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Electricity systems capacity expansion under cooling water availability constraints

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Abstract: Large and reliable volumes of water are required to cool thermal power plants. Yet across the world growing demands from society, environmental regulation and climate change impacts are reducing the availability of reliable water supplies. This in turn constrains the capacity and locations of thermal power plants that can be developed. The authors present an integrated and spatially explicit energy systems model that explores optimal capacity expansion planning strategies, taking into account electricity and gas transmission infrastructure and cooling water constraints under climate change. In Great Britain, given the current availability of freshwater, it is estimated that around 32 GW of combined cycle gas turbine capacity can be sustainably and reliably supported by freshwater. However, to maintain the same reliability under a medium climate change scenario, this is halved to 16 GW. The authors also reveal that the current benefit of available freshwater to the power sector is ∼£50 billion between 2010 and 2050. Adapting to expected climate change impacts on the reduced reliability of freshwater resources could add an additional £18–19 billion in system costs to the low-carbon energy transition over the time horizon, as more expensive cooling technologies and locations are required.

1 Introduction

Most modern energy policy makers face the ‘energy trilemma’, namely balancing energy security, environmental goals and affordability. Energy security is challenged by the decommissioning of legacy generation plants, introduction of new intermittent energy supplies and climate change impacts on both new and conventional supplies. Environmental goals, in particular relating to carbon emissions reduction, imply a major reconfiguration of the energy supply infrastructure, whilst options for energy transition are constrained by the challenge of ensuring that energy is affordable, in particular for low income households. Therefore, decisions regarding the magnitude, and appropriate time of incorporating new infrastructure in future energy systems to satisfy energy demand will depend on many factors, including ensuring that any new developments are economic, environmentally sound, and provide adequate energy security.

In the United Kingdom, as well as many other countries that are dependent on thermal power stations, availability of gas and cooling water need to be considered when planning new power generation capacity. Therefore, integrated and spatially explicit planning approaches are necessary to understand both the possible configurations but also the performance (in terms of economic, security and environmental objectives) of the future energy system under various scenarios.

In the United Kingdom, previous research has jointly considered future low carbon pathways and cooling water demands. Initial studies (e.g. [1–3]) calculated electricity sector water demands for the United Kingdom across low carbon pathways to 2050 at the national scale. Further work considered the regional demands for cooling water for different supply mixes in the power sector and compared these with water availability [4, 5], including under a medium emissions climate change impacts scenario (Special Report on Emissions Scenarios – SRES A1B [6]). Some regions, namely, the North West, East Midlands and Humber, and possibly the Thames region, have projected freshwater demands that exceed future water availability by 2050. More detailed analyses for the Trent catchment and North Yorkshire regions have also indicated substantial reductions in water availability during low flow periods under climate change, threatening both existing and planned capacity development with carbon capture and storage (CCS) [7, 8].

Water availability aside, decisions of where to locate power plants are based on a large number of factors, including but are not limited to: electricity demand and grid connections; fuel delivery and storage; environmental constraints; land availability and planning conditions; transport, workforce and logistical connectivity. While the application of optimisation techniques for energy systems planning is well established, spatial representation remains a challenge although increasingly analyses now incorporate multiple nodes to represent infrastructure (e.g. transmission lines; power stations; gas storage; gas terminals), economic markets (e.g. weighted demand centres; import/export) and environmental resource constraints (e.g. water availability; emissions caps).

To date, only a few studies have considered cooling water constraints in capacity expansion planning of power systems. In [9, 10], freshwater constraints and costs on capacity expansion for the United States was modelled, and it was found that while water availability does significantly alter cooling systems choice, there are only minimal impacts on the overall fleet technology choices (e.g. choosing gas or coal). In [11] energy–water nexus in China is investigated using ‘virtual water transfer’ concept. Tsolas *et al.* [12] developed a graph-theoretic network representation of water–energy nexus and maximised grid supplies for external demands by minimising the nexus redundancies. For the United Kingdom, it was found that constraining new supplies to sites that could use sea water for cooling could potentially incur additional system costs ∼5–10% [13]. Coupled systems modelling of the electricity system with the aim of ensuring sustainable water supplies for Saudi Arabia found that achieving both deep emissions cuts and water sustainability objectives are more expensive but can be useful for identifying important trade-offs [14, 15]. Recent work showed that coupled water–energy systems optimisation for Spain finds lower cost solutions than when the two sectors are optimised as independent systems [16].

The aim of the analyses described in this paper is to determine the impact of cooling water availability, which may change with time, has on capacity expansion modelling for the Great Britain (GB) electricity and gas network systems. The *CGEN + Water* modelling tool was developed as an extension to the combined gas and electricity network (*CGEN+*) energy systems optimisation model, which was validated and used in several previous research studies such as those reported by [17, 18]. The *CGEN + Water* model includes various cooling systems options with capital and operational costs and was used to analyse a range of scenarios and pathways that consider regional freshwater availability and environmental regulation as potential constraints on generation capacity expansion. A key novelty that goes beyond previous studies is that the model includes not only power generation plants but critically its coupling with both the electricity and gas transmission infrastructure, as it is increasingly acknowledged that electricity transmission can be a key option for mitigating regionalised water stress [14]. Most pertinently, using *CGEN + Water*, we show the impact of expected changes in freshwater availability as a result of climate change, on future configurations of the electricity system.

Section 2 of the paper presents an overview of cooling systems and water resources available for power plants in GB; Section 3 illustrates the methodology and description of the *CGEN + Water* model; Section 4 describes the scenarios developed for the simulation alongside the techno-economic assumptions related to different cooling technologies. In addition, constraints on the availability of water for cooling power plants are described. In Section 5, the modelling outputs for different scenarios are analysed and discussed. A conclusion is given in Section 6.

2 Cooling systems and cooling water sources

2.1 Cooling systems

Power stations with steam cycles (coal, CCGT, biomass and nuclear) need continuous supply of cooling to maintain efficiency. Cooling has traditionally been provided by water and cooling system choice is an important consideration in the design and operation of thermal power plants, dictated by a number of climatic, hydrological, environmental, social and economic factors. Cooling system choice also depends on the fuel type and generation technology of the power plant. While the amount of cooling required depends primarily on the thermal efficiency of the power plant (and scales with size), the efficiency of the power plant is also affected by the performance of the cooling system. Their performance is summarised in Table 1 and the exact water use factors used in this study are detailed in Section 3.3.

'Once through' (OT) cooling systems abstract large volumes of water (more than ∼100 ML/GWh) and cool using specific heat transfer, returning water to the water body at a higher temperature. Water consumption is minimal, but thermal discharge of water has impacts on the local aquatic ecology that need to be managed. 'Closed loop' tower and hybrid-cooled plants use predominantly water, but also air, to cool primarily via latent evaporative heat transfer. Their abstractions are two orders of magnitude lower than direct OT cooling, but consumptive losses may be between 40 and 80% of the volume abstracted, such that consumption can actually be higher than for OT cooling. 'Dry cooling' uses only air as a cooling medium. The use of fans results in higher energy consumption at the plant, reducing overall efficiency and increasing fuel use and emissions. Efficiency is also more sensitive to high air temperatures.

