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ÉCONOMIE DU DÉVELOPPEMENT DURABLE
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Development of a dispatch model of the European power system for coupling with a long-term foresight energy model

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Abstract

Renewable sources of electricity production are strongly increasing in many parts of the world. The production costs are going down quickly, thus accelerating the deployment of new solar and wind electricity generation. In the long-term, these variable sources of electricity could represent a high share of the power system. However, long-term foresight energy models have difficulties describing precisely the integration challenges of Variable Renewable Energy Sources (VRES) such as wind or solar. They just do not represent the short-term technical constraints of the power sector. The objective of this paper is to show a new approach of the representation of the challenges of variability in the long-term foresight energy model POLES (Prospective Outlook on Long-term Energy Systems). We develop a short-term optimization model for the power sector operation, EUCAD (European Unit Commitment And Dispatch) and we couple it to POLES year after year. The direct coupling, with bi-directional exchanges of information, brings technical precision to the long-term coherence of energy scenarios.

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Introduction

The risks of uncontrolled climate change are pushing national energy policies towards more sustainable and decarbonized ways of producing electricity. These long-term ambitions are developed, tested and studied with modelling tools for long term energy foresight. They feature a global rise in renewable energy production: hydro power, biomass, geothermal, marine energy (thermal, wave or tidal), but most of all they point to a strong expansion of Wind and Solar (W&S) power generation. However, these energy sources are variable across several time-scales, non-dispatchable, and imperfectly predictable. This represents an increasing challenge for the energy system, thus creating modelling challenges. Indeed, the time steps of long-term models (often one year, subdivided in a few representative time-slices) do not correspond to the typical time step required for representing the variability of wind and solar (one hour, one day) [1].

The integration of W&S variability issues is made possible by several practical options: electricity storage, demand side management, electric grid management (at the local level, with “smart-grids”, or at the international level, with stronger interconnections and “super-grids”), or using conventional power plants as a “back-up” (compensating for the presence or absence of W&S production) or in a load-following mode (short term balancing of demand and W&S production). In order to include these flexibility options in a long-term model, we develop a new coupling approach [2]. For this we use the long-term foresight energy model POLES (Prospective Outlook on Long-term Energy Systems), a recursive simulation model that produces scenarios up to 2100. Until now, the impact of W&S variability was only taken into account through a maximum wind penetration, linked to the availability of other dispatchable sources, and through a balancing cost correlated to the wind penetration. We improve this relatively simple representation by coupling POLES with a short-term optimization model for the power sector operation: EUCAD (European Unit Commitment And Dispatch). This working paper describes EUCAD in section 1 and its coupling with POLES in section 2. Section 3 shows some results for the validation of EUCAD and some insights gained from the coupling with POLES. Finally, section 4 presents some sensitivity analyses on EUCAD equations and input parameters.

1. EUCAD (European Unit Commitment And Dispatch)

Studying the impacts of W&S variability and the operation of storage requires inter-temporal constraints, which call for an optimisation model. Many existing models study the operation of the power system with unit commitment and economic dispatch problems [3,4]. Some examples of power system operation models are ReEDS [5,6], PRIMES [7], ELMOD [8,9], WILMAR [10–12], Van den Bergh et al. [13] or EUPowerDispatch [14]; just like them, EUCAD is developed in the GAMS optimisation language and with the CPLEX solver.

We present here the equations and modelling choices used in EUCAD, summarized in figure 1.

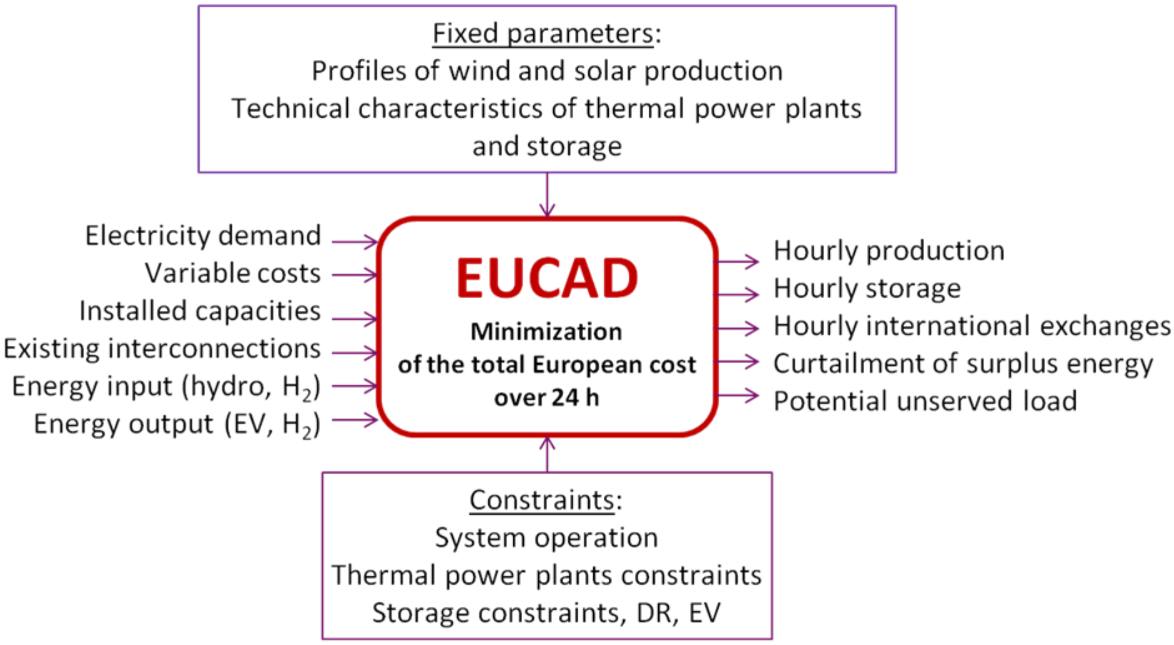


Figure 1: EUCAD diagram

Abbreviations used in EUCAD

The indices used are:

- *Country* (for the 24 European countries considered in the set *Europe*),
- *t* (for the 24 hours of the computed day),
- *DispTech* (for 32 dispatchable technologies, including production from storage technologies),
- *Stotech* (for 7 technologies consuming power).

The parameters (fixed inputs for GAMS) are:

- *VarCost*, the variable production cost of a technology (in \$/MWh);
- *RampingCost*, the cost due to thermal capacities with strong ramping (in $\$.MW^{-2}$), detailed in the section for ramping constraint;
- *SocioEcoCost*, the social and economic cost of curtailing load (in \$/MWh);
- *ResLoad*, the parameter describing the residual load (in MW), i.e. the load minus the W&S infeed;
- *Capacities*, the net transfer capacity of the interconnection lines (in MW);
- *Pmaxi*, the maximum power output at a given time of the day (in MW);
- *Pmax*, the maximum power output over a whole day (in MW);
- *STOmaxi*, the maximum storage consumption at a given time of the day (in MW);
- *STOmax*, the maximum storage consumption over a whole day (in MW);
- t_{on}, the minimum on-time of a technology (in hours);
- t_{off}, the minimum off-time of a technology (in hours).

The variables (outputs computed by GAMS) are:

- *TotCost*, the cost of the European production for an entire day (in \$);
- *P*, the production output (in MW);
- *Sto*, the consumption of storage technologies (in MW);
- *status*, a binary variable indicating if a technology is “off” or “on” (0 or 1)
- *NetExports*, the net exports of a given country (in MW), i.e. exports minus imports;
- *LineFlow*, the power flow from a country to another (in MW);
- *R*, the ramp between two consecutive hours (in MW);
- *UnservedLoad*, the curtailed load (in MW);
- *Surplus*, the curtailed surplus energy (in MW).

Objective of the optimisation

The optimisation objective of EUCAD is expressed as the minimisation of the total European power system operation cost. The 32 dispatchable technologies of 24

European countries[1] are optimised over a 24-hour period. The total cost is decomposed in the variable production costs, the cost of ramping the thermal power plants, and the social and economic cost of unsupplied energy to the customer (unserved load).

The equation defining the total cost is the following:

$$TotCost = \sum_{Country\,\epsilon\,Europe} \sum_{t=1}^{24} \Bigg(SocioEcoCost(Country) * UnservedLoad(Country, t) + \sum_{\substack{DispTech\,\in\,Technologies \\ s.t.Pmax(Country,DispTech)>0}} (VarCost(Country, DispTech) * P(Country, DispTech, t) + RampingCost(Country, DispTech) * R(Country, DispTech, t)^2) \Bigg)$$

The social and economic cost of unserved load (value of lost load) is a fixed parameter, set at 32500 \$/kWh for France [15], 14400 \$/MWh for Norway [15], 16100 \$/MWh for Ireland [16] and 20000 \$/MWh for the other countries (based on [17]).

Power system balance

The main constraint of the power system is the balance between production and demand. The national production, national consumption (including storage consumption), net exports and potential unserved load or surplus energy are considered in the equation below.

$$\forall(Country, t)\epsilon\{Europe, [1; 24]\}, \sum_{DispTech} P(Country, DispTech, t) = ResLoad(Country, t) + \sum_{Countrybis=1}^{24} NetExports(Country, Countrybis, t) + \sum_{Stotech} Sto(Country, Stotech, t) + Surplus(Country, t) - UnservedLoad(Country, t)$$

---

[1] Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Luxemburg, Netherland, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, United Kingdom.

Our modelling choices imply that the demand and W&S infeed are (perfectly) known for the upcoming 24 hours. In case the production cannot cover the load, there is some unserved load (variable *UnservedLoad*). Any over-production from inflexible generation, due to the non-dispatchability of W&S or the inflexibility of thermal power plants, is curtailed (variable *Surplus*). Exports and imports are possible through the European interconnections.

European electricity exchanges

Each country is represented as one node of the European international grid, which accounts for 24 nodes and 50 lines. All power flows (*LineFlow*) must be inferior to 90% of the installed net transfer capacity in order to represent possible technical and economic line constraints, e.g. an unplanned outage or an imperfect market (market power of an actor).

$$\forall (Country, Countrybis, t) \epsilon \{Europe, Europe, [1;24]\},$$
$$LineFlow(Country, Countrybis, t) \leq 0.9 * Capacities(Country, Countrybis)$$

For computing the net exports (used in the power system balance equation), we need to take into account the three European time-zones, since the load profile and the W&S production are parameters given in local time. Therefore we group the *Europe* countries in the subsets *Europe0* (UCT+0), *Europe1* (UCT+1) and *Europe2* (UCT+2). The net exports are the exports (*LineFlow* in local time) minus the imports (*LineFlow* from the neighbouring country at the same time, which may require a time conversion).

$$\begin{aligned}
&\forall (Country0, Country, t) \in \{Europe0, Europe, [1;24]\},\\
&NetExports(Country0, Country, t) = LineFlow(Country0, Country, t)\\
&-0.98 * \big(LineFlow(Country, Country0, t)_{s.t. Country\ \epsilon\ Europe0}\\
&\qquad\qquad + LineFlow(Country, Country0, t+1)_{s.t. Country \epsilon\ Europe1}\big)
\end{aligned}$$

$$\begin{aligned}
&\forall (Country1, Country, t) \in \{Europe1, Europe, [1;24]\},\\
&NetExports(Country1, Country, t) = LineFlow(Country1, Country, t)\\
&-0.98 * \big(LineFlow(Country, Country1, t)_{s.t. Country\ \epsilon\ Europe1}\\
&\qquad\qquad + LineFlow(Country, Country0, t+1)_{s.t. Country\ \epsilon\ Europe2}\\
&\qquad\qquad + LineFlow(Country, Country0, t-1)_{s.t. Country\ \epsilon\ Europe0}\big)
\end{aligned}$$

$$\begin{aligned}
&\forall (Country2, Country, t) \in \{Europe2, Europe, [1;24]\},\\
&NetExports(Country2, Country, t) = LineFlow(Country2, Country, t)\\
&-0.98 * \big(LineFlow(Country, Country2, t)_{s.t. Country\ \epsilon\ Europe2}\\
&\qquad\qquad + LineFlow(Country, Country2, t-1)_{s.t. Country\ \epsilon\ Europe1}\big)
\end{aligned}$$

We consider a fixed 2% loss in all international exchanges (i.e. the average French losses in the transmission grid).

