2030 Peak Power Demand in North-West Europe

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A report from: E-CUBE Strategy Consultants and the Institute of Energy Economics at the University of Cologne gGmbH (EWI)

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References to TYNDP 2020

All mentions of TYNDP 2020 refer to the latest version of public documents published by ENTSO-E and ENTSOG on 29 June 2020.

Executive Summary

1 In North-West Europe, the electrification of end uses and replacement of dispatchable thermal generation with intermittent renewable generation may impact the resilience of the electricity system to winter cold spells.

This challenge has become a reality now that the historical over-capacity in certain countries has receded (e.g. in France). ENTSO-E analysis shows that in case of a cold spell, Belgium and France would have risked supply shortages this past winter[1]. By 2022-2023, RTE estimates that there is almost 100% probability that a 2012-type cold spell would lead to Loss of Load in France.

To study the power system's response to cold spells in 2030, we define three electricity demand scenarios based on TSO scenarios and national energy policy objectives for North-West Europe. The three scenarios assume different degrees of electrification. We then analyze the occurrence of supply-demand gaps under TYNDP 2020-like supply scenarios and evaluate the associated costs.

2 Our results show that by 2030, the risk of supply-demand gaps at peak time under cold temperatures increases.

Overall, we estimate that cold spells such as those experienced in 1985, 1997 or 2012 would generate costs up to ~30 bn EUR, or ~0.4% of the annual GDP for North-West Europe (using a Value of Lost Load assumption from RTE for all countries). These costs result from the loss of up to ~0.4% of the annual electricity load of North-West Europe, with up to ~35 to 70 GW of power interruptions during ~100 to 250 hours affecting large industrial sites, and possibly commercial and residential customers.

3 These results are especially driven by the assumed increased role of heat pump heating. Heat pumps are critical since their performance (COP) and power output significantly decrease with low temperatures, which results in higher electricity demand.

There is significant uncertainty concerning the performance of heat pumps: real-life performance is significantly lower than certification test performance, notably because the operating conditions are different. Moreover, the composition of the future fleet of heat pumps is a further critical aspect in the assumptions, since heat pump performance varies among the different technologies. A further uncertainty lies in the level of flexibility offered by heat pumps, i.e. their ability to shift the load from one time of day to the next.

All these uncertainties are all the more an issue since properly sizing generation and flexibility assets to heat pump demand will be key for adequacy: we find that beyond a certain penetration level of heat pumps in the electricity sector, each additional air-to-air heat pump would generate ~2,000 EUR of additional cost during cold spells. This figure can also be interpreted as the societal value of installing a hybrid heat pump instead of an air-to-air heat pump, because the contribution of hybrid heat pumps to peak demand is very limited.

In comparison, electric vehicles contribute less than air-to-air heat pumps to peak demand during cold spells in our scenarios: each additional EV would generate an additional cost of ~300 EUR for society during cold spells.

4 Other risk factors affect the potential size of the supply-demand gap, such as low availability of nuclear generation and low output from hydro generation, as experienced over the past few years. These would also significantly increase Energy Not Served during cold spells.

5 Thus, we identify the potential demand-supply gap as an important challenge for the European energy transition: if the increase in electricity demand were not appropriately compensated with

[1] See ENTSO-E's Winter Outlook 2019-2020

the increase in supply & flexibility assets, decarbonizing Europe could prove more costly than anticipated.

Changes to the electricity system should be carefully managed within each country and between countries to ensure adequacy at peak time. This is especially the case as rapid diffusion of heat pumps will be part of the chosen pathway.

Several solutions could be used to address this challenge:
- On the supply side: increasing dispatchable capacity, which would most likely be thermal generation
- On the demand side: lowering the peak, by targeting a specific mix of heating technologies, e.g fewer electrical resistance and more hybrid heat pumps

The path to decarbonizing the European energy system will therefore require a trade-off between different types of cost:
- Cost of Energy Not Served
- Cost of equipment on the supply and demand side (e.g. heat pumps, gas turbines, hybrid heat pumps)
- Cost of supplying this equipment with low-CO_2 or CO_2-free energy (e.g. green gas)

Since adding peaker capacity or replacing heating equipment can take years, the way the 2030 power system will fare under cold spells will already depend on decisions made in the early 2020s.

6 By 2050, unless technologies such as long-term hydrogen storage provide additional solutions to bridge supply-demand gaps, the issue is likely to become more acute as electrification of end uses and intermittent renewable capacity further develop.

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1 In cold winters, the 2030 power system in North-West Europe would experience power interruptions of over 10% of demand during 100 to 250 hours, with economic cost of ~10 to 30 bn EUR

1.1 In case of a cold winter, the 2030 supply-demand gap could reach ~35 to 70 GW, possibly leading to ~100 to 250 hours of Loss of Load and ~1.7 to 5.6 TWh of Energy Not Served

1.1.1 We studied the hourly matching of electricity supply and demand by 2030 under 9 scenario combinations, mostly based on assumptions from TYNDP, TSOs, and national policy objectives

The 9 combinations are based on 3X3 supply and demand scenarios:

- The 3 scenarios for electricity supply (generation & flexibility) which mostly come from TYNDP 2020 (Global Ambition, National Trends, Distributed Energy), with a few adjustments and assumptions[2].
- 3 custom demand scenarios (Low, Mid, High): since the currently available documents regarding TYNDP 2020 offer little detail as to the assumptions on the demand side, we devised our own sets of assumptions. The three scenarios assume different degrees of electrification. To build these scenarios, we drew inspiration from publications by TSOs in each country, as well as national plans for the energy sector. Under the climate year used as reference in TYNDP 2020 (year 1984), our results for peak demand are consistent with TYNDP 2020 (see Appendix C).

Methodological note

Our approach is to define 3 possible scenarios for electricity demand and study their matching under cold spell conditions with 3 preexisting TYNDP scenarios for electricity supply. Whereas the TYNDP produces combinations of demand and supply scenarios that were designed together, we base our demand assumptions on TSOs and national energy policies, and TYNDP 2020 when possible/disclosed.

Because the TYNDP provides limited information regarding demand assumptions (e.g. number of households and commercial area by heating and water heating technology, COP, bivalent and operating limit temperatures for heat pumps), we are not able to ascertain the differences between our scenarios and those of TYNDP. Based on the data released at the end of June 2020 regarding 2 of the 3 TYNDP scenarios (Distributed Energy and Global Ambition), it seems that there are differences between our demand scenarios and those of the TYNDP regarding the types of heat pumps used. Among heat pumps, the TYNDP seems to assume a higher % of the types of heat pumps that contribute the least to peak electricity demand:

- Ground-source heat pumps (as opposed to air-source heat pumps)
- Hybrid heat pumps (in particular in Benelux and Germany) – In our base case, we assume 0% of hybrid heat pumps, but we run a sensitivity with a high % of hybrid heat pumps in paragraph 3.2

[2] We made adjustments to factor in the latest developments regarding generation capacity (e.g. coal plants and the security reserve mechanism in Germany, nuclear plants in Belgium). For detailed hydro generation capacity by technology (run-of river & pondage, reservoir, pumped storage), we used detailed assumptions from TYNDP 2018.

The TYNDP also assumes a significant market share for gas heat pumps, in particular in France.

Despite those discrepancies, our scenarios reach peak demands similar to TYNDP under the climate year used as reference in TYNDP 2020 (year 1984),

Even if one could argue that some of the demand scenarios were not designed to match some of the TYNDP supply scenarios, our analysis shows similar results across all three supply scenarios.

The geographical scope of our analysis is France, Germany, Belgium, Denmark, Luxembourg and the Netherlands. Countries outside of this area are not modelled, and it is assumed that the net interconnection exchange with countries outside the studied area is zero. See 1.3 for the validity of this assumption.

1.1.2 Low temperatures would lead to ~1.7 to 5.6 TWh of Energy Not Served (ENS) in the High demand scenario, for ~10 to 25% of power demand during ~100 to 250 hours

When temperatures drop, electricity demand strongly increases due to more use of electric heating, especially in households and commercial buildings. As a result, during severe cold spells such as those experienced in 1985, 1997 and 2012, the power system could fail to match all of the electricity demand. This would result in a Loss of Load (LoL) for certain customers. For the purpose of this analysis, we study the matching of demand from our scenarios with supply from TYNDP-like scenarios. At this stage, we do not take into account how the market may incentivize investment in peakers[3] or different end-user heating systems to bridge supply-demand gaps during cold spells.

[3] Controllable power plants with very low full load hours, typically gas turbines.

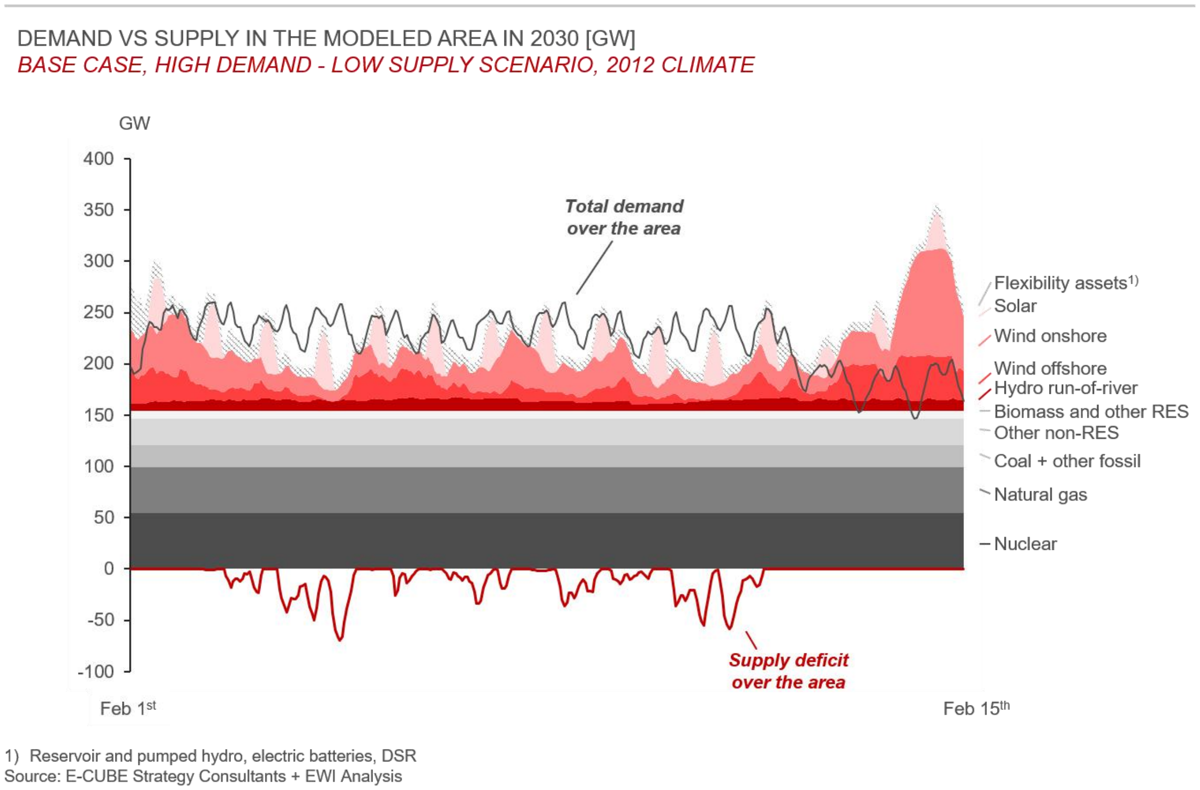


Figure 1: Example of supply-demand mismatch during a cold spell in North-West Europe

In our High demand scenario, the amount of Energy Not Served (ENS) would reach up to ~5.6 TWh. This corresponds to ~100 to 250 hours of lost load over the duration of the cold spell, with power not served reaching ~35 to 70 GW (or ~10 to 25% of demand).

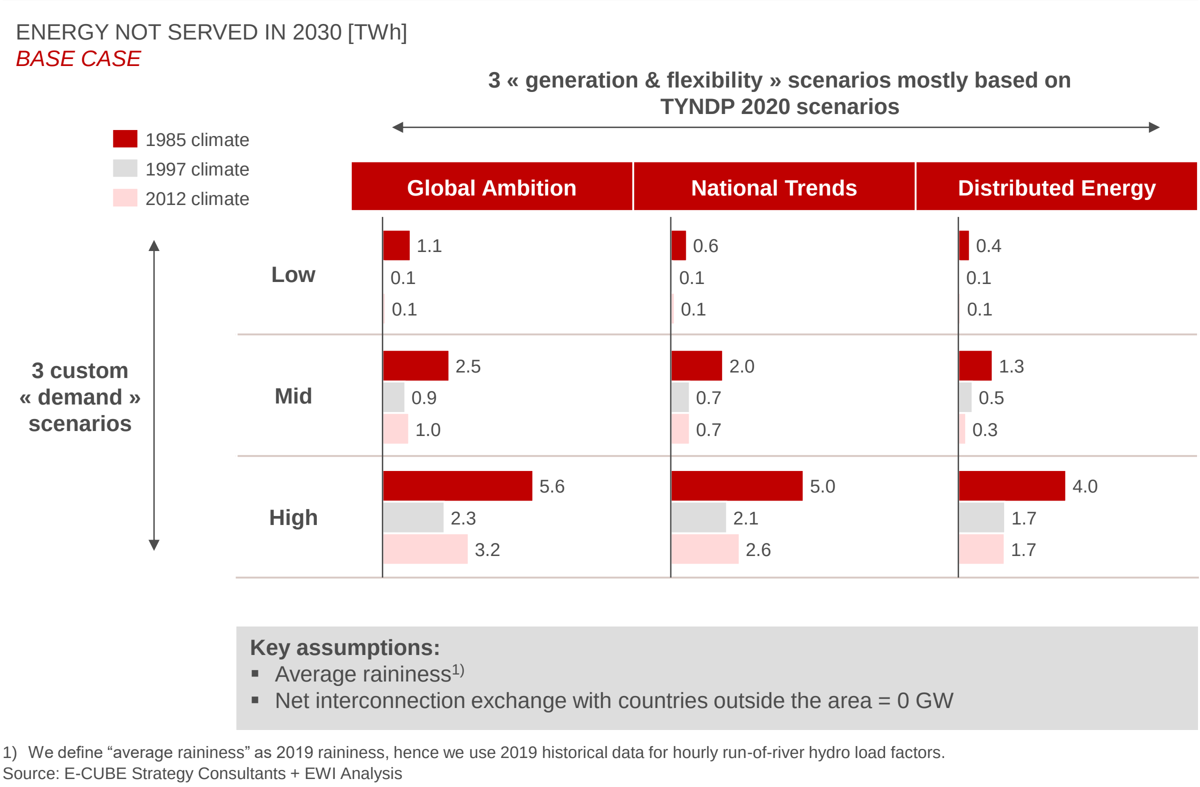
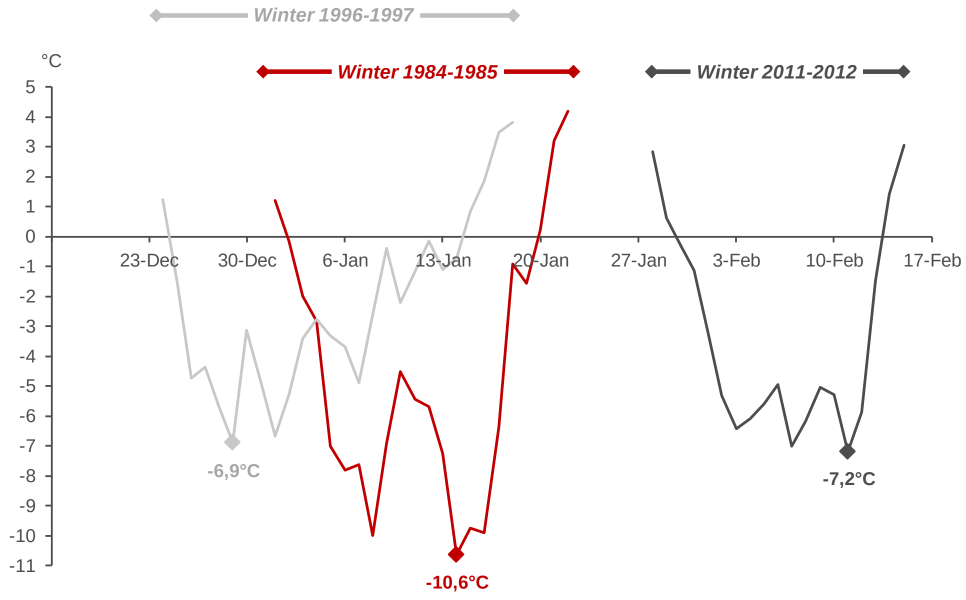


Figure 2: Estimated Energy Not Served (ENS) in the 9 scenario combinations, under 1985, 1997 and 2012 climate conditions

The stress on the power system is related to the severity of the cold spell: in 1985, average daily temperatures dipped lower than in 2012, which leads to higher ENS in 1985 than 2012.

