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Hajar Filahi, Philippe Drobinski, Boutheina Oueslati, Sandra Claudel, Marie-Hélène Laurent. Rising power system strains despite decreasing heating demand in a warming climate. *Scientific Reports*, 2025, 15 (1), pp.12470. <10.1038/s41598-025-96174-5>. <hal-05345160>

HAL Id: hal-05345160

<https://hal.science/hal-05345160v1>

Submitted on 5 Nov 2025

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OPEN **Rising power system strains despite decreasing heating demand in a warming climate**

Hajar Filahi¹, Philippe Drobinski^{2,3}✉, Boutheina Oueslati¹, Sandra Claudel¹ & Marie-Hélène Laurent¹

Electrifying systems like heating is essential for reducing greenhouse gas emissions. France provides a compelling case study due to the high share of electricity used in its buildings sector. Using a heating degree-days methodology alongside a power demand model applied to ten climate model simulations, we examine four emission scenarios, assuming the actual electricity mix and use. Our results indicate a significant decrease in average power demand, with a slight reduction in peak demand during cold waves, driven by rising winter temperatures. This trend may give the misleading perception of a reduction in grid constraints. However, counterintuitively, the demand surge during cold waves—relative to normal conditions—is projected to increase with climate change, which could heighten the pressure on the power system. With the probability of such events decreasing, and heating needs becoming more fragmented, adaptation will be crucial for power system preparedness.

Electricity is a key sector for steering the world toward the 2°C climate target. Decarbonizing the energy system requires a combination of measures: electrifying the energy mix, decarbonizing the electricity production, and improving energy efficiency—actions that must be fully implemented and on time¹. The potential to reduce emissions in electricity production is substantial, with current technologies, enabling a fivefold reduction in electricity's carbon intensity by 2040². Electrification of the energy mix involves replacing fossil fuel use with electricity generated from non-fossil sources. This shift applies across many sectors, including transportation, heating, and hydrogen production. Globally, electricity accounted for 19.3% of final energy consumption in 2018, up from 9.4% in 1973. Currently, electricity production remains overwhelmingly ensured by coal (38.2%) and natural gas (23.1%)³ but by 2040, electricity is expected to make up one-third of final energy consumption, with renewable energy becoming the primary source².

Decarbonizing the heating sector is essential for reducing global carbon emissions, as natural gas currently provides about 40% of the energy used for building heating worldwide. Assessing the impact of climate change on temperature-sensitive power demand is crucial for evaluating the electric system's vulnerability and planning resilience measures for a shift toward widespread electric heating. To estimate the future effects of climate change on energy demand globally and regionally, most studies use the heating degree-days (HDD)^{4,5}, which measure the cumulative daily deviations of temperature below a winter heating setpoint. Despite some limitations^{6–8}, HDD is widely used in climate impact studies across Europe and other regions^{9–18}. These studies show that heating need trends changed by less than 10% from 1950 to 1990, but are projected to decline by more than 10% from 1990 to 2030 and beyond. By converting HDD to electric consumption, several studies have assessed the effects of climate changes on electricity demand in Europe, consistently showing decreases with rising temperatures, down to approximately –15 TWh per year for a +2 °C global warming level^{18–21}.

One of the primary risks to maintaining supply-demand balance in winter is the occurrence of cold waves, which drive power demand significantly above average levels and strain the grid's capacity to meet demand. The impacts of extreme cold waves on peak electricity demand extends well beyond simple shifts in net annual consumption; it has crucial implications for system design and power supply strategies²². Understanding how climate change will affect the intensity and frequency of peak electricity demand is essential for planning adaptive measures that ensure grid resilience. This is especially important given the increased demand from the electrification of heating and transport mainly, alongside a more variable renewable energy supply. However, only few studies have specifically examined the variability in power demand, with most suggesting that the

¹EDF R&D, Campus EDF Paris-Saclay, 91120 Palaiseau, France. ²Laboratoire de Météorologie Dynamique-Institut Pierre-Simon Laplace, Ecole Polytechnique, Institut Polytechnique de Paris, Ecole Normale Supérieure (ENS), CNRS, Paris Sciences Lettres Research University, Sorbonne Université, Palaiseau, France. ³Energy4Climate Interdisciplinary Center, Institut Polytechnique de Paris, Ecole des Ponts, CNRS, CEA, Palaiseau, France. ✉email: philippe.drobinski@lmd.polytechnique.fr

standard deviation of winter energy consumption—and thus the response to extreme cold events—may remain relatively stable^{19,20,23}.