Minimum and maximum operating point

The first operating constraint of the production and storage capacities are described with a maximum power output.

$$\forall(Country, DispTech, t), P(Country, DispTech, t) \leq status(Country, DispTech, t) * Pmaxi(Country, DispTech, t)$$

$$\forall(Country, Stotech, t), Sto(Country, Stotech, t) \leq STOmaxi(Country, Stotech, t)$$

The binary variable *status* makes EUCAD a mixed integer problem (MIQCP, since it is also Quadratically Constrained). When they are not switched off, production technologies also have a minimum power output.

$$\forall(Country, DispTech, t), P(Country, DispTech, t) \geq status(Country, DispTech, t) * Pmin(Country, DispTech)$$

It implies that a technology can either be "on", above a minimum power output (in our base case, 500 MW for nuclear plants, 400 MW for coal and biomass plants, 200 MW for gas plants, and zero for all oil plants, hydro and storage technologies[2]), or is "off", with zero output. This is implemented even though we only consider the whole technologies and not the individual power plants. A power plant fleet management would define the plant-by-plant constraints but we don't have the necessary precision; moreover, the computation time would be much higher and hinder any coupling with a long-term model.

The maximum power output (*Pmaxi*, *STOmaxi*) depends on the hour of the day: the maintenance outages are planned when the residual load is the lowest (this is exogenous to EUCAD). In the following, we also need to define *Pmax* and *STOmax*, the daily maxima of *Pmaxi* and *STOmaxi*.

$$\forall(Country, DispTech, t), Pmax(Country, DispTech) = max_t\left(Pmaxi(Country, DispTech, t)\right)$$

$$\forall(Country, Stotech, t), STOmax(Country, Stotech) = max_t\left(STOmaxi(Country, Stotech, t)\right)$$

Minimum on- and off-time constraints

Thermal power plants often have constraints of minimum on-time and off-time [4,18,19], i.e. they cannot start-up and shut-down repetitively in short time-scales. For example, nuclear power plants must manage the xenon effect when they stop producing, which implies at least 6 hours of successive off-time. More generally for thermal power plants (nuclear, coal or gas), the boiler's temperature must be managed: long heating times imply technical and economic constraints (fatigue

[2] We assume that this minimum power output is reduced to 50 MW for technologies with less than 500 MW of installed capacity and to zero for technologies with less than 50 MW.

induced by each start-up cycle, lost fuel for heating purposes and reduced efficiency during the start-up cycle). We include two constraints on the status of dispatchable power plants.

Minimum on-time:

$$\forall(Country, DispTech), \forall t_1 and\ t_2, s.t.\ t_2 > t_1 - t_{on}(DispTech) and\ t_2 \leq t_1,$$

$$status(Country, DispTech, t_1) \geq status(Country, DispTech, t_2) - status(Country, DispTech, t_2 - 1)$$

Minimum off-time:

$$\forall(Country, DispTech), \forall t_1 and\ t_2, s.t.\ t_2 \geq t_1 - t_{off}(DispTech) and\ t_2 \leq t_1,$$

$$1 - status(Country, DispTech, t_1) \geq status(Country, DispTech, t_2 - 1) - status(Country, DispTech, t_2)$$

The minimum on-time and off-time are defined for each technology (values are from [19]: minimum on-time of 8 h for nuclear, 6 h for lignite, 4 h for coal and combined cycle gas ; minimum off-time of 10 h for nuclear, 6 h for lignite, 2 h for coal and combined cycle gas ; no constraints for the other plants).

However, these constraints are mostly valid for the management of a single power plant; when managing a fleet of several power plants, the constraints can be overlooked. As it increases the overall computation time, we decide to ignore these constraints in future computations (see section 4, where the sensitivity analysis is carried out).

The ramping constraints

The dynamic constraints linked to ramping and cycling of the power plants are classical components of unit commitment problems [20,21]. In our approach, we represent both their technical and economic consequences. The technical constraint is defined by the limited speed of output variations, at the hourly time-step.

$$\forall(Country, DispTech, t), R(Country, DispTech, t) = P(Country, DispTech, t) - P(Country, DispTech, t - 1)$$

$$\forall(Country, DispTech, t), R(Country, DispTech, t) \leq Rmax(DispTech)$$

$$\forall(Country, DispTech, t), -R(Country, DispTech, t) \leq Rmax(DispTech)$$

Rmax is the parameter defining the maximum rate of output variation between two consecutive hours. The values used are 35% for all thermal technologies, except for nuclear (20%) and some fast ramping technologies which are supposed to be able to ramp 100% in one hour (thermal gas with simple cycle, combined cycle gas, and the *FastRamping* subset, which includes gas turbine, oil turbine, thermal oil with simple cycle, hydraulic lake, and all storage technologies, detailed later).

We also account for an economic impact of ramping, included in the total cost. Indeed, although it may be technically possible to ramp up or down a thermal power plant, the costs associated (O&M, ageing, etc.) may discourage such actions. The cost due to the ramping of thermal capacities is proportional to the fuel, operation and maintenance costs. Based on [22], we consider that a 1 GW coal power plant incurs a cost of around 2450 $ for a 330 MW change in output (around 640 $ for gas power plants). *RampCost* defines this cost of ramping 33% in one hour for a 1 MW plant. We choose to represent this cost as a quadratic function of ramping, in order to discourage strong cycles while having little impact on small output variations. In the total operating cost, *RampingCost* is multiplied by the square of *Ramp*.

$$\forall(Country, DispTech), RampingCost(Country, DispTech) = RampCost(DispTech) * Pmax(Country, DispTech) * \left(\frac{1}{0.33 * Pmax(Country, DispTech)}\right)^2$$

As explained above, we do not represent the start-up and shut-down trajectories of the individual power plants [23] because we lack a plant-level description. The ramping constraint and cost (that are high for a strong output variation) are already partly avoiding unrealistic operation of thermal power plants.

Frequency reserve requirement

A European-wide frequency reserve constraint is also accounted for, upwards and downwards. The contribution of a technology to this reserve is the fourth of the hourly ramping capability (thus approximating the 15-minute frequency response). The contribution from *FastRamping* and *Stotech* technologies is only limited by the total amplitude of operation (up or down margins between the current output level and the minimum or maximum output). The upwards frequency reserve is defined by:

$$\forall t, \sum_{Country \in Europe} \left(\sum_{\substack{DispTech \\ s.t. not\ FastRamping}} Pmax(Country, DispTech) * \frac{Rmax(DispTech)}{4} + \sum_{FastRamping} \big(Pmaxi(Country, FastRamping, t) - P(Country, FastRamping, t)\big) + \sum_{Stotech} Sto(Country, Stotech, t) \right) \geq 0.07 * TotLoad(t)$$

The downwards frequency reserve is defined by:

$$\forall t, \sum_{Country \in Europe} \left(\sum_{\substack{DispTech \\ s.t. not\ FastRamping}} Pmax(Country, DispTech) * \frac{Rmax(DispTech)}{4} \right.$$
$$+ \sum_{FastRamping} \big(P(Country, FastRamping, t)$$
$$- status(Country, FastRamping, t) * Pmin(Country, FastRamping)\big)$$
$$\left. + \sum_{Stotech} \big(STOmaxi(Country, Stotech, t) - Sto(Country, Stotech, t)\big) \right)$$
$$\geq 0.07 * TotLoad(t)$$

The need for frequency reserve, which corresponds to the dimensioning incident of the power system, is assumed to be 7% of the total load (*TotLoad*). This criterion corresponds to the primary and secondary reserves in France (2.5%+4.5%); it could change with higher penetrations of VRES but we did not focus our work on this aspect.

Storage constraint

Additional equations are necessary to take into account the specificities of storage. Their technical and economical characteristics are already analysed in [11,24]. The most important constraint is that all storage capacities must ensure the balance between consumed electricity and produced electricity plus the efficiency losses.

$$\forall (Country, StoProdTechnos), \sum_{t} \big(Sto(Country, StoProdTechnos, t)$$
$$* efficiency(StoProdTechnos) - P(Country, StoProdTechnos, t)\big) \geq 0$$

The subset *StoProdTechnos* includes all technologies storing and producing electricity: hydro pumping, adiabatic Compressed Air Energy Storage (a-CAES), Demand Response (DR), batteries and EV used for Vehicle-to-Grid (V2G). In our baseline the round-trip efficiencies are fixed in time (80% for stationary batteries and V2G batteries, 75% for hydro pumping, 65% for a-CAES and 100% for DR) but they could also follow a learning process. The set *Stotech* contains *StoProdTechnos* but also water electrolysis for the production of hydrogen and Grid-to-Vehicle (G2V) for EV vehicle charging.

Demand response constraints

In our work, DR is equivalent to load shifting; it shifts power in time like storage (so that the storage balance equation also applies to DR). Thus, DR can integrate the VRES variations and improve the reliability of the power system [25]. However, DR also has specific constraints, difficult to model because there is little experience on how a dynamic demand side program can control various electric appliances [26,27] (each consumer and each electric appliance are specific).

EUCAD's assumptions are that the "produced" power during one hour (obtained by reducing the consumption) is partly compensated on the next hour (one third) and partly dispatched across the entire day (two thirds, the total making a total "efficiency" of 100%).

$$\forall(Country, t), Sto(Country, DR, t) \geq P(Country, DR, t-1)/3$$

DR is also constrained in the total energy shifted every day (number of activations of the DR program). We consider that it can displace each day the energy equivalent of its installed capacity operating for one hour (either at full power for one hour or at partial load but divided in several time-periods).

$$\forall Country, \sum_t P(Country, DR, t) \leq Pmax(Country, DR) * 1$$

This gives production and storage characteristics as shown in figure 2.