2.2 Cooling sources

The cooling water source available and the local environment largely dictates the type of cooling system used. Operation of OT cooling is generally permitted on coastal, estuarine and some tidal stretches as long as environmental impacts from thermal discharges can be managed. OT cooling can also be used on freshwater stretches if there is sufficient flow, however this is increasingly rare and not encountered in the United Kingdom. Closed-loop wet tower and wet-dry hybrid cooling is the preferred choice for freshwater cooling sources and is also increasingly common on tidal water sources, especially where the ecology is sensitive.

As of 2016, 75% of GB's electricity is provided by thermoelectric power plants [20], which are distributed across the country. Currently, close to one-third of the GB's thermal capacity uses freshwater sources for cooling, a further half is split on tidal water stretches, estuaries and on the coast, while approximately 20% is air cooled or does not require cooling [1]. Furthermore, all current and future nuclear capacity is to be based on estuarine and coastal sites, mainly due to the lack of sufficient cooling water availability [21].

2.3 Water resources in the GB

The GB has a temperate maritime climate with generally cool and wet winters and temperate summers, predominantly influenced by the Atlantic Ocean. High population density and lower rainfall in the southern, eastern and midlands areas means that a number of catchments are water stressed, with strong competition for reliable and plentiful freshwater resources, such as those needed by power stations and water utilities. Unlike most other parts of the world, water withdrawals for agriculture are a relatively small proportion of total water use, with municipal water supplies being the largest use of water in most catchments.

Expected population growth of ∼25% by 2050 and the impacts of climate change are both expected to increase pressure on water resources in the GB, particularly in the southeast and Midlands regions. Warmer and drier summers with reduced rainfall and runoff [22] are expected to substantially reduce summer and autumn river flows by the 2050s [23–26]. Inter-annual hydrological

Table 1 Description of the performance of different types of cooling systems. CapEx – Capital expenditure. OpEx – Operational expenditure. Data on water use show the range difference between more thermally- and water-efficient CCGT plants (e.g. LHV ∼55%), and less efficient sub-critical coal power plants (e.g. LHV ∼38%). For more information see [19]

	Unit	Once through	Closed-loop tower	Hybrid	Dry
Water aspects					
Abstraction	ML/GWh	∼100 to 170	0.75 to 2.2	0.4 to 1.7	∼0
Consumption	ML/GWh	1 to 1.5	0.7 to 2	0.3 to 1.6	∼0
Thermal impacts	—	high	low	low	none
Chemicals usage	—	medium	medium	medium	none
Cost and carbon emissions					
CapEx	£k/MW_{Th}	5	8 to 10	14	11
OpEx (Fuel use, carbon costs)	—	—	+1 to +3%	+2 to +5%	+5% to +20%
Carbon emissions	tCO_2 / MWh		*same as for OpEx*		
Site considerations					
Visual impact	—	minimal	tall cooling towers with plume	cooling towers, plume abatement possible	cooling towers or condensers, no plume
Space requirements	m^2/MW_{th}	10	40–90	40–60	50

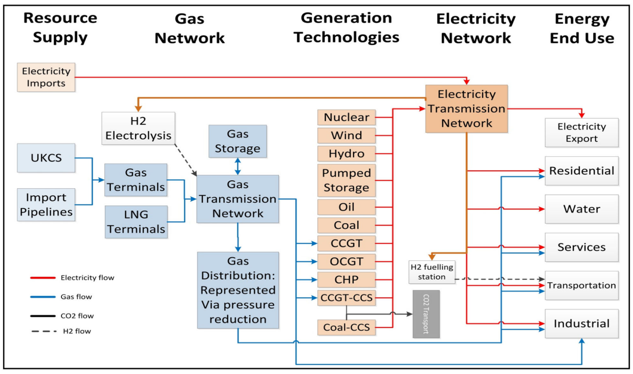

Fig. 1 *CGEN + water flow diagram*

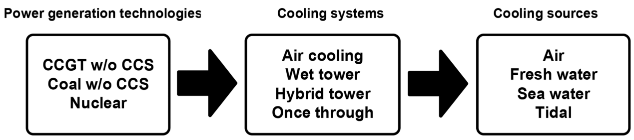

Fig. 2 *Power generation and cooling technologies combinations modelled in CGEN + Water*

variability adds to the challenge of planning reliable water resources.

The sustainable management of water resources requires that water is allocated with an expectation as to its reliability of supply, normally informed by historical flow records. Power stations require highly reliable allocations of water. The methods we used was taken from [4] (also in Supplementary Information) and estimates the volume of highly reliable (99% of the time) water available on a water body for the power sector, based on flow duration statistics and the current water abstraction regulation used in England and Wales. This method, applied both under current and expected flows under climate change for each region in the GB, was added as the water constraint to the *CGEN + Water* energy planning optimisation model developed in this study.

3 Methodology and model description

The *CGEN+* model is an optimisation tool for long term infrastructure planning of interdependent gas and electricity networks. Following a number of upgrades (e.g. [18]) from the first version by Chaudry *et al.* [17], the *CGEN+* model has been enhanced to incorporate different types of cooling technologies and their costs for thermal power stations, as well as considering constraints on available resources for cooling water. The enhanced modelling tool is referred to as *CGEN + Water* in this paper.

Operationally, the *CGEN + Water* model consists of DC power flow formulation for the electricity network. This enables the calculation of MW power flows in each individual transmission circuit. Representation of the gas network includes detailed modelling of pipelines, compressors, and storage facilities. The gas flows in a pipe are determined by employing the Panhandle 'A' equation which calculates the gas flow rate given the pressure difference between upstream and downstream nodes.

The *CGEN + Water* model includes characterisation for various generation technologies such as CCGT, coal, wind and nuclear etc. Generation technologies are described by several characteristics such as maximum generation and efficiencies. Renewable technologies are modelled by taking account of resource availability such as wind speeds at specific locations and time periods based on historical values.

The interaction between the gas and electricity networks is through gas-fired generators (e.g. CCGT, OCGT and gas with CCS) connected to both networks (Fig. 1). They are considered as energy converters between these two networks. For the gas network, gas-fired generators are gas sinks in the network, so the load on the gas network depends on their electrical power generation and the efficiency of the plants. In the electricity network, gas-fired generators are a source of electricity.

The *CGEN + Water* model incorporates different types of cooling technologies and their associated costs for thermal power stations, as well as considering constraints on available resources for cooling water. The thermal power generation and cooling technology combinations that are accounted for within the overall modelling framework is shown in Fig. 2.

In addition to operational analysis, the *CGEN + Water* model can perform expansion planning. For both gas and electricity networks transmission capacity is added to satisfy peak demand requirements. The optimisation routine within *CGEN + Water* explores all possible solutions to satisfy peak demand. This ranges from building additional generation or network capacity to the re-dispatching of energy (e.g. substituting cheaper gas from Scotland with potentially more expensive gas from liquefied natural gas (LNG) terminals in the south of England to bypass power transmission bottlenecks). The model will select the cheapest solution over the entire time horizon.

3.1 Gas network operation and expansion modelling

The gas network assets reinforced in the model over the planning period are gas pipes, compressor station, LNG/gas terminal capacity, import pipeline capacity, and gas storage facilities. Gas network planning optimisation will simultaneously satisfy operational and planning constraints. The model performs operational and investment cost minimisation, so for example if LNG terminal expansion is relatively cost effective but at the same time LNG supplies are expensive relative to pipeline gas imports then the model might determine the latter is a more cost-effective option over its service life time.

