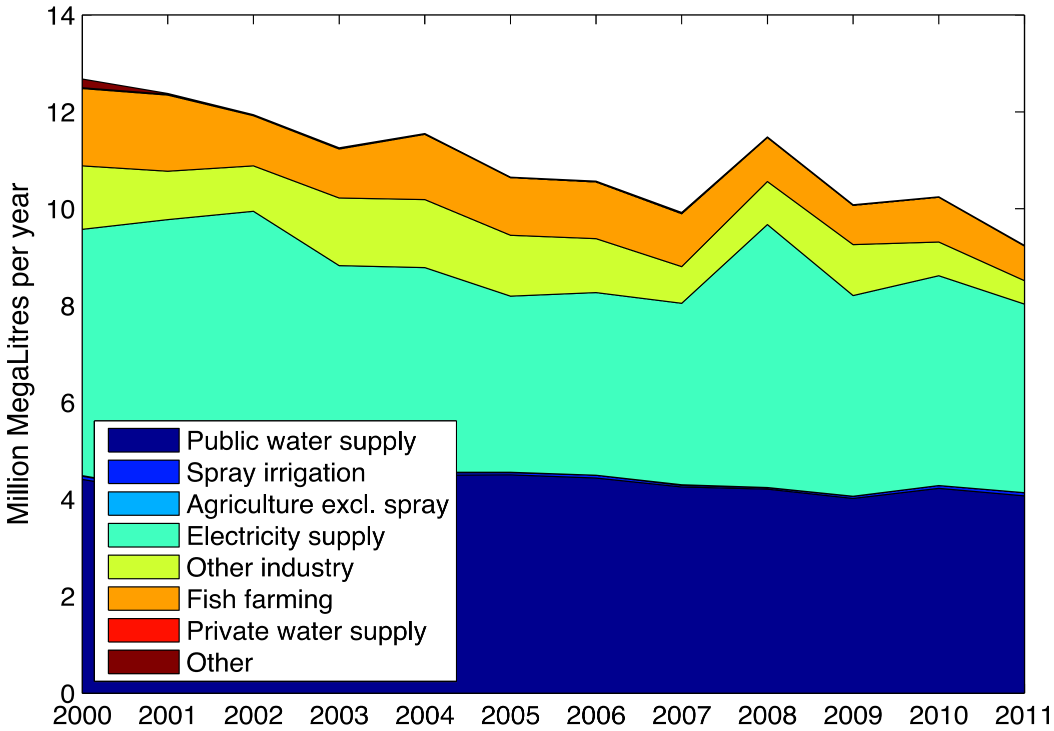


Figure 3-5. Estimated non-tidal surface water (freshwater) abstractions for England and Wales. Data source: Environment Agency (2012a).

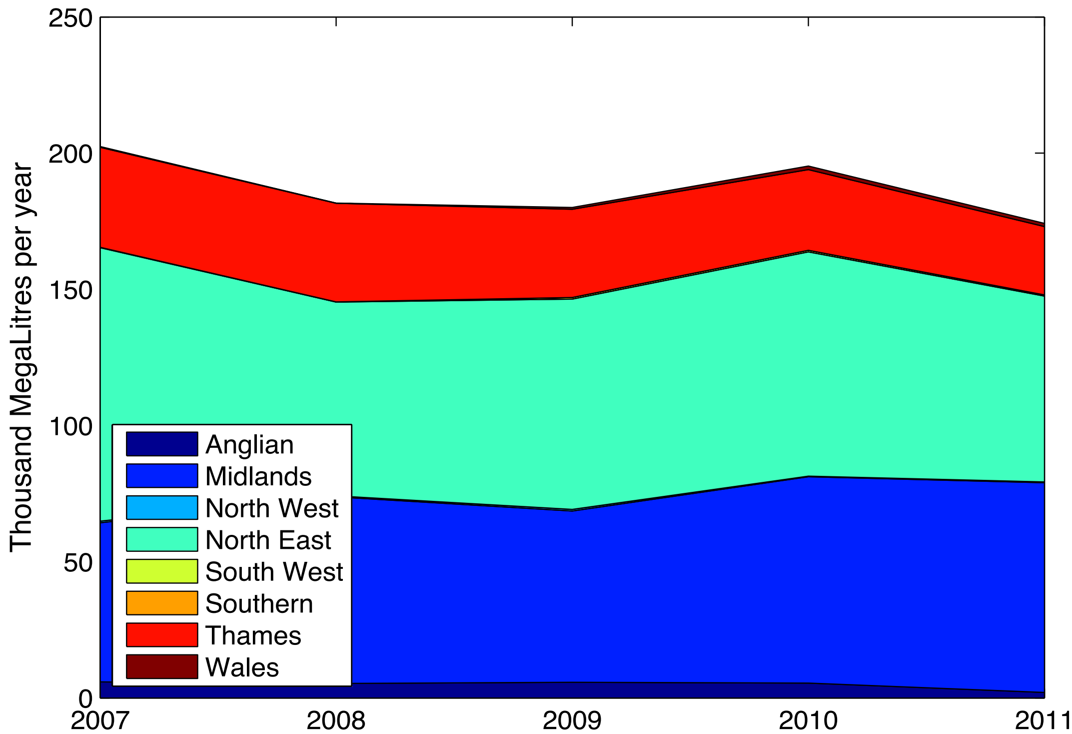


Figure 3-6. Estimate abstractions from the electricity sector (excluding hydro) from non-tidal surface waters. *N.B. the value from Midlands for 2008 (653,016) was an order of magnitude higher than in other years and assumed to be anomalous and thus set to the mean of the other years (68,514). Data source: Environment Agency (2013b).

As presented in Figure 3-6, the electricity abstractions must be categorised to a cooling water source. Whilst the ABSTAT datasets automatically assign abstractions to the correct water source, the EA could not provide more details of the electricity supply licence holders and which sources they abstract from, neither what are the abstraction limits on their licences.

3.3.2.2 Identifying the cooling water sources and cooling methods

The cooling water sources of each power station were verified using publicly available information on the internet. Using Table 5.11 from DUKES (DECC, 2011b) the following sources were checked to establish the cooling source and cooling method:

- The power station was located using Google Maps and/or Bing! Maps. The cooling water source and cooling method were verified from the satellite imagery.
- Mentions of the source and method were verified against any published information on company websites, documentation and press releases.
- This information was also cross-checked against any other information published on the internet, including Enipedia (Davis *et al.*, 2014) and Wikipedia (Wikipedia, 2012).

The list was then checked against the table in the MSc thesis of Schoonbaert (2012). Any discrepancies were scrutinised further. The above procedure was performed twice, in approximately November 2012 and July 2013. The list was then verified by the Environment Agency in August 2013. The importance of ensuring the correct cooling methods and sources is discussed in section 3.4.2.

3.3.2.3 Classification of cooling source

Cooling water source classification is important because different sources of water have different qualities and values attributed to them by society. Although there are many different objective and subjective ways in which water quality can classified, water sources are usually classified most basically according to the type of water body from which they are taken. Concerning their value to society, freshwater sources are generally valued above brackish and saline water sources, due to both their comparative scarcity and also their utility for societal needs such as drinking water and agriculture.

Cooling sources were classified here primarily according to the classifications used by the EA for abstraction licensing for non-tidal and tidal surface waters, in addition to seawater and air-cooled:

i. **Non-tidal surface water:** Also referred to in this work as freshwater, this includes all non-tidal stretches of surface waters, such as rivers, reservoirs, and lakes, as defined by the Map of Freshwater Limits under section 192 of the Water Resources Act 1991.

ii. **Tidal surface water:** Tidal surface waters include all stretches of tidal waters, beyond the limits of the Map of Freshwater Limits, up to and including estuaries, and to the exclusion of coastal sea water.

iii. **Seawater:** Includes abstractions on the coast that are clearly from the sea and excludes abstractions from estuaries.

iv. **Air-cooled:** Power stations that do not require water for cooling purposes, either due to the use of dry cooling, air-cooled condensers, or because no cooling is required.

Given that almost all abstraction pipes are submerged and buried in the ground, the water source is established by assuming that nearby sources of water are the ones used for cooling. Evidence of culverts, intake and outfall structures and the direction of river flow must be used to form this judgement. Both satellite imagery and Ordnance Survey Digimap were used to identify manmade intake and outfall structures.

3.3.2.4 Classification of cooling method

The cooling method of a power station is usually identifiable from observation of satellite imagery, but can be verified against available company documents, if possible, given that technologies have evolved in function and shape over time. Cooling technologies are explained in more detail in Chapter 2. The following four classifications were used in this study:

i. Open-loop (once-through, direct cooling)
ii. Closed-loop evaporative (re-circulatory evaporative wet tower cooling)
iii. Hybrid (combination of wet tower and dry air cooling)
iv. Air-cooled (can be either dry tower cooling or air-cooled condensers)

3.3.2.5 Cooling water source and method distributions for the UK

The database of power stations was populated with the information collected from the survey and is presented in Appendix A.1. This information is presented for 2010 in the pivot table below (Table 3-2) and Figure 3-7, Figure 3-8 and Figure 3-9. This gives percentage distributions by cooling source and method for each generation technology. These distributions form the basis of future assumptions for cooling water source and method.

Table 3-2. 2010 Pivot table of distribution of cooling types for each generation classes. Table source: Byers, Hall and Amezaga (2014) (CC-BY).

Cooling source	**Air**	**Sea**	**FW**			**FW Total**	**TW**			**TW Total**	**Total**
Cooling method	**Air cooled**	**Open**	**Open**	**Closed**	**Hybrid**		**Open**	**Closed**	**Hybrid**		
Nuclear	0.0%	71.4%	0.0%	0.0%	0.0%	0.0%	28.6%	0.0%	0.0%	28.6%	100.0%
Gas											
CCGT	24.2%	6.7%	0.5%	11.9%	4.9%	17.3%	16.7%	28.0%	7.0%	51.8%	100.0%
CCGT CHP	6.6%	0.0%	0.0%	7.2%	5.7%	12.8%	0.0%	41.5%	39.0%	80.6%	100.0%
GT/OCGT	96.4%	0.0%	3.6%	0.0%	0.0%	3.6%	0.0%	0.0%	0.0%	0.0%	100.0%
Coal, Biomass, etc.											
Biomass	13.0%	0.0%	0.0%	6.3%	0.0%	6.3%	76.8%	0.0%	3.9%	80.7%	100.0%
Coal	0.0%	29.5%	0.0%	53.0%	0.0%	53.0%	17.5%	0.0%	0.0%	17.5%	100.0%
Coal/ biomass	0.0%	0.0%	0.0%	85.3%	0.0%	85.3%	0.0%	0.0%	14.7%	14.7%	100.0%
Waste	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Oil - steam	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	99.2%	0.0%	0.0%	99.2%	100.0%
Total	**17.6%**	**19.2%**	0.4%	18.6%	2.6%	**21.7%**	20.2%	15.4%	5.9%	**41.5%**	100.0%

From Figure 3-7 it is observed that distribution by source and cooling method depends, to some extent, on the fuel-type used. CCGT and coal/biomass capacity is spread amongst all the cooling water sources, whilst nuclear power is confined to tidal and seawater sources. Almost all the capacity using air-cooling is gas-fired CCGT and CCGT CHP due to the relatively low cooling requirements, besides a small portion of biomass capacity. These generalised observations, whilst likely to be similar in other countries, may depend substantially upon access to coastal water sources and whether freshwater bodies are large enough to support power generation.

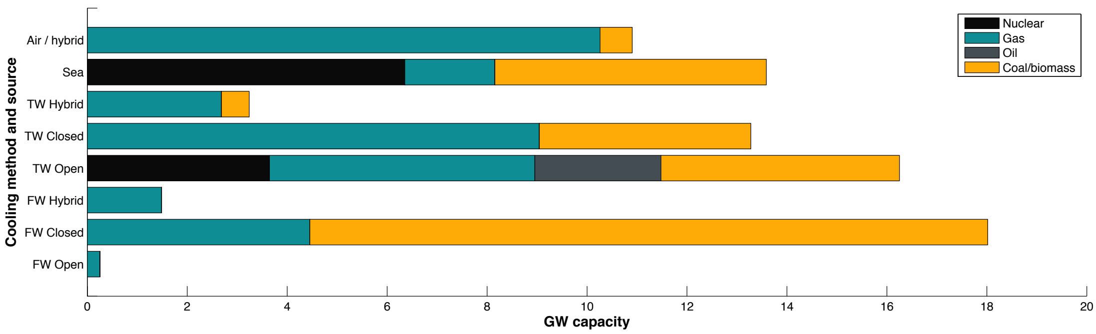


Figure 3-7. Distribution of capacity amongst water sources in 2010 (own survey data). FW – freshwater, TW – tidal water, SW- sea water. Figure source: Byers, Hall and Amezaga (2014) (CC-BY).

Further analysis of the generation capacity is possible when plants are split by size. Considering the distribution of cooling sources by power station size (Figure 3-8), we see that the majority of the capacity is at large power stations with capacity in excess of 1000 MW_e. The majority of small plants (<100 MW_e) are air cooled as most of these plants are open-cycle gas turbines (OCGT), which do not require water for cooling. They are usually only used at winter peak loads and are maintained as 'Black Start' capacity due to their ability to be fired up rapidly and without auxiliary power. The largest plants (>1000MW$_e$) make up the majority of the capacity mix and use a variety of both sources and methods. This suggests that measures addressing water use could be effectively tackled by targeting a small number of large power stations.

The proportions are similar when distributed by cooling methods (Figure 3-9), with the majority of power stations using open-loop and closed-loop evaporative cooling. Common for both graphs is that larger power stations tend to use water for cooling, whilst the use of air-cooling is more common for smaller capacity stations. Air-cooling, whether air-cooled condensers or dry-towers, tend to use much more space and are about 2-4 times more expensive than wet towers (NETL, 2009b), hence are less common for large facilities.

For the UK overall, capacity is split by source with 32 GW$_e$ (41%) on freshwater, 17 GW$_e$ (22%) on non-tidal surface water, 15 GW$_e$ (19%) on seawater and the remainder 14 GW$_e$ (18%) is air-cooled. More detailed analysis of the constituents reveals that all coal-fired plants on freshwater use closed-loop or hybrid cooling and that the only once-through cooling on freshwater is gas CCGT.

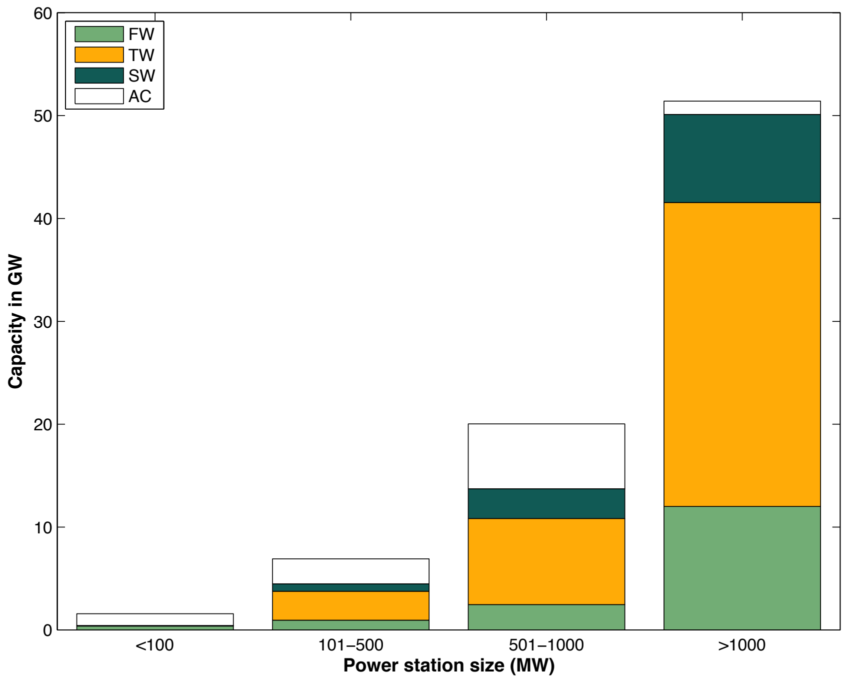


Figure 3-8. Distributions of cooling water sources split by power station size. Figure source: Byers, Hall and Amezaga (2014) (CC-BY).

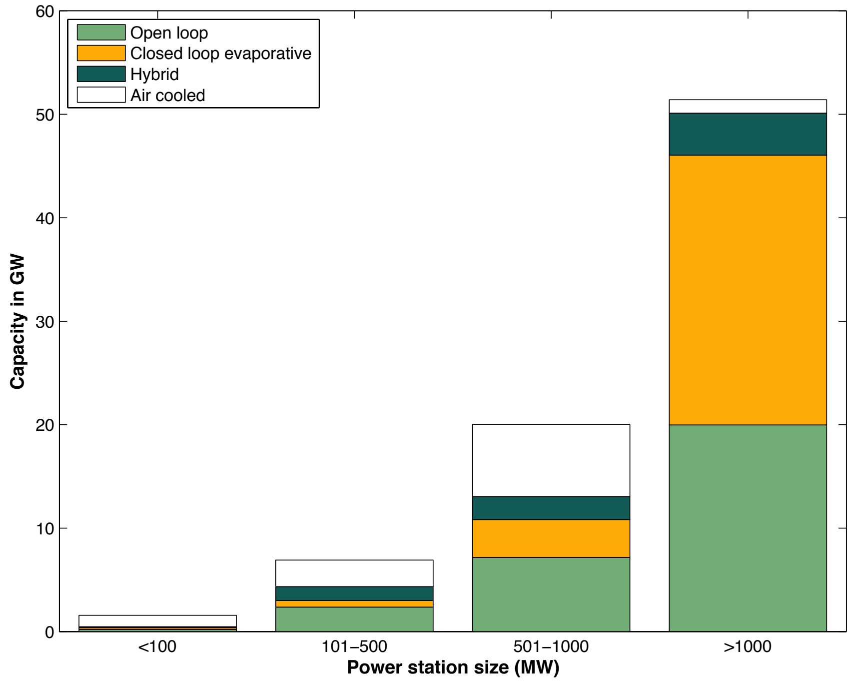


Figure 3-9. Distributions of cooling methods split by power station size. Figure source: Byers, Hall and Amezaga (2014) (CC-BY).

N.B the constituent capacity in the >1000MW$_e$ columns in Figure 3-8 and Figure 3-9 are very different. In both figures the majority of FW capacity is closed-loop wet tower, most TW is once-through and all SW capacity is once-through.

3.3.2.6 Water use factors

Water use factors are as of yet currently unavailable for the UK, as previously discussed in Chapter 2. A composite set of factors was created from a range of sources required to complete the dataset for all generation technologies. This was based principally on data from Macknick *et al.* (2011), National Energy Technology Laboratory (2009), Zhai, Rubin and Versteeg (2011) and Zhai and Rubin (2010). Although the figures for the UK will differ slightly, the US data in the various aforementioned reports has shown an acceptable level of consistency over time and is thus considered suitable for this study, similarly concluded by Schoonbaert (2012).

Table 3-3. Water abstraction and consumption factors used in the study.

Litres/kWh ML/GWh	**Abstraction**	**Consumption**	**% loss**
Once-through			
Nuclear	164.4	1.3	0.8
OCGT	0	0	0
CCGT	49.3	0.4	0.8
Oil (steam cycle)	134.4	1.1	0.8
Coal / biomass	118.5	0.8	0.7
Gas+CCS	90	0.9	1
Coal+CCS	220	2.1	1
Closed-loop wet evaporative tower			
Nuclear	3.9	2.7	68.6
OCGT	0	0	0
CCGT	0.98	0.75	77.1
Oil (steam cycle)	2.08	1.82	87.3
Coal / biomass	2.11	1.77	83.8
Gas+CCS	1.82	1.36	74.3
Coal+CCS	4.29	3.22	75
Hybrid cooling			
Nuclear	2.5	1.7	67.9
OCGT	0	0	0
CCGT	0.6	0.5	78
Oil (steam cycle)	0.7	0.6	87.3
Coal / biomass	1.3	1.2	88
Gas+CCS	1.2	0.9	74.3
Coal+CCS	2.8	2.1	75

Notes

- Biomass consumption assumed to be the same as coal given that the thermal efficiency of these plants is often similar and in some cases they are co-fired.
- Hybrid assumed to be 35% less than wet tower closed-loop tower performance.
- Values taken for super-critical coal plants, compared to sub-critical for non-CCS plants.

Sources:

1. Macknick *et al.* (2011)
2. EPRI (2002)
3. NETL (2009b)
4. Tzimas (2011)

In addition to the notes presented in Table 3-3, further points concerning biomass and hybrid are worth drawing attention to.:

Biomass

- Figures for assumed biomass proportion (from DECC pathways) has used the same water use figures as coal, although the literature suggests that biomass plants could be in the order of 10% less water-efficient. This has been done due to the uncertainty in the proportion of biomass used (whether exclusively or in co-firing) in the different DECC pathways.

Hybrid cooling

- For hybrid cooling the figures for closed-loop evaporative cooling were used and reduced by 35% - equivalent to a split for wet and dry cooling duties being 65:35. Actual operation may be different depending on water availability at each power plant and the design, configuration and operation mode of the hybrid system.
- It could be assumed that water availability would decrease with time and that the proportion between wet and dry operation might change, with more low water use in summer months. Given that the performance factors for other cooling methods and generation classes have not been modified with time for this study, all water use factors remain constant, similarly by both Macknick *et al.* (2012) and Schoonbaert (2012).

Open cycle gas turbines (OCGT)

- In the UK, about 97% of gas-fired generation comes from CCGT plant whilst 3% comes from gas turbines and OCGT plant. By capacity however, the proportion of OCGT is higher.
- Gas turbines (and OCGT) do not require cooling in the same way that conventional thermoelectric plant do, due to the absence of a steam cycle. Hence, these plants use no water for cooling.
- They are very flexible in operation hence their use for peak loading, although overall are less efficient than CCGT (around 28% compared to 50% to 55%).

3.3.2.7 Validation of the model for current generation

Aggregate water abstraction figures were compared with *ABSTAT* estimated abstraction data from the Environment Agency (2012a, 2012c, 2013b) to validate the model over a control period from 2007-11 using reported generation data from DECC (2009b, 2012b). The EA data, which includes hydropower and pumped storage, covers England and Wales thus validation of the model was for these nations only. Abstraction figures for Scotland and Northern Ireland are unavailable and not strictly necessary in this case. 100% of the UK's thermoelectric generation on freshwater is in England and Wales whilst for tidal water the proportion is 91%. The remaining 9% on tidal waters in Scotland and Northern Ireland were excluded from validation and the modelled figures were scaled down accordingly.

Crucial to achieving this model validation was obtaining data from the Environment Agency that splits electricity sector freshwater abstractions into hydropower and non-hydropower categories, summarised in Table 3-4. Despite the low level of hydropower capacity in the UK the subsector is still responsible for the majority of abstractions. This was a relatively unknown fact until the data below was specially extracted from the ABSTAT database for the purposes of this modelling work. Analysis of the regional abstractions and installed capacity led to the subsequent assumptions to complete validation.

Table 3-4. Summarised data from the Environment Agency (2013b) of annual abstractions from the Electricity Supply sector, split by 'hydropower' and 'non-hydropower'.

	Hydropower			Non-hydropower		
ML/yr	England	Wales	Total	England	Wales	Total
2007	870,077	2,675,085	3,545,162	202,158	266	202,424
2008	891,567	3,755,780	4,647,347	766,061	74	766,135
2009	1,328,668	2,635,992	3,964,660	179,414	674	180,088
2010	1,586,868	2,550,953	4,137,821	193,923	1,321	195,244
2011	1,250,840	2,466,450	3,717,290	173,018	1,222	174,240

Wales has very little thermoelectric capacity on freshwater, totalling 515 MW_e from Deeside CCGT power station, which has incidentally reported hybrid cooling water usage at the plant since 2001. Thus, by subtraction, abstractions reported for Wales by the EA are almost exclusively hydro and pumped storage (99.9%). Hydro abstractions in England were confirmed by the EA to b 0.870-1.587 million megalitres (mML) per year (mML/year) for the period, henceforth also subtracted from the validation figures. Most importantly, the abstraction records are dominated by the small numbers of plants that use once-through cooling, whose abstraction rates are two orders of magnitude higher than the majority of plants which use closed-loop evaporative cooling. This has made validation very sensitive to figures from the few plants that use open-loop cooling on freshwater. The estimated abstraction records in all sectors have considerable variability that make it difficult to validate on a year to year basis. Similarly, whilst the constituent generation capacity may only change a little from year to year with the addition or decommission of a few power plants, electricity generation is more variable and may depend on maintenance cycles, weather, fuel prices and the electricity market balancing. FW abstractions in Wales have been consistently between 2.5-2.7 mML/year between 2006-2011, excluding the year of 2008 which was 3.8 mML. In England for the same period abstractions have ranged between 1.1 and 1.8 mML/year besides a 2008 figure of 0.7 mML. Validation was thus performed for 2007-2011 with the exclusion of 2008.

For the freshwater abstractions, the model under-estimates values by 8-24% with a mean of -18%. For tidal surface water the model generally overestimates with a mean of +16.6%. Combined, the model overestimates by 3.6%. For the purposes of this analysis this was judged to be satisfactory given that the EA data are only estimates and the uncertainties that arise from the model, discussed below.

Table 3-5. Model validation for 2007-2011. The validations compare modelled cooling water abstractions (in $ML.year^{-1}$) from freshwater (FW) and tidal surface water (TW) against figures reported by the Environment Agency (EA) in 2012. Cooling water demands are presented in Table 3-6. G_g is the total electricity generation in that year (including renewables) from DECC (2012b). * The means reported for Freshwater exclude 2008 values. Table source: Byers, Hall and Amezaga (2014) (CC-BY).

	Abstractions in mega litres per year										
	***FW* (x 10^6)** *(England only)*				***TW* (x 10^6)** *(England & Wales)*			***FW + TW* (x 10^6)** *(England & Wales)*			**G_g** *(UK)*
	EA hydro	EA non-hydro	Model	Δ%	EA	Model	Δ%	EA	Model	Δ%	TWh
2007	0.870	0.202	0.248	+18.5	8.10	7.16	-13.1	8.30	7.41	-12.0	397
2008	0.892	0.766	0.232	-230	6.69	6.71	+0.3	7.46	6.95	-7.4	389
2009	1.329	0.179	0.196	+8.5	6.83	7.02	+2.8	7.00	7.22	+3.0	377
2010	1.587	0.194	0.198	+2.2	6.53	7.00	+6.7	6.72	7.20	+6.6	382
2011	1.251	0.173	0.179	+3.6	6.82	7.29	+6.5	6.99	7.47	+6.4	368
μ	*1.259*	*0.187*	*0.205*	*+8.2**	*6.99*	*7.03*	*-0.8*	*7.29*	*7.25*	*-0.7*	*376*

Parametric uncertainty comes primarily from the water use factors used and uncertainty in the EA classifications of power station abstraction sources and cooling methods. Water use factors were derived mostly from US data reported in sector-wide meta-analyses. Whilst the machinery and power stations are largely the same, load factors, ambient conditions and age distribution are likely to be different to the UK. Further operational decisions, such as number of cooling cycles, may influence the factors and may vary between FW and TW plants. The cooling methods, classified from satellite images and online search for records was verified subsequently against the data of Schoonbaert (2012) and is available in Appendix A.1. The split of power stations between freshwater, tidal surface water and sea water was defined in the same way, checked against the Maps of Freshwater Limits and verified by the Environment Agency. Unable to check Schoonbaert's source classifications and noting a few differences in cooling method we believe explains the significant differences in freshwater abstraction estimates.

It was not possible to validate the results for the levels of consumption that arises from the abstractions given that no figures of consumptive use are reported. The calculation for consumptive use is the same as that used for abstraction and depends on the water use factors that are used. Whilst discharges are regulated, there is no stipulation that abstractors must return any specified proportion of the abstraction and thus these are not always recorded.

3.4 Results and discussion of current water abstraction

3.4.1 Results

The results presented in Table 3-6 and Figure 3-10 report estimated water abstraction and consumption for the whole of the UK in 2010, compared against generation by the same sources. The results have been split by generation type, cooling method and water source. These results present the most comprehensive snapshot to date of cooling water use for thermoelectric electricity generation in the UK.

The current levels of TW and SW water abstraction are an order of magnitude higher than FW abstraction and this has been confirmed through the validation. Freshwater abstractions in England and Wales are as high for the electricity sector (including hydro and pumped storage) as they are for public water supply. However, when hydro is excluded, thermoelectric in the UK is responsible for only 3% of freshwater abstractions; compared to the US for which thermoelectric makes up 39% of abstractions (US Department of Energy, 2006). Consumptive levels of freshwater have been estimated to be in the order of 120 x 10^3 ML per year, equivalent to domestic water demand of 900,000 households.

Concerning the main constituents of water use, the trends are again different across sources. For freshwater, 61% of abstraction and 85% of consumption derives from coal power with closed-loop wet tower cooling. Worth noting also is the 28% of abstractions from once-through cooled gas power stations that only contribute 1% of the electricity generation on freshwater; a significant proportion of abstractions results from very small contributors to electricity supply.

The current levels of tidal and sea water abstraction are 40-50 times higher than freshwater abstraction, although consumptive proportions are only 2% and 1% respectively, due to the use of once-through cooling. Tidal and sea water abstractions are dominated by once-through cooled nuclear power with significant contribution from once-through cooled coal power. For tidal water, almost half the abstractions are from nuclear for only 15% of the supply, thus entailing a disproportionate contribution to negative environmental impacts. Meanwhile, power plants with closed-loop cooling on tidal water have comparatively negligible impacts on water use. For sea water, the contributions to electricity supply in this case are more balanced with their water use given that all plants use once-through cooling and the fact that coal and nuclear plants have similar water use intensities.

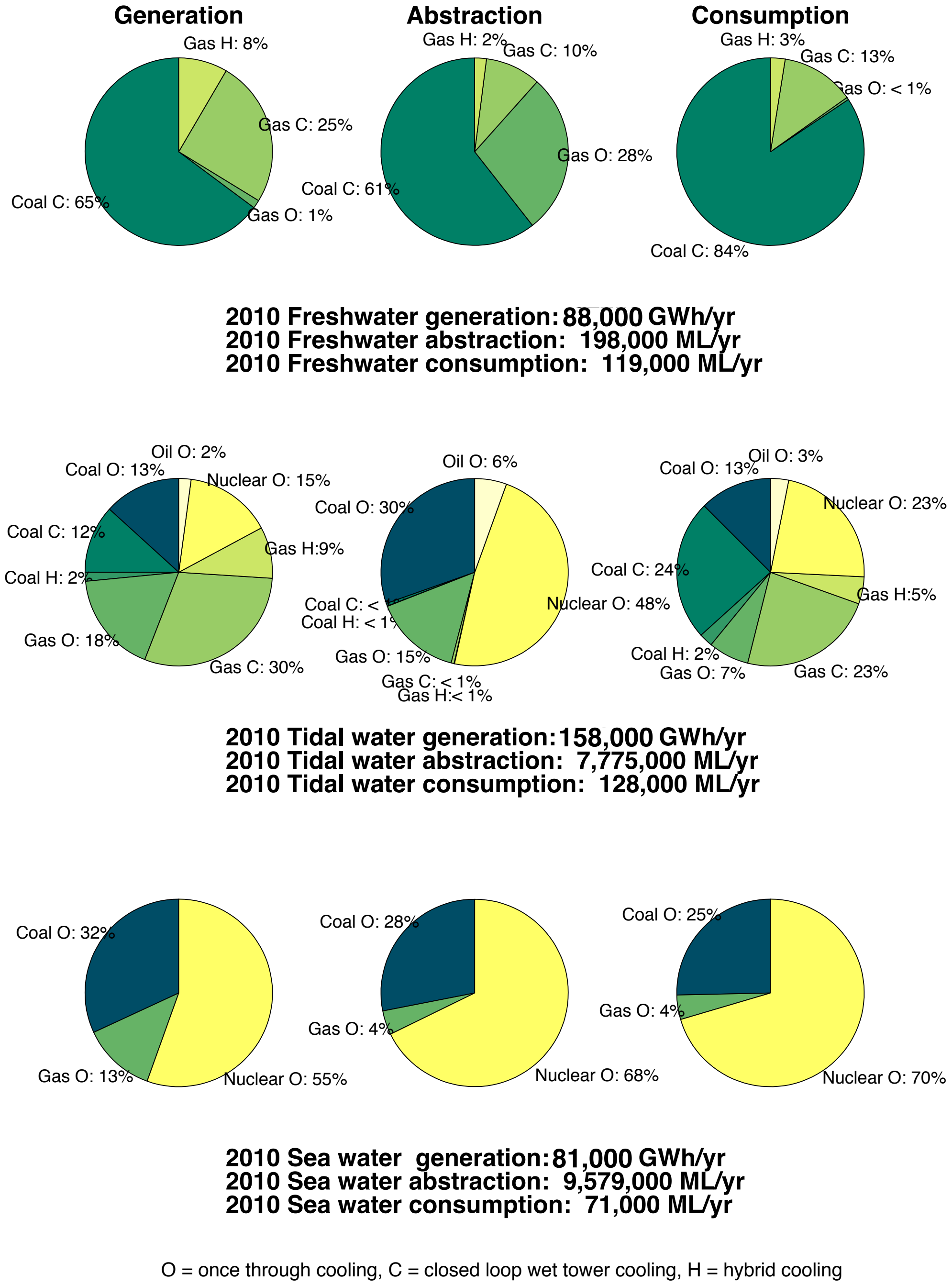


Figure 3-10. Freshwater, tidal water and sea water generation, abstraction and consumption by generation capacity type in 2010. Note the different scales of water use by each category.

Table 3-6. UK thermoelectric electricity Capacity and Generation in 2010 with resultant Abstraction and Consumption. Each generation class is split by cooling method (open, closed, hybrid) and the cooling sources in *W* of freshwater (FW), tidal surface water (TW) and sea water (SW). Air-cooled (AC) capacity has also been included. Source: Byers, Hall and Amezaga (2014) (CC-BY).

	Capacity GW_e				**Generation x10^3 GWh**				**Abstraction x10^3 ML/ year**				**Consumption 10^3 ML/ year**			
	FW	TW	SW	Sum	FW	TW	SW	Sum	FW	TW	SW	Sum	FW	TW	SW	Sum
Coal & biomass																
Open	-	5	5	10	-	20	23	43	-	2,400	2,700	5,100	-	16	18	33
Closed	14	4	-	18	57	18	-	75	120	37	-	160	100	31	-	130
Hybrid	-	1	-	1	-	2.3	-	2.3	-	3	-	3	-	3	-	3
Gas & CCGT																
Open	0	5	2	7	1.3	26	9.0	37	55	1,200	400	1,600	-	9	3	13
Closed	4	9	-	13	22	45	-	67	19	39	-	58	15	30	-	45
Hybrid	1	3	-	4	7.4	13	-	21	4	7	-	11	3	6	-	9
Nuclear																
Open	-	4	6	10	0	23	40	62	-	3,700	6,500	10,200	-	29	50	79
Oil																
Open	-	3	-	3	-	3.2	-	3.2	-	430	-	430	-	4	-	4
Air-cooled (AC), mostly OCGT																
AC				11.5				0.06		-				-		
Totals (including AC)																
Sum	20	33	14	79	88	150	71	310[a]	200	7,800	9,600	18,000	120	130	71	320
%	30	50	20	100	28	49	23	100	1	44	55	100	37	40	22	100

3.4.2 The results in context

Looking over Figure 3-10 and comparing the pie charts by different water sources, it is worth noting the different constituents of cooling systems for each water source. All capacity on sea water uses once-through cooling as this is the most efficient, economical and not constrained in volume. Conversely, almost all capacity on freshwater uses closed-loop wet tower or hybrid cooling, besides a very small amount using once-through cooling. This is because the freshwater sources in the UK are generally too small for once-through cooling on a large scale and would probably entail result in unacceptable river body temperature changes from the thermal discharges.

In terms of the overall amount of freshwater abstracted and consumed, the volumes are considerably lower than expected. Freshwater abstractions for cooling water constitute only approximately 3% of national abstractions, although around 75% is consumptive. Public water supply constitutes around 40% of which around 40% is consumptive. On a per person basis, freshwater use for cooling water is approximately 10 litres per person per day (lpd), compared to the 150 lpd for public water supply. Naturally these figures are subject to regional variation which is at the scale at which water use becomes most important. Nonetheless, this comparison serves to highlight an argument that water use efficiencies may be more effective or more easily achieved in the public water supply sector, than from cooling water use.

Unlike freshwater, abstractions on tidal waters occur from a variety of different generation technologies and cooling systems. Although tidal abstractions are also licensed, the whole range of technologies are used due to the wide range of possible conditions that are encountered at tidal water sources. In some instances, tidal stretches reach tens of kilometres inland, hence inland conditions might be substantially different to conditions encountered at an estuary. Therefore, it is important that the consenting of abstractions on tidal stretches are considered in detail on a case-by-case basis as opposed to resorting to more *rule of thumb* approaches. The Best Reference Document (EC JRC, 2001) for identifying Best Available Technology (BAT) for industrial cooling systems under the Integrated Prevention and Pollution Control Directive (IPPCD), does not specify general BAT for different water sources. However, *general BAT* conclusions are drawn about the characteristics of different water bodies and approaches to, for example, reduce heat emissions or chemical emissions to water.

Consents for tidal water abstractions can be contentious, as has recently occurred in Pembroke, Wales. In 2012 RWE npower commissioned a 2,099 MW_e combined cycle gas plant on a legacy site that lies within the Milford Sound *Special Area of Conservation.* It had been under considerable pressure by local groups and authorities to use closed-loop wet tower cooling in order to minimise thermal discharges and entrainment and impingement of fauna. However a once-through system was authorised by the Environment Agency and consented by the Department for Energy & Climate Change (DECC) (ENDS Report, 2009). Being a large power plant this project was classified as *nationally significant infrastructure project* (NSIP) hence the central government consent. This decision however elicited a European Commission letter of infringement to DECC regarding non-compliance of numerous articles in the EU's Habitats, Environmental Impact Assessment (EIA), Nitrates and IPPCD Directives (ENDS Report, 2012; European Commission, 2012).

3.4.3 Comparison to historical abstractions

There has been a gradual reduction in non-hydro electricity sector freshwater abstractions in England and Wales between 2007 and 2011, averaging 14% over the period or 2.8% per annum (Table 3-4 and Figure 3-6). Abstractions from the whole electricity supply sector decreased 23% between 2000-2011 (Figure 3-5), an average of 2.1% per annum, whilst for the same period as above from 2007-2011, abstractions in fact marginally increased by 3.8%. Recent years have seen slight growth in hydropower abstractions in England, probably as a result of incentives for small-scale run-of-the-river hydro.

3.5 Methodological discussion

The framework and worked-through example of this chapter has aimed to estimate the baseline level of cooling water abstractions from UK thermoelectric capacity making comparison with available data on abstractions from the sub-sector. The intention of the method presented above is to enable estimation of water use from any portfolio of electricity generation capacity at any point in time, given the correct information and reasonable assumptions. In achieving this, the framework facilitates, in a systematic way, the testing of multiple electricity pathways. In undertaking this work, the importance of data quality and validation merit further discussion in the context of using this framework to undertake similar studies for other regions or countries. Both aspects can present significant challenges and uncertainties.

3.5.1 Data

Data quality and availability for the energy sector is vastly disparate across different countries. In any case, accessing accurate data on a nation's electricity system may be challenging even if it exists, particularly concerning cooling methods and cooling sources. Nonetheless the application of the framework used in this study should be possible for most countries around the world, largely due to the availability of good quality and freely available satellite imagery.

Satellite imagery was used in this study extensively to identify both cooling methods and sources for all the power stations in the portfolio. With practice and guidance, both can be identified rapidly and with a high degree of certainty for attribution against a list of generation facilities. This method of physical identification, is arguably preferable to reliance on externally-sourced datasets.

In some similar studies of water use by the electricity sector, such as by van Vliet et al. (2012) and Macknick et al. (2012b), extensive datasets detailing the cooling method and source have been used. Macknick et al. (Macknick *et al.*, 2012b) used satellite imagery to fill data gaps and verify the existing records. Other *crowd-sourced* datasets such as Enipedia and Wikipedia may be useful for obtaining, at least, locations and capacity types. That said, often said datasets are incomplete (even paid ones e.g. Platt's World Electric Power Plants Database) and the characteristics of the complete data need to be extrapolated across the incomplete fields of the dataset, according to power plant typology. In this case, completion and verification through a satellite imagery survey is recommended. Cross-checking datasets of cooling methods should be performed where possible. Datasets should also, ideally be limited to a fixed baseline year and take into account recent capacity developments or closures.

In the absence of a centrally-sourced dataset for the UK, such as the U.S Department of Energy Coal Power Plant Database (NETL, 2007a), a satellite imagery survey was the only option available for this study. This was repeated twice using both Google Maps and Bing! Maps and checked against the dataset in Schoonbaert (2012). Given the presence of a few once-through cooled power station s on both fresh and tidal waters in the UK, the modelling work was most sensitive to the cooling method and subsequent cooling source assumptions. Going forwards to the future study, whereby the use of once-through cooling is ruled out from freshwater sources, the model becomes more sensitive to cooling source allocation and the water use factors.

Obtaining accurate water use factors, as already discussed earlier in this thesis, can be challenging. However, in cases where once-through cooling is part of the portfolio, it is secondary to the data quality of the cooling methods. This is because of the one-to-two orders of magnitude difference in abstraction volumes between once-through and closed-loop wet cooling systems, regardless of generation technology. Whether a power station category (such as a coal-fired plant) uses 1 or 2 megalitres per GWh for closed-loop wet tower cooling is inconsequential, if, one power station in the portfolio is incorrectly assigned as a once-through cooled power station with abstractions of 100 megalitres per GWh. Nonetheless, the distinction between different generation technologies and cooling methods is important for methodological completeness.

In selecting a set of water use factors for use in a study, one should consider prioritising different sources in order to reduce uncertainty in the quality of the water use factors. This subjective prioritisation depends on the scale of the study and number of power plants being analysed. Further considerations have already been discussed in Chapter 2. Future repetitions of this study will benefit from improved water use factors if and when they become available for the UK. Similarly, although the classifications of cooling methods and sources are thought to be correct, it is possible that one or two classifications may be inaccurate. The dataset was presented to the community with the very intention of eliciting external scrutiny and validation and will be updated as the landscape of the UK electricity system evolves.

3.5.2 Validation

Validation of the model and assumptions is important, not only for determining the current water use, but also for assisting in the formulation of assumptions needed to calculate future water use. In some cases, validation of the current model is not necessarily needed, for example if the data availability is so extensive that water use factors and electricity generation at the discretised power station level has been used to formulate the model. This information would be used to check whether national-level records of water use by a sector are indeed correct.

Instead, when data at the power station level is unavailable, validation is best performed against regional or national level water use records that have been aggregated by the water and environmental regulator.

In the case of the UK, this was done against regional abstraction records of the Environment Agency, which themselves are only classed as estimates. The data in

Figure 3-6 was obtained via a special data processing request to the EA. Establishing the split between hydro and non-hydro electricity sector abstractions has been crucial for the validation. It is not clear whether this data had ever been queried from the ABSTAT database previously, even though it existed within the system. This serves to highlight the 'data gap' discussed in the opening chapters.

Validation nonetheless was useful in ensuring that the scientific method was rigorous and was key to identifying differences in the work presented here and that done by Schoonbaert. The validation assisted in reducing the uncertainty surrounding the cooling sources and was useful in narrowing down on the correct figures for tidal water abstraction. The transitional waters between fresh and tidal, and tidal and sea water sources, results in epistemic uncertainty unless the boundaries between these waters are very clearly defined or the source of abstraction is definitively known. This uncertainty does not affect all assets in a dataset, only those close to the boundaries. The category of tidal water has two of these uncertain boundaries (as it lies between sea and fresh water), whilst sea and fresh water have only one.

The regulator may have defined the difference between fresh, tidal and sea waters although this is not always apparent on a case-by-case basis. Maps such as Ordnance Survey often have tidal extents marked onto them. The demarcation between tidal water and sea water is usually less explicit. Sometimes power stations lie right at the transition and detailed inspection for evidence of intake and outfall culverts is required. In a few cases, intake and outfall occurs in different water bodies. Demarcation may also be deduced from man-made structures such as locks, weirs, dams and breakwaters.

Inter-annual variability of a number of parameters may complicate validation if it is performed using a timeseries, as was done in this thesis from 2007 to 2011. We can group these variables according to the two main constituents of water use calculation;

- Variables that impact on the level of electricity generation, e.g.:
    - Demand, which itself is impacted by economy, weather and other factors
    - Balance of supply between intermittent renewables and thermoelectric
    - Market conditions that alter the type, location and temporal loading of generation
    - Age, decommissioning and maintenance cycles of the generation stock
- Variables that impact on the water use performance of power plants, e.g.
    - Air and water temperatures, and humidity

- Abstraction regulations (affecting both volume and temperature)

Variability in the level of electricity generation can be reduced if annual validation is performed by using actual generation figures from each technology, such as presented in **Table 3-1**. This however does not address any differences that occur between cooling sources however; for example, during a drought year more generation might take place at coastal plants compared to freshwater plants, of the same technology. Variability in the water use factors is, as aforementioned, primarily governed by the type of cooling system and then by the thermal efficiency of the power plant. It is only worth exploring the sensitivity of water use factors if there is a high level of certainty that other assumptions (particularly regarding once-through cooling) are correct, or if there are power stations operating in conditions, climatic or regulatory for example, outside of what may normally be expected.

3.5.3 Scale

The study scale is an important consideration for implementation of this framework. It depends on both data availability and ability to validate, as well as the perspective of the observer. Considering this study for the UK with outputs at a national level, it could be criticised for not assessing water use at the regional level, which has now been demonstrated in Chapter 5, Hall *et al.* (2015) and Tran *et al.* (2014). Yet this work has been done at a similar, if not finer, geographical scale to the work of Macknick et al. (2012b), who calculated U.S. freshwater use disaggregated by 17 hydrographic regions, almost all of them larger than the UK.

Hydrographic and climatic regions are an obvious scale upon which to base an analysis as water use will ultimately impact on a discrete river catchment. Climatic regions themselves define a much wider range of parameters, from the availability of water to the technologies and locations used by power stations.

Approaching this work at this broad scale has both benefits and caveats. Analysts, particularly those of the energy sector, concerned with regional and national level infrastructure systems may find this scale of outputs useful. Similarly, high-level policy and decision-makers are able to quickly digest national and regional water use trends, without concerning themselves with individual river catchments or power stations. In the context of comparing the water use from different national-level future electricity pathways, understanding the general trend at national level is useful. Macknick *et al.* (2012b) are self-critical about their analysis at the national level. However, they recognise the benefits of national-scale energy pathways (such as the predominantly renewables one), without recognising the benefits of the approach that enabled this conclusion. Energy analysts and policy makers who concern themselves with national scale pathways and scenarios, may take into account national-level water use and hence analysis at this scale serves its purpose. This has already been recognised in national level policy-making in the US for a number of years, most notably in the US Department of Energy's report to Congress: *Energy demands on water resources* (US Department of Energy, 2006).

From a water impacts perspective however, the scale cannot be ignored. Water's availability is spatially variable and this has defined, in part, the exact locations of power stations. Hydrological systems are almost always studied at scales that are physically defined, namely river basins. Thus, to assess water use at a scale that is outside the normal realm of water analysts and planners, is bound to draw criticism from that sector; it is not the most convenient format for the sector. That is not to say that the information cannot be useful, neither that it is not useful for other sectors, namely the energy sector. The exploration of water demands from the electricity system at a systems level is a new perspective for the energy sector and contributes to the already prominent area of energy systems' analysis that now dominates energy policy and planning. Ultimately, from an energy perspective, understanding the use of water from the energy sector's perspective is the first step. This has been done at power station level for many years yet only more recently at electricity systems level. Understanding the use of water from the water sector's perspective follows, in Chapters 5 and 6, in pushing this area of research, forwards.

3.6 Conclusions

This Chapter has presented a general framework for the calculation of water use from a portfolio of thermoelectric power stations, the electricity systems level. This framework has its applications particularly in the analysis of future electricity generation pathways, as well as the assessment of current water use at a national or regional scale as demonstrated for the UK in this chapter.

The approach has been applied in this chapter to establish a detailed picture of the current cooling water use from thermoelectric generation in the UK. Current freshwater abstraction amounts to 198,000 ML/year with consumption estimated at 119,000 ML/year. By comparison consumptive use of public water supply is approximately an order of magnitude higher. Tidal water and sea water abstractions are both approximately one and a half magnitudes larger at 7,775,000 ML/day and 9,579,000 ML/day, with consumption at similar levels to freshwater. The majority of freshwater use and impacts results from closed-loop coal-fired generation, whilst on tidal and sea water, nuclear is the largest user. In both cases the impacts are disproportionally greater when compared to their share of electricity generation.

The framework was developed with flexibility in mind that will facilitate its application to a wide variety of locations and contexts. The framework is flexible in terms of scale and temporal extent. It can also be implemented with ease into most programming and mathematical software. Implementation of the framework is also versatile to data availability, something that serves it well for exploring uncertain energy futures.

Implementation of this framework has been demonstrated for the UK and worked through in detail exploring the key variables and assumptions. The implementation and quality of outputs depends on the data availability and quality; the development of this framework and indeed the implementation were shaped by what may be considered a moderate level of data availability and quality. The insights provided at this level already tell us much about the water use of the UK's electricity system, most importantly providing a reference point from which to compare alternative energy futures. More discretized data would not necessarily lead to much greater insights, merely higher certainty concerning the outputs.

A resounding issue discussed in this chapter has been the availability and quality of data and validation of results. This chapter has explored different options for procuring data and discussed at length, benefits, caveats and sensitivities of different data types. This is a small contribution to an important issue that has not been explored widely in the literature.

This framework provides a skeleton upon which to make assessments, from either an energy or a water perspective. Presented in this way for the UK, it has taken an energy sector perspective at national level by not specifying the impacts on different hydrological systems. Ultimately, in its current form it is not immediately useful to the guardians of the water upon which the energy sector depends. But it serves as a starting point to engage both communities; it is accurate and sufficiently detailed from an energy systems perspective and can be tailored to more of a water systems perspective as shown in Chapter 5.

Chapter 4. NATIONAL COOLING WATER DEMANDS TO 2050

4.1 Introduction

Using the six electricity generation pathways, the model framework from Chapter 3 is used to project abstraction and consumption demands for cooling water from the electricity sector in the UK from 2007 to 2050. The first section details the application of the model for future electricity generation pathways through analysis of the planned and consented capacity and through use of cooling method and source trajectories. The second section presents the results from the projections, including a sensitivity analysis of different cooling method and source assumptions.

4.2 Model framework application for UK electricity pathways to 2050

Chapter 3 presented in detail the development and implementation of a modelling framework for calculation of cooling water use from a portfolio of thermal electricity generation. When considered as a static portfolio this can be and was used to calculate current cooling water use at a national electricity systems level for the UK. When portfolios are changed through time, we consider them as *pathways* of future electricity generation.

Different electricity generation pathways are developed in order to explore alternative futures of one of civilised societies greatest achievements. The importance, impacts, longevity and path dependency of the energy system make it worth exploring changes to the energy system many decades in advance; the system cannot be substituted overnight. More recently, future pathways of energy systems have been used extensively at a variety of national (DECC, 2010; Lovins, 2011; VTT Technical Research Centre of Finland, 2012), continental (European Commission, 2009) and global scales (German Advisory Council on Global Change (WBGU), 2011; GEA, 2012; U.S. Energy Information Administration, 2013) to explore transitions to not only secure and affordable systems, but also low-carbon systems with the aim of mitigating climate change.

4.2.1 Future electricity generation pathways

The six electricity pathways chosen for analysis explore the boundaries of how the UK electricity mix could evolve. They do not cover all eventualities given the multitude of realistic policy options available, but they give an indication of how some quite different pathways perform. We test the four pathways presented in the UK Government's Carbon Plan (HM Government, 2011), a document that outlines the strategy space for achieving the 80% emissions stipulated by the Climate Change Act 2008 and keeping the country in line with the carbon budget framework. We also add two new pathways, CCS+ and UKM+, for reasons explained below. The pathways are labelled according to their source in Table 4-1 with their electricity mix in 2050 presented in Figure 4-1. For more details see also The Carbon Plan (HM Government, 2011). DECC 2050 Pathways model input selections are detailed in Appendix A.2.

Table 4-1. Description of the low-carbon electricity pathways to 2050. Source: Byers, Hall and Amezaga (2014) (CC-BY).

Label	Name	Narrative
UKM-326	UK MARKAL 3.26	*Core run of cost-optimised UK MARKAL 3.26.* A steady mix of renewables, nuclear and CCS is combined with ambitious energy demand reductions across all sectors, this is a least-cost pathway.
CP1-REN	Carbon Plan 1 – Renewables	*Higher levels of renewables and more energy efficiency*. Investment and innovation in renewables and storage driven by high fossil fuel prices and global commitment to tackling climate change. Mix of wind, solar and marine renewables, backed up by gas.
CP2-NUC	Carbon Plan 2 - Nuclear	*Higher nuclear and less energy efficiency*. Nuclear dominates and CCS not commercially viable. Gas meets peak demands and energy efficiency is low. Heat and transport are largely electrified.
CP3-CCS	Carbon Plan 3 - CCS	*Higher carbon capture and storage (CCS) and more bioenergy*. Commercial deployment of CCS for generation and industry fuelled by high levels of natural gas imports due to low fossil fuel prices and extensive shale gas. Involves negative emissions through Biomass-CCS.
CCS+	CCS+	*Higher carbon capture and storage (CCS) and no nuclear*. Similar to CP3-CCS although nuclear is replaced with further coal CCS, biomass, waste and renewables.
UKM+	UK MARKAL 3.26+	Similarly proportioned mix to the cost-optimised MARKAL run, although specified to meet 26% higher demand.

