A new, central role for hydroelectricity in the energy transition

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Introduction

Most European countries are now engaged in the energy transition whose ultimate goal is to meet energy demand from human activities solely with renewable sources. In its current intermediate stages, the transition steadily increases the penetration of nondispatchable electricity productions, which results in large uncontrolled fluctuations in power generation. Enforcing the balance between power demand and production under these circumstances becomes a challenge, which requires increased capacities of flexible, freely dispatchable power productions as well as storage solutions. Dam hydroelectric power plants are expected to play an important role in the energy transition. In the context of the liberalized pan-European electricity market, low carbon taxes, decreasing coal prices as well as subsidies for new renewables have however brought electricity prices down and eroded profit margins so much that new investments in the hydroelectric sector are all but frozen in alpine countries. It is therefore of utmost importance to investigate the future of the hydroelectric sector as the energy transition progresses.

In this manuscript, we construct an aggregated pan-European model for electricity production, transmission and consumption where European countries are represented by supernodes on an aggregated, equivalent electric grid. Each country's production capacity for 2030 is extracted from ENTSO-E's "2030 visions". A mathematical order of merit for dispatching each production is developed from cost functions calibrated to reproduce 2015 data. Increased penetrations of new renewables leads to large daily, weekly and seasonal fluctuations in power generation which govern dam productions in countries with large hydroelectric capacity - such as Norway and Switzerland. Conversely, dam productions from these countries will be invaluable to ensure a smooth, economically viable energy transition, minimizing production curtailment and ensuring a safe, stable supply of electric power.

1. Background

The European Union has set itself ambitious targets for increasing the penetration of renewable energy sources (RES).[1] It has been recognized long ago that the resulting large, fluctuating but nondispatchable power productions will strongly affect the pan-European electric power grid. A large number of studies exist, which attempt to predict the impact of this energy transition on the way we produce, transmit and consume electric power. The complexity of the pan-European grid motivated to construct aggregated, equivalent models (often referred to as "regional" models) where the grid's busses are grouped into regions. This aggregation allows to keep a certain level of geographical resolution, while still allowing to visualize the model and understand its specificities qualitatively. A second difficulty is to predict future power dispatches, based on technical and economical constraints on the various future types of production, their capacity and geographical distribution. We give a necessarily incomplete survey of these two aspects of the problem before discussing our own electric power and dispatch model.

1.1 Equivalent models

Equivalent aggregated models have a relatively long history. From a mathematical point of view, elements in the power grid that are assumed unnecessary - based on subjective or objective criteria - are neglected and the parameters of the resulting grid are adapted to try and obtain realistic aggregated flows on the remaining lines connecting the remaining busses.[2,3,4,5,6] Recent investigations focus on power-market simulations[7] where geographically simplified models are used to predict some of the power grid's future behavior under various scenarios of production and consumption changes, upgrades to the grid, market evolution and so forth.[8,9,10,11,12] It is important to realize that, no matter how much effort one puts into these models, internodal flows generally differ from the aggregated sum on the physical lines[12] because parallel and loop flows on neglected lines are missing. How big the discrepancy is depends on how aggregation was performed and on the chosen regional subdivisions.

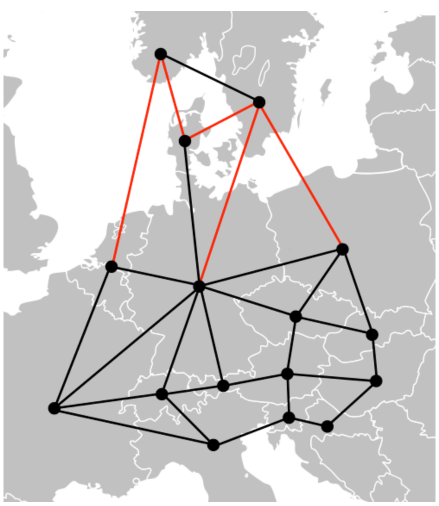
1.2 Dispatch models / optimized power flows

Once an aggregated model is constructed, production forecasts are made based on dispatch models. The latter include technical constraints such as ramp rate and maximal capacity for each production type, as well as economical indicators such as production costs, CO_2 and other taxes, prices of combustibles and so forth. Except for ramp rates, all these ingredients come with often large uncertainties typical of politico-economical forecasts.[7,8,9,10,11,12] Of particular interest in such studies is to identify what upgrades and additional backup systems are needed, if any,[10,13] and to optimize investment costs for grid upgrades and the addition of backup energy and capacity against the resulting levelized price of supplied electricity.[9,11] Existing dispatch models only seldomly deal with dam hydroelectricity, due to the complexity inherent to this production type - the dispatch of dam power plants is flexible on time scales of few minutes or less and depends on a variety of short-, mid- and long-time contracts, depending on the plant capacity, its location, its owner and so forth. One of our main results to be presented below is that a simple dispatch model based on well-known technical constraints combined with a simple, self-consistent cost function reproduces past production time series with a remarkable accuracy. The latter is expected to become even better in the future electricity market.

2. An aggregated model for future pan-European electricity dispatch

We develop a tractable model of the European grid to determine future power dispatches in the pan-European power grid at different stages of the energy transition. In Section 3. we present calibration data reproducing 2015 productions country-by-country and hour-by-hour and then move on to apply the model to predict the productions in 2030, using the planned capacities of different types of production. Our model consists of an aggregated version of the power grid, where each zone is described by a single node.