Trends in both average and peak energy demand may create a misleading perception that the power grid will be resilient to climate change impacts during winter, particularly with increased electrification of heating. However, the electric grid remains vulnerable to power demand variability, an issue that has received limited attention in the context of climate change. Notably, the excess power demand during cold waves—defined as the difference between peak and average demand—is crucial for estimating the reserve of dispatchable power required to ensure future grid resilience. This study focuses on France, a relevant case due to its high electricity share in its final energy consumption²⁴ and building energy use, largely due to the historic role of electric heating alongside the country's nuclear energy program. In winter, cold waves can drive French electricity consumption to extreme levels, due to the temperature sensitivity of heating putting significant stress on the electric grid. This study analyses the climate-driven energy demand for heating in France, considering current demand patterns and projecting future trends in the duration and frequency of heating periods, as well as daily power demand, including uncertainties from temperature projections. To this end, we used proxies of the climate-driven heating needs derived from heating degree-days, and calculated power demand based on simulated surface air temperatures from a selection of 10 debiased and downscaled historical and future climate projections from the Coupled Model Intercomparison Project phase 6 (CMIP6). We assessed these models using four socio-economic pathways (SSPs) representing varying greenhouse gas concentration trajectories (SSP1-2.6, SSP2-4.5, SSP3-7.0, and SSP5-8.5). These pathways, labeled from SSP1 (sustainability, “Taking the Green Road”) to SSP5 (fossil-fuel-based development, “Taking the Highway”), represent distinct scenarios of CO₂ emissions and radiative forcing by 2100. For example, SSP1-2.6 aligns with a goal of net-zero CO₂ emissions by around 2075, while SSP5-8.5 involves tripling emissions by 2075. These scenarios yield projected temperature increases of 1.7 °C to 2.4 °C for mid-century (2041–2060) and 1.8 °C to 4.4 °C for late-century (2081–2100), with likely ranges reflecting model uncertainty.

Fragmentation of heating needs

Heating periods are defined here as the number of successive days where the temperature is below a heating setpoint of 15.5 °C. In practice, these periods are defined as the number of consecutive days during which the HDD value—calculated from daily mean, minimum, and maximum temperatures using the UK Met Office methodology (see Methods section for details)—exceeds 1 °C, with a minimum of two consecutive days to account for building thermal inertia and to align with the power demand model used in this analysis. In Fig. 1, we analyze the changes in the duration and frequency of heating periods across four future emission scenarios (SSP1-2.6, SSP2-4.5, SSP3-7.0, and SSP5-8.5) and for four time horizons (central years 2000, 2030, 2050 and 2085). The figure illustrates that while the overall duration of heating periods significantly decreases, especially in high-emission scenarios, the number of heating periods increases. In the best-case scenario (SSP1-2.6), the duration of heating periods drops by 55% on average from 62 days, nowadays, to 28 days at the end of the 21st century, while the number of heating periods increase from 3.5 today to around 5. In the worst-case scenario (SSP5-8.5), the number of heating periods increases to around 7.5 lasting 10 days on average

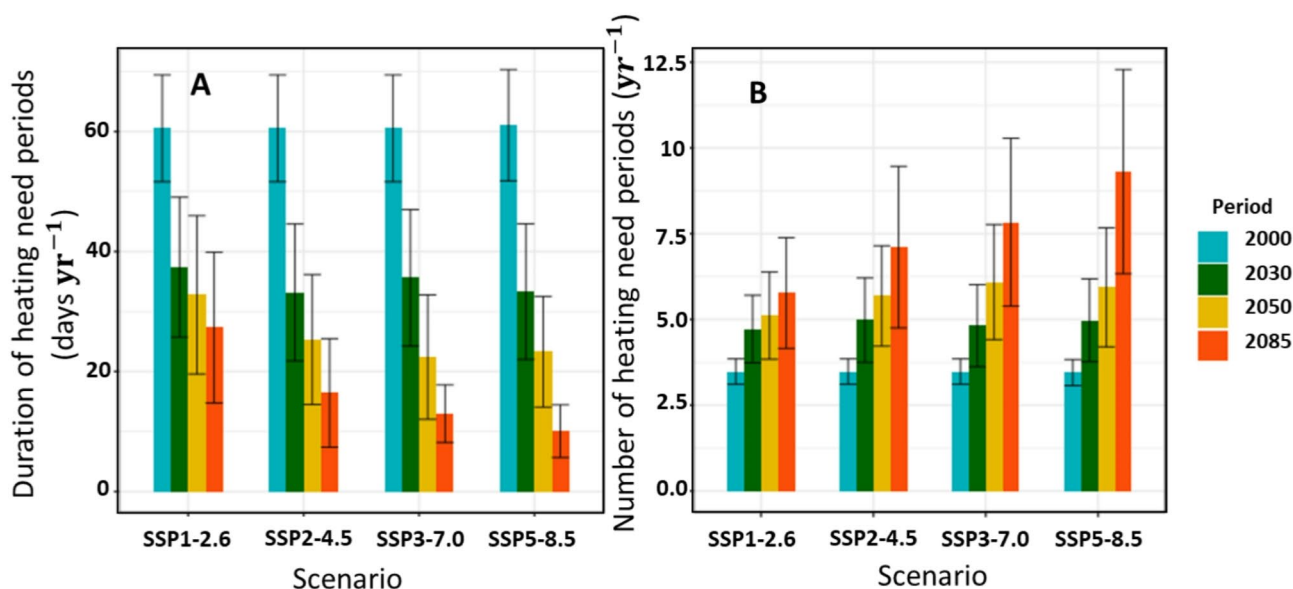


Fig. 1. Duration and frequency of heating periods for four time-horizons: 1985–2015 (central year 2000), 2015–2044 (central year 2030), 2035–2064 (central year 2050) and (2071–2100) (central year 2085) across four SSP scenarios (SSP1-2.6, SSP2-4.5, SSP3-7.0 and SSP5-8.5). Error bars show the uncertainty ($\pm\sigma$, where σ is the standard-deviation), reflecting both internal climate variability of the 10 CMIP6 models and differences in their responses to anthropogenic forcing.