UKM-326 is a cost-optimised pathway that results in a balanced electricity mix and relies on ambitious but cost-effective demand reductions. The Carbon Plan pathways, CP1-3, push the boundaries of the three main generation categories of renewables, CCS and nuclear. Whilst CP2-NUC assumes a future of commercially unviable CCS, there is no pathway corresponding to a future where no further nuclear power is deployed, be it for commercial reasons or moral policies already passed by Germany, Austria, Sweden, Italy and Belgium who join a growing number of opposed countries. Hence, CCS+ is similar to CP3-CCS yet replaces nuclear with more CCS and renewables. Our analysis of the cost-optimised UKM-326 pathway identifies highly ambitious challenges in demand reduction (HM Government, 2011) and it is possible not all would be achieved (DECC, 2010). As such UKM+ comprises a similarly balanced and proportional mix to UKM-326 yet meets a 26% higher electricity demand and the carbon reduction targets. Overall the six pathways cover both a range in meeting demand from 520 to 752 TWh/year whilst also testing various proportions of nuclear, CCS and renewable generation mixes.

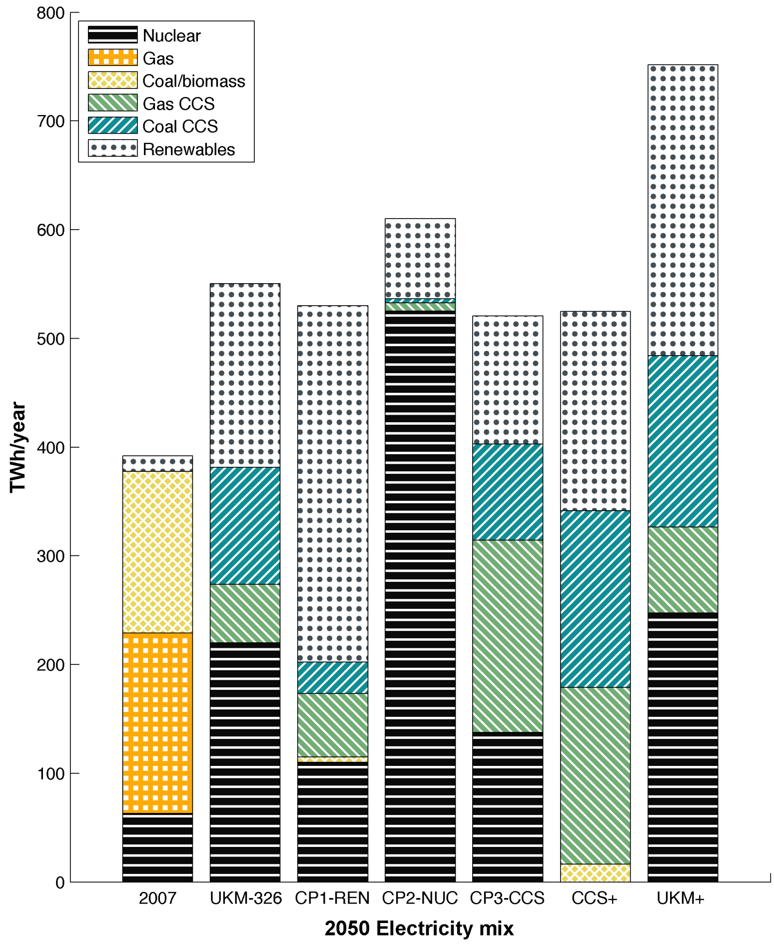


Figure 4-1. Stacked bar chart of the 2007 and future pathways showing electricity generation per year in 2050. Source: Byers, Hall and Amezaga (2014) (CC-BY).

4.2.2 Decommissioning, consented and future nuclear capacity

4.2.2.1 Decommissioning and consented capacity

The EU Large Combustion Plant Directive will result in the decommission of 11.8 GW_e of thermoelectric capacity by 2016. Thus, 2016 was chosen a key timestep in the model as in the years surrounding it is expected that additional capacity will come online to replace the decommissioned plants. Given that this did not happen in the preceding years as much as expected when left to the existing market mechanisms, the Government conducted the Electricity Market Reform from 2011-2013, publishing a delivery plan alongside the Energy Act 2013 which ascended in December 2013.

The DECC Infrastructure Planning Portal (The Planning Inspectorate, 2012) is an online repository of planning information and records all applications for energy infrastructure in England and Wales, including generation and transmission capacity. All consented thermoelectric plants from 2005-2013 were recorded in a similar database as for the current capacity (Appendix A.1), with the details on cooling method and source noted where this information could be found in the Section 36 planning application documents. The information was compared against a similar table by Schoonbaert (2012) , who also used the same resource. This results in a detailed capacity split, similar to 2010, presented in Table 4-5 and

Table 4-6.

It must be noted that not all capacity that is consented is constructed immediately, as developers may wait for the most opportune moments in the market. Market conditions may also change over the planning process. In this work from 2010 onwards, the cooling method and sources are defined by proportional distributions (as percentages). Only the percentage distribution (Table 1-2, Chapter 3) is used in the model as a descriptor of what capacity is in development and is intended to represent the trend as opposed to specific power plants. This approach is more adept for work that involves extremely different pathways, where specification of exact power stations and their location to be in operation in 40 years time is highly uncertain.

4.2.2.2 Future nuclear capacity

In 2011 the UK Government identified 11 sites that had been identified as suitable for future development of nuclear power stations, published in the National Policy Statements for Nuclear Generation (DECC, 2011d, 2011e). Some of these sites would redevelop existing sites which are still active but due for decommission around the

2020s. This is detailed in the tables below (Table 4-2, Table 4-3) and thus a trajectory of future nuclear capacity split over tidal water and sea water was developed (Table 4-4), by assuming that the sites decommissioned longest ago will be the first to be re-commissioned.

Table 4-2. Current nuclear capacity in the UK. Table adapted from DECC (DECC, 2012d).

Power station	**Type**	**Capacity MW_e**	**Current Operator**	**Commercial operation**	**Accounting closure date**	**Cooling water source**
Wylfa	Magnox	980	Magnox Ltd	1972	2012	Sea
Dungeness B	AGR	1,110	EDF Energy	1985	2018	Sea
Hinkley Point B	AGR	1,220	EDF Energy	1976	2023	Sea
Hunterston B	AGR	1,190	EDF Energy	1976	2023	Sea
Hartlepool	AGR	1,210	EDF Energy	1989	2019	Tidal
Heysham 1	AGR	1,150	EDF Energy	1989	2019	Tidal
Heysham 2	AGR	1,250	EDF Energy	1989	2023	Tidal
Sum		10,548				

Table 4-3. Assumed future nuclear capacity in the UK. Order of commission has been assumed according to the order of decommission in the case where sites have previously had power plants.

Power station	**Region**	**Capacity MW_e**	**Cooling water source**	**Commission date**
Hinkley Point B	South West	3,200	Sea	2022
Wylfa	Wales	3,200	Sea	2024
Bradwell	Scotland	3,200	Tidal	2026
Sellafied	South East	3,200	Sea	2026
Oldbury	Scotland	3,200	Tidal	2028
Hartlepool	North East	3,200	Tidal	2028
Heysham 3 and 4	North West	3,200	Tidal	2030
Sizewell C	East	3,200	Sea	2030
Sum		25,600		

Table 4-4. Assumed trajectory of cooling water source split for nuclear capacity.

Year	**Tidal**	**Sea**	**Tidal %**	**Sea%**	**Capacity MW_e**
2012	3,610	6,938	34%	66%	10,548
2013	3,610	5,958	38%	62%	9568
2019	3,610	4,848	43%	57%	8458
2020	1,250	4,848	20%	80%	6098
2022	1,250	8,048	13%	87%	9298
2024	0	7,588	0%	100%	7588
2026	3,200	10,788	23%	77%	13,988
2028	9,600	10,788	47%	53%	20,388
2030	12,800	13,988	48%	52%	26,788
2035	12,800	12,800	50%	50%	25,600

4.2.2.3 2016 capacity distribution

All the consented and decommissioned capacity detailed in the previous two sections (Table 4-2 to Table 4-4) were added to the current capacity portfolio database for 2010. Distributions were subsequently recalculated as shown below in Table 4-5. During this period, 3.5 GW_e of oil-fired steam plants will have closed (Fawley, Grain and Littlebrook).

Table 4-5. 2016 Pivot table of distribution of cooling types and generation classes. Source: Byers, Hall and Amezaga (2014) (CC-BY).

	Air	Sea	FW			FW Total	TW			TW Total	Total
Cooling method	Air cooled	Open	Open	Closed	Hybrid		Open	Closed	Hybrid		
Nuclear	0.0%	47.9%	0.0%	0.0%	0.0%	0.0%	52.1%	0.0%	0.0%	52.1%	100.0%
Gas											
CCGT	23.5%	5.1%	0.4%	19.5%	3.8%	23.6%	20.8%	24.6%	2.3%	47.7%	100.0%
CCGT CHP	24.7%	0.0%	0.0%	5.8%	4.6%	10.3%	0.0%	33.5%	31.4%	64.9%	100.0%
GT/ OCGT	95.1%	0.0%	4.9%	0.0%	0.0%	4.9%	0.0%	0.0%	0.0%	0.0%	100.0%
Coal, Biomass, etc.											
Biomass	76.2%	0.0%	0.0%	11.7%	0.0%	11.7%	0.0%	8.0%	4.1%	12.1%	100.0%
Coal	0.0%	12.0%	0.0%	30.0%	0.0%	30.0%	13.1%	44.9%	0.0%	58.0%	100.0%
Coal/ biomass	0.0%	0.0%	0.0%	29.2%	0.0%	29.2%	0.0%	70.8%	0.0%	70.8%	100.0%
Waste	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Oil - steam	All oil-fired steam plants decommissioned										
Total	18.2%	11.7%	0.4%	17.9%	2.2%	20.5%	20.8%	25.9%	2.9%	49.6%	100.0%

4.2.3 Cooling source and cooling method trajectories

In order to test a variety of electricity pathways, a consistent and common set of assumptions about the cooling sources and methods is required. The use of percentage distributions allows a set of assumptions to be applied to future pathways, whilst remaining independent of the future states of those pathways. By consistently applying the assumptions across all the pathways, the analysis of these pathways was focused on their constituent generation mix. The sensitivity analysis enables testing of different cooling trajectories and their effects on the different pathways. This removes the possibility of subjective bias that may occur if cooling trajectories were specified for each pathway.

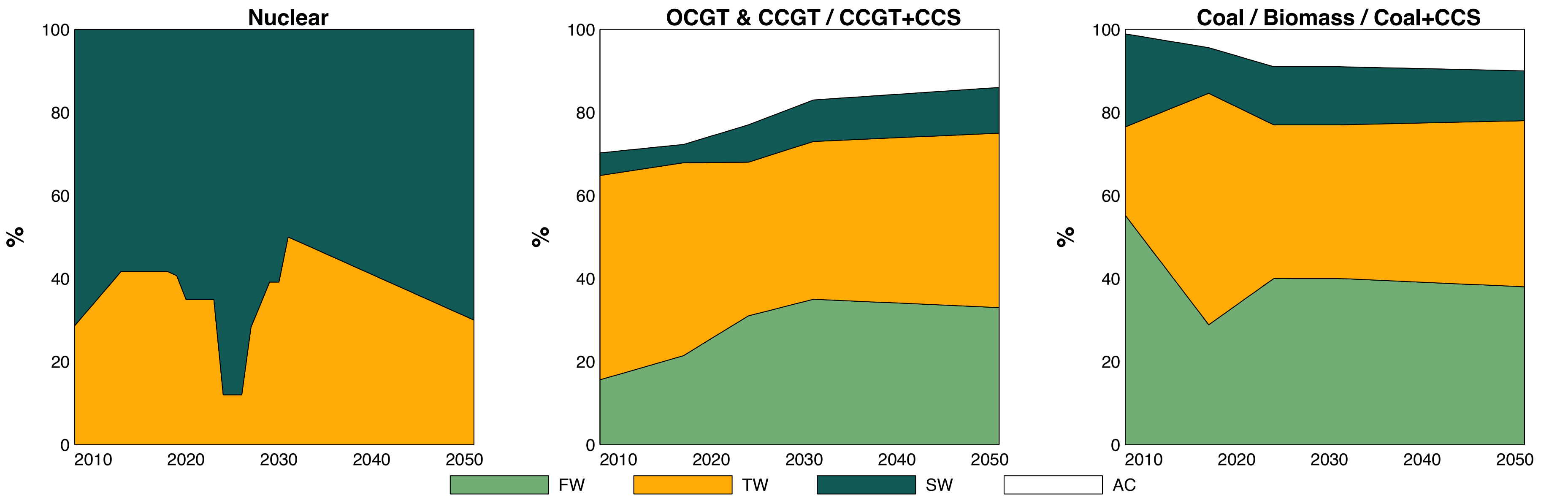
Cooling source and method trajectories have been defined at the timesteps of 2010, 2016, 2023, 2030 and 2050 and intermediate points were interpolated linearly. Whilst this results in trajectories of cruder form, linear interpolation is necessary in order to avoid Runge's phenomenon (Runge, 1901). The years 2010 and 2016 are defined according to the present and planned capacity changes. Trajectories from 2023-2050 were based on the assumptions below. Not much change overall is expected however given the preference for redevelopment of legacy sites, as previously discussed in Chapter 1.

4.2.3.1 Cooling source assumptions

- Freshwater capacity for both coal and gas plants is expected to decrease slightly based on diminishing availability of and increased competition for freshwater resources. Coal and biomass capacity on freshwater will decrease more given their higher water use intensity and may face challenges obtaining abstraction rights for additional CCS equipment.
- Tidal and seawater capacity will for the most part replace the reductions in freshwater capacity. Part of this will be due to the CCS clusters of power generation and industry as identified in the CCS Roadmap (DECC, 2012a), the majority of which lie on tidal water stretches and the coast.
- The proportion of air-cooled gas plants is expected to decrease as most plants will be CCGT in lieu of air-cooled OCGT plant.
- An increase in smaller biomass capacity will lead to greater use of air cooling.
- The staggered decommission of nuclear power will see a sharp reduction in tidal water use, expected to rise again slightly as the first generation of plants come online up to 2030. Beyond this, given lack of available sites and environmental pressures, it can expected that future sites will be located on the sea and so this proportion will rise.

4.2.3.2 Cooling method assumptions

- All new freshwater capacity will use at least closed-loop cooling, if not hybrid or air-cooling. This matches U.S. EPA Section 316(b) amendments to the Clean Water Act 1976 (Environmental Protection Agency, 2014) to phase out the use of once-through cooling of freshwater sources.
- Tidal water capacity for both coal and gas with CCS will use a mixture of open, closed and hybrid cooling.
- Use of sea water stays fairly constant, increasing slightly for gas and decreasing slightly for coal and biomass.



Nuclear	OCGT & CCGT/CCGT+CCS	Coal/Coal+CCS (or biomass)
The new generation of nuclear plants will be split 50:50 between sea water (SW) and tidal water (TW) following the classifications of past sites stated by the Environment Agency (2010) and the identified future sites. Decommission and commission will be staggered and hence reduces overall TW proportion in the 2020s but increases again by 2030. Beyond the first generation (up to 26GW$_e$), from 2030 to 2050 we assume a split of 70:30 between SW and TW due to less availability of sites on estuaries and environmental legislation	The trend observed from planning applications since 2005 has indicated an increase in combined cycle gas turbines cooled by freshwater (FW) (in closed-loop, AC and hybrid configurations) which have and will replace, in some cases, smaller air-cooled open cycle gas turbines (OCGT). Due to their peaking capacity and black-start capability however, some OCGT capacity remains. Past 2030, plants will require additional abstraction rights for carbon capture retrofit which may limit further FW development, hence slightly higher levels of TW and sea-cooled capacity can be expected.	Tidal water (TW) reduces towards 2016 as older plants are decommissioned with the Large Combustion Plant Directive. Beyond this, the use of legacy sites and higher water requirements (roughly double for carbon capture) compared to combine cycle gas turbines increases a shift towards tidal water and sea water sites. Past 2030, plants will require additional abstraction rights for carbon capture retrofit which may limit further freshwater development. Increase in air-cooled capacity is due to smaller biomass plants.

Figure 4-2. Cooling water source trajectories as a percentage of installed capacity type. In the 2030s Gas and Coal generation transition to their equivalents with CCS respectively. Source: Byers, Hall and Amezaga (2014) (CC-BY).

Future cooling source and method distributions

Table 4-6 details the future pathways of cooling water source and cooling methods for the generation types. This table extends from the 2010 and 2016 values from Chapter 3 Table 3-2 and Table 4-5. Although presented in groups below (Nuclear, CCS-Gas, CCS-Coal), the percentages are split across each generation class {1-12} taking into account the four cooling sources {FW, TW, SW, AC} and three cooling methods {Open, Closed, Hybrid, Air Cooled} available for each year, such that the sum for each year (a total of 12 elements in the matrix) is equal to 1 (100%).

Table 4-6. Intermediate points of future cooling method and source pathways for 2023, 2030 and 2050. This presentation facilitates evaluation of the capacity distribution by both cooling source and method. Source: Byers, Hall and Amezaga (2014) (CC-BY).

Nuclear	2023				2030				2050			
	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ
FW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
TW	12%	0%	0%	12%	50%	0%	0%	50%	30%	0%	0%	30%
SW	88%	0%	0%	88%	50%	0%	0%	50%	70%	0%	0%	70%
AC	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Σ	100%	0%	0%	100%	100%	0%	0%	100%	100%	0%	0%	100%
Gas+CCS	2023				2030				2050			
	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ
FW	0%	25%	10%	35%	0%	25%	10%	35%	0%	22%	11%	33%
TW	10%	18%	12%	40%	10%	18%	10%	38%	10%	21%	11%	42%
SW	14%	0%	0%	14%	10%	0%	0%	10%	11%	0%	0%	11%
AC	0%	0%	11%	11%	0%	0%	17%	17%	0%	0%	14%	14%
Σ	24%	43%	33%	100%	20%	43%	37%	100%	21%	43%	36%	100%
Coal+CCS	2023				2030				2050			
	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ
FW	0%	29%	10%	39%	0%	34%	6%	40%	0%	23%	15%	38%
TW	11%	20%	10%	41%	6%	21%	10%	37%	12%	14%	14%	40%
SW	10%	0%	0%	10%	14%	0%	0%	14%	12%	0%	0%	12%
AC	0%	0%	10%	10%	0%	0%	9%	9%	0%	0%	10%	10%
Σ	21%	49%	30%	100%	20%	55%	25%	100%	24%	37%	39%	100%
Gas	2023				Up to 2030				2050 – effectively phased out			
	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ
FW	0%	24%	7%	31%	0%	25%	10%	35%	0%	25%	12%	37%
TW	15%	14%	8%	37%	10%	18%	10%	38%	11%	21%	11%	43%
SW	9%	0%	0%	9%	10%	0%	0%	10%	12%	0%	0%	12%
AC	0%	0%	23%	23%	0%	0%	17%	17%	0%	0%	8%	8%
Σ	24%	38%	38%	100%	20%	43%	37%	100%	23%	46%	31%	100%
Coal	2023				Up to 2030				2050 – effectively phased out			
	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ	Open	Closed	Hybrid	Σ
FW	0%	34%	6%	40%	0%	34%	6%	40%	0%	26%	12%	38%
TW	6%	21%	10%	37%	6%	21%	10%	37%	12%	14%	14%	40%
SW	14%	0%	0%	14%	14%	0%	0%	14%	12%	0%	0%	12%
AC	0%	0%	9%	9%	0%	0%	9%	9%	0%	0%	10%	10%
Σ	20%	55%	25%	100%	20%	55%	25%	100%	24%	40%	36%	100%

By 2030, Coal and Gas have almost entirely transitioned to coal+CCS and gas+CCS, so although the table still displays splits for these generation classes between 2030-2050, the actual installed capacity in the model in minimal.

4.2.4 Water use factors

4.2.4.1 Changes through time

Water use factors are assumed to stay constant from 2010-2050 and are the same as the factors used in Chapter 3. Although thermal efficiencies and cooling technologies have improved with time, no reliable sources that document the speed of historical efficiency improvements could be found in order to indicate the speed of future improvements might. Thermal efficiency improvements of already very well-established steam cycles may be achieved in the order of no more than a few percent over the next few decades. By comparison, water use factors, as aforementioned are likely to be more susceptible to greater variation if switching of cooling methods occurs, or by changes in regulation regarding abstraction volumes or discharge temperatures.

4.2.4.2 Carbon capture and storage technology

Whilst there is uncertainty concerning the exact additional cooling requirements that will result from CCS-enabled generation, estimates from empirical and theoretical sources range from between +44% to +140% increased demand for cooling depending on the generation and cooling type (Parsons Brinckerhoff, 2012). Further details have been discussed in section 2.3.7.

4.3 Results and sensitivity analysis

The results presented in the following sections draw largely from the results in Byers, Hall and Amezaga (2014). They are based primarily on the standard set of assumptions that have been presented in the preceding sections of this chapter. Further sensitivity analysis is presented in section 4.3.2.

4.3.1 Results

4.3.1.1 All water sources

Considering all sources in the future (Figure 4-3), water use by the electricity pathways increases on 2007 levels in all cases besides the CCS+ pathway for abstraction and CP1-REN for consumption. Nuclear power with once-through cooling significantly affects the level of tidal and sea water abstraction and consumption, demonstrated by difference between the two polarised pathways of CP2-NUC and CCS+. For abstraction, the range of 2050 values is between -28% and +394% over the 2010 value, with a median increase of 111%. The largest increases come from the two pathways CP2-NUC and UKM+, heavily influenced by the presence of nuclear plants on coastal and tidal sites, with sea water abstraction in CP2-NUC increasing more than a six-fold. Again, for tidal water there is a 235% abstraction increase in CP2-NUC pathway compared to a 20% decrease in the nuclear-free CCS+ pathway. Freshwater abstractions which are all closed-loop wet tower cooling, are insignificant by comparison. In general, the trend is that pathways with high levels of nuclear power (UKM-326, CP2-NUC, UKM+), result in high levels of tidal and sea water abstraction, and subsequently high levels of thermal discharges to the environment. Pathways with low levels of nuclear power (CP1-REN, CP3-CCS, CCS+), result in low levels of tidal and sea water abstraction.

For consumption, the range of 2050 values is between -15% and +138% over the 2010 value, with a median increase of 78%. What differs in these pathways are the levels of freshwater use from carbon capture and storage generation, indicated by the particularly high levels of freshwater consumption in UKM+ (compare Figure 4-3 and Figure 4-4), and the very low levels of freshwater use in CP1-REN and CP2-NUC.

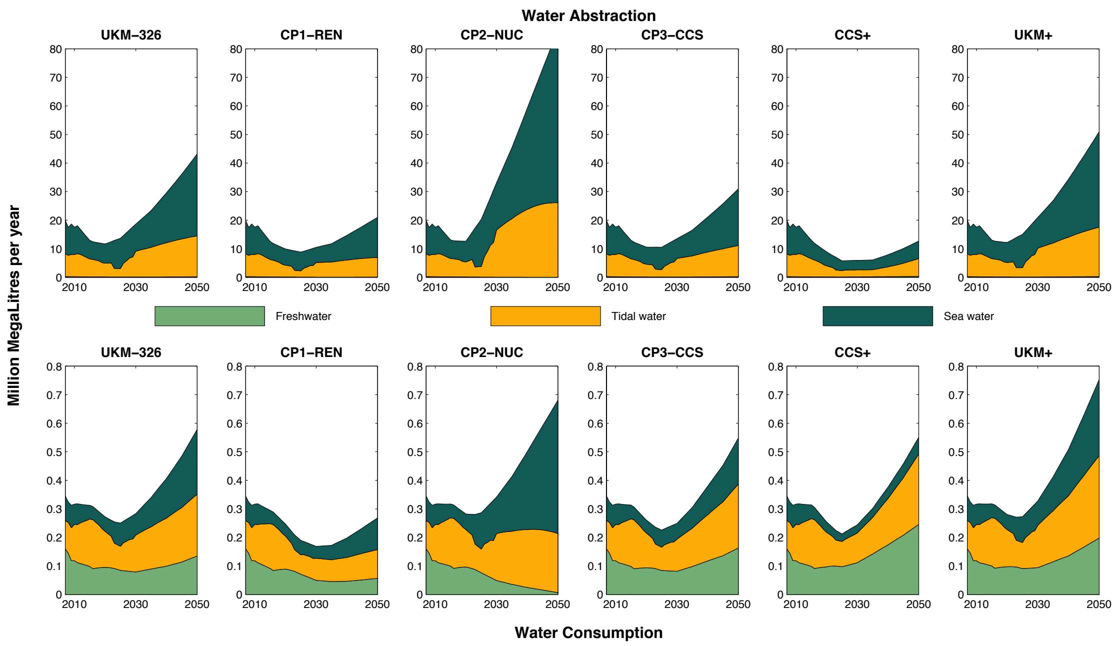


Figure 4-3. Water abstraction and consumption over all sources for the 6 pathways from 2007 to 2050. Source: Byers, Hall and Amezaga (2014) (CC-BY).

4.3.1.2 Freshwater only

The results for freshwater use presented in Figure 4-4, especially in the context of growing socio-economic demands and the impacts of climate change, are arguably of more importance. In all cases there are large decreases in abstraction towards 2030, driven by two factors. Firstly is the decommission of older and less efficient coal and oil-fired plant due to the EU Large Combustion Plant Directive. Whilst predominantly closed-loop cooling, they continue to be abstraction intensive. Secondly is the transition to closed-loop and hybrid cooling for all plants that abstract from FW sources. A few small CCGT plants, which are already inherently water-efficient in open cooling configuration, have their abstractions reduced through this switch of cooling methods. This coincides with some decommissioning and a gradual transition to carbon capture equipped capacity, which drives increases in freshwater use from 2025 onwards.

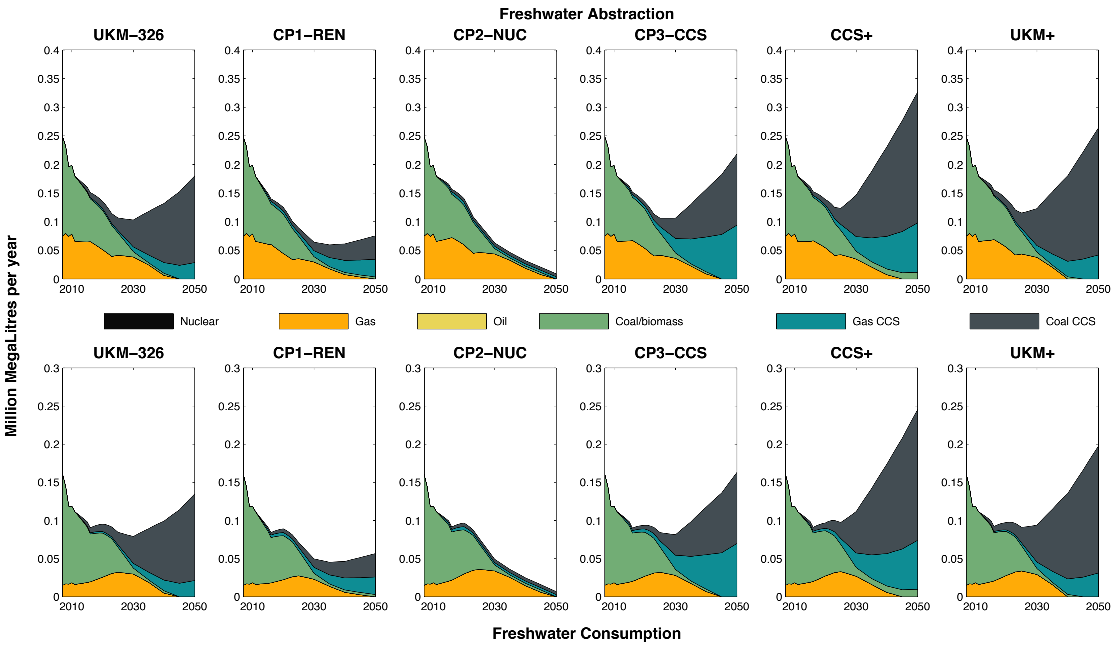


Figure 4-4. Water abstraction and consumption by generation class for freshwater from 2007 to 2050. Source: Byers, Hall and Amezaga (2014) (CC-BY).

For consumptive water use, the decommission of coal plants results in rapid reduction of consumption despite a slight increase in gas consumption towards 2030 as more plants come online through the UK's Gas Generation strategy. They are considerably more water-efficient (0.72 ML/GWh) than the coal plants (1.77 ML/GWh) they replace, hence the overall decline. From 2030 onwards to 2050 it is projected that almost all fossil fuel generation is abated by carbon capture and storage (CCS) making it possible to analyse overall effects of CCS on water use. CP2-NUC is the only pathway without significant CCS capacity and thus surface water use approaches zero as electricity demand is met mainly through nuclear and renewables. The CCS+ pathway, with no further nuclear, results in not only the highest freshwater abstraction but also consumption, exceeding 2010 by the 2040s and is 107% higher by 2050. CP3-CCS and UKM+ in 2050 were respectively 37% lower and 67% higher than 2010. Worth noting also are the CCS distributions between coal and gas and the effect on overall water use. UKM-326 and UKM+, both low cost pathways, have 67% coal and 33% gas generation with CCS; thus coal+CCS's higher consumptive water intensity for the same cooling systems (3.22 vs. 1.36 ML/GWh) dominates water use results. CP1, CP2 and CP3 are the opposite; 33% coal and 67% gas result in a more even water use split. CCS+ is split 50:50 and therefore water use from coal is again higher. In summary, replacing and upgrading current coal and gas capacity to CCS equivalents results in freshwater consumption that approaches, if not exceeds, current levels post 2025 when the first CCS plants start to come online.

4.3.1.3 Carbon and water intensity

Figure 4-5 plots the average consumptive water intensity of thermoelectric capacity on freshwater. Figure 4-6 plots both 'carbon dioxide intensity' ($MTCO_2$/TWh) and 'consumptive freshwater intensity' in ML/TWh of the six pathways averaged over the whole capacity of the grid. Whilst all the electricity pathways modelled are expected to significantly reduce the carbon intensity of generation with an aim of meeting the statutory carbon budgets, there has not yet been any in-depth investigation into changes in water intensity for UK energy pathways.

Considering only the capacity on freshwater, Figure 4-5 shows that in all cases, intensity of freshwater consumption increases through a switch to coal and gas with carbon capture and storage by a range of 24-62%. The ratio between coal and gas is the key determinant in the water intensity as can be noted by the labels. This general trend of rising freshwater use capacity must be interpreted at the plant level. It tells us that if a new power plant from a chosen pathway were to be consented, what would be the expected water use intensity of that plant, if no further information about generation type or cooling system were known. It represents the weighted average, by volume of electricity generation, of the pathway's water use across all the configurations of generation type and cooling method used in that pathway. Given that assumptions regarding cooling source and method are fixed across the pathways, the determining factors of this graph are the generation type. Hence, it is the split between coal and gas and not the level of installed capacity that is important. If we compare this to the consumptive water use figures for coal and gas with CCS (closed-loop cooling), 3220 and 1360 ML/TWh respectively, we see that the water use intensity figures lie in-between these ranges; primarily due to the generation split, but also because some capacity is air cooled.

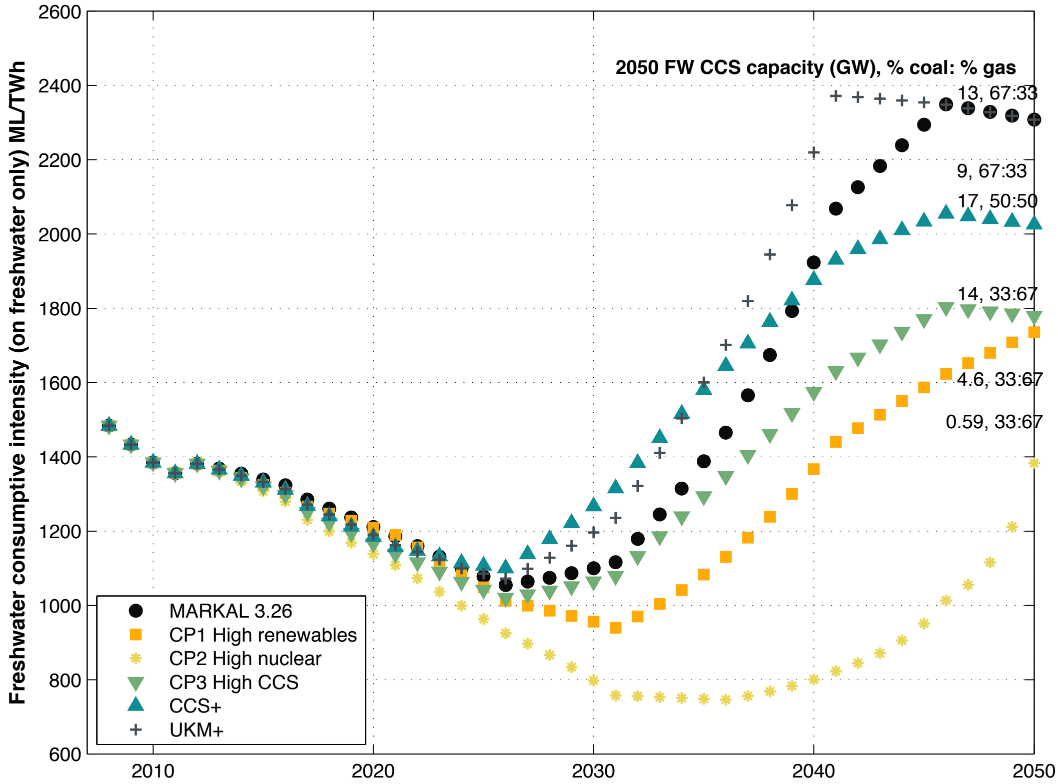


Figure 4-5. Non-tidal surface water consumption intensity (ML/TWh) averaged over FW capacity only, shows that as capacity is replaced the average water intensity increases, due to CCS equipment. Source: Byers, Hall and Amezaga (2014) (CC-BY).

In Figure 4-6 we compare both water use intensity and carbon emissions intensity of the pathways. Thee results are presented as grid averages that include all generation types. Taking into account all electricity generation (i.e. including renewables), grid emissions intensities all reduce as intended, in fact achieving negative figures through use of bioenergy with carbon capture and storage. For cooling water, the levels of freshwater consumed per unit electricity generated vary from 11 to 468 ML/TWh in 2050 over 2010 levels of 311 ML/TWh. Despite the water intensity of carbon capture plants being considerably higher than current capacity (as shown in Figure 4-5), higher levels of nuclear and renewables bring the overall grid average down. The level of nuclear power also has an indirect inverse effect on consumption, as higher proportions of nuclear power displace freshwater capacity and lower the overall freshwater intensity. Where freshwater use is reduced due to higher levels of nuclear power, tidal water use is significantly increased.

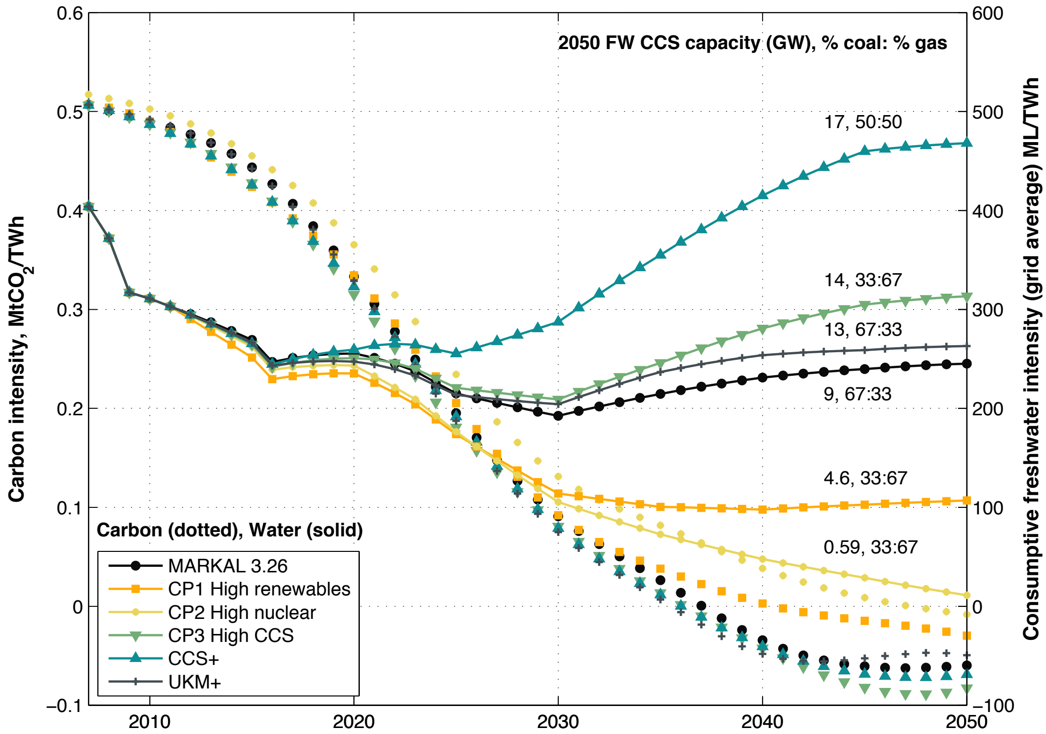


Figure 4-6. Dotted lines show 'grid' carbon intensity in $MtCO_2/TWh$ (equivalent to gCO_2/kWh), solid lines show freshwater consumption intensity in ML/TWh, averaged over all the capacity in the grid. Source: Byers, Hall and Amezaga (2014) (CC-BY).

Considering freshwater and tidal water together, 2050 consumption intensity differs greatly between CP2-NUC and CCS+ with 350 and 939 ML/TWh respectively. However, despite having the highest intensity, the CCS+ pathway balances this across both fresh and tidal water whilst CP2-NUC is particularly water-intensive on tidal water only. Considering tidal intensity alone, all pathways increase from 333 to the range of 339-471 ML/TWh besides CP1-REN whose intensity decreases to 190 ML/TWh. Total water intensity in 2050 for all sources including sea water was consistent across all pathways ranging from 1,002-1116 ML/TWh over a 2010 value of 830 ML/TWh, besides the CP1-REN pathway whose final intensity was 507 ML/TWh.

4.3.2 Sensitivity analysis

These results presented are highly sensitive to the assumptions on cooling sources and methods described in section 4.2.3. These assumptions were based on detailed review of historical trends, the current situation and trends in planned capacity. They also assume that competition for water resources in the future will increase due to population growth, climate change and economic growth, thus more water-efficient cooling systems will be more preferable. The assumptions made also take into account the rate of generation capacity replacement, considering the fact that cooling system retrofit and relocation of power stations midway through operational lifetime is unlikely. These assumptions are tested through the wide range of scenarios presented in the following section. We also test the water use through capacity-constrained scenarios where capacity on freshwater is limited.

4.3.2.1 Cooling source and method scenarios

Different cooling scenarios (#1-10) were tested to identify how the most effective reductions in freshwater consumption can be achieved compared to the 2050 baseline projections (#0) presented in section 4.3.1. These modify the assumptions around cooling method and cooling source. For both coal (#1-4) and combined cycle gas turbines (#5-8) with carbon capture and storage, the following five scenarios were tested:

- 50% reduction in freshwater capacity (transferred to tidal water) (#1 & #5)
- 50% relative increase in hybrid cooling on freshwater capacity (#2 & #6)
- 100% of freshwater capacity with closed-loop cooling (#3 & #7)
- 100% of freshwater capacity with hybrid cooling (#4 & #8)
- Additionally, two scenarios where all cooling, for both coal and combined cycle gas turbines, was either closed-loop or hybrid (#9 & #10).

These scenarios are detailed further in Table 4-7 and results presented in Figure 4-7, showing the exact distributions of generation type, cooling method and cooling source for the alternative scenarios.

Presented in Figure 4-7, the greatest reductions were achieved by either reducing the proportion of coal with carbon capture capacity on freshwater by 50% (from 39% to 19.5% with the remainder on tidal water in 2050) or by using hybrid cooling on all the freshwater-based coal with carbon capture capacity. Similar reductions were achieved with the same measures for combined cycle gas turbines (CCGT) although absolute reductions were smaller given the lower water intensity of CCGT. Finally we evaluated potentially worst- and best-case scenarios – respectively whereby all freshwater capacity was either closed-loop (18-21% increase) or hybrid cooling (20-23% decrease).

On this basis, for a fixed quantity of freshwater available it would be possible to support 41% more thermoelectric capacity if using hybrid cooling over closed-loop.

Table 4-7. Scenario details and modifications made to the cooling trajectories for Open (O), Closed (C) and Hybrid (H) cooling methods on freshwater and tidal water sources. Source: Byers, Hall and Amezaga (2014) (CC-BY).

#	Scenario	Description	Freshwater (FW)			Tidal water (TW)		
			O	C	H	O	C	H
1	2050 Base	Baseline results						
	- Coal+CCS		0%	23%	15%	12%	14%	14%
	- Gas+CCS		0%	22%	11%	10%	21%	11%
CCS-Coal modifications			Changes only for Coal+CCS					
2	Coal+CCS FW-50%	Reduce proportion of FW capacity by 50% - transfer evenly to TW.	0%	12%	8%	18%	20%	20%
3	Coal+CCS Hybrid+50%	Increase proportion of FW Hybrid capacity by 50% - taken from Closed	0%	16%	23%	12%	14%	14%
4	Coal+CCS 100% Closed-loop	Set 100% FW capacity to use Closed-loop cooling	0%	38%	0%	12%	14%	14%
5	Coal+CCS 100% Hybrid	Set 100 % FW capacity to use Hybrid cooling	0%	0%	38%	12%	14%	14%
CCS-Gas modifications			Changes only to Gas+CCS					
6	Gas+CCS FW-50%	Same as above but for Gas+CCS	0%	11%	6%	16%	27%	17%
7	Gas+CCS Hybrid+50%		0%	17%	17%	11%	21%	11%
8	Gas+CCS 100% Closed-loop		0%	37%	0%	11%	21%	11%
9	Gas+CCS 100% Hybrid		0%	0%	37%	11%	21%	11%
Coal+CCS & Gas+CCS			Changes to Coal+CCS & Gas+CCS					
10	100% Closed-loop	Set all Coal+CCS & Gas+CCS FW capacity to 100% Closed-loop cooling.						
	- Coal+CCS		0%	38%	0%	12%	14%	14%
	- Gas+CCS		0%	37%	0%	11%	21%	11%
11	100% Hybrid	Set all Coal+CCS & Gas+CCS FW capacity to 100% Hybrid cooling.						
	- Coal+CCS		0%	0%	38%	12%	14%	14%
	- Gas+CCS		0%	0%	37%	11%	21%	11%

What is also clear from Figure 4-7 is the sensitivity of different pathways to changes in cooling source and method assumptions. The more water-intensive the pathways (i.e. CCS+, UKM+) are obviously more sensitive to the cooling scenarios. This highlights the importance of paying more attention to detail in the water-related regulation and governance of water-intensive pathways, as small changes will have more significant impacts.

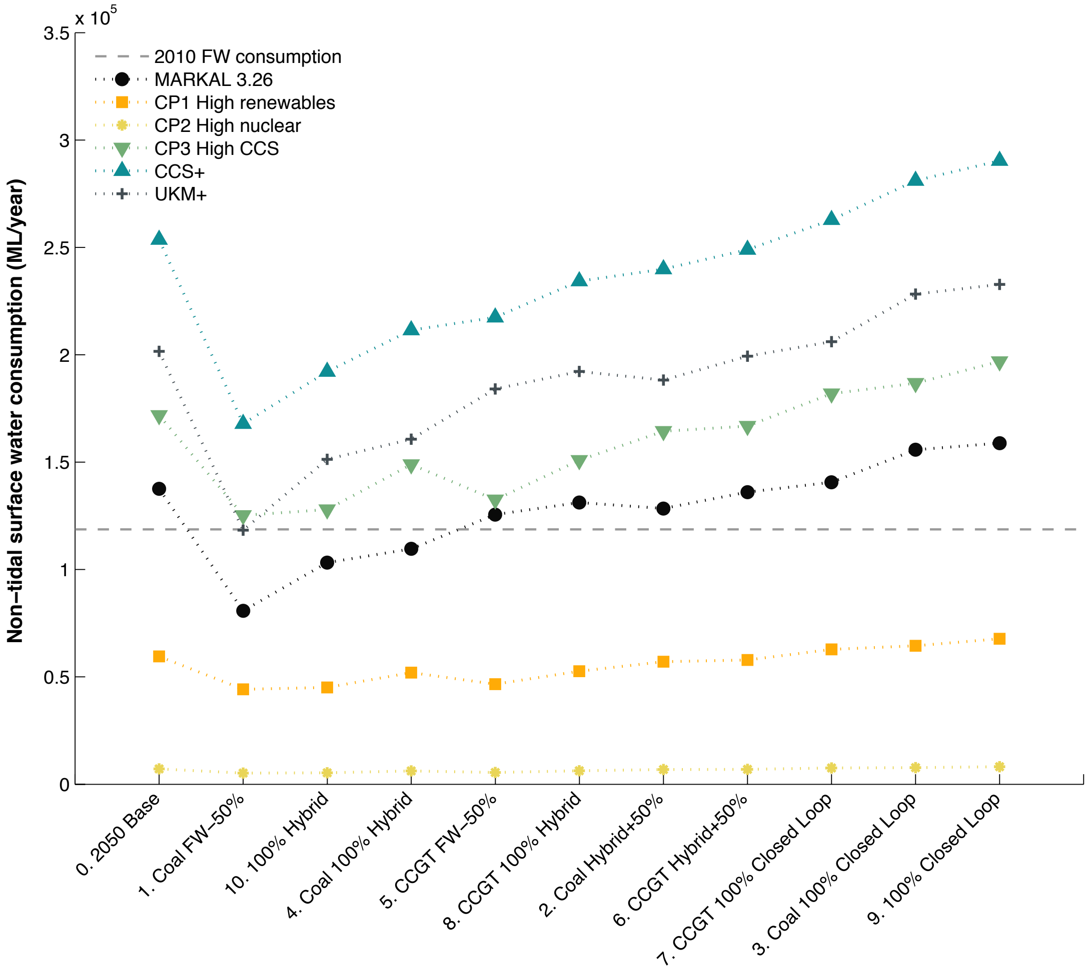


Figure 4-7. 2050 freshwater (FW) consumption using the different cooling scenarios, ranked by water use. Source: Byers, Hall and Amezaga (2014) (CC-BY).

4.3.2.2 Constrained capacity on freshwater

For the six pathways we tested the sensitivity of freshwater consumption in 2050 to different levels of generation capacity on surface water. By limiting the level of capacity on freshwater we established the sensitivity of freshwater consumption for each pathway, which in 2010 was 6,009 ML/GW of thermoelectric capacity. For UKM-326, UKM+, CP3-CCS pathways freshwater consumption increases to the range of 11,104-11,731 ML/GW$_e$, 13,574 for CCS+ whilst the CP1-REN and CP2-NUC pathways were considerably lower, at 4,089 and 1,357 ML/GW$_e$. For assessment on a national scale, these figures indicate the volume of freshwater consumed by each pathway, for each additional GW$_e$ of capacity added (equivalent to a medium-large power station). The point at which the lines level out indicate the maximum expected level of freshwater capacity for that pathway. If the level of freshwater resource is limited and electricity sector development is closely following one of these pathways, the maximum level of capacity served by the level of freshwater can therefore be determined.

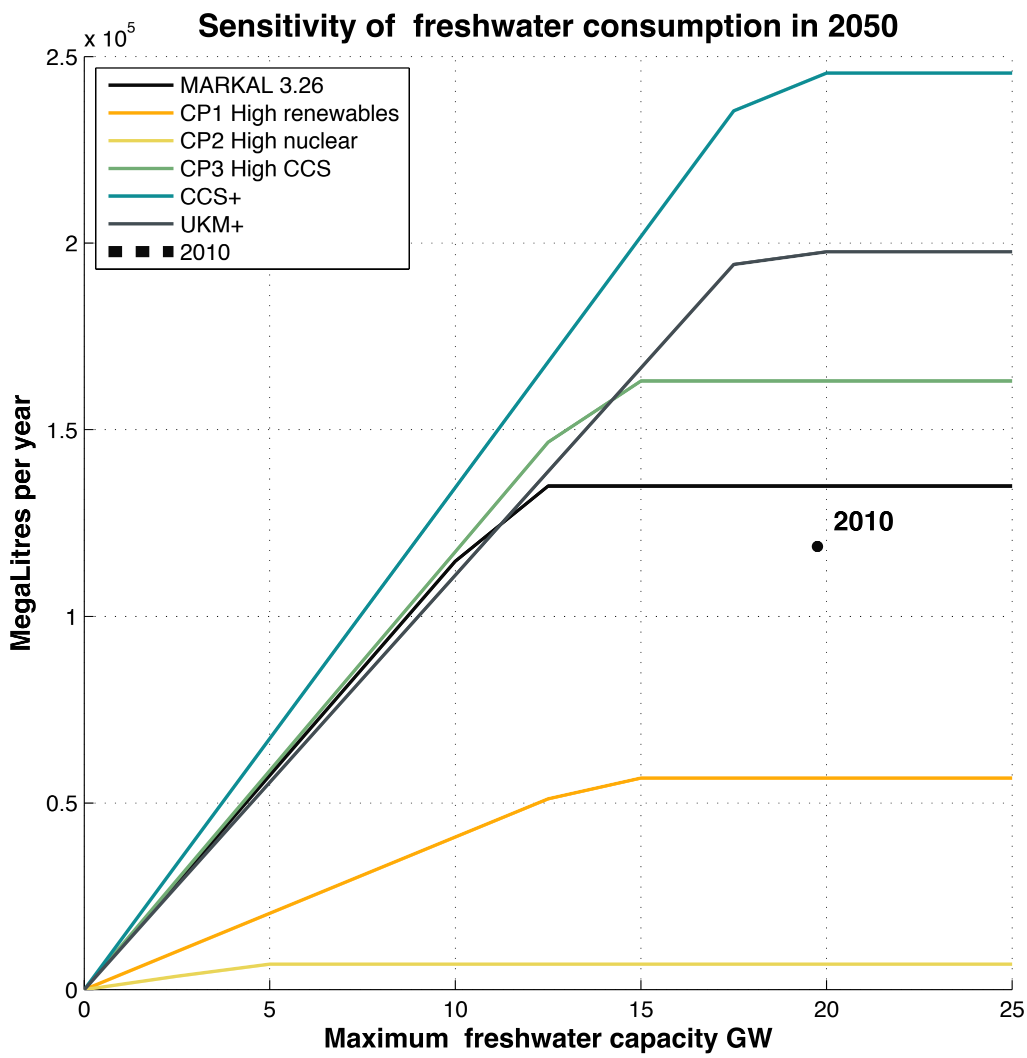


Figure 4-8. Sensitivity of freshwater consumption to the level of capacity by different pathways. Source: Byers, Hall and Amezaga (2014) (CC-BY).

4.4 Discussion

Current water use by the electricity sector is substantial in volume and critical to its operation, yet pressures of population growth, climate change and hydrological variability will complicate the issue further even if water use in 2050 remains at current levels. Our results have shown a mixture of trends, depending on the perspective of analysis.

4.4.1 Changes in cooling methods and sources

Freshwater abstractions will reduce if all the remaining open-loop cooling is replaced by closed-loop or hybrid configurations. This will bring benefits through reduction of thermal pollution and ecological impacts, but can also result in higher consumptive losses, in the majority of cases. Freshwater consumption will depend primarily on the level of carbon capture and storage (CCS) capacity installed, and subsequently on whether it is gas or coal. Pathways with more coal will have higher freshwater usage, which in the 'cost-optimised' pathways (UKM-326 & UKM+) will be 69% more water-intensive per unit electricity output than current levels. If water resources are limited, less capacity (than at present) will be able to use freshwater and hence more will shift to tidal and sea water use. If low flows are experienced, not only will the coal plant be more vulnerable to the water scarcity due to higher requirements, but its water consumption and downstream impacts would be twice that of a similar gas plant. Therefore, whilst the headline result of indicates freshwater consumption across the grid as decreasing or staying at current levels (Figure 4-6), we must be wary that at the plant level the intensity of freshwater consumption will increase substantially with the use of CCS (Figure 4-5).

Given this increase in water intensity and limited abstraction licenses, the future is unlikely to see an increase in the level of capacity on freshwater, but an increase in absolute consumption is possible. Besides the generation offset by renewables, we can expect higher levels of capacity on tidal and coastal locations. Both abstraction and consumption will increase substantially, primarily through the use of once-through nuclear power but also additional CCS capacity (Figure 4-3 and Figure 4-4).