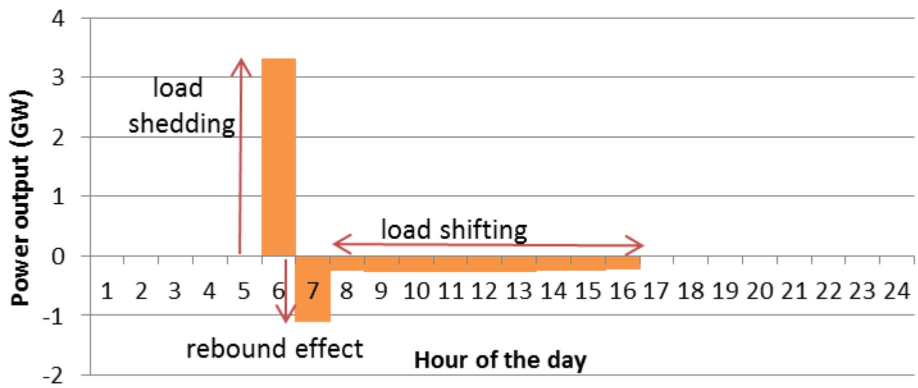


Figure 2: Illustration of the DR production and consumption profile (France, a summer day of 2050, "no policy" scenario, result of EUCAD).

The case of dispatchable energy sources

Some components of the power system have stored energy available for electricity production; hydraulic dams and hydrogen fuel cells are modelled in this way in EUCAD.

Hydro lakes have water inflows, which are considered as a free stored energy arriving every day in the dams. This energy can be dispatched when it is most valuable. Therefore the optimisation sets a daily limit to their production (still limited by the installed capacity). The longer-term management of the water resource (weekly and seasonal storage) is not represented. All valley effects (dams situated one after another, in a chain) and non-energetic constraints (touristic, fishing or agricultural activities) are neglected.

The hydrogen fuel cell technology is also handled as an amount of energy available for electricity production. The equation constraining this "stored" energy is:

$$\forall(Country, StockIn), \sum_t P(Country, StockIn, t) \leq EnergyINday(Country, StockIn)$$

The subset *StockIn* contains hydro lakes, hydrogen fuel cells, but also V2G. Indeed, EV used for V2G services also have a maximum energy to produce each day, because the use of an EV battery for V2G is limited by the consumer's driving needs and comfort (this is detailed later).

The yearly energy available is equally dispatched across all days of the year. The hydro lake resource evolves differently in summer and in winter, according to the HadGEM2-ES environmental model results [28]. The hydrogen vector develops consequently, linked to the decentralised electricity production.

The case of dispatchable loads

Symmetrically, some sectors have dispatchable electricity consumption, which are modelled as energy to be produced from electricity; it is the case of water electrolysis for hydrogen production and EV charging in EUCAD (G2V).

$$\forall(Country, StockOut), \sum_t Sto(Country, StockOut, t) \geq EnergyOUTday(Country, StockOut)$$

Similarly to *StockIn* technologies, *StockOut* is the subset of (dispatchable) technologies that have to consume a certain amount of energy across the day: EV charging and water electrolysis. Another constraint is necessary in EUCAD to ensure that these consuming-only technologies are not producing.

$$\forall(Country, StockOut, t), P(Country, StockOut, t) = 0$$

EV constraints

The management of EV batteries is also an active area of research, summarised in [29]. Madzharov et al. use a unit commitment problem [30] to emphasize the benefits for the system of controlling the EV charging. Nunes et al. [31] use EnergyPlan to model the interactions between the power system (with high shares of VRES like solar) and the transport sector (EV charging optimisation).

In EUCAD, there is only one constraint added specifically for EV: the daylight charging (7h - 19h) cannot represent more than half of the total EV charging.

$$\sum_{t=7}^{19} Sto(Country, G2V, t) \leq 0.5 * EnergyOUTday(Country, G2V)$$

This is traducing the fact that most of the trips are two-way, with a 'commuting' profile between 7am and 7pm [30]. We assume that the EV drivers will want to charge their vehicle twice a day, especially if the daylight hours have an attractive electricity cost (fostered by the appearance of excess solar production during daylight hours). Since the night slow-charging is considered to be a logical behaviour, only up to half of the daily consumption can be supplied during daylight hours, (corresponding to the first part of the daily trip).

All the other specific constraints of EV are already represented with the other equations: the “energy ouput” equation for the daily EV charging, the general storage equation for the V2G storage cycle and the “energy input” equation for the maximum V2G energy storage. The parameters used in these constraints are detailed here.

Although the EV fleet is not connected to the grid at all times, the connected vehicles still represent more than 80% of the total fleet at all times of the day [32]. The connecting power is set at 3.2 kW and the battery size is 24 kWh, which are the characteristics of the Nissan Leaf and are in the range of most commercial EV today [29]. These characteristics may be improved in the future due to the development of battery technologies (higher energy density, lower cost). On the other hand, not all EV participate in the charging optimisation every day because they don’t all behave similarly in terms of driving pattern and personal behaviour (e.g. some drivers may only use their vehicle on week-ends). By lack of further information, we keep these numbers and consider that all EV not used are available to the grid.

V2G agreements are expected to develop progressively, from 0% of all contracts in 2020, to 60% in 2050 and for the rest of the century. The EV battery is larger than the daily average driving need: it usually allows for trips of more than 100 km, whereas the driving need is evaluated at 35 km per day in Portugal [31] and 32 km in Western Australia [33]. Therefore, the underutilization of the batteries can be used by the system for V2G applications – as long as the driving needs are not affected. We traduce this comfort limitation by keeping at least 30% of the battery capacity unused. As an example, a Nissan Leaf with a consumption of 0.137 kWh/km will still have half the theoretical capacity of its battery available for V2G, after a 35 km drive and with a 30% comfort reserve.

2. Coupling EUCAD and POLES

The originality of this work is the coupling of the unit commitment model EUCAD with the long-term energy model POLES. We present here the data exchanges of the direct coupling and how the feedback of EUCAD is integrated in the long-term approach of POLES.

2.a. Data exchange between POLES and EUCAD

EUCAD only covers European countries, so the rest of POLES regions are not impacted. For each simulation year, POLES and EUCAD exchange data in both ways, thanks to a two-way coupling between the Vensim (POLES) and GAMS (EUCAD) languages. The data exchange is summarised in figure 3.

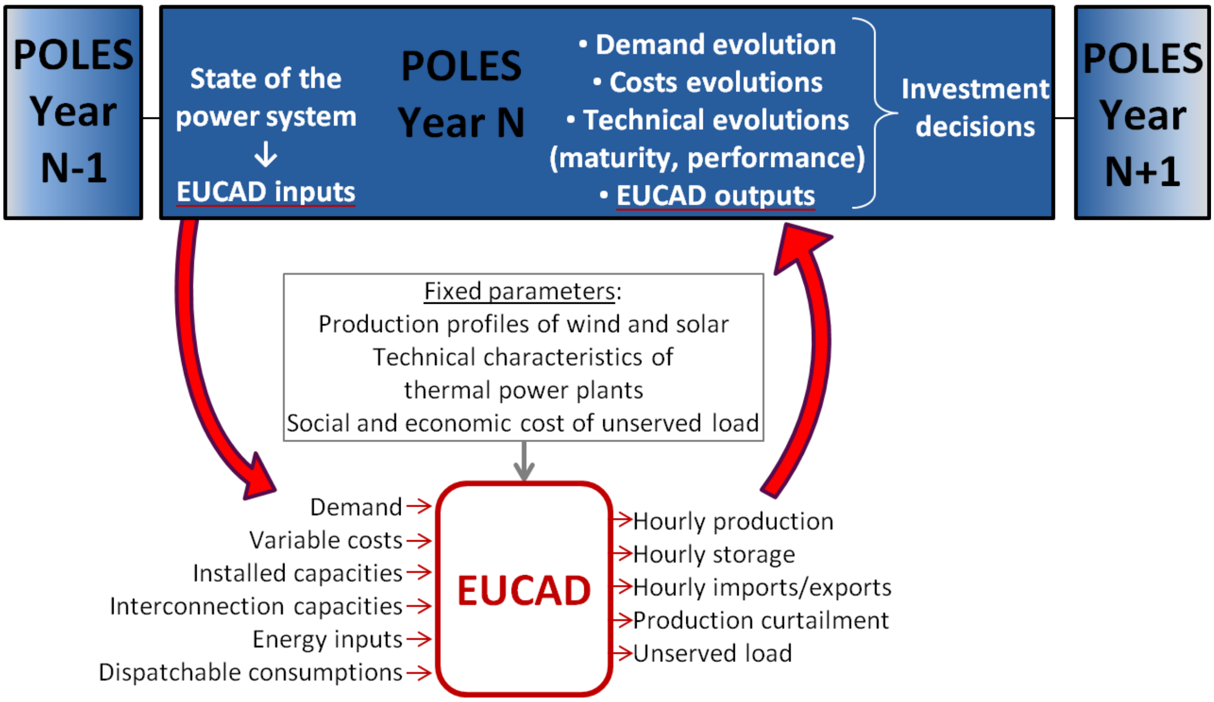


Figure 3: Direct coupling and data exchanges between POLES and EUCAD

All the main inputs of EUCAD are taken from POLES (load, variable costs, installed production, storage and interconnection capacities, energy available for dispatching and energy to produce from electricity). All these inputs change in time, following the evolution of the energy scenario handled in POLES (learning factors, investment decisions). Only the wind and solar typical production profiles and the technical characteristics of thermal power plants are fixed in time (in theory, they could also evolve within POLES, if data was available).

The outputs of EUCAD are sent back to POLES for each year: the hourly production, storage and net exportations are aggregated to two-hour blocks, so that they fit the POLES data format. The amount of energy lost in surplus energy curtailment and the energy not distributed to consumers (unserved load) are also monitored in POLES.

2.b. Representation of the wind and solar variability

Different W&S production profiles (at the European level) are used to compute several typical days per season (summer and winter). These profiles are determined using a clustering algorithm detailed in [34]. It is based on meteorological data from the summer and winter seasons of 2006, transformed into hourly capacity factors [35] and grouped until six clusters for each season are reached. The European share of VRES in electricity production (in 2050 for a “no policy” scenario) is illustrated for all 6 clusters in figure 4.

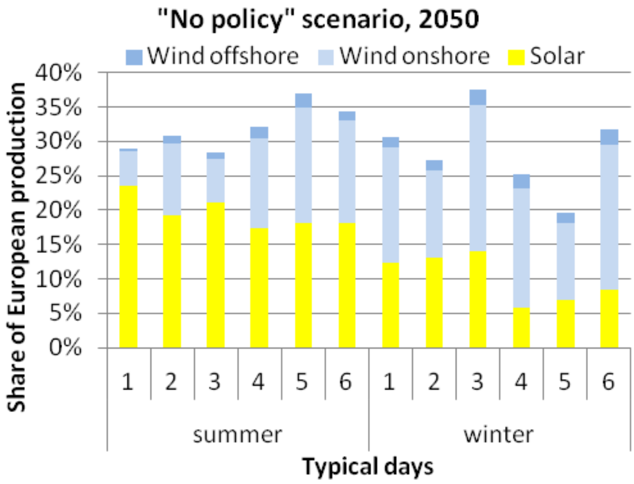


Figure 4: VRES share in Europe electricity production for the 12 typical days obtained with the cluster algorithm. 2050, “no policy” scenario.

In figure 5 and figure 6 we show the geographical repartition of two European typical days, one in summer and one in winter.