DAILY AVERAGE POPULATION-WEIGHTED TEMPERATURE UNDER WINTER 84-85, 96-97 AND 11-12 CLIMATE IN FRANCE [°C]



Source: MERRA-2, E-CUBE Strategy Consultants + EWI Analysis

Figure 3: Daily average population-weighted temperature under 1985 and 2012 climate in France

1.1.3 The temperature dependence of electricity demand is expected to increase overall, and increase especially fast at low temperatures

At constant climate, annual electricity consumption in North-West Europe is expected to remain relatively stable. This results from the cumulated effects of:

- Higher electrification of energy uses, especially for space heating, water heating and transportation with the development of electric vehicles
- Higher energy efficiency, both of buildings and of appliances

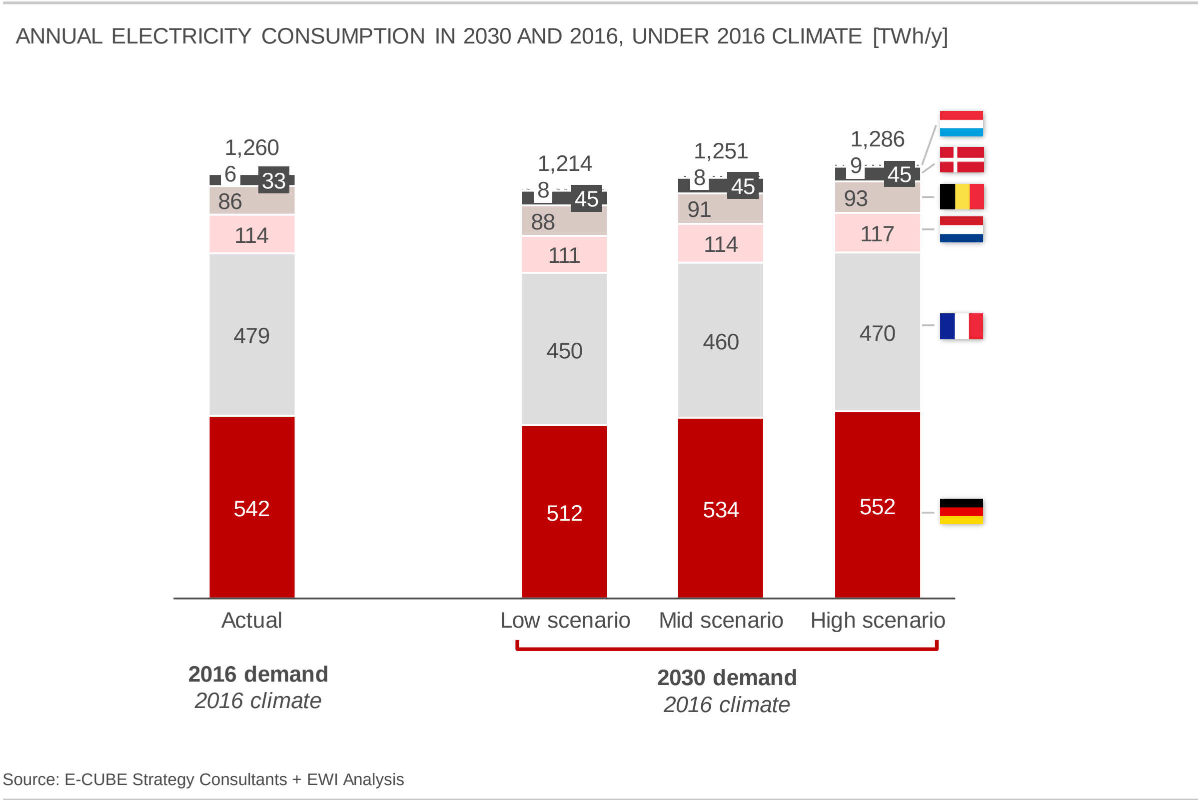


Figure 4: Annual electricity consumption in 2016 and 2030, under 2016 climate

On the other hand, peak demand is expected to increase, especially under low temperatures. At mild temperatures, such as experienced in 2016, energy efficiency compensates for the higher demand for space heating, but under very low temperatures (e.g. lower than -5°C, as experienced in 2012), the consumption for space heating will increase even more, resulting in higher peak demand overall.

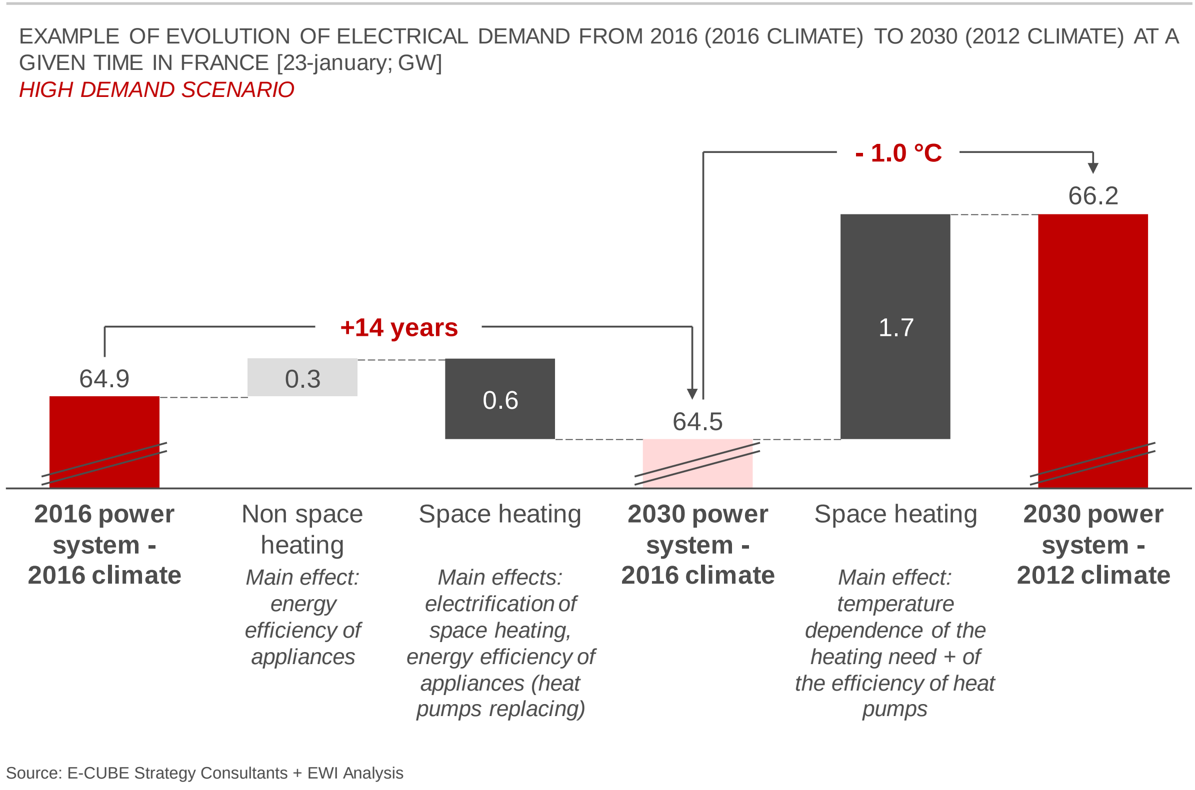
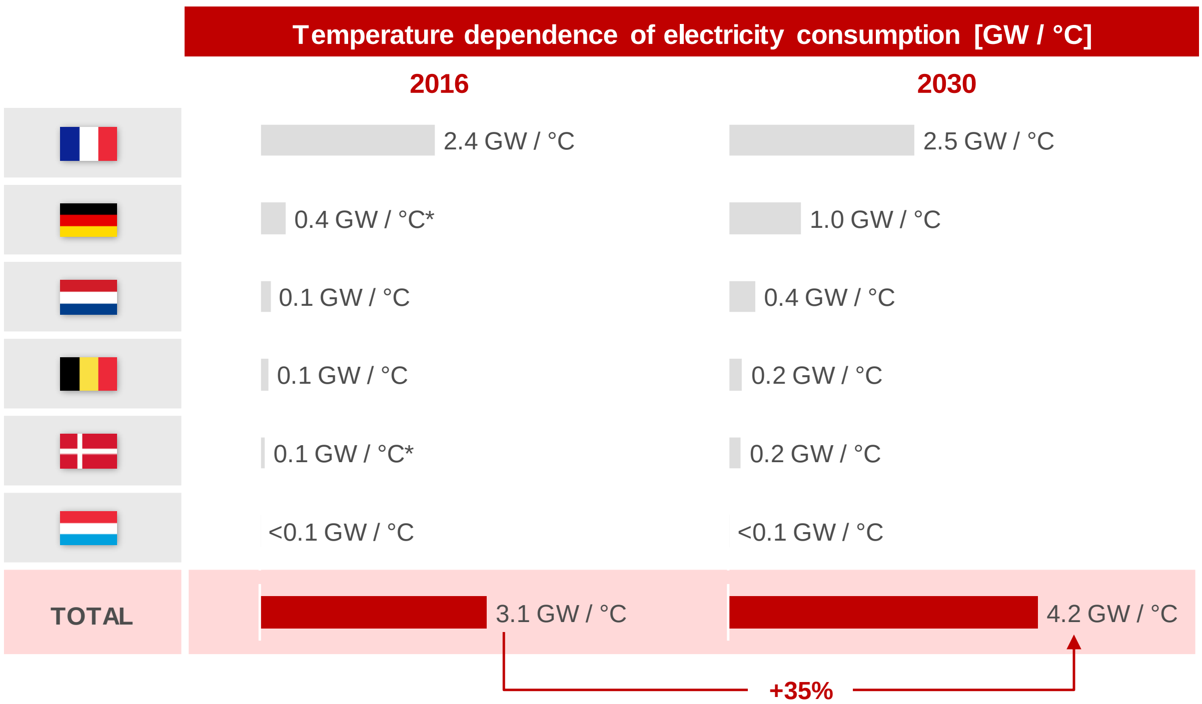


Figure 5: Example of evolution of electrical demand from 2016 (2016 climate) to 2030 (2012 climate) at a given time in France

The temperature dependence is expected to increase in all countries by 2030:

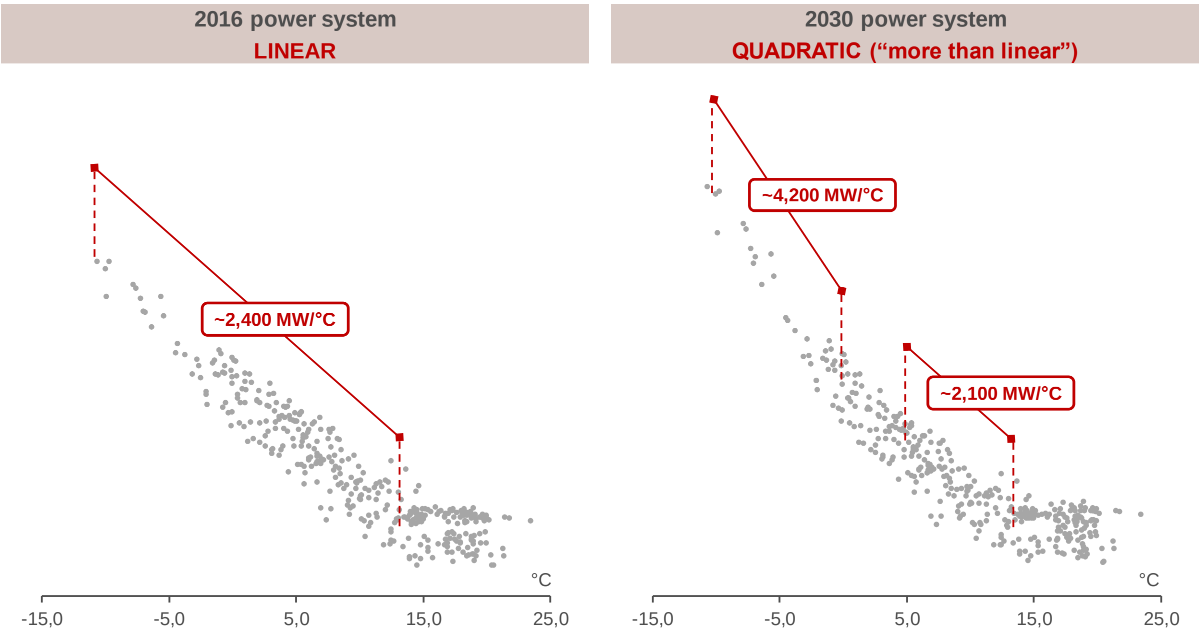


*Winter Outlook 2019-2020, ENTSOE

The temperature dependence of electricity demand will increase, especially at low temperatures:

- Currently, the temperature gradient of electricity consumption is mostly the same at all temperatures, because the temperature dependence of the heating need is linear, and the efficiency of resistance heaters is not impacted by temperature
- By 2030, since heat pumps will account for a higher share of electricity consumption vs resistance heaters and because their efficiency decreases at low temperatures, the temperature gradient of electricity consumption will be higher at low temperatures than at mild temperatures. The figure below illustrates the fact that the relation between peak demand and temperature takes a quadratic shape in France by 2030.

SHAPE OF TEMPERATURE-DEPENDENCE OF ELECTRICITY CONSUMPTION IN FRANCE, 2016 VS 2030 [MW]



Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 6: Shape of the temperature dependence of electricity consumption in France, 2016 vs 2030

1.1.4 The effect of "post-market" measures to mitigate Energy Not Served would be limited in the case of deep and prolonged losses of load

Example of post-market measures: Germany

In Germany, three reserves are put in place: the grid reserve, the capacity reserve and the security reserve. Due to the primary purpose of securing redispatch potential, the capacities of the grid reserve are assumed not to contribute to generation adequacy. The German Network development plan assumes 2 GW of capacity reserve[4]. The Security Reserve could provide additional supply to reduce

[4] https://www.netzentwicklungsplan.de/sites/default/files/paragraphs-files/%C3%9CNB-Entwurf_Szenariorahmen_2030_V2019_0_0.pdf page 23

the supply-demand gap, however its capacity is currently uncertain and will depend on the coal exit law. We therefore assume 2 GW of power plant capacity to account for the mobilisation of additional reserves by the TSO. The TSO can further cut contracted load.