4.4.2 Carbon capture and storage

For freshwater, the analysis shows that a gradual switch to closed-loop and hybrid cooling reduces abstraction volumes substantially whilst maintaining high levels of consumptive use. Most significantly, the intensity of freshwater consumption increases with the level of coal capacity with carbon capture and storage (CCS) whilst thermal discharges switch from water bodies to the air. Reducing abstractions should reduce vulnerability to low flows (Förster and Lilliestam, 2009), whilst bringing benefits to local environments by minimising thermal pollution and fish entrainment. However, high levels of consumption could increase the risk of low flows and we expect the Government's Roadmap for carbon capture and storage deployment (DECC, 2012a) to exacerbate this issue. The Roadmap explicitly specifies clustering in order to reduce the costs of CO_2 compression and transport infrastructure and has identified, with good reason, clusters of high point-source emissions around which CCS infrastructure and high-carbon industry can develop. Such sites may contribute to and be vulnerable to localised water shortages, increasingly so due to the higher water use intensity. The

River Trent, which supports eight stations totalling approximately 11.1 GW_e capacity (3.0 GW_e on freshwater, 8.1 GW_e on tidal water) with a further 3.6 GW_e approved for construction on freshwater, could come under considerable water stress when CCS infrastructure is installed and water use intensity doubles. One of the largest rivers in the UK, the Trent still has water available for licencing, but only under 'Hands off Flow' conditions that would prevent abstraction for the lowest 30% of flows when compared to the observed record (Environment Agency, 2008). Yet CO_2 pipelines along this corridor will inevitably attract further power station development. In summary, and similarly concluded by Naughton, Darton and Fung (2012), if CCS development is to occur in series or clusters, water abstractions and cooling provisions should be evaluated as such (and not as single plants), before CO_2 infrastructure is constructed.

4.4.3 Coastal locations

The greater the need to protect inland water resources for agriculture and public water supply, whilst maintaining levels of environmental quality, the greater the pressure will be to shift thermoelectric generation towards the coast. Most tidal and sea water sites afford developers the use of direct cooling, which combined with greater cooling efficiency, offers both capital and operational cost reductions and has been identified as the *Best Available Technology* for large coastal and estuarine power stations (EC JRC, 2001). The scale of increases presented by pathways UKM-326, UKM+ and CP2-NUC, between 148% and 399%, will require careful management of the effects of fish entrainment and thermal pollution in marine and estuarine environments. Whilst not beyond current engineering expertise, it may complicate the planning process when sites are in close proximity or near sensitive environments. This was the case at the Pembroke combined cycle gas plant recently constructed in the Milford Sound in Wales, as discussed in Chapter 3. Coastal locations are also vulnerable to storm surges and coastal flooding, with the greatest risks in the UK on the east coast where carbon capture clusters have already been identified. However, the costs of flood protection may be offset against the savings from not building more expensive low-water cooling systems.

4.4.4 Nuclear power

Nuclear plants in the UK use open-loop cooling with abstraction in the order of 65 m^3/s per 1.6 GW_e reactor, resulting in substantial ecological impacts, despite careful management via intake and outfall structures (Turnpenny *et al.*, 2010). A very high nuclear capacity, such as the 75 GW_e in CP2-NUC (20% more than France at present), may require a highly distributed configuration across the UK or alternatively, clusters of reactors and acceptance that local effects on the environment would be concentrated. Even the 31 GW_e of capacity in UKM-326 would require 10 sites of 2x1.6 GW_e reactors, yet the UK Government's Strategic Siting Assessment authorised only 8 suitable sites in the National Policy Statement (DECC, 2011d). Identification of further sites is possible, yet probably not without compromise; a study by Atkins (2009) for DECC identified only 3 additional sites *worthy of further consideration* having assessed 270 areas in England and Wales in addition to a further 82 historical sites that had already been ruled out by energy companies. Of the 270, in excess of 80% were ruled out due to *potential adverse impacts to internationally designated sites* of ecological importance. Ambitious proliferation of nuclear power will only happen through compromising at least one of the existing selection criteria.

4.4.5 Trade-offs, location choice and cooling methods

The assumptions and distributions on cooling sources and technologies, designed to be realistic and to reduce the freshwater abstractions without excessively abstracting from tidal and sea water environments, may not always be available to other water-scarce or landlocked countries undergoing electricity transitions. With limited availability of water abstraction licences in the UK, power station location choice will become increasingly important and contentious. Our assumptions about the distribution of capacity over different sources and the cooling methods are based on the legacy of the current configuration, planned capacity and expectation that the large majority of generators will continue to use the most commercially-efficient cooling technologies permitted by regulation.

That said, we have noticed three plants on tidal waters using hybrid cooling (Uskmouth, Wilton, Connah's Quay), a choice usually made for plume abatement and public acceptability, not lack of water. Thus, the benefits of legacy site redevelopment, such as existing grid connections, land ownership and local workforce appear in these observed cases seem to outweigh the additional costs of hybrid cooling or alternative of finding more suitable greenfield sites elsewhere. This is a trend we expect to continue and corroborated by Schoonbaert (2012).

We have tested additional cooling scenarios to explore potential water use reductions in the sector. Both reduction in freshwater coal capacity (by 50%) and universal use of hybrid cooling for coal and combined cycle gas with carbon capture have the potential to reduce freshwater consumption in the range of 20-42% for all pathways. Reduction in capacity on freshwater would inevitably mean a shift to greater tidal and sea water cooled capacity, which as discussed may increase risks to local ecology unless more costly closed or hybrid loop cooling is used. Alternatively, freshwater capacity could use higher levels of hybrid cooling, with yet again higher capital and operational costs to the generators and ultimately consumers. We have assumed hybrid operation equivalent to 35% dry cooling and 65% wet cooling (section 4.2.4 and Chapter 3) in such a way that low water cooling would be employed mostly during summer and autumn months when water is usually most scarce. This would increase the resilience of the electricity sector to low flows whilst leaving more water available for other uses but at an estimated cost of 4-7% higher fuel input and an equivalent increase in greenhouse gas emissions per power station.

4.4.6 Opportunities for the UK energy sector and the global context

The Energy Act 2013, granted subsidies for low-carbon thermoelectric generation with indirect implications for water use by the electricity sector. It makes nuclear and carbon capture-enabled generation increasingly competitive with renewables, thus, the potential for long-term lock-in of water-intensive electricity generation is a distinct possibility facilitated by the legislation.

The pathways tested all meet the 2050 80% emissions reduction targets and come close to or succeed in achieving the defeated 2030 decarbonisation target of 50gCO_2/kWh, an amendment recommended by the Committee on Climate Change (CCC, 2013), the House of Commons Energy and Climate Change Select Committee (ECC, 2012) and supported by a long list of large businesses and non-governmental organisations (FOE UK, 2013). It is clear from Figure 4-4 that up to the 2030s, water use performance in all pathways and by all measures improves in line with rapid decarbonisation. Up to this point, renewables increase their share whilst older coal, gas and nuclear plant are decommissioned and more affordable deployment of new nuclear and carbon capture-equipped generation begins to take shape. It is in the 2030s that water security of the UK could be in the balance as the water intensity of the pathways diverges; coal and gas plants would be forced to shut down if they do not adopt carbon capture and storage (CCS) yet this will increase their water intensity. Hence we see that decarbonisation policy at first plays an important role in reducing the water intensity of the sector, yet beyond 2030 will play a pivotal role depending on what generation capacity emerges. If CCS and nuclear power are deployed on wider scales, water intensity will rapidly increase. Unless more hybrid or air cooling is employed, developers will be forced to choose between using limited freshwater supplies or increasing abstraction from tidal and sea water, both of which could be problematic for the environment.

Worth a mention is the possibility of using combined heat and power to reduce the cooling requirements of power plants by supplying waste heat to industrial, commercial and domestic users through district heating. Uptake in the UK is currently very low, probably due to the penalty on electricity production (MacKay, 2009). The additional penalty induced by CCS, is probably why it is only specified somewhat indirectly, in the UKM-326 pathway. Other long-standing barriers, such as long-term reliable customers, also need to be overcome (Foxon *et al.*, 2005; Kalam *et al.*, 2012).

We conclude that the current path dependency of the system, particularly facilitated by the aforementioned delays in carbon capture and nuclear deployment, sets the UK on a sustainable pathway that is reducing emissions as well as dependency on water resources. It is only the fruition of new nuclear and carbon capture and storage schemes in the pathways analysed, that reinstates the high dependency on water for cooling, which will come under increasing pressure from population growth and climate change.

These findings are widely applicable to the wider world, of which some 67% of generation is fossil-fuelled thermoelectric (IEA, 2009). Macknick *et al.* (2012b) report broadly similar trends of reduction in freshwater abstractions and rising consumption, in a similar study for the U.S., as well as similar findings concerning pathways with high penetrations of renewables. Whilst decarbonisation of the electricity sector is essential to mitigating anthropogenic greenhouse gas emissions, national strategies for the roll out of carbon capture and storage retrofits, if and when it becomes commercially viable, will need to strongly consider impacts on water resources. Coal power, responsible for 40% of global generation and widely used in China and India, is approximately twice as water and carbon intensive as combined cycle gas plants, with the performance well modelled (Zhai and Rubin, 2010; Zhai, Rubin and Versteeg, 2011) and the water impacts of Chinese coal use investigated by Pan *et al.* (Pan *et al.*, 2012). We also reiterate that this analysis has not considered the water use impacts of fossil fuel extraction and production, which is thought to be substantial worldwide and could become increasingly important in this UK context if domestic shale gas extraction takes off (Entrekin *et al.*, 2011).

4.5 Conclusions

We have shown that whilst some electricity pathways present opportunities to simultaneously reduce water dependency and carbon emissions, others increase the dependence on water resources.

- In cases with high levels of nuclear and carbon capture and storage, abstraction and consumption, respectively, increase to levels that far exceed current use. With high levels of nuclear, abstractions of tidal and seawater can be expected to increase substantially, in the CP2-NUC pathway up to six times the current levels.
- Even though the volume of seawater abstracted is inconsequential, the evidence examined indicates a lack of suitable sites for wide scale nuclear power if negative environmental impacts are to be avoided.

The research has also shown a range of possible changes in the absolute volumes of freshwater consumption, however:

- All-round significant increases in the intensity of freshwater consumption are due primarily to carbon capture and storage technology.
- Pathways with high levels of coal with carbon capture will be the most water-intensive. We expect the intensity of this consumption to have negative localised environmental impacts, exacerbated by the clustering of plants with carbon capture.
- Significant reductions in freshwater consumption are possible through wide scale use of hybrid cooling, which would increase the level of freshwater resources available, for either the electricity sector or other uses. Hybrid cooling would however marginally increase cost and emissions, but also security of supply, by enabling the use of air-cooling during low flows when abstractions may be prohibited.

We have shown that up to 2030, good progress is made on both decarbonisation and water intensity:

- It is the capacity developed post-2030 that will determine whether pathways exploit the inertia of this progress or revert to water-intensive but low-carbon generation.

- Our findings show that the usage of high levels of carbon capture and storage and nuclear will bring environmental risks related to water use that will require trade-offs between emissions, cost and the environment.
- Pathways with low levels of nuclear and carbon capture, such as CP1-REN, minimise these risks, the benefits of which should be accounted for.

Chapter 5. Regional Water Resources and Cooling Water Use in a Changing Climate

5.1 Introduction

Whilst Chapters 3 and 4 have estimated water use at a national scale, the demands do not have any spatial disaggregation. This chapter uses a similar but different and reduced set of electricity supply projections that are regionally disaggregated. Furthermore, these cooling water demands are compared against hydroclimatic projections of future water availability under climate change in order to identify potential conflicts.

This method is intended to provide overview with geographical context. The detail of the results need not be overcomplicated, so that they are easily understood by a variety of stakeholders. Lastly, it identifies regions for more detailed analysis that can be done at the river basin scale.

5.1.1 Water abstraction licensing and reliability

The reliability of the cooling water source is critical to the security of electricity supply. Amongst a variety of other considerations, power stations choose highly reliable water sources and seek to obtain water abstraction licenses that permit *unconstrained* availability of a determined volume of water. However, substantial hydrological variability is present even in mid-latitude hydro-climates such as that of the UK, leading to significant risks from sustained periods of low flows associated with droughts.

Abstractions of water from fresh water bodies are regulated to allow fair allocation of water between competing demands (including municipal water supplies and agriculture, as well as cooling water), at the same time as safeguarding flows for the natural environment. In the UK, water resources are licensed by assessing the volumes available at very low flows, which are derived from statistical analysis of the historical record of flows in the catchment, called a flow duration curve (FDC). The FDC is similar to an annual load duration curve for an electricity system, although it is considered over a period long enough to capture the natural hydrological variability experienced over years, and ideally over decades, of climatic variability. The Q_{95} and Q_{99} values are 5th and 1st percentile statistics from the flow duration curve (FDC), and are typically used in water resources assessment as benchmark low flows. Taking a very low flow, typically $Q_{99.9}$ which is the flow exceeded 99.9% of the time, a portion of this flow can be reserved to maintain environmental quality (normally 75% in England and Wales) whilst the remainder is licensed for high-reliability unconstrained abstraction (normally 25%) (Figure 5-1) (Environment Agency, no date b). Once this volume is fully licensed, further volumes can be licensed, but are constrained by lower levels of reliability such as the 5th percentile Q_{95}, or the 10th percentile Q_{90} as in Figure 5-1. If the flow falls below this level, called a 'Hands Off Flow' (HOF), these license holders must cease or reduce abstraction in order to maintain reliability for the unconstrained users.

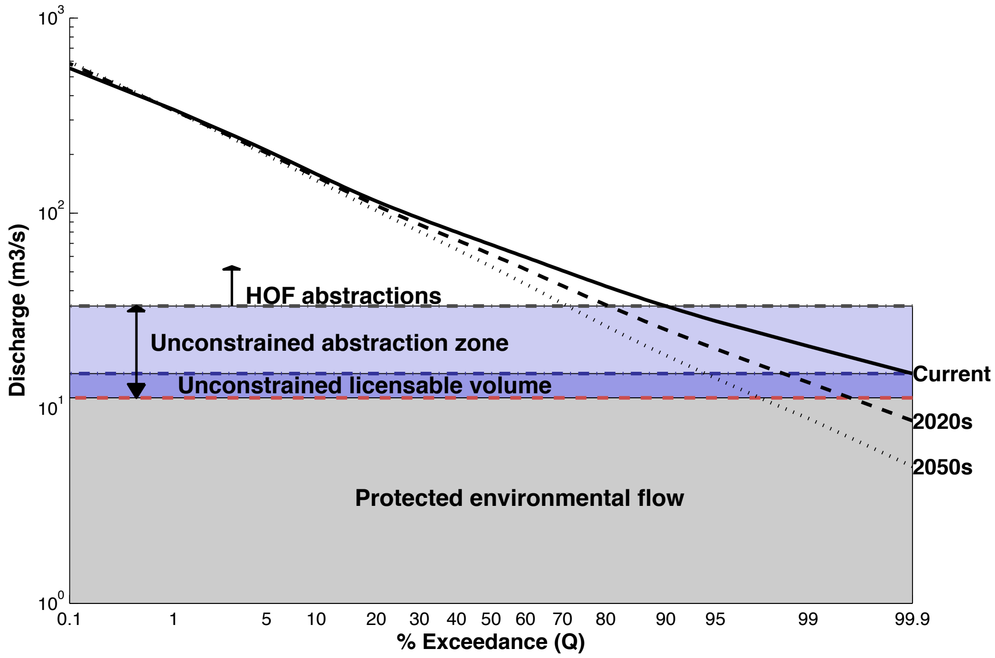


Figure 5-1. Example flow duration curves (in this case the Trent) for current, 2020s and 2050s flows. Shaded areas show the volumes that define the current abstraction regime. Source: Byers *et al*. (2015) (CC-BY).

With a changing climate the profile for the flow duration curve on which licensed abstraction volumes are based, will change. Thus, if the same volume is to be available to a user, the reliability of that volume will be lower, as what was historically a 1st percentile flow may be a 5th percentile flow in the 2020s and a 12th percentile in the 2050s, for example. Conversely, if one is to maintain the same reliability for a user, the volume of water available at say the 1st percentile, will decrease. Given the importance of reliability to the electricity sector, this work takes the second perspective to assess potential volume reduction of high-reliability flows.

5.1.2 Electricity planning model and supply strategies

Electricity supply strategies were developed in the CGEN+ planning model (combined gas and electricity network) (Chaudry, Jenkins and Strbac, 2008; Chaudry *et al.*, 2014), using energy strategies developed for the UK Infrastructure Transitions Research Consortium (ITRC) (Tran *et al.*, 2014; Hall *et al.*, 2015). Generation and capacity is spatially split by a 16-*busbar* electricity network, representing the GB high voltage transmission network (Figure 5-2). Each busbar represents a point in the transmission network at which electrical power is available for transmission or distribution. Electricity generation, demands and transfers for each region represented by a busbar are resolved at this point. This is also connected to a gas storage and transmission network (Figure 5-3). The busbars have been matched to corresponding water resource regions listed in Table 5-7 and Figure 2-1 in Chapter 2.

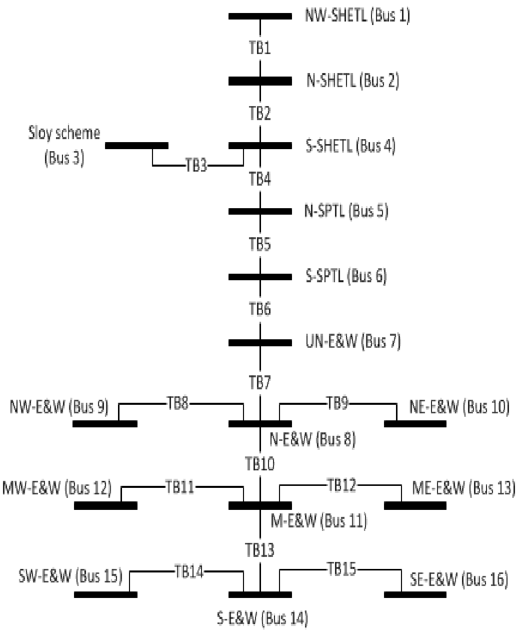


Figure 5-2. A simplified electricity network for GB. Source: Byers *et al.* (2015) (CC-BY).

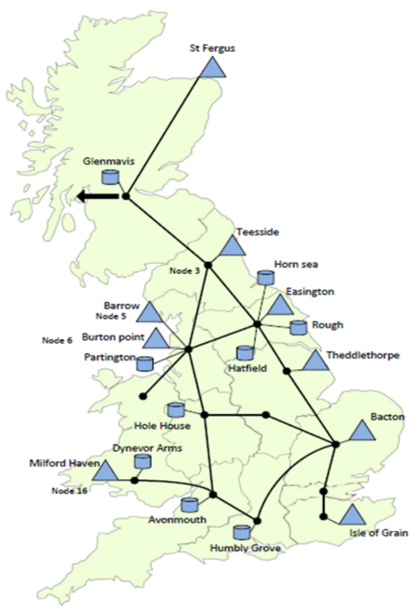


Figure 5-3. A simplified gas network for GB. Source: Byers *et al.* (2015) (CC-BY).

In this chapter, three out of a possible five future generation strategies were chosen for analysis, as summarised in Figure 5-4. The two excluded strategies were MPI-NoCC and EHT-NUC, which have no carbon cost and high levels of nuclear power, respectively. Neither adds much value to this analysis in the context of freshwater demands. Those results are also presented in Hall *et al.* (2015) and Tran *et al.* (2014).

The strategies chosen for this analysis are:

- MPI-CC is the *minimal policy intervention* strategy with a rising carbon price floor. It entails no significant demand efficiency improvements and little electrification of heat and transport. The generation mix totalling 506 TWh/year in 2050 is dominated by 73% CCGT and 26% nuclear power.
- EHT-Offshore and EHT-CCS, have demand characterised by electrified heat and transport (EHT) and thus have electricity demand that is 35% higher at 684 TWh/year.
    - The EHT-CCS strategy is made up by 35% each of CCGT and coal+CCS, and additionally 14% each of nuclear and CCGT+CCS.
    - The EHT-Offshore strategy has 43% offshore wind, 20% CCGT, 18% nuclear and the remaining 19% mostly other offshore renewables.

All strategies (except MPI-NoCC) have a rising carbon price floor, from £16/tonne in 2016, £30/tonne in 2020 and £70/tonne in 2030 and beyond.

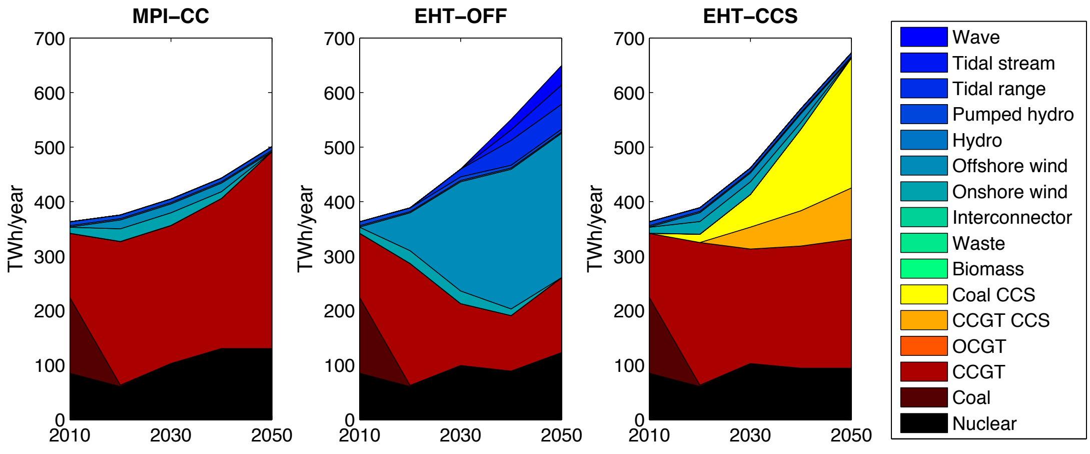


Figure 5-4. Electricity generation of the three strategies from 2010 to 2050. Source: Byers *et al.* (2015) (CC-BY).

5.1.3 Hydrological model

The work presented in this chapter uses a hydrological model developed for water resources planning (Leathard and Kilsby, no date). The model is an 11-parameter lumped conceptual model of daily mean discharge established for 72 catchments across Great Britain. It is calibrated using a machine-learning algorithm (Wall, 1996) that minimises differences between mean, variance and correlation of historical and simulated observations using a single representative metric after Gupta et al. (2009). The procedure rejects solutions with less than 95% agreement or more than 5% difference in water-balance, when comparing between observed and modelled series of flow. Observed series of daily rainfall and potential evapotranspiration (PET) are from UK Met Office data sets ((Perry and Hollis, 2005a, 2005b) and flow data were taken from the National River Flow Archive (Centre for Ecology & Hydrology, 2012) for the period 1961-2002.

Future river flows were generated by using as inputs UKCP09 Weather Generator (WG) (Kilsby *et al.*, 2007; Jones *et al.*, 2009) time series of rainfall and PET for the SRES A1B medium emissions scenario in the 2020s, 2050s and 2080s. Results are detailed further in Appendix B.2. From the bias-corrected hydrology results, values for the Q_{95} and Q_{99} (5th and 1st percentile, respectively) are taken from the flow duration curve (FDC) to calculate water availability.

5.2 Assessment framework and calculation

This chapter brings together established models from both the energy and water sectors. Firstly, the methodological framework is presented in brief. This is followed by details on each of the models that have been previously introduced.

5.2.1 Overview

The framework aims to compare regional demands for fresh cooling water against regional availability of freshwater. These are then compared at different temporal resolutions and with different statistical measures of energy demand and water availability. Thus, the potential for surplus or deficit may be identified (Figure 5-5).

For electricity supply, take alternative supply strategies that are disaggregated by generation capacity, region and annual generation. Then, calculate cooling water demands according to the methods in Chapters 3 and 4. For water availability, climate model outputs for emissions scenarios are used as inputs to regional hydrological models to generate accounts of the water balance in different water bodies within the region. Statistical measures of water availability are used to allocate water to the electricity sector based on assumptions of water rights and regulation. Dimensions of electricity sector demands (i.e. average or peak capacity factors) may be assessed against different statistics of water availability.

Cooling water demands vary through time, depending on the load at each power plant, as does the availability of water in rivers. Therefore, as well as presenting thermoelectric water abstraction and consumption on an annual basis, instantaneous average and peak loads are also presented. These different demands are compared against regional projections of water availability at low flows under a changing climate.

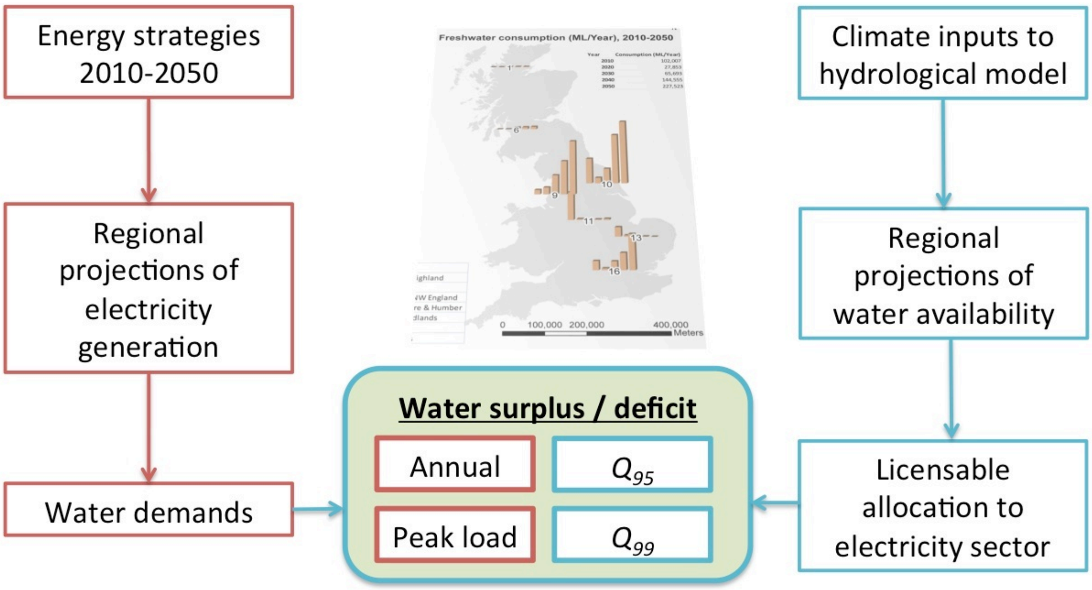


Figure 5-5. Assessment framework diagram. Source: Byers *et al*. (2015) (CC-BY).

5.2.2 Electricity generation and cooling water use framework

In order to apply the framework presented in Chapter 3, the spatial dimension is added in order to calculate regional cooling water demands. Thus, add dimension n_r to the $n_t \times n_g$ generation matrix $\boldsymbol{G}$, such that the elements $g_{t,j,r}$: $t = 1,\ldots n_t$, $j = 1,\ldots n_g$, $r=1,\ldots n_r$ now define the electricity generation by capacity, timestep *and* region. The assumptions about cooling water sources ($w = 1,\ldots n_w$) and methods ($m = 1,\ldots n_m$) in the $n_t \times n_g \times n_m \times n_w$ array $\boldsymbol{S}$ must also be made on a regional basis, hence $\boldsymbol{S}$ is modified to be $n_t \times n_g \times n_m \times n_w \times n_r$ (Figure 5-6). The matrices of cooling water factors $\boldsymbol{A}$ and $\boldsymbol{C}$ may also be given an additional r dimension, if such data exists.

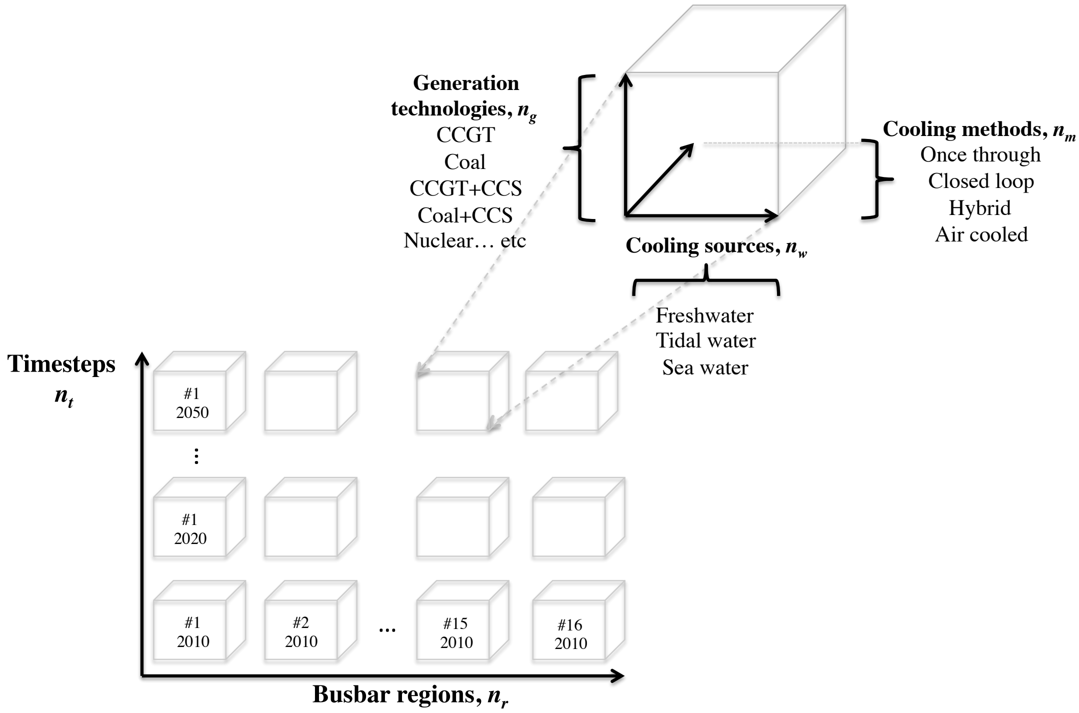


Figure 5-6. Illustration of the array ***S*** to show its five dimensions. This may be considered as a 3-D array of the size $n_g \times n_m \times n_w$ consisting of different assumptions for n_t timesteps as in Chapters 3 and 4, and additionally for n_r busbar regions as in this chapter.

5.2.2.1 Regional distributions of cooling water method and source

Adding the regional dimension results in the need for sets of regional assumptions for cooling water sources and cooling methods. Instead of aggregation on a national basis as in Chapter 4, capacity, electricity generation, cooling method and cooling sources are regionally distributed in the modified version of ***S***. Thus, matrices assuming the distribution of cooling source and method are required for every generation technology in each busbar. The datasets are described below:

1. Electricity capacity, generation, and capacity factors are from the ITRC energy strategies (Tran *et al.*, 2014; Hall *et al.*, 2015) with decadal timesteps from 2010 to 2050, distributed by 16 regional 'busbars' and 3 temporal seasons.
2. The dataset of cooling methods and sources was taken from Byers, Hall and Amezaga (2014) and allocated to corresponding busbar regions (Appendix A.1). The dataset described above (1.) has corresponding regional distributions for cooling methods and technologies as in Appendix B.1. These were determined using DECC Digest of UK Energy Statistics (DECC, 2011b). East Midlands and Yorkshire and the Humber regions were aggregated for this work into Humber/East Midlands.
3. Distributions of capacity were developed for the 2020 and 2050 timesteps (Appendix B.1), with linear interpolation for the intermediate decades.

Whilst full details are in Appendix B.1 – the following broad statements can be made about the future cooling water source and method distributions in 2050:

- There is almost no once-through cooling on freshwater, besides a very small proportion of the smaller capacity, such as some biomass, diesel, waste and gas and CHP schemes.
- For nuclear power:
    - All nuclear is once-through cooled;
    - In the southern, eastern and Thames/London regions of England, all nuclear power is on SW;
    - In other regions the approximate ratio between TW and SW is 1:2.
- For fossil-fuel capacity:
    - In most of the Scottish regions, 40% of capacity is on freshwater, with the remainder roughly split between tidal and sea water;
    - In north England, Midlands and Wales regions, FW, TW and SW splits are quite evenly distributed between 20-40% each. For CCGT 10% was air-cooled, but none for coal/biomass;
    - In the southern, eastern and Thames/London regions of England, 0-20% of capacity is on FW, 20-40% on TW and 40-80% on SW. Again, 10% of CCGT is air-cooled.

5.2.2.2 Water use factors

Annual water abstraction and consumption was calculated on an annual basis using the framework and model presented in Chapters 3 and 4, and Byers, Hall and Amezaga (2014), modified to accommodate regional disaggregation over the 16 busbars. The abstraction and consumption factors used (Table 5-1) are derived from a variety of sources from the literature (Zhai and Rubin, 2010; IEAGHG, 2011; Tzimas, 2011; Zhai, Rubin and Versteeg, 2011; Macknick *et al.*, 2012a; Parsons Brinckerhoff, 2012), given that such data is difficult to obtain from both regulators and industry.

Table 5-1. Summary of abstraction and consumption factors for electricity generation used in the study. CCGT – combined cycle gas turbine, CHP – combined heat and power. Hybrid cooling is assumed to have water use that is on average 65% of closed-loop wet tower cooling. Source: Byers *et al*. (2015) (CC-BY).

ML/GWh L/kWh	**CCGT**	**Coal**	**CCGT+CCS**	**Coal+CCS**	**Waste/ Biomass**	**CHP gas**	**CHP coal**
Once-through cooling							
Abstraction	43.07	102.53	81.84	194.80	132.48	25.84	61.52
Consumption	0.38	0.43	0.72	0.81	0.95	0.23	0.23
Closed-loop wet tower cooling							
Abstraction	0.97	2.22	1.92	3.62	3.32	0.58	1.16
Consumption	0.78	1.81	1.49	2.71	2.69	0.47	0.70

5.2.2.3 Application of capacity factors in the analysis

The capacity factor of a power station represents the ratio between the actual electrical output compared to the potential output over a set period of time. A power station will not operate at 100% capacity for 100% of the time for reasons such as demand variation, maintenance cycles and outages. Hence, in this analysis, the difference between the water demands at the annual capacity factor and the peak load are distinguished.

Annual capacity factor for thermoelectric plants is normally between 60-80%. This means that the annual output over the year averaged at say 70% of nameplate capacity. However, in practice there would have been periods of operation at 100% nameplate capacity output, periods with 0% output and periods with outputs in-between these levels. The annual capacity factor is suitable for estimating cooling water demands on an annual basis.

Peak capacity factor is suitable for analysing the maximum abstraction that might occur over a shorter period of time. Hence, it is useful for determining whether water would be available for maximum load operation during periods of low flows and drought. It is not suitable for analysing demands over long period such as a year, because a power station would never operate 100% of the time.

5.2.3 Water availability framework and implementation

Water availability is calculated using flow duration statistics and by allocating a portion of the flow for abstraction. Of this abstraction volume, a subset is allocated to the electricity sector. Let $b= 1,\ldots, n_b$ be the regions under assessment. Within each region, let $i_b= 1,\ldots, r_b$ be the individual rivers in the region b.

The licensable flow Q_L, on river i_b, can be determined by multiplying percentiles on the Flow Duration Curve (i.e. Q_{95}, Q_{99}) by factors that reflect the abstraction sensitivity of the water body at those flow percentiles. In England and Wales, these are known as Abstraction Sensitivity Bands, A_{95} (Environment Agency, 2013a). This gives the licensable volume, Q_L, of which the electricity sector holds a portion of the abstraction licenses, S_e. The abstraction available to the electricity sector, Q_e at Q_{95}, is hence the Q_{95} flow multiplied by the abstraction sensitivity factor (A_{95}) and the portion of licenses held by the sector (S_e):

$$Q_{e95} = Q_{95} A_{95} S_e \tag{1}$$

The total resource available to the sector in a busbar region b is the sum of Q_e from r_b suitably-sized rivers in the region b.

$$Q_{e95}^{b} = \sum_{i=1}^{r_b} Q_{e95}^{i_b} \tag{2}$$

Parameters A_{95} and S_e are determined in the sections that follow.

5.2.3.1 Abstraction sensitivity bands

The licensable volume, Q_L, is the proportion of flow that is available for licensing at a given flow level in order to maintain *Good Ecological Status* under the EU Water Framework Directive. When more water is available, a higher proportion of the flow is available for abstraction.

The amount of water available also depends on the sensitivity of the water body, to abstraction. The Environment Agency considers a variety of Environmental Flow Indicators in order to assign each waterbody to an Abstraction Sensitivity Band (ASB). The amount of water available at each flow interval (i.e. Q_{95}) depends on the ASB of the waterbody. The factors for the ASB are reproduced in the table below.

Table 5-2. The Abstraction Sensitivity Band factors according to the water body sensitivity and different flow percentiles. Source: Environment Agency (2013).

	Q_{30}	Q_{50}	Q_{70}	Q_{95}
ASB 3 – high sensitivity	24%	20%	15%	10%
ASB 2 – moderate sensitivity	26%	24%	20%	15%
ASB1 – low sensitivity	30%	26%	24%	20%

Given that ASB factors are set for thousands of water bodies, an ASB factor (A_{95}, A_{99}) was determined to represent all the water bodies within the region. In some cases, an intermediate value (i.e. 12.5% and 17.5%) was more appropriate. Furthermore, ASB factors are not set at the Q_{99} hence the same value for Q_{95} has been used (Table 5-3).

Table 5-3. ASB factors used for each busbar region at Q_{95} and Q_{99}.

BB #	A_{95}, A_{99}
1	15%
2	15%
3	15%
4	15%
5	15%
6	15%
7	15%
8	15%
9	10%
10	17.5%
11	15%
12	12.5%
13	17.5%
14	15%
15	12.5%
16	15%

5.2.3.2 Abstraction licence holding

Given that not all the licensable volume (Q_L) in a catchment or region is available to the sector, the proportion (S_e) of licensable volume is estimated using previous abstractions by the sector. In most cases this has been conservatively estimated to be approximately 20% higher than the current holding as a maximum proportion the sector may hold in the future (Table 5-4).

Table 5-4. Assumed proportion of licensable volume available to the electricity sector in reach region, S_e, calculated from the ABSTAT database (Environment Agency, 2012a).

Region	2000-2011 average	Electricity busbar	Maximum future abstraction share cap, S_e
England Wales	40%	-	
NW	24%	9, 12	30%
NE	32%	8	40%
MIDLANDS	40%	10, 11	50%
ANGLIAN	1%	13	10%
THAMES	4%	16	10%
SOUTHERN	0%	14	10%
SW	29%	15	35%
WALES	73%	12	30% [1]
Scotland	- [2]	1-7	20%

[1] A lower proportion has been chosen due to the very high volume of abstractions attributable to Dinorwig hydro-electric power station.
[2] This data is unavailable for Scotland, hence a very low proportion of 20% has been assumed, given that there is currently almost no capacity on freshwater.

5.2.3.3 *Identifying rivers suitable for power generation*

In calculating the water availability we only want to include rivers considered large enough to support abstraction from a small-medium sized power station with wet cooling towers and CCS. As a key assumption of the analysis, the size of 500 MW_e would derive from a coal power plant with two steam turbines in the order of 250 MW_e each, or four at 125 MW_e each. Whilst most coal power plants in the UK are much larger (750-2250 MW_{e} – see Chapter 3 Figure 3-8, Figure 3-9) due to the considerable infrastructure requirements (such as coal delivery, processing and storage), technical feasibility and existence of a few plants in this size range, make it a reasonable minimum threshold size. Hence, we consider a 500 MW_e coal-fired power station with CCS, operating at 100% capacity with an abstraction factor of 4.34 ML/GWh:

$$Q_e = 500\ (MW_e) \cdot \frac{3.62\ \left(\frac{ML}{GWh}\right)}{3600\ (s)} \tag{3}$$

$$Q_e = 0.603\ \mathrm{m}^3/s$$

This is compared to other power station types with wet tower cooling below.

Table 5-5. Indicative abstraction volumes from 500 MW_e power stations operating at 100% capacity. Abstraction factors are the same as those used in Chapters 3 and 4.

Type	**Capacity (MW_e)**	**Abstraction factor (ML/GWh)**	**Abstraction (m_3/s)**
Gas CCGT	500	0.97	0.135
Coal (sub-critical)	500	2.22	0.308
Gas CCGT+CCS	500	1.92	0.267
Coal+CCS	500	3.62	0.603

To calculate the minimum Q_{95} flow required in a river to support the given power station demand of 0.6 m^3/s, equation 1 is rearranged to find $Q_{95.min}$. It is assumed that the river has a moderate abstraction sensitivity band factor (A_{95}) of 15%, meaning that only 15% of the Q_{95} flow will be licensed for abstraction. It is also assumed, generously, that the sector may hold 70% of the licensed abstraction volume, S_e. Hence:

$$Q_e = Q_{95} A_{95} S_e \tag{4}$$

$$Q_{95.min} = \frac{Q_e}{A_{95}\ S_e} \tag{5}$$

$$Q_{95.min} = \frac{0.503}{0.15 \cdot 0.7} \tag{6}$$

$$Q_{95.min} = 4.790\ m^3/s \tag{7}$$

Subsequently, for all rivers in region *b*, rivers with $Q_{95} \geq Q_{95.min}$ must be identified. For the UK, a search on the National River Flows Archive website (Centre for Ecology & Hydrology, 2012) for $Q_{95} \geq 5.0$ m^3/s (432 ML/day) yields the following rivers with a gauging station meeting the $Q_{95.min}$ criteria (Table 5-6). Subsequently, the sum of Q_{e95} for all suitably-sized rivers in each region *b* is determined using eq. 2.

Table 5-6. Rivers with a gauging station above the minimum threshold of 5 m^3/s.

Q95 > m^3/s	# of gauging stations	Main rivers / hydrometric areas
5.0	76	Aire, Avon, Beauly, Clyde, Conon, Dee, Don – Eden, Ewe, Forth, Glass, Leven, Lochy, Lower Bann, Mersey, Ness, Ouse, Severn, Spey, Tame, Tay, Test, Thames, Trent, Tummel, Tweed, Tyne, Wye.

5.3 Cooling water demands and water availability

5.3.1 Regional cooling water demands

Regional cooling water demand and availability is assessed on two temporal dimensions; annualised demands to determine the long term trend in absolute water use in this section, and instantaneous demands to assess the risk specifically at low flows (sections 5.3.2 and 5.3.3). Annual demands are calculated by aggregating water use of the electricity sector over a year at each decadal timestep. Assumptions about the intra-annual variation may be taken for more detailed analysis, for example by applying monthly or seasonal capacity factors. The low flow demands are calculated with capacity factors to determine the volume of instantaneous or daily abstractions according to different levels of power station operation (the load). For this study the low flow demands are assessed on an instantaneous basis (m^3/s) at average capacity factors for each technology in the strategy.

Figure 5-7 presents water abstraction and consumption by source, for the three strategies, aggregated over all 16 busbar regions. Table 5-7 and Figure 5-8 present these results on a regional basis for 2010 and 2050, with consumptive use displayed as a proportion of abstraction. Figure 5-9 is a Sankey diagram of freshwater use in 2050 for the EHT-CCS strategy, disaggregating water use by generation capacity and busbar region. It is an example output of an online web-tool being developed by the ITRC to analyse different strategies.

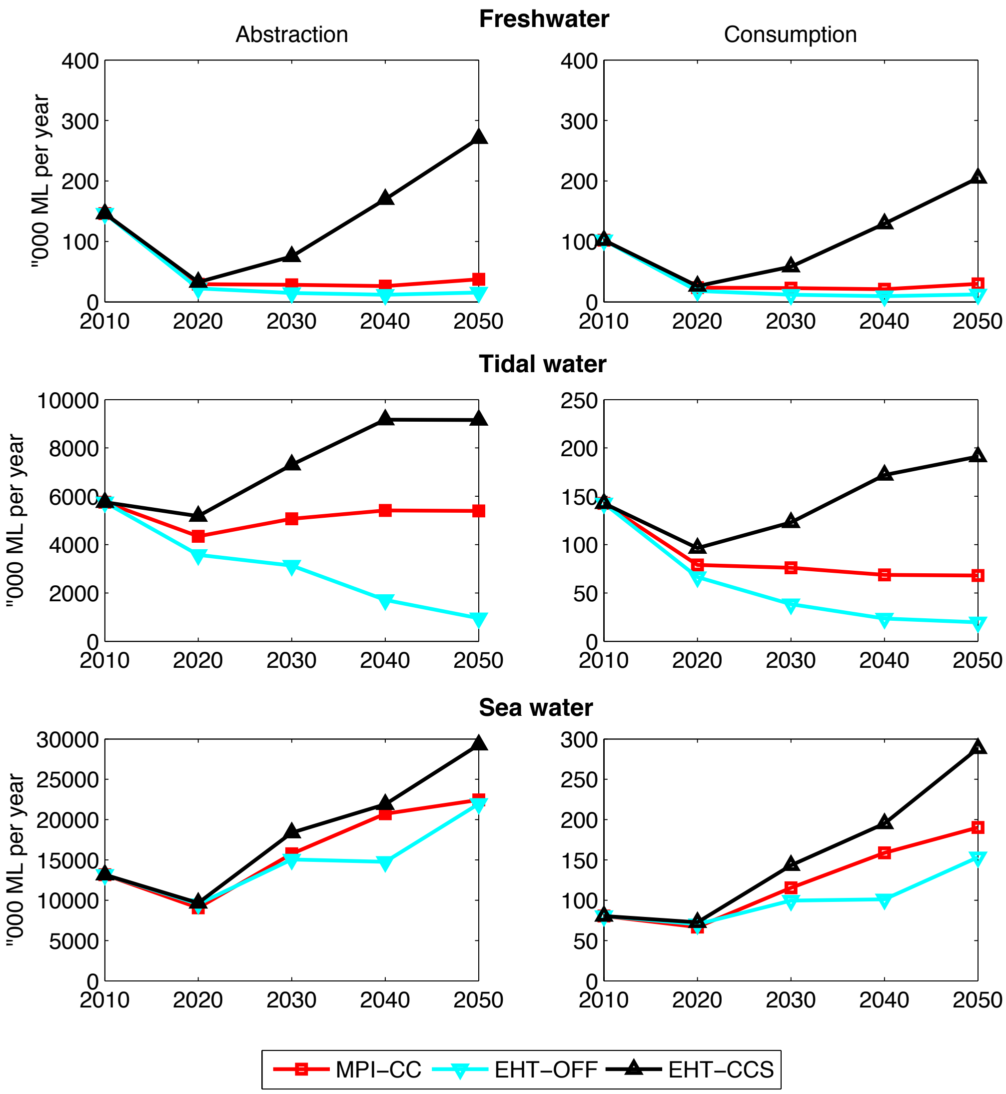


Figure 5-7. Abstraction and consumption, for all water sources aggregated across all busbar regions. Source: Byers *et al*. (2015) (CC-BY).

EHT-Offshore results in the greatest reductions of 89-88% for abstraction and consumption of freshwater, respectively, and 83-86% for tidal water by 2050. Reductions are distributed through most regions, with only southwest England and Thames projected to see increases in sea water use.

MPI-CC respectively sees 74-71% and 6-52% reductions in fresh and tidal water use, mostly occurring in the Humber/East Midlands, Anglian, Thames/London and Forth regions. Sea water abstraction increases by 70% however, most substantially in the North West, South West, South East and Thames/London regions of England, due to growing nuclear capacity.

The EHT-CCS strategy results in 85-100% and 59-34% increases in fresh and tidal water use by 2050. Very large increases occur in the Humber/East Midlands, Thames/London, North West England and North East Scotland due to concentrations of CCS capacity; only 7% of water use occurs elsewhere. In particular, Humber/East Midlands and Deeside/North West regions respectively see abstractions rising to 105- and 89-thousand ML/year, with consumptive losses in the order of 65% of abstractions. The strategy also results in significant increases in both tidal and sea water use, 59% and 122% respectively, in particular due to the nuclear and coal+CCS capacity. For tidal water large increases are projected in Humber/East Midlands and Thames/London, whilst Thames/London and Solway/Tweed may expect large increases in sea water use (Figure 5-10).

Table 5-7. Freshwater abstraction and consumption in 2010 and as projected for 2050 for the three energy strategies. Source: Byers *et al*. (2015) (CC-BY).

Abstraction (#BB) (ML/year)	2010	MPI-CC	2050 EHT-OFF	EHT-CCS
NE Scotland (2)	0	538	64	21,800
NW England (9)	6,960	1,680	3,260	88,600
Humber & E Midlands (10)	50,400	2,580	1,130	105,000
W Midlands & Severn (11)	56,100	179	797	2,280
Anglian (13)	12,600	0	0	0
Thames & London (16)	11,400	7,930	2,510	28,600
Others	8,640	24,400	7,770	24,300
Total	**146,000**	**37,300**	**15,540**	**271,000**
Consumption (#BB) (ML/year)	**2010**	**MPI-CC**	**2050 EHT-OFF**	**EHT-CCS**
NE Scotland (2)	0	433	51	16,600
NW England (9)	5,600	1,350	2,620	66,500
Humber & E Midlands (10)	31,700	2,070	911	79,000
W Midlands & Severn (11)	34,400	144	640	1,830
Anglian (13)	11,500	0	0	0
Thames & London (16)	10,700	6,370	2,020	21,800
Others	8,12	19,500	6,130	19,300
Total	**102,000**	**29,800**	**12,400**	**205,000**

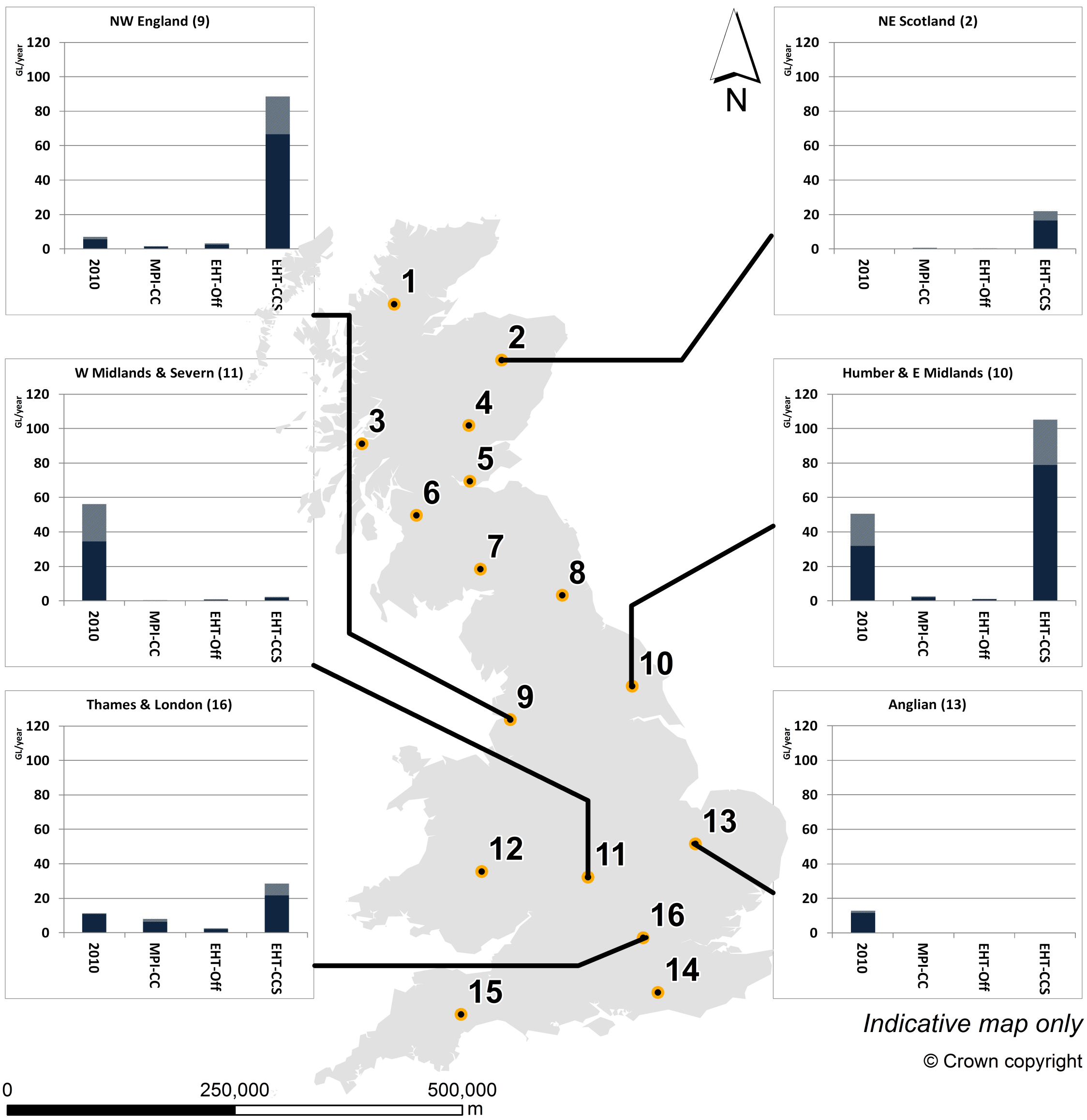


Figure 5-8. Regional freshwater abstraction (solid blue + hatched), of which consumption (solid blue only) for all three strategies in 2050 in GL per year. Figure credit: David Alderson. Source: Byers *et al.* (2015) (CC-BY).

Worth noting in Figure 5-7 is the dip in water use, particularly freshwater, observed in 2020 due to the closure of capacity from the EU Large Combustion Plant Directive and CCS capacity not yet being available, similarly observed in Chapter 4 (Byers, Hall and Amezaga, 2014). Looking across the strategies, EHT-CCS is consistently the most freshwater-intensive, although in the cases of EHT-CCS and EHT-Offshore, the elevated sea water use is largely due to increased capacity of nuclear power. Across the busbar regions, in MPI-CC and EHT-CCS, Humber and East Midlands, Thames and London, and North West England are repeatedly projected to see large increases in both fresh and tidal water abstractions. South West England will also see elevated sea water use in strategies with high nuclear generation.