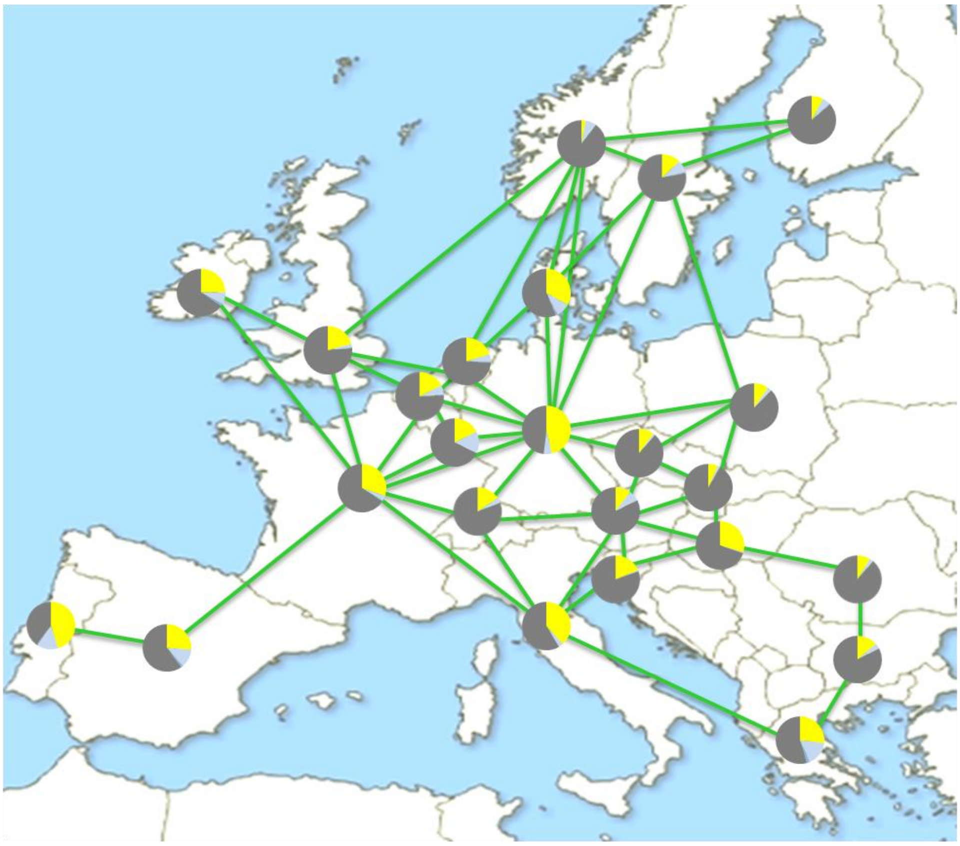


Figure 5: Spatial distribution of the summer day, type 1. 2050, “no policy” scenario. In green are the grid connections between countries.

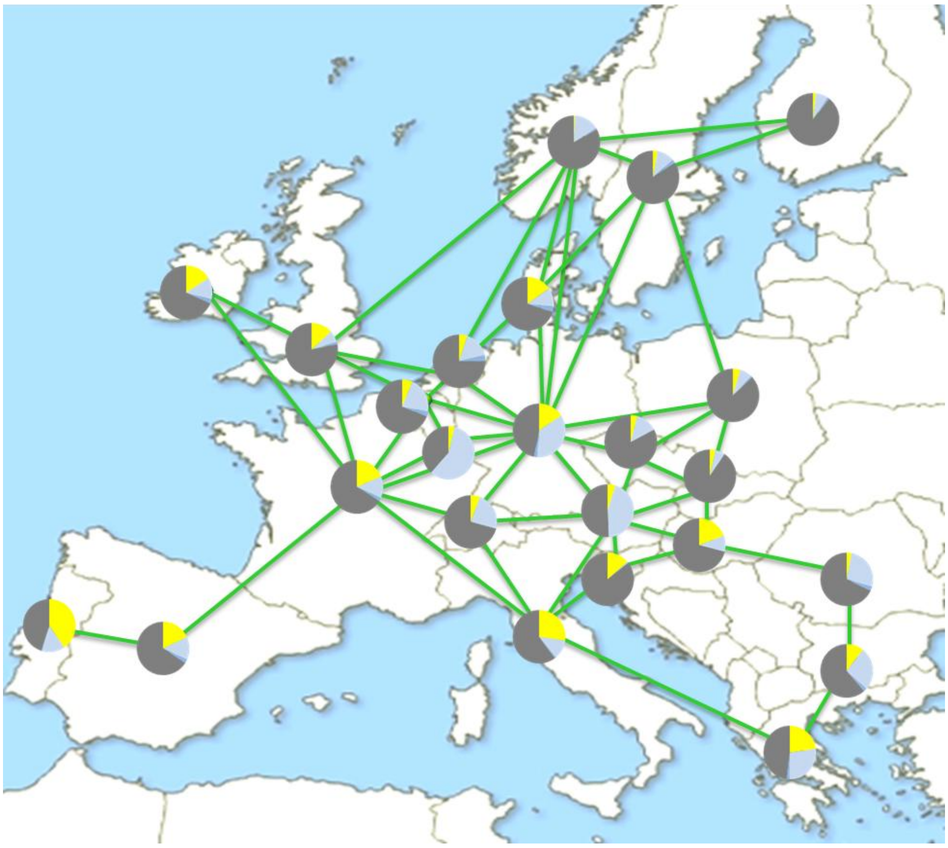


Figure 6: Spatial distribution of the winter day, type 1. 2050, “no policy” scenario. In green are the grid connections between countries.

EUCAD runs sequentially for each of the typical days of W&S production, before sending the aggregated results to POLES and moving on to the next year. This becomes the main time-consuming task in POLES+EUCAD, as the few seconds of solving the unit commitment problem quickly add up (12 days per year, 101 years for a classical scenario).

2.c. Inclusion of EUCAD feedback in POLES

A two-way coupling

Recent research has emphasised the importance of representing the short-term specificities of renewable generation within long-term energy models [36,37]. Some long-term energy models have been linked to short-term detailed computations of the power system operation. For example, the outputs of the optimisation models TIMES or ReEDS can be fed into a separate optimisation of the power system (PLEXOS) [38]. However, these articulations are only soft-linking, in the sense that the data from a long-term model are sent to a more detailed model, but without any feedback. To the contrary, EUCAD feedback is used in POLES for each simulation year.

Feedback on the power system operation

The energy produced by each technology is now computed in EUCAD. The operating constraints (with the short-term detail of EUCAD) and the variability of renewable production (with the several typical days of W&S production) are thus reflected in the results.

Electricity storage operation is computed in EUCAD, bringing another power sector component in POLES. This is only possible thanks to the optimisation framework of EUCAD (at the hourly time-step).

The electricity exchanges computed in EUCAD also bring new information to POLES (adapting the annual balances of imports and exports along the scenarios).

Some load management (EV charging, hydrogen production from water electrolysis) and some production profiles (hydro lakes, hydrogen fuel cells) are also computed in EUCAD and then used to improve the approximations of POLES.

Feedback on the investments

EUCAD results also impact the investment mechanisms of POLES. Indeed, the operation hours are used in POLES, impacting the total costs of every technology, and therefore the competition between the technologies. The operating hours of storage power plants and demand response capacities also affect their further investments.

The curtailed surplus energy is computed with EUCAD, thus taking into account all possible flexibility sources: European grid interconnections, storage, demand response, load management. It is used in POLES to fine-tune the expected load factor of wind and solar power plants. The unserved load is also monitored in POLES (indicating a potential failure of the investment mechanism), although it never occurs in actual scenarios.

The grid interconnection capacities are considered to be known until 2025, by using a linear approximation between 2010 and the projected capacities in 2025 according to ENTSO-E [39]. After 2025, they are set to increase if their operating hours are high. Here we do not evaluate the costs and benefits of strengthening an individual interconnection, by lack of input data and because a case-by-case analysis would take too long in computation time.

3. An approach to the new modelling possibilities

3.a. EUCAD results and real-case validation

We carried out two types of tests to validate EUCAD with real data. The first test is at national scale, with the following input:

- load profile and international exchanges from RTE data,
- installed capacities and variable costs from POLES database,
- availability of nuclear (maximum power available on the day), run-of-river hydro (base-load hydro production of the day), lake hydro (energy available for hydro production on the entire day), wind and solar (non-dispatchable production of the day), from RTE data.

The second test is at European scale:

- load profile provided by ENTSO-E,

- installed capacities and variable costs from POLES database,
- availability of French nuclear (maximum power available on the day) and run-of-river hydro (base-load hydro production of the day), lake hydro (energy available for hydro production on the entire day) from RTE data,
- wind and solar production from an additional extensive work[3] of collecting as many European renewable production data as possible (extrapolation to neighbouring countries is used when data is missing in some of the 24 EUCAD countries).

The first national test, for France, was carried out for a day of each month of 2013 (two representative days are shown in figure 7); the second one, i.e. the European comparison, was carried out for the 12 days of the clustering algorithm of wind and solar productions (two of them are shown in figure 8, for France again, being the country with most precise and reliable input data at the time of our study).

[3] Study carried out with the help of Sacha Hodencq, Valentin Maillot, Romain Bick, Martin Encinas, Anne LOZE, Hannah Goux, Capucine Grange and Marie Volatier.