(-84%). The error bars in Fig. 1 represent the uncertainty from internal climate variability and different model responses to anthropogenic forcing (Table 1). This indicates a shift from fewer long-duration heating needs to more frequent but shorter heating periods. A fragmentation of temperature-sensitive energy consumption may require additional flexibility at few-day time scale, referred as maneuverability, and have an operational and economic impact on the balancing of the energy system.

The impact of fragmented heating needs on energy consumption is assessed using EDF's (Électricité de France) energy consumption model, which is based on a generalized additive model that takes temperature data as input. Developed for forecasting, the model is calibrated with a wide range of predictors, including weather, calendar effects, and consumer behaviour, to ensure high accuracy and reliability^{25,26} (further details in the Methods section). The model was calibrated and run using data from 2009 to 2019, reflecting current usage and equipment levels. The electricity consumption model's goodness-of-fit was evaluated using the mean absolute error and R^2 , yielding values of 1.4% and 99% on the training dataset (2009 to 2017), and 1.6% and 98.7% on the validation dataset (2018–2019), respectively. In this analysis, we focus solely on the impact of climate change on temperature-sensitive energy demand, assuming other factors remain constant. Future scenarios vary only by temperature, while consumption usage remains fixed. Figure 2 displays the relative change in daily averaged power demand in winter, shown with green box plots for three future time horizons and four SSP scenarios. Each box represents the interquartile range (25th to 75th percentiles), with the median marked by a black line, whiskers extending 1.5 times the interquartile range, and outliers indicated by black dots. Overall, future warmer temperatures are projected to significantly reduce winter power demand, consistent with prior studies^{13,18,19}. This temperature-sensitive reduction becomes more pronounced over longer time horizons and higher greenhouse gas emission scenarios. For SSP1-2.6, projected changes across time horizons are relatively similar, as indicated by overlapping inter-model ranges. For more emissions-intensive scenarios, the trend becomes more distinct. By 2050, reductions in temperature-sensitive power demand range from -3% to -6%, while by 2085, the decline is estimated between -4% (SSP1-2.6) and -12% (SSP5-8.5). Figure 2 also shows reductions in power demand specifically due to fragmentation of heating periods (i.e. periods without heating), which are represented by boxed values. In 2030, this reduction is around -0.3% across all scenarios but could reach nearly -5% by 2085 under SSP5-8.5, accounting for 42% of the projected total reduction of -12%. These projected changes in average daily power demand are smaller than those from previous CMIP5 model studies and less accurate HDD-based energy consumption models^{13,18,19}.

Impact of climate change on extreme daily power demand during cold-wave events

However, extreme power demand can significantly stress the grid with potential cascading failures and major blackouts²⁷. Due to the high level of electrified heating in France, electricity demand peaks in winter, with daily peak hours typically between 7:00 a.m. and 12:00 p.m., and again between 6:00 p.m. and 8:00 p.m., as shown on France's transmission system operator RTE's Ecowatt website (<https://www.monecowatt.fr/>). If supply cannot meet demand during these peak periods, the grid is placed under considerable strain, which could lead to outages, leaving many without heat for hours. Such scenarios require intraday flexibility from dispatchable energy sources, which are often highly carbon-intensive.

To establish a threshold for extreme daily power demand, we calculated the 98th quantile of daily power winter demand over the 1985–2015 period based on power demand simulated using temperatures from each CMIP6 model. The minimum, median and maximum threshold values across the 10 CMIP6 models are 82.7, 83.3 and 84.1 GW, respectively. Figure 2 shows the relative change in daily power demand for days classified as extremes, using red box plots to represent three future time horizons and the four SSP scenarios. It shows a slight decrease, up to most -1.3%, as extreme cold events should still occur in France, though less frequently^{28,29}. These findings are qualitatively consistent with previous studies based on CMIP5 projections, which use different indicators^{19,20,23}. Figure 3 shows the projected changes in both the duration and frequency of extreme power demand episodes during winter across the same time horizons and scenarios as Fig. 1. The data indicate that while the duration of these extreme demand episodes remains relatively stable as the changes are within the uncertainty range displayed by the error bars (Table 1) and are therefore not significant. Conversely, their frequency decreases markedly, particularly in high-emission scenarios. It decreases by 60% in the best-case emission scenario (SSP1-2.6) to 90% in the worst-case (SSP5-8.5) at the end of the 21st century. This suggests that although extreme cold waves will occur less often, they will still pose significant challenges to the power grid. Indeed, the decrease in average power demand, along with the frequency of extreme demand events, may create a misleading impression that the strain on the electric grid will similarly decrease.

One indicator of the potential constraints on the power grid is the excess in daily power demand during cold waves, relative to average daily power demand. This excess is calculated as the difference between the daily power demand on the days that exceed the 98th quantile—defined here as “extreme cold conditions”—and the

Period	SSP1-2.6	SSP2-4.5	SSP3-7.0	SSP5-8.5
1985–2015	97.7	97.7	97.7	97.9
2015–2044	85.2	83.7	74.2	87.9
2035–2064	80.9	82.1	73.6	85.3
2071–2100	67.9	62.4	41.9	47.7

Table 1. Contribution to the total variance of internal variability (%) (the complementary contribution is due to differences in the model responses to anthropogenic forcing).