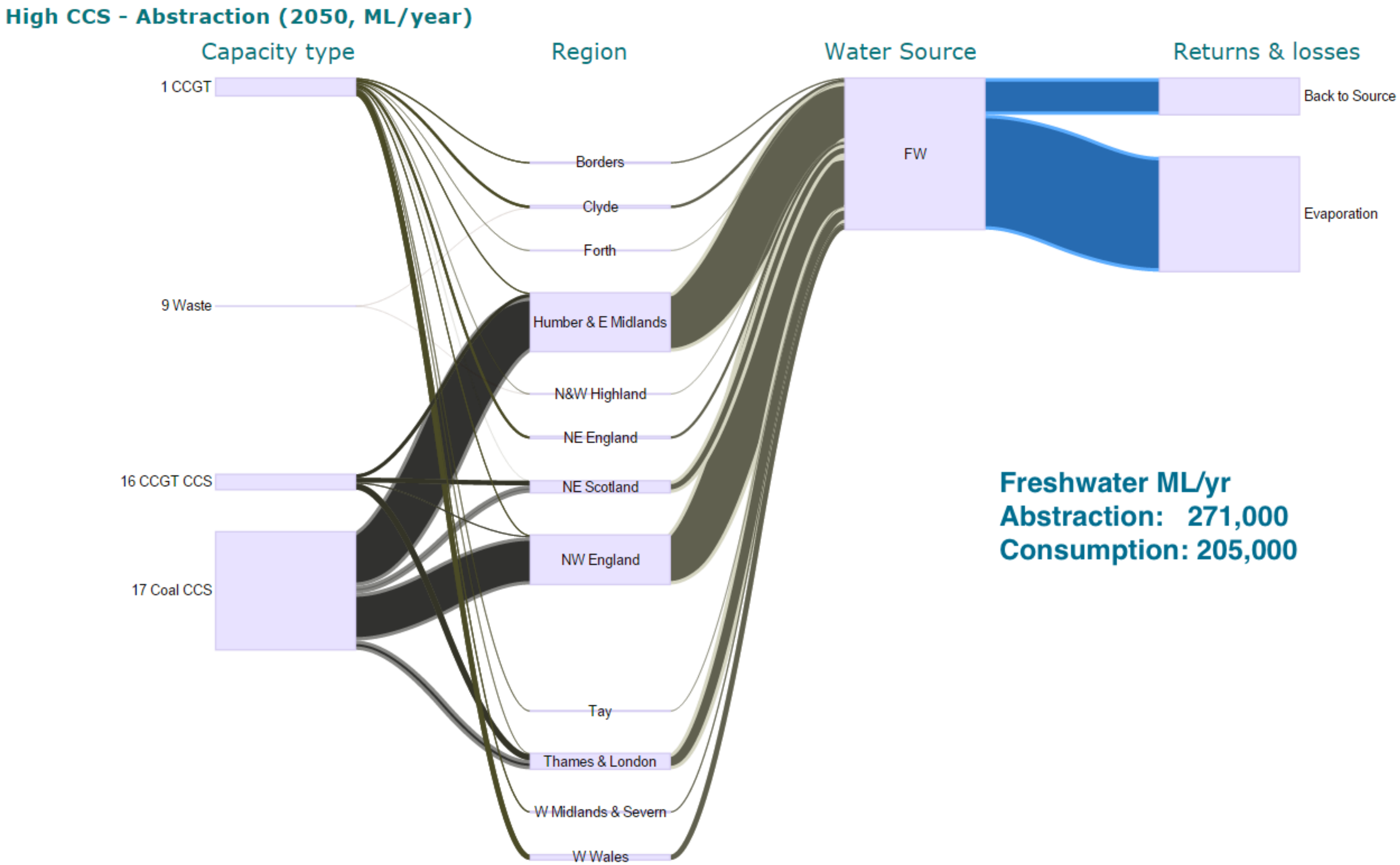


Figure 5-9. Sankey diagram of 2050 freshwater use by thermoelectric generation for the EHT-CCS strategy, where line thickness is proportional to water use. Figure credit: David Alderson and Edward Byers. Sankey tool: Bostock (2012) and Counsell (2013). Source: Byers *et al*. (2015) (CC-BY).

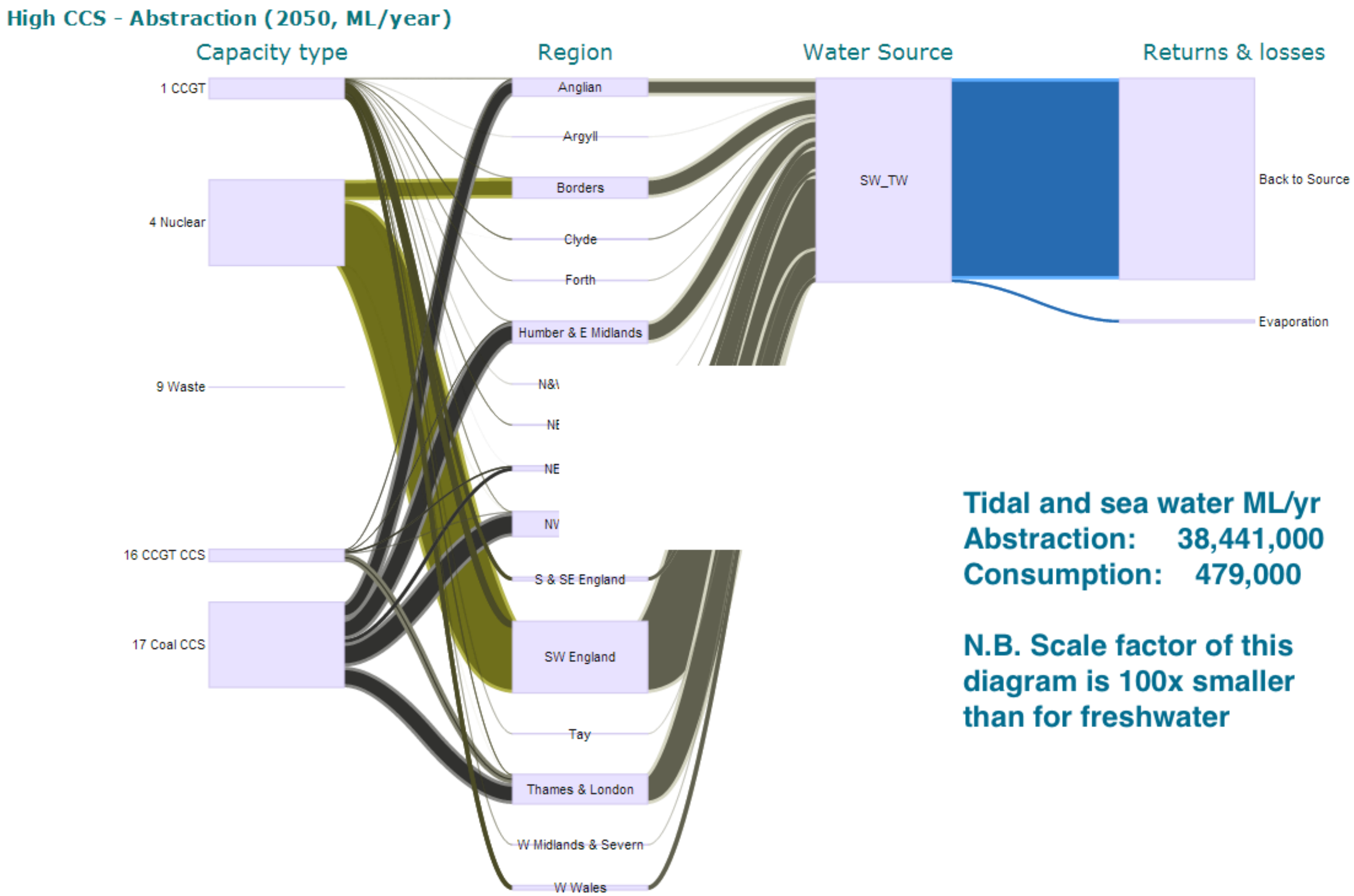


Figure 5-10. Sankey diagram of 2050 tidal and sea water use by thermoelectric generation for the EHT-CCS strategy, where line thickness is proportional to water use. N.B. the scale of flows is 100x greater than those shown in Figure 5-9 for freshwater. Figure credit: David Alderson and Edward Byers. Sankey tool: Bostock (2012) and Counsell (2013). Source: Byers *et al*. (2015) (CC-BY).

5.3.2 *Water availability*

5.3.2.1 *Instantaneous abstraction demands against water availability at Q_{95} and Q_{99}*

The results of the hydrological water resource modelling indicate significant reductions in flows at Q_{95} and Q_{99} due to climate change. The reductions in median flows at Q_{95} and Q_{99} are presented below (Table 5-8) for the A1B SRES medium emissions climate scenario. These results are then compared against the cooling water demands (Table 5-9).

Table 5-8. Changes in water resource in the rivers with Q_{95} above 5 m^3/s, calculated by the hydrological model. Source: Byers *et al*. (2015) (CC-BY).

	Region (*b*)	(m^3/s) ΣQ_{95} hist.	Q_{95} Available resource change (%) 2020s	2050s	2080s	(m^3/s) ΣQ_{99} hist.	Q_{99} Available resource change (%) 2020s	2050s	2080s
1	N & W Highlands	36.6	-8	-20	-19	21.6	-12	-30	-32
2	NE Scotland	53.7	-19	-34	-44	39.0	-22	-38	-49
3	Argyll	0.0	-	-	-	0.0	-	-	-
4	Tay	43.5	-12	-26	-35	31.7	-14	-32	-44
5	Forth	5.7	-10	-22	-31	3.9	-15	-30	-43
6	Clyde	19.4	-10	-22	-31	15.3	-15	-30	-43
7	Borders	24.3	-19	-40	-50	18.1	-15	-39	-51
8	NE England	12.4	-25	-44	-53	9.5	-31	-50	-61
9	NW England	13.4	-23	-42	-50	9.1	-39	-66	-78
10	Humber & E Midlands	43.8	-22	-45	-55	34.6	-24	-49	-58
11	W Midlands & Severn	19.9	-20	-41	-50	15.5	-23	-46	-56
12	W Wales	11.2	-34	-60	-71	7.4	-39	-66	-78
13	Anglian	0.0	-	-	-	0.0	-	-	-
14	S & SE England	0.0	-	-	-	0.0	-	-	-
15	SW England	11.9	-17	-31	-40	9.8	-20	-36	-45
16	Thames & London	7.5	-41	-70	-81	3.6	-49	-77	-86
	Sum	303.8				219.5			
	Mean Δ %		-21%	-40%	-48%		-25%	-47%	-57%

Key **Δ %**

0 to -20%
-21% to -40%
-41% to -60%
-61% to -80%
<-81%

The impacts of abstraction at low flows are assessed by calculating the rate of instantaneous abstraction for each strategy in each region at average capacity factors. This is presented in Table 5-9 at Q_{95} and Q_{99} flows in a 2050s climate against projected abstractions in 2050. The same table is also presented in Appendix B.3 for the 2020s and 2080s.

In the majority of regions there is sufficient resource or only a small volume of abstractions, even at very low flows. Three regions in particular however show cause for concern: 9. North West England; 10. Humber/East Midlands; and 16. Thames /London regions. The former two have high concentration of CCS capacity in the EHT-CCS strategy. Subsequently demands for water resource greatly exceed the available freshwater by 2050, even without the impacts of climate change. This is an important conclusion in itself, given the uncertainties that are inevitably present in projections of future flows. Freshwater shortages and limited availability of abstraction licenses could lead to an elevated concentration of power stations on the tidal stretches of the Trent and in the Humber and Mersey estuaries. For these two regions it has been assumed that 30-35% of CCGT and 35-40% of coal-fired capacity is on freshwater, with similar proportions on tidal water. This analysis confirms that a much higher amount of the demand will have to come from tidal or sea water to ensure sustainable abstraction at low flows in these regions, even with power plants holding some 50% of licensed abstraction volume. As for the Thames and London region, where power plants are assumed to hold only 10% of the licensed freshwater volume and whereby only 10% of CCGT and coal-fired capacity is based on freshwater, there is simply no available resource at very low flows. Whilst it is unlikely that any capacity is developed on freshwater west of London, modelling a small proportion of 10% illustrates the sensitivity of this region to freshwater-based capacity development. Other regions, particularly in the north of England and south of Scotland, may be able to accommodate extra CCS capacity development on freshwater whilst not being located too far from the demand centres, neither CCS infrastructure. North East England (8) also has demands that exceed resource in the MPI-CC strategy.

Table 5-9. Water resource availability at Q_{95} and Q_{99} both currently and in the 2050s, compared to current and projected abstractions in 2050. Source: Byers *et al.* (2015) (CC-BY).

				Available resource			` Abstraction m³/s			
				Current	2050s			MPI-CC	EHT-OFF	EHT-CCS
BB	Region (*b*)	Main rivers (*i*)	Σ Q_{95} (m³/s)	Q_{e95}	Q_{e95}	Q_{e99}	2010	2050		
1	N & W Highlands	Lochy Conon Beauly Ewe	36.6	1.1	0.9	0.5	0.00	0.10	0.01	0.03
2	NE Scotland	Spey Ness Don	53.7	1.6	1.1	0.7	0.00	0.09	0.21	0.94
3	Argyll		0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
4	Tay	Tay	43.5	1.3	1.0	0.6	0.00	0.06	0.01	0.03
5	Forth	Forth	5.7	0.2	0.1	0.1	0.00	0.05	0.03	0.05
6	Clyde	Clyde Leven	19.4	0.6	0.5	0.3	0.00	0.28	0.09	0.23
7	Borders	Tweed Eden	24.3	0.7	0.4	0.3	0.00	0.02	0.07	0.05
8	NE England	Tyne Wear Tees	12.4	0.7	0.4	0.3	0.00	0.68	0.14	0.17
9	NW England	Eden Mersey Dee	13.4	0.4	0.2	0.1	0.08	0.11	0.10	3.13
10	Humber & E Midlands	Aire G. Ouse Trent	43.8	3.8	2.1	1.6	1.76	0.10	0.17	4.14
11	W Midlands & Severn	Severn	19.9	1.5	0.9	0.6	2.05	0.01	0.03	0.05
12	W Wales	Wye	11.2	0.4	0.2	0.1	0.00	0.13	0.05	0.20
13	Anglian	-	0.0	0.0	0.0	0.0	0.65	0.00	0.00	0.00
14	S & SE England	-	0.0	0.0	0.0	0.0	0.36	0.00	0.00	0.00
15	SW England	Test Avon	11.9	0.5	0.4	0.3	0.15	0.00	0.00	0.00
16	Thames & London	Thames	7.5	0.1	0.0	0.0	0.62	0.22	0.08	0.96
		Sum	303.8	13.0	8.1	5.5	5.67	1.85	1.00	9.98

Key

Future abstraction is within resource constraints

Future abstraction is equal to 2050s Q_{e99}

Future abstraction exceeds 2050s Q_{e99} and is smaller than or equal to Q_{e95}

Future abstraction exceeds 2050s Q_{e99} & Q_{e95}

Future abstraction exceeds 2050s Q_{e99} & Q_{e95}, and current Q_{e95}

5.3.3 Peak abstraction demands

The final aspect of the analysis evaluates the instantaneous demands in the EHT-CCS strategy assuming average and 100% capacity factor in regions 9, 10, and 16 (Table 5-10). This tests whether power stations in the region would be able to operate at full load during a period of low flows or drought.

In almost all cases, both the average capacity factor and the 100% capacity factor abstraction demands exceed the available Q_{e99} resource in 2050, not only due to the growing demands but also the diminishing resource. Hence it is important that abstraction license and planning applications for CCS-enabled generation capacity in the 2030s consider the impacts of climate change on water resources in the 2050s and beyond. Whilst long-term the annual volumes abstracted may not present a problem, it may be challenging to operate at full capacity during periods of drought without relaxation of abstraction regulations and water allocation trading. We also note that restrictions in one region may increase pressure on other regions to increase electricity generation and hence increase abstractions.

Table 5-10. Comparison of Q_{e95} and Q_{e99} flows with abstraction demands at average (CF) and 100% capacity factors. Source: Byers *et al*. (2015) (CC-BY).

	9. NW England					10. Humber & E Midlands					16. Thames & London				
	Resource			***Demand***		***Resource***			***Demand***		***Resource***			***Demand***	
m³/s	Q_{95}	Q_{e95}	Q_{e99}	CF	100%	Q_{95}	Q_{e95}	Q_{e99}	CF	100%	Q_{95}	Q_{e95}	Q_{e99}	CF	100%
2010	13.39	0.40	0.27	0.08	0.69	43.80	3.83	3.03	2.01	3.01	7.52	0.11	0.05	0.71	0.68
2020	10.43	0.31	0.17	0.53	0.92	33.97	2.97	2.29	0.38	1.03	4.44	0.07	0.03	0.05	0.16
2050	7.79	0.23	0.09	3.13	4.31	23.94	2.09	1.56	4.14	5.87	2.29	0.03	0.01	0.96	1.57

5.3.4 Sensitivity analysis

A sensitivity analysis was performed to test a) the sensitivity to percentage of capacity allocated to freshwater in busbars 9, 10 and 16, and b) the sensitivity to the levels of hybrid or wet tower cooling on freshwater.

Figure 5-11 presents the effect of the total GB freshwater consumption when the freshwater capacity on either busbar 9, 10 or 16, is adjusted between 0% and 50%. The percentage is the proportion of all the capacity in that busbar, the rest of which is tidal and sea water or air-cooled, as explained in section 5.2.2.1. For busbar 16 (Thames & London), there is little potential to reduce abstraction given the current level of only 10%, compared to busbars 9 & 10, whose current capacity is 35% and 40% on freshwater. Hence nationwide freshwater abstractions could be reduced significantly by a third to a half by reducing the capacity on freshwater in busbars 9 and 10.

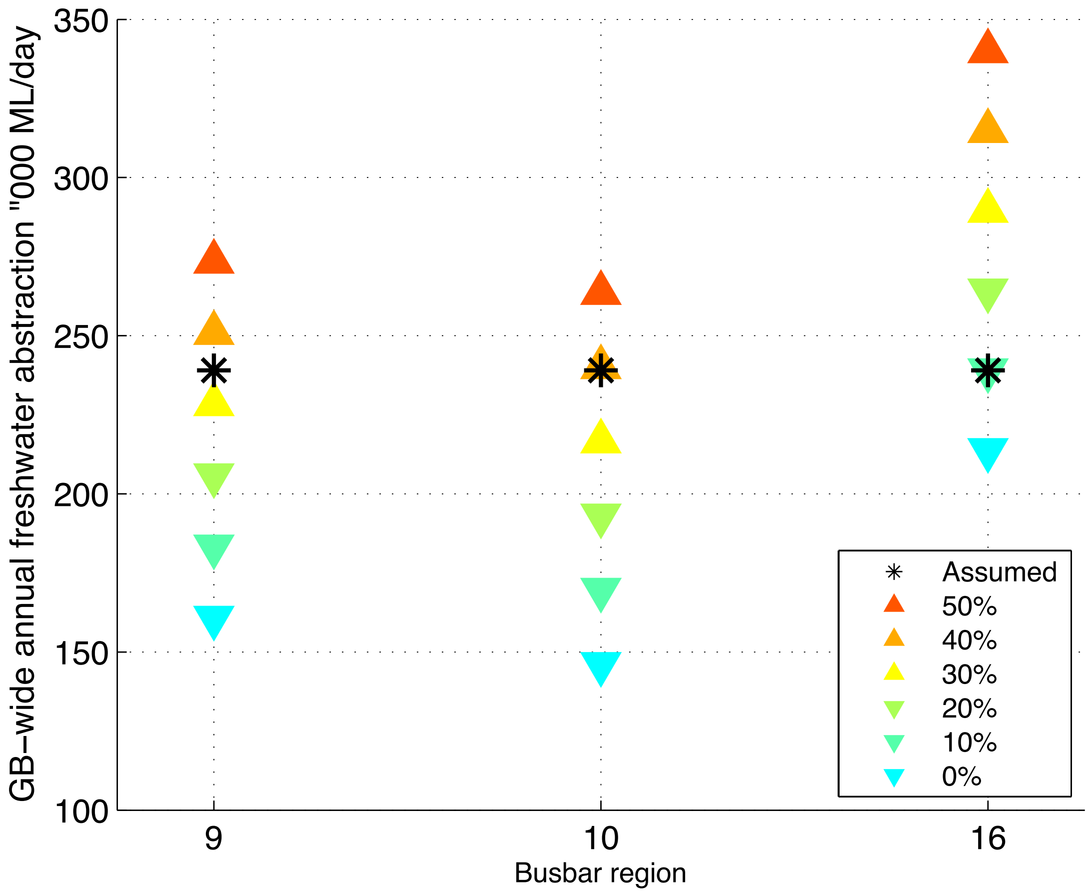


Figure 5-11. Sensitivity of total freshwater abstraction in EHT-CCS to changes in capacity distribution across busbar regions in 2050. Source: Byers *et al.* (2015) (CC-BY).

In the second sensitivity test we varied the penetration of hybrid cooling on freshwater capacity between 0% and 90% in 2050, compared to the current penetration of 5% and the modelled assumption of 30% by 2050 (Table 5-10). In the EHT-CCS strategy, each additional 10% of hybrid cooling (in the place of wet tower cooling), is estimated to save 10,500 ML of water per year. This is clearly much greater than for the other strategies given the higher water intensity of the strategy.

These two sensitivity analyses may be compared to possible policy options. The first test is considered akin to limiting the level of capacity development on freshwater in a region in order to constrain freshwater use, hence pushing capacity development to use tidal and coastal water sources or air-cooled systems. In this case, particular focus on busbars 9 and 10 would bring considerable reductions, quantified in Figure 5-11. The second test represents more of a regulatory regime, such as water-use efficiency targets or the mandate of specific low-water hybrid cooling technologies, whereby water-use efficiency gradually increases. This would be effective in the EHT-CCS strategy, yet probably unnecessary in the other two strategies.

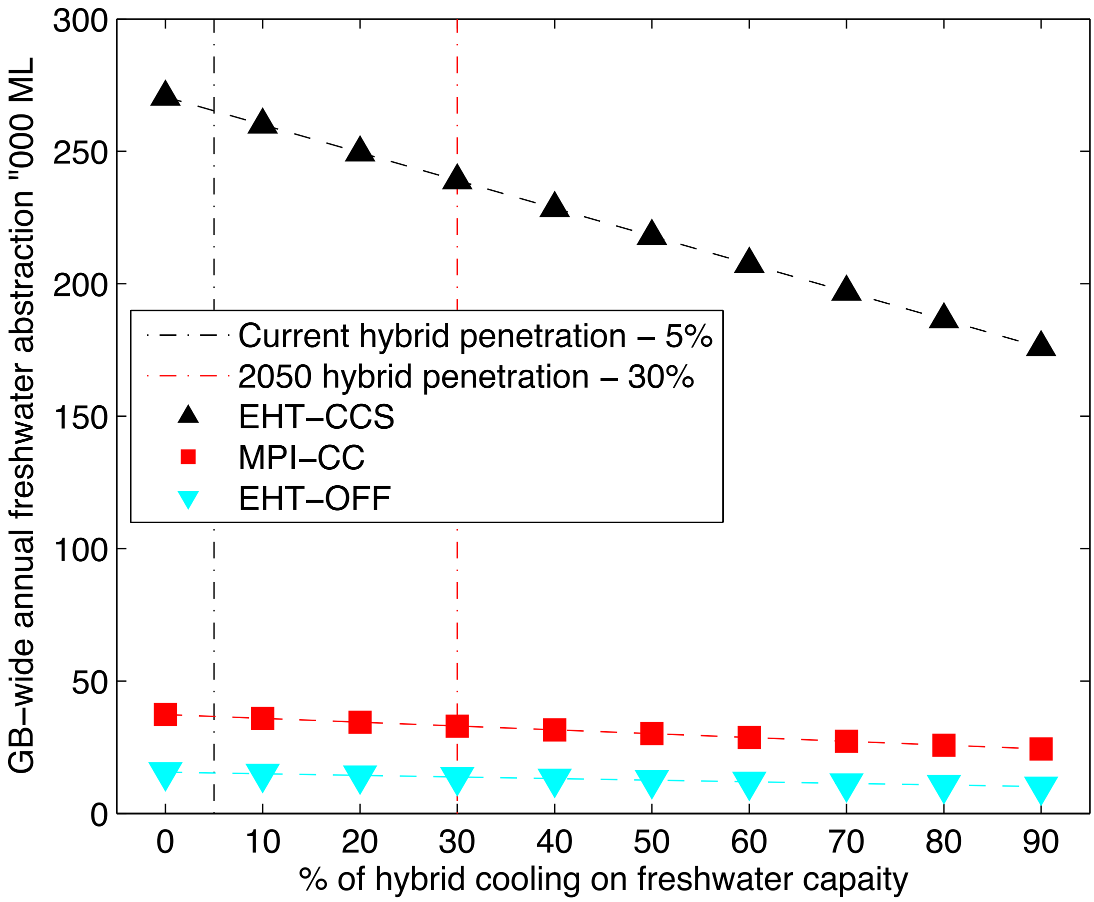


Figure 5-12. Sensitivity of freshwater use to the penetration of hybrid cooling on freshwater capacity, for all three strategies. Source: Byers *et al*. (2015) (CC-BY).

5.4 Discussion

This chapter has developed the framework from Chapter 3 and applied it successfully at a regional scale. In doing so the flexibility of the framework has been demonstrated, not just in the scale dimension, but also through changing other aspects such as the timestep resolution, the generation technologies and the energy pathways. Through these three chapters the flexibility of the model has also been demonstrated in its capability for testing through simulation the sensitivity of the assumptions, such as cooling systems and cooling sources. This is important given the considerable amount of assumptions needed for this type of analysis on a region-by-region basis.

This chapter has also presented a novel and straightforward method for quantifying the available to the electricity sector on a regional basis. Whilst in this case a large water resource model was used to assess climate impacts on flows across the country, water availability could also be modified arbitrarily on a percentage basis to account for changing demands and climate impacts. Assessing freshwater availability on suitably sized rivers at the downstream gauging point, works well for water use that is highly consumptive because the resources is effectively removed. Non-consumptive and high volume abstractions would be more difficult to account for in this method. The method, which relies on flow duration statistics, makes it easy to make inter-regional comparisons and also lends itself very well to assessing the reliability of a cooling water resource to the electricity sector, without running computationally-intensive distributed hydrological simulation models, as used in the following chapter. Thus, in the way that has been intended, the methods in this chapter have provided a high-level water resource assessment for the electricity sector that takes into account climate change. The findings of this study, inform more detailed analysis in the next chapter.

A warming climate is likely to bring reduced runoff and water availability to the UK, yet the pressure to decarbonise the electricity system may lead to greater localised water intensity. Delays in the Electricity Market Reform and recently ascended Energy Act 2013 have resulted in stagnated capacity development in recent years. Furthermore, CCS technology is still in development. Hence, there is still the opportunity for a coordinated approach to address the issues highlighted in this paper.

Coherent policy at the interface between the energy and water sectors is essential if we are to successfully govern high penetration of CCS capacity in a water-scarce future. Encouraged by the Government's CCS Roadmap (DECC, 2012a), CCS facilities will be developed in close proximity to one another to reduce infrastructure costs. Chapter 4 and Naughton, Darton and Fung (2012) have previously noted concern on the water impacts of *CCS clustering*, and this was embodied in this modelling work given the high capacities of CCS generation in busbars 9 and 10, in particular. Further policy attention to water-intensive CCS clusters is therefore warranted.

If options for freshwater abstraction are limited, generators will increasingly develop power stations with air-cooling or choose locations nearer the coast where tidal and sea water may be used. Dry air-cooled systems have both higher capital and operational costs, as discussed in Chapter 2. Using these systems will put additional pressure on the economic feasibility of CCS generation. Locating nearer the coast also brings challenges such as coastal erosion. Byers, Hall and Amezaga (2014) using evidence from Atkins (2009) identified that there may be a lack of coastal sites for power generation in strategies with high levels of coastal generation.

Meanwhile, Defra is currently investigating various options for water abstraction reform, with the aim of establishing a more dynamic regime that will also facilitate water trading. The regulatory instruments that are implemented could have an impact on the future of UK electricity supply in determining either technology choice or location of generation capacity. China has implemented its "Three red lines" policy based on economic productivity of different sectors, to drive efficiency and to increase water availability to other users (Liu *et al.*, 2013).

The possibility for water trading also features as an option in the abstraction reform process. Water trading in Australia's Murray Darling Basin has resulted in water being reallocated to more productive uses during prolonged drought. However, it raises unexplored challenges in terms of the joint operation and regulation of interdependent water and energy markets. How water trading would operate during low flows remains a concern to the energy industry (Energy UK, 2014). There are a few, very high volume abstractors (electricity included) and many very low volume abstractors. Large abstractors would require many small abstractors to forgo water abstraction in order to make up deficits, unless water is available from another high volume user, such as water companies or other, possibly less efficient, power generators.

5.5 Conclusions

Taking projections of water use by the sector, this chapter presents a high-level assessment comparing demands against water resource availability, on a regional basis and in a changing climate. This has enabled identification of potential conflicts between water availability and thermoelectric generation. This chapter has implemented the framework from Chapters 3 and 4 using different electricity projections demonstrating the versatility of the framework. Furthermore, methods to assess these demands against regional water availability have been developed and have led to successful identification of potential hotspots worth of more detailed analysis. Combined with Chapters 3 and 4, this completes Objective c).

At the national scale, electricity strategies with high penetrations of CCS capacity will lead to high freshwater use whilst strategies with more nuclear and offshore renewables minimise freshwater use. At the regional level, in strategies with high CCS, large increases in water demands may be expected in North West England, Humber and East Midlands regions. The Thames and southeastern regions can also expect higher demands for freshwater, although it is more likely that electricity generation capacity will be forced onto tidal and coastal water sources given the considerable existing pressures on water resources.

Our evaluation of future water resources has estimated future cooling water availability against the expected demands in scenarios with high uptake of CCS and found that availability at very low flows (Q_{e95} and Q_{e99}) will be exceeded in regions with high demands. This is the case at both average and especially at 100% capacity factors. Even without the expected impacts of climate change, we have identified cases where there may be constraints.

Subsequently, the sensitivity analysis has indicated where cooling water demand reductions would be most beneficial. Reducing the generation capacity on freshwater in either or both North West England and Humber/East Midlands regions could bring substantial regional reductions and reduce the national water-use by for electricity generation by between a third and a half. Alternatively, increasing the penetration of hybrid cooling systems would bring effective water-use reductions in the EHT-CCS strategy.

This analysis has identified three regions of potential conflict in the EHT-CCS strategy that are worthy of more detailed analysis. Given the existing capacity and planned development, The Humber/East Midlands region (10) is selected for detailed study in the following chapter.

As a final point we reiterate that the future regulatory arrangements for the energy sector and water abstraction will influence technology and location choices. Furthermore the delayed development of CCS, imminent generation capacity renewal and the abstraction reform being considered by Defra mean there are opportunities to effectively manage this cross-sectoral risk. It is essential that decision-makers take holistic and strategic views to long-term infrastructure planning to ensure both energy and water security.

Chapter 6. Impacts of Hydrological Variability and Climate Change on CCS Power Generation in the UK

6.1 Introduction

In the UK, currently 63% of the thermoelectric generation capacity is located on rivers, two-thirds of which on which non-tidal freshwater reaches. It has been calculated that 200,000 ML/year of freshwater is abstracted by thermoelectric power stations, of which approximately 60% is consumed (Chapter 4) (Byers, Hall and Amezaga, 2014). Whilst the volume of abstractions has decreased in recent years due to the decommissioning of coal and oil-fired steam plants under the EU Large Combustion Plant Directive, the consumption of freshwater from thermoelectric power generation could rise again considerably with the introduction of carbon capture and storage technology (CCS). The study also showed that energy portfolios with high levels of CCS result in freshwater consumption that is 37-107% higher than 2010 levels by 2050, largely due to the high water intensity of plants equipped with CCS technology.

However, carbon capture is an energy intensive process that results in parasitic loads on a power plant that can increase cooling demands by 90% in a supercritical coal-fired plant with a post-combustion capture system (Zhai, Rubin and Versteeg, 2011). Hence, power plants across the world will need to ensure that sufficient water resources are available if CCS technology is to be used. Yet the climate is changing and this is expected to have impacts on rainfall, air temperature and humidity, with subsequent impacts on water resources for the UK. Methods have subsequently been proposed to use probabilistic climate projections into risk-based water resources management and planning (Hall *et al.*, 2012b; Hall and Borgomeo, 2013; Borgomeo *et al.*, 2014).

This chapter builds on the work of Chapter 5 to investigate a critical catchment in more detail. The aim of chapter paper is to determine through simulation on a catchment level how different portfolios of future electricity capacity may be impacted by low flows as a result of hydrological variability, climate change and regulatory change. We test this on the River Trent in the Humber and East Midlands and area of the UK, an area previously identified for high levels of future CCS capacity.

- The rest of the introduction discusses thermal power plant cooling, hydroclimatic risks to generation capacity and the rationale for the choice of the Trent catchment.
- The Methods section explains the implementation of the hydrological model and the calculation of seasonally-adjusted water use by the electricity sector.
- In section 6.3 we present results of the hydroclimatic simulations, projections of electricity sector water use, simulation of abstractions under different licensing regimes and the costs of different cooling systems.
- Finally, the discussion covers uncertainties and perspectives on the hydroclimatic modelling, water abstraction regulation future electricity portfolios and the costs of more flexible hybrid cooling systems.

6.1.1 Cooling water demands of thermoelectric generation

The cooling system of a power plant is the primary determinant of the volume of cooling water used. Once-through systems abstract high volumes of water that removes heat through sensible heat transfer (conduction). Closed-loop wet tower systems abstract water which is recirculated and cooled predominantly via latent heat transfer (evaporation); their operation may be through natural air draft or fan-assisted. Evaporation can account for as much as 80% of abstracted volume during typical operation Air cooled condensers and mechanical air draught cooling towers have negligible water use, but result in efficiency losses at warm air temperatures and have a high parasitic load to power the fans. Wet/dry hybrid cooling towers combine principles of both wet and dry tower cooling. They are used in a variety of configurations, both to reduce water use as well as for plume abatement. Hybrid systems have higher capital and operational costs, but may offer flexibility and resilience to low water availability.

The second determinant of cooling water use is the cooling demand to be served by the cooling system, dictated by the thermal efficiency of the power plant. A sub-critical coal plant operating at 40% efficiency discharges roughly 50% more waste heat than a combined-cycle gas turbine (CCGT) plant operating at 60% efficiency. Cooling water demands will slowly improve with thermal efficiencies, but step changes are achievable when the choice of wet tower cooling is made over once-through systems, for example. Cooling water demands are described in section 6.2.4, Chapter 2 and in more detail in the literature (EC JRC, 2001; EPRI, 2002; US Department of Energy, 2006; NETL, 2007b, 2009b; Macknick *et al.*, 2012a). , Chapter 2 and in more detail in the literature (EC JRC, 2001; EPRI, 2002; US Department of Energy, 2006; NETL, 2007b, 2009b; Macknick *et al.*, 2012a).

6.1.2 Future trends in water demands and cooling technologies

Chapters 4 and 5 projected cooling water demands from a set of electricity generation projections for the whole of the UK to 2050. It was identified that most major power stations on freshwater currently use closed-loop wet tower cooling, with a few instances of wet/dry hybrid cooled systems at newer developments, a trend expected to continue. Given that the water intensity of electricity production from CCS is higher, this may increase the vulnerability of individual power plants to low flows and droughts. Reducing the dependency on water for cooling is an important step towards increasing resilience of generation capacity to expected impacts of climate change in the UK (Murphy *et al.*, 2009), such as low flows and droughts (Burke, Perry and Brown, 2010; Prudhomme *et al.*, 2012, 2013; Taylor *et al.*, 2013) and higher streamflow temperatures (Mohseni, Erickson and Stefan, 1999; Hannah and Garner, 2013; Johnson, Wilby and Toone, 2013; van Vliet *et al.*, 2013).

Carbon capture technology at power plants increases cooling demands in the order of 90% (ranging between 44-140%) due to the parasitic loads of the capture equipment and reductions of net thermal efficiency output (Zhai and Rubin, 2010; Zhai, Rubin and Versteeg, 2011; Parsons Brinckerhoff, 2012). All new coal power stations in the UK must be *CCS ready* (DECC, 2011c, 2011f) and will be required to capture approximately half of their emissions to meet the Emissions Performance Standard of the Energy Act 2013 (HM Government, 2013a). Despite emissions half those of coal, the use of CCS at CCGT plants is almost certainly necessary if the UK is to fully decarbonize the electricity sector (DECC, 2012c) and meet the 80% emissions reduction targets of the Climate Change Act 2008, by 2050 (Committee on Climate Change, 2012).. Furthermore, in line with the CCS Roadmap (DECC, 2012a), it is currently expected that *CCS clusters* of power stations and high emissions industry will be developed to reduce the costs of compression and transport infrastructure. Hence, the pressure on local water resources in these areas will be exacerbated (Naughton, Darton and Fung, 2012; Byers, Hall and Amezaga, 2014).

6.1.3 Water abstraction licensing and reform

Hands off Flow (HOF) levels are commonly used by water and environmental regulators to limit abstractions when river discharge falls to a threshold level. Limiting abstractions can ensure that sufficient resources are available downstream and to maintain the minimum flow necessary to protect the river ecology. Thus, a proportion of the flow is embargoed from abstraction, known in England and Wales as the *minimum residual flow* (MRF), which is typically set at 75% of the naturalized $Q_{99.9}$ flow (AMEC Environment & Infrastructure UK, 2013). The proportion of naturalised flows available for abstraction is determined primarily by the abstraction sensitivity band (ASB), at 10%, 15% or 20% of the naturalised flow at certain flow intervals. The ASB for a waterbody is determined by *environmental flow indicators* (EFI) (section 5.2.3.1) (Environment Agency, 2013a) . Once this volume has been licensed out to abstractors, further volumes can be licensed but only at higher flow volumes and subsequently with less security of supply.

A Hands off Flow level 1 (HOF1) is typically set between Q_{90} and Q_{95}, such that if flows at the assessment point, after abstractions, begin to fall below the HOF level, abstractors with HOF1 conditions on their license are required to reduce or stop abstraction in order to maintain a reliable discharge in the river. Further HOF levels can be set such that when more water is available, for example at Q_{70} and Q_{50} flows, more abstractors can take higher volumes of water.

This regime has worked well in the majority of cases and has been used in England and Wales for over 30 years. The government intends to reform the current system by 2020 to a more dynamic and responsive regime that facilitates water trading and reduces the abruptness of hands off flow levels (Environment Agency and Ofwat, 2011; Defra, 2013). In time, all abstractors will have Hands off Flow conditions, including those that are currently termed as *unconstrained* (HOF0). In both the *Current System Plus* and *Water Shares* proposals, the principle of HOFs will be maintained, but in such a way that abstractors will reduce abstractions on a graduated basis before reaching the HOF level, in what is termed a *soft landing* approach (AMEC Environment & Infrastructure UK, 2013). This will enable water to be used in a sustainable manner that reacts to changing flow conditions when discharge is between HOF levels.

6.1.4 *The risks to generation capacity*

The potential of increases in cooling water use coupled with low flows and droughts presents a risk to the electricity supply of the UK as well as other water users. A key dynamic of this risk is the regulation that determines what are deemed to be sustainable levels of abstraction and the levels at which abstractions must cease, currently the minimum residual flow and the Hands off Flow levels. Water temperature is also commonly considered a risk to the cooling of power stations but is much more critical to once-through systems than closed-loop towers, due to the large volumes abstracted (Hoffmann, Häfele and Karl, 2013). All major plants on freshwater in England use wet tower cooling, hence water temperature is not considered a significant risk and is excluded from this study. This risk has however manifested itself on various occasions, most notably in France in 2003 and recently in US (Spanger-Siegfried, 2013), amongst other locations. This is an issue expected to worsen with climate change, primarily for nuclear plants with once-through cooling (Förster and Lilliestam, 2009; Koch and Vögele, 2009; Flörke, Teichert and Bärlund, 2011; Koch *et al.*, 2012; Naughton, Darton and Fung, 2012; van Vliet *et al.*, 2012; Hoffmann, Häfele and Karl, 2013; van Vliet, Vögele and Rübbelke, 2013). This study focuses primarily on water availability to the electricity sector and how abstractions may be constrained by regulation.

6.1.5 *The River Trent*

Power stations located on freshwater have been identified and categorized according to their water source (Byers, Hall and Amezaga, 2014). The River Trent was found to have the highest level of generation capacity in the UK, split over non-tidal surface water (freshwater, 4.65 GW_e), and tidal surface water (8 GW_e). The Trent has been an important cooling water source in the UK since development of large scale coal-fired plants in the 1940s, peaking at 10 concurrently operational plants in the 1970s. More recently, the decommissioned Drakelow, Willington and Staythorpe plants have since received consents for redevelopment, with Staythorpe C reopening as a CCGT plant in 2011. The locational legacy of power generation on the Trent increases the likelihood of redevelopment and retrofit as the land may already be available, environmental consents already obtained and communities less averse to this type of industrial development. The UK Government CCS Roadmap may also encourage development along the Trent in the form of carbon-intensive clusters or as a CCS corridor along which compressed CO_2 is transported to the coast for storage (ONE North East and Amec, 2010; DECC, 2012a). Consented plans could potentially bring the generation capacity on freshwater to 7.87 GW_e within a few years (The Planning Inspectorate, 2012). Future electricity portfolios are discussed in section 6.2.4.

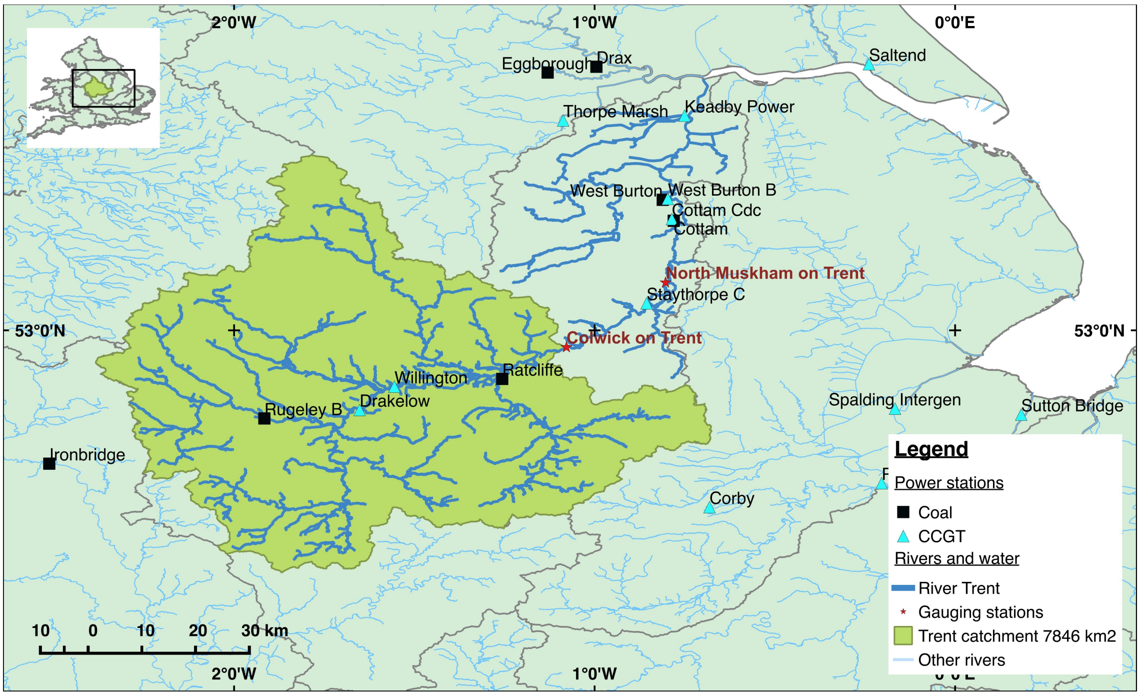


Figure 6-1. Map of the Humber and East Midlands area showing the River Trent, which flows from southwest to northeast, nearby power stations and the gauging stations at Colwick and North Muskham.

The main downstream gauging station on the Trent is at North Muskham Cromwell Lock, after which the flows have tidal influence. Hands off Flows are normally based on this gauge, however our hydrological model is based at Colwick gauging station due to data availability. Colwick is 28km southwest and upstream of North Muskham with only Staythorpe C between the two stations. The catchment area draining at Colwick is 7846 km^2 whilst at North Muskham it is 8231 km^2.

6.2 Method and framework

The general framework (Figure 6-2) for this analysis comprises four principal components:

a) probabilistic projections of future climate and hydrology;
b) projections of future electricity capacity, generation and cooling water use;
c) simulation of abstractions under alternate abstraction regimes and assessment of capacity availability under low flows; and
d) a cost analysis of different cooling system options.

Together these components allow the estimation of the probability of insufficient licensed cooling water. Alternative investment, technology and regulatory options can be explored by modification of relevant parameters in the simulation.

The approach aims to characterize the future hydrological regime under climate change scenarios and subsequently assess how changing hydroclimatic conditions will impact on portfolios of electricity capacity. The interaction between these natural and technological systems is governed by policy and regulation, both directly and indirectly; regulation determines the limits of abstraction and water temperature changes for different water users, whilst wider incentives for CCS or gas technologies, for example, may drive increases or decreases in water use by the electricity sector.

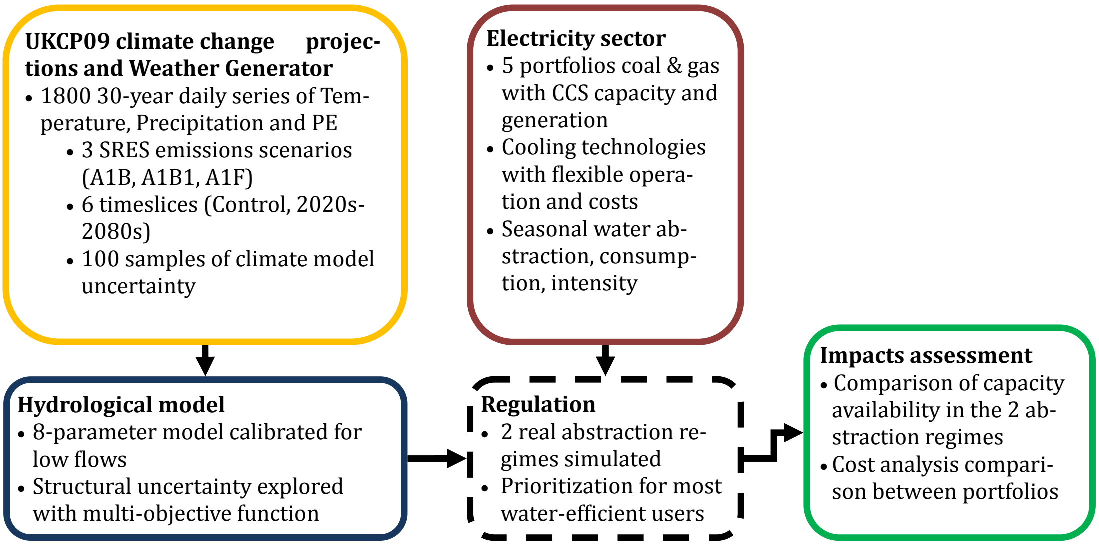


Figure 6-2. Model framework for the study. Climate projections drive a hydrological model. Projections of electricity sector water use are developed for assessment, the performance of which is assessed against the hydrology, governed by the regulatory interface between the two. System performance is characterized by an impacts assessment.

6.2.1 Hydrological model

During the design, development and application of the model, emphasis was placed on the simulation of periods of low flow, which are also a major focus of this study. This 8 parameter lumped conceptual model (Leathard and Kilsby, no date) simulates mean daily discharge, using rainfall and potential evaporation as forcings. A two-layer characterization of a catchment is used, comprising a fast responding upper soil layer and a slower groundwater store. The upper layer component closely follows the formalization of Wood, Lettenmaier and Zartarian (1992), Liang, Lettenmaier and Wood (1996) and Todini (1996), with the partitioning of rainfall between infiltration and rapid runoff controlled using a storage capacity curve that represents heterogeneity in total storage capacity across the catchment. Lateral interflow from the upper soil layer to the drainage network and percolation to the deeper groundwater layer are represented using the Brooks and Corey (1964) formulation and the relationship between potential and actual evaporation follows Wood, Lettenmaier and Zartarian (1992). Groundwater fed baseflow is simulated using a quadratic store (Moore and Bell, 2002). Generated runoff is routed through a linear reservoir to represent channel processes. A degree-day snow model is also incorporated (Martinec and Rango, 1986) but this was not considered here given the focus on low flow summer periods.

Historical observations of temperature and rainfall were sourced from UKCP09 (Perry and Hollis, 2005a, 2005b) and flows from the National River Flow Archive for the period 1961-2002 (Centre for Ecology & Hydrology, 2012). The former included the transformation of climate variables into reference crop evapotranspiration via the Revised FAO Penman-Monteith method (Allen *et al.*, 1998). Figure 3 shows the hydrograph of the model reproducing low flows during the drought of 1975-77.

6.2.1.1 Climate inputs

The model uses observations of total precipitation (in units of millimetres per day), total potential evapotranspiration (also in units of millimetres per day), and mean air temperature (in units of °C per day). Observations of precipitation, potential evapotranspiration, days of snow falling, and days of snow lying were aggregated in space to the extent of the catchment of River Trent at Colwick.

Table 6-1. Description of the datasets of observed data used in the model calibration.

Variable	**Spatial resolution**	**Temporal resolution**	**Temporal range**	**Source**
Mean discharge	River Trent at Colwick	Daily	1961-2002	National River Flow Archive (Centre for Ecology & Hydrology, 2012)
Precipitation	5 km	Daily	1961-2002	(Perry and Hollis, 2005a, 2005b)
Maximum temperature			1961-2002	
Minimum temperature			1961-2002	
Mean wind speed at 10 m		Monthly	1969-2002	
Mean vapour pressure			1961-2002	
Sunshine duration			1961-2002	
Days of snow lying			1971-2000	

6.2.1.2 Structural uncertainty of the model

To explore the model's structural uncertainty, 10,000 simulations were performed in which the parameters were selected using Latin hypercube sampling from reasonable ranges of the 8 variable parameters (Table 6-2). Ranges for the parameters were informed by values in the literature where possible.

Table 6-2. Parameter ranges used in testing the structural uncertainty of the model.

#	Parameter	Lower value	Chosen value	Upper value	Reference/ comment
Infiltration terms					
1	*Wmax*	1000	2571	7000	Max soil moisture capacity [mm] (Todini, 2002, eq.4)
2	*b*	0.03	0.3	0.4	Shape of variable capacity curve [-](Todini, 2002)
3	b_e	0.2	0.6	0.7	Actual to potential evaporation ratio [-] (Wood, Lettenmaier and Zartarian, 1992, eq. 4)
Lateral drainage (interflow)					(Todini, 2002, eq.15)
4	*ds*	50	184	1000	Drainage at saturation [mm/day]
5	*cl*	3	8.5	20	Soil property exponent [-]
Percolation					(Brooks and Corey, 1964)
6	p_s	300	953	2500	Percolation at saturation [mm/day]
7	*c2*	10	15.2	20	Percolation coefficient [-]
Groundwater					(Moore and Bell, 2002, tab. 1)
8	k_b	5000	11097.2	30000	Baseflow time constant [h mm^{m-1}]
9	*m*	0.5	0.5	0.5	Exponent of baseflow linear storage [-]

A variety of performance metrics were used to explore the model performance between the observed flows and the simulated model flows using the observed climate variables. These included *Nash-Sutcliffe Efficiency* (*NSE*) (Nash and Sutcliffe, 1970), log *Nash-Sutcliffe Efficiency* (NSE_{log}), *percentage bias* (*PBIAS*) (Gupta, Sorooshian and Yapo, 1999), the *Kling-Gupta Efficiency* (*KGE*) (Gupta *et al.*, 2009), the mass balance (*MB*), and the absolute difference from low flow percentiles Q_{99}, Q_{95} and Q_{90}.

In the final assessment, the performance of each simulation was ranked on the basis of the Nash-Sutcliffe Efficiency (Nash and Sutcliffe, 1970), and absolute difference between observed and simulated flows of low flow percentiles, Q_{99}, Q_{95} and Q_{90}, using a similar multi-objective procedure used by Deckers *et al.* (2010) (Figure 6-3). NSE_{log} is the Nash-Sutcliffe Efficiency performed on the log transformed flows to emphasize low flow periods (NSE_{log}) and avoids the high flow bias attributable for normal *NSE*. Absolute differences from low flow statistics was considered a critical performance attribute as the inclusion of Q_{99}, Q_{95} and Q_{90} weights the ranking procedure in favour of low flow performance. Subsequently, ranking with NSE, PBIAS and KGE was less effective than NSE_{log} in identifying behavioural sets.

From the top 10% of performing parameterisations that were selected on the basis of the combined rankings of the 4 flow metrics, 410 were found to have a mass balance $MB \leq 10\%$ with $0.603 \leq NSE_{log} \leq 0.746$. The highest ranked parameter-set, which is used in the analyses below, had an NSE_{log} of 0.71, percentage bias of -0.37% (Gupta, Sorooshian and Yapo, 1999), Kling-Gupta Efficiency of 0.56 (Gupta *et al.*, 2009) and error in the three percentiles whilst error in Q_{99}, Q_{95}, Q_{90}, was -29%, +4%, +19%, respectively. These top 410 parameterizations are shaded in , which shows the driest period in the observed record, in 1975-77.