3.1.1 Gas network operational model: *Gas flow constraints*: The GB gas National Transmission System (NTS) operates at high pressure. The Panhandle 'A' equation was used to model gas flow through all pipes in a gas network at each time period and is represented as

$$p_{\mathrm{u}}^2 - p_{\mathrm{d}}^2 = KQ_n^{1.854} \tag{1}$$

where p_{u} and p_{d} are the upstream and downstream pressures of a gas pipe, respectively. Q_n is the gas flow rate $K = 18.43\ L/E^2D^{4.854}$, L is pipeline length, E is pipeline efficiency, and D is pipeline diameter.

For each node in the gas network, the pipeline operates within maximum and minimum pressure bounds at each time period:

$$p^{\min} \le p \le p^{\max} \tag{2}$$

Gas compressor constraints: Compressors are installed in the pipe network to increase pressure that has been lost due to friction in the pipelines. Equation (3) describes the relationship between the power (P^c) required from the compressor prime-mover and the pressure ratio of the compressor $p^{\mathrm{out}}/p^{\mathrm{in}}$ (output/input pressures of the compressor).

Each compressor in a gas network is subject to the following constraints at each time step:

$$\frac{p^{\mathrm{out}}}{p^{\mathrm{in}}} = \left(\frac{P^{\mathrm{c}}Y\eta}{Q_n^{\mathrm{c}}} + 1\right)^{1/Y} \tag{3}$$

$$Q_n^c \le Q_n^{c,\mathrm{Max}} \tag{4}$$

$$P^c \le P^{c,\mathrm{Max}} \tag{5}$$

here Q_n^{c} and $Q_n^{\mathrm{c,Max}}$ are the compressor flow rate and maximum flow rate, respectively. η is the overall compressor efficiency and Y is a constant set by the polytropic exponent of the compressor. P^{c} and $P^{\mathrm{c,Max}}$ are the power required for operating a gas compressor and the maximum compressor power, respectively.

Gas storage constraints: Gas storage constraints are modelled as follows:

$S^{\text{Work}}_{s,t}$ (m^3) is the volume of gas in the storage facility s at operational time period t that can be withdrawn. At each time step, level of gas storage is calculated as follows:

$$S^{\text{Work}}_{s,t+1} = S^{\text{Work}}_{s,t} + Q_{s,t} \tag{6}$$

Withdrawal and injection of gas from/to storage ($Q_{s,t}$) were formulated using (7) and (8):

$$Q^{\text{Max Deliverability}}_{s,t} \geq Q_{s,t} > 0 \tag{7}$$

$$-Q^{\text{Max Injection}}_{s,t} \leq Q_{s,t} < 0 \tag{8}$$

Gas flow balance constraints: At each time step, the load at any node (Q^{Demand}) is equal to the sum of the gas pipe flows into and out of the node. This is expressed as

$$Q_{\text{Supply}} + Q_n + Q^{\text{c}}_n + Q_s = Q^{\text{Demand}} \tag{9}$$

3.1.2 Gas network expansion model: *Gas pipe transmission network expansion*: Gas transmission capacity expansion is based on building additional pipes in parallel to existing pipes. The *CGEN + Water* model adds pipe flow capacity via an equivalent pipe diameter (D^{Eq}_e). (10) shows the gas flow equation as a function of pipe diameter, where D_e and dD_e represent the diameter of the current and parallel gas pipe (T represents the planning time step):

$$Q^{T+1}_n\left(D^{\text{Eq}}_e\right) = Q^T_n(D_e) + Q^T_n(dD_e) \tag{10}$$

LNG terminal capacity expansion: LNG terminal capacity at all terminals can be increased at each planning time step

$$\text{LNG}^{T+1}_{\text{cap}} = \text{LNG}^T_{\text{cap}} + d\text{LNG}^T_{\text{cap}} \tag{11}$$

where $\text{LNG}^{T+1}_{\text{cap}}$ (mcm/d) is the LNG terminal capacity at the next planning time step and $d\text{LNG}^T_{\text{cap}}$ is the capacity added to the current LNG terminal capacity $\text{LNG}^T_{\text{cap}}$.

Import pipeline capacity expansion: Existing import pipelines are expanded by building pipelines in parallel. The capacity of import pipelines is determined by the diameter of the pipe. The *CGEN + Water* model increases the import capacity of a pipe by employing the following equation:

$$\text{IMP}^{T+1}_{\text{Pipe}} = \text{IMP}^T_{\text{Pipe}} + d\text{IMP}^T_{\text{Pipe}} \tag{12}$$

where $\text{IMP}^T_{\text{Pipe}}$ (mcm/d) is the current pipeline capacity and $d\text{IMP}^T_{\text{Pipe}}$ is the additional import pipe capacity.

Gas storage facility expansion: The *CGEN + Water* model has the capability to connect new gas storage facilities to the gas network. Each new storage facility ($d\text{STOR}^T_{\text{NS}}$ represents a new storage facility *NS*) at a location has a certain storage capacity with maximum gas deliverability and injection rates. If a node on the pipe network is selected by the *CGEN + Water* model for the connection of a storage facility, the gas flow rate in and out of the facility is represented by

$$\begin{aligned} Q^{\text{Max Deliverability}}_{Ns,t} &\geq Q_{Ns,t} \\ &\geq -Q^{\text{Max Injection}}_{Ns,t} \end{aligned} \tag{13}$$

where $Q_{Ns,t}$ (mcm/d) is the gas flow rate of the new storage facility (*Ns*) at time t.

3.2 Electricity operational and expansion planning model

Electricity network expansion takes place through increasing transmission capacity between buses. In addition, the expansion process builds new generation capacity and takes account of plant retirements. New generation capacity is placed around the electricity network to minimise overall operational and expansion costs.

3.2.1 Electricity network operational model: *Power balance constraints*: The power balance equations were satisfied such that total generation is equal to total demand minus load shedding at each time step:

$$\sum_i P^{\text{Gen}}_{i,t} = \sum_j P^{\text{Demand}}_{j,t} - \sum_j P^{\text{Elec Shed}}_{j,t} \tag{14}$$

where $P^{\text{Gen}}_{i,t}$ is the power output of generation unit i at time t. $P^{\text{Demand}}_{j,t}$ and $P^{\text{Elec Shed}}_{j,t}$ are the demand and load shedding at bus j at time t, respectively.

Power generation constraints: The generation schedule produced was kept within the physical limitations of the generating units:

$$P^{\text{Gen(min)}}_{\text{i}} \leq P^{\text{Gen}}_{i,t} \leq P^{\text{Gen(max)}}_i \tag{15}$$

Power flow constraints: The power flowing in each transmission line ($F_{l,t}$) was maintained within maximum power flow limits (*TX*) at each time period:

$$-TX^{\max}_{l,T} \leq F_{l,t} \leq TX^{\max}_{l,T} \tag{16}$$

Power demand security constraints: A security constraint was implemented to ensure that total generation capacity that can contribute to peak demand is equal or greater than the Average Cold Spell electricity peak [26, 27]:

$$\sum_{y,l}\left(P_{y,L,T} \times A_y\right) \leq \text{ACS}_T \tag{17}$$

where $P_{y,l,T}$ is the generation capacity of type y in location L in year T, and A_y is percentage of generation capacity of type y that can contribute to meeting peak demand [27], and ACS_T is average cold spell electricity peak in year T which is an input to the *CGEN + Water* model.