Example of post-market measures: France
In case of imbalance on the grid, several "post-market" measures would be implemented to limit cutting power to customers, including:

- Cutting the power supply to large industrial sites that have signed a contract to that effect with the TSO (RTE)
- Lowering the tension on the grid
- Communicating with customers to request them to temporarily reduce their electricity consumption

However, the effect of these measures would be limited in the case of deep and prolonged losses of load such as those envisioned in our High demand scenario.

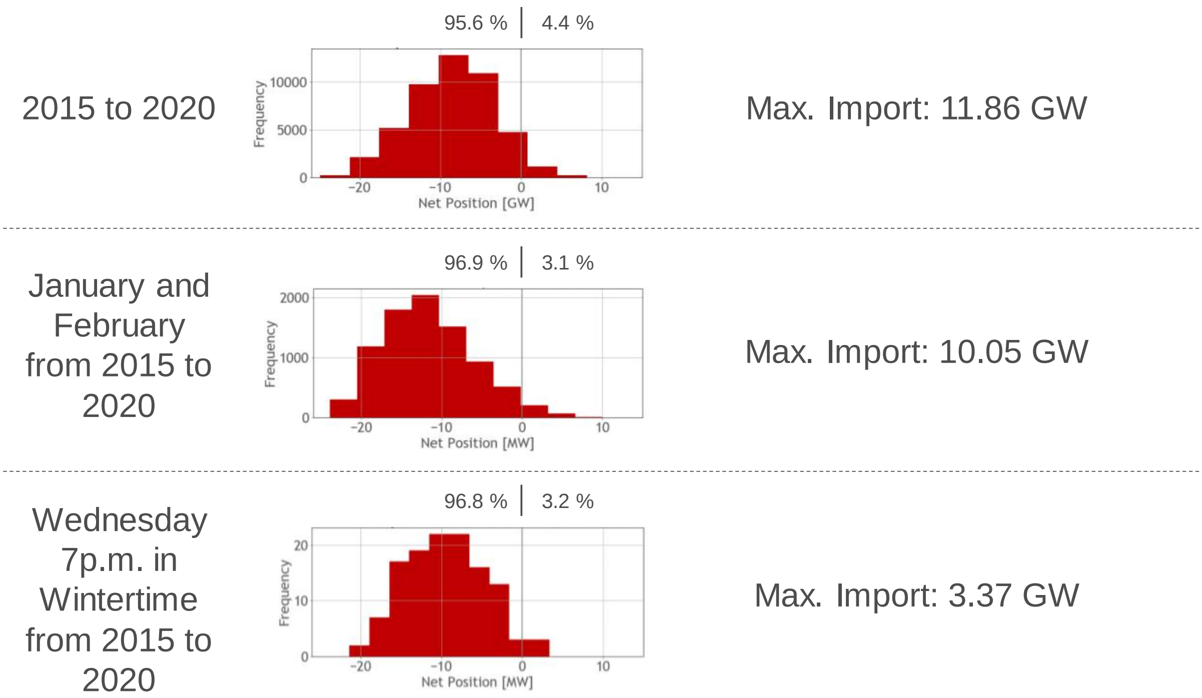
1.2 In its current state, North-West Europe does not rely on significant imports at peak: net imports have never exceeded 4 GW at synchronous peak hour in the winter, whereas net exports average ~10 GW

The demand and supply in the area we call North-West Europe for the purpose of this paper (Belgium, Germany, Denmark, France, Luxembourg, the Netherlands) is modelled explicitly. Since the other countries are not modelled explicitly, no conclusion can be raised about their contribution to the studied area in peak times. We therefore assume that the net interconnection exchange with countries outside the studied area is zero.

Analysis of 2015-2020 physical interconnection flows shows that North-West Europe finds itself in a net exporting position over 95% of the time, especially at the "synchronous peak time" as defined by ENTSO-E (i.e. wintertime Wednesdays at 7 pm CET). At that peak time, imports have never exceeded 4 GW.

Thus, North-West Europe currently hardly relies on significant imports from neighboring countries at peak time. It is unclear whether this could be the case in the future, but it can be argued that this is unlikely since cold spells are also likely to hit at least some of the neighboring countries as well. However, limited import flows from neighboring countries could contribute to reducing supply-demand gaps due to congestions within the modeled area.

HOURLY NET POSITION OF NORTH-WEST EUROPE VS ALL OTHER COUNTRIES [2015-2020]



Source: ENTSO-E TP, E-CUBE Strategy Consultants + EWI Analysis

Figure 7: Hourly net position of North-West Europe vs all other countries [2015-2020]

1.3 In the High demand scenario, the economic cost of Energy Not Served reaches ~10 to ~30 bn EUR

This amount of energy not served would translate into significant economic cost: ~10 to ~30 bn EUR for historical climate years 1985 and 2012.

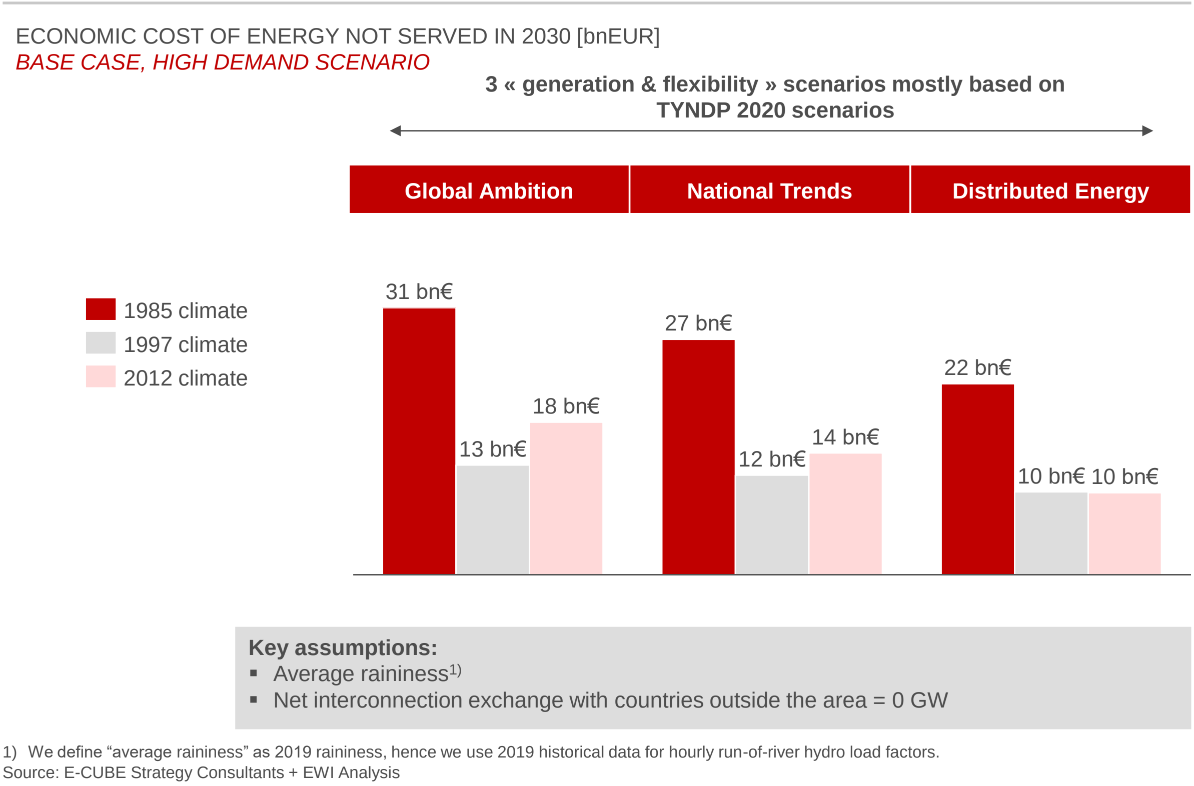


Figure 8: Economic cost of energy not served in 2030 in the High demand scenario – Base case

This cost estimate is based on the following assumptions:

- Because the power interruptions are mostly around ~35 GW, they mostly affect large industrial sites
- For those industrial sites, the cost of long power interruptions is ~6 EUR/kWh[5]

However, the cost may be higher if other types of customers are subjected to power interruptions, especially commercial companies and households. This could be the case:

- If power interruptions are "deeper", i.e. the number of missing GW to match demand is higher: depending on how storage assets (batteries, pumped hydro) will be managed, the ENS may result in shorter and "deeper" power interruptions, which could be more costly.
- If grid bottlenecks within countries create more acute imbalances in certain regions: this could be the case in areas with limited interconnection and generation capacity, such as Brittany or the South-East in France.

[5] Source: RTE, "Quelle valeur attribuer à la qualité de l´électricité ?", 2012

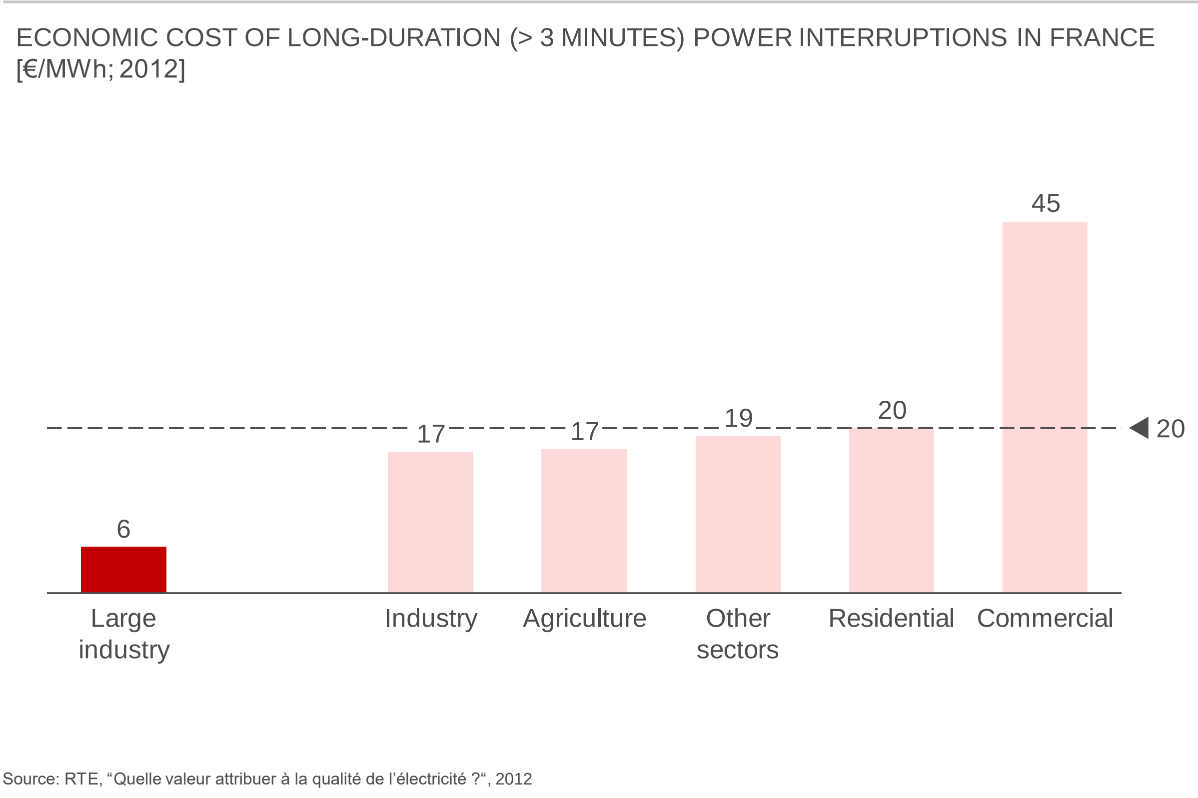


Figure 9: Unit economic cost of long-duration power interruptions in France

2 The contribution of heat pumps to peak demand during cold spells, which is subject to uncertainty, will be a key determinant for adequacy by 2030

2.1 The real-life performance of heat pumps is difficult to assess, yet important: lowering the COP of all heat pumps by 0.5 adds ~5 to 10 bn EUR to the cost of Energy Not Served

The real-life performance of heat pumps at low temperatures is subject to significant uncertainty, for three main reasons:

- Performance varies widely from one model to the next: certified COPs at – 7°C outdoor temperature span ~1 for air-to-air heat pumps and air-to-water heat pumps
- Certification test conditions do not reflect real-life use[6]:
  - During tests, heat pumps currently operate in steady state (e.g. fixed compressor speed), whereas in real life the operating point of heat pumps is constantly changing due to varying indoor and outdoor conditions (e.g. temperature, humidity): this "does not reflect real life operation due to abnormal operation" and can result in overestimating the COP by ~15%[7]
  - For water-loop heat pumps, the assumed sink-side (emitter system, e.g. radiator) temperatures are "too optimistic", which can also result in overestimating the COP by 15%[8]
- Many other reasons related to the installation and operation of heat pumps can make real-life performance lower than under specification conditions, these include:
  - Oversizing or undersizing of heat pumps, radiators, ductwork
  - Working fluid undercharge
  - Suboptimal setup (e.g configuration of the heating curve, inadequate airflow for air-source heat pumps, inadequate airflow for air-source heat pumps)
  - Suboptimal control outside test conditions (e.g. excessive fractioning of operating runtime, which is related to oversizing)
  - Operation for space heating and water heating (e.g. excessive auxiliary water heating system operation)
  - Humidity

These additional uncertainties are documented in several studies, with some of them showing an impact of those factors on the COP that can reach ~0.5 or more[9]. In particular:

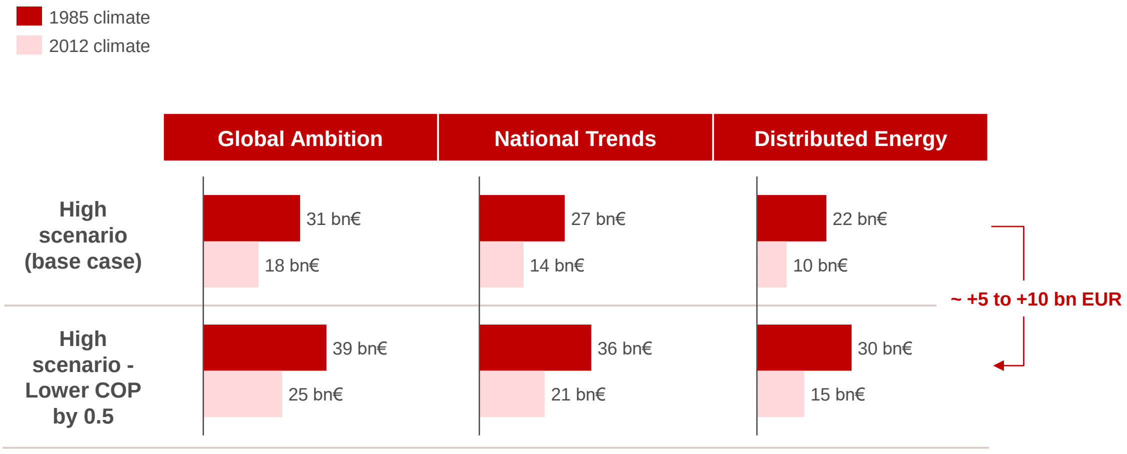
[6] In tests run in 2017 and 2020, ENGIE Lab found that the real-world SPF1 COP of the heat pump could be -45% to +5% compared to manufacturer data.
[7] Source: Space and combination heaters Ecodesign and Energy Labelling, Review study, Task 6 Final Report, July 2019, pages 59-60
[8] Source: Space and combination heaters Ecodesign and Energy Labelling, Review study, Task 6 Final Report, July 2019, page 55
[9] See for instance Annex 36 of the IEA Heat Pump Programme

- Scientific literature shows that oversizing an air-to-water heat pump by 50% can lower its SCOP by ~20%[10]
- ENGIE Lab tests show that undercharging an air-to-water heat pump by 50% can lower the COP by 60% with a 7°C outside temperature

Although changes in certifications are being discussed to start featuring dynamic (i.e. non-steady state) operation, and installers and users should improve their ability to set up and operate heat pumps, the uncertainty is likely to remain in the next few years.