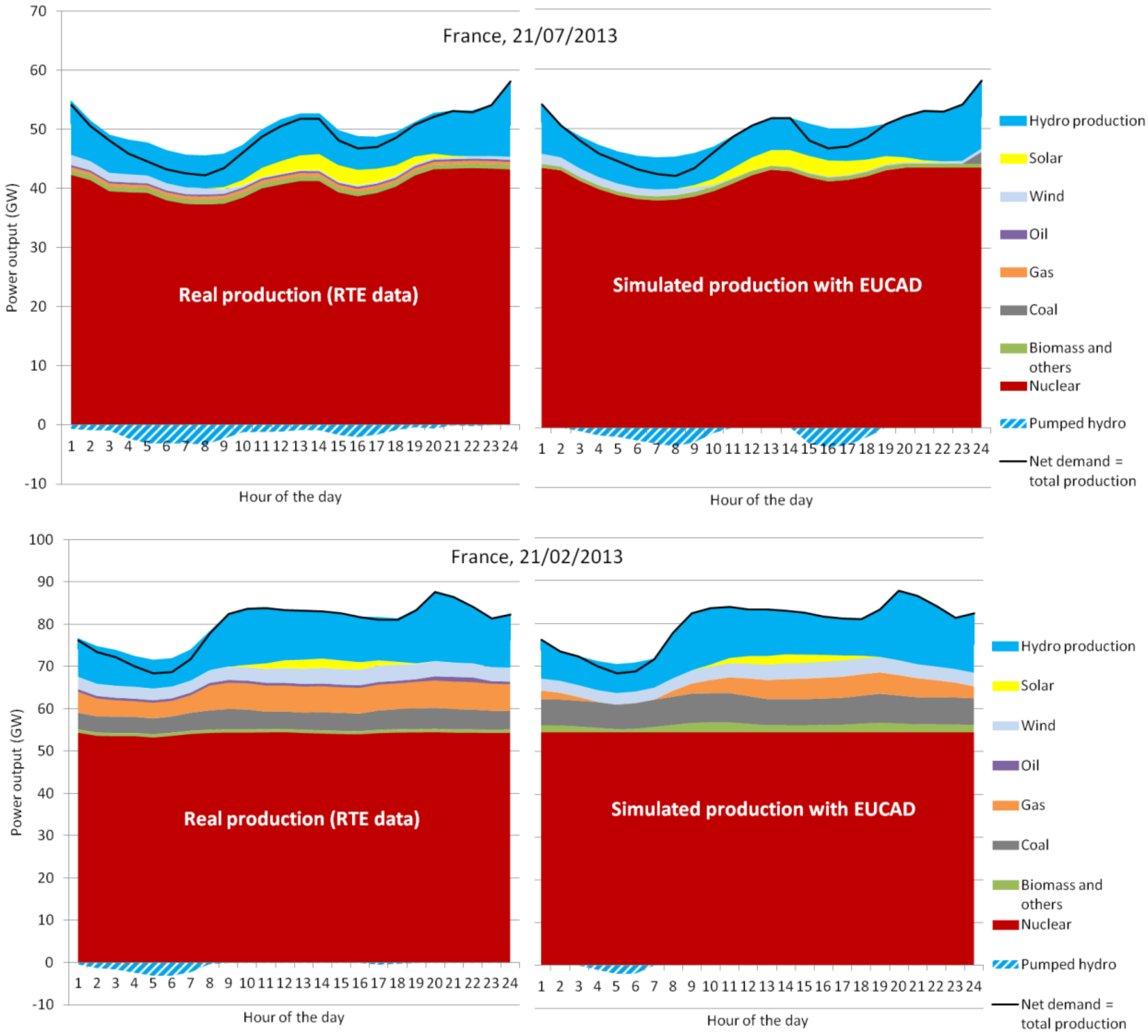


Figure 7: Comparison of the real production data (RTE data; left) and EUCAD national computation (right), for a summer day (top) and a winter day (bottom).

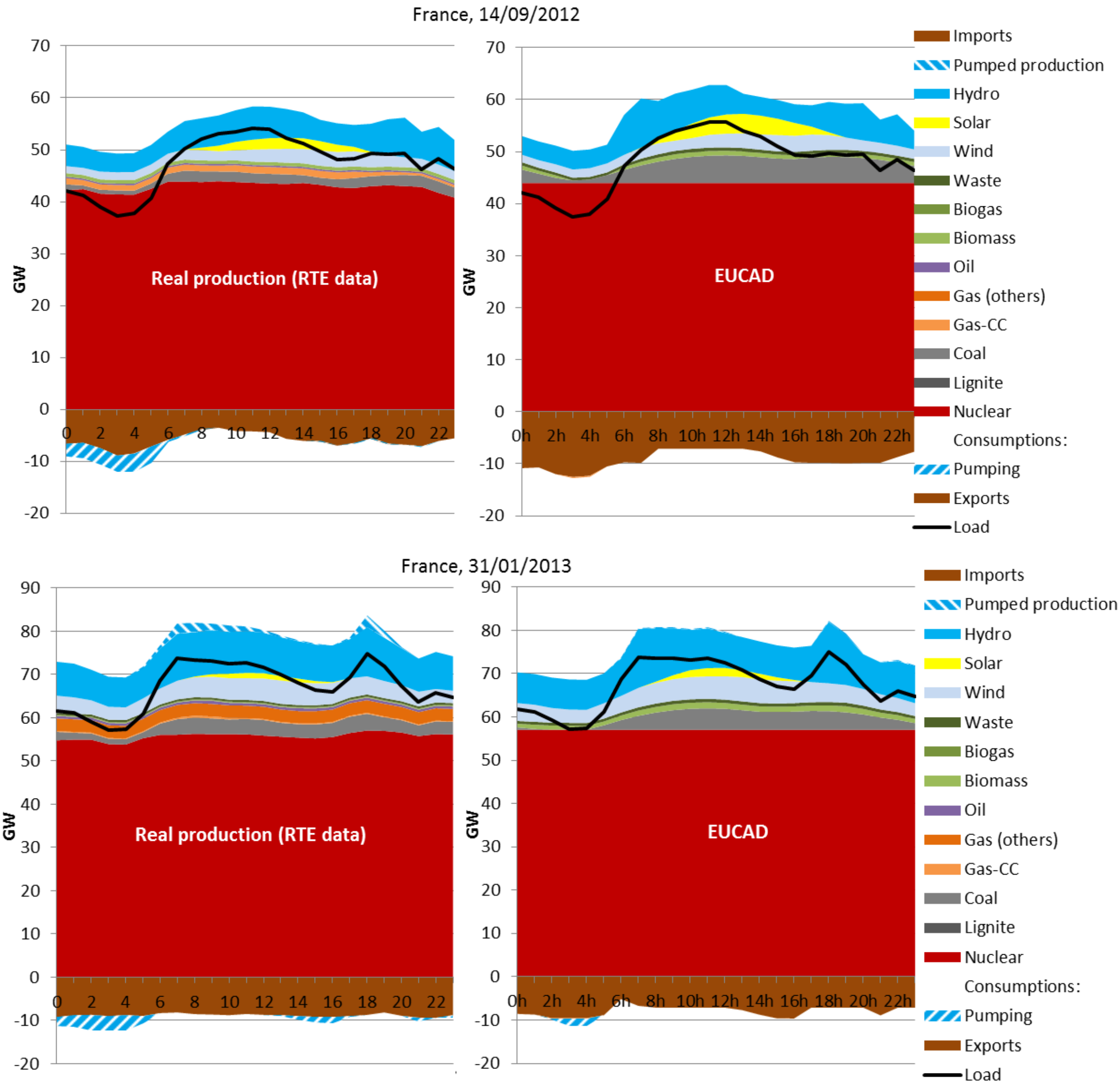


Figure 8: Comparison of the real production data (RTE data; on left) with EUCAD European computation (right), for a summer day (top) and a winter day (bottom).

This comparison entails a series of comments. As far as the first national validation test is concerned, our analysis shows that:

- There is a good match in the operation of nuclear and hydro power plants. This confirms that the load following capabilities are well taken into account (hydro power is more flexible than nuclear).
- However, in the winter day there is an exaggerated role of coal and an under-evaluation of gas and oil power plants. This observation was also found by Brancucci [39] with a different optimization model (EUPowerDispatch). We propose several possible explanations:
    - The European air pollution regulation imposes a limited number of hours of production until 2015 for old French polluting coal power plants, which is not taken into account in EUCAD.

- The real fuel efficiency may also be over-estimated and the international coal prices used in POLES' database may be an approximation for what EDF (the main French producer) actually pays. EDF might also use an internal carbon value so as to reach an environmental objective.
- The (small) size and actual availability of the coal power plants may have an impact (EUCAD only considers the capacity installed for entire technologies).
- Finally, the uncertainties on redispatching are not modelled in EUCAD; they could favour more flexible power plants and disadvantage coal power plants.

- In addition (not shown in these two examples), we observe that on week-end days the match is not as good, mainly because:
  - Hydro lakes offer weekly storage, while EUCAD only has daily storage;
  - Some dispatchable power plants are stopped during the week-end because the lower consumption period and lower power prices justify the shut-down and start-up costs (e.g. for short maintenance).

For the second comparison, at European-scale, the relevance of the representation of interconnections can also be studied. We observe some additional biases:

- Hydro storage is less used in EUCAD than in reality; interconnections are preferred;
- For France only, nuclear power is used in a more stable way in EUCAD than in reality (EDF chooses to use its nuclear power capacity in load-following mode, contrary to other countries which use nuclear in full-load mode). EUCAD finds that it is economically more efficient to run the nuclear power plants in full-load and export the surplus to neighbours, thus offsetting more expensive (and CO_2-emitting) power plants.

In a more general perspective, the structure of EUCAD loses some aspects of the actual electricity production:

- EUCAD uses optimization, which, in spite of the operating constraints, may lead to situations of "winner-takes-it-all", whereas the reality is never a "first-best optimum";
- The international exchanges are difficult to represent with all their peculiarities, and EUCAD does not have a real load flow computation;
- The geographical details within a country (e.g. voltage constraints, congestions of the internal grid) are not captured by EUCAD;
- All the technical and economic constraints cannot be known, as they are private and sensitive data.

3.b. EUCAD's impact on POLES

The operating hours of each technology are computed within the European-wide optimisation of EUCAD, which modifies the results of the scenarios. The representations of electricity storage or inter-countries exchanges in POLES are significantly strengthened by the coupling with EUCAD. In this section we show some results with and without the coupling with EUCAD, for the same "no policy" scenario (as defined in the AMPERE project [37]). However, the export balance of each country is modified by EUCAD coupling (even with the same policy assumptions), so that national productions are significantly different with or without the coupling of EUCAD.

A first observable consequence is a modification in the operation of some technologies. In figure 9, the production of a coal technology is shown, for two different two-hour blocks of a summer day.

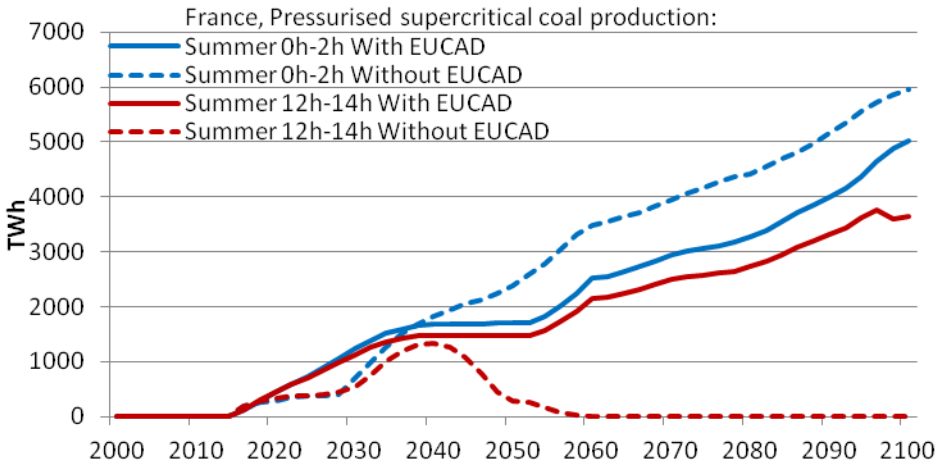


Figure 9: Results of coal production (pressurized supercritical technology) for two-hour blocks in the night and in day-light hours, with and without coupling EUCAD to POLES; “no policy” scenario.

EUCAD anticipates a base-load operation of coal, while POLES without EUCAD does not use these capacities during daylight hours. This is due to a better representation of the flexibility options in EUCAD (especially interconnections, but also storage and demand response), which allow an optimal use of the cheapest fuels throughout the day. The low flexibility of coal power plants is also represented in EUCAD, with technical and economic ramping constraints. In POLES without EUCAD, on the other hand, the high midday solar production removes all fossil fuel power plants. The operation of storage technologies also shows some significant differences (figure 10).