3.2.2 Electricity network expansion model: *Electricity transmission expansion*: If the maximum electricity transmission capacity of line l at planning time step T is $TX^{\max}_{l,T}$. After network expansion at time $T + 1$, the transmission capacity is

$$TX^{\max}_{l,T+1} = TX^{\max}_{l,T} + dTX_{l,T} \tag{18}$$

where $dTX_{l,T}$ (MW) is the transmission capacity added to line l in year T.

Generation capacity expansion and location of plants: Generation capacity is calculated at each planning time step:

$$P_{y,L,T} = P_{y,L,T-1} + P^{\text{n}}_{y,L,T} - P^{\text{d}}_{y,L,T} \tag{19}$$

where P is total generation capacity, P^{n} is new generation capacity, P^{d} is capacity of decommissioned power plants, index y is type of a power plant, index L is location of a power plant (busbar), index T is year.

Power generation capacity is subject to pre-defined availability factors and in the case of renewables such as wind historical capacity factors are used.

The *CGEN + Water* model optimally places future generation plants around the electricity network to minimise overall costs (from a systems perspective). New gas-fired plants are connected

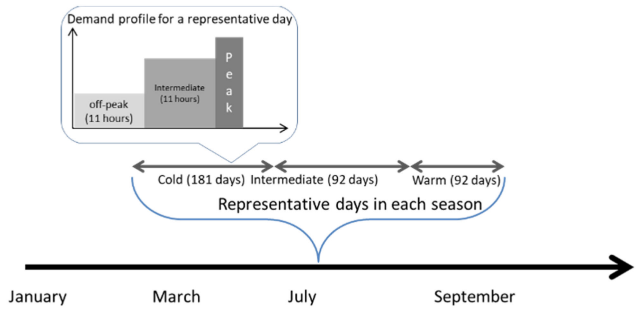

Fig. 3 *Planning and operational time steps*

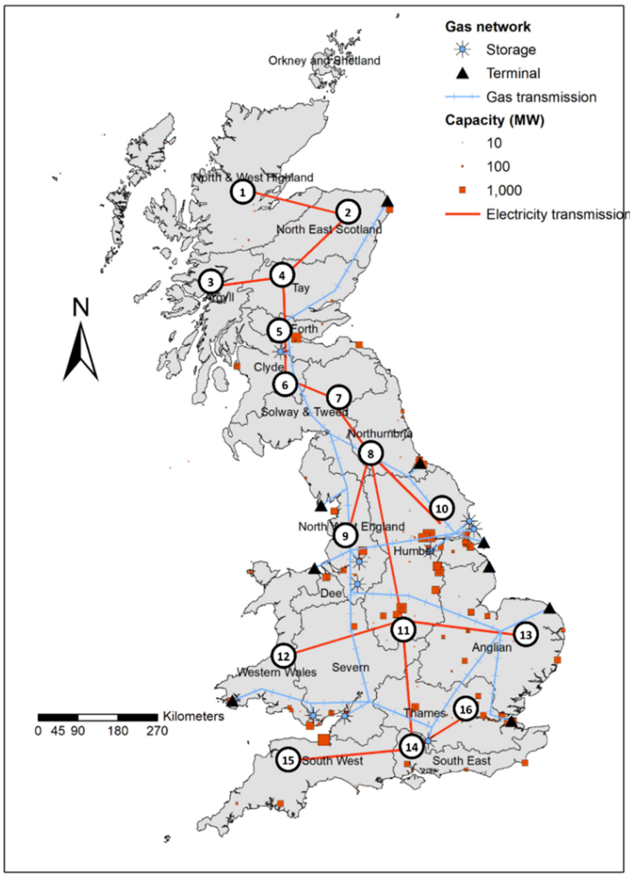

Fig. 4 *Simplified representation of the GB gas and electricity transmission infrastructure (numbered circles are the busbars), thermal power plants and the water resource availability regions (labelled by name)*

to both gas and electricity networks at locations that result in optimal operational and infrastructure reinforcement (pipes, power transmission lines) costs.

3.3 Water availability operational constraints

The constraint on available freshwater for cooling power stations in each region is shown in (see (20)) . The aggregate water abstraction by different thermal power stations in each region was calculated by summation of power generation by the cooling water rate. The total cooling water abstraction in each region set to be less or equal to the licensed available water to the sector ($Q_{\rm W}$; flow). The model cost-efficiently allocates new thermal generation capacity to water sources based on water availability and the costs of different cooling systems

$$\sum_i P_{i,L,T,t} \times W_i \le Q^{\rm w}_{L,T} \tag{21}$$

where $P_{i,L,T,t}$ is power generation (MW) by power station i, in location L, in year T and in within-day time steps t.

Thus, the model from an operational and planning perspective endogenously considers the water availability by linking generation technologies and the amount of water needed with the availability of water for cooling.

3.4 Model objective function

The objective of the CGEN + Water model is to minimise total discounted costs related to the combined operation and expansion of the gas and electricity networks while meeting demand requirements and water availability constraints over the entire planning horizon. The objective function is represented as (21).

Predefined cost elements are represented by $C_{\rm Suffix}$. These costs are attached to the appropriate decision variables (capital or operational) in the objective function.

The objective function is subject to operational network constraints of both gas and electricity networks and the constraint on the availability of water for cooling.

3.5 Temporal and spatial setup

The operational time horizon (in this case a representative day for each season) is modelled so that the peak (intra-day) energy demand can be captured is illustrated in Fig. 3. In the planning time frame (e.g. 2020; 2030 out to 2050 with planning steps of 10 years) the model determines the reinforcement of both the gas and electricity networks (e.g. new gas pipes and electricity transmission capacity) and physical constraints while establishing the optimal location of new generation plants in the system across the representative GB electricity system.

Spatially, the regional GB gas network with the key gas supply points and storage facilities and the 16 region GB electricity transmission network as well as available freshwater resources are modelled and shown in Fig. 4.

4 Scenarios and assumptions

4.1 Determining regional water availability for abstraction

Of all the water flowing within a river, only a portion is available for licensed abstraction and an even smaller proportion is licensed to the electricity sector. The rest is left for environmental flows to maintain ecosystem quality. The hydrological model used in this study is an 11-parameter lumped conceptual model of mean daily discharge applied to 72 catchments across GB [27], aggregated to the water resource regions. The flow duration statistics are used to determine water available for licensing to all users, and subsequently water available to the electricity sector [4].

Water availability is determined for each region by aggregating the volume of high reliability flows (the first percentile flows, Qe99) available to the electricity sector on all rivers sufficiently large to support the cooling water demands of a 500 MWe CCGT power plant (Table 2) [4]. Rivers unable to sustainably support this demand are excluded.

$$\text{Min Total}(\pounds) = \sum_{T}^{\text{Horizon}} \left[\underbrace{C_X dTX^T + C_D dD^T L + C_I d\text{IMP}^T_{\text{Pipe}} + C_L d\text{LNG}^T_{\text{Cap}} + C_C dX^T_C + C_S d\text{STOR}^T_{NS} + C_G P^{\text{n},T}}_{\text{Capital costs}} + \underbrace{\sum_{t}^{\text{Period}} \left(C_{\text{Supply}} Q^{t,T}_{\text{Supply}} + C_{\text{StorOp}} Q^{t,T}_{\text{Storage}} + C_{\text{Gshed}} Q^{t,T}_{\text{GasShed}} + C_{\text{Gen}} P^{t,T}_{\text{Gen}} + C_{\text{Eshed}} P^{t,T}_{\text{ElecShed}} \right)}_{\text{Operational costa}} \right] \tag{20}$$