Assuming a lower COP by 0.5 would result in ~5 to ~10 bn EUR of additional cost of Energy Not Served.

ECONOMIC COST OF ENERGY NOT SERVED IN 2030 [bnEUR]
HIGH DEMAND SCENARIO, LOWER COP BY 0.5



Key assumptions:
- Average raininess[1)]
- Net interconnection exchange with countries outside the area = 0 GW

1) We define "average raininess" as 2019 raininess, hence we use 2019 historical data for hourly run-of-river hydro load factors.
Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 10: Economic cost of energy not served in 2030 in the High demand scenario – Lower COP by 0.5

2.2 Properly sizing generation and flexibility assets to heat pump demand will be key for adequacy: once the electricity system has reached its limit, each additional air-to-air heat pump generates over ~2,000 EUR of additional cost during cold spells

As the historical over-capacity in parts of North-West Europe is dwindling due to the retirement of dispatchable thermal generation assets and electrification of energy demand, keeping supply capacity

[10] Source: Matteo Dongellini, Claudia Naldi, Gian Luca Morini, « Sizing effects on the energy performance of reversible air-source heat pumps for office buildings », Applied Thermal Engineering, vol. 114, p.1073-1081, 2017; Programme RAGE, « Consommations et performances réelles des pompes à Chaleur », Règles de l'Art Grenelle Environnement 2012 (RAGE), juin 2014

apace with demand becomes increasingly challenging. Adding heat pumps faster than the power system can accommodate thanks to new generation and flexibility assets (wind, PV, batteries) would increase the amount of energy not served during cold spells.

We analyze the cost of an additional 1 million air-to-air heat pumps in France, when the penetration of heat pumps in the system leads to supply demand gaps (Total: 16.1 million Heat pumps, High scenario under 2012 climate). Based on our analysis, each additional air-to-air heat pump would add ~400 kWh of Energy Not Served, thus generating an additional cost of ~2,000 to 2,500 EUR for society.

This figure can also be interpreted as the societal value of installing a hybrid heat pump instead of a regular heat pump, because the contribution of hybrid heat pumps to peak demand at low temperatures is very limited[11].

This result shows the importance of coordinating the electrification of end uses, especially space heating:

- **Coordinating in time**: adding heat pumps faster than new generation and flexibility assets (wind, PV, batteries) can keep up with could create significant additional cost for society due to supply-demand mismatch during cold spells, especially if these heat pumps have a lower COP than expected
- **Coordinating in space**: it is essential that North-West European countries coordinate the electrification of demand and ensure the development of adequate supply and flexibility assets

It is worth noting that the impact on Energy Not Served depends on the type of heat pump added: for instance, ground-source heat pumps have a lower impact than air-source heat pumps because their efficiency is less sensitive to outside temperature.

In comparison, electric vehicles contribute less than air-to-air heat pumps to peak demand during cold spells: adding 1 million passenger EVs in France, each additional EV would generate an additional cost of ~300 EUR for society[12]. However, a full comparison of EVs and air-to-air heat pumps from a societal point of view would require comparing the CO_2 abatement cost (cost of equipment + operation + energy not served) of 2 actions:

- Using EVs instead of ICE vehicles
- Using air-to-air heat pumps instead of other heating systems

3 Choices regarding heating systems, such as directing heat pumps to replace resistance heaters, and installing hybrid heat pumps, would mitigate the risk of Loss of Load

3.1 The number of remaining resistance heaters in France will have a key impact on electricity demand: each additional million households with resistance heaters results in an additional ~3 to 6 bn EUR of Energy Not Served during cold spells

[11] Hybrid heat pumps may contribute to peak demand if they are operating in a higher-temperature area when temperatures are very low over most of North-West Europe

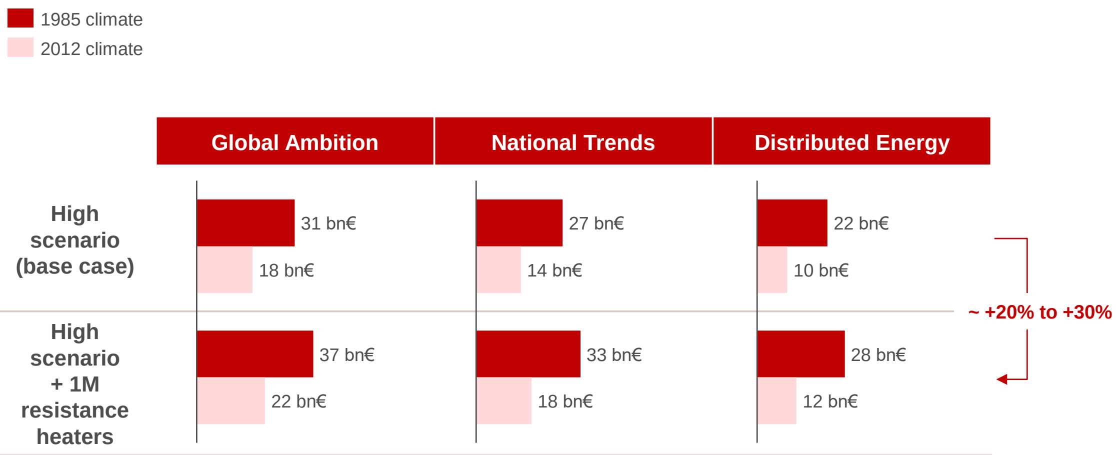
[12] This result is based on the EV load profiles presented in Appendix A

France has set national objectives in the PPE[13] regarding the number of heat pumps. Each additional heat pump can displace either hydrocarbon boilers (fuel oil, LPG, natural gas) or resistance heaters. These two options have very contrasted outcomes:

- When a heat pump displaces a resistance heater, it lowers annual consumption and peak demand because heat pumps are more efficient by a factor of ~3 to 4 on average. During cold spells, the efficiency of heat pumps is lower because of lower temperatures, but they remain more efficient than resistance heaters. When the temperature reaches the low level at which heat pumps stop operating (theoretically -10°C to -20 °C for air-source heat pumps), a resistance heater takes over as backup.
- When a heat pump displaces another type of heating system, it is a net addition to peak demand. On the other hand, it lowers CO_2 emissions (more or less according to the type of boiler that is displaced).

Because resistance heaters are installed in ~7M households in France today, the impact on peak demand of replacing more or fewer resistance heaters is very significant. In the High demand scenario, we assumed that ~4.9 million French households use resistance heaters, and ~10.4 million are equipped with heat pumps. Keeping the same number of heat pumps, having 1 more million resistance heaters would translate into an additional ~3 to 6 bn EUR of Energy Not Served (or 0.5 to 1 TWh).

ECONOMIC COST OF ENERGY NOT SERVED IN 2030 [bnEUR]
HIGH SCENARIO / +1M RESISTANCE HEATERS SENSITIVITY



Key assumptions:
- Average raininess[1)]
- Net interconnection exchange with countries outside the area = 0 GW

1) We define "average raininess" as 2019 raininess, hence we use 2019 historical data for hourly run-of-river hydro load factors.
Source: E-CUBE Strategy Consultants + EWI Analysis

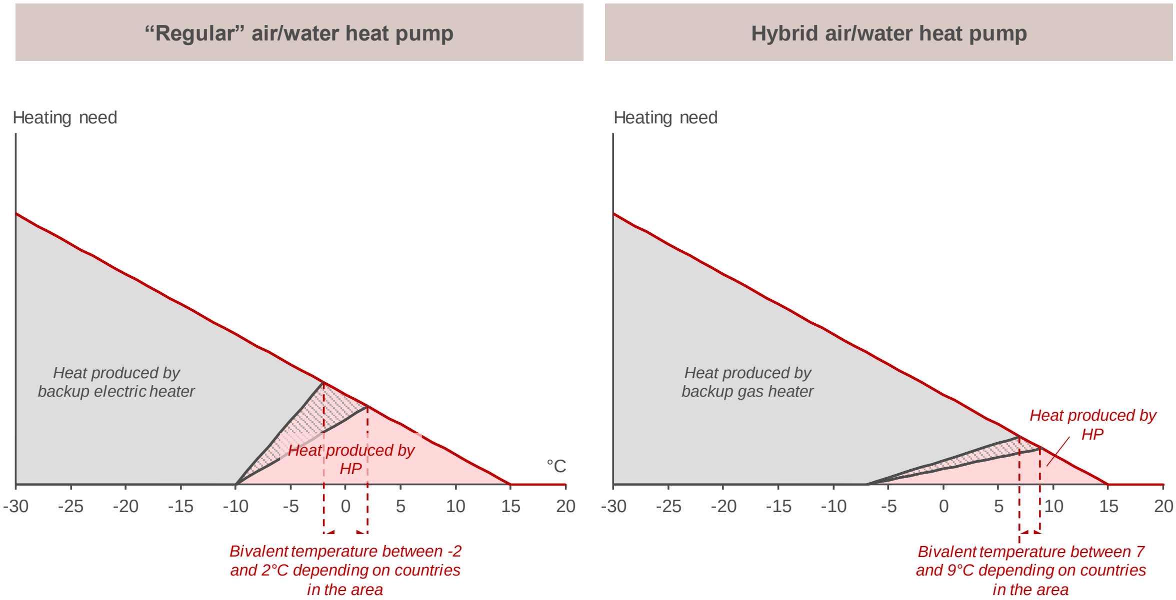
Figure 11: Economic cost of energy not served in 2030 in the High demand scenario – + 1M resistance heaters

[13] Programmation Pluriannuelle de l'Energie

3.2 In all countries, resorting to hybrid heat pumps significantly mitigates peak electricity demand

At low temperatures, the electric consumption of heat pumps increases for two reasons: the heating need is greater, and the efficiency of heat pumps is lower. Compared to “regular” heat pumps, hybrid heat pumps, which are essentially gas boilers coupled with heat pumps, cut the electricity demand of heat pumps at low temperatures by letting the gas boiler satisfy part or all of the heating demand.

ENERGY CONSUMPTION IN OPERATION OF « REGULAR » VS HYBRID HEAT PUMP



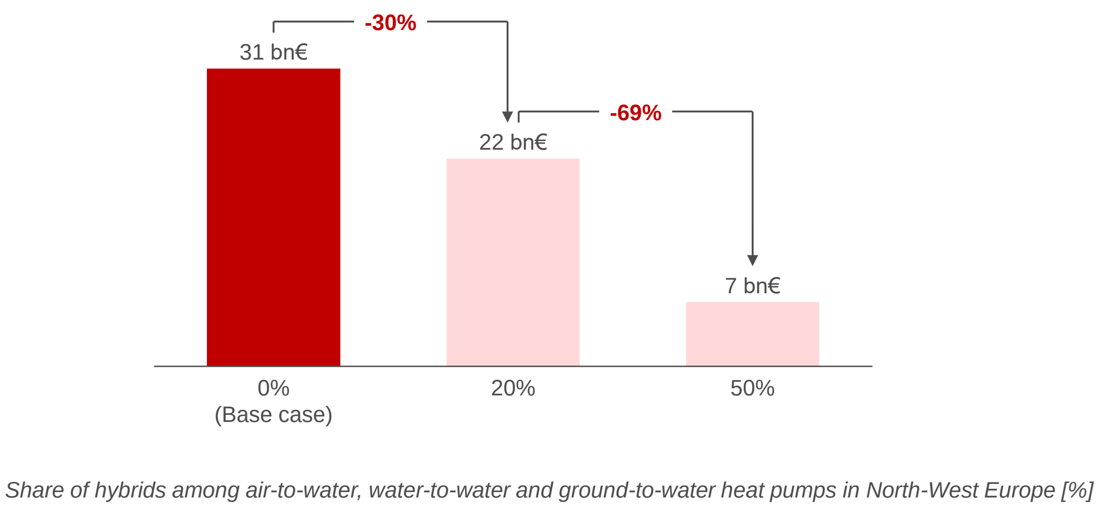
Source: E-CUBE Strategy Consultants + EWI Analysis, METIS

Figure 12: Unit electricity consumption in operation of « regular » vs hybrid heat pump

Our analysis shows that if 50% of “water-loop” heat pumps (i.e. air-to-water, water-to-water or ground-to-water) are hybrids over North-West Europe, the cost of Energy Not Served would be ~7 bn EUR in the High scenario under 1985 climate, down from ~31 bn EUR in the base case, in which we assume no hybrid heat pumps.

The same impact could be achieved by any other means of backup for the heat pump, such as wood-based heating.

ECONOMIC COST OF ENERGY NOT SERVED IN 2030 UNDER A 1985 COLD SPELL [bn EUR]
HIGH DEMAND SCENARIO



Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 13: Economic cost of energy not served in 2030 under a 1985 cold spell, as a function of the % of hybrid heat pumps among water-loop heat pumps

3.3 The contribution of heat pumps to peak demand is very sensitive to the assumed electricity demand profile

An important uncertainty lies in the shape of the electricity demand profile of heat pumps.

In our base case, we assume that for a given heating need, the only difference between the load profile of heat pumps and gas boilers or electric resistance heaters is the dependence of COP on temperature.

The German DSOs provide standard heat pump load profiles. These very smooth electric load profiles, as illustrated on Figure 14 are synthetic and do not allow to explicitly model the COP and further technical detail. These profiles can therefore not be used to assess the impact of the different COP, bivalent temperature and back-up heating across heat pump technologies as we do in this study.