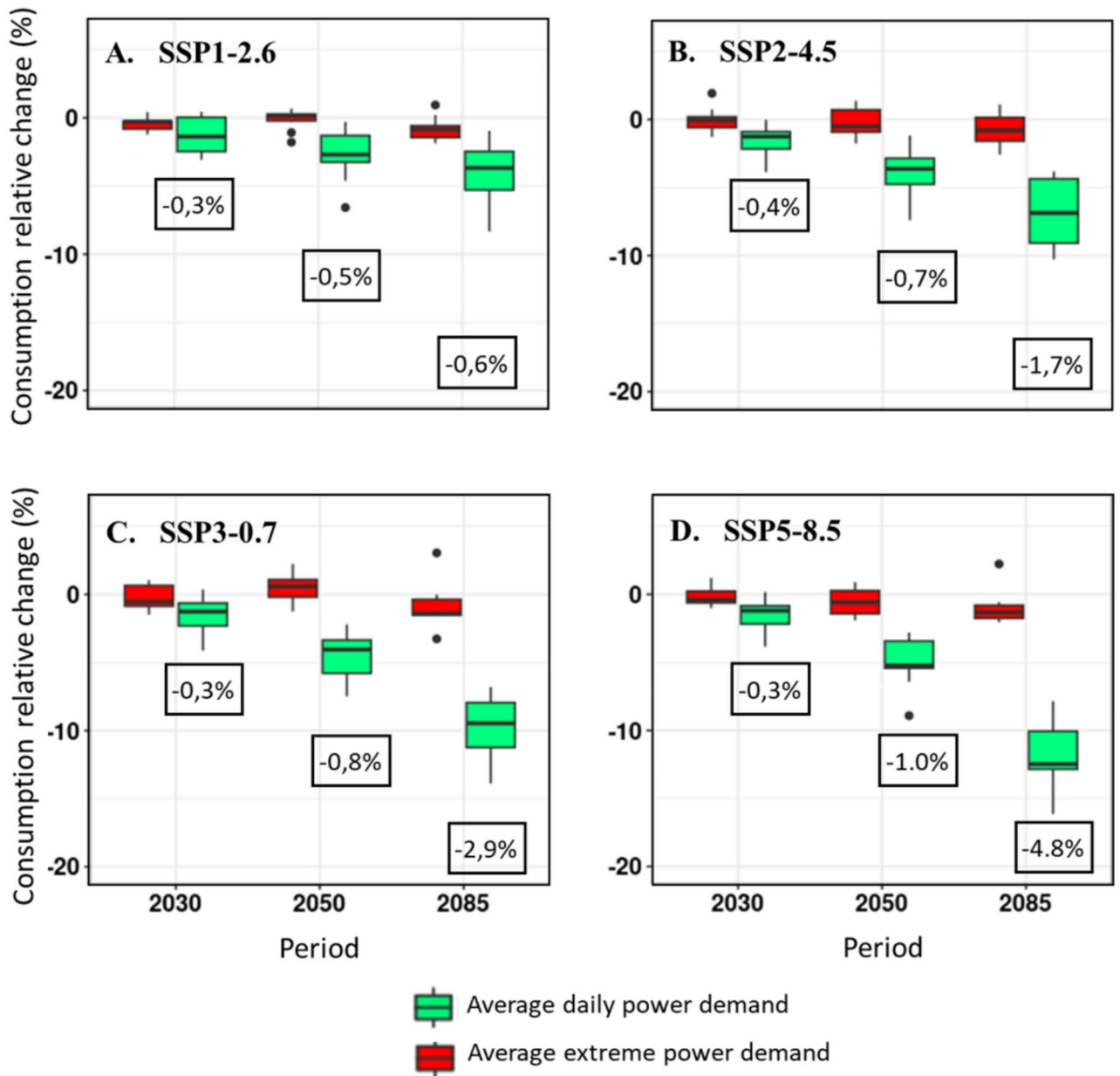


Fig. 2. Relative change in average daily power demand in winter (November to January) for three future time-horizons: 2015–2044 (central year 2030), 2035–2064 (central year 2050) and (2071–2100) (central year 2085) compared to the historical period 1985–2015, across four SSP scenarios (SSP1-2.6, SSP2-4.5, SSP3-7.0 and SSP5-8.5). Each box represents the interquartile range (25th to 75th percentiles), with the median marked by a black line, based on the 10 selected climate models. Whiskers extend 1.5 times the interquartile range on both sides, and outliers are shown as black dots. The red boxplots display the change in extreme peak demand due to cold waves, while the green boxplots show changes in average power demand. Numbers within the boxes indicate the average change in daily power demand attributable to fragmented heating needs; the remaining change reflects milder winter temperatures).

average daily power demand for the same days averaged over the 1985–2015 period, which represents “normal conditions”. To ensure accuracy, we compare like days (e.g., working days to working days or weekends and holidays to similar non-working days), even if it requires using the nearest matching day.