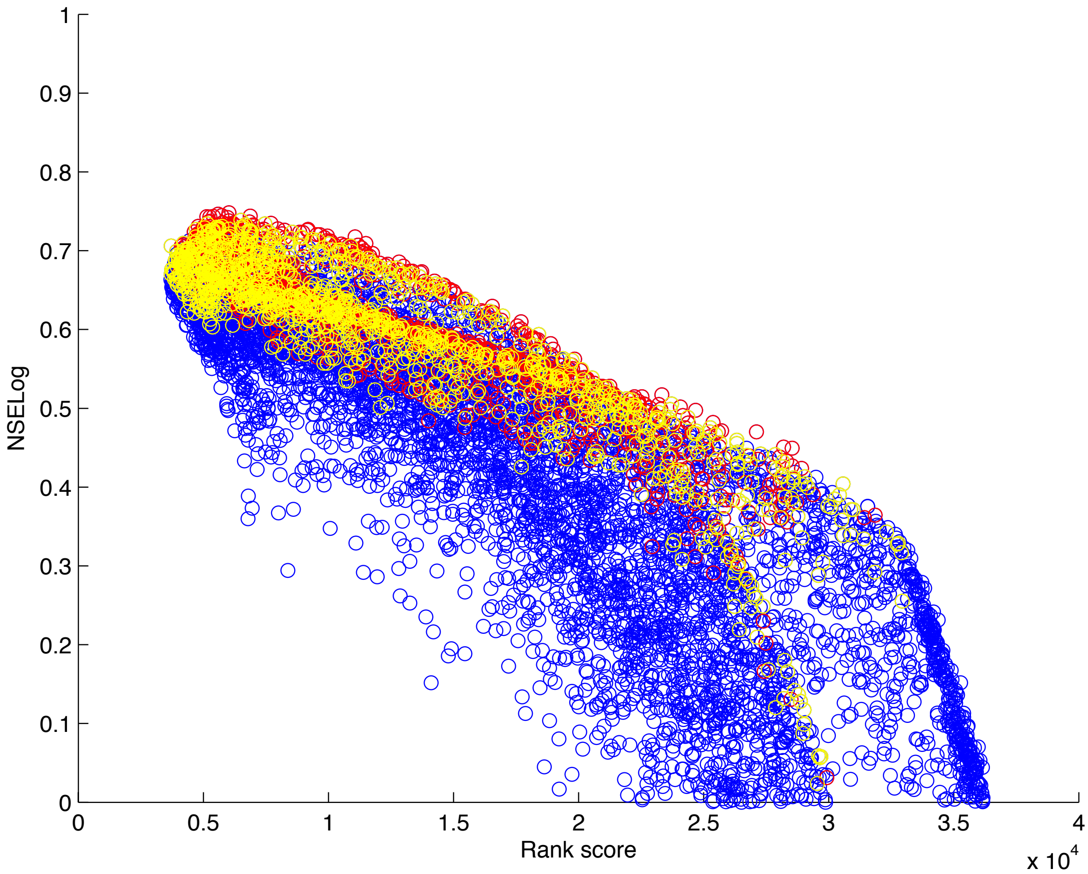


Figure 6-3. Scatter plot showing NSE_{log} vs. Rank score. Points in red have a mass balance, *MB < 5%*, whilst yellow denotes *5% < MB < 10%*.

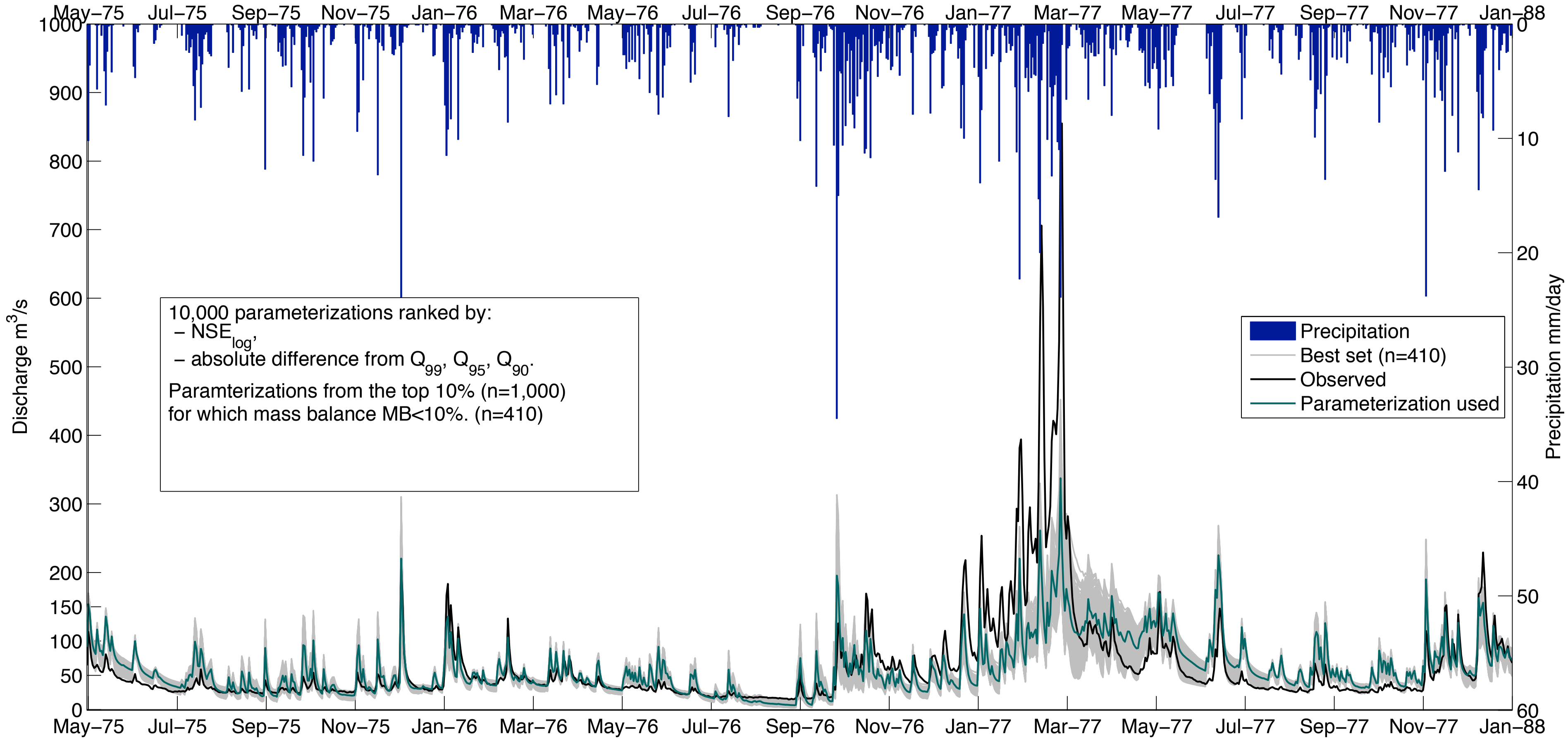


Figure 6-4. Hydrographs of the calibrated model against the observed flow and precipitation for the period May 1975 to January 1988, when historically low flows were observed. Grey shading show the 410 best-ranked paramterisations by the criteria over the period 1961-2002.

6.2.2 Climate change projections

The UK Climate Projections 2009 (UKCP09) are the principal set of projections available to the UK for impact assessment, designed for use across government, research and business. UKCP09 uses a perturbed physics ensemble of 11 General Circulation Models from the Met Office Hadley Centre, HadCM3, consisting of 280 model variants, to account for the uncertainties arising from the representation of natural processes and due to the effects of natural climate variability. Eleven runs of the regional climate model HadRM3 were used to downscale the ensemble of GCM runs to a 25km grid. UKCP09 makes available the full range of 1000 climate change factor vectors from the UKCP09 probability distributions.

Using the observed climatology perturbed by change factors derived from the downscaled projections, the UKCP09 Weather Generator (WG) creates internally consistent meteorological variables for future emission scenarios (Jones *et al.*, 2009). The WG is based around the Neyman-Scott Rectangular Pulses model, with other variables, including temperature and PE, generated according to rainfall state (Kilsby *et al.*, 2007; Jones *et al.*, 2009) and calibrated using the Perry and Hollis (2005a, 2005b) data.

Future climate time series for precipitation, temperature and potential evapotranspiration were sourced from the UKCP09 Weather Generator for 30-year timeslices for the 2020s (2010-2039), 2030s (2020-2049), 2040s (2030-2059), 2050s (2040-2069) and 2080s (2070-2099) for three Special Report Emissions Scenarios (SRES: A1B, A1B1, A1F), Low, Medium and High, respectively. The WG 5km gridsquare location was chosen from within the catchment that closely matches the observed aerially averaged catchment rainfall. This was done using the Standard period Annual Average Rainfall (SAAR) value matching the SAAR value for the catchment (761-771 mm/year), according to the HiFlows-UK database (Environment Agency, 2011). For each emissions scenario and timeslice, 100 30-year time series of daily mean air temperature, precipitation and potential evaporation were simulated on the model, keeping the random number seed consistent across all climates and timeslices. For each of the 100 time series, a vector of change factors are randomly sampled from the full probabilistic distribution of UKCP09 change factor vectors (1000 max), subsequently used to perturb the baseline climatology of the gridsquare. An initial two-year spin-up of the hydrological model was specified, with the subsequent 28 years of flow data used in the analyses. Figure 6-5 presents the mean Flow Duration Curves (FDC) for the

2030s and 2080s as well as the WG Control and Observed profiles against the regulatory flow levels.

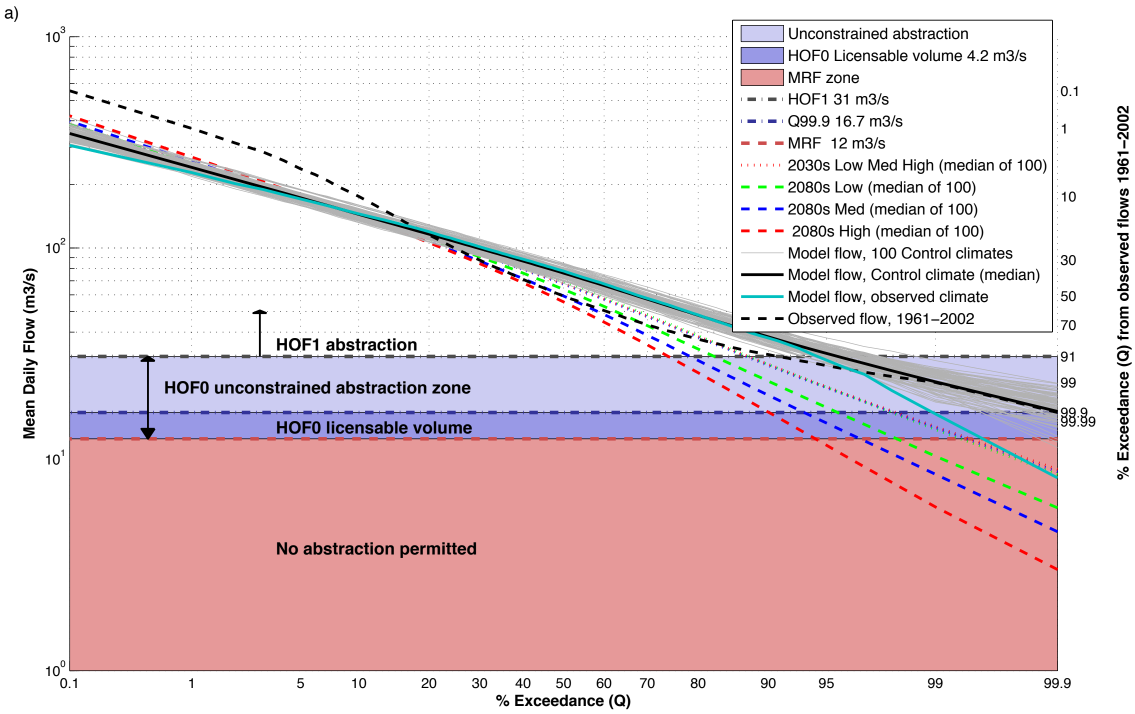


Figure 6-5.Flow duration curves (FDC) compared against the levels that define the abstraction regime at Colwick on Trent.

In Figure 6-5, the observed FDC (1961-2002) is compared against the model reproduction for both observed climate, 100 control climates (grey lines) and the median of the control climates. The median FDCs for the 2030s and 2080s simulations using three emissions scenarios and the full distribution of change factors (100 variants) are also shown. The shaded background show the minimum residual flow level (MRF), the interval of unconstrained abstraction (HOF0) and licensed volume, and the HOF1 level, all used to limit abstractions in order to protect environmental flows and water resource (section 6.1.3).

On an annual basis, the Control model reproduces the flow characteristics of the river well across the profile, with slight over-estimation between Q_{30} and Q_{90} (Figure 6-5). On a seasonal basis, the control model overestimates in March, April, May and slightly underestimates in September, October, November (Figure 6-6).

Based on the flow duration curves of the simulations above, the MRF and HOF levels for the timeslices going forwards have been determined as they are currently; MRF at 75% of the $Q_{99.9}$, HOF1 at 85% of the Q_{91} and licensable volumes constituting the remainder (25% and 15%, respectively) in Table 6-3.

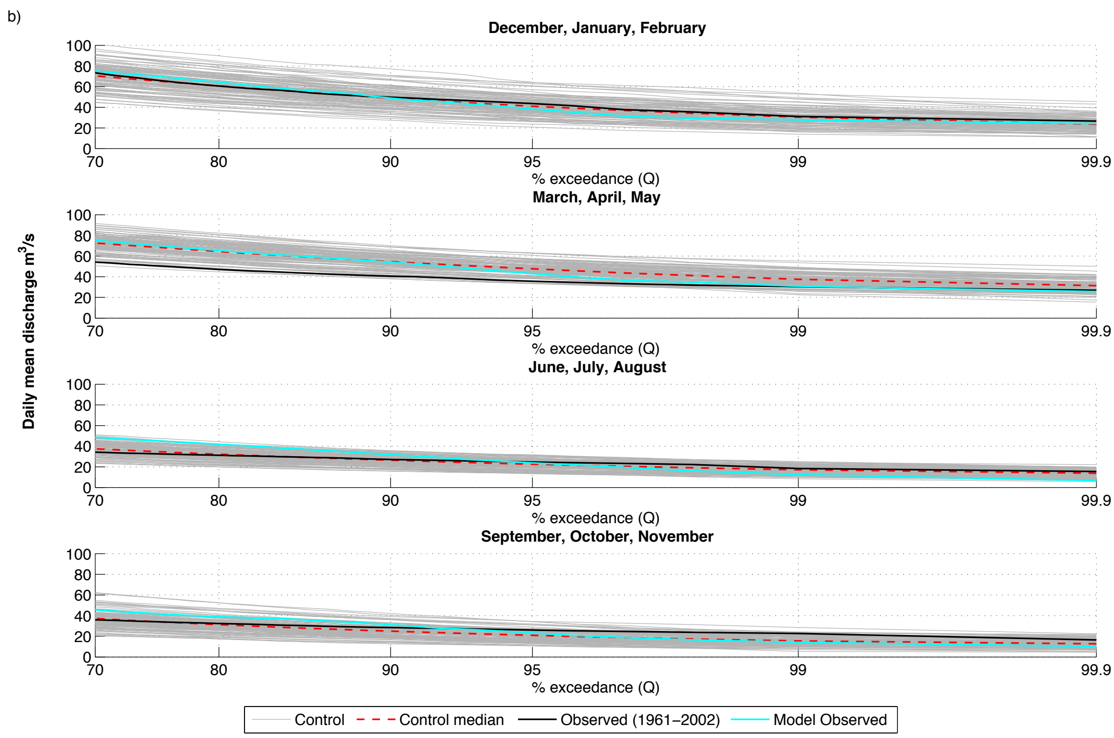


Figure 6-6. Validation of seasonal FDCs showing the observed FDC, and control and observed model FDCs.

Table 6-3. Projected median $Q_{99.9}$ and Q_{91} flows, the derived minimum residual flow (75% of the $Q_{99.9}$) and licensable volumes for each timeslice for the medium emissions scenario.

m^3s^{-1}	Current	2020s	2030s	2040s	2050s	2080s
HOF0 licensing (between $Q_{99.9}$ and Q_{91}) [a]						
$Q_{99.9}$	18.0	13.5	11.2	10.2	9.6	7.6
MRF	13.5	10.1	8.4	7.7	7.2	5.7
Q_{91}	36.9	30.2	27.4	25.4	23.0	20.3
Licensable	5.5	4.5	4.1	3.8	3.5	3.0
Δ%	0%	-18%	-26%	-31%	-38%	-45%
HOF1 licensing (between Q_{91} and Q_{71})						
Licensable	4.4	3.9	3.5	3.2	3.0	2.7
Δ%	0%	-11%	-20%	-27%	-32%	-39%

[a] Normally Q_{95}, but for the Trent this is Q_{91}.

6.2.3 Seasonality of future electricity generation and demand

Over 85% of the domestic heating demands in the UK are satisfied by gas, hence electrification of heating can be an effective method of decarbonising if decarbonisation of the electricity sector simultaneously occurs. Overall demands for heating may reduce due to better insulation and also warmer winters but this could be offset by behavioural changes, for example, due to desire for warmer temperatures or more working from home (DECC, 2010). Higher electricity demands for heating and cooling are expected in both commercial and domestic sectors (Building Research Establishment, 2008), particularly with regard to expected warmer summers (Hitchin and Pout, 2001; McColl, Angelini and Betts, 2012). Our analysis also used UK Department of Energy and Climate Change 2050 Pathways (DECC, 2010) projections to determine the proportional contributions of electrified heating, cooling and lighting to the seasonality of electricity demand, and subsequent generation.

The DECC 2050 Pathways projections show significant increases in electricity demand for all forms of heating and cooling; electricity demand for heating increases two and a half times, whilst cooling demands double from 2010 to 2050. The effect that this will have on the annual distribution of electricity is however uncertain. A literature search for projections of monthly or even quarterly distribution was performed but there appear to be no credible projections for this.

Further analysis of the DECC 2050 Pathways determined the current and future contributions of electrified heating and cooling and transport with respect to the overall generation mix. Heating and cooling projections were taken from the "Nuclear – central electric" pathway in version 2.1 of the Pathways Excel model (DECC, 2011a).

Of all the subcomponents of electricity demand in the UK, the only ones considered to be significantly seasonal were lighting, heating and cooling. The seasonality of lighting demands is not expected to change with climate change, unlike both heating and cooling.

As a proportion of total generation, heating and cooling increases from approximately 17.5% to 25% of total generation in 2050 (DECC, 2011a). Thus, seasonal peaks in winter and summer are accentuated whilst spring and autumn generation are lower. We have assumed the coal load profile to respond and by 2050 is projected to be the same as the average profile for coal and gas. This results in growing summertime demands, albeit winter demands remain the highest (Figure S 8b).

Using the heating and cooling distributions from DECC (2010), the monthly proportions of H&C demand were separated from the other monthly demands. The H&C portions were then scaled by the growing proportion of total demands, from 17% in 2007 to 25% in 2050. These scaled H&C demands were then added back to the other demands, to give monthly distribution of the electricity demands across the year, scaled to take into account the growing heating and cooling demands, as in Figure 6-7 and Table 6-4.

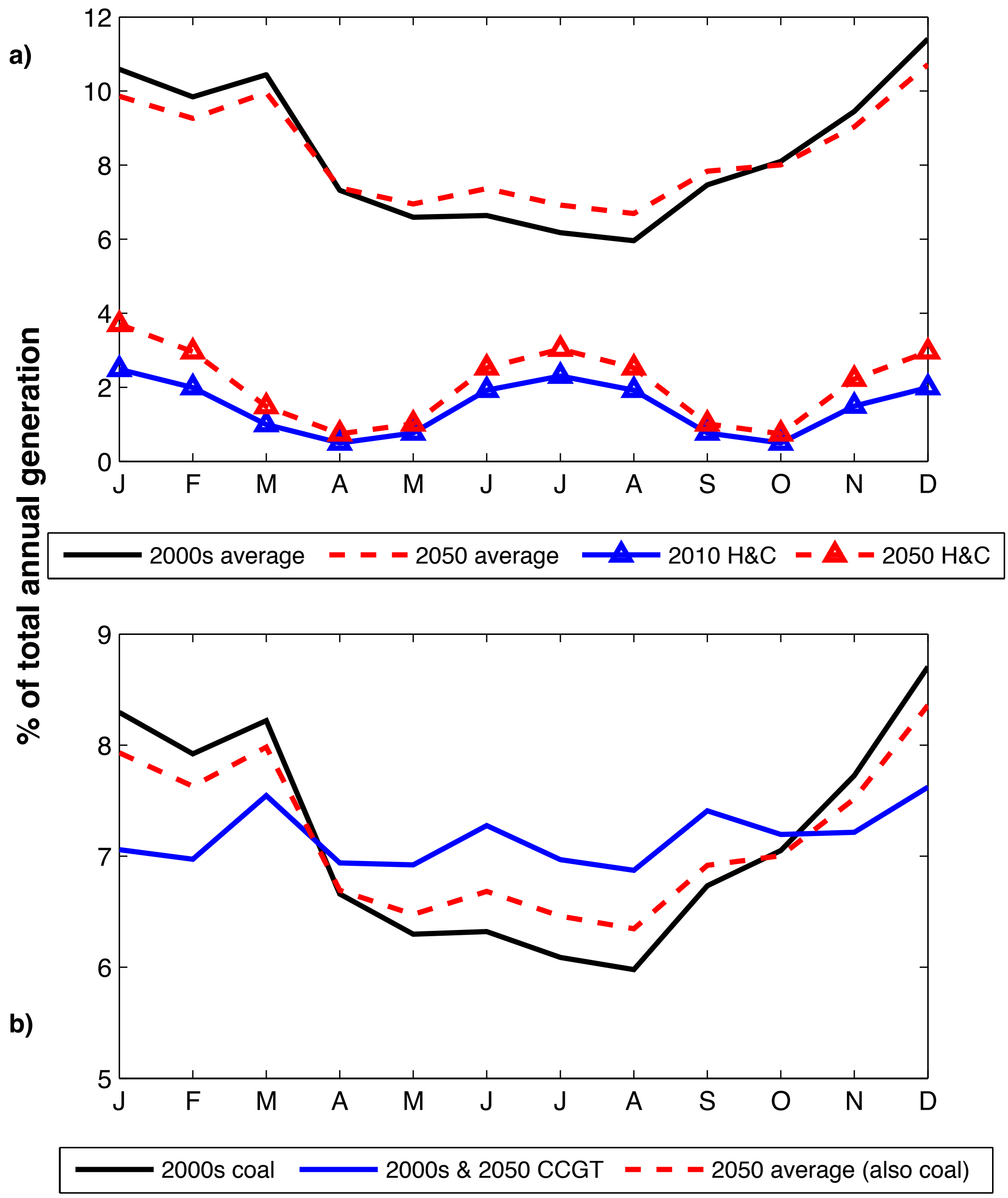


Figure 6-7. a) Seasonality of recent and 2050 electricity demands, influenced by changes in heating and cooling (H&C). b) Seasonality of recent and future coal and CCGT generation. CCGT assumed to remain the same, whilst we assume that coal will still be seasonal, to the same extent as the future grid average.

Table 6-4. Monthly distribution of electricity generation for coal and gas.

	Coal			Gas	Coal & Gas weighted average		
	2010	2025	2050	2010-2050	2010	2025	2050
JAN	10.59%	9.33%	10.13%	8.12%	9.67%	9.50%	10.13%
FEB	9.84%	8.82%	9.38%	7.95%	9.16%	8.97%	9.38%
MAR	10.44%	9.68%	9.57%	9.09%	10.03%	9.72%	9.57%
APR	7.32%	7.59%	7.17%	7.88%	7.68%	7.42%	7.17%
MAY	6.60%	7.35%	6.81%	7.84%	7.25%	7.13%	6.81%
JUN	6.64%	7.98%	7.64%	8.55%	7.64%	7.73%	7.64%
JUL	6.18%	7.40%	7.32%	7.94%	7.10%	7.29%	7.32%
AUG	5.96%	7.25%	7.02%	7.75%	6.94%	7.06%	7.02%
SEP	7.47%	8.07%	7.64%	8.82%	8.18%	8.02%	7.64%
OCT	8.10%	7.90%	7.67%	8.39%	8.24%	7.96%	7.67%
NOV	9.45%	8.62%	8.98%	8.43%	9.05%	8.82%	8.98%
DEC	11.41%	10.02%	10.68%	9.24%	10.62%	10.37%	10.68%

6.2.4 Electricity portfolios and abstraction demand calculation

On the non-tidal freshwater stretches of the Trent there is currently 3 GW_e of coal-fired power plants (Ratcliffe on Soar and Rugeley) both using closed-loop wet tower cooling, in addition to the wet/dry hybrid-cooled 1.65 GW_e Staythorpe C CCGT power plant. Five alternative portfolios for power station development on the River Trent were developed to explore the boundaries of future water demands from the sector on the river from 2020 to 2050 at 5-year time steps (Table 6-5, Figure 6-10, and Appendix C.2).

All portfolios result in 9.87 GW_e capacity by 2040, consistent with strong regional population growth and recently announced government subsidies for low-carbon electricity generation and CCGT capacity (HM Government, 2013a). The alternative portfolios differ primarily by the cooling systems.

- Portfolios 1 and 2 have low levels of hybrid cooling, whilst portfolios 3-4 have 70% and 100%, respectively.
- Portfolio 5 is has only CCGT+CCS capacity, 57% of which hybrid cooled.
- All plans assume that the consented Drakelow and Willington CCGT power station projects will come online in 2015 and 2020.
- By 2020 there is 7.87 GW_e of unabated capacity but from 2025 CCS equipment begins to be added, present on all capacity by 2030.
- A further 2 GW_e of CCS capacity, half coal and half CCGT, is added in 2040, except for the *Gas Future* portfolio where all capacity from 2025 is gas CCGT+CCS.
- Future coal plants with CCS are assumed to be super-critical, whilst current capacity is of the less efficient, sub-critical type.

Electricity generation was calculated using 70% average load factor and 100% peak load factor. This high load factor for CCS is consistent with scenarios with high penetration of CCS, as in Chapter 5 (DECC, 2010; Tran *et al.*, 2014). Generation figures are made monthly by multiplying the generation for that timestep by the distributions described in section 6.2.3. Monthly generation figures are multiplied by water use factors to estimate abstraction and consumption, by each generation class and cooling method, similar to the framework in Chapters 3 and 4.

Table 6-5. Portfolio names, descriptions, capacity and cooling types between 2010 to 2040. Detailed in the Appendix C.2.

Portfolio		**2010**	**2020**	**2025**	**2030**	**2040**
				Capacity (MW_e)		
# 1-4	Coal:	3,000	3,000	3,000	3,000	4,000
	CCGT:	1,650	4,870	4,870	4,870	5,870
#5	Coal:	3,000	3,000	0	0	0
	CCGT:	1,650	4,870	7,870	7,870	9,870
% of which CCS		0	0	50%	100%	100%
				Cooling system, capacity (MW_e)		
#1 Business as usual (BAU)				Closed-loop wet tower cooling on all capacity (Wet)		
	Wet:	3,000	6,220	6,220	6,220	8,220
	Wet/dry:	1,650	1,650	1,650	1,650	1,650
#2 Coal new hybrid				All new coal capacity uses hybrid wet/dry tower cooling		
	Wet:	3,000	6,220	6,220	6,220	7,220
	Wet/dry:	1,650	1,650	1,650	1,650	2,650
#3 New Hybrid				All new capacity uses hybrid wet/dry tower cooling		
	Wet:	3,000	3,000	3,000	3,000	3,000
	Wet/dry:	1,650	4,870	4,870	4,870	6,870
#4 All hybrid				All new capacity is hybrid cooled, existing capacity is retrofit from 2025-2030		
	Wet:	3,000	3,000	1,500	0	0
	Wet/dry:	1,650	4,870	6,370	7,870	9,870
#5 Gas future				Only CCGT capacity, half of new and replacement capacity is hybrid wet/dry tower cooling		
	Wet:	3,000	6,220	3,220	3,220	4,220
	Wet/dry:	1,650	1,650	4,650	4,650	5,650

Water use factors are similar to as used in Chapter 5, based on Macknick *et al.* (2011, 2012a), Tzimas (2011) and Zhai, Rubin and Versteeg (2011). For closed-loop wet tower cooling, abstraction factors are 0.97, 1.93, 1.92 and 3.62 ML/GWh (or litres/kWh), for CCGT, coal, CCGT+CCS and coal+CCS, respectively. Consumption factors are approximately 75% of the abstraction values.

For wet/dry hybrid cooling, we have assumed three operational modes to test the operational sensitivity, corresponding to the values for the wet tower cooling. In normal mode the wet/dry tower operates as a closed-loop wet tower and water use is assumed to be effectively the same (100%). Reduced mode operates using more mechanical air draught and less water and hence water use is 85% of normal operation. Dry mode operates using mostly mechanical air draught with reduced water use, assumed to be 65% of normal operation. Annual cooling water abstractions described in section 6.2.4 are multiplied by the distributions in Table 6-4 to make abstractions monthly.

6.2.5 Cooling demands

Calculating the cooling loads for each pathway is done using the assumed higher heating value (HHV) for the efficiency of the power plants and an estimate of thermal losses to other sinks besides the cooling system. Additional thermal losses have been approximated from Delgado (2012) as 15% for unabated generation and 8% for CCS generation, mostly arising from heat loss via the flue gas. Cooling load M_T (waste heat to cooling system), is hence:

$$\boldsymbol{M_T} = \frac{\boldsymbol{M_e \cdot (1 - \eta_e - \eta_l)}}{\boldsymbol{\eta_e}} \tag{1}$$

where M_T is the cooling system load in MW_{th}, M_e is the electrical output, η_e is the net plant electrical efficiency (HHV) and η_l are the other losses .The assumed efficiencies are constant in the period 2010-2050, presented in Table 6-6 and probably at the upper range of technical feasibility in the 2020s-2030s.

Table 6-6. Assumed efficiencies for calculating the cooling loads.

Capacity type	$\boldsymbol{\eta_e}$	$\boldsymbol{\eta_l}$	**1-$\boldsymbol{\eta_e}$-$\boldsymbol{\eta_l}$**
CCGT	0.6	0.15	0.25
Coal (super-critical)	0.45	0.15	0.40
CCGT+CCS	0.45	0.08	0.47
Coal+CCS (super-critical)	0.31	0.08	0.61

Although there is a small change in efficiency between using wet tower and hybrid cooling, instead it is assumed that a marginally higher fuel input is required to maintain the same output and hence this is attributed in the costs.

6.2.6 Simulating abstractions and establishing the capacity deficit

An algorithm was developed to determine, for each energy portfolio, the most efficient use of the water available at different flow intervals whilst maximizing electricity generation for the amount of available water. Let L_e be the current licensed water availability. In some cases this is insufficient, hence demand is reduced by the sector in the following ways. Firstly, hybrid cooling is considered flexible generation, whose operational water use mode, h, is reduced when necessary, $65\% \leq h \leq 100\%$, noting that $h = 100\%$ is the most economically efficient, water-intensive and preferred mode of operation. D_C is the water demand from wet tower cooled capacity, and is proportionally reduced by adjusting f_C, the load factor. The load factor of hybrid capacity, f_H, can also be reduced, $100\% \geq f_H \geq 0\%$ to meet L_e, when the hybrid mode $h = 65\%$ and $f_C = 0\%$.

1. If licensed volume available exceeds the maximum demand, $L_e > D_{max100}$

$$f_C = 100\%,\ f_H = 100\%,\ h = 100\%;$$

$$D_{p,t} = D_{max100} \tag{2}$$

2. If licensed volume available lies between the maximum and minimum demands at 100% load factor, hybrid cooling is used to moderate demand, $D_{min100} < L_e < D_{max100}$

$$f_C = 100\%,\ f_H = 100\%,$$

$$D_{p,t} = L_e$$

$$h = \frac{L_e - D_C}{D_{max100} - D_C} \tag{3}$$

3. If licensed volume is lower than the minimum demand at 100% load factor but higher than the minimum demand for only hybrid cooling at 100% load factor, the load factor of wet tower cooled capacity is reduced to moderate demand, $D_{min100.H} < L_e < D_{min100}$

$$h = 65\%, f_H = 100\%,$$

$$D_{p,t} = L_e$$

$$f_C = \frac{D_C - D_{min100} - L_e}{D_C} \tag{4}$$

4. If licensed volume is lower than the minimum demand for only hybrid cooling at 100% load factor, wet tower cooled capacity is reduced to 0%, and hybrid cooled capacity is reduced to moderate demand, $L_e < D_{min100.H}$

$$f_C = 0\%,\ h = 65\%$$

In this case, more water efficient CCGT capacity is prioritized over coal such that in solving $D_{p,t} = L_e$ for f_H, load factor of hybrid cooled coal, $f_{H.coal}$ is reduced to 0%, before finally reducing $f_{H.CCGT}$.

$$f_H = \frac{L_e}{D_{min100.h}} \tag{5}$$

In order to prioritise CCGT over coal, $D_{H.CCGT}$ starts as the demand of CCGT with $f_{H.CCGT}$=100% and similarly, $D_{H.coal}$ starts as the demand of coal with $f_{H.coal}$=100%. If $L_e > D_{H.CCGT}$, $f_{H.CCGT}$=100%

$$f_{H.coal} = \frac{L_e - D_{H.CCGT}}{D_{H.coal}} \tag{6}$$

If $L_e < D_{H.CCGT}$ with $f_{H.CCGT}$=100%, then $f_{H.coal}$=0%:

$$f_{H.CCGT} = \frac{L_e}{D_{H.CCGT}} \tag{7}$$

The procedure is iterated for each flow interval. In cases where additional volumes are available at higher intervals, such as the Hands Off Flow, then this is repeated for the remaining capacity. The load factors are then multiplied by the capacity types in each portfolio in order to determine how much capacity would be operational at different flows.

6.2.7 Cost analysis of cooling systems

6.2.7.1 Plant capital and operational costs

Capital costs were taken from DECC Electricity Generation Costs (DECC, 2013a), which are projections for the levelised costs of electricity of a variety of generation technologies. Where applicable, central estimates were used. Where more than one technology for CCGT or coal was available, the mean fuel and carbon costs were assumed.

Table 6-7. Capital costs used in the analysis derived from DECC (2013a), using modelling work provided by Parsons Brinkerhoff.

£/kW$_e$ (First of a kind FAOK)	**CCGT+CCS** CCGT with post-combustion CCS	**Coal+CCS** Advanced super-critical with oxy combustion CCS
Pre-development	30	25
Construction	1300	2200
Total capital	1330	2225
Capital per £billion/GW$_e$	1.33	2.225

Fuel costs are also considered in order to estimate additional costs of hybrid cooling operation. These are similarly taken from the DECC Electricity Generation Costs (DECC, 2013a). The figures under *wet tower cooling* (Table 6-8) are the components termed *fuel*, *carbon* and *CCS* costs based on *"nth of a kind"* central levelised cost (LCOE) estimates with a 10% discount rate for projects starting in 2019 (DECC, 2013a

Table 10). Costs for future years were calculated from Table 12 (of (DECC, 2013a)) by applying similar proportions for fuel, carbon and CCS costs to the total levelised cost estimate. Hybrid cooling costs have been increased using the efficiency loss factors calculated in Table 6-9 in the next section.

Table 6-8. Fuel, carbon and CCS costs used to calculate the additional costs of hybrid-cooled generation.

	Wet tower cooling				**Hybrid cooling**			
£ / MWh	CCGT	Coal	CCGT+CCS	Coal+CCS	CCGT	Coal	CCGT+CCS	Coal+CCS
2013	£67.00	£44.00	£0.00	£0.00	£67.23	£44.88	£0.00	£0.00
2019	£73.00	£44.00	£74.75	£66.75	£73.25	£44.88	£76.66	£70.62
2025	£73.86	£42.66	£75.11	£65.69	£74.11	£43.51	£77.02	£69.50
2030	£75.58	£42.36	£74.75	£65.23	£75.83	£43.21	£76.66	£69.01

6.2.7.2 Cooling system capital and operational costs

Personal correspondence from a UK based sales representative for SPX Cooling technologies (Aqua Cooling Solutions) (Fowles, 2014), estimated that wet/dry hybrid tower cooling typically has capital costs 3-4 times traditional wet tower cooling systems. This agrees with estimates from the US (NETL, 2009b).

Cooling system costs are derived from the E.ON Environmental Impact Statement on cooling systems for the additional CCS capacity (E.ON UK, 2011). Using the figures derived from E.On below, the standard wet tower cooling system has been estimated at £5,000 per MW_{th} heat rejected.

For a hybrid cooling system, the E.On report estimates a cost of £4 million for 274 MW_{th} cooling duty attributable to the cooling of the CCS plant. Thus this cooling is achieved at capital costs of £1m / 68.5 MW_{th} heat rejection or £1.46m /100 MW_{th} (£14,600 per MW_{th}).

Due to higher approach temperatures, the use of tower and hybrid cooling will normally result in slight efficiency losses over once-through cooling. Using similar methods to those used in the EU IPPCD Reference for Best Available Techniques to Industrial Cooling Systems (EC JRC, 2001; pp. 69, 161–177), the additional fuel load required for wet/dry hybrid cooling over wet tower cooling is calculated. The total additional energy consumption, over direct once-through cooling is calculated in a table similar to Table 3.2 (EC JRC, 2001; p. 69) on a per unit heat rejected basis:

$$\boldsymbol{M_C} = \boldsymbol{M_T}(\boldsymbol{C_D} + \boldsymbol{k} \cdot \Delta\boldsymbol{T}) \tag{8}$$

where M_C is the additional energy consumption from the cooling system, C_D is the direct energy consumption of pumps and fans, k is the temperature factor (1.4 $kW_e/MW_{th}°C$) (EC JRC, 2001, Annex 2), ΔT is the process side temperature change, and M_T is the cooling load being served by the cooling system.

Table 6-9. Cooling system energy consumption and additional fuel inputs required, worked through for a 1000 MW_e power station at 70% load factor. Based on data the IPPCD (EC JRC, 2001) and fuel costs in the DECC Electricity Generation Costs (DECC, 2013a) in Table 6-8.

Capacity type (% HHV efficiency)	Cooling system	Cooling load MW_{th}	Direct energy consumption MW_e			Indirect energy consumption MW_e	Total energy consumption (Direct + indirect) MW_e	Fuel input required MW_{th}	% Fuel input increase (over once-through cooling)	% Difference (compared to wet tower equivalent)	Additional fuel, carbon, CCS cost £/yr (over wet tower equivalent)
CCGT (60%)	Wet tower	417	6.25	2.08	8.33	2.92	11.25	18.75	1.1%		-
CCGT (60%)	Wet/dry hybrid	417	5.00	5.00	10.00	4.67	14.67	24.44	1.5%	0.3%	£1,530,000
Coal (45%)	Wet tower	889	13.33	4.44	17.78	6.22	24.00	53.33	2.4%		
Coal (45%)	Wet/dry hybrid	889	10.67	10.67	21.33	9.96	31.29	69.53	3.1%	0.7%	£1,970,000
CCGT+CCS (45%)	Wet tower	1044	15.67	5.22	20.89	11.70	32.59	72.41	3.3%		
CCGT+CCS (45%)	Wet/dry hybrid	1044	12.53	12.53	25.07	11.70	36.76	81.70	3.7%	0.4%	£1,910,000
Coal+CCS (31%)	Wet tower	1968	29.52	9.84	39.35	22.04	61.39	198.04	6.1%		
Coal+CCS (31%)	Wet/dry hybrid	1968	23.61	23.61	47.23	22.04	69.26	223.43	6.9%	0.8%	£3,220,000

6.3 Analysis and results

6.3.1 Future hydrology simulations

Here we compare the hydrology against the current *minimum residual flow* (MRF) level. The MRF is the lowest level at which it is likely that abstraction restrictions would be imposed on currently unconstrained abstractors, such as power stations. Figure 6-8 shows an increasing trend with time of the minimum residual flow (MRF) being breached compared to the control profile. MRF breach means specifically that the daily-simulated discharge, before any abstractions, falls below the MRF threshold, considered in this study as 75% of the $Q_{99.9}$. Hence, it is an extreme low flow experienced far less than 0.1% of the time, and in this case is lower than the lowest ever observed flow (Q_{100}).

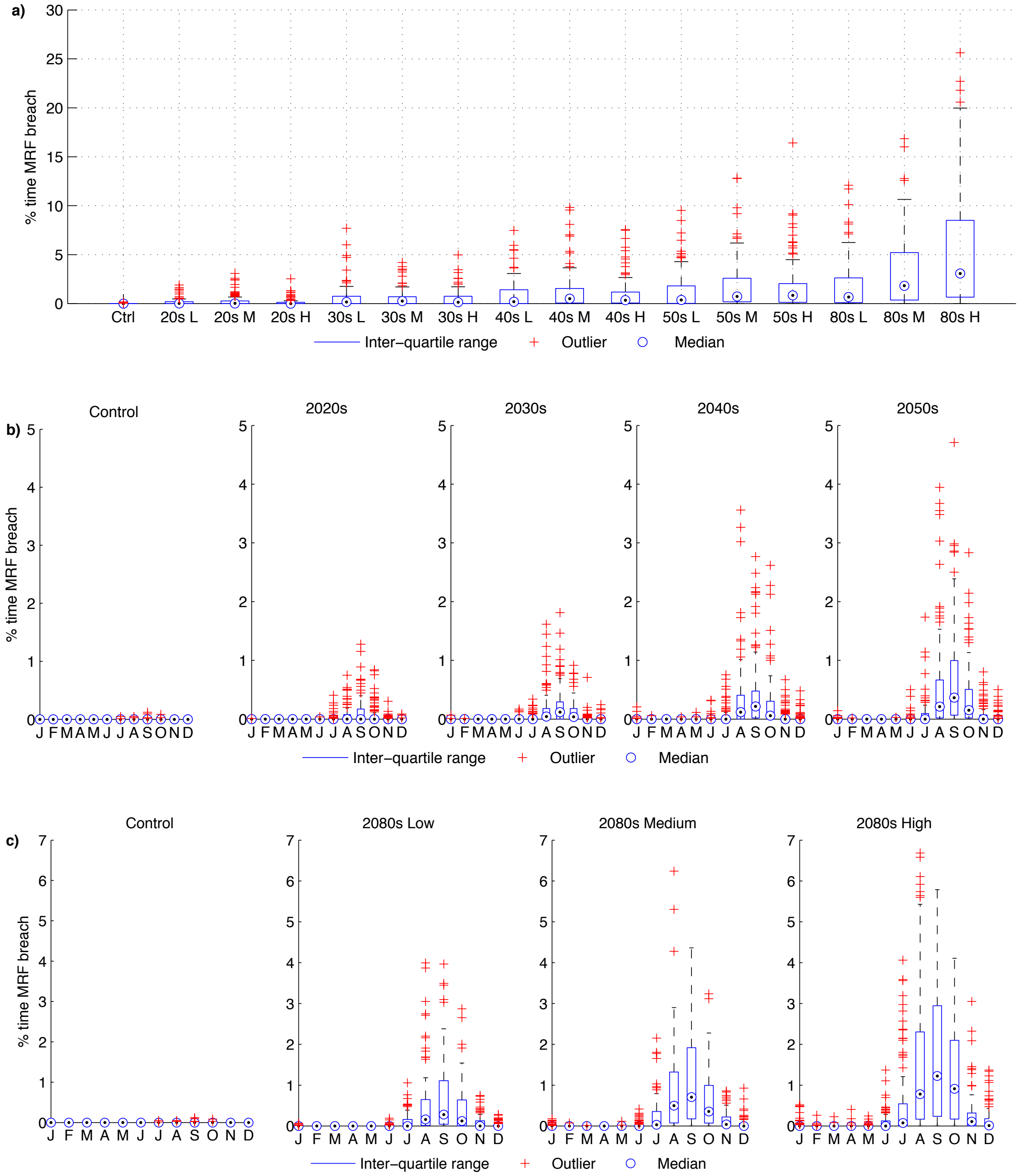


Figure 6-8. **a)** Each box-whisker plots the distribution of the total percentage of time that flows are below the MRF for the one hundred 28-year time series for each timeslice and emissions scenario. **b)** As with a), but on a monthly basis for the medium emissions scenario. Low and high emissions were excluded as the differences are not visually discernible. **c)** Similar to b, but comparing the three emissions scenarios in the 2080s against the Control profiles. Worth noting is that even the low emissions scenario in 2080s only delays effects of climate change, matched by the medium scenario in the 2050s. Whiskers extend to 1.5x the boundaries of interquartile range, with outliers beyond this value.

The *% time MRF breach* is the total number of days on which flows fell below the MRF as a proportion of the total number of days in the individual time series. The individual box-whisker plots for each timeslice and emissions scenario simulated present the distribution of total time (%) that flows are below the MRF across the 100 28-year time series. Such that in Figure 6-8 a) the median percentage of time that the MRF is breached over the course of a timeslice increases from 0% in the control simulations, to 0.5% and 1.8% in the 2040s and 2080s medium emissions scenarios. For the 2080s high emissions case, the interquartile range (central 50% of values) lies between 0.7% and 8.4% over the course of the timeslice.

The data in Figure 6-8 b) and c) evaluate how MRF breaching is distributed by month and is similarly presented for consideration over the timeslice. In b), up to the 2050s, the median amount of time that the MRF is reached increases from 0.0% in the control simulations to 0.2-0.4% in the 2050s for August and September medium emissions case. For July through November in the 2050s the interquartile ranges lie between 0.0-0.1% and 0.2-1.0% whilst in extreme cases the whiskers extend to over 2.4%. When taking a specific percentile, for example the median cases in Figure 6-8 b) and c), the sum of the median markers from January through December is equivalent to the median values presented in Figure 6-8 a). The interquartile ranges for September, between 0.0-1.1% and 0.2-2.9%, give a good indication to the amount of time the MRF will be breached over the period of the 2080s timeslice. In extreme cases (whiskers), the 2080s may experience 2.4-5.8% of September flows below the MRF. Whilst these are seemingly small numbers, they are unprecedented in the history of the flow record.

The incidence of low flows and MRF breaching is not characteristically attributed on an annual basis, given that the MRF value is set using a percentile of the historical flow record. Breaching the MRF indicates a extreme low flow likely to be sustained during drought conditions that may affect only a few of the drier years in a simulation of 28 years. Figure 6-9 a) summarizes the simulation data on an annual basis, by summing the number of days each year below the current MRF. The distribution of each bar is based on 2800 years of simulation for each timeslice and emissions scenario based on 100 vectors of change factors sampled from the full UKCP09 distribution. There are two results to report: firstly that the number of years with a flow below the MRF increases in frequency as shown by the decreasing black bars; secondly that the number of days breaching the MRF within a year also increases, shown by the different colours above the black bars. Whilst not a proxy for drought durations, Figure 6-8 b) and c) clearly indicate the increased likelihood of these days occurring in the months of July through November and hence the likelihood that these increasingly likely low flows occur consecutively in an extreme year.

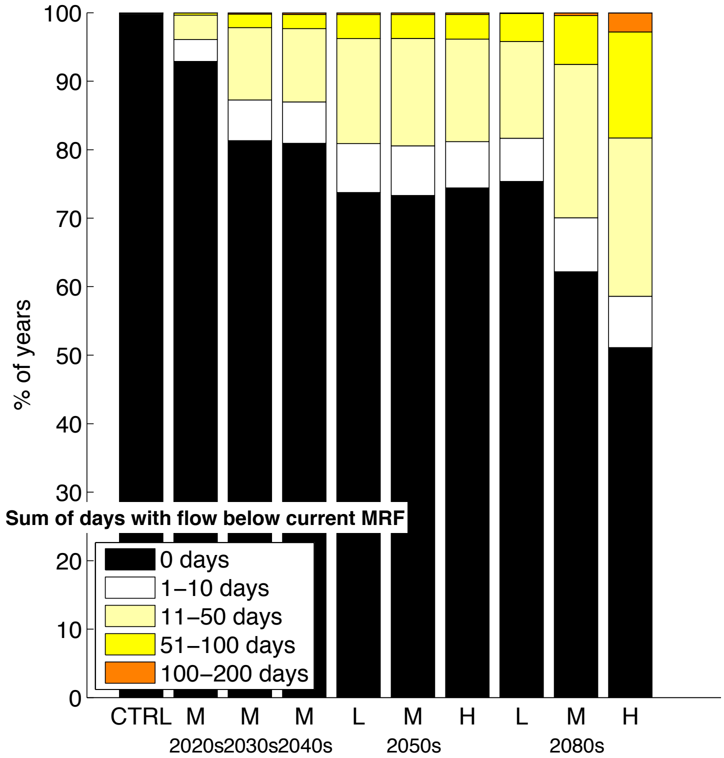


Figure 6-9. Number of years with flows below the MRF. In the control simulation, 100% of 2800 years had 0 days below the MRF. With climate change, the likelihood of a year with at least 1 day below the current MRF increases significantly to 24-49% by the 2080s, as do the number of days below the MRF in a particular year.

6.3.2 Water abstraction and consumption

Figure 6-10 below presents the five portfolios with 5-year time step resolution in terms of capacity on freshwater, generation, abstraction, consumption and freshwater abstraction intensity from 2010 to 2050, split by generation class and cooling type. All portfolios have the same capacity and generation and hence are directly comparable in this respect (section 6.2.4). Water use by 2040 is expected to increase given the increased capacity, however varies according to portfolio. Excluding the Gas Future portfolio, the cooling systems used across 5.87 GW_e of CCGT and 4.0 GW_e of coal significantly affects the water use, with a 200-249% increase by 2040, between All hybrid and BAU portfolios, assuming the reduced hybrid operation mode. Almost half of the changes however are attributable to the widespread use of CCS, which almost doubles the intensity of water use, shown in the bottom row of the figure. Coal capacity also has a water use intensity of just over double that of gas CCGT, so despite the fact that coal and CCGT capacity is roughly equal, the majority of water use is attributable to the coal. For this reason, the Gas Future portfolio, with no coal capacity from 2025, is the most water-efficient of all. CCGT is much more thermally efficient than coal capacity due to the configuration of gas turbines and steam turbines, which also offers more flexible operation. This can be useful for reactive capacity, peaking loads and possibly when water is unavailable, however the operation is uneconomic for sustained operation and not modelled in this analysis. The three lines in the bottom row also highlight the different water use intensity afforded by higher penetrations of hybrid cooling, operating between the normal, reduced and dry modes, described in section 6.2.4. The All hybrid portfolio offers a flexible range of water-use intensity (between 1.83-2.83 ML/GWh in 2050) compared to the BAU and Coal new hybrid portfolios.

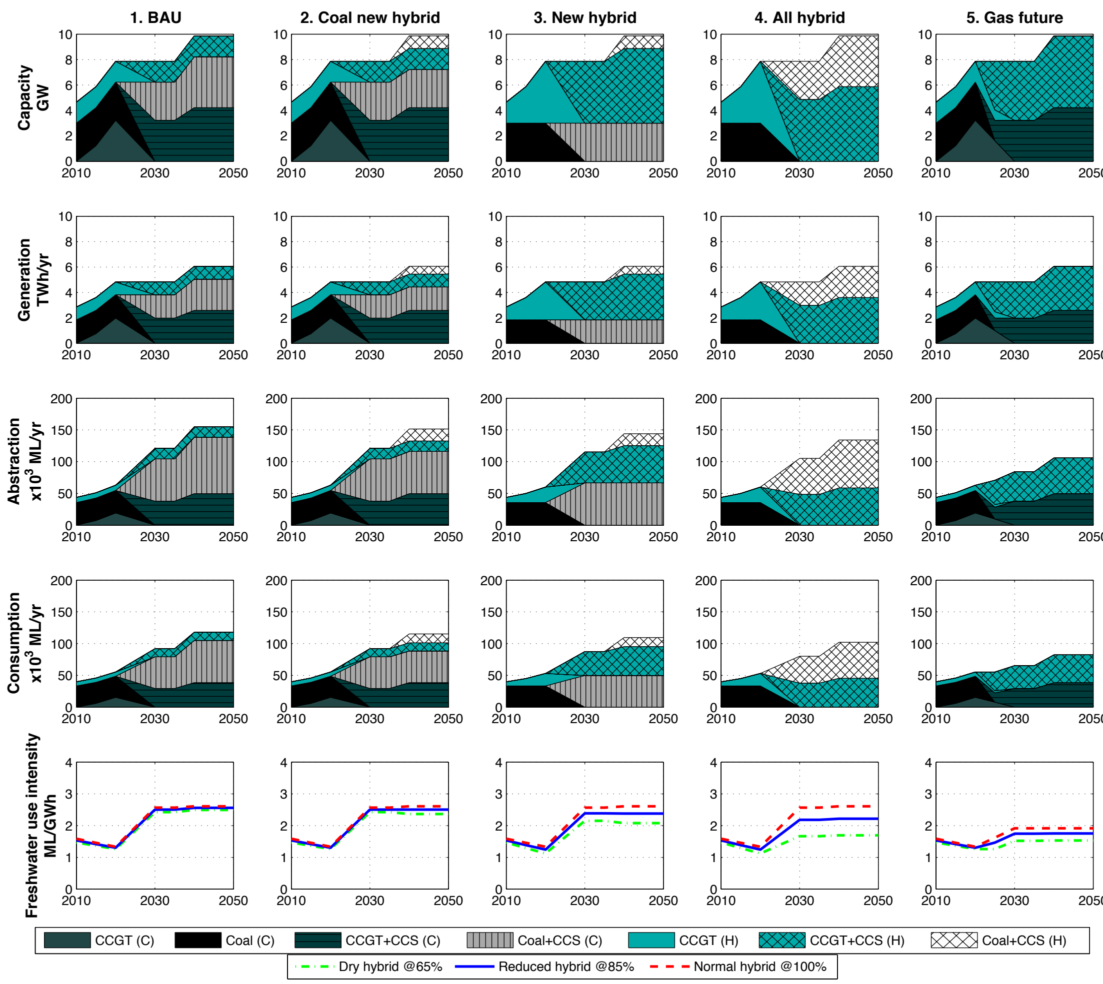


Figure 6-10 - Portfolios of Capacity, Generation, Abstraction, Consumption and Freshwater use intensity to 2050. All the portfolios have the same total capacity and annual generation, but different capacity and cooling types result in different levels of abstraction, consumption and water use intensity (ML/GWh). In the case above, hybrid cooling (H) is assumed to be 85% of closed-loop wet tower cooling (C) (*reduced* operation). Green shades are gas CCGT capacity, greyscale is coal. Plain fill is unabated capacity, single hatching is capacity with CCS and cross-hatching is capacity with CCS and hybrid cooling. Intra-annual variation is not shown, but presented in Figure 6-11 and Appendix C.3. Bottom panel shows the average water use intensity, according to different hybrid modes.