Compared to the profiles used in this study:

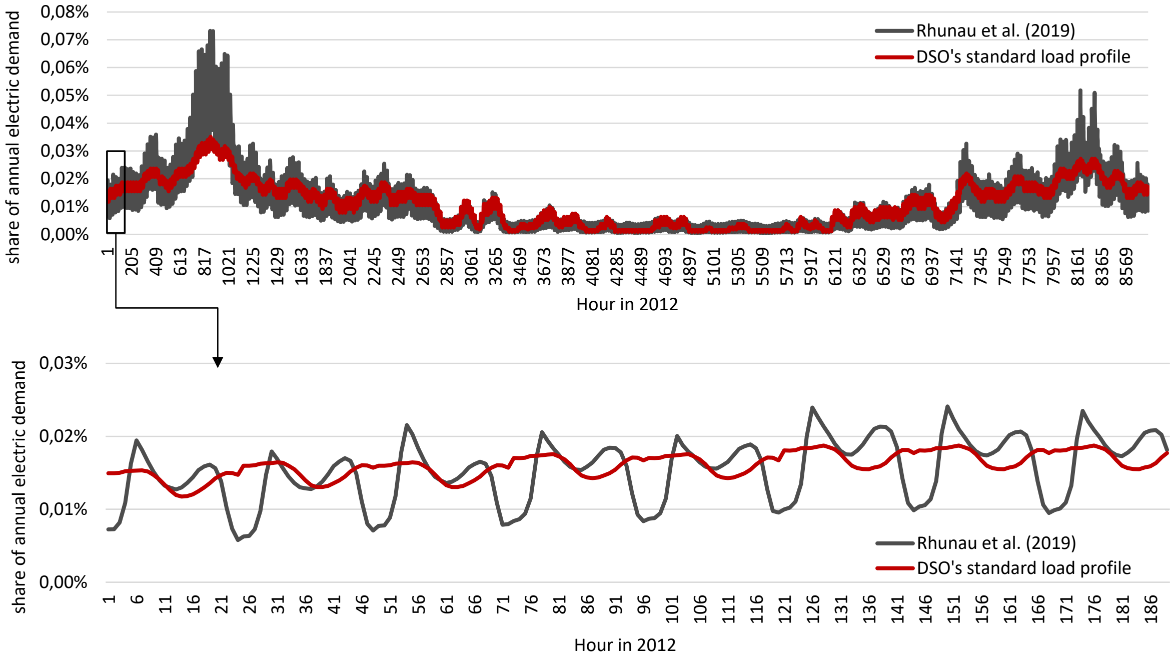
- The DSOs’ standard load profiles seem to assume a lower temperature sensitivity at low temperature, which could come from higher assumed efficiency of heat pumps or better insulation of buildings. This results in lower electricity consumption during cold spells.
- Besides, and relatively to the profile we use in our base case, the heat pump operation is shifted within the day, by up to 10 hours. Specific factors can make the load curve of heat pumps smoother than assumed. In the German Network Development Plan[14], it is

[14] Netzentwicklungsplan Strom 2030, Version 2019

assumed that the consumption of heat pumps can be displaced from high to low consumption time windows within the day. The use of water storage tanks is common in the operation of air-to-water and water-to-water heat pumps. For instance, in the METIS study[15], the water storage is dimensioned to store the equivalent of two hours of heat production at full capacity. Further smoothening factor lies in the automation and chosen control logic. Moreover, in Germany the §14a of the Energy Industry Act (EnWG) enables DSOs to control flexible demand, like heat pumps or electric vehicles. Reform proposals are currently discussed to reinforce the existing opportunity to do so.

Our simulations with the standard load profile provided by DSOs for heat pumps in Germany show that the cost of Energy Not Served in North-West Europe is reduced by ~7 to 12 bn EUR (corresponding to ~1 to 2 TWh).

HEAT PUMP DEMAND PROFILES IN THE BASE CASE AND IN THE SENSITIVITY ANALYSIS [% of annual consumption]

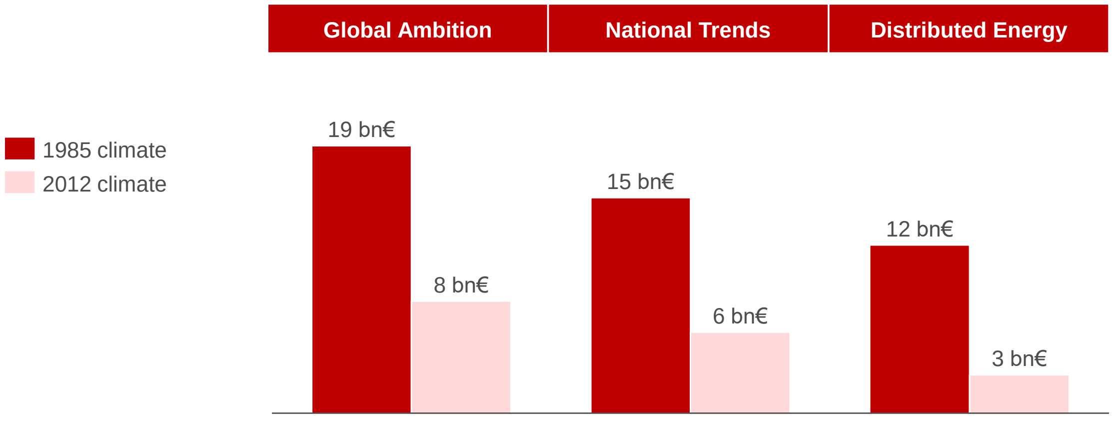


Source: Rhunau et al, BDEW, E-CUBE Strategy Consultants + EWI Analysis

Figure 14: Examples of heat pump load profiles in Germany under 2012 climate - Ruhnau et al (2019) vs. DSOs standard load profile

[15] METIS study 2018 Decentralised heat pumps: system benefits under different technical configurations

ECONOMIC COST OF ENERGY NOT SERVED IN 2030 [bnEUR]
HIGH DEMAND SCENARIO, STANDARD LOAD PROFILES FOR HEAT PUMPS IN GERMANY AND DENMARK



Key assumptions:
- Average raininess[1)]
- Net interconnection exchange with countries outside the area = 0 GW

1) We define “average raininess” as 2019 raininess, hence we use 2019 historical data for hourly run-of-river hydro load factors.
Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 15: Economic cost of energy not served in 2030 in the High demand scenario – using Standard Load Profiles for all heat pumps in Germany and Denmark

This sensitivity shows the importance of coordination mechanisms to unfold the flexibility potential. Smart meters and time-varying electricity prices can provide further flexibility and enable such coordination.

4 Other risk factors, such as low availability of nuclear generation, could significantly increase the risk of Energy Not Served during cold spells

4.1 Situations of supply-demand mismatch will increasingly result from other risk factors than low temperature, such as low availability of nuclear generation, which could increase the cost of Energy Not Served by ~50 to 150% (or ~14 to 19 bn EUR)

In addition to low temperatures, other risk factors could contribute to stressing the North-West European grid during cold spells, including:

- Low levels of nuclear availability in France and Belgium
- Low levels of raininess, leading to lower water reserves and lower run-of-river hydro generation

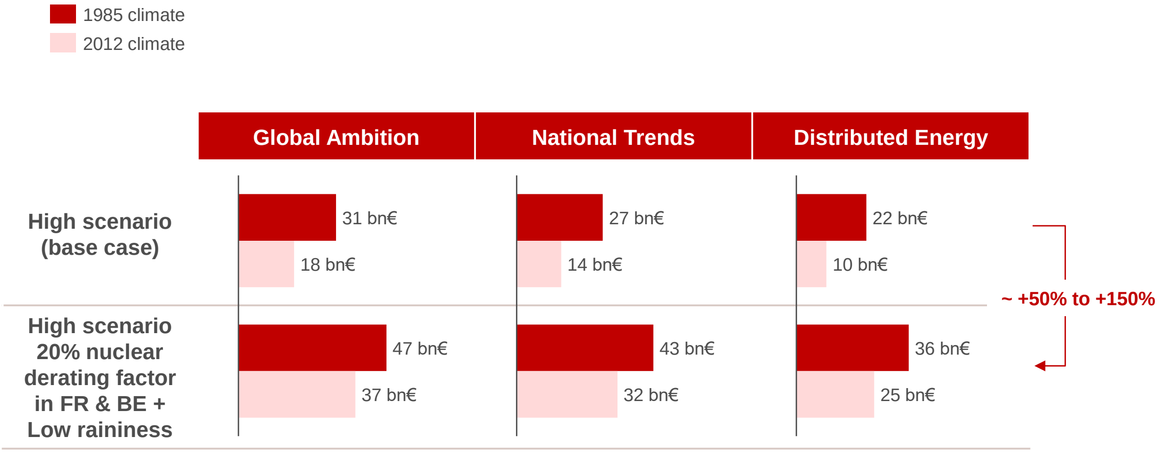
Both these factors have been illustrated in recent years:

- The rescheduling of maintenance work in French nuclear power plants has led the government to communicate possible losses of load during the upcoming winter, with availability of nuclear generation forecasted as low as ~80% in February
- In Belgium, the availability of nuclear power plants has been under 70% for some of the past years due to various outages
- Water reserve levels in France have reached 10-year lows in 2017 and 2018

In our base case, we assumed a 5% derating factor on the installed capacity of French nuclear power plants, to reflect possible scheduled or unscheduled unavailability during the cold spell.
Assuming a 20% derating factor on nuclear generation in France and Belgium[16] (instead of 5% in the base case) and lower levels of raininess than in the base case (as experienced in 2017), the High demand scenario would lead to ~25 to 47 bn EUR in cold climate years.

[16] In the coming decade, ageing plants and increasingly demanding nuclear safety authorities may increase the frequency of outages in both countries

ECONOMIC COST OF ENERGY NOT SERVED IN 2030 [bnEUR]
HIGH DEMAND SCENARIO, 20% NUCLEAR DERATING IN FRANCE AND BELGIUM + LOW RAININESS



Key assumptions:
- Average raininess[1)]
- Net interconnection exchange with countries outside the area = 0 GW

1) We define "average raininess" as 2019 raininess, hence we use 2019 historical data for hourly run-of-river hydro load factors.
Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 16: Economic cost of energy not served in 2030 in the High demand scenario – 20% nuclear derating in France + low raininess

4.2 If North-West Europe experiences supply-demand gaps during cold spells, its inability to export electricity could cause or worsen Energy Not Served in neighboring countries

In the base case, we assumed 0 GW export and import between North-West Europe and neighboring countries during cold spells. This is a reasonable assumption because the power system of 2030 will be very different from that of 2020, both on the supply and on the demand side, which could change the predominant flows of electricity from what they are today.
However, if these flows followed the same trend in 2030, neighbouring countries could hope to rely on North-West Europe to balance the supply-demand gap during cold spells. Whereas we do not estimate the amount of Energy Not Served in those countries, one can argue that they are likely to be face a supply-demand gap - at least some of them - as well. In the case they rely on North-West European countries, the amount and cost of Energy Not Served at the European level could therefore exceed those estimated in this study.

5 Conclusions

We identify the potential demand-supply gap as an important challenge for the European energy transition: if the increase in electricity demand were not appropriately compensated with the increase in supply & flexibility assets, decarbonizing Europe could prove more costly than anticipated.

Changes to the electricity system should be carefully managed within each country and between countries to ensure adequacy at peak time. This is especially the case as rapid diffusion of heat pumps will be part of the chosen pathway.

Several solutions could be used to address this challenge:

- On the supply side: increasing dispatchable capacity, which would most likely be thermal generation
- On the demand side: lowering the peak, by targeting a specific mix of heating technologies, e.g. fewer electrical resistance and more hybrid heat pumps

The path to decarbonizing the European electricity sector will therefore require a trade-off between different types of cost:

- Cost of Energy Not Served
- Cost of equipment on the supply and demand side (e.g. heat pumps, gas turbines, hybrid heat pumps)
- Cost of supplying this equipment with low-CO_2 or CO_2-free energy (e.g. green gas)

Since adding peaker capacity or replacing heating equipment can take years, the way the 2030 power system will fare under cold spells already will depend on decisions made in the early 2020s.

By 2050, unless technologies such as long-term hydrogen storage provide additional solutions to bridge supply-demand gaps, the issue is likely to become more acute as electrification of end uses and intermittent renewable capacity further develop.

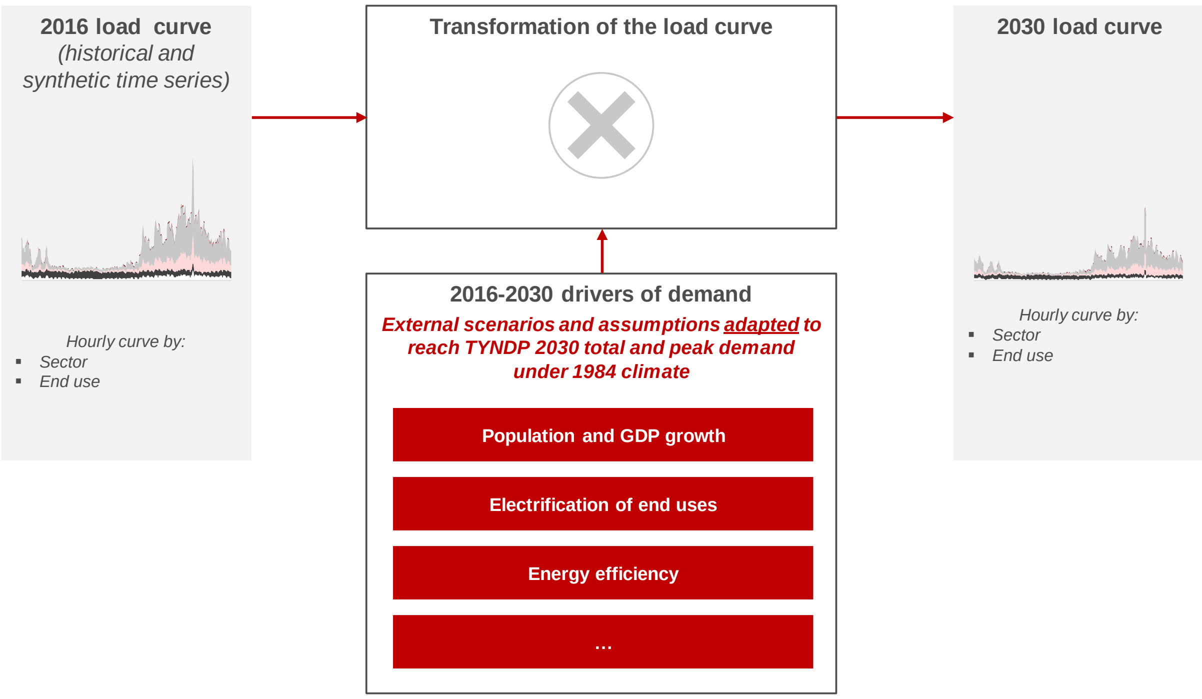
Appendix A: This study is based on a model of hourly demand over North-West Europe

Our model transforms the 2016 load curve into the 2030 load curve in each country

To estimate the hourly demand in each country in 2030 under a given climate year, we apply the following steps:

- Break down the hourly electricity load curve for 2016 by sector and end use: this breakdown is based
    - For non-temperature dependent end uses: on publicly available time series and standard load profiles
    - For temperature-dependent end uses
        - In France: on our own analysis of the temperature-dependence of electricity demand in the residential and commercial sectors
        - In Belgium, Germany, Denmark, Luxembourg, the Netherlands: on load profiles from the when2heat study[17] (and as a sensitivity, on the Standard Load Profiles of DSOs in Germany)
- Transform the load curve by applying evolution factors by sector and end use:
    - For non-temperature dependent end uses: the load profile is scaled by the same factor for the whole year
    - For temperature-dependent end uses: the evolution factor changes hour by hour as a function of temperature, due to 2 effects:
        - The heating need is a linear function of outside temperature
        - The efficiency of heating systems (e.g. heat pumps) also depends on temperature

[17] https://www.nature.com/articles/s41597-019-0199-y



Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 17: Method to estimate the hourly demand curve in 2030

Four heat pump technologies, their demand profiles and performances are explicitly modelled

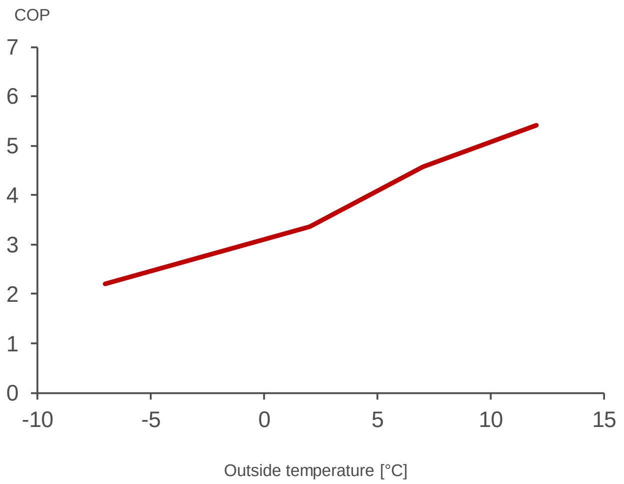
COP assumptions

Our base case assumptions on the COP of air-to-air heat pumps are based on the median values of Eurovent certified air-to-air heat pumps[18], which we multiply by 0.85[19].