Figure 4a illustrates the concept of daily power demand excess for one cold wave event in February 2012, which clearly shows the strain extreme demand places on the electric grid. Due to a severe cold surge, one of the most extreme events in French history³⁰, daily peak demand repeatedly broke records, culminating in a historic peak of 102.1 GW on February 8 at 7:00 p.m.³¹. The daily average power demand reached 93.9 GW (Fig. 4a), with

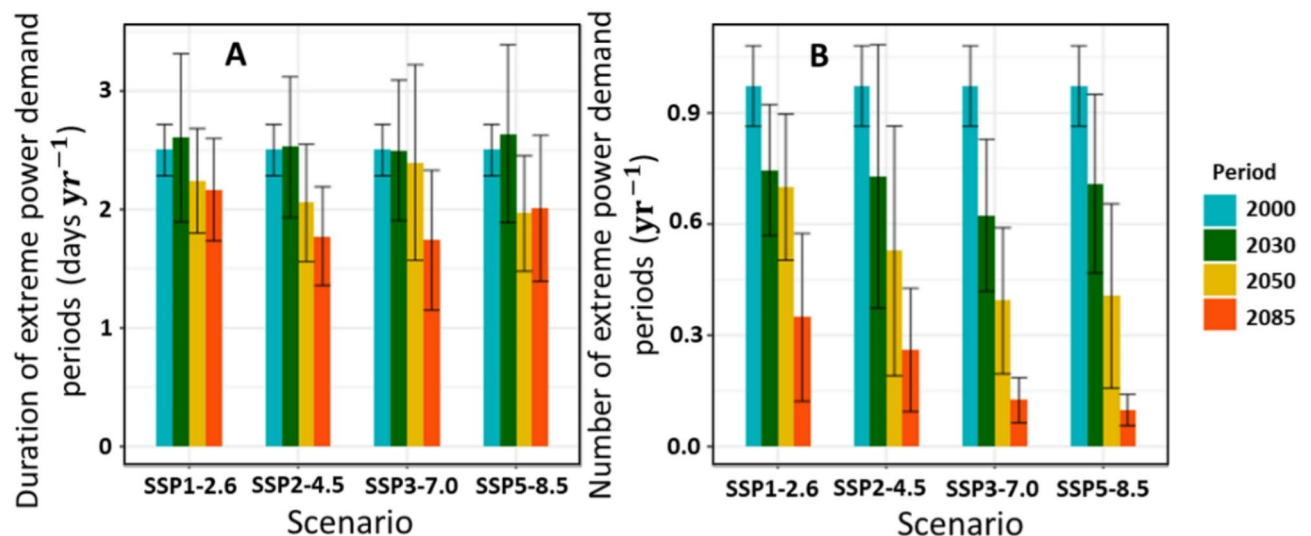


Fig. 3. Duration and frequency of extreme power demand periods for four time-horizons: 1985–2015 (central year 2000), 2015–2044 (central year 2030), 2035–2064 (central year 2050) and (2071–2100) (central year 2085) across four SSP scenarios (SSP1-2.6, SSP2-4.5, SSP3-7.0 and SSP5-8.5). Error bars show the uncertainty ($\pm\sigma$, where σ is the standard-deviation), reflecting both internal climate variability of the 10 CMIP6 models and differences in their responses to anthropogenic forcing.

approximately 40% of electricity consumption attributed to the exceptionally cold temperatures. During this period, coal consumption surged by 70% compared to February 2011, and natural gas consumption by +32%³². To manage the demand, 400 MW of contracted load-shedding capacity was deployed, with additional targeted measures in Brittany, an area particularly vulnerable due to its geographical isolation and limited local generation capacity³¹. Using RTE data, we calculated the daily power demand excess for this day, with the “normal” daily power demand defined as the average February 12 demand from 2006 to 2020. We found a daily power demand excess of 22 GW (Fig. 4a), which is hereafter used as a threshold corresponding for extreme stress conditions on the power grid. Less extreme situations can also place significant stress on the French electric grid. For instance, on December 15th, 2010, demand peaked at 96.7 GW at 7:00 p.m., with a daily average of 86.6 GW.

Figure 4b shows the projected evolution of excess daily power demand due to extreme cold waves expected for 2050 and 2085 across the four SSP scenarios. It also indicates the 22 GW threshold corresponding to the extreme case of February, 8th, 2012 (the figure shows how a modified threshold would affect quantitatively the results without changing the overall analysis qualitatively). This serves as an indicator of potential grid stress under climate change, assuming all other factors remain constant. Currently, the daily power demand excess during “extreme cold conditions” averages about 18 GW (Fig. 4b), which is approximately 25% higher than under “normal conditions”, with uncertainty mainly due to internal variability (Table 1). In the future, daily power demand excess during extreme cold is projected to increase across all SSP scenarios. By 2050, it may reach an average of 23 GW (33% above average daily demand), and by 2085, it could exceed 24 GW (over 35% above average) under SSP3-7.0 (Figs. 4b, c). In the most extreme cases, this excess could surpass 28 GW. Table 2 details the probability of power demand excess in “extreme cold conditions” exceeding the 22 GW threshold. Currently, the probability is about 20% for all “extreme cold conditions”. Assuming other factors remain unchanged, this probability rises to approximately 30% by 2030. Beyond 2030, the trend remains insignificant in SSP1-2.6 and SSP2-4.5 but becomes more pronounced in SSP3-7.0, with probabilities reaching around 45% by 2050 and exceeding 70% by 2085, although with fewer overall episodes.