Seasonal abstraction and consumption was calculated at the 70% and 100% load factors for the three modes on hybrid cooling. The results presented below are for the 70% load factor abstraction at the 85% hybrid cooling mode. By 2050 the difference in intra-monthly abstractions are accentuated due to the growing demands, even though summer abstractions are proportionally more similar to the scale of winter abstractions (Figure 6-11). Results for 100% load factor and consumption are available in Appendix C.3.

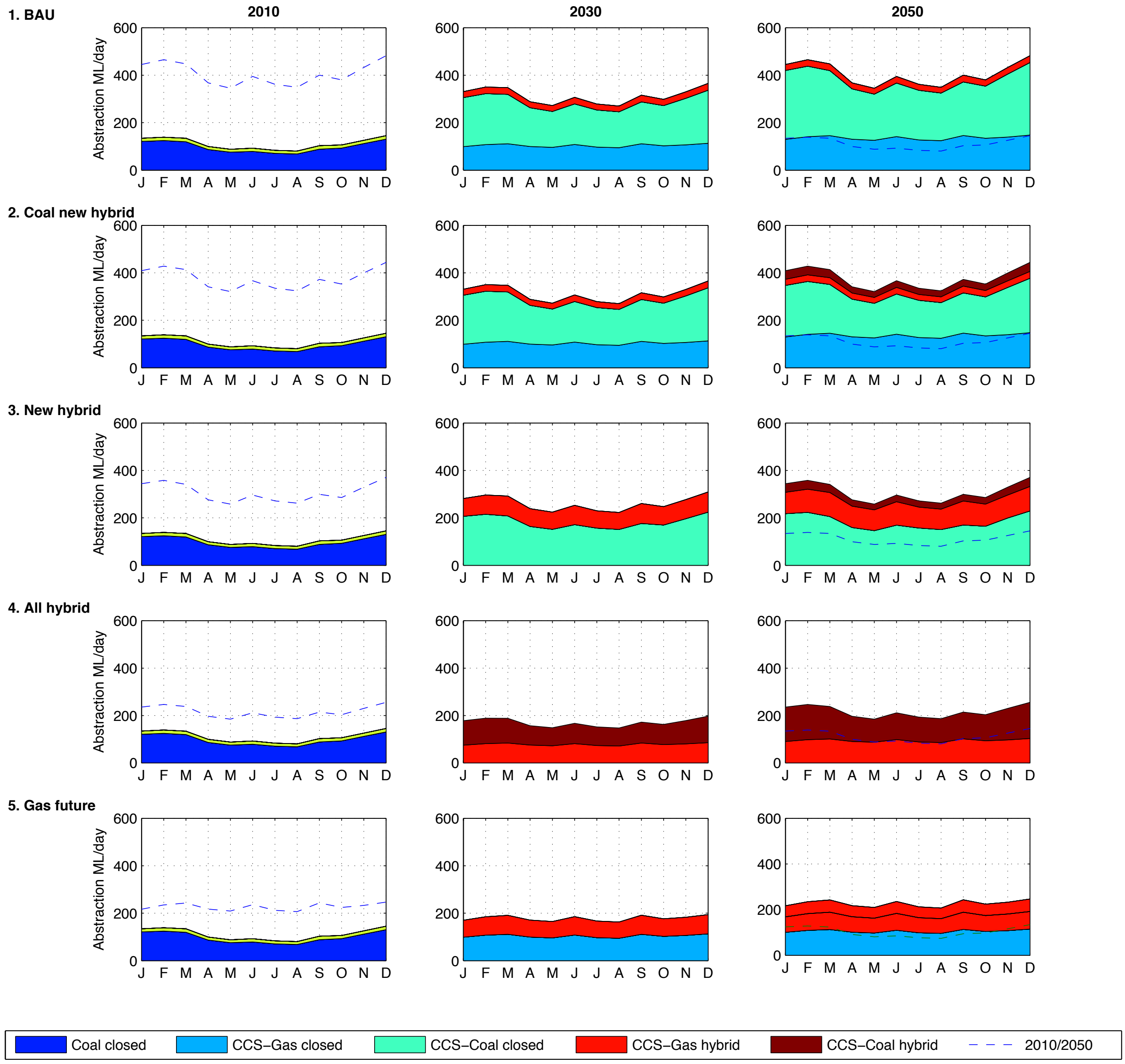


Figure 6-11. Abstraction at 70% load factor and reduced (85%) hybrid operation.

6.3.3 Water abstraction as a proportion of flows

Figure 6-12 presents the growing demands of the electricity sector against the diminishing water resource of the Trent at low flows. These results consider that as available resource decreases with climate change (section 6.3.1), the amount of water licensed for abstraction is also reduced by the regulator. The mean discharge (dark blue) at $Q_{99.9}$ under all emissions scenarios reduces significantly from 1455 ML/day in the

Control profile to approximately 550 ML/day in a 2050s climate. From the 2050s to the 2080s, not only does the mean $Q_{99.9}$ discharge reduce significantly, but the differences between the emissions scenarios is accentuated to a range of 260-510 ML/day. The licensable abstraction (green) at 15% of the Q_{91} is considerably lower reducing from 477 ML/day to 205-290 ML/day by the 2080s. The purple and red shaded ranges are the projected abstractions for peak and average loads, respectively, under dry operational conditions. They clearly show that unless the most water-efficient capacity and cooling configurations are used, normal operation may not be possible under low flows in the future. The overlap of the peak load abstractions and $Q_{99.9}$ flows shows that in some cases there would not even be enough water, let alone maintaining the minimum environmental flows. To what extent electricity generation would need to be ramped down is now investigated.

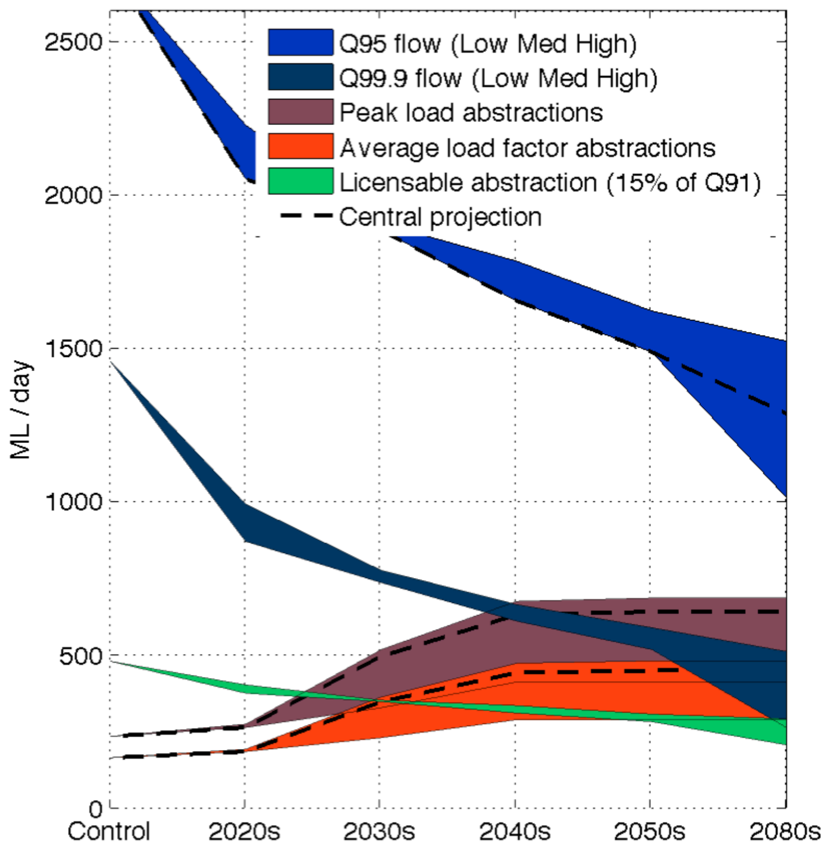


Figure 6-12. The range of $Q_{99.9}$ and Q_{95} flows for all three emissions scenarios (blue). Q_{91} is used to define the level of 'licensable abstraction' (green) for all sectors, in this case 15%. Behind are the ranges of potential electricity sector abstraction, sampled from the maxima and minima between June and October at each 5-year time step, assuming dry hybrid operation for the minimum values. Red is the range at assumed load factor of 70%, overlaying the wider range of all capacity operating at peak load (100%) (purple). Currently (as in Control), thermoelectric abstractions are well below the maximum value allowing abstraction from other sectors. Going forwards, not only will the amount of available water decrease, but abstractions will increase.

6.3.4 Capacity deficits under the different abstraction regimes

The results in Figure 6-13 compare two key dimensions of this study: the operation of the two abstraction regimes and the effects of hybrid cooling on the electricity portfolios. This is done by calculating the capacity availability using the equations in section 6.2.6. In Figure 6-13 a) and c) the abruptness of the HOF1 at Q_{91} is evident at future timesteps as more capacity is added and less water is available. Light green and white bars show the capacity only available above Q_{91}. The advantages of hybrid cooling, particularly on coal, are evident in portfolios 3 and 4 (New hybrid, All hybrid, respectively), which maintain consistently high levels of operational capacity through to the 2080s at a medium emissions scenario $Q_{99.9}$ flow. With 100% hybrid cooling systems, portfolio 4 performs best, bar the Gas Future portfolio (5), which maintains close to 70% of capacity even in the lowest flows.. Portfolios 1 and 2 (Business as usual and Coal new hybrid), with 1.65 and 2.65 GW_e of hybrid capacity, respectively, are increasingly vulnerable in climates from the 2030s, struggling to maintain more than 3.1GW_e online in a $Q_{99.9}$ low flow.

Taking the integral of these capacity curves results in significant differences in long-term capacity availability across the different portfolios but not between the abstraction regimes where the differences were on average only 0.4%. Comparing portfolios, availability in portfolios 3-5 drops from 100% as present to 95.2-96.6% in the 2080s whilst for portfolios 1 and 2 availability drops from 100% to 82.4-86.4%.

This analysis supports that close to 10 GW_e of capacity similar to portfolios 3-5, may be operated on the Trent with a high level of reliability, under the median flow duration curve in a medium emissions scenario. Only a lower level, of roughly 5-6 GW_e capacity could be operated in portfolios 1 and 2 in order to maintain similar levels of reliability. Depending on the way that graduated flows are apportioned, the analysis also shows that that there is little discernible difference between the two abstraction regimes in terms of availability when considering the whole FDC. However there are both advantages and disadvantages afforded to the sector when considered at different flow intervals between $Q_{99.9}$ and Q_{86}. Proactive water management and trading whilst approaching the Q_{95} level, could avoid the more drastic limitations beyond this point in the proposed regime. However, it is up to the sector to determine whether fixed or variable volumes of water for abstraction at low flows are best at meeting their operational needs. Similarly the environmental regulators may consider the benefits of the soft landing approach.

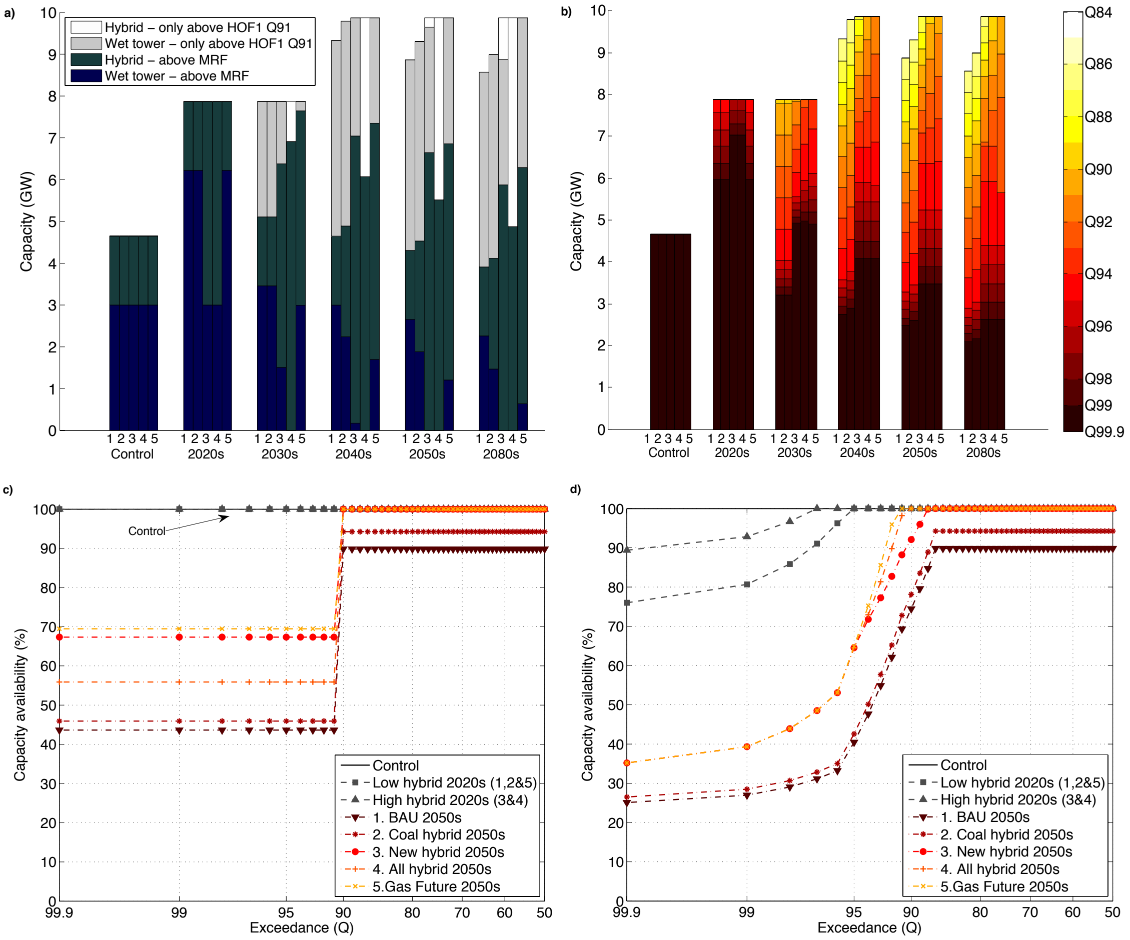


Figure 6-13. Shows the capacity available for operation when low flows occur for the electricity projections under, a) the current abstraction regime, and b) the proposed abstraction regimes with the soft landing. The dark shaded bars (blue, green and brown – a), b)) show the level of available capacity at $Q_{99.9}$ flows and above. Light shaded areas (grey, yellow and white) represent the capacity available only above the hands off flow at Q_{91} and above. The bottom panels compare c) the abrupt drop in capacity availability at Q_{91} HOF1 and below in the current regime, with d) gradual reductions between Q_{91} and $Q_{99.9}$, for the 2020s and 2050s.

By comparison, the proposed abstraction regime (b) and d)) affords gradual increases in capacity between $Q_{99.9}$ and Q_{91} as would be expected, however with the caveat that slightly lower levels are available between $Q_{99.9}$ to Q_{96}, particularly evident in plot d). Nonetheless, full capacity, for example in portfolios 3-5, is restored earlier than the existing HOF1 level, indicating an improvement.

6.3.5 Cost analysis of cooling systems

The cooling system design and specification has an effect on the price of the investment, capital costs and operational costs. Subsequently, measures such as levelised cost of electricity (LCOE) are also impacted.

Capital costs for a standard wet tower cooling system was estimated to be £500,000 per 100 MW_{th} cooling capacity, compared to the estimated £1.46 million per 100 MW_{th} for a hybrid wet/dry tower cooling system derived from an Environmental Impact Study for CCS cooling (E.ON UK, 2011). The level of MW_{th} cooling capacity required is inversely proportional to the efficiency of the power plant. At £1.33 billion and £2.23 billion capital costs per GW_e installed capacity for CCGT and coal with CCS, respective cooling system costs as a proportion of capital costs are estimated to be 0.4% for wet tower and 1.2-1.3% for wet/dry hybrid cooling systems (Table 6-11). The capital costs of hybrid cooling in the three best performing portfolios requires £63-144 million over the BAU portfolio (Table 6-10).

The cooling system is highly influential on operational costs through the performance they provide and additional fuel expenditure resulting from efficiency losses. The efficiency impacts of hybrid cooling range between £201-551 million in additional operational costs over a 40-year period for the three most reliable portfolios. However, compared to the total OpEx, this only represents an additional 0.2-0.4%.

Table 6-10. Capital and operational costs of capacity with hybrid cooling over the 40-year period, 2010-2050, compared to the BAU portfolio.

Capital costs 2010-2050	**Wet**	**Wet/dry hybrid**	**Total**	**Total additional cost over 40 years**	**Additional cost of hybrid**	**Annual additional cost of hybrid / GW_e capacity**
		£ millions			*%*	*£ millions*
BAU	68	34	102	-	-	-
Coal new hybrid	58	61	120	18	17.4%	0.0
New hybrid	30	142	171	69	68.2%	0.2
All hybrid	-	224	224	123	120.4%	0.3
Gas future	29	92	121	19	18.8%	0.0

Fuel & carbon costs 2010-2050	**Wet**	**Wet/dry hybrid**	**Total**	**Total additional cost over 40 years**	**Additional cost of hybrid**	**Annual additional cost of hybrid / GW_e capacity**
		£ millions			*%*	*£ millions*
BAU	113,963	33,277	147,240	-	-	-
Coal new hybrid	107,963	39,324	147,287	47	0.0%	0.1
New hybrid	47,123	100,408	147,531	291	0.2%	0.7
All hybrid	14,103	133,688	147,791	551	0.4%	1.4
Gas future [a]	72,982	81,639	154,621	201 (7,832)	0.2% (5.0%)	0.8 (18.7)

[a] Operational costs for the Gas future portfolio are higher also due to higher fuel cost of gas over coal. Hence figures present the additional hybrid cost, with the total additional costs in brackets.

Table 6-11. Capacity costs, cooling loads and cooling system costs.

					Wet tower		Wet/dry hybrid		
	Plant cost (1000 MW_e) £ millions	Assumed thermal efficiency	Heat input (MW_{th})	Heat rejection MW_{th}	£ millions (£5,000 per MW_{th})	% of construction	Hybrid cooling energy penalty	£ millions (£14,000 per MW_{th})	% of construction
CCGT	610	60%	1,667	417	2.083	0.3%	0.3%	6.083	1.0%
Coal	460	45%	2,222	889	4.444	1.0%	0.7%	12.978	2.8%
CCGT+ CCS	1,330	45%	2,222	1,044	5.222	0.4%	0.4%	15.249	1.2%
Coal+C CS	2,225	31%	3,226	1,968	9.839	0.4%	0.8%	28.729	1.3%

6.4 Discussion

6.4.1 Hydrological Modelling and climate change

Three climate change emissions scenarios were tested using the full distribution of UKCP09 change factor vectors whilst keeping assumptions about how abstractions are licensed and minimum residual flows, constant. We have employed a hydrological model specifically developed for low flows analysis of the flow duration curve and have run the model in a robust simulation to explore the range of future flows that may be experienced in the Trent in median and extreme circumstances. Even low emissions climate projections in the near term (2020s and 2030s) indicate substantial reductions in $Q_{99.9}$ flows and subsequent volumes of licensable abstractions (Figure 6-12), that would likely put even the current 4.65 GW_e generation capacity at greater risk. We have explored the climate model and emissions scenario uncertainty in order to present the full range of changes that may impact the electricity sector. The National Policy Statements require capacity developers and the consenting Secretary of State to consider as minimum,

> *"the emissions scenario that the Independent Committee of Climate Change suggests the world is most closely following… [with] these results… considered alongside relevant research which is based on the climate change projections."* (DECC, 2011f)

However, CCC was not actually consulted on this policy measure and in fact recommends taking into account

> *"a range of future climate risks, including across a range of plausible emissions scenarios where these have a bearing on risk."*. (Personal communication: (CCC, 2014)).

This work presents decision makers with a probabilistic methodology and results for the range of uncertainty between emissions scenarios, climate change impacts and the performance of different electricity portfolios.

An uncertainty worth mentioning is the slight underestimation of the lowest flows between Q_{97}- $Q_{99.9}$ for the Control simulation. In the context of this study, which considered the impact of hands-off flows from Q_{86}-$Q_{99.9}$, this was considered acceptable given the slight overestimation that occurs between Q_{86}-Q_{96}. The model used in this work was designed for national-scale analysis for replication across catchment. Hence, more accurate hydrological modelling on this catchment for this work is technically possible, however would be challenging to replicate accurately across a number of catchments.

6.4.2 Electricity Capacity Projections

Variations in fuel mix and cooling technology were tested whilst keeping other assumptions such as monthly generation distribution, total capacity, load factors and water use factors, constant across the portfolios. However, electricity generation in the UK is a complex market also dependent on other uncertain variables such as international fuel prices, availability of intermittent renewables, commercialisation of CCS, consumer demands and the weather. Our five portfolios of electricity capacity were developed to explore the sensitivities of capacity type and cooling technology, given the scenario of increasing regional capacity from 4.65 GW_e to 9.87 GW_e in the coming decades. This is a reasonable increase, given expected high regional population growth, the historical legacy of thermal power generation in the region and currently consented capacity of 3.22 GW_e. Whether any of this additional capacity is developed is open to debate, but the intention has been to determine to what extent water-dependent thermal generation capacity may be impacted by climate change and abstraction regulation set by the Environment Agency. The portfolios tested cover a range of water use and technologies such that most future 9.87 GW_e combinations of CCGT and coal with CCS, with wet tower and hybrid cooling, will likely fall within the bands presented. Whilst fossil fuel capacity typically has operational lifetimes of 30-40 years, the legacy of power stations in the region and expected installation of CCS infrastructure is likely to lock in development and upgrades, thus has warranted testing 2080s climate impacts.

6.4.3 Abstraction reform and regulatory implications

The reforms under consideration by the UK government propose a more dynamic system of limiting abstractions under hands off flows that is more responsive to the actual conditions of the river. In both cases of *Current System Plus* and Water *Shares*, there will be the soft landing whereby abstractors will reduce abstractions incrementally instead of abruptly curtailing abstractions when HOF levels are reached. We have modelled the proposals and as expected, the soft landing approach changes the availability of water to abstractors. Our work has shown that disruptions can be reduced considerably, in the majority of cases enabling 1-2 GW_e of extra capacity over the MRF level, depending on the flow (Figure 6-13).

One key assumption was that when facing water shortages, power plant operation would be prioritised according to water efficiency so as to maximise generation output. Regulatory measures to either maximise economic benefit when water is scarce or to minimise the risk to energy security could establish the prioritisation of water use within the sector. Similarly, given the limited resource, the Water Shares proposal could see more water-efficient operators temporarily purchasing the water allocations of less efficient ones given their increased profits per unit of water.

It is currently unclear how the ecological flow indicators and minimum residual flow will be determined in the future, but if the same principles are maintained, i.e. the minimum residual flow at 75% of the $Q_{99.9}$, it is to be assumed that the river environments will gradually change with climate change, with associated ecological impacts and adaptations. This study has projected the licensable abstraction volumes going forwards for each timeslice, however these are normally determined through observation of historical and recent flow records. However, we have demonstrated how it is important to consider potential future changes when setting ecological flow indicators that may impact on long-term investments.

6.4.4 Cost analysis

There is a little uncertainty around the capital costs of the cooling systems, however these are small compared to the operational costs, which have been derived from DECC figures and work with Parsons Brinckerhoff (2013). There is no doubt much greater uncertainty in the fossil fuel price projections for coal and natural gas, suggesting that the small incremental costs (0.2-0.4%) incurred from wet/dry hybrid cooling could be absorbed. The additional reliability benefits provided by hybrid cooling, as demonstrated in Figure 6-12 and Figure 6-13, have not been economically quantified but may exceed the costs.

6.5 Conclusions

This chapter has simulated a wide range of critical variables of the problem between electricity sector water use and hydrological variability. The hydrological variability of the Trent has been explored and modelled using the historical flow record and climate. The structural uncertainty of the hydrological model was also tested to increase confidence in the model used with future climates. The full range of climate change factors has been tested for three emissions scenarios extending to the end of the century (2080s). Finally, both the current and a Government-proposed abstraction regime has been simulated to determine the behaviour of five portfolios of generation capacity with different cooling systems. Finally, the different cooling system costs have also been tested such that these may be compared with the different levels of reliability.

Together, this work has demonstrated methods and results for comparing the effects of a wide range of uncertain variables on electricity production and water use. The first half of the work mainly compares the effects of emissions scenarios and timeslices on hydrological variability and licensed water availability. The second half has mainly compared performance of the five capacity portfolios and two abstraction regimes in the medium emissions climate scenario. Further extensive results are possible but these dimensions have been excluded for simplicity. In particular, simulation of the two abstraction regimes makes this a novel and timely contribution to the science, and serves to illustrate the importance of considering alternative policy and regulation in addressing global water-energy challenges. This work also matches or exceeds, in many aspects, the ranges of uncertainty covered in a number of prominent similar studies such as by Koch, Vögele *et al.* (Koch and Vögele, 2009, 2013; Koch *et al.*, 2012, 2014a, 2014b), van Vliet *et al.* (van Vliet *et al.*, 2012; van Vliet, Vögele and Rübbelke, 2013) and Stillwell *et al* (Stillwell, Clayton and Webber, 2011; Stillwell and Webber, 2013). All of this has been done to meet Objective d).Together, this work has demonstrated methods and results for comparing the effects of a wide range of uncertain variables on electricity production and water use. The first half of the work mainly compares the effects of emissions scenarios and timeslices on hydrological variability and licensed water availability. The second half has mainly compared performance of the five capacity portfolios and two abstraction regimes in the medium emissions climate scenario. Further extensive results are possible but these dimensions have been excluded for simplicity. In particular, simulation of the two abstraction regimes makes this a novel and timely contribution to the science, and serves to illustrate the importance of considering alternative policy and regulation in addressing global water-

energy challenges. This work also matches or exceeds, in many aspects, the ranges of uncertainty covered in a number of prominent similar studies such as by Koch, Vögele *et al.* (Koch and Vögele, 2009, 2013; Koch *et al.*, 2012, 2014a, 2014b), van Vliet *et al.* (2012; 2013) and Stillwell *et al.* (Stillwell, Clayton and Webber, 2011; Stillwell and Webber, 2013). All of this has been done to meet Objective d).

Disregarding climate change impacts on the Trent's hydrology, the projected cooling water abstractions will reach the licensable abstraction limit (for all sectors) between the 2030s-2040s. Similarly, even if there is no increase in electricity sector cooling water abstractions, in a 2050s climate this demand will be equivalent to the licensable abstraction volume for all sectors.

If water use by the sector is unaddressed, under our growth projections and a changing climate the water deficit at a Q_{95} low flow on the Trent in the 2050s is in the range of 52-56% for the BAU portfolio. Hence, further water-intensive electricity capacity development on the freshwater River Trent could present risks at low flows to both the energy sector as well as other water users, significantly compounded by the impacts of climate change on the hydrology of the River Trent.

Our analysis has shown that these risks may be cost-effectively reduced, if:

1. water allocation is prioritised on an efficiency basis when limited quantities are available (either through market, cooperative or regulatory mechanisms), such that a less efficient water user would be required to reduce abstraction before a more efficient user;
2. higher proportions of wet/dry hybrid tower cooling is used at new power stations in order to maximize water-efficient operation and increase flexibility under low flows and drought conditions.

The simulation of different abstraction regimes has found no significant difference when capacity availability is summed across the whole flow profile, but appraisal at different flow intervals does have an impact. In the proposed system, less water and hence capacity is available at very low flows whilst more is available at low flows. These differences in capacity availability can now be scrutinized. Operators may identify preferences between the two depending on their expected operation at different flow intervals and in different months. Advantages of either regime in this respect may yet be identified through extreme value analysis of individual time series.

This work has also shown the importance of considering the cooling requirements of CCS cluster developments in a more integrated fashion. Given that the economic case for CCS is based on facilities sharing pipeline infrastructure, we recommend that cooling water requirements are evaluated in a similar way so as to ensure sustainability and reliability of water resources.

Chapter 7. WATER POLICY CHALLENGES AND ADAPTATION FOR A CCS FUTURE

7.1 Introduction

The research in this thesis has highlighted, in particular, concerns regarding the water intensity and clustering of fossil-fuelled generation with carbon capture and storage. The pathways which result in very low levels of freshwater use and intensity are unlikely to require further policy attention in this specific area and can probably be safely accommodated within the existing wider arrangements. CCS, however, brings the prospect of almost double the water intensity and volumes of current water abstractions. How well does this fit in with the existing licensing arrangements?

Innovative adaptations to mitigate this have also been proposed, such as hybrid cooling, combined heat and power (CHP) and use of wastewater. Whilst not necessarily new technologies, does the current policy and regulation landscape facilitate the implementation of such extra-ordinary solutions? Is there a way through which we can develop CCS clusters and improve water-efficiency without additional costs?

This chapter starts with a brief recap of the current cross-sector regulatory landscape around cooling water abstractions, including a key implication for water abstraction regulation brought about by carbon capture and storage. First, we consider the current process of development consent and abstraction licensing. This is followed by a detailed discussion on the importance of CCS clustering, which has been previously raised as a concern. Considering the importance of clustering, we then present alternative cooling measures that could be used at CCS cluster to reduce freshwater use and dependency.

The chapter ends with a critical discussion of the wider challenges surrounding CCS from UK and global perspectives.

7.2 The current cross-sectoral regulatory environment

The first aspect to acknowledge is that the topic of cooling water abstraction constitutes only one very small component of many responsibilities covered by the governing institutions and interested parties. This is true for: ministerial departments, namely DECC and Defra; the directly responsible regulators, primarily Ofgem and the Environment Agency; as well as the *Major Power Producers* (MPP) themselves and their respective power stations. Combined with a number of other stakeholders with a variety of other interests, this results in a pressurised multi-stakeholder environment (Figure 7-1). Besides this, we must consider that as publicly traded companies, they are also obliged to maximise shareholder value (shareholder primacy) under the Companies Act 2006.

7.2.1 Current regulatory context in England

In the UK, policy and regulation is set by central Government and ministerial departments, and regulated and managed via *independent* regulators, agencies and non-departmental government bodies, all of whom usually receive government funding. In the following sections, for the perspective of the environmental regulator, we will focus on England and the EA given that almost all power stations on freshwater are in England.

The Department for Environment, Food and Rural Affairs (Defra) is the overarching ministry responsible for water in England. Government sets policy via the Cabinet Office, HM Treasury and through ministerial departments such as Defra. Water and the wider environment are regulated by the Environment Agency in lines with the policy set by Government. Specific aspects of the water industry are also regulated by Ofwat and the Drinking Water Inspectorate.

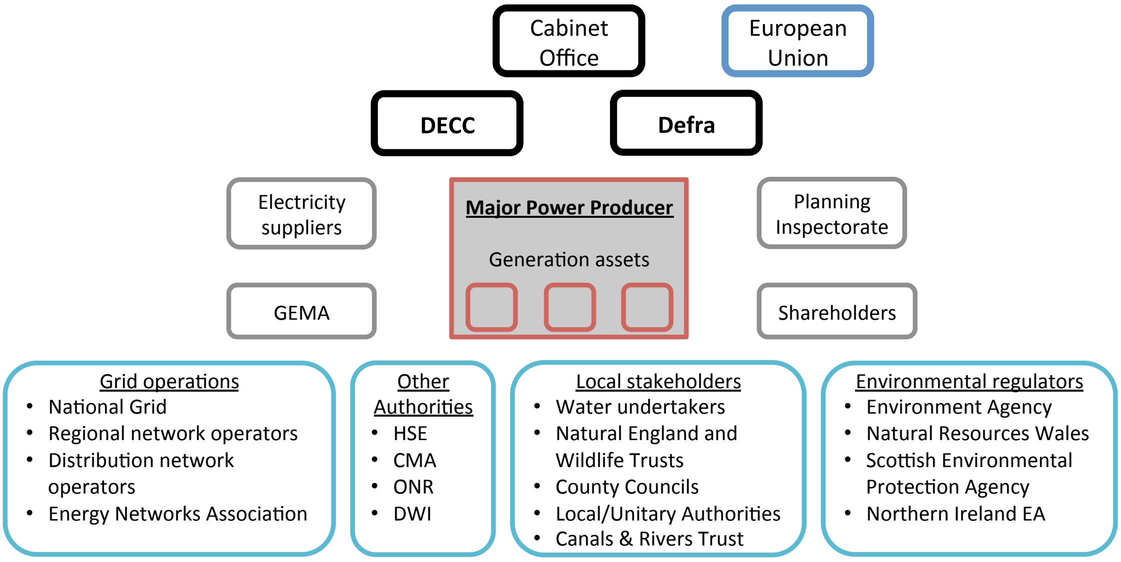


Figure 7-1. Stakeholder environment.

The Environment Agency, founded in 1996, has an aim to *"work to create better places for people and wildlife, and support sustainable development"*. This broad aim encompasses a wide range of activities including: water quality and water resources; conservation and ecology; air quality, waste and permitting; and strategic overview of flooding and coastal erosion.

By comparison, the energy sector is overseen by the Department of Energy and Climate Change (DECC) with regulatory duties for:

- the Gas and Electricity Markets Authority (GEMA) run by Ofgem on a day-to-day basis responsible primarily for economic duties including competition, pricing and licensing;
- the EA (in England) to cover environmental duties and permitting;
- as well as the Competition and Markets Authority (CMA), Health and Safety Executive (HSE) and the Office for Nuclear Regulation (ONR).

Notably, GEMA's *"principal objective is to protect the interests of existing and future consumers"* in the markets it covers, explicitly stating that *"consumer interests are taken as whole, including their interests in the reduction of greenhouse gases in the security of the supply of gas and electricity to them"* (Ofgem, 2013).

Ofgem does not have in interest in water issues, but may take one if it threatens security of supply. However, it is likely that blame would be deflected to the regulator of water abstraction, normally the Environment Agency. As steward of water resources, the onus would be on the EA to demonstrate it had managed resources responsibly, likely receiving pressure not only from the power plant, but also Ofgem and the Minister for Energy.

For both regulators, cooling water abstractions fall into subsets of much wider activities that have to be managed and balanced across interests. Water abstractions are made by many sectors, of which electricity is just one. Abstractions form only part of the management of water quality and resources, which also contribute to wider duties and activities for conservation and ecology. The electricity sector also intersects with other activities of the regulator unrelated to water abstraction, such as in managing waste, emissions and permitting of industrial facilities.

Similarly, cooling water use is an environmental aspect that does not even feature in Ofgem's environmental programmes, such as feed-in tariffs, the Renewables Obligations and Renewable Heat Incentives (Ofgem, 2015). Ofgem also manages other concerns such as security of supply and pricing controls, both of which are extensive, complex and ever-changing. Cooling water may affect security of supply and pricing, however, it scarcely appears to be on Ofgem's radar.

The environmental regulator's difficulties of implementing environmental policy in a landscape dominated by political and economic decision-making are pertinently characterised by Young (2001), summarised in the rest of this passage. As commented by Lord Crickhowell, first chairman of the National Rivers Authority, predecessor to the EA, the role is not just as a regulator but as manager of a major resource (Carter and Lowe, 1995). An environmental regulator is tasked with a role that cuts across sectors, ministerial departments and *a wide-ranging network of interests*, unlike more traditional economic regulators of single economic sectors such as telecoms, electricity and gas. This can be challenging when concerned with what other regulators may consider are secondary duties or *externalities*, such as environmental degradation and air pollution. Externalities may be hard to resolve between political decisions and economic costs, although methods for more comprehensive social and environmental accounting do now exist and are used. Furthermore, the existence of separate environmental and economic regulators, can result in subjective interpretation of Government policy and conflicting objectives. Companies in regulated industries may use this circumstance, in addition to private industry information (information asymmetry), to play off regulators against each other. This can amount to cooperation or other strategies between the regulators, covered by the field of game theory, such as in Baron (1986) and Madani (2010).

7.2.2 Implementation of EU legislation

Above the policy set by central Government are the influences that come from the European Commission. Much of the environmental and health protection afforded to the UK's citizens derives from EU legislation. Central Government and departments are responsible for the implementation of European Directives in a procedure known as transposition. In brief, HM Government's approach (Guiding Principles) (HM Government, 2013b) is to:

- implement policy and legal obligations without putting UK business at a competitive disadvantage with European counterparts;
- use alternatives to regulation wherever possible;
- not go beyond *"(save exceptional circumstances)"* the minimum requirements of the measure.

There are numerous EU Directives with impacts on the design of industrial cooling systems for power stations. Central to cooling water systems are the Water Framework Directive (2000/60/EC, WFD) and the Integrated Pollution Prevention and Control Directive (2008/1/EC, IPPCD), which together cover emissions to land, air and water and hence all types of cooling systems.

The IPPCD stipulates the use of BAT (Best Available Techniques), which may be determined by Member States using various BAT Reference Documents (BREFs), some of which are sector-specific. These are summarised well by Turnpenny *et al.* (2012; pp. 428–429 Table 20.2). The IPPCD BREFs take a *"horizontal approach"* aiming to address *"all relevant environmental aspects and the way that they are interrelated"*, the balancing of which *"requires expert judgement"* (EC JRC, 2001). This includes balancing operational considerations (costs, risks, design), emissions to air (GHGs, noise, pollutants, plumes), emissions to water (thermal, chemical, physical), resource consumption (water, air, energy, chemicals, waste arising) and decommission (Table 7-1).

Table 7-1. Comparison of cooling systems, with the key concerned stakeholders for each particular issue noted in the left column. MPP: Major Power Producer.

Main Stakeholders		Unit	Once-through	Closed-loop tower	Hybrid	Dry
	Water aspects					
Environment Agency	Volume	ML/GWh	~100-170	0.75-2.2	0.4-1.7	~0
Environment Agency	Consumption	ML/GWh	1-1.5	0.7-2	0.5-1.7	~0
Environment Agency	Thermal impacts		High	Low	Low	None
Environment Agency	Chemicals usage		Medium	Medium	Medium	None
	Cost and carbon emissions					
DECC, Ofgem, MPP	CapEx	£k/MW_{Th}	5	8-10	14	15
DECC, Ofgem, MPP	OpEx (Fuel use, carbon costs)	£ / MW_e	-	+1 to +3%	+2 to +5%	~5% to ~20%
DECC, Ofgem, MPP	Carbon emissions	tCO_2 / MWh			*Same as for OpEx*	
	Extreme scenario performance					
DECC, Ofgem, MPP	High air temperatures		None	Slight efficiency reduction	Small efficiency reduction	Cooling significantly impacted
DECC, Ofgem, MPP	High water temperatures		Cooling significantly impacted	Slight efficiency reduction	Small efficiency reduction	None
DECC, Ofgem, MPP	Low flows		Cooling significantly impacted	Possible	Possible	None
	Site considerations					
MPP, Public	Visual impact		Minimal	Cooling towers with plume	Cooling towers, plume abatement possible	Cooling towers or condensers, no plume
MPP, Public	Space requirements		Low	Medium	Medium	High

The WFD is the common framework for managing water bodies across Europe by balancing the needs of societal development and protection of the natural environment. These are managed primarily via River Basin Management Plans for River Basin Districts (RBD) (the same scale used in Chapter 5). Within RBDs, water bodies are given objectives in order to achieve standards relating to biological, ecological, flow and chemical quality measures. These define their current *chemical* and *ecological status*, defined between *high*, *good*, *moderate*, *poor* and *bad*. Waterbody status is the lesser of the two, and the WFD stipulates that all water bodies must reach at least *Good Status* by 2015 (Acreman and Ferguson, 2010).

In England, assessment of water bodies is managed by the Environment Agency, also responsible for the licensing of water resources for abstraction. This is assessed via the Catchment Abstractions Management Strategy (CAMS) which uses Environmental Flow Indicators (EFIs) to determines the *environmental flows* of water available for sustainable abstraction and form the basis of abstraction licensing and regulation

(Acreman and Ferguson, 2010; Environment Agency, 2013a). Licences for abstraction are issued according to availability at defined flow intervals that determine the reliability of a specified volume water (see *Abstraction Sensitivity Bands* as discussed in Chapters 5 and 6 and Acreman and Ferguson (Acreman and Ferguson, 2010)(Acreman and Ferguson, 2010)).

The way that water will be licenced and allocated is set to change in the Abstraction Reform. The intention is to establish a more dynamic and flexible regime to take into account changing flow regimes and more efficient allocation, as already extensively described in Chapters 1 and 6. This will likely move the regime towards market-based and economically- and water-efficient mechanisms to achieve WFD objectives. One aspect seemingly not yet comprehensively addressed by Government policy and of direct relevance to this thesis is the concept of *carbon capture readiness* (CCR) and the future demands of CCS plants.

7.2.3 Carbon capture readiness and future abstraction licensing

Following Article 33 of the EU Directive on the Geological Storage of Carbon Dioxide (2009/31/EC), new fossil fuel power stations larger than 300 MW_e have been required to demonstrate *carbon capture readiness* (CCR) in their planning applications prior to receiving consent. This is in order to allow power stations to be retrofit with a carbon capture plant (CCP) when CCS becomes commercially available. In the UK, all commercial fossil fuel generating stations must demonstrate CCR on at least 300 MW_e of the proposed generation capacity, and all the capacity if the plant is less than 300 MW_e. The feasibility of retrofit is to be reported and reviewed every two years between DECC and the operator (DECC, 2009a). When, retrofit becomes technically and economically possible, power plant operators will need to either retrofit or face closure. In order to retrofit the operator will have to make a new planning application and acquire relevant permits for the CCP. This includes additional water abstraction licences required for the CCP. It is not yet clear, however, whether there have been any specific reviews on how this new legislation impacts on abstraction licensing.

In the UK, for *Nationally Significant Infrastructure Projects* (NSIPs), planning is the first stage that requires a Development Consent Order (DCO) from the relevant Secretary of State, following application and scrutiny via the Planning Inspectorate and the Examining Authority (ExA) (The Planning Inspectorate, 2014). After DCO, the applicant must apply for a number of relevant permits and consents, relating to water abstractions and discharges, waste controls, emissions to air, health and safety compliance and CO_2 transport and storage (see Turnpenny *et al.* (2012) for more details).

During the planning stage, statutory *consultees*, such as the Environment Agency, may comment via a *Representation* and in doing so indicate whether the planning application is likely to receive the necessary consents, based on the information that has been provided. The EA expects a *parallel tracking* approach to planning and permitting, which means that the applicant involves them in planning process (Environment Agency, 2012b). In this way, the EA can make recommendations and indicate unsatisfactory components, at the earliest opportunity.

In the case of Water Abstraction Licences, the EA normally expects to receive a preliminary enquiry (form WR48). Guidance by DECC (2009a) lays out in detail the CCR technical, spatial, environmental and economic feasibility requirements for CCP consent, to be assessed by the Planning Inspectorate. The guidance includes consideration of the additional cooling systems required. Nonetheless, at the time of retrofitting the CCP, the applicant must submit another application to the Planning Inspectorate for the DCO, complete with Environmental Statements.

Whilst there have been detailed discussions and reviews regarding space requirements, for example Florin and Fennell (no date), how the EA considers licensing of the future water demands of the CCP does not appear to have been reviewed. The interim period between development of the power plant and the CCP, brings the risk that additional water may not be available for abstraction come the time for planning and permitting of the CCP. This may be due to a number of reasons, for example:

- additional abstractors obtaining the remaining licensable water resource, including other power stations;
- hydrological changes in the catchment due to climate change;
- changes to the EA's methodology for assessing licensable resource in order to meet WFD requirements for GES;
- changes in the WFD target ecological status for that catchment/waterbody.

Conversely, this may be considered as an adaptive policy approach, that allows the Government to establish or change the rules with more information, if and when the time for CCS comes. When this situation was queried with the EA and the Planning

Inspectorate, some proposals were given, however, the impression is that there is no defined approach for dealing specifically with the CCR abstraction issue, besides the established water abstraction licensing regime. Some excerpts of text from email correspondence are stated below (Appendix D.1).

One option is to license abstraction allocations that include the expected additional water demand for the CCP, acknowledging that this portion of the allocation would be unused for a number of years. This would have high certainty for the power plant, however, the premise of licensing based on possible future business expansion, is objectionable as it may prevent other users from using available water.

> *"I'm not sure we would agree to a strategy like that."* (Environment Agency employee #2 Email, 2015)

One potential, but not ideal, safeguard to allow this possibility is through the use of *"self destruct"* clauses that would allow the EA to reclaim unused portions of licences.

Another option, as currently in place, is to wait until the CCP developments are going through planning to assess water availability. This is the fairest approach, yet runs the risk that the catchment has no water available at time of permit application. The developer would have to buy a water allocation from other users, adopt other measures (such as dry cooling[3]), or reduce electricity production so as not to be over-abstracting.

> *"I'm not sure a power provider would build a new power station if there was uncertainty with regard to getting the water, about an important [issue] such as carbon capture especially if this is something that they would have to build."* (Environment Agency employee #2 Email, 2015)

This is a logical point, however, does not explain the Government's lack of attention to the issue. DECC were obviously concerned that power plants could be foolish enough not to leave sufficient land available for the CCP. Conversely, cooling water availability, which is time-variable and in increasingly short supply, is not of concern? A final pertinent point made by the employee is the need for

> *"… a system which is operationally manageable from a regulatory [and] enforcement position and doesn't create licensing problems for the future."* (Environment Agency employee #2 Email, 2015)

This comment was made with more direct reference to the first option made above, and was chosen in the case of Hatfield power station. However, what is clear is that, as of

[3] With little water availability, dry cooling seems like an obvious choice. Whilst probably feasible with CCGT plants, the already very low thermal efficiency (~28-33%) of coal+CCS plants will make this an extremely costly and unattractive option.

yet, and this may yet be addressed by the end of the Abstraction Reform, decisions regarding the water licensing of yet-to-be-built CCPs are being made on an *ad-hoc* basis. Such an approach may lead to future decisions being made on a precedential basis (in belief that in the first instance the correct action was taken), as opposed to having a defined policy with respect to the issue.

With the prospect of large amounts of CCR capacity being developed in the next few years, if unresolved and unattended to, this may indeed lead to said *"licensing problems for the future"*. Conversely, if resolved, this would not only make licensing decisions more consistent and easier to make, but would also increase the all-important certainty required for these costly CCS investments.

7.3 The importance of clustering

Concerns have been raised through this thesis about the aspect of CCS clustering and the concentration of high water demands. This has not been done to argue against the need for CCS clustering, merely to raise the cooling water issues that occur when CCS is clustered. Key issues and a detailed rationale for clustering are described in the sections that follow.

7.3.1 CCS will increase water demands and intensity

As described extensively already, the use of a carbon capture plant at a thermal power station is expected to increase cooling demands in the order of 70-90% (Macknick *et al.*, 2012a; Parsons Brinckerhoff, 2012). If water is widely available, the intensity of operations is inconsequential and should be used to maximise economic benefits. However, water intensity is more critical when supplies are limited. This could limit output and cause additional costs in acquiring reserve supplies, either via import or through licence trading. An increase in water intensity also goes against the historical trend of improvements in water efficiency of the electricity sector. But does this mean that CCS power plants should be spatially distributed to avoid the water risks of clustering?

7.3.2 The case for CCS clusters

As already mentioned, various reports (E.ON UK, 2009; The Crown Estate, Carbon Capture & Storage Association and DECC, 2013; The Global CCS Institute, 2013) and strategies (DECC, 2012a) recommend the clustering of CCS facilities as a key measure to reducing infrastructure costs. This is envisaged both in line with the current locations of high point-source emissions in the UK, as well as the least-cost storage options in the North Sea and Irish Sea (Figure 7-2).

The case for the clustering of CCS facilities is driven by a few interconnected issues:

- the legacy of power generation sites, industry and water availability;
- proximity to the coast and CO_2 storage sites; and,
- subsequently the economic advantages of clustering infrastructure.

Potential clusters in the UK were identified in Government's CCS Roadmap, in Scotland, Yorkshire and Humber, Teeside and near the east Irish Sea (the North West) given that concentrations of power generation and industry are also close to storage locations offshore (DECC, 2012a). Amongst other recommendations, the CCS Cost Reduction Task Force concludes that costs can be reduced through investment in large CO_2 clusters and in large shared pipelines (The Crown Estate, Carbon Capture & Storage Association and DECC, 2013). From demonstration to more wide scale development, it is estimated that transport and storage costs can be reduced by two-thirds when shared pipelines have high utilisation and clusters are supplying CO_2 to clusters of storage sites. That is, for example, from transport and storage costs of £46/MWh in 2013 to £8/MWh in 2030. To date the identification of clusters has led to more coordinated work such as for the Thames estuary (E.ON UK, 2009), the Don Valley (Powerfuel Power Ltd, 2008) and the Tees Valley (ONE North East and Amec, 2010) projects.

The size of these clusters is important in determining what potential impacts may arise. The E.ON Thames estuary cluster study identified 10 major power generation sites with total annual emissions potential of 27.9 $MtCO_2$/year, whilst 67% of the North East's emissions could be captured from just six sites in the Tees valley. When evaluating the available water resources, the EA will need to consider carefully the aforementioned increased water-use intensity of CCS facilities, dependent on the proportion of emissions captured from the site. In the first stages of CCS development only 25-50% of emissions will be captured. However, this proportion will increase in the future, for both new and existing facilities. Hence, power plant operators may come across difficulties in obtaining further abstraction licences when seeking to expand the CCS facilities at a plant.

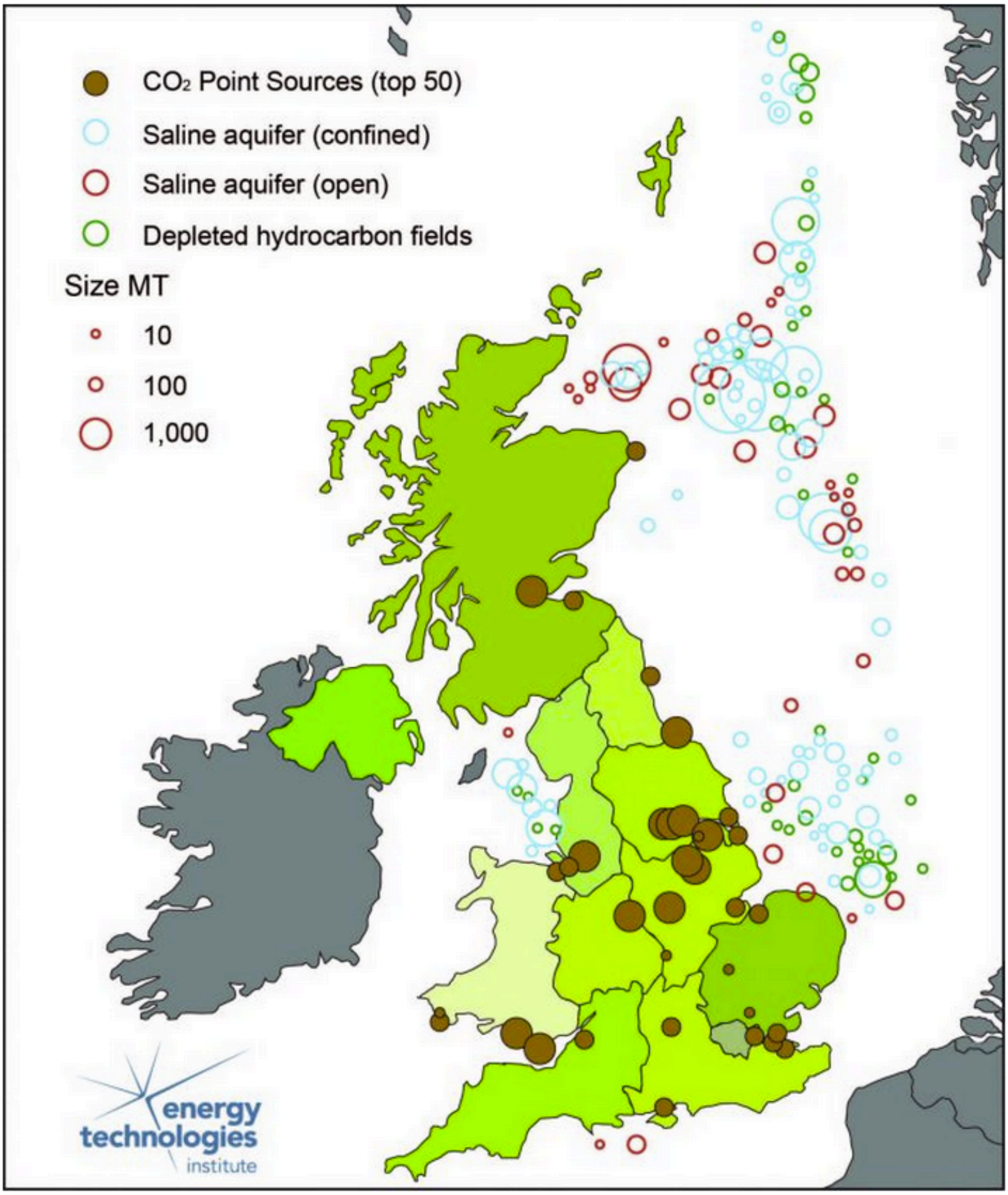


Figure 7-2. Map of the UK's largest industrial point sources of CO_2 and the potential offshore storage sites. Source: (Energy Technologies Institute, 2014).