[18] Source: Air conditioners and comfort fans, Review of Regulation 206/2012 and 626/2011 Final report, June 2018, page 249

[19] The 0.85 factor is used in the when2heat study for air-to-water, water-to-water and ground-to-water heat pumps. It is also on the optimistic end for discrepancy between certified and real-life performance of those heat pumps (see Space and combination heaters Ecodesign and Energy Labelling, Review study, Task 6 Final Report, July 2019, page 60).

ASSUMED COP FOR AIR-TO-AIR HEAT PUMPS



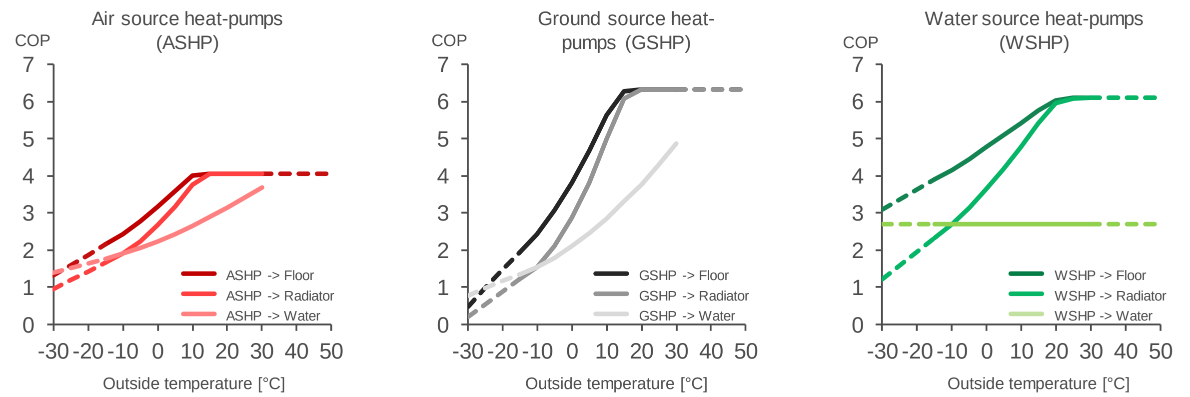
Source: Air conditioners and comfort fans, Review of Regulation 206/2012 and 626/2011 Final report, June 2018, page 249, E-CUBE Strategy Consultants + EWI Analysis

Figure 18: Assumed COP for air-to-air heat pumps

The coefficient of performance of Air-source heat pumps (ASHP), Ground-source heat pumps (GSHP) and Water source heat pumps (WSHP) are explicitly modelled[20]. The method further differentiates whether the heat is distributed via floor heating or radiators.

ASSUMED COP FOR AIR-TO-WATER, WATER-TO-WATER AND GROUND-TO-WATER HEAT PUMPS

$$COP = \begin{cases} 6{,}08 - 0{,}09 * \Delta T + 0{,}0005 * \Delta T^2, & ASHP \\ 9{,}97 - 0{,}20 * \Delta T + 0{,}0012 * \Delta T^2, & WSHP \\ 10{,}29 - 0{,}21 * \Delta T + 0{,}0012 * \Delta T^2, & GSHP \end{cases}$$



Source: when2heat study

Figure 19: Assumed COP for air-to-water, water-to-water and ground-to-water heat pumps

[20] Large scale heat pumps in the district heating network are not included. It is assumed that these technologies do not contribute to the peak demand. In the German Network development plan, these are flexibility options using electricity at times of renewables oversupply, and are paired to innovative CHP systems in the district heating networks

The COP values on which we based our analysis reflect those of models currently for sale:

- For AAHPs: median values from certification (derated to reflect real-life conditions)
- For other types of heat pumps: sample values from certification (derated to reflect real-life conditions, as in the when2heat study)

The performance of heat pumps assumed in the model is most likely higher than that of heat pumps currently in use, which accounts for possible improvements to the performance of heat pumps in use by 2030 (notably thanks to component, fluid and control efficiency). However, it remains a question how much this improvement of season-average heat pump performance will impact performance at low temperatures, which are the key determinant of the supply-demand gap.

Backup heating assumptions

Heat pumps are often coupled to a back-up heater, to supplement the heat pump during days with very cold temperatures. Our study considers monoenergetic heat pumps (i.e. paired with an electric boiler) and bivalent (or hybrid) heat pumps (paired with gas, oil or biomass heater).

Regarding the operating limit temperature, we used different values for France and Benelux (which fall under the “average” climate for regulations on heat pumps) and Germany and Denmark (which partly fall under the “colder” climate), to reflect the fact that customers in colder areas will tend to look for heat pump models which can still operate at lower temperatures. Values for France+Benelux are based on the observed standard in certification data for the “average” climate, whereas values for Germany+Denmark are based on the METIS study.

	Air-to-air	Air-to-water	Water-to-water or Ground-to-water
France + Benelux	-20 °C	-10 °C	-20 °C
Germany + Denmark	-20 °C	-26 °C	-26 °C

Figure 20: Assumed operating limit temperature (TOL) for heat pumps

In the case of hybrid heat pumps, we assume that the heat pump output stops at -7°C in France + Benelux, and -26°C in Germany+Denmark.

Regarding bivalent temperature for heat pumps or hybrid heat pumps, we use the country-specific values from the METIS study.

Heat pump demand profile

The hourly electric demand profile of heat pumps is built by approximating the useful heat demand profile with the gas standard load profile. This profile is then multiplied with the temperature dependent COP to obtain the hourly electric demand. The used profiles thereby neglect specific factors which can make the load curve of heat pumps smoother than assumed. The use of water storage tanks, which is common in the operation of air-to-water and water-to-water heat pumps is such a factor. For instance, in the METIS study[21], the water storage is dimensioned to store the equivalent of two hours of heat production at full capacity. In the German Network Development Plan[22], it is assumed that the consumption of heat pumps can be displaced from high to low consumption time windows within the day.

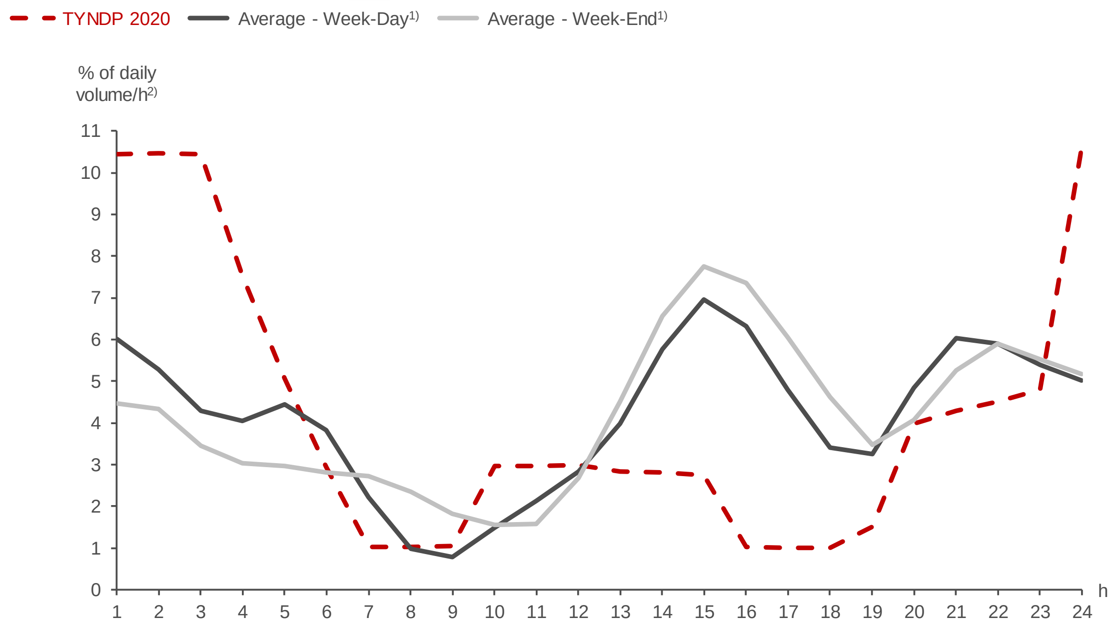
Three categories of electric vehicles, their demand profiles and performance are modelled

Electric vehicles are included via a bottom-up approach in the demand model 2030, and the consumption by electric vehicles is assumed to be negligible in 2016. Trucks, busses, and light-duty vehicles are split in three vehicle categories with their own consumption and average yearly mileages characteristics. Light-duty vehicles, additionally, are split into plug-in hybrid and full electric vehicles. With the assumptions regarding the number of vehicles of each category in 2050, the expected consumption of the electric vehicles is estimated.

Besides mobility characteristics, the charging profiles differ among the defined vehicle categories. Additionally, for each vehicle category, different profiles are considered depending on the day of the week and the charging behavior. Regarding the latter, smart and basic charging are taken into account. The profiles for the respective vehicle categories are assumed to take the same shape across countries but are shifted relatively to each other according to country-specific characteristics. The shapes are taken from RTE[23] and shifted by two hours for Germany and Denmark[24]. As illustrated in Figure 21, the resulting average load profile for light-duty EVs + PHEVs over the 6 countries differs from the average load profile from TYNDP 2020 over EU28, for which detailed assumptions are not available. In terms of number of vehicles however, our scenarios for e-mobility are close to the TYNDP 2018 data, with discrepancies including the latest market developments (Figure 22).

[21] METIS study 2018 Decentralised heat pumps: system benefits under different technical configurations
[22] Netzentwicklungsplan Strom 2030, Version 2019
[23] Enjeux du développement de l’électromobilité pour le système électrique, p39
[24] Erstnutzer von Elektrofahrzeugen in Deutschland, DLR, 2015

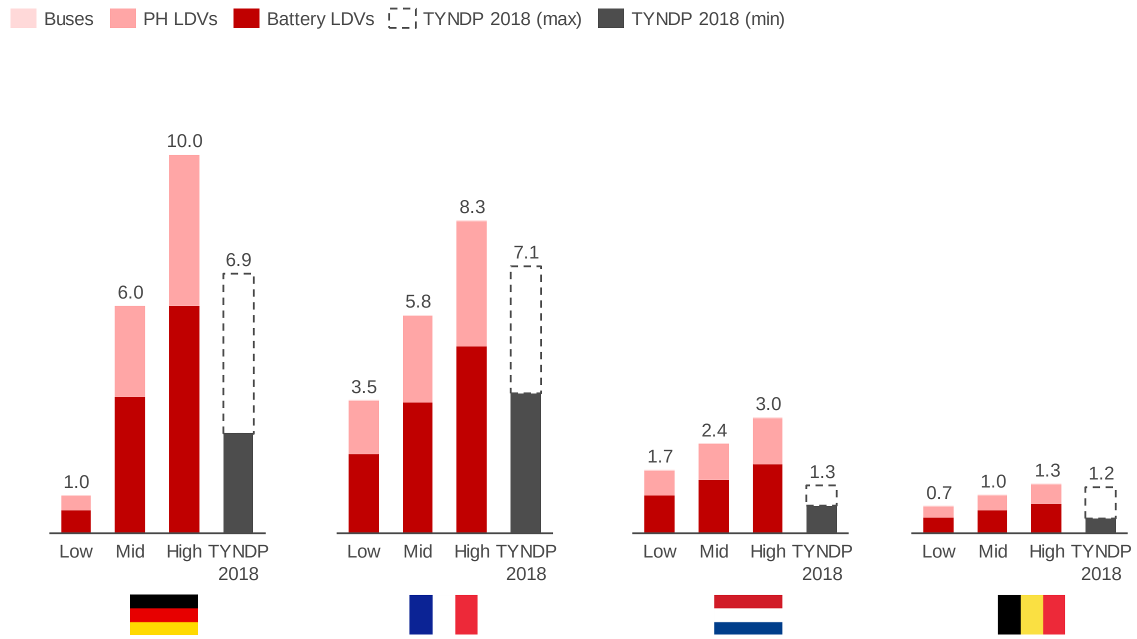
AVERAGE CHARGING PROFILES FOR PASSENGER VEHICLES – **COMPARISON WITH TYNDP 2020 ASSUMPTIONS** [% of daily volume charged per hour; 24h] -



1) By 2030, 50% of EVs follow a natural charging profile while 50% follow a smart charging profile
2) Electricity volumes charged during a day by an EV differ between week-days and week-ends
Source: TYNDP 2018, RTE,E-CUBE Strategy Consultants + EWI Analysis

Figure 21: Average charging profiles for passenger vehicles – Comparison with TYNDP 2020 assumptions

2030 SCENARIOS FOR ELECTRIC PASSENGER CARS + LIGHT UTILITY VEHICLES – COMPARISON WITH TYNDP 2018 [millions]



Source: TYNDP 2018, E-CUBE Strategy Consultants + EWI Analysis

Figure 22: 2030 scenarios for electric passenger cars + light utility vehicles – Comparison with TYNDP 2018

Demand profiles for Germany and Denmark

The demand model for Germany is mainly based on assumptions from the German Network Development Plan (NEP). Our "low", "mid" and "high" scenarios correspond to the Scenarios A, B and C respectively. Scenario A (low) is the business-as-usual scenario of the NEP with a rather low penetration of innovative electricity applications, a low level of sector coupling and a slight decrease in net electricity consumption compared to today. Scenario B (middle), with an increasingly flexible energy system transformation, provides an intermediate path between scenarios A and C. Scenario C (high) leads to an increase in electricity consumption and flexibility options, resulting from a high penetration of new electricity applications and a stronger coupling of the energy sectors.

As the demand profiles used in the NEP are not disclosed, we use the following sources:

- For the household electricity demand profile (without heat pumps) the standard load profile as provided by the DSOs
- For the service sector electricity demand profile (without heat pumps) the standard load profile as provided by the DSOs
- For the transport sector electricity demand profile, we use the profile provided by the Dynamis study (without electric vehicles)[25]
- For the industry we use the profiles provided by the Dynamis study[26]
- For the losses at transmission network level, we use a regression analysis of historical losses with the temperature
- For the losses at the distribution network level we assume an equal repartition of the yearly losses over the time frame
- For electric vehicles we use the natural and smart charging profiles provided by RTE[27] and adjust them to German and Danish characteristics
- For heat pumps we base our analysis on the methodology proposed in Rhunau,et al. (2019)[28]. As data is very scarce about the number of installations, we assume that only new-builds have floor heating. For the assumption regarding the share of heat pumps between ASHP, WSHP and GSHP we use the statistics from the German Heat Pump Association (BWP) for Germany and European Heat Pump Market and Statistics for Denmark. Further we assume that 28% of all HPs are installed in the service sector (20% for Denmark)[29].

[25] Load Profiles of the Mobility Sector – Dynamis Reference Scenario (Germany): http://opendata.ffe.de/dataset/load-profiles-of-the-mobility-sector-dynamis-reference-scenario-germany/; München: Forschungsstelle für Energiewirtschaft e. V. (FfE), 2020.

[26] Load Profiles of the Industry Sector – Dynamis Reference Scenario (Germany): http://opendata.ffe.de/dataset/load-profiles-of-the-industry-sector-dynamis-reference-scenario-germany/; München: Forschungsstelle für Energiewirtschaft e. V. (FfE), 2020.

[27] Enjeux du développement de l'électromobilité pour le système électrique, p39

[28] Ruhnau, O., Hirth, L. & Praktiknjo, A. Time series of heat demand and heat pump efficiency for energy system modeling. Sci Data 6, 189 (2019).