Considering the current electricity mix and usage, the excess daily power demand caused by cold waves is projected to increase significantly with climate change, leading to heightened constraints on the power supply system. Historical examples, like those mentioned, highlight scenarios where pressures on both demand and supply compounded, placing major strain on the grid. The French electricity system is designed to limit potential power supply shortages to a maximum of three hours per year on average, aligning with similar standards across Europe to meet peak demands even in extreme conditions³³. This “loss of load expectation” ensures that sufficient generation and demand-side resources are available to meet demand projections under various scenarios, including severe weather. However, the economic viability of reserve units, such as peaker plants, faces challenges as extreme peak demands become less frequent. Peaker plants, traditionally used only during high-demand periods, may see reduced utilization, leading to higher per-unit electricity costs as fixed costs are spread over fewer operational hours, impacting investment recovery and profitability³⁴. Additionally, the shift toward renewable energy and energy storage systems further challenges the role of traditional peaker plants. Energy storage offers a more cost-effective and flexible solution for peak demand management, reducing reliance on peaker plants and potentially leading to their underutilization, impacting economic feasibility and possibly leading to phased retirement^{35,36}. Regulatory and market design considerations are also critical. Energy-only markets, for instance, may not provide sufficient revenue to cover the fixed costs of peaker plants, particularly if

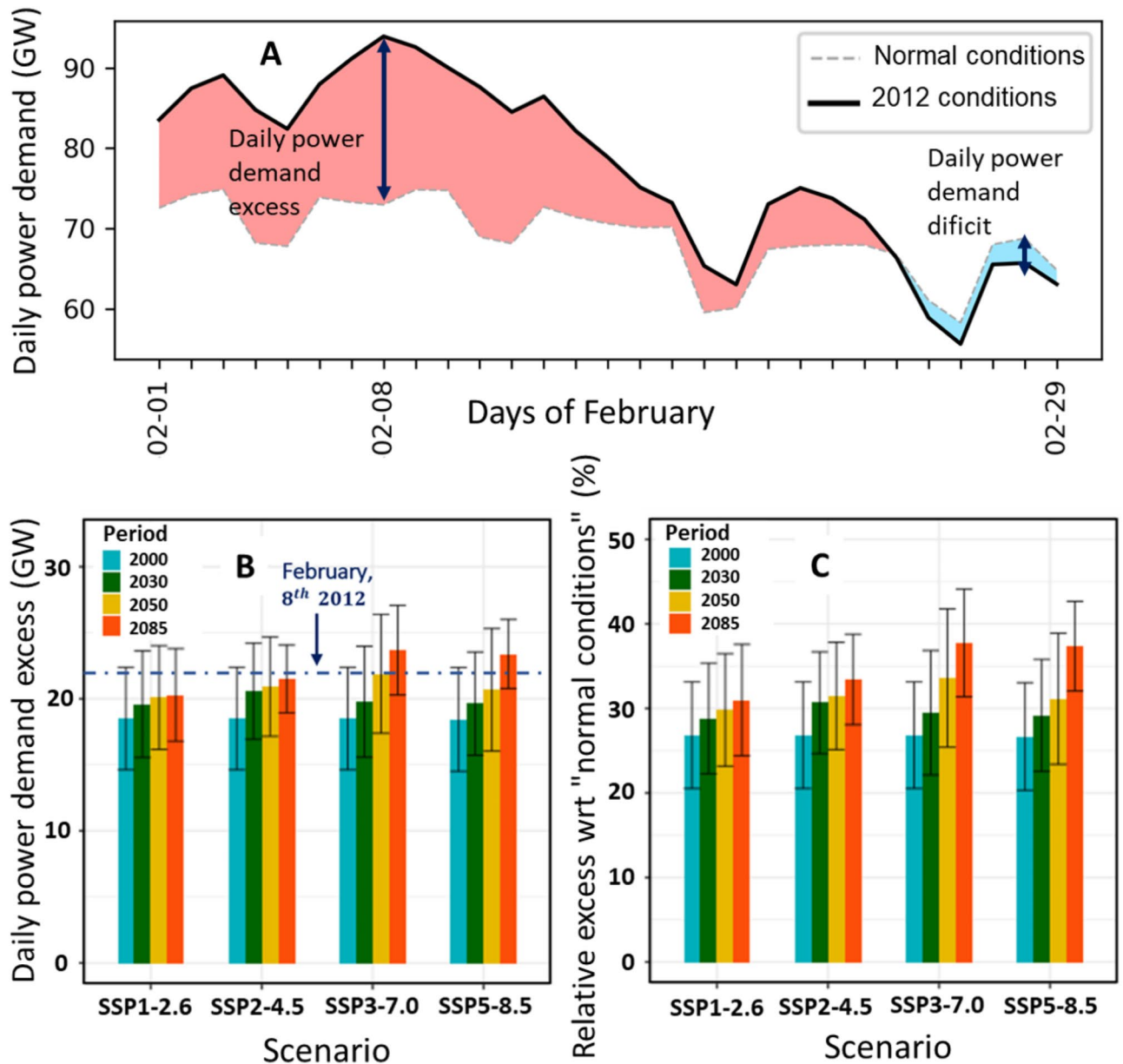


Fig. 4. (A) Daily power demand in February, 2012 (thick solid line) compared with the daily power demand averaged over 1985–2015 (“normal” conditions). The red shaded area represents the excess daily power demand above normal levels, while the blue shaded area shows any deficit. On February 8, daily power demand reached 93.9 GW, resulting in an excess of 22 GW, which is considered here as a threshold for extreme stress on the power grid. (B) Daily power demand excess during “extreme cold conditions” (where daily power demand exceeds the 98th quantile of winter power demand from the 1985–2015 period) is shown for four time-horizons: 1985–2015 (central year 2000), 2015–2044 (central year 2030), 2035–2064 (central year 2050) and (2071–2100) (central year 2085) across four SSP scenarios (SSP1-2.6, SSP2-4.5, SSP3-7.0 and SSP5-8.5). C/ Same as B/ but showing the fraction of daily power demand excess relative to average daily power demand (%). Error bars indicate the uncertainty ($\pm\sigma$, with σ the standard-deviation), reflecting both internal climate variability of the 10 CMIP6 models and differences in their responses to anthropogenic forcing.

they are rarely dispatched. This highlights the need for evolving market mechanisms that adequately compensate capacity resources essential for reliability while promoting the integration of more economically viable alternatives like energy storage systems^{35,37}. With a decreasing frequency of extreme events and fragmented heating needs, the strain on the grid could therefore increase.