Table 2 Current and future available water resource to the electricity sector by region. Adapted from [4]

BB	Region	Main rivers	ΣQ_{95}, m^3/s	ΣQ_{99}, m^3/s	Available resource to electricity sector					
					Current		2020		2050	
					Q_{e95}	Q_{e99}	Q_{e95}	Q_{e99}	Q_{e95}	Q_{e99}
1	N & W Highlands	Lochy Conon Beauly Ewe	36.6	21.60	1.1	0.65	1.0	0.6	0.9	0.5
2	NE Scotland	Spey Ness Don	53.7	39.00	1.6	1.17	1.3	0.9	1.1	0.7
3	Argyll	—	0.0	0.00	0.0	0.00	0.0	0.0	0.0	0.0
4	Tay	Tay	43.5	31.72	1.3	0.95	1.2	0.8	1.0	0.6
5	Forth	Forth	5.7	3.89	0.2	0.12	0.2	0.1	0.1	0.1
6	Clyde	Clyde Leven	19.4	15.31	0.6	0.46	0.5	0.4	0.5	0.3
7	Borders	Tweed Eden	24.3	18.11	0.7	0.54	0.6	0.5	0.4	0.3
8	NE England	Tyne Wear Tees	12.4	9.46	0.7	0.57	0.6	0.4	0.4	0.3
9	NW England	Eden Mersey Dee	13.4	9.13	0.4	0.27	0.3	0.2	0.2	0.1
10	Humber & E Midlands	Aire G. Ouse Trent	43.8	34.61	3.8	3.03	3.0	2.3	2.1	1.6
11	W Midlands & Severn	Severn	19.9	15.52	1.5	1.16	1.2	0.9	0.9	0.6
12	W Wales	Wye	11.2	7.40	0.4	0.28	0.3	0.2	0.2	0.1
13	Anglian	—	0.0	0.00	0.0	0.00	0.0	0.0	0.0	0.0
14	S & SE England	—	0.0	0.00	0.0	0.00	0.0	0.0	0.0	0.0
15	SW England	Test Avon	11.9	9.79	0.5	0.43	0.4	0.3	0.4	0.3
16	Thames & London	Thames	7.5	3.62	0.1	0.05	0.1	0.0	0.0	0.0
		Sum	303.8	219.2	13.0	9.68	10.6	7.5	8.1	5.5

Table 3 Additional capital costs and impacts on net thermal efficiencies. N.B. Absolute reductions in thermal efficiency result in increases of operation costs due to higher fuel input

	Additional capital cost per unit cooling load £/MW$_{th}$	Absolute impact on net thermal efficiency %	
cooling system type		CCGT	coal
once through	—	—	—
closed loop wet tower	5000	−1.0	−0.9
hybrid tower	14,000	−1.2	−1.2
air cooled condenser	11,000	−2.0	−2.0

To obtain future river discharges the hydrological model was run using samples of temperature and precipitation from the UK Climate Projections 2009 (UKCP09) weather generator, for the 2020s (2010–2039) and 2050s (2040–2069) under a medium emissions climate change scenario[6] UKCP09 uses an ensemble of global climate models (GCM) which are downscaled to 25 km resolution using the perturbed physics ensemble of the Hadley Centre HadRM3 regional climate model [22, 28]. Using UKCP09 incorporates the full structural model and climate variability uncertainties present in GCMs.

4.2 Cooling systems and water use

This paper uses water use factors primarily derived from a Parsons Brinkerhoff report commissioned by the Environment Agency [29]. These factors are more representative of the new and more efficient generation plant to be built in the United Kingdom and are subsequently lower than factors used in previous studies.

These water use factors were matched with published capacity costs data [30], with additional capacity and operational costs added according to cooling system type (Table 3). Different cooling systems have different capital costs, that are sized according to the thermal cooling load (MW$_{th}$) that needs to be dissipated. Different cooling systems also result in marginally different net thermal efficiencies, relative to OT cooling. Thus, depending on the cooling system, lower efficiencies must also be taken into account in the operational costs for each plant, while marginally higher cooling loads also result in slightly higher capital costs.

Due to significant water requirements for once-through cooling and due to limited availability of freshwater in the GB, the use of this type of cooling system is limited to tidal and coastal zones. Furthermore, construction of power stations on coastal zones was assumed to require additional capital cost (5%) to incorporate costs resulting from coastal flood defences, sea level rise, storm surges, corrosion and higher land values.

4.3 Energy demand

Long-term projections for electricity and gas demand are shown in Fig. 5. Detailed descriptions of methodology and underlying assumptions for projecting energy demand are reported in [31].

4.4 Scenarios

Several studies have investigated electricity sector water use, identifying both cooling systems and the supply mix as key drivers of water use [1, 4, 32–34]. In order to investigate how future availability of cooling water will affect the optimal power generation capacity expansion in GB, a number of scenarios with different levels of renewable generation capacity and available cooling water resources were defined (Table 4).

In terms of cooling water availability, four possibilities were considered: (i) no constraints on freshwater use (*NoCon*), (ii) constraint based on historical Q_{99} availability (Q_{99}*Hist*), (iii) constraint based on expected Q_{99} availability for the 2020s and 2050s (Q_{99}*CC*) under medium emissions climate change, and (iv) transition to zero freshwater available for cooling power stations beyond 2030 (*ZFW*).

In conjunction with the above variants of cooling water constraints, two distinct levels of wind generation capacity were considered in construction of the scenarios. This is to investigate to what extent a larger penetration of wind generation in GB will reduce the reliance of the power generation sector on cooling water, and therefore make it less vulnerable against future uncertainty in cooling water availability.

5 Results and discussions

5.1 Power generation mix, cooling technologies and water resources

The capacity of different types of thermal power stations with the type of their cooling system and cooling water resources for reference scenarios (i.e. *Ref-NoCon*, *Ref-Q99Hist*, *Ref-Q99CC*, *Ref-ZFW*) in 2050 are shown in Fig. 6. With no abstraction limit on

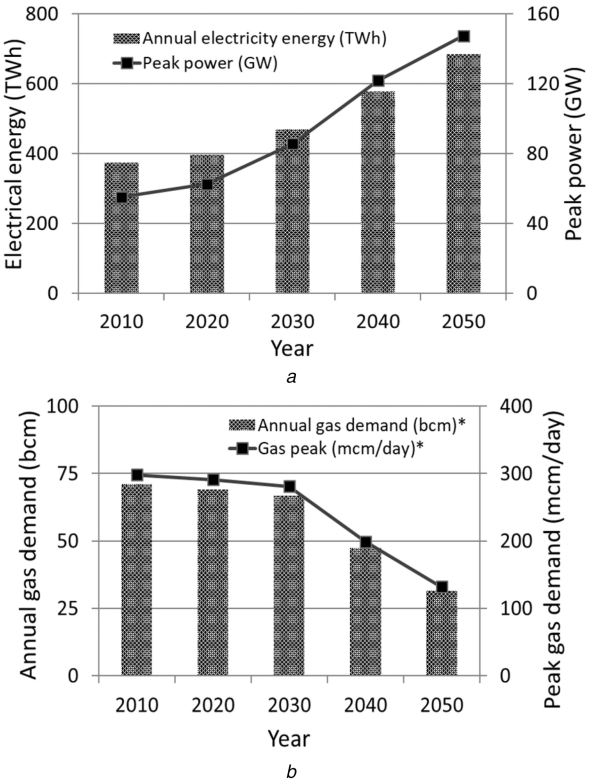

Fig. 5 *Long-term electricity and gas demand projection [31]*
(a) Annual and peak electricity demand, ***(b)*** Annual and peak gas demand