[29] Wärmewende 2030, Agora Energiewende (2017) and POTEnCIA, JRC-IDEES (2019)

These profiles are scaled to the annual electricity consumption as disclosed by the NEP for Germany and to the values disclosed in Denmark's Energy and Climate Outlook 2019[30], for Denmark. The proposed methodology explicitly accounts for heat pumps for warm water supply, for which no value is disclosed in the NEP. The assumptions are based on the German Heat Pump Association (BWP) statistics.

Demand profiles for Benelux and France

We used the following sources to build our Low, Mid and High demand scenarios

- Documents from TSOs (Elia, TenneT, CREOS, RTE)
- The JRC-IDEES databases
- National policy objectives (e.g the Programmation Pluriannuelle de l'Energie 2020 in France, PNEC in Belgium)
- Other sources (e.g AFPAC, CEREN, CGDD for France, Eurobserver for Belgium and the Netherlands)

We adjusted the values in the Low and Mid scenarios to match peak demand results from TYNDP 2020 under 1984 climate (see Appendix D).

Source: Eurobserv'er HP barometer, NEP, RTE, Tennet, France's PPE, E-CUBE Strategy Consultants + EWI Analysis

Figure 23: Scenarios for heat pumps and resistance heaters in Benelux and France – Residential sector

[30] Denmarks's Energy and Climate Outlook 2019, https://ens.dk/en/our-services/projections-and-models/denmarks-energy-and-climate-outlook

Source: Eurobserv'er HP barometer, NEP, RTE, Tennet, France's PPE, E-CUBE Strategy Consultants + EWI Analysis

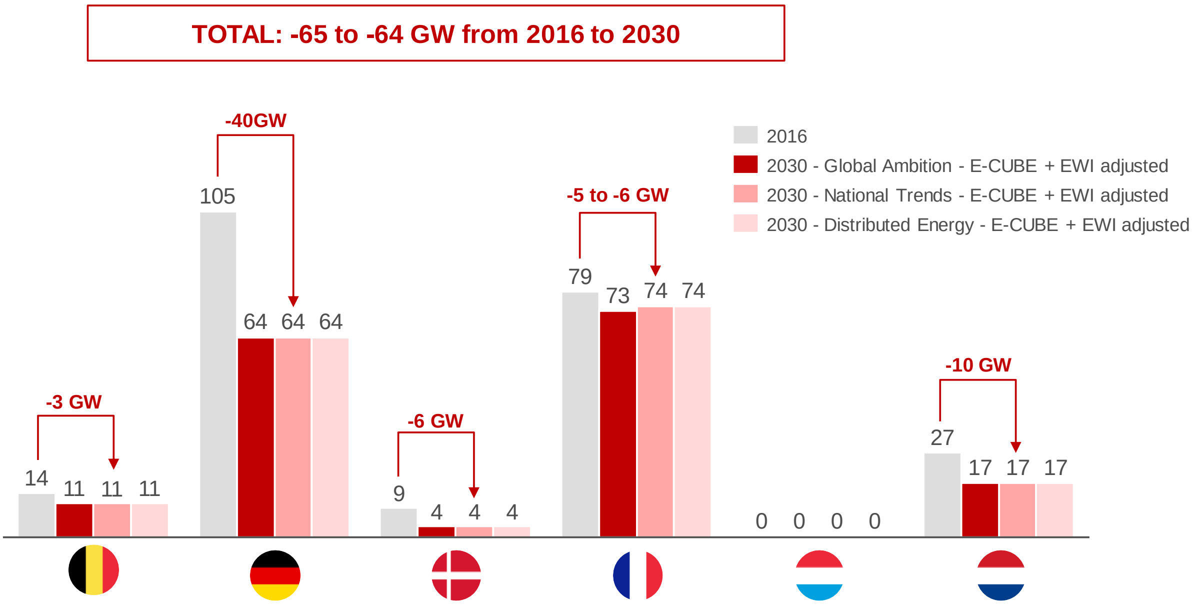
Figure 24: Scenarios for heat pumps and resistance heaters in Benelux and France – Commercial sector

Appendix B: On the supply side, our model reflects the major changes that will affect the North-West European power system by 2030

From 2016 to 2030, in TYNDP 2020-like scenarios, North-West Europe is expected to lose ~64 GW of dispatchable thermal generation

By 2030, dispatchable thermal capacity (nuclear, coal, gas, oil, waste, biomass) will decrease by ~64 to 65 GW in North-West Europe, mostly due to decisions to close coal and nuclear plants, especially in Germany.

DISPATCHABLE THERMAL GENERATION CAPACITY[1] [GW]



1) Includes: nuclear, gas, coal, oil, waste, biomass and other non-RES generation
Source: ENTSO-E TP, TYNDP 2020, E-CUBE Strategy Consultants+EWI Analysis

Figure 25: Dispatchable thermal generation capacity in North-West Europe, 2016 and 2030

Although additional wind and solar capacity will also be significant, it will not compensate for the decrease in dispatchable capacity during winter cold spells

Compared to 2016, 209 to 276 GW of wind and solar capacity is expected to be added by 2030.

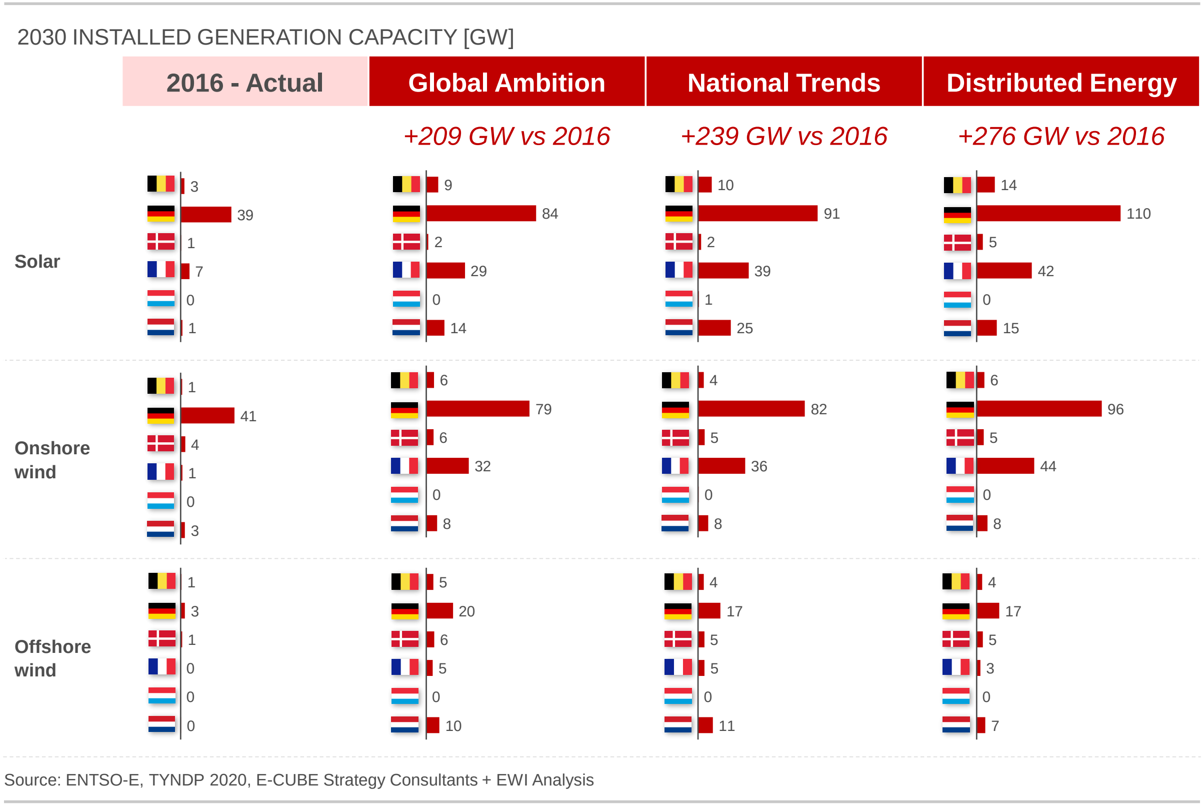
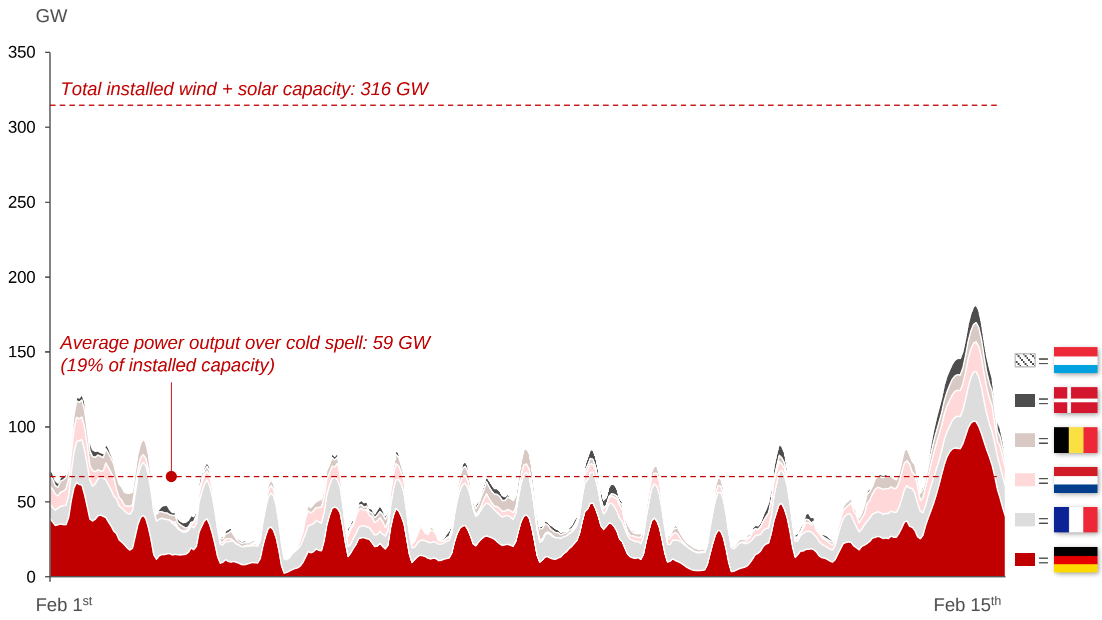


Figure 26: Wind and solar capacity in North-West Europe, 2016 and 2030

However, wind & solar generation varies with time: it is estimated that with climate conditions such as the 2-week cold spell of 2012, the average wind + solar generation would only reach 59 GW, which is less than the removed dispatchable thermal generation capacity.

CUMULATED WIND + SOLAR GENERATION IN 2030 IN NORTH-WEST EUROPE, UNDER 2012 CLIMATE CONDITIONS [GW]
GLOBAL AMBITION SCENARIO



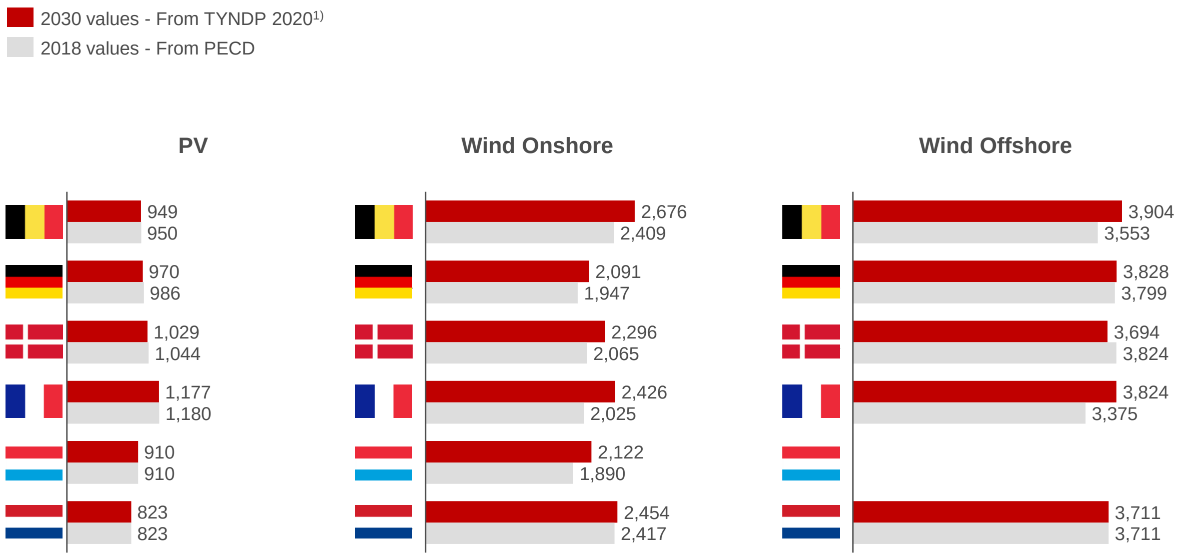
Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 27: Cumulated wind + solar generation in 2030 in North-West Europe, under 2012 climate conditions (2-week cold spell)

We use TYNDP assumptions on the development of full load hours and apply them to the load factors of each climate year using exponential scaling

To model the in-feed of intermittent renewable generators as wind onshore, wind offshore and photovoltaic we use the hourly load factors for each weather year provided in ENTSO-E's PECD database. To account for the future development of full load hours and to be consistent with TYNDP, we scale the load factors exponentially to the full load hours shown in Figure 28. In contrast to linear scaling the exponential scaling ensures that hourly load factors never exceed 1 and that small load factors are more affected than high load factors. The exponential scaling factor is determined for each type of generation (PV, wind onshore, wind offshore) and each country so that the feed-in under the TYNDP reference weather year (1984) matches the target full load hours. The same exponent is applied to the feed-in of each weather year. Thereby, different weather years do result in different full load hours, depending on the specific weather conditions.