The potential of CCS clusters comes with promise and dangers as establishment will lead to a locational lock-in. Further developments will be attracted to clusters given the relatively low costs of connecting to already established networks of CO_2 transport infrastructure. This will be attractive to small- and medium-sized industry. The case for redevelopment of power station sites into the second half of the century will also be stronger than ever given the sunk costs.

7.3.3 Synergy and interdependency

Furthermore, clustering of industrial facilities also presents the opportunity to move towards well functioning industrial ecosystems. Waste heat and wastewater can be reused by power stations and other facilities whilst the business case for auxiliary services becomes stronger with more customers. Demineralised and desalinated water services for large industrial clusters would be more cost-competitive if serving several industrial customers and might be in a position to use waste heat from the cluster to reduce energy costs. If so, spatially-concentrated dependency on water resources could be reduced (see Ehrenfeld and Gertler (1997) for a good example involving water).

However, such deliberate clustering increases interdependencies, *lock-in* and possibly risk of failure. Facilities are not only *physically* interdependent for the supply or removal of feedstock/waste products, but they are also *geographically* interdependent and vulnerable to hazards such as flooding (emphasis in reference to the dimensions of infrastructure interdependencies defined by Rinaldi, Peerenboom and Kelly (2001)). It could probably be argued, either way, that such integrated systems are both more and less adaptive to adverse situations that require a policy change.

Nonetheless, with such substantial cost reductions expected from clustering alongside other potential benefits for industry, it seems unlikely that water-risks will outweigh the financial benefits of clustering. This puts the imperative on ensuring sufficient and sustainable cooling water resources.

7.4 Alternative cooling sources for the energy sector

Considerable focus of previous sections and chapters considered only the more conventional approaches to power station cooling. These were via use of different cooling technologies and the more conventional water sources. More innovative alternatives do exist, however. The use of CHP, wastewater and water storage are discussed in more detail. They may be more costly and present less conventional engineering challenges, but are all nonetheless technically feasible and may be well suited to CCS clusters. Their adaptive capacity is also an important consideration.

7.4.1 Reduce cooling demand through combined heat and power

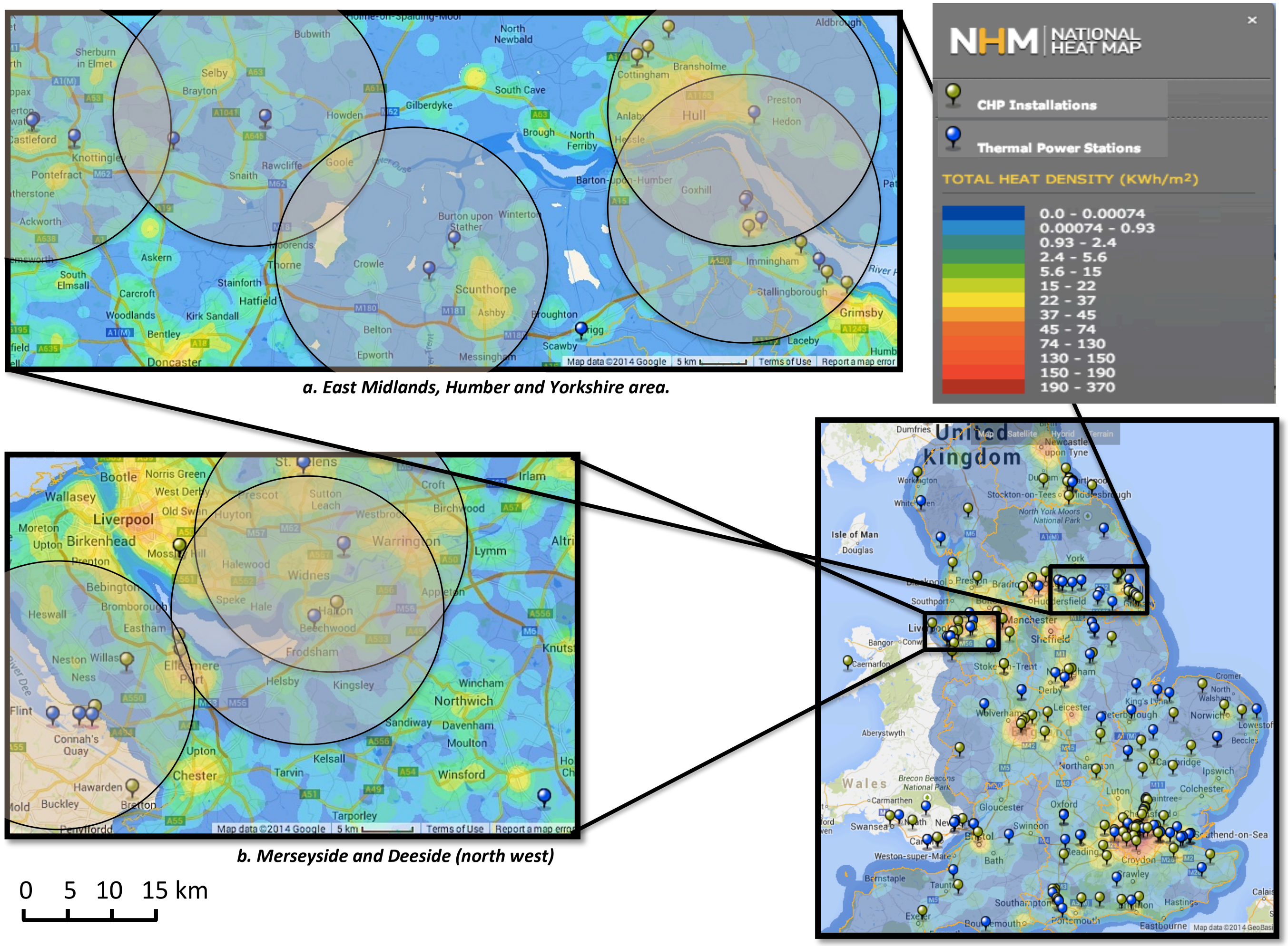
One key way to reduce cooling water demands is by reducing the requirement for cooling. This can be achieved by use of combined heat and power (CHP), which may be well suited to CCS clusters. CHP is the process of removing the waste heat from power generation and providing it for use by another user, usually domestic or industrial.

Since 2006, all development applications for thermal power stations under Section 36 of the Electricity Act 1989 must either include CHP or demonstrate that possibilities have been fully explored (DECC, 2011f) and are not economically or technically feasible. The clustering of CHP plants with CCS facilities presents technical challenges such as the availability of space, but also synergistic opportunities. Industrial facilities can make use of waste heat; otherwise heat can be transported for district heating, with the costs shared amongst power stations. Such implementation however would require significant strategic direction and inclusion at the beginning of the design cycle.

Uptake of district heating in the UK to date has been low compared to other parts of Europe, contributing less than 2% of heat demand. With the right conditions, including government incentives, it is thought this could contribute up to 14% (Davies and Woods, 2009). Subsequently, DECC have developed a National Heat Map for England which shows the intensity of heating demand across the country (DECC, 2014a, 2014b). Inspection indicates that the use of CHP on CCS could be economical in the North West, but less likely in the Yorkshire, Humber, East Midlands and North East areas (Figure 7-3).

Several recent NSIP applications for CCS or CCR power plants in South Yorkshire have ruled out the use of CHP on economic terms: White Rose CCS project at Drax power station; Knottingley Power Project; Killingholme Power Project; and Ferrybridge Multifuel FM2. Detailed inspection of their 'Combined Heat and Power Assessments' gives the impression of a general lack of appetite for this type of solution, acknowledging that some attempts at identifying local users and demonstrating economic *unfeasibility*, are considerably more convincing than others.

The seasonal variation of heat demand (unless industrial) also complicates economic implementation of CHP in the UK. In any case, economic feasibility is also highly susceptible to the prices of both electricity and gas. Economic feasibility seems to only occur in the UK when new power plants are being built at industrial facilities, such as South Hook CHP plant at the Pembrokeshire Liquefied Natural Gas (LNG) plant. Other uncertainties are also present. Whilst the need for heating will not change very much, even with climate change, the scale of that demand may well do, as is subject to external influences such as energy costs and energy efficiency policy.



a. East Midlands, Humber and Yorkshire area.

b. Merseyside and Deeside (north west)

Figure 7-3. The National Heat Map from DECC (DECC, 2014b). Blue markers indicate current power stations, green markers are current CHP schemes. The heat demand intensity is indicated by the shaded colours. Shaded circles indicate radii of 15km from power stations from which heat could be economically transported.

7.4.2 *Wastewater as a cooling source*

The use of treated wastewater as a cooling water source in closed-loop wet cooling towers is also an option. As of 2007, over 50 power plants in the US used wastewater, mostly for cooling but also boiler feed water in some cases (Veil, 2007). There is a growing body of technical research in this area coming from the US that has been pilot- and field-tested (Donovan *et al.*, 2004; EPRI, 2006; Veil, 2007; Ciferno, Aljoe and Dzombak, 2009; NETL, 2010b; Arthur, 2011; Dzombak, Vidic and Landis, 2012; Walker *et al.*, 2013). Municipal wastewater is even used for cooling at the Palo Verde nuclear power plant, the largest in the US, providing a reliable cooling water source in Arizona whilst increasing revenue for the local water company (Rodriguez *et al.*, 2013). In the UK, both the 363 MW_e coal (soon to be mothballed) and 834 MW_e CCGT Uskmouth power stations also pioneer the use of treated wastewater for their boiler feed water, but not for cooling (Power Engineering, 2010).

Further challenges of using wastewater include contaminants and nutrients in the water, condenser tube fouling, increased risk of Legionnaire's disease, proximity to wastewater sources and increasing competition for sources of treated wastewater (Dzombak, Vidic and Landis, 2012). In some UK rivers, treated wastewater makes up a considerable proportion of the river flows and maintains the environmental integrity. Reducing municipal wastewater returns could subsequently increase the occurrence of low flows. Conversely this may be welcomed by wastewater treatment companies who are finding it increasingly difficult to meet effluent quality regulations in low flows due to lack of dilution. A further non-technical barrier could be Ofwat, the economic regulator for the water sector, who have prevented capital investment with consumer cost-recovery in areas outside the core business, such as renewables electricity generation (Watson and Rai, 2013). This wastewater infrastructure could fall within the core business, however.

Successful integration between wastewater and electricity production will be highly contextual and location specific. Given the right incentives, wastewater for cooling presents an innovative opportunity for the UK's wastewater system, which in some places is over 100 years old. A sewage treatment works capable of serving one million people at full capacity is of sufficient size to provide a reliable cooling water flow of approximately 1 m^3/s assuming that 60% of the supply volume is discharged. This would be sufficient for large power stations operating at full load: a 1 GW_e coal+CCS plant, or almost a 1.8 GW_e gas CCGT+CCS plant, if using closed-loop wet tower cooling. For current capacity without CCS, the potential would be a further 70-90% higher. There are approximately 25 wastewater treatment plants with this capacity of 1 million people, a further 90 that can serve 300,000 people, and even four plants with capacity in the order of 3-4 million people (Figure 7-4). More detailed studies evaluating technological, geographic, economic and regulatory feasibility, as has been done in the US by Stillwell (2014), are highly recommended for the UK.

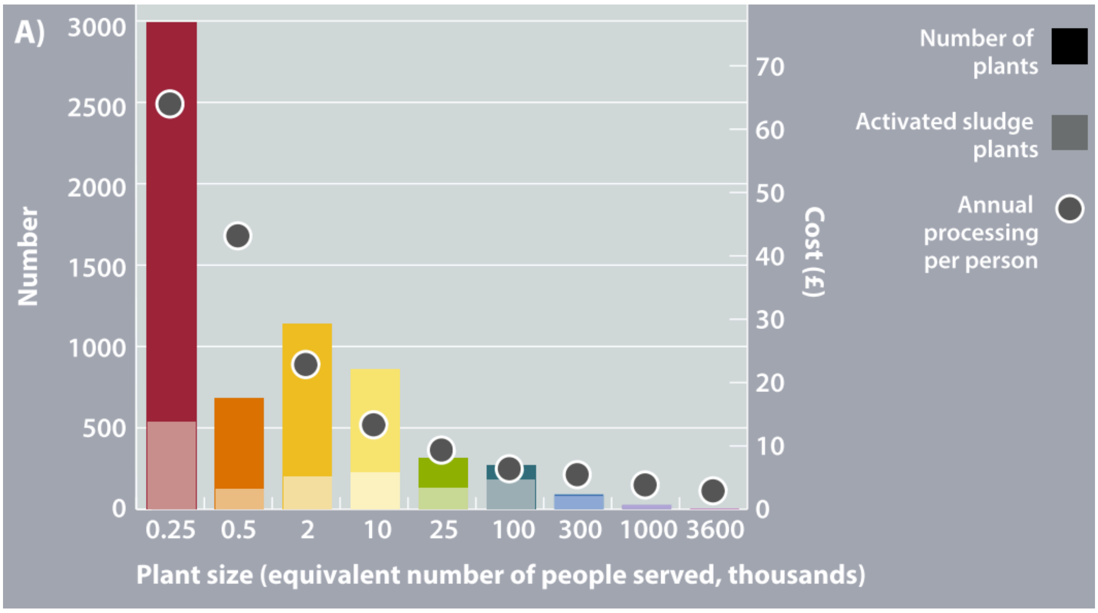


Figure 7-4. Wastewater treatment plant sizes in Great Britain. Source: Tran *et al.* (2014).

7.4.3 Water storage

Water storage also offers a potential solution to water-scarcity, but only on shorter timescales and is dependent on the volumes permitted for storage. Stillwell (2013) has shown comprehensively for a case study of Texas that storage can increase power plant reliability in certain cases but is very much power plant specific. It can also negatively impact users downstream depending on the often substantial volumes stored, which in this case was equal to one month’s supply. The economic analysis suggested that this is more likely to be beneficial when the plant is of peaking capacity, which in this case is the summer time demand. It is also cost-competitive with using dry cooling.

For long-duration licences (maximum 24 years), the EA needs to be convinced through a business case that abstractions meet four conditions, (Environment Agency, no date a), one of which is the contribution to sustainable development. In the examples given for this requisite, there are several references to storage, both to mitigate low flows as well as other environmental problems. Developing this principle to stimulate greater consideration of storage solutions could be very beneficial, not only for the abstractor, but also other users and the environment.

One suggestion would be to strengthen the requirement to consider storage in the same way that power plants must also investigate the feasibility of CHP, as previously discussed. The space requirements are considerable however. Using a 75% load factor, one week of supply in a 3m deep storage reservoir would require approximately a 25 hectares (ha) footprint for a. 1 GW_e CCGT+CCS plant and 46 ha for a 1 GW_e coal+CCS plant. This must be compared in addition to the site requirements of generation units and CCPs, which are in the order of 12 ha per GW_e of CCGT+CCS capacity and 36 ha per GW_e of coal+CCS capacity (DECC, 2009a). The reservoir could be filled during high flows, and could offer significant ecological and resilience benefits. More detailed analysis is required to determine whether this is economic. If so, policy should be strengthened accordingly to promote water storage solutions.

7.4.4 Alternative perspectives

The three solutions just discussed bring a different perspective to finding cooling solutions for the power industry. All are highly contextual and would require site-specific design, but do not require any new technologies. All would likely require early involvement at the design stage. They may also cost slightly more, but also bring wider-reaching benefits due to their interactions with other sectors and the wider environment. They bring both resilience benefits but also interdependency risks. They are also unlikely to occur without external impetus to encourage such solutions.

The CHP and wastewater options put some control of the cooling, an essential function for power stations, outside the direct influence of the power company. This may, on the face of it, appear risky. However, it is not too different from the management of other essential feedstock and infrastructural arrangements, such as the provision of fuel, grid connections, waste removal and water abstraction from a shared water body.

7.5 Challenges ahead

The majority of this chapter exists solely to address issues that arise from the pathways with high levels water use, i.e. those with carbon capture and storage. As previously shown, the UK electricity sector is on a sustainable trajectory regarding water use and is expected to reduce freshwater use substantially up to 2025. If the sector's water use remains at these low levels, policy and regulatory reviews of the issue will not necessarily be needed. It is the fruition of CCS that dichotomises the future of the water-for-electricity nexus in the UK; CCS will require a more precautionary approach from Government towards interactions between energy and water. The same is also likely to apply to the development of unconventional hydrocarbons, such as shale gas and underground coal gasification.

7.5.1 A future without CCS

In aiming for a sustainable electricity system, the use of freshwater is a cross-cutting issue; it has implications not only for environmental sustainability, but also the costs and security of supply. Pathways with low freshwater demands (those without CCS) mostly remove water concerns from the equation, at least in the UK. This includes not only abstraction licensing and volumes but also the risks that come from low flows and droughts, both of which are expected to be more severe with climate change.

This is not to say that water is the only concern and that alternative electricity pathways without CCS will be more straightforward. Pathways with high levels of nuclear power and renewables come with caveats and benefits that divide public opinion. Both options are very low-carbon and the technologies are well established. A pathway with a mix of renewables and nuclear would also entail very low freshwater demands. The electricity system could deal with baseload nuclear and the intermittency of renewables if backed up by CCGT and pumped storage.

Whilst the UK Government's aim is to run a "*low-carbon technology race between CCS, renewables and nuclear power*" (HM Government, 2011), ample appetite to use renewables as far as possible over the other two is emerging and is increasingly cost competitive. The costs of renewables have fallen dramatically in recent years and are expected to continue, particularly for wind and solar. Pöyry expects onshore wind to reach wholesale grid parity in Great Britain in 2021, whilst solar PV will reach parity in southern Europe in the mid-2020s (Pöyry, 2014). This will truly be a transformational point for energy markets at which renewables start to challenge conventional coal and gas investments on an equal footing. By the 2030s, when we can expect CCS to finally be commercially available at a large scale, its economic viability will be seriously challenged by renewables. Michael Taylor, a Senior Analyst in renewables costs at the International Renewable Energy Agency (IRENA) expects that CCS will struggle to challenge renewables because development has been *"too little, too late"*.

Public acceptability of various forms of renewables is considerably higher than that of maintaining fossil fuels, even if this includes CCS, albeit to a lesser extent. Acceptability of nuclear power, however, is even lower than fossil fuels (Parkhill *et al.*, 2013). The high costs, safety concerns and intergenerational burden of radioactive waste make this an unattractive option to many, but one that could step up low-carbon electricity generation relatively quickly within a decade. As discussed in Chapter 4, high levels of nuclear power would also entail substantial impacts to coastal and estuarine sites, more of which need to be identified by Government. High levels of renewables would require substantial land requirements, in addition to challenges and costs for the required storage, well discussed by Mackay (2009, 2013).

CCS will also be required for decarbonisation of industry, even though alone this will not be enough to reduce global industrial emissions by the required 50% by 2050. A variety of sector-specific strategies will be required (Allwood, Cullen and Milford, 2010). Without CCS, decarbonisation and limiting dangerous climate change is likely to be even more challenging and will require significant societal and economic transformations. With only low levels of CCS in the energy system, the use of CCS in industry will inevitably be more expensive, even if essential for decarbonisation.

7.5.2 A future with CCS

The International Energy Agency states CCS is essential for stabilising at a 2°C global temperature increase in its 450 ppm scenarios, and that it forms substantial parts of the most cost-effective emissions reductions pathways (IEA, 2013a, 2013b). However, the IEA also expects that by 2035, only 1% of the world's fossil fuel-fired power plants will be equipped with CCS. Uncertainty is abound.

Time is also not in the favour of CCS, even in the UK, let alone the rest of the world. Watson, Kern and Markusson (2014) note a wide range of challenges and uncertainties ahead, regarding successful CCS deployment in the UK, taking evidence from historical analogues of the energy sector. For example, that *appraisal optimism* typically underestimates costs, such as occurred with flue gas desulphurisation and nuclear power. Furthermore, that the speeds of scaling up technologies and wide-scale deployment often takes longer than expected, especially when aiming for industrial systems that operate at a power-plant scale (e.g. it took 30-years to scale CCGT from 5 MW_e to 200 MW_e). Lastly, we must be wary of the expected speed at which economy-of-scale cost-reductions for CCS can be achieved. Flyvbjerg, Bruzelius and

Rothengatter (2003) have documented a series of megaprojects where economic costs are typically overestimated and social and environmental costs typically underestimated.

In the long term, CCS is the key technology that will allow the fossil fuel industry to maintain some status quo in a world that is supposedly serious about limiting dangerous climate change. Even still, recent research suggests that to have a 50% chance of limiting warming to 2°C, 82-88% of coal reserves and 49-52% of gas reserves are *unburnable* between 2010-2050 (McGlade and Ekins, 2015); the lower bounds of those ranges indicating a future without CCS, the latter in a future with CCS. Such a seemingly small difference is the effect of CCS in the short term, strengthens the argument for a long-term paradigm shift. A paradigm that does not mainstream the use of abated fossil fuels but a paradigm that focuses its attention on avoiding the use of fossil fuels, as far as possible.

7.5.3 Robust water policy to minimize cost-risks to CCS

Much of what has been mentioned above points towards significant economic challenges in achieving low-carbon electricity systems. There are contrasting opinions as to whether CCS can economically decarbonise the energy system. What is important is that barriers to its safe and environmentally-sound development are avoided. From the perspective of this thesis, this means reducing the costs and risks associated with water and climate change. The prospect of planning delays, design changes, operation outages and retrofits due to water-related risks will all add costs to the development of CCS. Strong policy and coordinated planning of clusters are essential to minimising both water and financial risks to CCS development.

The work in this and previous chapters points away from considering power plants on an asset basis and towards a broader perspective that considers electricity generation assets within their wider system. Water resources are well suited to catchment and regional development planning given its spatial characteristics and difficulty of transport. Water resource availability is assessed at River Basin District (RBD) level and catchment level, as a resource to be used in an economically productive way by society and the environment.

The National Policy Statements for Energy are explicit in specifying that energy infrastructure developments must demonstrate in the Environmental Statement that that they have taken into account the potential impacts of climate change (DECC, 2011f) (also discussed in section 6.4.1 of Chapter 6). Whilst an important step towards improving the resilience of the UK's infrastructure, resilience of assets and components does not amount to the same thing as systems resilience. The electricity system is a *complex* one and hence its properties (including performance, behaviour, resilience) do not amount to the aggregation of its parts (see Barabási, Newman, Perrows, Taleb, Bar-Yam and other scholars of complex systems). Thus, to fundamentally achieve an electricity system that is water-efficient and reliable against water-related risks, we need policy and planning beyond the power-plant level that considers a wider environment and system boundaries.

7.6 Conclusions

The importance of electricity sector abstractions in water policy will depend largely on whether CCS is extensively developed in the UK. This chapter has explored this discussion, primarily from the expectation that CCS will be developed in the UK. Overall, the joint conclusion is that more specific policy and regulatory attention on CCS and water is required to:

- reduce risks and barriers to CCS development related to uncertainty of water licensing and availability;
- promote water efficiency and resilience to water and climate risks;
- facilitate implementation of more innovative cooling water options and reduce the costs of risk and uncertainty;
- avoid other excessive costs that may hinder the economic case for CCS.

Firstly, a review of the current policy and regulatory landscape suggests that there are already apparent shortcomings in the planning and permitting processes regarding carbon capture readiness and water abstraction licensing. This is particularly the case given the possibility of extensive CCS development, as evidenced in the previous chapters. More publicly available information from the regulators on electricity sector water use is also required.

There are also adaptive interventions through which CCS could avoid water risks, in order to ensure reliable cooling. These include the use of more costly low water cooling technologies, the use of coastal locations, increasing storage and the use of alternative cooling sources, such as CHP and wastewater. To make these adaptations feasible requires more detailed policy attention, not only to facilitate such innovations but also to reduce costs and ensure that interdependencies do not exacerbate risks to other infrastructure.

Subsequently, various cases have been discussed in which more integrated planning and higher water-efficiency of CCS clusters would strengthen the economic case for CCS in a sustainable manner. Promotion of higher water efficiency in clusters via market or cooperative mechanisms, as also demonstrated in Chapter 6, would also increase availability of the electricity supply during low flows and drought.

Finally, water efficiency and strong water policy will remove one of many barriers that threaten the economic competitiveness of CCS throughout its lifecycle. The integrated nature of CCS infrastructure not only needs a more integrated planning approach, but is well suited to it. These synergies must be exploited. Without it, we will likely expose ourselves to avoidable water risks, whilst making the challenge of mitigation and adaptation to climate change, even more expensive than necessary.

Chapter 8. CONCLUSIONS

8.1 Introduction and key contributions

This thesis set out to study the interactions between water resources and low-carbon electricity generation in the UK. This chapter will outline the extent to which the aims and objectives have been accomplished, the contributions made to the field and existing knowledge, and suggestions for further research. Some of the more concrete contributions of this work are mentioned in this text and in the *Statement of Contributions and Publications* (pg. iv).

8.1.1 Key findings and contributions

Foremost, this thesis has made several noteworthy contributions to the field, split by *methodology* and *results*:

Methodology

- Chapter 2 included much needed exposition of data availability and different methods for calculating water use factors, as well as the basis for addressing the aim at a range of scales;
- A methodological framework for calculating water use of the current system and future low-carbon energy pathways, tested, validated and demonstrated for the UK electricity system;
- A new high-level approach for assessing regional licensed sectoral water availability under climate change scenarios in order to facilitate comparison against regional electricity projections and identify regional hotspots;

- A hydroclimatic simulation of CCS clusters and cooling technologies under scenarios of climate change and alternative abstraction regimes considered by UK Government;

Results and key findings

- The quantity of freshwater used by the electricity sector for cooling is far less than previously expected and is on a downward sustainable trajectory. The volume used over the long term is less of an issue than with the dependency during more extreme situations, such as droughts. Nonetheless, a future with high levels of CCS could see freshwater consumption at double the current levels by 2050. Pathways with low levels of CCS, minimise freshwater use;
- In the long term, an electricity system with inland carbon capture and storage would be most vulnerable to drought, particularly in the Humber and East Midlands and North West regions. Demands in these regions may exceed availability during low flows, particularly under climate change impacts;
- The River Trent may experience substantial reductions in water availability during low flows under climate change. This could limit or put at risk CCS developments in the area, especially if coal and conventional cooling towers are used;
- By studying the issue from national to catchment scales, conflicts between national energy policy and catchment water abstraction licensing have been identified. Whilst not currently an issue, there are no provisions in place to ensure that *carbon capture ready* plants will have sufficient cooling water resource available if and when CCS is developed in the coming decades.

8.1.2 Meeting the objectives

This work has been comprehensive by covering both the scales most familiar to water and energy systems analysts (river basin and national), as well as an intermediate scale. Thus a detailed picture of current and future scenarios, has been developed, with relevance for a variety of stakeholders, providing a foundation from which more detailed studies can be based.

The framework in Chapter 3 proved itself suitable and adaptive to national- and regional-scale analysis for current use and future energy pathways from different energy models. Through developing a method to assess water availability to the electricity sector at low flows, regional hotspots were also identified for a high CCS pathway. Together, these Chapters 3 to 5 fulfil Objectives b) and c).

This work was referenced in a recent report by the Adaptation Sub-Committee (2014), has been similarly applied to projects: in Turkey with the State Electricity Production Company (EÜAS); by the International Renewable Energy Agency (Ferroukhi *et al.*, 2015); the Energy Technologies Institute (Personal communication, 2014); for Chinese electricity pathways; and, various activities of the ITRC project (Byers *et al.*, 2014; Tran *et al.*, 2014; Hall *et al.*, 2015)

Chapter 6 addresses Objective d) by performing a comprehensive analysis at a catchment scale for the River Trent in the East Midlands. This work also demonstrated from a water use and capacity availability perspective, the benefits of cooperative and water-efficient allocation. Chapter 6 explores multiple sources of uncertainty, in particular through the inclusion of alternative abstraction regimes, constituting a novel, timely and policy-relevant contribution to the field.

Finally, the work has been completed with a cross-cutting analysis of the wider policy and regulatory issues raised in the preceding chapters. Much of Chapter 7 focussed on the implications of pathways with high levels of carbon capture and storage, which will require additional policy attention on the abstraction licensing of *carbon capture ready* developments, both to sustainably manage water resources and also to reduce uncertainty impacts on the costs of CCS. The rationale for CCS clustering is explored in detail, alongside additional water-efficiency measures that could be well suited to CCS clusters, such as the use of CHP, wastewater and water storage. This completes Objectives a) and e).

8.1.3 The thesis' integrated contribution

Moreover, and alluded to in the discussion of Chapter 7 and Objectives a) and e), is the perspective and contribution that this thesis makes as an integrated body of work. At each stage of this study the detail and fidelity of both sectors is enhanced. This iterative approach of identifying key strategies and hotspots for further analysis has proved itself to be informative and time-efficient; it avoided detailed hydroclimatic modelling studies of catchments with no prospects of hosting power stations.

This thesis has provided a foundation of facts, methods, datasets and perspectives regarding interactions in water-for-electricity studies for the UK. We now know how to model electricity sector water use, which datasets are required and how to apply it to different energy models. This has been informed by excellent studies from both the US and Europe.

A variety of options have been put forward to promote water efficiency and resilience to water and climate risks. There is a deficiency in the current policy and regulatory arrangement concerning carbon capture readiness and water abstraction licensing, which whilst not currently problematic, must be addressed if we are serious about CCS. Electricity infrastructure consents are largely national scale decisions about individual assets, quite different to the management of water resources, which takes place at catchment and river basin scales. Furthermore, a solid case has been made to demonstrate that driving water efficiency is not necessarily a barrier, but an opportunity reduce uncertainty and risk and associated costs, to CCS clusters. In the context of tackling climate change, both locally and globally, reducing the costs and risks of CCS is of paramount importance.

Thus, overall we may conclude that analysis of these water and energy systems is required at multiple scales, not only for numerical representations, but crucially also for cross-sectoral policy analysis. Together, these fulfil the aim of the study: **to analyse the use of water resources for cooling of UK power stations, under climate change, energy and water policy pressures to ensure sustainability and security of the energy and water systems.**

8.1.4 Policy relevance of the work

The work has addressed energy and climate change policy through continuous consideration of security of supply and decarbonisation, as well as cost impacts. All the energy pathways tested decarbonise the electricity system to meet Climate Change Act 2008 targets. They come from two well-established energy systems models (DECC 2050s Pathways; CGEN+), some of which from HM Government's *Carbon Plan* (2011).

Regarding water and environmental policy, the WFD and the IPPCD have been considered extensively, including the UK Government's transposition into regulation such as abstraction licensing. This includes the latest proposals under consideration in Defra's Abstraction Reform programme in order to make both the current and future assessments timely and relevant.

Lastly, water and energy security have been considered with national and regional scale assessments using the latest UK Climate Projections (UKCP09) in order to make the results consistent and comparable with other climate impacts assessments, as recommended by the National Policy Statements (DECC, 2011f). This work has also proposed and demonstrated for one important catchment, how different portfolios of electricity capacity availability are impacted by limitations to water availability, whether induced by climate change (as simulated) or other sectors, under two different abstraction regimes. The work has also simulated adaptation measures, of which there has been little work to date in the field (Sanders, 2015).

8.2 Limitations and evaluation

Limitations of the work derive from a variety of constraints. The following dominant uncertainties have been encountered in this work, and are likely to be relevant for other studies in the field (Table 8-1). These have also been discussed in more detail in section 2.4.

Table 8-1. Relevant dominant uncertainties in this study.

Uncertainty	Description
Water use factors	Can vary according to empirical and theoretical calculations, and depend on hydroclimatic conditions, operational decisions, regulatory constraints and the engineering of the power plant. Aggregation of factors over multiple plants also masks variability.
Hydrological model performance at low flows	Reproduction of low flows in hydrological models remains a challenge. This in particular makes it difficult to assess the impacts of more extreme events.
Climate modelling uncertainty	Climate model uncertainty arises primarily from natural climate variability, incomplete understanding and representation of physical climate processes and future emissions uncertainty. Thus use of mulimodel ensembles with a full range of emissions scenarios is advised.
CCS performance	CCS is yet to be demonstrated at large scale. Efficiency, performance and water use are not yet empirically known and may vary considerably in the early stages of development.

Data availability and quality has been a challenge throughout that has required time-consuming methods to build a detailed picture of cooling water use in the UK (Chapters 3 and 4). With time, updates and better information of power station water use in the UK will build on the data presented here and reduce uncertainty in both current and future estimates. This is a problem also commonly experienced in the US (Sanders, 2015). More spatially explicit energy models will certainly be an advantage when considering the impacts of CCS.

The work in Chapters 3-5 has both benefits and limitations due to the fact that it takes energy model outputs in order project future water use. Methodologically, this is desirable for wide applicability and flexibility, as has been demonstrated, but there is also good reason to argue for water use and availability projections to be integrated into existing energy systems models. Alternatively, there could be direct coupling with water resource models, which has not been possible in this instance. Linking these two aspects, is the spatial and temporal resolution of future energy and water projections.

Another development for these chapters would have been to have taken more of a simulation-based approach to some of the key parameters in Chapter 4, such as power plant location, as performed by Gasparino (2012). The work, similar in nature though covering only two pathways (CP1-REN and CP2-NUC), has a more comprehensive approach to uncertainty analysis than the sensitivity analysis that has been presented here. Despite the robust approach to assumptions regarding freshwater use, the analysis excludes all the water-intensive CCS pathways and it is not clear why the work has not been made more widely available.

More spatially-explicit hydrological modelling could have been performed in Chapter 6, such as by Koch *et al.* (2014a). However, it is not clear how much more useful this would be for determining hands off restrictions, which are normally determined at a downstream gauging point in this case. Similarly, the methods in Chapter 6 could have been replicated to other areas, such as north Yorkshire and the Humber, or the North West/Deeside areas, to assess potential impacts in other regions expected to have high concentrations of CCS as indicated by the results of Chapter 5. This should be done in the near future.

8.3 Recommendations

These key recommendations have the purpose of, firstly building knowledge in this topic area for the UK, and subsequently facilitating better policy analysis upon which Government policy is based.

- Government, regulators, industry and associated trade bodies must work together to provide better data on this topic to facilitate independent analysis. Sufficient data exists, but obtaining it is time-consuming and problematic. It is not commercially sensitive and they do not own the water. Government should indicate responsibility for this.
- Actors involved in energy systems modelling should consider including water aspects to models at a variety of levels through: water use statistics; water-related development constraints; and water-related climate impacts (section 8.4).

- Government, industry and academia should investigate and review more thoroughly the impacts of specifically water-intensive high CCS futures, in order to establish appropriate policy and regulatory measures to safeguard against risks to water resources and the electricity sector.
- More detailed hydrological and drought impacts studies are required for the regions identified in Chapter 5, namely, the North West, Humber and East Midlands and the Thames/London regions.
- The regulators should consider the impacts of very low flows and procedural options for maximising water productivity and available generation capacity, as simulated in Chapter 6.
- Government should actively address the concerns mentioned regarding water abstraction licensing for yet-to-be built carbon capture plants at CCR power stations. This should be considered in the on-going abstraction reform. This thesis has demonstrated a case whereby water-efficiency could reduce the costs of shared CCS infrastructure.
- Numerous other adaptation synergies and opportunities exist in the clustering of CCS facilities that Government should actively promote. This includes CHP (which is already encouraged) as well as other water-efficient solutions, such as water storage and the use of wastewater for cooling.

In addition to those recommendations, there are many potential avenues of research yet to be explored, with the potential for iterative policy recommendations.

8.4 Further research

From a UK perspective, this study is to date, the most comprehensive and current publicly available study of water resource use by the electricity sector. The work in Chapters 3-5 will be subject to updates in the coming years, both in order to update the baseline estimations as well as future energy pathways and cooling trajectories with the current policy context. Quality and certainty of the datasets should improve in the coming years if they are used and scrutinised by other researchers. It is hoped that with time, water use reports from all power stations will be easily available such that each asset can be attributed the correct water use factors. Future energy systems modelling could also include water use and water availability metrics relatively easily in the same way that current models already consider GHG emissions, carbon prices, land availability, fuel prices and technology costs.

With better national and regional assessments now accomplished, more detailed studies can now be carried out, such as the one in Chapter 6. Work in the US and in Europe has used demand and dispatch electricity models to better identify how localised climate- and water-related production shortages may impact the wider electricity network capacity availability and prices (Rübbelke and Vögele, 2011; Stillwell and Webber, 2013; van Vliet, Vögele and Rübbelke, 2013). Some other capacity-expansion and -planning models have taken into account water resource availability in the US (Pacsi *et al.*, 2013; Cohen *et al.*, 2014). The work in Chapter 5 will continue to be used by the ITRC project by using the CGEN+ model to include water availability as a capacity constraint for the UK in the near future. Alternatively, studies to investigate adaptations such as wastewater retrofit (Stillwell and Webber, 2014) and zero-freshwater use options (Tidwell *et al.*, 2014) would also be useful for the UK.

Economic impacts analyses are also required for water-related risks and droughts. These may determine impacts at asset, company, sector and wider economy levels. There is currently considerable uncertainty surrounding future climate impacts on hydrological variability and droughts. Building the evidence base in this area, particularly using the UKCP09 climate projections, would be particularly useful to the planning authorities and water resource managers when making assessment of power plant planning applications, in light of the policy imperative to make power plants resilient to climate change impacts (DECC, 2011f).

In the wider water-for-electricity nexus the field is rapidly filling and expanding with innovative approaches. The very large majority of the US-based research (e.g. Macknick, Webber, Sanders, Stillwell) has been primarily energy sector driven and has focussed on energy sector impacts, energy technologies and sector transformations. More work is required from the water resources and hydrological variability angle, similar to approaches in Chapters 5 and 6, as well as by van Vliet *et al,*, Koch *et al.* and Averyt *et al.*, the latter of which has shown sectoral contributions to water stress across the US (Averyt *et al.*, 2013).

Better information is also required to assist decision-making. Data presentation in this field can be challenging, especially when spatial dimensions are added. Visualisation tools, such as Sankey diagrams (e.g. Foreseer tool, (Allwood *et al.*, 2014)), are improving yet may still be overwhelming for non-experts. There is also confusion in some aspects amongst non-experts that the field must work collectively and persistently to define and explain, for example: cooling systems and water use; thermal impacts; and the terminology of withdrawals, abstraction, consumption and water use. Within the field, there still has not been a thorough discussion in the literature (besides Chapter 2) of when and where empirical (e.g. Macknick *et al.* (2012a)) and theoretical water use factors (e.g. Koch and Vögele (2009)) are best used; the latter of which is infrequently used but is probably more suited for climate impacts analysis. With concerted efforts this will all improve, crucially for water regulators and policy makers such that they are better positioned to make fair decisions.

Very little work to date has focussed on the impacts of CCS infrastructure, even in the US. Alongside water availability, it will play a significant role in determining the locations of future power plants. More work similar to Chapters 5 and 6, with a focus of regions and river basins with high CCS is needed, not just in determining impacts on water resources, but also in leading to a better understanding of the clustering of industrial systems in the future. This could lead to a resurgence in the interest of well-designed industrial ecosystems and their place in sustainable regional development. Despite the implications and challenges of CCS for energy, water and infrastructure, it may well be more difficult to achieve a low-carbon future in the complete absence of CCS. Thus reduction of water and climate risks and uncertainties surrounding CCS is key to economic decarbonisation.

In this respect, I would propose taking a new *cluster perspective* for planning of CCS developments. In the cluster perspective, more resilient water efficiency measures facilitate higher CCS capacity development for a fixed availability of water. This higher CCS capacity development results in marginal savings on the shared infrastructure cost due to scale economies, which can be used to pay for the water efficiency measures. This enables higher water efficiency for the same cost.

8.5 The global perspective

Hopefully with CCS, but possibly without, much more is to be done across the rest of the world, particularly in the coal nations such as China, India, South Africa, Turkey, amongst other rapidly industrialising countries such as Mexico, Nigeria, Brazil, Indonesia and Malaysia. Substantial energy investments, including coal facilities, will be made now and in the coming decades. These must be climate sensitive and climate resilient. Projects funded by development banks are under increasing pressure to demonstrate resilience to climate impacts and positive contributions to sustainable development. More robust considerations of climate change and water-for-electricity issues should be included in the funding guidelines, such as those produced by International Finance Corporation/World Bank Group (International Finance Corporation, 2008), and as demonstrated in the Asian Development Bank's funding for the O Mon IV CCGT plant in Viet Nam (Asian Development Bank, 2012).

Finally, the UK case is somewhat unusual in the respect that there is very little use of hydropower. This is not the case across the world. It may be easy to downplay the water risks to thermal power plants when compared to those of hydropower, when we think simply of the volumes used. But thermal power is often considered a reliable backup. Droughts are indiscriminate and have impacted on electricity production across the range of hydropower and thermal electricity mixes. France and Brazil, two quite opposite electricity mixes, have both suffered severe impacts of drought on both hydro and thermal on two separate occasions in the past 15 years. Ironically, their electricity mixes are also amongst the most low-carbon in the world. The time for considering the diversity of electricity mixes, not just across fuel and technology types, but also across water and climate related risks, is upon us.

APPENDICES

Appendix A - CHAPTERS 3 AND 4

A.1 Power plant database

Plants closing according to the Large Combustion Plant Directive are highlighted in red and removed from 2016 onwards.

Table A 1. Table of generation capacity in the UK, with associated cooling methods and source, adapted from DUKES Table 5.11.

2010					
Station Name	Capacity (MW)	Type	Cooling source	Cooling type	Location
Little Barford GT	17	GT/OCGT	AC	Open-loop	East
Stornaway	19	Oil-ST	SW	Open-loop	Scotland
Keadby GT	25	GT/OCGT	AC	Open-loop	Yorkshire & Humber
Charterhouse St Citigen London	31	GT/OCGT	AC	Air cooled	London
SELCHP (South East London CHP)	32	Waste	AC	Air cooled	London
Kingsnorth GT	34	GT/OCGT	AC	Air cooled	South East
Ratcliffe GT	34	GT/OCGT	AC	Air cooled	East Midlands
Ferrybridge GT	34	GT/OCGT	AC	Air cooled	Yorkshire & Humber
Fiddler's Ferry GT	34	GT/OCGT	AC	Air cooled	North West
Elean	38	Biomass	AC	Air cooled	East
Wilton 10	38	Biomass	TW	Hybrid	North East
Thetford	39	Biomass	AC	Air cooled	East
West Burton GT	40	GT/OCGT	AC	Air cooled	East Midlands
Knapton	42	GT/OCGT	AC	Air cooled	Yorkshire & Humber
Wilton GT 2	42	GT/OCGT	AC	Air cooled	North East
Chickerell	45	GT/OCGT	AC	Air cooled	South West
Teeside Power station	45	CCGT	FW	Evaporative	North East
Burghfield	47	CCGT	FW	Open-loop	South East
Thornhill	50	CCGT	FW	Open-loop	Yorkshire & Humber
Sandbach	50	CCGT	FW	Evaporative	North West
Steven's Croft	50	Biomass	AC	Air cooled	Scotland
Rugeley GT	50	GT/OCGT	AC	Air cooled	West Midlands
Aberthaw GT	51	GT/OCGT	AC	Air cooled	Wales
Coolkeeragh	53	GT/OCGT	AC	Air cooled	Northern Ireland
Grain GT	55	GT/OCGT	AC	Air cooled	South East
Castleford	56	CCGT	FW	Open-loop	Yorkshire & Humber
Blackburn Mill	60	CCGT	FW	Hybrid	North West
Slough	61	Biomass	FW	Evaporative	South East
Tilbury GT	68	GT/OCGT	AC	Air cooled	East
Fawley GT	68	GT/OCGT	AC	Air cooled	South East
Drax GT	75	GT/OCGT	AC	Air cooled	Yorkshire & Humber
King's Lynn	99	CCGT	AC	Air cooled	East
Didcot GT	100	GT/OCGT	AC	Air cooled	South East
Littlebrook GT	105	GT/OCGT	AC [c]	Air cooled	South East
Ballylumford B OCGT	116	GT/OCGT	AC	Air cooled	Northern Ireland
Wilton Power Station Gas	130	GT/OCGT	FW [c]	Air cooled	North East
Taylor's Lane GT	132	GT/OCGT	AC [c]	Air cooled	London
Cowes	140	GT/OCGT	AC	Air cooled	South East
Indian Queens	140	GT/OCGT	AC [c]	Air cooled	South West
Kilroot OCGT	142	GT/OCGT	AC	Air cooled	Northern Ireland
Wilton Power Station Coal/biomass	150	Coal/Biomass	FW [c]	Evaporative	North East
Fellside CHP	180	CCGT CHP	FW	Hybrid	North West

Shotton	210	CCGT CHP	AC	Air cooled	Wales
Derwent	228	CCGT CHP	FW	Evaporative	East Midlands
Roosecote	229	CCGT	SW	Open-loop	North West
Barry	230	CCGT	AC	Air cooled	Wales
Glanford Brigg	260	CCGT	FW	Evaporative	Yorkshire & Humber
Uskmouth	363	Coal/ Biomass	TW	Hybrid	Wales
Cottam Development Centre	390	CCGT	TW [c]	Hybrid	East Midlands
Shoreham	400	CCGT	TW [c]	Open-loop	South East
Corby	401	CCGT	AC	Air cooled	East Midlands
Peterborough	405	CCGT	AC	Air cooled	East
Coolkeeragh	408	CCGT	TW	Open-loop	Northern Ireland
Enfield	408	CCGT	AC	Air cooled	London
Seabank 2	410	CCGT	TW	Hybrid	South West
Great Yarmouth	420	CCGT	TW [c]	Open-loop	East
Oldbury	424	Nuclear	TW	Open-loop	South West
Wylfa [e]	490	Nuclear	SW	Open-loop	Wales
Baglan Bay	510	CCGT	TW [c]	Evaporative	Wales
Deeside	515	CCGT	TW [c]	Hybrid	Wales
Kilroot	520	Coal	SW	Open-loop	Northern Ireland
Ballylumford B	540	GT/OCGT	AC	Air cooled	Northern Ireland
Ballylumford C	616	CCGT	SW	Open-loop	Northern Ireland
Killingholme A	665	CCGT	TW [a]	Air cooled	Yorkshire & Humber
Medway	688	CCGT	TW	Evaporative	South East
Keadby	710	CCGT	TW [c]	Open-loop	Yorkshire & Humber
Little Barford	714	CCGT	FW	Evaporative	East
Rye House	715	CCGT	AC	Air cooled	East
Tilbury B [e]	750	Biomass	TW [c]	Open-loop	East
Coryton	800	CCGT	AC	Air cooled	East
Damhead Creek	800	CCGT	AC	Air cooled	South East
Rocksavage	810	CCGT	FW	Evaporative	North West
Seabank 1	812	CCGT	TW	Hybrid	South West
Sutton Bridge	819	CCGT	AC	Air cooled	East
Marchwood	842	CCGT	TW [c]	Open-loop	South West
Severn	848	CCGT	AC	Air cooled	Wales
Hinkley Point B [e]	870	Nuclear	SW [c]	Open-loop	South West
Spalding	880	CCGT	AC	Air cooled	East Midlands
Hunterston B [e]	890	Nuclear	SW	Open-loop	Scotland
Killingholme B	900	CCGT	TW [c]	Hybrid	Yorkshire & Humber
Langage	905	CCGT	AC	Air cooled	South West
Ironbridge [e]	940	Coal	FW	Evaporative	West Midlands
Fawley [e]	968	Oil-ST	TW [c]	Open-loop	South East
Barking	1,000	CCGT	TW [c]	Open-loop	London
Rugeley	1006	Coal	FW [c]	Evaporative	West Midlands
Dungeness B	1,040	Nuclear	SW	Open-loop	South East
Cockenzie [e]	1152	Coal	SW	Open-loop	Scotland
Heysham1	1,160	Nuclear	SW	Open-loop	North West
Hartlepool	1,180	Nuclear	TW	Open-loop	North East
Peterhead	1180	CCGT	SW	Open-loop	Scotland
Torness	1,190	Nuclear	SW	Open-loop	Scotland
Sizewell B	1,191	Nuclear	SW	Open-loop	East
Saltend	1200	CCGT	TW	Evaporative	Yorkshire & Humber
Heysham 2	1,220	Nuclear	TW	Open-loop	North West
Immingham CHP	1,240	CCGT CHP	TW	Hybrid	Yorkshire & Humber
West Burton CCGT	1270	CCGT	TW [c]	Evaporative	East Midlands
South Humber Bank	1,285	CCGT	TW	Open-loop	Yorkshire & Humber
Grain [e]	1300	GT/OCGT	AC	Air cooled	South East
Grain	1320	CCGT CHP	TW [c]	Evaporative	South East
Littlebrook D [e]	1370	Oil-ST	TW [c]	Open-loop	South East
Connahs Quay	1380	CCGT	TW	Hybrid	Wales

Didcot B	1430	CCGT	FW [c]	Hybrid	South East
Aberthaw B	1586	Coal	SW [c]	Open-loop	Wales
Staythorpe C	1724	CCGT	FW	Evaporative	East Midlands
Teeside CCGT	1875	CCGT	TW [c]	Evaporative	North East
Kingsnorth [e]	1940	Coal	TW [c]	Open-loop	South East
Didcot A [e]	1958	Coal	FW [c]	Evaporative	South East
Eggborough	1,960	Coal	FW	Evaporative	Yorkshire & Humber
Ferrybridge C [e]	1960	Coal/ Biomass	FW [c]	Evaporative	Yorkshire & Humber
Ratcliffe	1960	Coal	FW [c]	Evaporative	East Midlands
Fiddler’s Ferry [e]	1961	Coal/ Biomass	TW [c]	Evaporative	North West
Cottam	2,008	Coal	TW [c]	Evaporative	East Midlands
West Burton	2,012	Coal	TW [c]	Evaporative	East Midlands
Pembroke	2180	CCGT	TW	Open-loop	Wales
Longannet	2304	Coal	TW	Open-loop	Scotland
Drax	3,870	Coal	TW [b]	Evaporative [1]	Yorkshire & Humber
2016 Planned and Approved capacity					
Lostock	60	Waste	AC	Air cooled	West Midlands
Tilbury Docks	60	Biomass	AC	Air cooled	East [d]
Stallingborough	65	Biomass	FW	Evaporative	Yorkshire & Humber
Belvedere	70	Waste	AC	Air cooled	London
Peterborough Fengate	79	Biomass	AC	Air cooled	East
Bristol Dock	100	Biomass	TW	Evaporative	South West
Didcot B	120	CCGT	FW	Evaporative	South East [d]
MGT Teesside	295	Biomass	AC	Air cooled	North East [d]
Port Talbot Docks	350	Biomass	AC	Air cooled	Wales [d]
Carrington	380	CCGT	FW	Evaporative	West Midlands [d]
Willington C OCGT	400	OCGT	AC	Air cooled	West Midlands [d]
Hatfield Park 1	450	CCGT	FW	Evaporative	Yorkshire & Humber
Hatfield Park 2	450	Coal	FW	Evaporative	Yorkshire & Humber
Bridestones Carrington	860	CCGT	FW	Evaporative	West Midlands [d]
Gateway energy centre	900	CCGT	AC	Air cooled	London
West marsh road					
Spalding expansion	900	CCGT	AC	Air cooled	West Midlands [d]
Seal Sands	1,020	CCGT CHP	AC	Air cooled	North East
Drakelow	1,220	CCGT	FW	Evaporative	East Midlands [d]
Isle of Grain	1,260	CCGT	TW	Open-loop	South East [d]
Willington C CCGT	2400	CCGT	FW	Evaporative	West Midlands [d]
Hinkley point C	3620	Nuclear	TW	Open-loop	South West [d]

[a] Killingholme – Reported that this was tower (evaporative) cooling although the satellite imagery suggests strongly that Hybrid tower cooling is being used.
[b] Drax – Reported that Drax uses open-loop cooling however it is clear from the satellite imagery that evaporative towers are used.
[c] The cooling water source was the same as communicated by the Environment Agency.
[d] The consented power station is on or very close to the site of an existing power station, in order to evaluate the extent of legacy site redevelopment.
[e] Plant to be decommissioned for ‘opting out’ of the Large Combustion Plant Directive, besides Wylfa which is nuclear and closed in 2013.

A.2 Electricity Pathways

UKM-326, CP1-REN, CP2-NUC, CP3-CCS have been taken from the DECC 2050s Pathways calculator, "calculator with costs" version, more information available from: http://2050-wiki.greenonblack.com/pages/72

CCS+: This pathway has intended to mirror the CP2 Pathway, but testing the assumption that no further Nuclear is built in the UK and is hence replaced with further CCS and renewables. This results in a large amount of carbon free generation coming from coal and gas with CCS.

UKM+: Having noted that the cost-optimised pathway of UKM-326, "Analogous to MARKAL 3.26", had a high number of ambitious demand reductions, a similar pathway (in terms of generation class distribution) was made with less demand reductions such that a higher electricity demand would need to be met.

Table A 2. DECC 2050s Pathways Calculator inputs.