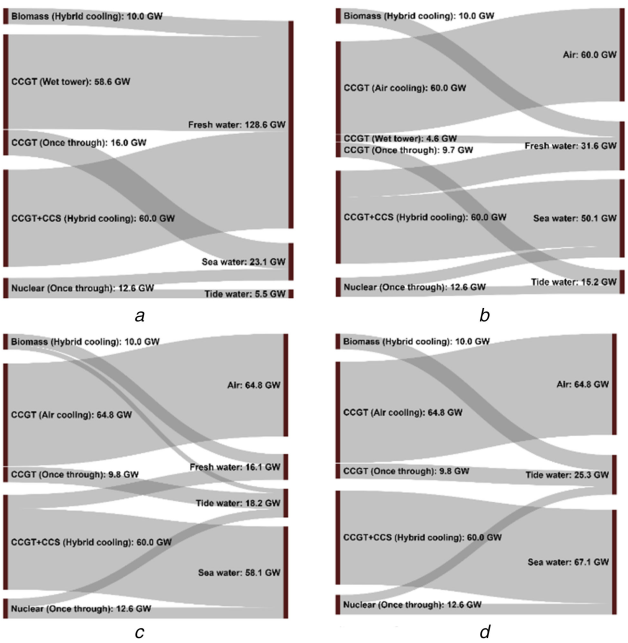

Fig. 6 *Power generation (left side) in MW_e, cooling technologies and water resource use (right side, also MW_e)*
(a) Ref-NoCon, ***(b)*** Ref-Q99Hist, ***(c)*** Ref-Q99CC, ***(d)*** Ref-ZFW

freshwater, total generation capacity of 128 GW, including CCGT with wet tower cooling (58 GW), CCGT + CCS (60 GW) and biomass-fired (10 GW) both with hybrid cooling, would be in operation on freshwater. The significantly large capacity of power stations using freshwater reflects the higher capital cost of constructing power stations in coastal zones.

The introduction of a Q_{99} limit on freshwater abstraction, representative of the historical climate from 1970s to 2010s, significantly limits the capacity of power stations able to abstract from freshwater to around 32 GW. This was achieved by placing 43 GW CCGT + CCS plants in coastal zones (despite higher costs)

Table 4 Definition of scenarios – emission targets: 2030 to 2050: 50 gCO_2 e/kWh

Scenarios	Generation mix	Cooling water
Ref-NoCon	emission targets up to 2050 +	no constraint on cooling water
Ref-Q99Hist	renewable target in 2020	historical (2010) Q_{99} limit on freshwater abstraction
Ref-Q99CC	—	Q_{99} limit on freshwater abstraction after taking into account the climate change impacts
Ref-ZFW	—	zero freshwater for cooling
Wind-NoCon	emission targets up to 2050 +	no constraint on cooling water
Wind-Q99Hist	renewable target in 2020 +	historical (2010) Q_{99} limit on freshwater abstraction
Wind-Q99CC	enforcing development of wind farms (from [35])	Q_{99} limit on freshwater abstraction after taking into account the climate change impacts
Wind-ZFW	—	zero freshwater for cooling

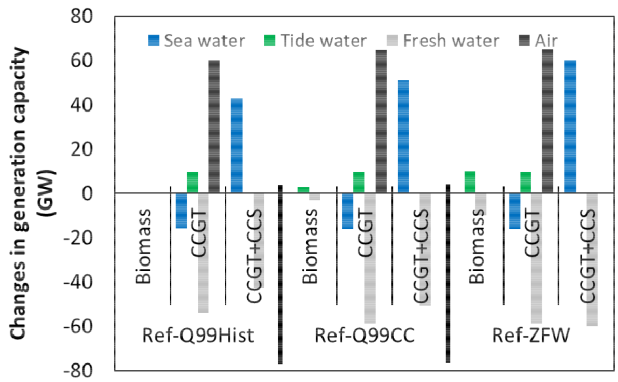

Fig. 7 *Changes in generation capacity in 2050 based on cooling source (compared to the case with no freshwater constraints (Ref_NoCon)). In all cases there is a clear shift away from freshwater use, with increased use of air cooling, and sea and tidal water sources*

and using air cooling for 60 GW CCGT plants. The bulk of CCGT, the most thermally efficient thermal generation technology and with the highest marginal costs, switches to air cooling technologies as there is a geographic limit on the use of coastal sources.

Taking into account the impact of climate change on the availability of freshwater for cooling power stations reduces the Q_{99} limit in 2050, and leads to only 16 GW generation capacity to be cooled by freshwater, 50% less than the historical Q_{99} in 2010 (see Table 4). Therefore, freshwater use is limited to low water intensive combinations of generation and cooling technologies.

The complete avoidance of freshwater use in power generation sector results in significant increase in generation capacity built on coasts and tidal zones.

The changes – compared to no constraints on freshwater abstraction – in generation capacity based on cooling sources are summarised in Fig. 7. When freshwater abstraction is constrained, there is a clear shift of CCGT capacity with CCS from freshwater to sea water cooling sources (despite the higher capital costs). For unabated CCGT capacity the major shift is from freshwater towards air cooling. A fraction of CCGTs that were using freshwater in *Ref-NoCon* also shift to tidal water sources. It was assumed that the thermal discharge capacity in estuaries and tidal areas in future will remain the same as in 2010.

In terms of cooling technologies, applying constraints on the availability of freshwater mainly results in CCGTs going from once-through and wet tower cooling to air-based cooling systems.

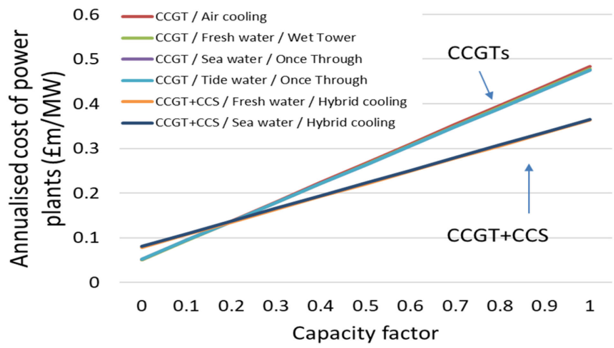

Fig. 8 *Power generation cost 'screening curves' for CCGT and CCGT + CCS*

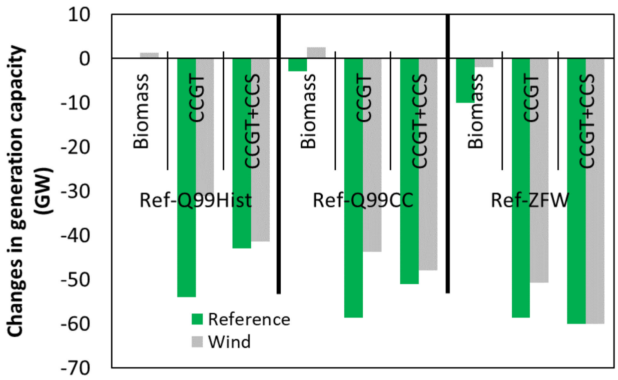

Fig. 9 *Changes in capacity of thermal power plants in 2050 (compared to the cases with no freshwater.constraints imposed)*

Fig. 8 compares the annualised costs of typical CCGTs and CCGTs + CCS with different cooling systems and water resources for various capacity factors (no constraints for availability of cooling water was considered in this comparison). It is shown that CCGT + CCS is the economical option for higher capacity factors while CCGT is the preferred option for providing backup. In addition, the annualised costs for the same generation technologies with different cooling systems and water sources vary only marginally. This means the introduction of constraints on available water resources will result in changing the cooling system and/or water sources rather than moving to different generation technologies.