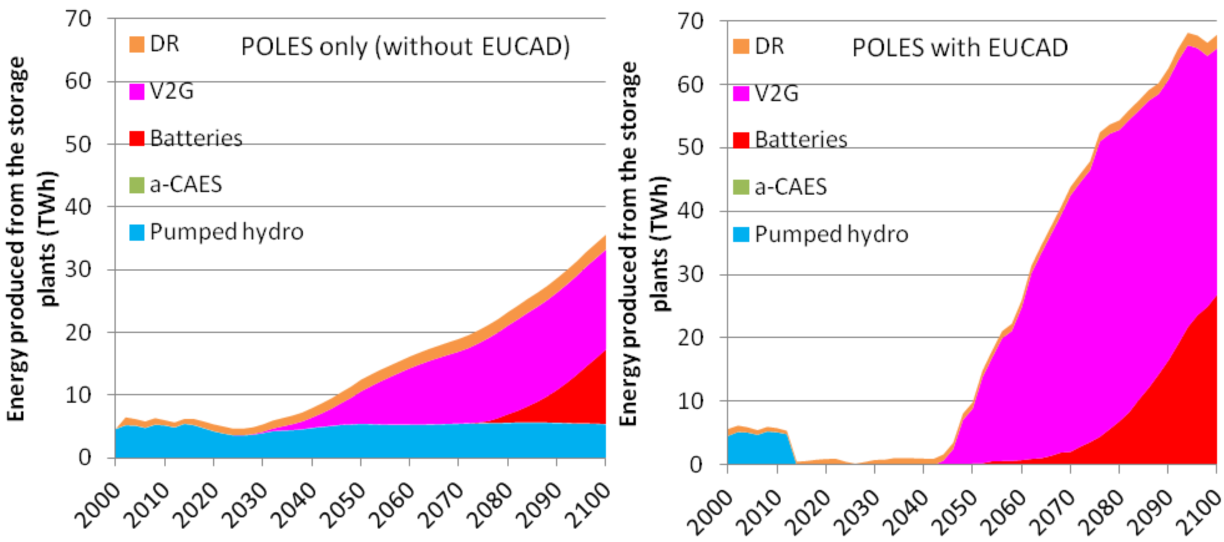


Figure 10: Operation of the pumped hydro, a-CAES, V2G, stationary batteries, and demand response in France, without (left) and with (right) coupling EUCAD to POLES ("no policy" scenario).

The operation of storage in POLES without EUCAD shows more inertia than the results of EUCAD optimisation coupled with POLES. The hydro pumping operating hours are maintained for the rest of the century. Batteries are used after 2035, first through V2G as it is less expensive, then in stationary batteries after 2080. When using EUCAD’s optimisation for the power system operation, we observe however barely any need for storage until 2045. Then V2G is developed a lot, followed by stationary batteries after 2070. These marked differences are due to the different computational approaches (simulation in POLES, optimisation in EUCAD) and to the possibility in EUCAD of using international exchanges to mitigate the impacts of VRES (whereas POLES has constant export balances). The evolution of the import and export balances is illustrated in figure 11 (for the same “no policy” scenario).

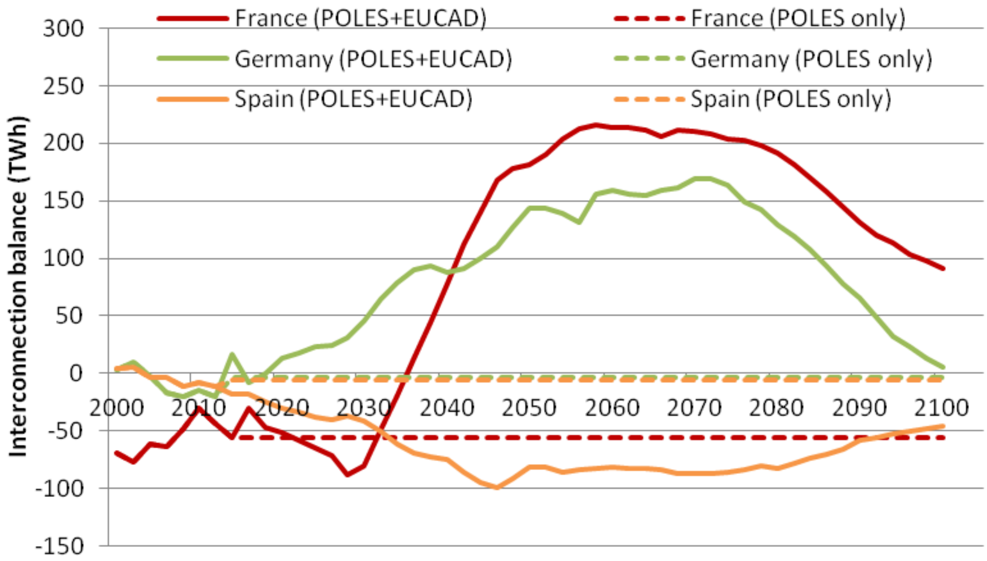


Figure 11: Imports and exports annual balance in France, Germany and Spain, with and without coupling EUCAD to POLES ("no policy" scenario).

The impact of this import and export balance on the power system development of each country is very important. Here, France and Germany become largely importing countries, while Spain becomes a net exporter. However, these evolutions are overlooked in POLES without EUCAD.

3.c. The evolution of a typical summer day

As an illustration of the detail brought by coupling EUCAD and POLES, we show in appendix A the evolution of the power system operation for one of the typical days of wind and solar production, from 2020 to 2100. The scenario chosen for this example is a 2°C policy scenario, which uses a strong carbon value to ensure a 66% chance of limiting global warming to 2°C by 2100. This shows that the exporting balance evolves along the century. Storage is significantly developed and used until 2050 (thus avoiding the use of expensive CO_2-emitting plants); around 2070 it looses its role in the supply and demand balance, but by the end of the century it finds a renewed importance regarding this aspect (for the integration of solar surplus) [2].

We also compare below some snapshots of the situation in 2050 (through the typical summer and winter days), for the "2°C policy" scenario, in France. The modelling of POLES-only is shown in figure 12, and POLES+EUCAD is shown in figure 13 (by aggregating the 12 representative days of the year into the same summer and winter representative days).

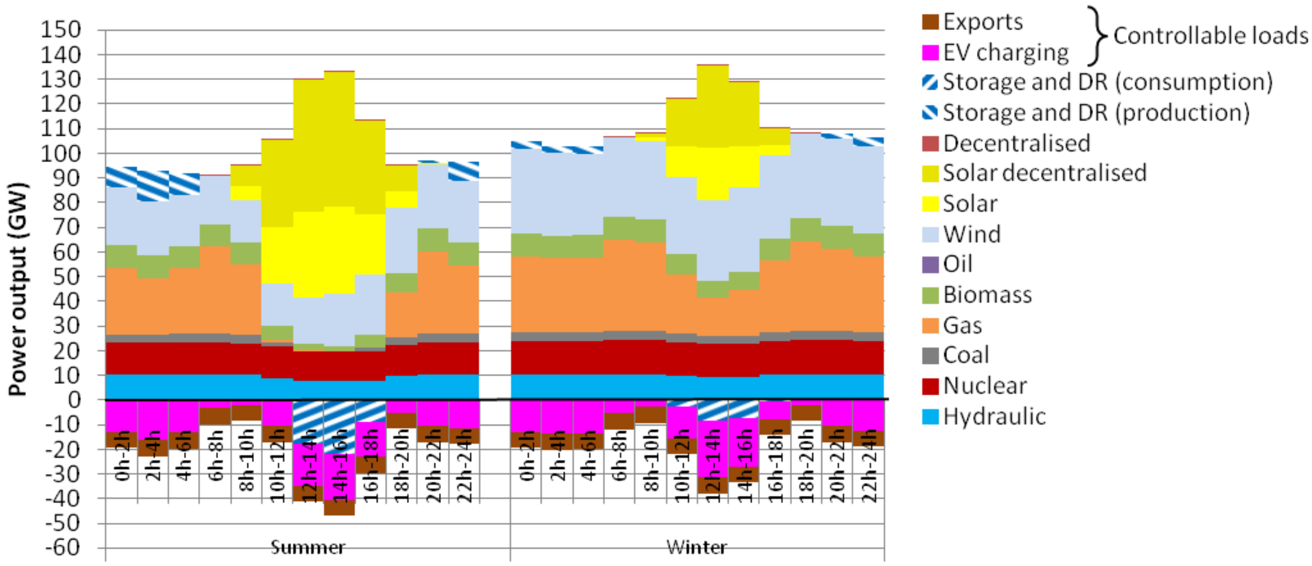


Figure 12: Power system operation in POLES without EUCAD, for the 24 two-hour blocks of 2050 ("2°C policy" scenario), in France.

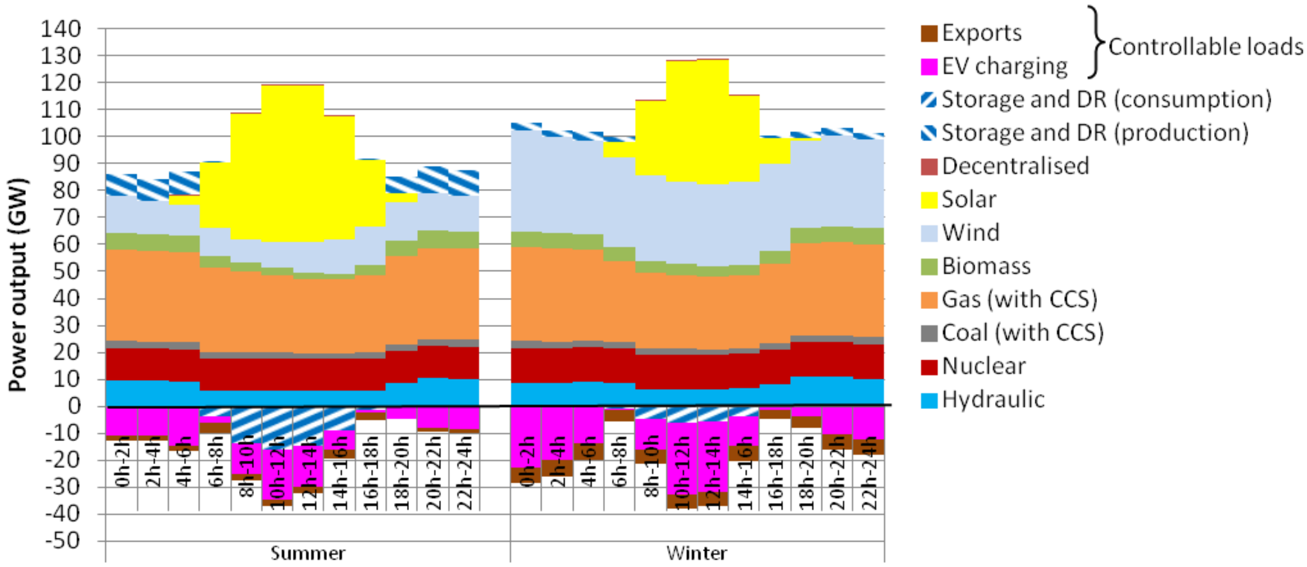


Figure 13: Power system operation in POLES with EUCAD (all typical days of wind and solar production are aggregated), for the 24 two-hour blocks of 2050 ("2°C policy" scenario), in France.

The power system operation in EUCAD uses more efficiently the flexibility options (e.g. EV charging and interconnections). They are better adapted to the residual demand, which allows thermal power plants to operate at an almost constant output. For example, the coal and gas power plants can operate more efficiently thanks to these flexibility options.