FULL LOAD HOURS @ 1984 CLIMATE [h/year]



1) 2030 full load hours from TYNDP are estimated by dividing total renewable generation by installed capacity. Deviating from TYNDP, we used full load hours from the PECD database for PV in Luxembourg and the Netherlands and for offshore wind in the Netherlands, because the full load hours of TYNDP are unrealistically low

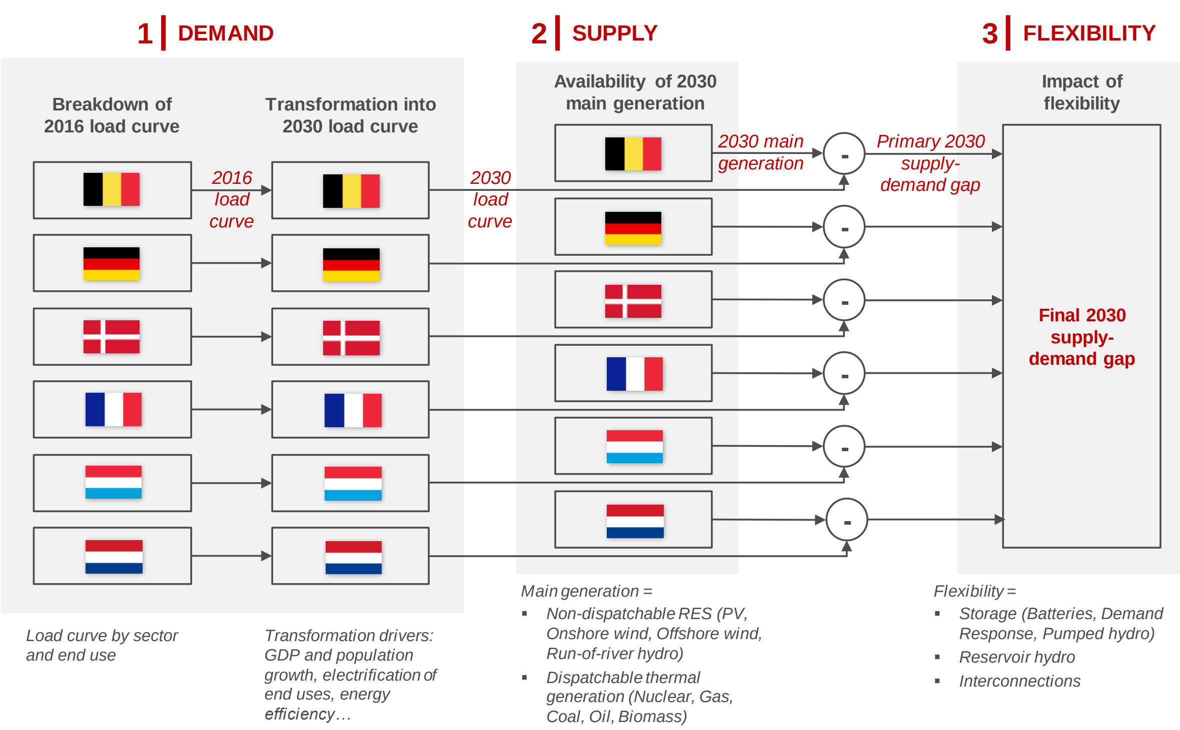
Source: TYNDP 2020, PECD, E-CUBE Strategy Consultants+EWI Analysis

Figure 28: Assumed full load hours of PV, Wind Onshore and Wind Offshore in 2030 under 1984 climate conditions

Appendix C: Over the duration of the cold spell, we apply an optimization algorithm to estimate the amount of Energy Not Served

The "Flexibility" model seeks to minimize the total supply-demand gap over the modeled area thanks to flexibility solutions and interconnections

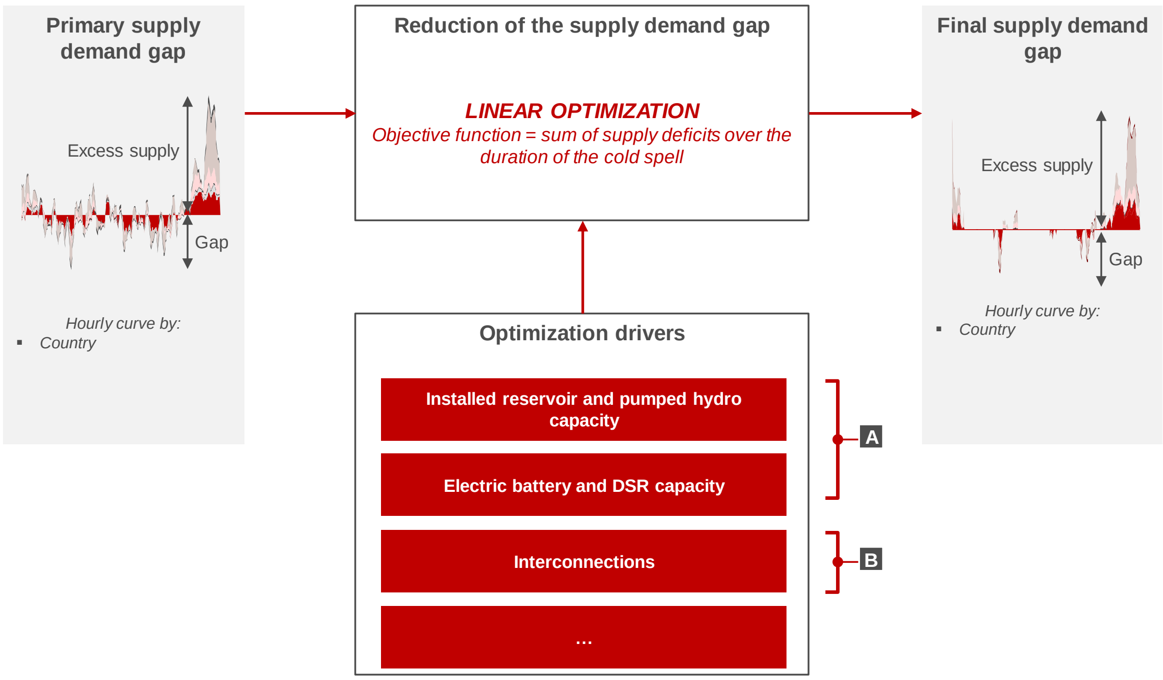
The flexibility model takes inputs from our demand and supply models.



Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 29: Articulation of the demand, supply and flexibility models

We apply a linear optimization to minimize the supply-demand gap over the duration of the cold spell.



Source: E-CUBE Strategy Consultants + EWI Analysis

Figure 30: Principle of the flexibility model

In the flexibility model, several modelling choices may lead to underestimating the supply-demand gap:

- Considering that assets are managed with the aim of minimizing the gap
- Assuming perfect foresight of demand and supply
- Disregarding internal grid bottlenecks

Our capacity assumptions for the flexibility model are based on TYNDP 2020 and TYNDP 2018

Our capacity assumptions are based on TYNDP 2020 whenever possible, and TYNDP 2018 when information is not available in TYNDP 2020 documents. These assumptions are:

- Battery storage capacity (TYNDP 2020)
- DSR capacity by country (TYNDP 2020)
- Hydro capacity by type of hydro and by country (TYNDP 2018)
- Interconnection capacities within North-West Europe (TYNDP 2018, assumptions for 2027)

Although the capacity of batteries and Demand-Side Response (DSR) is expected to grow by 2030, their impact during long cold spells will be mostly limited to shifting load within the day.
Unless other long-term storage assets are available (e.g. hydrogen), the management of water reserves, especially in France, would be key to limiting losses of load during long cold spells.

Besides the specifications of the TYNDP, we must make further assumptions:

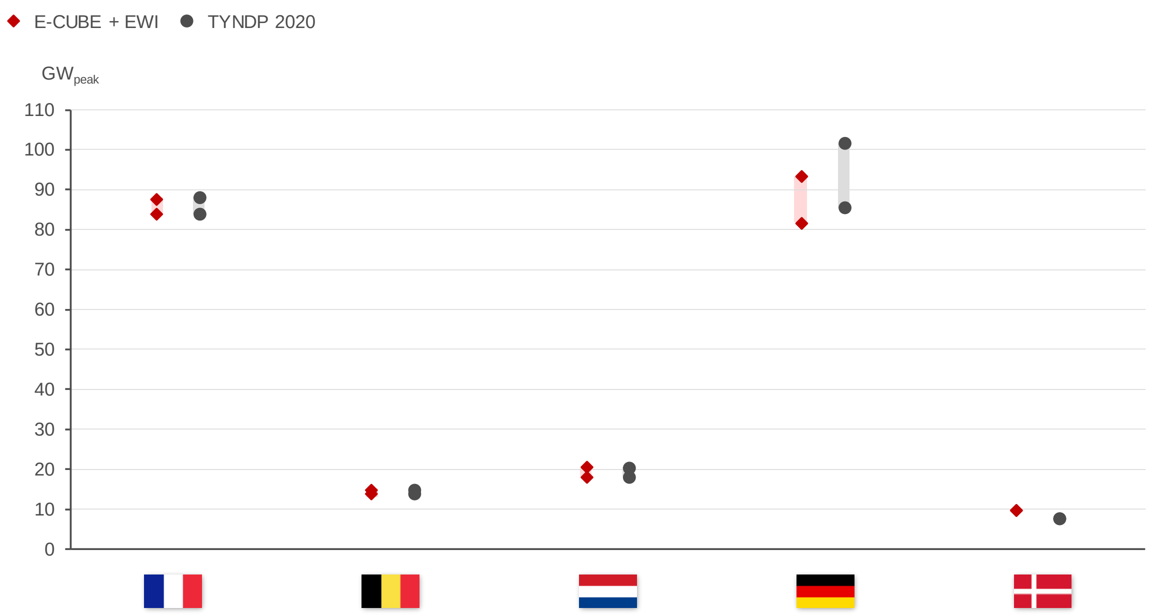
- In- and output efficiencies of flexibility technologies based on EDF & IRENA data
- Filling level of batteries and pump storages at beginning of the cold spell is 100%
- Filling level of hydro reservoirs at beginning of the cold spell is based on historical observations

- Based on historical data, we set a minimal filling level of hydro reservoirs of 30%
- Water inflow based on historical data provided on ENTSOEs transparency platform
- For interconnections we apply an additional de-rating factor based on ENTSOEs Winter Outlook

Appendix D: Under the climate year used as reference in TYNDP 2020 (year 1984), our results for peak demand are consistent with TYNDP 2020

ENTSO-E and ENTSOG publish the peak demand by country under 1984 climate conditions in TYNDP 2020 scenarios.
The figure below shows that peak demand in our scenarios is close to that of TYNDP 2020, with the exception of Germany, where the national assumptions of the TSOs in the high scenario lead to lower peak demand than the assumptions of TYNDP 2020.
However, the significance of this comparison is limited because 1984 is a relatively mild year, and our study aims at studying the power system's response to cold spells.

2030 PEAK DEMAND UNDER **1984 CLIMATE** [GW]



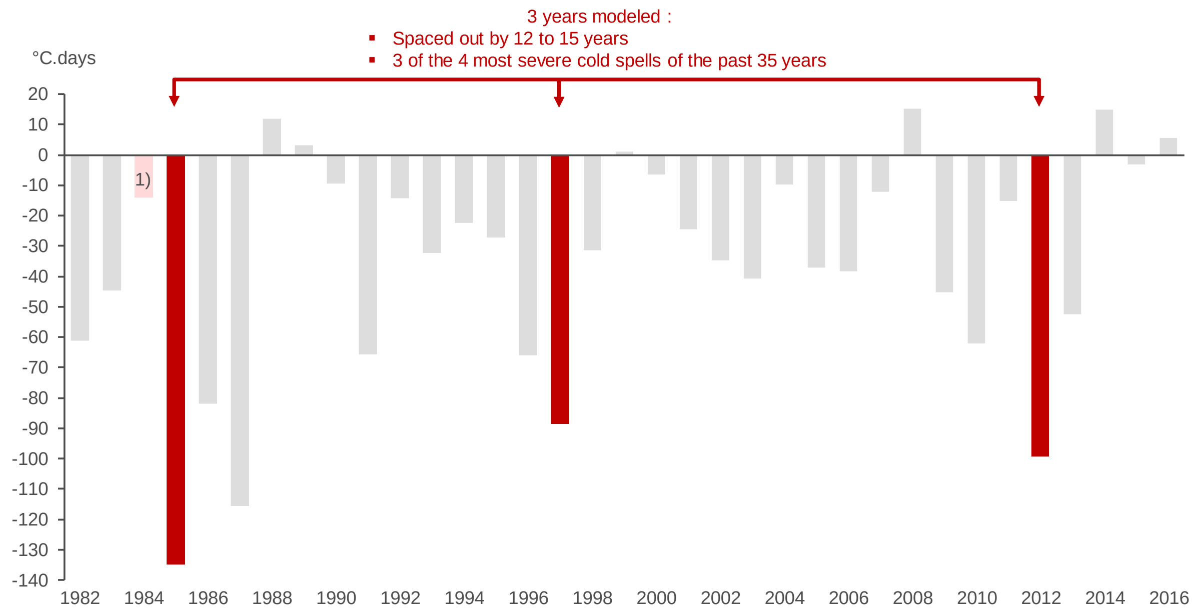
1) The TYNDP 2020's only published values for peak demand and yearly demand are under a 1984 climate
Source: TYNDP 2020, E-CUBE Strategy Consultants + EWI Analysis

Figure 31: Range of peak demand under 1984 climate in E-CUBE+EWI and TYNDP 2020 scenarios

Appendix E: 1985, 1997 and 2012 were the most intense cold spells of the past 35 years

1985, 1997 and 2012 saw 3 of the 4 most severe cold spells of the past 35 years in North-West Europe.

MINIMUM 15 DAYS ROLLING TEMPERATURE.DAYS – AVERAGE OVER FR+BENELUX+DE+DK [1982-2016; °C.days]



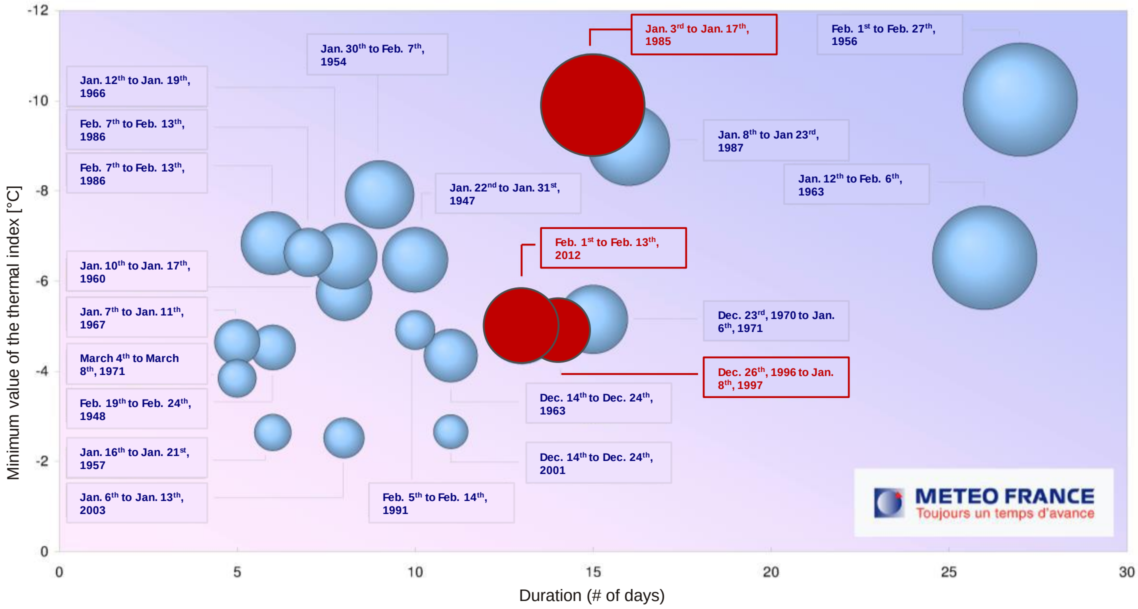
1) 1984 is the only year for which the TYNDP 2020 documentation gives peak and annual consumption values
Source: E-CUBE Strategy Consultants + EWI Analysis, PECD data

<u>Figure 32: Indicator of cold spell severity in North-West Europe from 1982 to 2016</u>

Before 1982, other cold spells have proven as severe, or even more severe than in the three focus years, for instance in France.

COLD SPELL PERIODS FROM 1947 TO 2013 IN FRANCE

THE YEARS IN RED ARE THE YEARS ADDRESSED IN THE REPORT



- The thermal index is defined as the mean of the daily temperatures during the cold spell period in Metropolitan France
- The size of the bubbles represents the intensity of the cold spell: the larger the bubble, the more severe the cold spell

Source: Meteo France

Figure 33: Cold spells from 1947 to 2013 in France

Table of Figures

Table of Acronyms

AAHP	*Air-to-air heat pump*
ASHP	*Air-source heat pump*
AWHP	*Air-to-water heat pump*
ENS	*Energy Not Served*
GSHP	*Ground-source heat pump*
GWHP	*Ground-to-water heat pump*
LoL	*Loss of Load*
NWE	*North-West Europe*
TYNDP	*Ten-Year Network Development Plan*
VoLL	*Value of Lost Load*
WSHP	*Water-source heat pump*
WWHP	*Water-to-water heat pump*

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