The economic performance of CCGT and CCGT + CCS at various capacity factors dictates different role for these plants (i.e. CCGT as backup, and CCGT + CCS as base load generation technology). In a water-constrained power system, expected capacity factor for each technology affect the choice of cooling system and cooling sources. For example, in our analysis, the high capacity factor of CCGTs + CCS is required for meeting the emission targets in 2050. Therefore, CCGT + CCS are mainly built on coastal zones to have access to sufficient cooling water. On the other hand, in 2050 in *Ref-Q99Hist,* the CCGTs with capacity factor of 7% use wet tower cooling systems and are located on freshwater, while those CCGTs with capacity factor of 36% use Once Through cooling systems and are located on tidal water.

5.2 Impact of increased wind generation capacity on the reliance of power system on cooling water

The increased share of wind power in the generation mix results in less thermal generation capacity requiring freshwater resources, thus the risk of drought on the power generation sector, as a whole, is reduced. Fig. 9 shows the impact of freshwater constraints on the generation mix with higher share of wind is less sever.

5.3 Abstraction and consumption of cooling water

The abstraction and consumption of freshwater for cooling thermal power stations increases significantly from 2010 to 2050 in the absence of freshwater abstraction constraints as these are the cheapest locations (Fig. 10). Higher levels of wind generation capacity contributes to reductions of 17 and 25% for water abstraction and consumption, respectively.

Three intensities of water abstraction and consumption in the GB power generation sector are presented in Fig. 11 for different scenarios. 'Grid water intensity' represents the water intensity across all generation types and all water sources, while 'grid freshwater intensity' considers only the freshwater use for all generation types. 'freshwater intensity of FW capacity' includes only the freshwater used by generation capacity on freshwater.

Due to reduced use of open-loop cooling on tidal and sea water, as well as overall decreased penetration of thermal in the power sector, in all scenarios the abstraction grid water intensity reduces, with minor increases in consumption. The large share of wind in the generation resulted in significantly reduced grid water abstraction intensity in 2050 – around 17 ML/GWh compared to the scenarios in which wind generation plays a limited role in meeting electricity demand. Despite the decreasing trend in the grid intensity of water abstraction, grid intensity of cooling water consumption for the reference scenarios increases slightly and for scenarios with larger penetration of wind remained almost constant over the planning horizon. This is due to gradual substitution of power stations (mainly coal-fired) equipped with once-through cooling system by power stations with closed-loop cooling system (wet tower, hybrid cooling) which have lower water abstraction but higher evaporation.

The figures for abstraction and consumption of freshwater intensity are similar as only closed-loop cooling systems are viable on freshwater in the United Kingdom. Imposing more strict abstraction limit on freshwater in different scenarios resulted in lower freshwater intensity for both abstraction and consumption.

Validation of the model is challenging due to a lack of publicly available data on actual water use by power stations in GB. The freshwater results presented here for 2010 are considerably below those from previous studies due to the water use factors chosen for this study. In order to verify this and demonstrate that the model behaves consistently with previous studies, e.g. Byers *et al.* 2014 [1], 2015 [4], water use factors from those studies were tested with freshwater abstraction and consumption and were found to give results within the expected range.