4. Sensitivity analysis on EUCAD modelling choices

In this section we carry out sensitivity analysis based on the European power system in the year 2050 for the “2°C policy” scenario.

4.a. Modelling equations

The fundamental equations of EUCAD are those handling the supply and demand balance, the maximum power output of a power plant, the interconnection limits and the storage capacities. All other equations (“minimum power output”, “maximum ramping”, “minimum on and off time”, “frequency reserve”) are used to describe some technical constraints. In this section we look at the impact of each of these technical constraints on the computation time[4] and the total operating cost, as an approximation of the importance of a given constraint on the optimisation. We also study the impact of these constraints on the structure of the power supply through two indicators: the daily production of storage and peak gas power plants (gas simple cycle plants and gas turbines).

[4] The computer used is a DELL laptop with intel core i7 processor, 2.80 GHz, with 8 Go RAM.

Indicator	Average computation time of a typical day (s)	Average daily European operating cost (million $ per day)	Average daily European storage production (GWh per day)	Average daily European peak gas plant production (GWh per day)
All equations	19.8	460.3	330	98.7
All equations except "frequency reserve"	19.7 (-0.5%)	460.3	330	98.7
All equations except "minimum on and off time"	13.0 (-34%)	460.8 (+0.1%)	331 (+0.3%)	99.5 (+0.8%)
All equations except "minimum power output"	9.0 (-55%)	452.6 (-1.7%)	321 (-2.7%)	89.2 (-9.6%)
All equations except "maximum ramping"	19.7 (-0.5%)	455.2 (-1.1%)	321 (-2.7%)	91.2 (-7.6%)

Table 1: Sensitivity of the European-wide optimisation to the operation constraints (the base case is the 2050 situation of the European power system under a "2°C policy" scenario).

In order to keep the computation time reasonable, we choose not to use the "minimum on and off time" constraint when coupling POLES and EUCAD. The other constraints are less time-consuming (maximum ramping, frequency reserve constraint) or have too much impact on the results (minimum power output and maximum ramping), and for this reason they are kept in the optimisation.

The power system is described on a technology by technology basis and not plant by plant. The installed capacities are aggregated per technology, with no plant-by-plant description. Therefore, the constraints of single power plants are less useful in our aggregated representation than in a unit commitment and dispatch representing every individual power plant. However, by lack of input data and computation time, it is not yet possible to use a plant-by-plant level of detail while coupling year-after-year EUCAD and POLES.

In a second approximation, we use relaxed mixed integer quadratically constrained (RMIQCP) algorithms, instead of mixed integer quadratically constrained (MIQCP) algorithms (as shown in table 1). When ignoring the "minimum on and off time" constraint, the average computation time of a single day drops to 2.8 second, thus making it possible to run 12 days per year, from 2000 to 2100 (the total computation time of a POLES+EUCAD run reaches 75 minutes).

4.b. Impact of the input parameters

We consider that the cost of unserved load is satisfactory since it is high enough to prevent any unserved load in all cases studied. This means that the system does not fail to supply electricity to consumers.

We also test several values for the key input parameters used in EUCAD. We focus particularly on the change in production of peak gas plants (gas turbines and gas simple cycle power plants) and batteries (stationary and in EV with V2G), as well as the coal and biomass production (which are closer to a base-load production).

First, we set the ramping costs to multiples of the base value [22] (see figure 14).

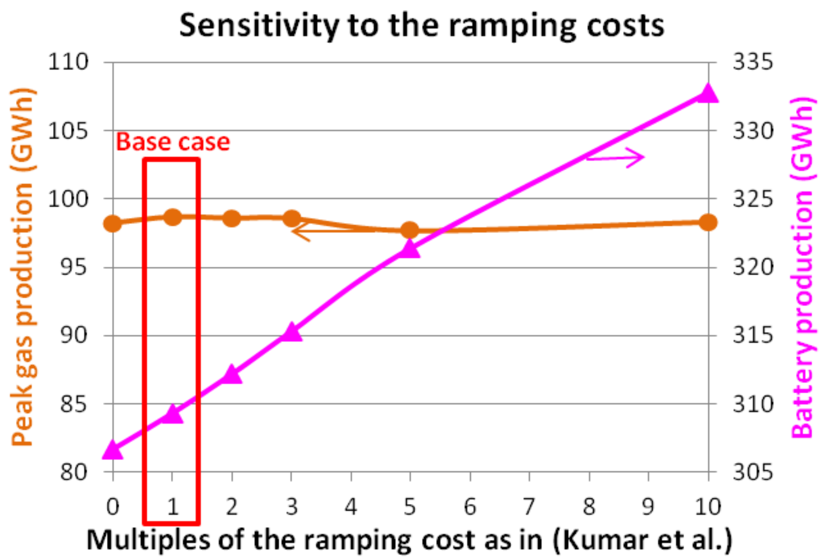


Figure 14: Evolution of the European daily peak gas production (left axis) and battery production (right axis) with the ramping costs of thermal technologies.

The ramping costs have a negligible effect on the production of peak gas power plants, but strongly impact the battery production: storage is more used when ramping thermal power plants has a higher cost. Indeed, storage has no ramping cost, and the efficiency losses are more easily compensated when ramping has a high cost for thermal power plants.

When we test the sensitivity of the technical limit for ramping capabilities of thermal power plants, we see a similar effect on battery production, together with a more important impact on peak gas power plants (see figure 15).

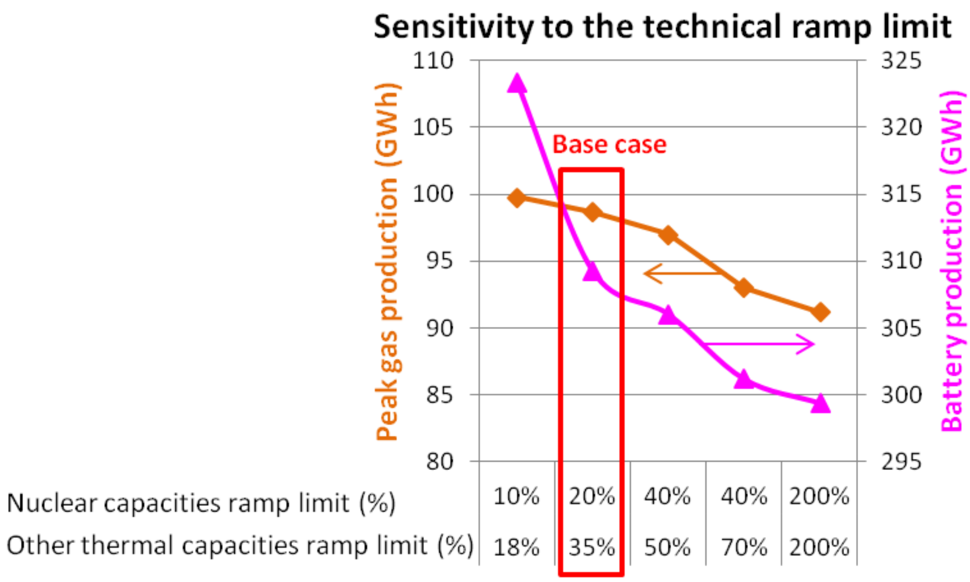


Figure 15: Evolution of the European daily peak gas production (left axis) and battery production (right axis) with the technical ramp limit of thermal plants (coal, biomass, gas and nuclear)

The stronger impact on peak gas plants is because when mid-load plants meet their technical ramping limit, peak plants are needed (when the constraint is only an economic constraint, this switch to peaking plants is not always necessary).

We also conducted a sensitivity analysis on the minimum power output. The impact of the minimum power output of nuclear and gas power plants is almost zero, but this characteristic for coal and biomass power plants has a high influence on the operation of peak gas power plants as well as coal power plants, as shown in figure 16.

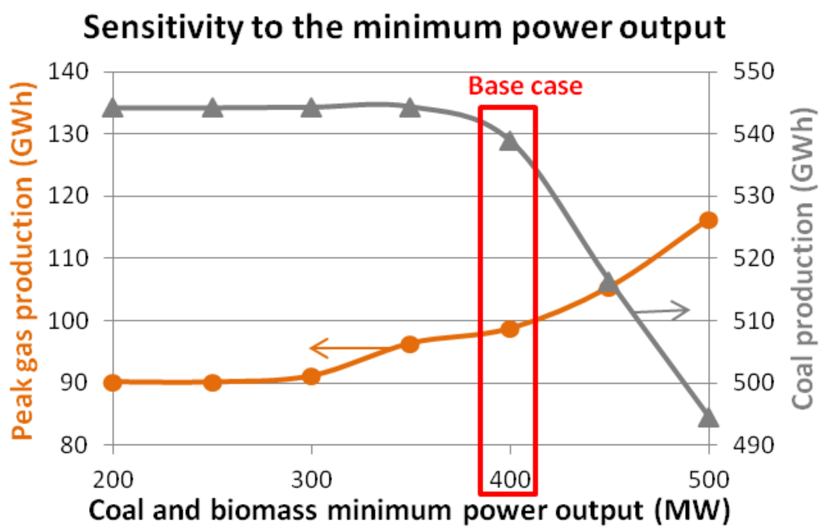


Figure 16: Evolution of the European daily peak gas production (left axis) and coal production (right axis) with the coal and biomass minimum power output

We see that a more severe constraint on the minimum power output for coal and biomass power plants shifts the production from base-load (in this case, coal) to peak-load (here, peak gas). The minimum power output of a technology seems to be a real constraint above 350 MW. This is visible although, as explained earlier, we do not have a plant-by-plant representation of the technologies.