Component	MARKAL 3.26	CP1	CP2	CP3	CCS+	UKM+
Supply						
Nuclear power stations	1.8	1.4	2.7	1.5	1	1.9
CCS power stations	1.6	1.3	1	2	2.55	1.9
CCS power station fuel mix	2	3	3	3	3	2
Offshore wind	1.3	1.9	1.2	1.3	1.5	1.4
Onshore wind	1.3	2.7	1.4	1.5	1.5	1.4
Wave	2	1.6	1	1	1	2
Tidal Stream	2.5	2	1	1	1	2.5
Tidal Range	2.5	2	1	1	1	2.5
Biomass power stations	1	1	1	1	1.2	1
Solar panels for electricity	1	1.2	1	1	1.3	1.4
Solar panels for hot water	2	1.8	1	1	1	2
Geothermal electricity	1	1	1	1	1	1
Hydroelectric power stations	1.5	2	1	1	1	1.5
Small-scale wind	1	1	1	1	1	1
Electricity imports	1.8	1	1	1.5	1.5	1.8
Land dedicated to bioenergy	3	2	4	3	3	3
Livestock and their management	2	2	2	2	2	2
Volume of waste and recycling	2	2	2	2	2	2
Marine algae	1	1	3	1	1	1
Type of fuels from biomass	1	1	3	2	2	1
Bioenergy imports	2.5	2	3.7	3	3	2.5
Demand						
Domestic passenger transport						
Domestic transport behaviour	4	4	2	3	3	3
Shift to zero emission transport	3	4	3	2	2	3
Choice of fuel cells or batteries	1	2	2	2	2	1
Domestic freight	4	3	2	3	3	4
International aviation	1	2	2	2	2	1
International shipping	1	2	2	2	2	1
Domestic space heating and hot water						
Average temperature of homes	4	4	2	3	3	3

Home insulation	3	4	3	3	3	3
Home heating electrification	3	4	3	3	3	4
Home heating that isn't electric	3	4	3	2	2	3
Domestic lighting, appliances, and cooking						
Home lighting & appliances	4	4	2	3	3	3
Electrification of home cooking	2	2	2	1	1	2
Industrial processes						
Growth in industry	2	2	2	2	2	2
Energy intensity of industry	3	3	1	3	3	3
Commercial heating and cooling						
Commercial demand for heating and cooling	4	4	2	3	3	3
Commercial heating electrification	3	4	3	4	4	4
Commercial heating that isn't electric	2	4	3	3	3	2
Commercial lighting, appliances, and catering						
Commercial lighting & appliances	4	4	2	3	3	3
Electrification of commercial cooking	2	2	2	1	1	2
Electricity Balancing & Other						
Geosequestration	1	1	1	2	2	1
Storage, demand shifting & interconnection	2	4	2	2	2	2
Indigenous fossil-fuel production	1	1	1	1	1	1

Appendix B - CHAPTER 5

B.1 Regional capacity cooling source and method distributions

Table B 1. Capacity distributions by cooling source for 2010.

Busbar	DECC Region (-cooling water source)	CCGT	Other	Coal / coal-biomass	Nuclear	Grand Total
13	East (Anglian)	12.24%	8.95%	0.00%	12.34%	7.60%
	FW	2.20%	0.00%	0.00%	0.00%	0.89%
	TW	1.29%	7.36%	0.00%	0.00%	1.46%
	SW	0.00%	0.00%	0.00%	12.34%	1.49%
	AC	8.75%	1.59%	0.00%	0.00%	3.75%
10	East Midlands*	14.38%	2.96%	21.63%	0.00%	13.70%
	FW	5.31%	2.24%	7.09%	0.00%	4.89%
	TW	5.12%	0.00%	14.54%	0.00%	7.11%
	AC	3.95%	0.73%	0.00%	0.00%	1.70%
16	London	4.34%	1.91%	0.00%	0.00%	2.01%
	TW	3.08%	0.00%	0.00%	0.00%	1.25%
	AC	1.26%	1.91%	0.00%	0.00%	0.75%
8	North East	5.92%	2.06%	0.54%	12.22%	4.33%
	FW	0.14%	1.28%	0.54%	0.00%	0.41%
	TW	5.78%	0.37%	0.00%	12.22%	3.87%
	AC	0.00%	0.41%	0.00%	0.00%	0.05%
9	North West	3.54%	2.10%	7.09%	24.65%	7.14%
	FW	2.84%	1.77%	0.00%	0.00%	1.38%
	TW	0.00%	0.00%	7.09%	12.01%	3.90%
	SW	0.71%	0.00%	0.00%	12.64%	1.81%
	AC	0.00%	0.33%	0.00%	0.00%	0.04%
-	Northern Ireland	3.16%	8.35%	1.88%	0.00%	3.00%
	TW	1.26%	0.00%	0.00%	0.00%	0.51%
	SW	1.90%	0.00%	1.88%	0.00%	1.42%
	AC	0.00%	8.35%	0.00%	0.00%	1.06%
1-7	Scotland	3.64%	0.68%	12.50%	21.54%	8.49%
	TW	0.00%	0.00%	8.33%	0.00%	2.88%
	SW	3.64%	0.19%	4.17%	21.54%	5.54%
	AC	0.00%	0.49%	0.00%	0.00%	0.06%
14	South East	10.37%	54.20%	14.10%	10.77%	17.29%
	FW	4.55%	0.60%	7.08%	0.00%	4.37%
	TW	3.35%	35.91%	7.02%	0.00%	8.36%
	SW	0.00%	0.00%	0.00%	10.77%	1.30%
	AC	2.47%	17.69%	0.00%	0.00%	3.26%
15	South West	9.15%	1.82%	0.00%	13.40%	5.56%
	TW	6.36%	0.00%	0.00%	4.39%	3.11%
	SW	0.00%	0.00%	0.00%	9.01%	1.09%
	AC	2.79%	1.82%	0.00%	0.00%	1.36%
12	Wales	17.46%	2.56%	7.05%	5.08%	10.46%
	TW	14.13%	0.00%	1.31%	0.00%	6.19%
	SW	0.00%	0.00%	5.74%	5.08%	2.60%
	AC	3.32%	2.56%	0.00%	0.00%	1.68%
11	W. Midlands & Severn	0.00%	0.49%	7.04%	0.00%	2.50%
	FW	0.00%	0.00%	7.04%	0.00%	2.43%
	AC	0.00%	0.49%	0.00%	0.00%	0.06%
10	Yorkshire & the Humber *	15.80%	13.90%	28.17%	0.00%	17.93%
	FW	1.13%	0.00%	14.18%	0.00%	5.36%
	TW	14.67%	12.17%	14.00%	0.00%	12.35%
	AC	0.00%	1.73%	0.00%	0.00%	0.22%
	Grand Total	100.00%	100.00%	100.00%	100.00%	100.00%

Key:
FW – freshwater
TW – tidal water
SE – sea water
AC – air cooled

Table B 2. Assumed capacity distribution for 2020 by capacity type and cooling method for freshwater and tidal water.

2020	FW				FW Total	TW				TW Total
	Once-through	Evaporative	Hybrid	Air cooled		Once-through	Evaporative	Hybrid	Air cooled	
CCGT	0%	85%	10%	5%	100%	35%	30%	20%	15%	100%
C&B	0%	85%	10%	5%	100%	45%	25%	20%	10%	100%
Nuclear	100%*	0%	0%	0%	100%	100%	0%	0%	0%	100%
Other	5%	50%	20%	25%	100%	10%	40%	20%	30%	100%
Total	105%	220%	40%	35%	400%	190%	95%	60%	55%	400%

* There is no nuclear power on freshwater, but the distribution must be assigned to a cooling method.

Table B 3. Assumed capacity distribution for 2020 by capacity type and cooling method for sea water and air-cooled.

2020	SW				SW Total	AC				AC Total
	Once-through	Evaporative	Hybrid	Air cooled		Once-through	Evaporative	Hybrid	Air cooled	
CCGT	60%	20%	20%	0%	100%	0%	0%	0%	100%	100%
C&B	60%	20%	20%	0%	100%	0%	0%	0%	100%	100%
Nuclear	100%	0%	0%	0%	100%	0%	0%	0%	100%	100%
Other	80%	5%	0%	15%	100%	0%	0%	0%	100%	100%
Total	300%	45%	40%	15%	400%	0%	0%	0%	400%	400%

Table B 4. Assumed capacity distribution for 2050 by capacity type and cooling method for freshwater and tidal water.

2050	FW				FW Total	TW				TW Total
	Once-through	Evaporative	Hybrid	Air cooled		Once-through	Evaporative	Hybrid	Air cooled	
CCGT	0%	60%	30%	10%	100%	35%	20%	30%	15%	100%
C&B	0%	60%	30%	10%	100%	35%	20%	35%	10%	100%
Nuclear	100%*	0%	0%	0%	100%	100%	0%	0%	0%	100%
Other	5%	50%	20%	25%	100%	10%	40%	20%	30%	100%
Total	105%	170%	80%	45%	400%	180%	80%	85%	55%	400%

* There is no nuclear power on freshwater, but the distribution must be assigned to a cooling method.

Table B 5. Assumed capacity distribution for 2050 by capacity type and cooling method for sea water and air-cooled.

2050	SW				SW Total	AC				AC Total
	Once-through	Evaporative	Hybrid	Air cooled		Once-through	Evaporative	Hybrid	Air cooled	
CCGT	60%	20%	20%	0%	100%	0%	0%	0%	100%	100%
C&B	60%	20%	20%	0%	100%	0%	0%	0%	100%	100%
Nuclear	100%	0%	0%	0%	100%	0%	0%	0%	100%	100%
Other	80%	5%	0%	15%	100%	0%	0%	0%	100%	100%
Total	300%	45%	40%	15%	400%	0%	0%	0%	400%	400%

Table B 6. Assumed cooling source distribution for each capacity type and busbar in 2050 (Coal and Gas incl. CCS variants).

2050	Busbar	FW	TW	SW	AC	FW	TW	SW	AC
DECC zone	2050	Gas				Coal			
Scotland	1	40%	20%	40%	0%	40%	20%	40%	0%
	2	40%	20%	40%	0%	40%	20%	40%	0%
	3	0%	35%	65%	0%	0%	35%	65%	0%
	4	35%	25%	40%	0%	35%	25%	40%	0%
	5	20%	50%	30%	0%	20%	50%	30%	0%
	6	40%	30%	30%	0%	40%	30%	30%	0%
	7	40%	40%	20%	0%	40%	40%	20%	0%
North East	8	40%	40%	15%	5%	40%	40%	20%	0%
North West	9	30%	30%	30%	10%	35%	35%	30%	0%
Yorkshire and the Humber	10	35%	35%	20%	10%	40%	40%	20%	0%
EM & WM	11	35%	35%	20%	10%	40%	40%	20%	0%
Wales	12	20%	40%	35%	5%	20%	40%	40%	0%
East	13	0%	25%	65%	10%	0%	30%	70%	0%
South East	14	0%	20%	60%	20%	0%	30%	70%	0%
South West	15	0%	20%	65%	15%	0%	20%	80%	0%
London	16	10%	35%	35%	20%	10%	45%	45%	0%

Table B 7. Assumed cooling source distribution for each capacity type and busbar in 2050 (Nuclear and Other).

2050 DECC zone	Busbar 2050	FW	TW	SW	AC	FW	TW	SW	AC
		Nuclear				Other (biomass, waste, CHP)			
Scotland	1	0%	0%	100%	0%	30%	30%	20%	20%
	2	0%	0%	100%	0%	30%	30%	20%	20%
	3	0%	0%	100%	0%	30%	30%	20%	20%
	4	0%	0%	100%	0%	30%	30%	20%	20%
	5	0%	20%	80%	0%	30%	30%	20%	20%
	6	0%	20%	80%	0%	30%	30%	20%	20%
	7	0%	25%	75%	0%	30%	30%	20%	20%
North East	8	0%	40%	60%	0%	30%	30%	20%	20%
North West	9	0%	30%	70%	0%	30%	30%	20%	20%
Yorkshire and the Humber	10	0%	40%	60%	0%	30%	30%	20%	20%
EM & WM	11	0%	40%	60%	0%	30%	30%	20%	20%
Wales	12	0%	35%	65%	0%	30%	30%	20%	20%
East	13	0%	0%	100%	0%	30%	30%	20%	20%
South East	14	0%	0%	100%	0%	30%	30%	20%	20%
South West	15	0%	0%	100%	0%	30%	30%	20%	20%
London	16	0%	0%	100%	0%	30%	30%	20%	20%

B.2 Available water resource under climate change

Available water resource is calculated by applying the regional climate change factors to the historical flow values at each of the rivers selected.

Table B 8. Water resource at Q_{95} flow.

ITRC busbars		UKCP09 RB region					Q_{95}			
Busbar	BB#	Region name	Main rivers	Gauges	CEH Gauge #	Area km2	Control/hist	2020s	2050s	2080s
NW-SHETL	1	North & West Highlands	Lochy	Camisky	91002	1252	5.8	5.3	4.7	4.7
			Conon	Moy bridge	4001	961.8	11.0	10.1	8.8	8.9
			Beauly	Erchless	5001	849.5	14.2	13.0	11.4	11.4
			Ewe	Poolewe	94001	441.1	5.7	5.2	4.6	4.6
N-SHETL	2	North Scotland	Spey	Boat o Brig	8006	2861.2	19.5	15.8	12.9	10.8
			Ness	Ness-side	6007	1839.1	20.0	16.3	13.2	11.1
			Don	Parkhill	11001	1273	5.5	4.5	3.7	3.1
				Park	12002	1844	8.8	7.2	5.8	4.9
S-ARGL	3	Argyll								
S-SHETL	4	Tay	Tay	Ballathie	15006	4587.1	43.5	38.4	32.3	28.1
N-SPTL	5	Forth	Forth	Craigforth	18011	1036	5.7	5.1	4.4	3.9
S-SPTL	6	Clyde	Clyde	Daldowie	84013	1903.1	9.7	8.8	7.5	6.7
				Linnbrane	85001	784.3	9.6	8.7	7.5	6.6
UN-E&W	7	Borders	Solway & Tweed	Norham	21009	4390	14.4	11.9	8.8	7.2
			Eden	Sheepmount	76007	2286.5	9.9	7.6	5.7	4.9
N-E&W	8	North East England	Tyne	Bywell	23001	2175.6	6.3	4.7	3.5	3.0
			Wear	Chester le Street	24009	1008.3	3.1	2.3	1.7	1.5
			Tees	Low Moor	25009	1264	3.0	2.2	1.7	1.4
NW-E&W	9	North West England	Dee	Chester suspension bridge	67033	1816.8	5.1	4.0	3.0	2.5
			Mersey	Westy	69037	2030	8.3	6.4	4.8	4.1
NE-E&W	10	Humber & E Midlands	Aire	Beal weir	27003	1932	7.9	6.3	4.6	3.9
			Trent	N Muskham	28022	8231	28.3	22.7	16.6	14.0
			Great Ouse	Skelton	27009	3315	7.7	4.9	2.7	1.9
M-E&W	11	West Midlands/ Severn	Severn	Haw bridge	54057	9895	19.9	16.0	11.7	9.8
MW-E&W	12	Western Wales	Wye	Redbrook	55023	4010	11.2	7.3	4.5	3.2
ME-E&W	13	Anglian								
S-E&W	14	South/ SE England								
SW-E&W	15	South West	Test	Test	42004	1040	5.7	4.7	3.9	3.4
			Avon	Avon	43021	1706	6.2	5.1	4.2	3.7
SE-E&W	16	Thames/ London	Thames	Kingston	39001	9948	7.5	4.4	2.3	1.5

Table B 9. Water resource at Q_{99} flow.

ITRC busbars		UKCP09 RB region					Q_{99}			
Busbar	BB#	Region name	Main rivers	Gauges	CEH Gauge #	Area km2	Control/hist	2020s	2050s	2080s
NW-SHETL	1	North & West Highlands	Lochy	Camisky	91002	1252	4.6	4.0	3.2	3.1
			Conon	Moy bridge	4001	961.8	6.0	5.3	4.2	4.1
			Beauly	Erchless	5001	849.5	7.8	6.9	5.4	5.3
			Ewe	Poolewe	94001	441.1	3.2	2.9	2.3	2.2
N-SHETL	2	North Scotland	Spey	Boat o Brig	8006	2861.2	14.2	11.1	8.9	7.2
			Ness	Ness-side	6007	1839.1	14.4	11.2	9.0	7.3
			Don	Parkhill	11001	1273	4.5	3.5	2.8	2.3
				Park	12002	1844	5.9	4.6	3.7	3.0
S-ARGL	3	Argyll								
S-SHETL	4	Tay	Tay	Ballathie	15006	4587.1	31.7	27.2	21.6	17.7
N-SPTL	5	Forth	Forth	Craigforth	18011	1036	3.9	3.3	2.7	2.2
S-SPTL	6	Clyde	Clyde	Daldowie	84013	1903.1	8.1	6.9	5.6	4.6
				Linnbrane	85001	784.3	7.2	6.2	5.1	4.2
UN-E&W	7	Borders	Solway & Tweed	Norham	21009	4390	10.5	9.8	7.0	5.4
			Eden	Sheepmount	76007	2286.5	7.6	5.6	4.1	3.4
N-E&W	8	North East England	Tyne	Bywell	23001	2175.6	4.3	3.0	2.2	1.7
			Wear	Chester le Street	24009	1008.3	2.7	1.9	1.4	1.1
			Tees	Low Moor	25009	1264	2.4	1.7	1.2	0.9
NW-E&W	9	North West England	Dee	Chester suspension bridge	67033	1816.8	4.5	2.7	1.5	1.0
			Mersey	Westy	69037	2030	4.6	2.8	1.5	1.0
NE-E&W	10	Humber & E Midlands	Aire	Beal weir	27003	1932	5.9	4.6	3.2	2.6
			Trent	N Muskham	28022	8231	23.2	17.9	12.5	10.3
			Great Ouse	Skelton	27009	3315	5.5	3.6	2.1	1.5
M-E&W	11	West Midlands/ Severn	Severn	Haw bridge	54057	9895	15.5	12.0	8.4	6.9
MW-E&W	12	Western Wales	Wye	Redbrook	55023	4010	7.4	4.5	2.5	1.7
ME-E&W	13	Anglian								
S-E&W	14	South/ SE England								
SW-E&W	15	South west	Test	Test	42004	1040	4.8	3.8	3.1	2.6
			Avon	Avon	43021	1706	5.0	4.0	3.2	2.7
SE-E&W	16	Thames/ London	Thames	Kingston	39001	9948	3.6	1.9	0.8	0.5

B.3 Available resource to the electricity sector

Table B 10. Sum of water resource in each busbar region at Q95.

m^3/s	Available resource $\Sigma\ Q_{95}$				Abs factor	Licence	Available to electricity sector $\Sigma\ Q_{e95}$			
BB	Current	2020s	2050s	2080s	A_{95}	S_e	Current	2020s	2050s	2080s
1	36.60	33.73	29.43	29.51	15%	20%	1.10	1.01	0.88	0.89
2	53.75	43.79	35.53	29.84	15%	20%	1.61	1.31	1.07	0.90
3	0.00	0.00	0.00	0.00	15%	20%	0.00	0.00	0.00	0.00
4	43.51	38.40	32.32	28.13	15%	20%	1.31	1.15	0.97	0.84
5	5.65	5.10	4.40	3.90	15%	20%	0.17	0.15	0.13	0.12
6	19.38	17.41	15.02	13.29	15%	20%	0.58	0.52	0.45	0.40
7	24.26	19.55	14.51	12.06	15%	20%	0.73	0.59	0.44	0.36
8	12.41	9.29	6.96	5.82	15%	40%	0.74	0.56	0.42	0.35
9	13.39	10.34	7.79	6.64	10%	30%	0.40	0.31	0.23	0.20
10	43.80	33.97	23.94	19.84	17.5%	50%	3.83	2.97	2.09	1.74
11	19.87	15.98	11.67	9.85	15%	50%	1.49	1.20	0.88	0.74
12	11.20	7.34	4.50	3.21	12.5%	30%	0.42	0.28	0.17	0.12
13	0.00	0.00	0.00	0.00	17.5%	10%	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	15%	10%	0.00	0.00	0.00	0.00
15	11.85	9.87	8.15	7.12	12.5%	35%	0.52	0.43	0.36	0.31
16	7.52	4.44	2.29	1.45	15%	10%	0.11	0.07	0.03	0.02
Sum	303.19	249.21	196.50	170.67			13.01	10.55	8.12	6.98
Reduction %		-17.80	-35.19	-43.71				-18.93	-37.64	-46.38

Table B 11. Sum of water resource in each busbar region at Q99.

m^3/s	Available resource $\Sigma\ Q_{99}$				Abs factor	Licence	Available to electricity sector $\Sigma\ Q_{e99}$			
BB #	Current	2020s	2050s	2080s	A_{95}	S_e	Current	2020s	2050s	2080s
1	21.60	19.01	15.04	14.72	15%	20%	0.65	0.57	0.45	0.44
2	39.00	30.43	24.34	19.73	15%	20%	1.17	0.91	0.73	0.59
3	0.00	0.00	0.00	0.00	15%	20%	0.00	0.00	0.00	0.00
4	31.72	27.17	21.56	17.71	15%	20%	0.95	0.82	0.65	0.53
5	3.89	3.30	2.72	2.23	15%	20%	0.12	0.10	0.08	0.07
6	15.31	13.02	10.72	8.78	15%	20%	0.46	0.39	0.32	0.26
7	18.11	15.37	11.01	8.82	15%	20%	0.54	0.46	0.33	0.26
8	9.46	6.53	4.73	3.72	15%	40%	0.57	0.39	0.28	0.22
9	9.13	5.52	3.08	2.05	10%	30%	0.27	0.17	0.09	0.06
10	34.61	26.14	17.81	14.42	17.5%	50%	3.03	2.29	1.56	1.26
11	15.52	12.01	8.40	6.88	15%	50%	1.16	0.90	0.63	0.52
12	7.40	4.48	2.50	1.66	12.5%	30%	0.28	0.17	0.09	0.06
13	0.00	0.00	0.00	0.00	17.5%	10%	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	15%	10%	0.00	0.00	0.00	0.00
15	9.79	7.85	6.31	5.38	12.5%	35%	0.43	0.34	0.28	0.24
16	3.62	1.86	0.84	0.49	15%	10%	0.05	0.03	0.01	0.01
Sum	219.15	172.70	129.05	106.59			9.68	7.53	5.51	4.53
Reduction %		-21.20	-41.11	-51.36				-22.19	-43.11	-53.24

Table B 12. Water resource availability at Q95 and Q99 in the 2020s compared to current and projected abstractions in 2020.

							Abstraction m³/s			
			Sum of Q_{95}	Current	Available to sector in 2020s			MPI-CC	EHT-Off	EHT-CCS
BB	Region	Main rivers	(m³/s)	Q_{e95}	Q_{e95}	Q_{e99}	2010	2020		
1	N & W Highlands	Lochy Conon Beauly Ewe	36.6	1.1	1.0	0.6	0.00	0.00	0.00	0.00
2	NE Scotland	Spey Ness Don	53.7	1.6	1.3	0.9	0.00	0.02	0.02	0.02
3	Argyll		0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
4	Tay	Tay	43.5	1.3	1.2	0.8	0.00	0.00	0.00	0.00
5	Forth	Forth	5.7	0.2	0.2	0.1	0.00	0.00	0.00	0.00
6	Clyde	Clyde Leven	19.4	0.6	0.5	0.4	0.00	0.00	0.01	0.00
7	Borders	Tweed Eden	24.3	0.7	0.6	0.5	0.00	0.01	0.01	0.02
8	NE England	Tyne Wear Tees	12.4	0.7	0.6	0.4	0.00	0.07	0.04	0.14
9	NW England	Eden Mersey Dee	13.4	0.4	0.3	0.2	0.08	0.50	0.40	0.53
10	Humber & E Midlands	Aire G. Ouse Trent	43.8	3.8	3.0	2.3	1.76	0.31	0.24	0.38
11	W Midlands & Severn	Severn	19.9	1.5	1.2	0.9	2.05	0.10	0.08	0.09
12	W Wales	Wye	11.2	0.4	0.3	0.2	0.00	0.03	0.03	0.03
13	Anglian	-	0.0	0.0	0.0	0.0	0.65	0.13	0.11	0.12
14	S & SE England	-	0.0	0.0	0.0	0.0	0.36	0.01	0.04	0.00
15	SW England	Test Avon	11.9	0.5	0.4	0.3	0.15	0.00	0.00	0.00
16	Thames & London	Thames	7.5	0.1	0.1	0.0	0.62	0.03	0.03	0.05
		Sum	303.2	13.0	10.6	7.5	5.67	1.22	1.01	1.41

Key
Future abstraction is within resource constraints
Future abstraction is equal to 2020s Q_{99}
Future abstraction exceeds 2020s Q_{99} and is smaller than or equal to Q_{e95}
Future abstraction exceeds 2020s Q_{99} & Q_{95}
Future abstraction exceeds 2020s Q_{99} & Q_{95}, and current Q_{95}

Table B 13. Water resource availability at Q_{95} and Q_{99} in the 2080s compared to current and projected abstractions in 2080.

BB	Region	Main rivers	Sum of Q_{95} (m^3/s)	Current Q_{e95}	Available to sector in 2080s Q_{e95}	Q_{e99}	Abstraction m^3/s 2010	MPI-CC 2050*	EHT-Off	EHT-CCS
1	N & W Highlands	Lochy Conon Beauly Ewe	36.6	1.1	0.9	0.4	0.00	0.10	0.01	0.03
2	NE Scotland	Spey Ness Don	53.7	1.6	0.9	0.6	0.00	0.09	0.21	0.94
3	Argyll		0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
4	Tay	Tay	43.5	1.3	0.8	0.5	0.00	0.06	0.01	0.03
5	Forth	Forth	5.7	0.2	0.1	0.1	0.00	0.05	0.03	0.05
6	Clyde	Clyde Leven	19.4	0.6	0.4	0.3	0.00	0.28	0.09	0.23
7	Borders	Tweed Eden	24.3	0.7	0.4	0.3	0.00	0.02	0.07	0.05
8	NE England	Tyne Wear Tees	12.4	0.7	0.3	0.2	0.00	0.68	0.14	0.17
9	NW England	Eden Mersey Dee	13.4	0.4	0.2	0.1	0.08	0.11	0.10	3.13
10	Humber & E Midlands	Aire G. Ouse Trent	43.8	3.8	1.7	1.3	1.76	0.10	0.17	4.14
11	W Midlands & Severn	Severn	19.9	1.5	0.7	0.5	2.05	0.01	0.03	0.05
12	W Wales	Wye	11.2	0.4	0.1	0.1	0.00	0.13	0.05	0.20
13	Anglian	-	0.0	0.0	0.0	0.0	0.65	0.00	0.00	0.00
14	S & SE England	-	0.0	0.0	0.0	0.0	0.36	0.00	0.00	0.00
15	SW England	Test Avon	11.9	0.5	0.3	0.2	0.15	0.00	0.00	0.00
16	Thames & London	Thames	7.5	0.1	0.0	0.0	0.62	0.22	0.08	0.96
		Sum	303.2	13.0	7.0	4.5	5.67	1.85	1.00	9.98

Key

Future abstraction is within resource constraints

Future abstraction is equal to 2080s Q_{99}

Future abstraction exceeds 2080s Q_{99} and is smaller than or equal to Q_{e95}

Future abstraction exceeds 2080s Q_{99} & Q_{95}

Future abstraction exceeds 2080s Q_{99} & Q_{95}, and current Q_{95}

As the strategies only go to 2050, we have compared 2080s water availability against 2050 generation.

Appendix C – CHAPTER 6

C.1 Additional results from hydrological modelling

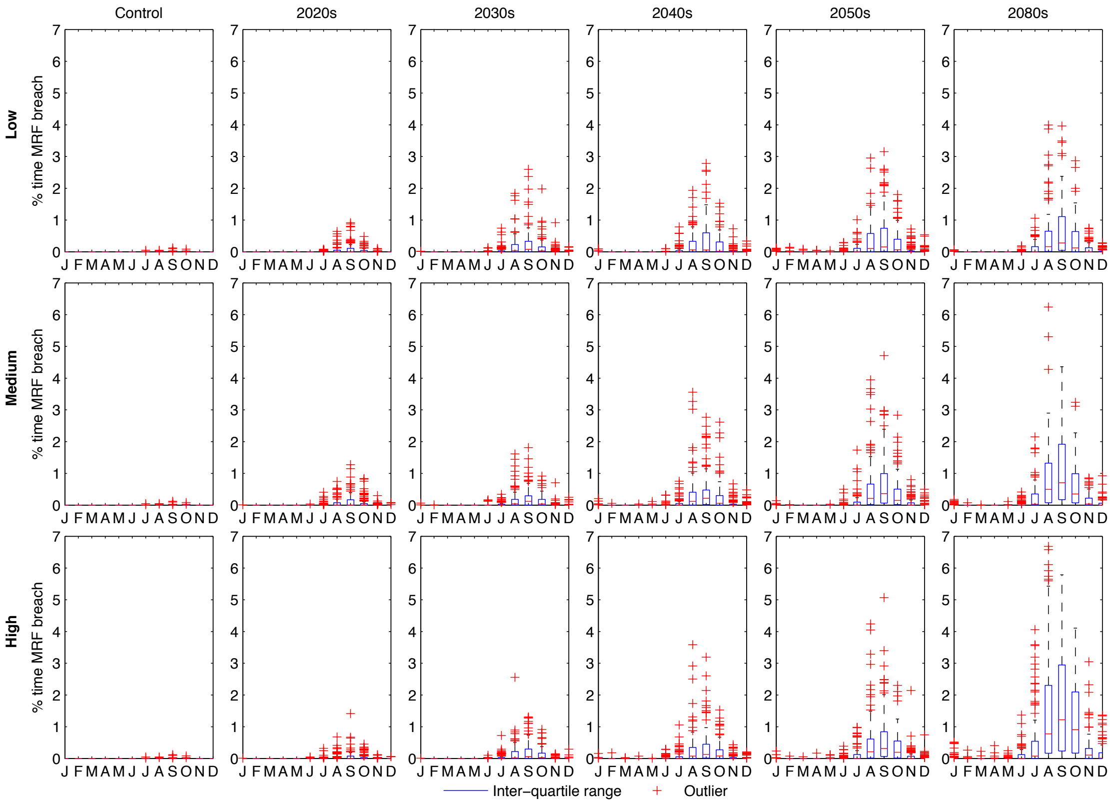


Figure C 1. Monthly boxplots of the frequency of flows below the minimum residual flow for different timeslices and emissions scenarios.

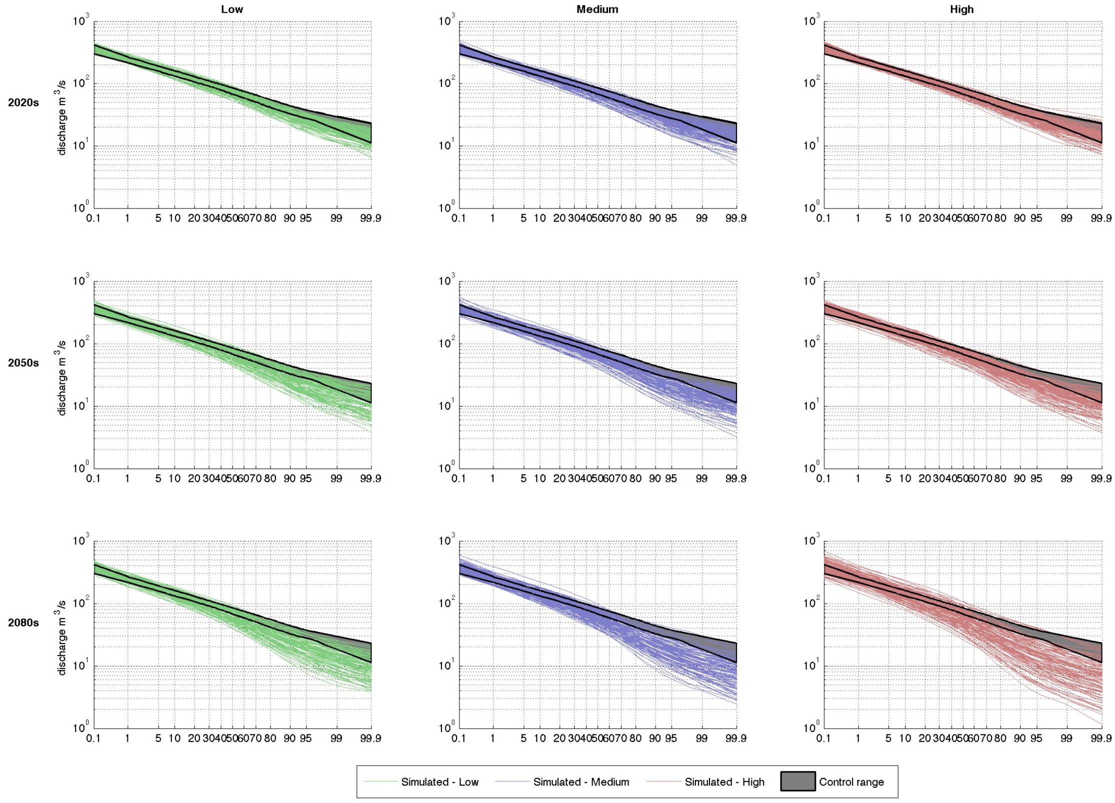


Figure C 2. Ranges bounding the uncertainty of the flow duration curves, comparing the Control profile to different emissions scenarios and timeslices. Taking the 2080s as an example, whilst the median values are relatively similar across emissions scenarios, extreme values span a much wider range in the high emissions scenario.

C.2 Electricity capacity portfolios

Table C 1. Business as usual (BAU) capacity and generation data

	Wet tower				Hybrid							
MW	CCGT	Coal	CCGT CCS	Coal CCS	CCGT	Coal	CCGT CCS	Coal CCS	Total	TWh /yr*	TWh/ 5yrs	Notes
2010	0	3000	0	0	1650	0	0	0	4,650	24	122	
2015	1220	3000	0	0	1650	0	0	0	5,870	31	154	Drakelow C commissioned
2020	3220	3000	0	0	1650	0	0	0	7,870	41	207	Willington commissioned
2025	1610	1500	1610	1500	825	0	825	0	7,870	41	207	CCS on half
2030	0	0	3220	3000	0	0	1650	0	7,870	41	207	CCS on all
2035	0	0	3220	3000	0	0	1650	0	7,870	41	207	
2040	0	0	4220	4000	0	0	1650	0	9,870	52	259	Additional 1GW for Coal and Gas
2045	0	0	4220	4000	0	0	1650	0	9,870	52	259	
2050	0	0	4220	4000	0	0	1650	0	9,870	52	259	

Table C 2. All new hybrid capacity and generation data

	Wet tower				Hybrid							
MW	CCGT	Coal	CCGT CCS	Coal CCS	CCGT	Coal	CCGT CCS	Coal CCS	Total	TWh /yr*	TWh/ 5yrs	Notes
2010	0	3000	0	0	1650	0	0	0	4650	24	122	
2015	0	3000	0	0	2870	0	0	0	5870	31	154	Drakelow C commissioned
2020	0	3000	0	0	4870	0	0	0	7870	41	207	Willington commissioned
2025	0	1500	0	1500	2435	0	2435	0	7870	41	207	CCS on half
2030	0	0	0	3000	0	0	4870	0	7870	41	207	CCS on all
2035	0	0	0	3000	0	0	4870	0	7870	41	207	
2040	0	0	0	3000	0	0	5870	1000	9870	52	259	Additional 1GW for Coal and Gas
2045	0	0	0	3000	0	0	5870	1000	9870	52	259	
2050	0	0	0	3000	0	0	5870	1000	9870	52	259	

Table C 3. Coal new hybrid capacity and generation data.

	Wet tower				Hybrid							
MW	CCGT	Coal	CCGT CCS	Coal CCS	CCGT	Coal	CCGT CCS	Coal CCS	Total	TWh /yr*	TWh/ 5yrs	Notes
2010	0	3000	0	0	1650	0	0	0	4650	24	122	
2015	1220	3000	0	0	1650	0	0	0	5870	31	154	Drakelow C commissioned
2020	3220	3000	0	0	1650	0	0	0	7870	41	207	Willington commissioned
2025	1610	1500	1610	1500	825	0	825	0	7870	41	207	CCS on half
2030	0	0	3220	3000	0	0	1650	0	7870	41	207	CCS on all
2035	0	0	3220	3000	0	0	1650	0	7870	41	207	
2040	0	0	4220	3000	0	0	1650	1000	9870	52	259	Additional 1GW for Coal and Gas
2045	0	0	4220	3000	0	0	1650	1000	9870	52	259	
2050	0	0	4220	3000	0	0	1650	1000	9870	52	259	

Table C 4. Gas future capacity and generation data.

	Wet tower				Hybrid							
MW	CCGT	Coal	CCGT CCS	Coal CCS	CCGT	Coal	CCGT CCS	Coal CCS	Total	TWh /yr*	TWh/ 5yrs	Notes
2010	0	3000	0	0	1650	0	0	0	4650	24	122	
2015	1220	3000	0	0	1650	0	0	0	5870	31	154	Drakelow C commissioned
2020	3220	3000	0	0	1650	0	0	0	7870	41	207	Willington commissioned
2025	1610	0	1610	0	825	0	3825	0	7870	41	207	CCS on half
2030	0	0	3220	0	0	0	4650	0	7870	41	207	CCS on all
2035	0	0	3220	0	0	0	4650	0	7870	41	207	
2040	0	0	4220	0	0	0	5650	0	9870	52	259	Additional 2GW for CCGT+CCS
2045	0	0	4220	0	0	0	5650	0	9870	52	259	
2050	0	0	4220	0	0	0	5650	0	9870	52	259	

Table C 5. All hybrid capacity and generation data.

	Wet tower				Hybrid							
MW	CCGT	Coal	CCGT CCS	Coal CCS	CCGT	Coal	CCGT CCS	Coal CCS	Total	TWh /yr*	TWh/ 5yrs	Notes
2010	0	3000	0	0	1650	0	0	0	4650	24	122	
2015	0	3000	0	0	2870	0	0	0	5870	31	154	Drakelow C commissioned
2020	0	3000	0	0	4870	0	0	0	7870	41	207	Willington commissioned
2025	0	1500	0	0	2435	0	2435	1500	7870	41	207	CCS on half
2030	0	0	0	0	0	0	4870	3000	7870	41	207	CCS on all
2035	0	0	0	0	0	0	4870	3000	7870	41	207	
2040	0	0	0	0	0	0	5870	4000	9870	52	259	Additional 1GW for Coal and Gas
2045	0	0	0	0	0	0	5870	4000	9870	52	259	
2050	0	0	0	0	0	0	5870	4000	9870	52	259	

*Calculated assuming a 70% annual load factor.

C.3 Monthly abstraction and consumption in 2010, 2030 and 2050

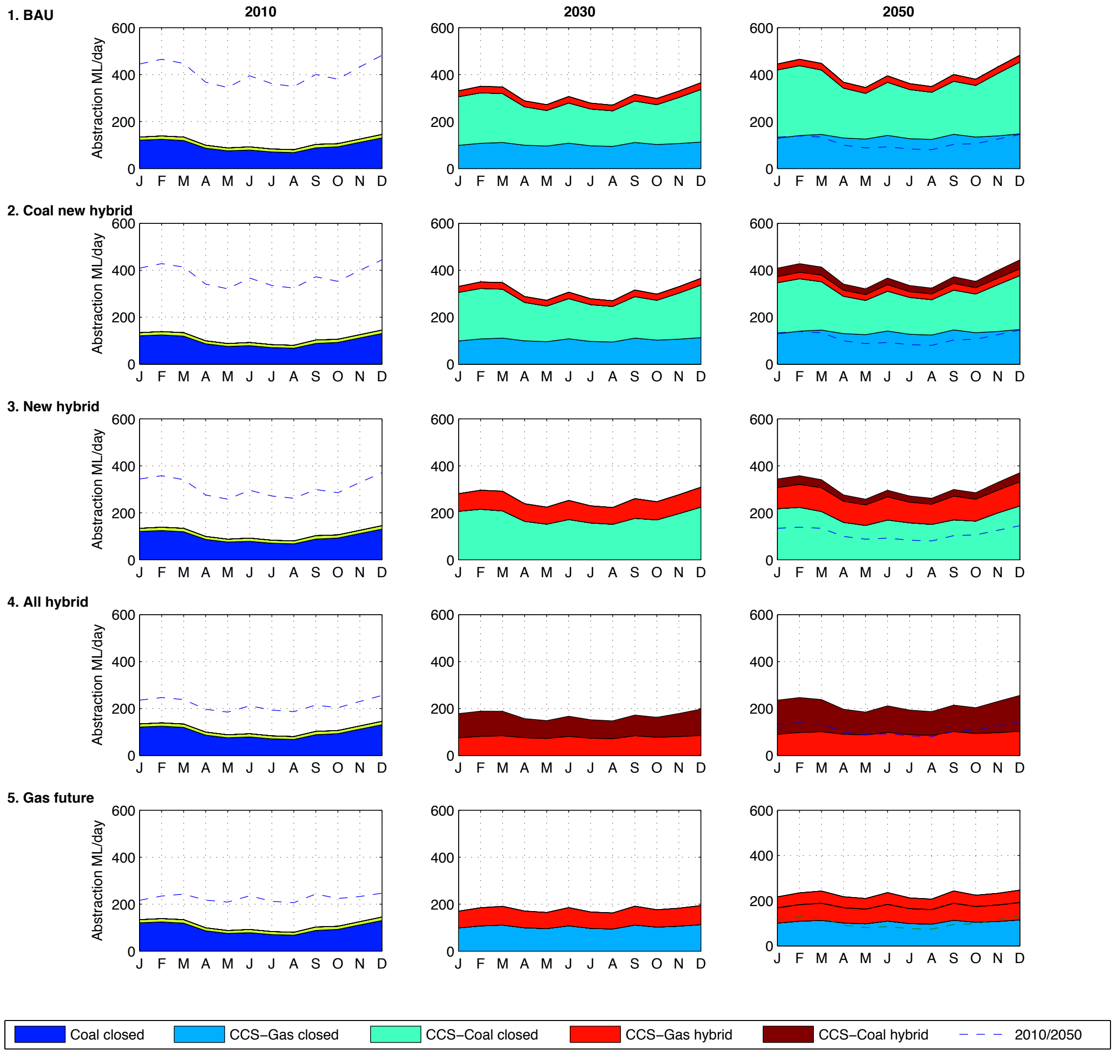


Figure C 3. Abstraction at 70% load factor and reduced (85%) hybrid operation.

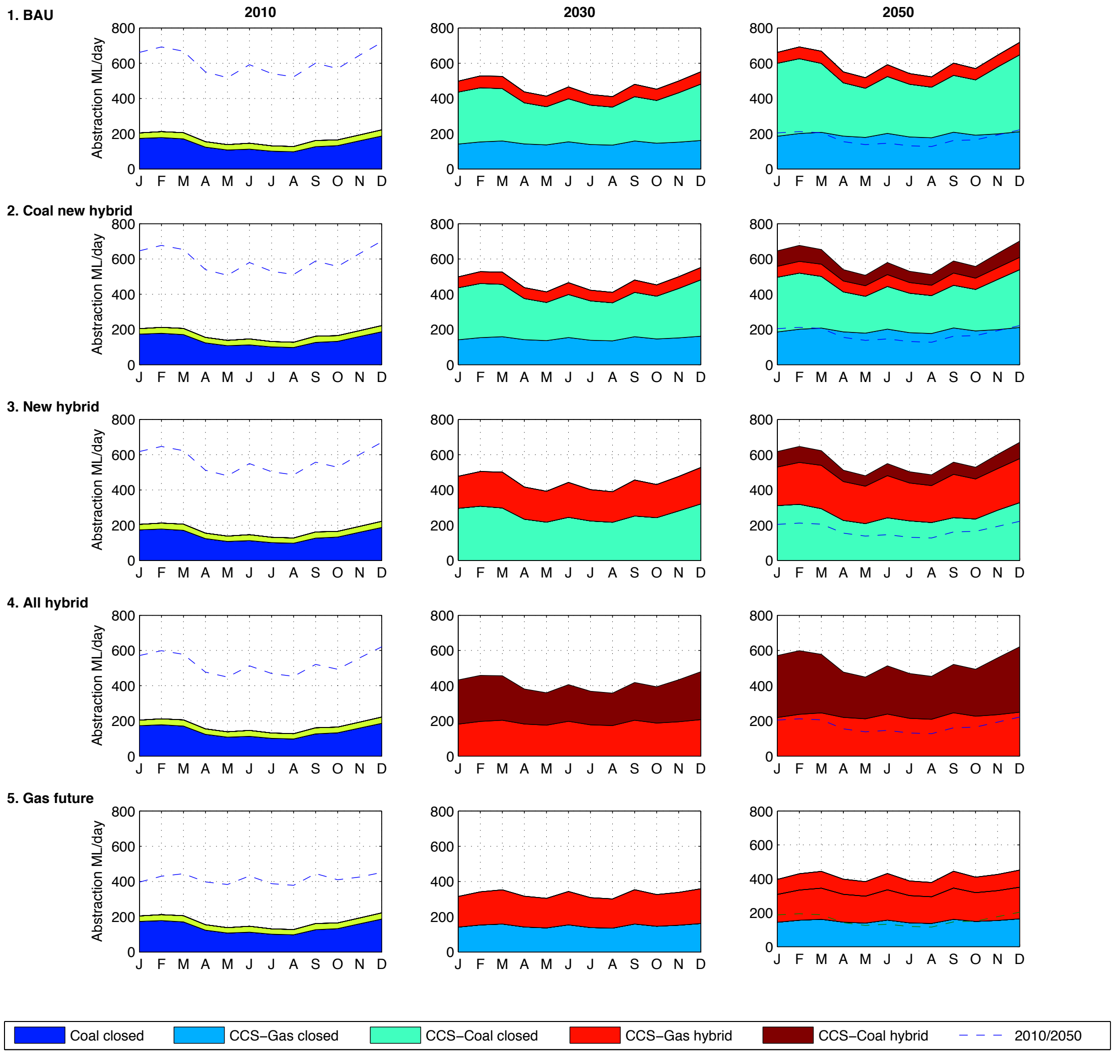


Figure C 4. Abstraction at 100% load factor and reduced (85%) hybrid operation

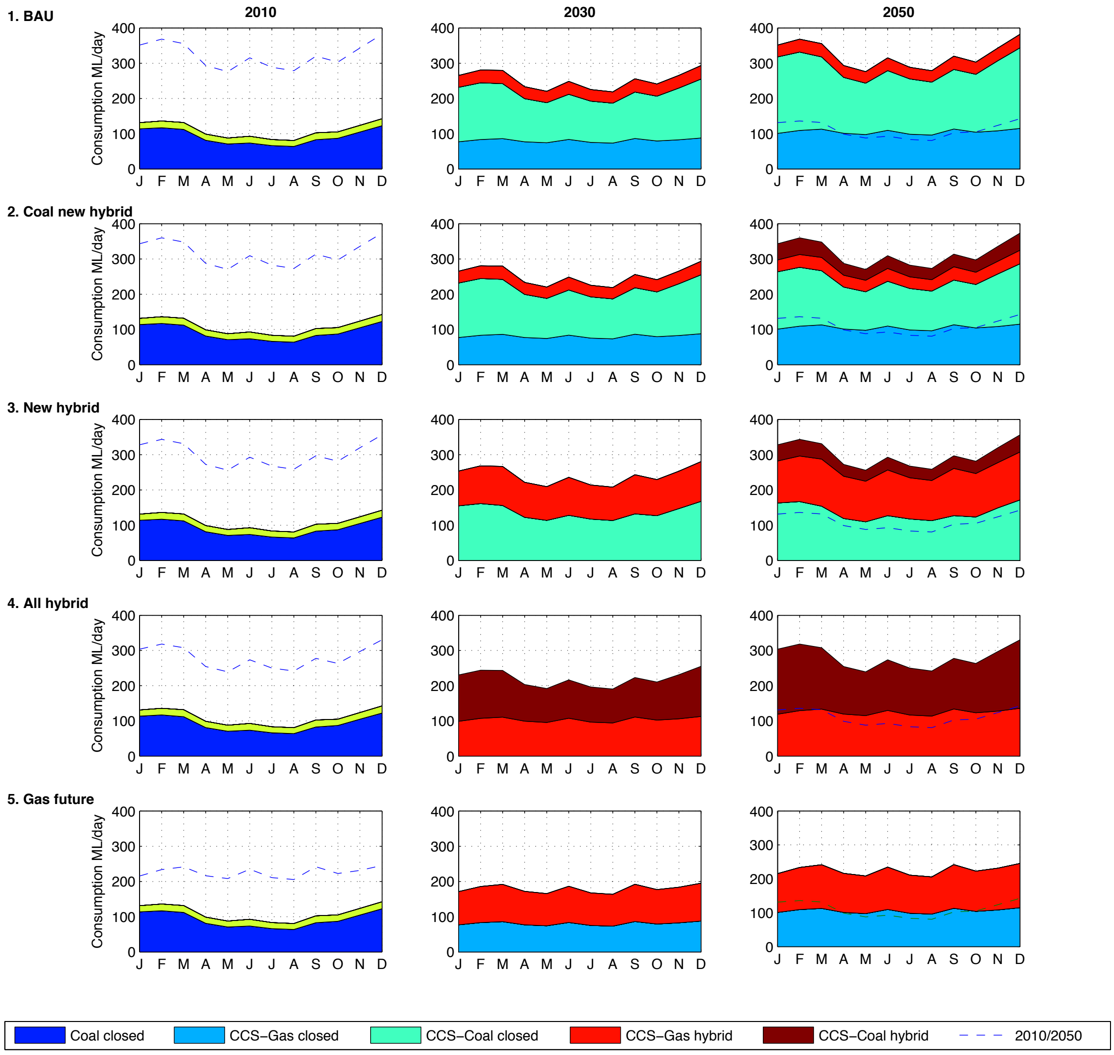


Figure C 5. Consumption at 70% load factor and reduced (85%) hybrid operation.

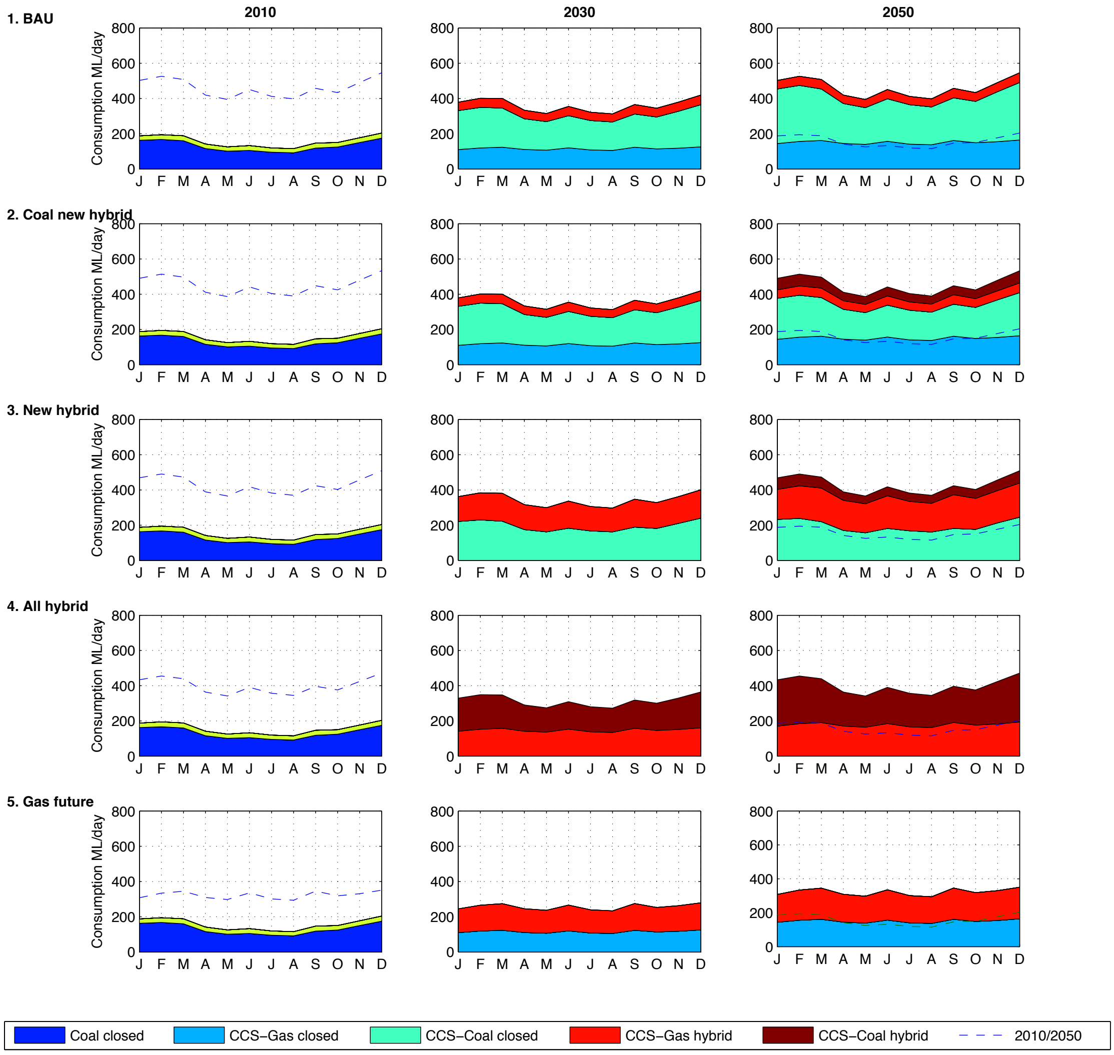


Figure C 6. Consumption at 100% load factor and reduced (85%) hybrid operation.

In Figure C 3 to Figure C 6 abstraction and consumption are presented for the 5 pathways under normal load factor (70%) and maximum load factor (100%) conditions, at 2010, 2030 and 2050. In pathways with hybrid cooling it is assumed that the hybrid cooling is operating in reduced mode at 85%. Hence red and dark red shaded areas are variable demands, that could in effect be 15% points higher (normal operation) or 15% points lower (dry operation).

By 2050 the difference between the least and most water-efficient pathways is by a factor of about 2. It is also worth noting how monthly variations are accentuated at higher demands, with differences between summer and winter abstraction/consumption approaching 100 ML/day.

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