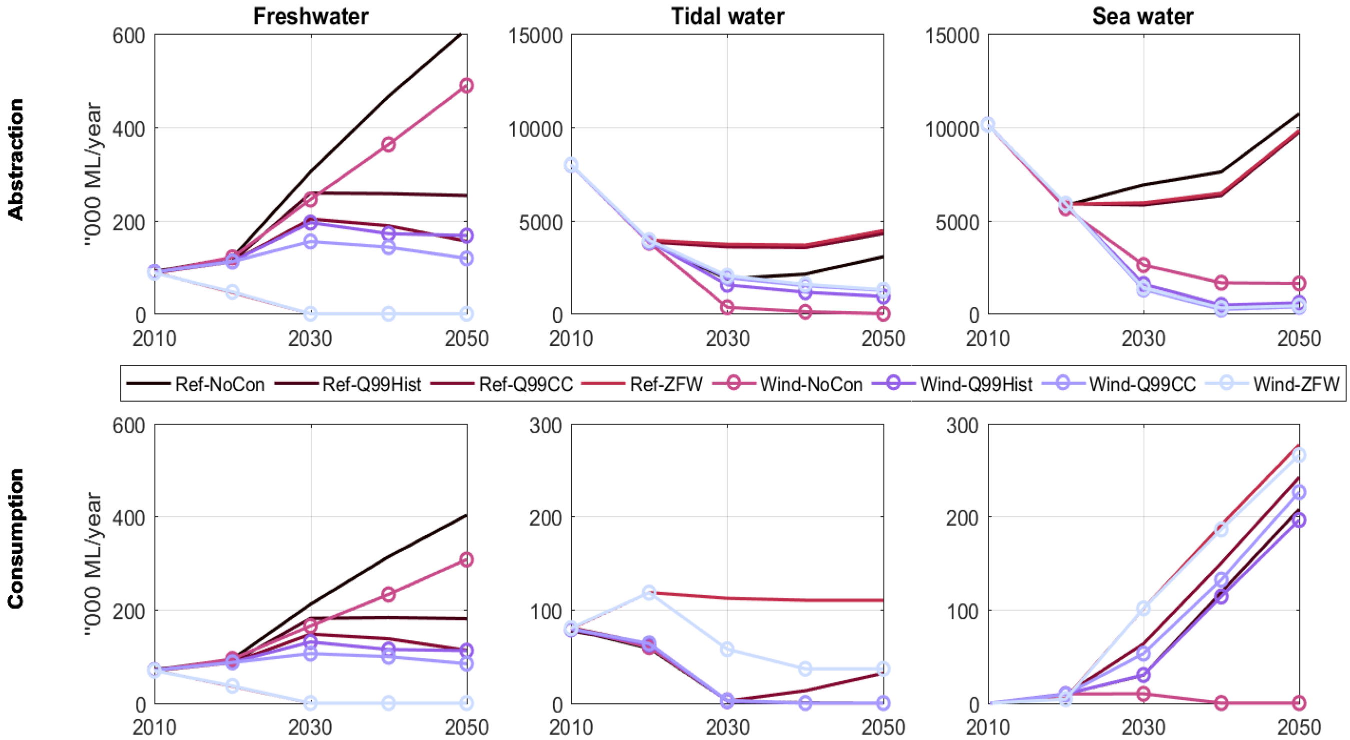

Fig. 10 *Cooling water abstraction and consumptions for different scenarios*

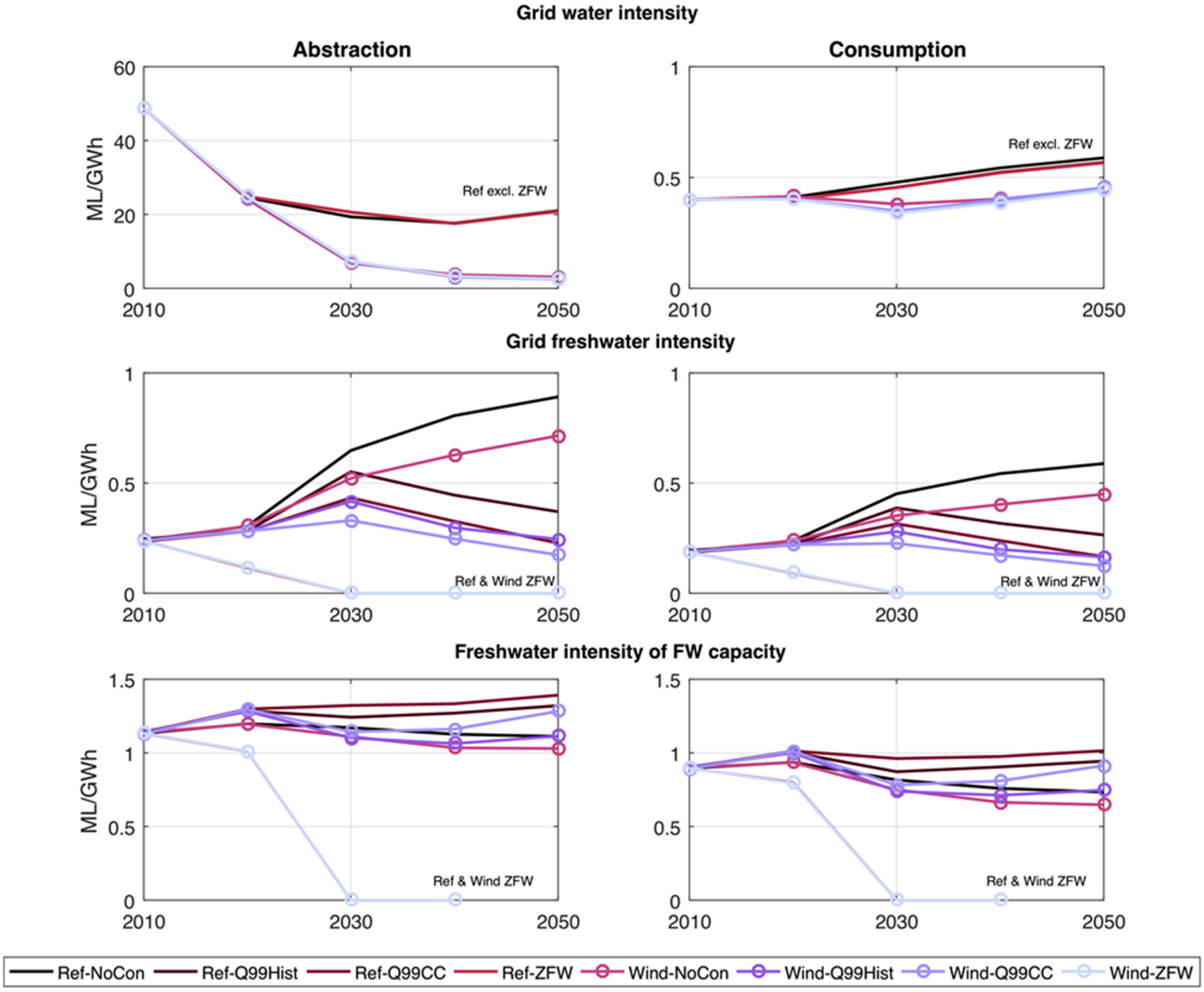

Fig. 11 *Projections of grid water intensity to 2050*

Table 5 Total costs of electricity and gas supply systems for different scenarios

Scenario	Total cost (£ billion)	Change in the cost compared to the reference cases
Ref-NoCon	736	—
Ref-Q99Hist	801	8.8%
Ref-Q99CC	820	11.4%
Ref-ZFW	851	15.6%
Wind-NoCon	1027	—
Wind-Q99Hist	1091	6.2%
Wind-Q99CC	1109	7.9%
Wind-ZFW	1140	11%

5.4 Cost implications of freshwater abstraction constraints

The total discounted costs of electricity and gas supply systems from 2010 to 2050 are presented in Table 5. Imposing a constraint for maximum abstraction of freshwater resulted in increasing the system's costs, in particular because of additional capital costs of flood protection measures for power stations constructed along the coastal zones and estuaries. Analysis showed that imposing a constraint on the freshwater abstraction in those scenarios with large capacity of wind (or other zero-water generation technologies, such as PV etc) in the generation mix resulted in smaller changes in the capital costs due to lower thermal power plant capacity.

The cost implications reveal the extent to which the power generation sector benefits from reliable freshwater availability. Comparing the costs of the current situation of Q99Hist to Q99CC, we see that reduced water availability due to climate change would increase system costs by £18–19 billion (1.6–2.4%) for the period 2010–2050. The zero freshwater use scenarios, even if seemingly unlikely, gives us insights into the value of current freshwater availability to the sector as a whole: £49–50 billion over the period 2010–2050.

6 Conclusion

The CGEN + Water modelling tool was developed based on the Combined Gas and Electricity Network (CGEN+) optimisation model and takes account of various cooling systems and water-related constraints while minimising operational and infrastructure expansion costs in the gas and electricity networks over the time horizon from 2010 to the 2050.

In order to explore how future availability of cooling water affects the optimal capacity expansion of power generation in the GB, a number of scenarios with different levels of renewable generation capacities and available freshwater resources were defined. The availability of freshwater ranged from no water constraints (unlimited amount of freshwater) to increasingly limited levels (Q_{99}) under climate change, and an extreme case in which no freshwater is available for cooling power stations.

With no water availability constraints, almost 60 GW of CCGT plant with wet tower cooling technology are built on freshwater as this is the most cost-effective solution to meet future demand. As water constraints become progressively more stringent, technologies that use large quantities of water, such as CCGT + CCS and nuclear, are deployed on coastal sites. Cooling system technologies such as hybrid cooling and air cooling are also increasingly selected, which despite marginally higher costs, offer more flexibility for siting power plants in water-constrained regions and closer to demand.

In a system with high levels of renewable capacity installed, the increased share of wind generation results in all round lower water use and water use intensity in the range of 17–25%. This highlights the fact that increased share of wind generation reduces the dependency of the power sector on water resources, and mitigates the risk caused by uncertainty in the availability of cooling water in the future due to the climate change.

The results point out the economic costs of reduced water availability due to climate change, expected to increase system costs by £18–19 billion (1.6–2.4%) for the period 2010–2050.

In addition to the simulation of future energy systems under water constraints, the cost-optimisation model has provided unique insight into the economic value that reliable freshwater resources provide to the electricity sector. Under the current freshwater availability, our analysis shows that the GB energy system in 2050 is £50bn cheaper (4.8–6.8% depending on electricity mix) than under a system where no freshwater was available for use by the sector.

Despite various well-known interactions, energy and water systems are traditionally modelled and planned as two separate systems. Co-optimisation of power systems and water resources systems allows infrastructure planners and operators to examine the interdependencies and minimise trade-offs over various uncertainties (technologies, demand, water availability, climate change etc) and across multiple scenarios. Future work in this area could include improved representation of water resources and infrastructure, further exploration of climate and hydrological uncertainties through robust optimisation [36] and more site-specific heterogeneity of costs.

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