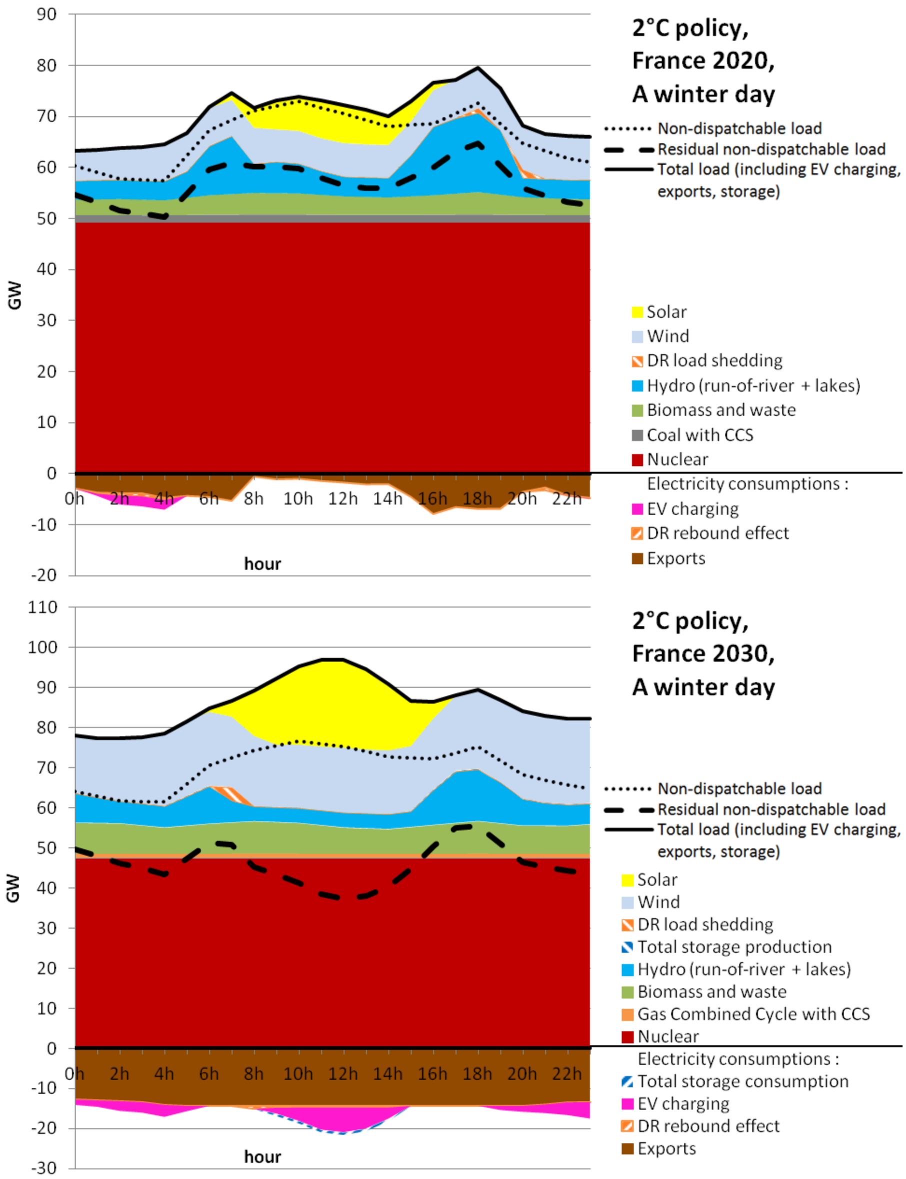
In conclusion, we have shown in this section the impacts of several key parameters in EUCAD on the production of the different technologies. Since it is difficult to forecast the evolution through time of these parameters, at this stage we keep them constant along the scenario.

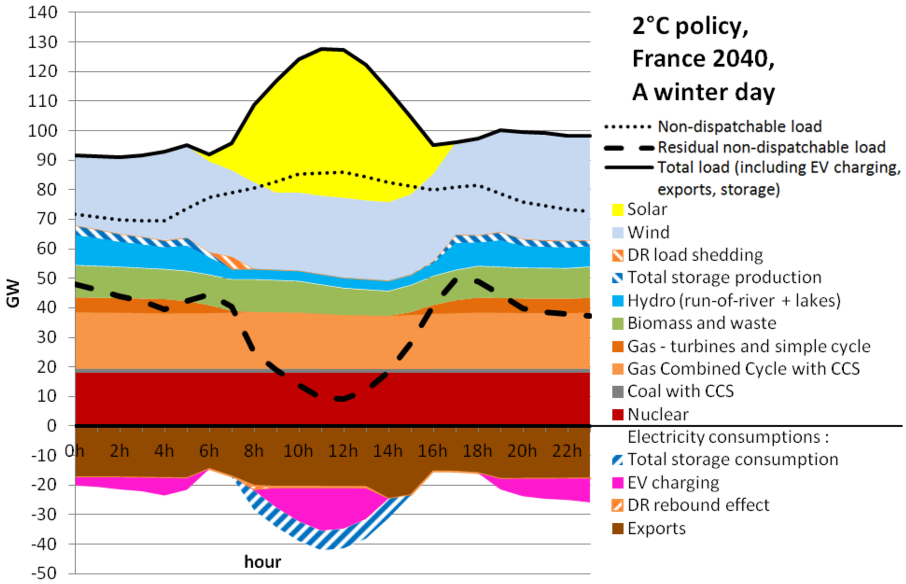
Conclusion

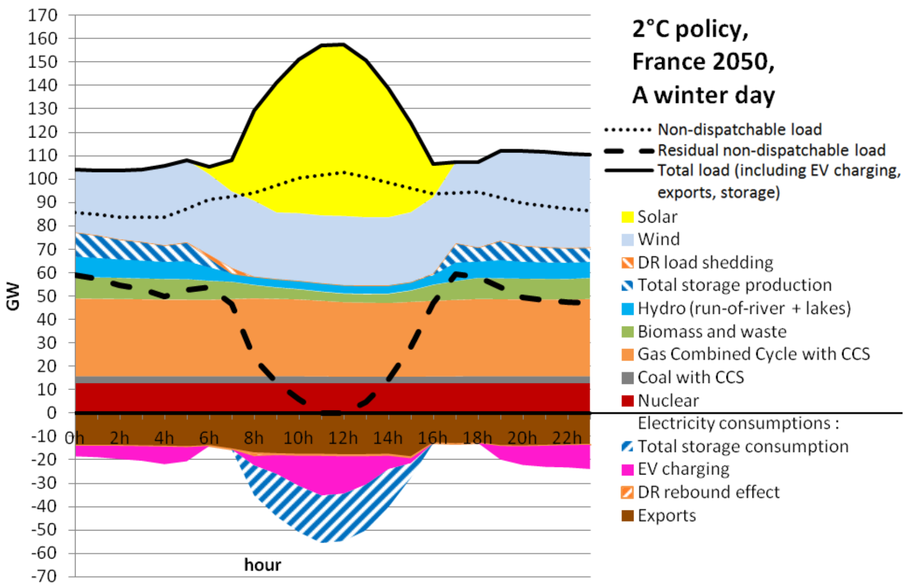
The linkage between POLES and EUCAD, and therefore two different programming languages (simulation for Vensim; optimisation for GAMS), and therefore between POLES and EUCAD, allows to combine the long-term coherence of an energy scenario (carried out in POLES) and the short-term operation detail for the power system (with EUCAD). Thanks to detailed operation constraints and a diverse set of representative days, the power system operation module of POLES is now more reliable and reflects the challenges of the integration of high shares of variable renewable energy sources. This paper analyses the deviations between EUCAD computation and the reality of the power system operation. The impact of the key equations and input parameters has also been studied.

In the new modelling, electricity storage, demand response programs, EV charging and interconnection operation are included in the power system representation. This contributes to a better description of wind and solar integration in the electricity sector. Therefore, the coupling of POLES with EUCAD brings crucial elements to the study of energy scenarios, in particular in cases with high shares of wind and solar power.

Appendix A: EUCAD operation of a same W&S day across a 2°C policy scenario




2°C policy,
France 2040,
A winter day
Non-dispatchable load
Residual non-dispatchable load
Total load (including EV charging, exports, storage)
Solar
Wind
DR load shedding
Total storage production
Hydro (run-of-river + lakes)
Biomass and waste
Gas - turbines and simple cycle
Gas Combined Cycle with CCS
Coal with CCS
Nuclear
Electricity consumptions :
Total storage consumption
EV charging
DR rebound effect
Exports
GW
hour
0h 2h 4h 6h 8h 10h 12h 14h 16h 18h 20h 22h
140 130 120 110 100 90 80 70 60 50 40 30 20 10 0 -10 -20 -30 -40 -50


2°C policy,
France 2050,
A winter day
Non-dispatchable load
Residual non-dispatchable load
Total load (including EV charging, exports, storage)
Solar
Wind
DR load shedding
Total storage production
Hydro (run-of-river + lakes)
Biomass and waste
Gas Combined Cycle with CCS
Coal with CCS
Nuclear
Electricity consumptions :
Total storage consumption
EV charging
DR rebound effect
Exports
GW
hour
0h 2h 4h 6h 8h 10h 12h 14h 16h 18h 20h 22h
170 160 150 140 130 120 110 100 90 80 70 60 50 40 30 20 10 0 -10 -20 -30 -40 -50 -60 -70

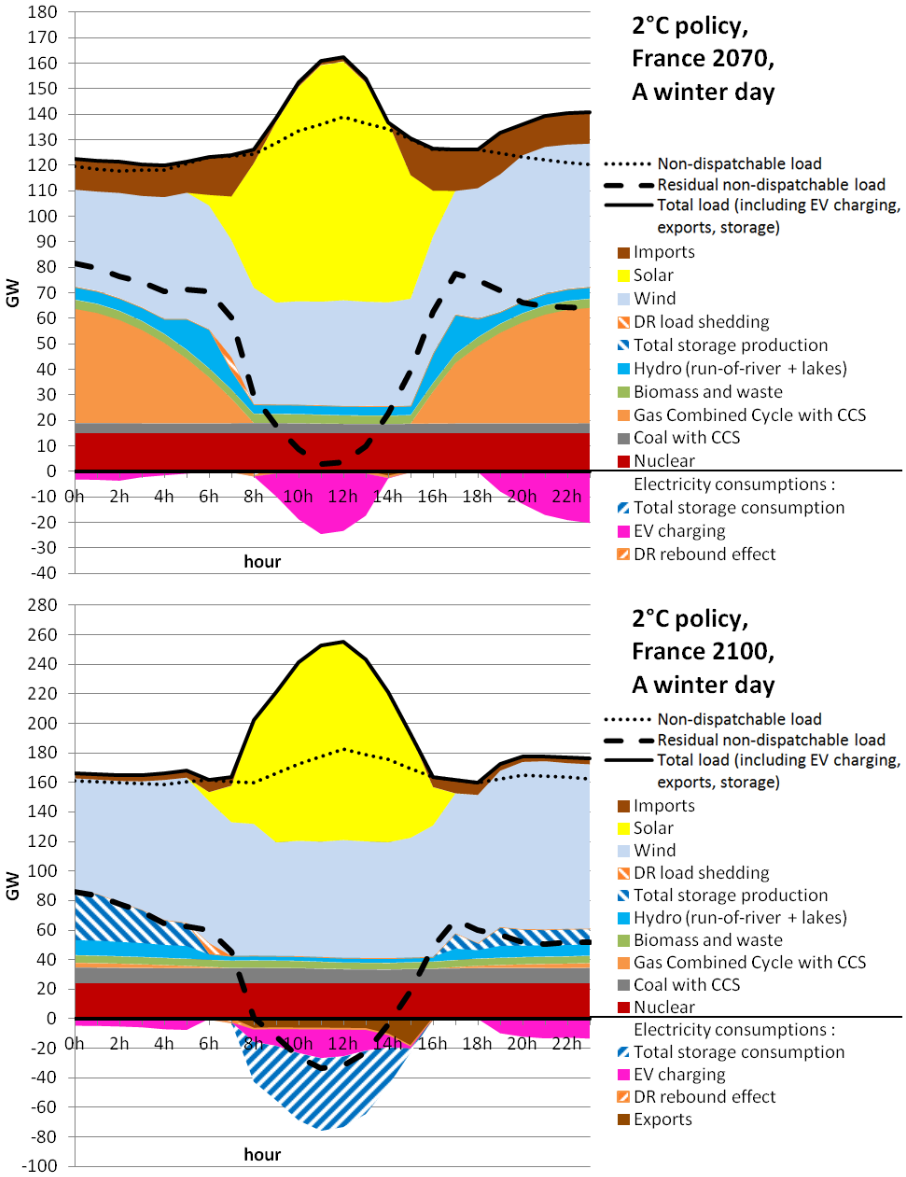


Figure A: Operation of the power system across an entire scenario, in France for a given winter day (2°C policy scenario).

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