These results should be contextualized alongside factors such as changes in the number of electrically heated homes, which would raise power demand, and improvements in heating efficiency (e.g., better building insulation, deployment of heat pumps) which would lower it. If greater electrification of heating increases temperature sensitivity, it could lead to higher demand variability, a greater likelihood of demands exceeding the

Period	SSP1-2.6	SSP2-4.5	SSP3-7.0	SSP5-8.5
1985–2015	19.7±5.6 (6.8)	19.7±5.6 (6.8)	19.7±5.6 (6.8)	19.7±5.6 (6.8)
2015–2044	22.6±12.6 (5.6)	32.9±18.5 (7.6)	27.4±16.4 (6.7)	19.4±8.9 (5.3)
2035–2064	29.3±12.7 (6.4)	27.7±23.5 (4.7)	46.5±21.8 (6.7)	27.7±13.6 (4.6)
2071–2100	21.9±22.1 (2.4)	44.7±36.8 (2.5)	79.6±40.0 (2.0)	70.0±47.6 (2.2)

Table 2. Probability (%) that peak demand excess during extreme cold waves exceeds the 22 GW threshold, with the number of corresponding events shown in brackets, averaged over the 10 CMIP6 models. Inter-model uncertainty is indicated as $\pm\sigma$ (where Σ is the standard-deviation).

mean, and increased peak power demand³⁸. When combined with climate change scenarios, these effects would likely amplify the findings of this study. Additionally, shifts in behaviour and more flexible electricity demand, particularly with the adoption of electric vehicles, could also influence power demand. The future electricity mix, increasingly shaped by renewables that are less flexible and manageable, will have impactful effects on the power system. Our findings highlight the need for vigilance regarding necessary adaptations of the electrical system through appropriate measures.

Methods

CMIP6 models and selection

We analysed the historical runs over the period 1985–2015 and future climate projections for four Shared Socio-economic Pathways (SSP) (SSP1-2.6, SSP2-4.5, SSP3-7.0 and SSP5-8.5) over the period 2016–2100 from 29 CMIP6 models to represent the present-day climate and future warmer climate, respectively; the former runs are forced by observed atmospheric compositions over the twentieth century and the latter runs by a greenhouse gas emission scenario with a radiative forcing ranging between 2.6 W m^{-2} and 8.5 W m^{-2} at the end of the twenty-first century. The 29 CMIP6 models include AWI-CM-1-1-MR, BCC-CSM2-MR, FGOALS-g3, CanESM5, CMCC-ESM2, CNRM-CM6-1, CNRM-CM6-1-HR, CNRM-ESM2-1, ACCESS-ESM1-5, ACCESS-CM2, EC-Earth3-CC, EC-Earth3, EC-Earth3-Veg, INM-CM4-8, INM-CM5-0, KIOST-ESM, MIROC6, MIROC-ES2L, HadGEM3-GC31-LL, UKESM1-0-LL, MPI-ESM1-2-LR, NorESM2-LM, NorESM2-MM, KACE-1-0-G, NESM3, IPSL-CM6A-LR, IPSL-CM6A-LR-INCA, KACE-1-0-G and TaiESM1. More detailed information on CMIP6 coupled models can be obtained from <https://wcrp-cmip.org/cmip-phase-6-cmip6/> and the data can be obtained from one of the Earth System Grid Federation (ESGF) node, e.g. <https://esgf-node.ipsl.upmc.fr/projects/esgf-ipsl/>.

Those models have been processed as they all had at least available daily average, maximum, and minimum near-surface temperatures for the historical simulation (1850–2014) and all four emissions scenarios (2015–2100). A subset of 10 models has been kept for debiasing and downscaling so that the subset maximizes the diversity of climate projections among the best-performing models for simulating past energy demand. The daily temperatures are regridded from each model's native spatial resolution to the $25 \times 25 \text{ km}^2$ grid of the ERA5 reanalysis of the European Center for Medium-range Weather Forecast (ECMWF)³⁹. For the model selection process, we only consider the 2071–2100 projection period with central year 2085 and the SSP5-8.5 scenario only. In our study, the model selection is based on two main criteria. The first criterion consists in choosing a set of models that represent a whole range of possible climate change in the future. The second criterion considers the historical performance of the models with respect to the ERA5 reanalysis, here considered as a reference “observation” dataset. In order to keep a large range of climate change in the future in the selected subset, we apply an ascending hierarchical classification to group similar models based on temperature change between the projection and historical periods. As the objective is arbitrarily to keep a maximum of 10 models in the final subset, for computing resource issues, the number of classes is set to 10, with one model only kept in each class. Finally, comparing the performances of the historical simulations from models belonging to the same class allows to exclude the models that are considered very unrealistic compared to the reference and keep only the most performing model in each class. The evaluation of the historical performances of models is performed using 4 skill scores based on the daily temperature: the absolute bias and the three statistics of the Taylor diagram, namely the correlation, the root mean square error and the standard deviation of the CMIP6 simulations with respect to the ERA5 reference dataset⁴⁰. The subset of climate models resulting from the selection process are CanESM5, CMCC-ESM2, CNRM-ESM2-1, ACCESS-ESM1-5, EC-Earth3-Veg, INM-CM4-8, UKESM1-0-LL, MPI-ESM1-2-LR, NorESM2-MM and IPSL-CM6A-LR.

Proxy of temperature-sensitive energy demand

Daily HDD is computed with the simulated temperature according to the UK Met Office for a day defined with a daily mean (T_{avg}), minimum (T_{min}) and maximum (T_{max}) surface air temperature:

If $T_{\text{max}} \leq T_{\text{base}}$ (i.e. uniformly cold day),	then $\text{HDD} = T_{\text{base}} - T_{\text{avg}}$
If $T_{\text{avg}} \leq T_{\text{base}} < T_{\text{max}}$ (i.e. mostly cold day),	then $\text{HDD} = [(T_{\text{base}} - T_{\text{min}})/2] [(T_{\text{max}} - T_{\text{base}})/4]$
If $T_{\text{min}} < T_{\text{base}} < T_{\text{avg}}$ (i.e. mostly warm day),	then $\text{HDD} = (T_{\text{base}} - T_{\text{min}})/4$
If $T_{\text{min}} \geq T_{\text{base}}$ (i.e. uniformly warm day),	then no heating is required, so $\text{HDD} = 0$

Daily average temperature (T_{avg}) is calculated as $(T_{\text{max}} + T_{\text{min}})/2$. It is the method used by Spinoni et al.¹³. For this study, T_{base} is set to 15.5 °C. Varying the heating setpoint affects the results quantitatively but not qualitatively (not shown).

Power demand model

The model of electric consumption in France used in this work has been developed by EDF (Electricité de France) electricity provider for electric consumption forecasting and is based on a Generalized Additive Model (GAM)^{25,26}. GAM is a statistical method that extends the generalized linear model. The GAM model is considered as a flexible nonlinear regression model, which can be fitted efficiently using the approximate Bayesian methods. This type of regression model is more relevant when the relationship is suspected to be “non-linear”, which is the case of the relation between temperature and consumption. In the model, the predictor remains in additive form, but it is possible to explain the consumption by “splines” of explanatory variables. These functions represent a way of dealing with the non-linear relationships that certain variables may have with the consumption. The model has been calibrated over 2009–2017 period and validated for 2018 and 2019 using electricity consumption data from the French transmission system operator RTE. The year 2020 was excluded as it displayed a very significant different consumption pattern due to the COVID-19 pandemic and associated disruption of the global economy. The model has been initially calibrated with trends over the entire study period from 2009 to 2019. We thus estimate the non-predictive part of electricity consumption linked to the effect of time (demography, insulation, heating) as we subtract from the consumption to be expected. We then recalibrate the models (without the trends) over the estimation period which we validate over the two years 2018 and 2019. The dataset used is available from the open-access database accessible at https://www.services-rte.com/en/download-data-published-by-rte.html?category=consumption&type=power_consumption.

Data availability

CMIP6 coupled model data can be obtained from one of the Earth System Grid Federation (ESGF) node, e.g. <https://esgf-node.ipsl.upmc.fr/projects/esgf-ipsl/>. The energy consumption dataset used is available from the open-access database accessible at https://www.services-rte.com/en/download-data-published-by-rte.html?category=consumption&type=power_consumption. The dataset created based on degree-days and proprietary EDF consumption model have a the following DOI: <https://doi.org/10.14768/cfcc831-1d43-469c-be00-021911a2a644>. The following links are also available on the “DOI landing page”: Data download: https://data.ipsl.fr/repository/e4c/DataHub_projects/P202103080001/. Code deposit: https://gitlab.in2p3.fr/energy4climate/public/cons-o-extreme-france/-/tree/main?ref_type=heads (accessible to all, without prior request if people are part of the EduGain federation, on request otherwise). Description of the project on the E4C DataHub: <https://e4c-ipsl.ip-paris.fr/#/fr/datahub/project/22>. Codes and data are licensed under CC BY-NC 4.0.

Received: 2 May 2024; Accepted: 26 March 2025

Published online: 11 April 2025

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Acknowledgements

This work was carried out at the Energy4Climate Interdisciplinary Center (E4C) of IP Paris and Ecole des Ponts, supported by 3rd Programme d'Investissements d'Avenir [ANR-18-EUR-0006-02], in collaboration with CNRS, CEA, EDF and TotalEnergies. It was jointly funded by EDF company and Association Nationale Recherche Technologie (ANRT) through a CIFRE grant.

Author contributions

Hajar Filahi: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Visualization, Writing—original draft, Writing—review & editing. Philippe Drobinski: Conceptualization, Formal analysis, Supervision, Validation, Writing—review & editing. Boutheina Oueslati: Conceptualization, Validation, Writing—review & editing. Sandra Claudel: Conceptualization, Validation, Writing—review & editing. Marie-Hélène Laurent: Conceptualization, Validation, Writing—review & editing.

Declarations

Competing interests

The authors declare no competing interests.

Additional information

Correspondence and requests for materials should be addressed to P.D.

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