2.1 Aggregation



CH-FR	6.3	DE-AT	3.0	HR-SI	2.1
CH-DE	5.4	IT-SI	1.2	AT-AT	2.1
CH-IT	4.8	PL-CZ	2.4	DE-DK	2.4
CH-AT	3.6	PL-SK	1.8	SE-NO	3.0
FR-NL	3.3	CZ-SK	3.0	NL-NO	0.7
DE-NL	5.4	CZ-AT	2.4	DE-SE	0.6
FR-DE	5.1	SK-HU	1.8	PL-SE	0.6
FR-IT	3.0	HU-HR	2.7	DK-SE	1.3
DE-PL	3.6	HU-AT	2.4	DK-NO	1.6
DE-CZ	3.6	AT-SI	3.0		

Fig. 1 (left): Aggregated model of the Central and Northern European grid. Each node represents a dispatch zone. The lines represent interconnections: AC connections are in black and DC connections in red. Table 1 (right) thermal limit power of each connection in GW.

Our motivation to construct an aggregated model is twofold. First, aggregation allows to obtain readable, qualitatively understandable results, and second, it keeps the system size small enough that it is easily solved with short computation times. Conversely, this allows us to perform many different calculations to compare different scenarios while varying cost functions, parameters in our order of merit and so on. Fig.1 shows our aggregated European grid, with each node representing an independent dispatch zone. Consumptions and productions are aggregated within each dispatch region and attributed to the corresponding node. We use the same aggregated model for 2015 and 2030.

2.2 Productions and Consumptions

Power productions are subdivided into two sets. They are,

- **Non-flexible productions,** consisting of run-of-the-river (RoR), solar photovoltaics (PV) and wind turbine productions, as well as baseload productions such as biomass, geothermal plants and incinerators, which we group into "miscellaneous productions". Note that some RoR plants have a small pondage which allows them to slightly modulate and optimize their production on a daily basis. This feature gives small variations of production, even on a pan-European scale, and it is therefore neglected in our model. The profiles of inflexible productions are known at the beginning of the dispatch process and are extracted from existing data for the year 2015.[15]
- **Flexible productions:** They consist of all remaining productions. We classify them into 5 types, which are (i) dam hydroelectricity, (ii) gas and oil, (iii) nuclear, (iv) hard coal and (v) lignite productions.

Data for power consumptions of 2015 are taken from the ENTSO-E platform,[14] which we cross-checked with data available from individual transmission system operators (TSOs). For each zone and at each time, we define the *residual consumptions* $C_{Ri}(t)$ as the difference between the consumption and the non-flexible productions, i.e.

$$C_{Ri}(t) = C_i(t) - \mathrm{P}_i^{\mathrm{nflex}}(t),$$

where $C_i(t)$ and $\mathrm{P}_i^{\mathrm{nflex}}(t)$ respectively give the consumption and the sum of the non-flexible productions at time t in the ith zone. In our investigations of the 2030 power dispatch, we keep the same consumptions as in 2015. While a consumption increase may be expected from the European demographic momentum, energetically more efficient households (thermal insulation; heat pumps substituted for resistive heaters) and other electric devices will counterbalance this increase. We assume here that the two effects cancel. In any event, existing forecasts and planifications seem to agree that electric consumption is not going to increase by more than few percents, and that its time profile is not going to change drastically between now and 2030.[15]

ENTSO-E proposes various scenarios for future electricity production, with different energy mixes. A list of expected future capacities and yearly RES productions in 2030 can be found in Ref.17. Here, we follow the *Vision 4* scenario, which has the highest penetration of RES. The 2030 RES production profiles are obtained by scaling up the 2015 profiles according to the capacity increases in that scenario. It is important to note that this procedure retains important time correlations, such as meteorological correlations, between the different RES zonal productions.

Our task is to dispatch all flexible productions so that their production is equal to the total residual consumption at all times - this is equivalent to satisfy the condition that consumption is equal to production at all times. The power generated by each production type, labelled k, in each geographical zone, labelled i, and at each time t is represented by a function $P_i^k(t)$ which needs to satisfy the constraint

$$0 \leq P_i^k(t) \leq \; P^k_{\mathrm{max}i},$$

that it never exceeds its maximal installed capacity $P^k_{\mathrm{max}i}$.[14,17]

2.3 Economic dispatch

Our dispatch algorithm follows a merit order. The latter is based, first, on marginal costs, a^k, specific to each production type, k. These marginal costs are listed in Table 2. We fixed them starting from the values in Ref.15, which we then adapted to better reproduce the actual 2015 production profiles. Second, we introduce *repulsion costs*, b^k, which progressively increase the total production cost as the production increases and reaches its maximal possible value. This ensures that full power is engaged only when it is really needed. Repulsion costs parameters are also listed in Table 2. With these two parameters, the production cost in the ith zone at each time step Δt=1h is given by a sum over the marginal and repulsion costs for all production types as

$$W_i(t) = \sum_k (a^k P_i^k(t) + b^k [P_i^k(t)]^2 / P^k_{\max i}) \Delta t \, .$$

This formula makes it clear that repulsion costs are negligible at low production but become more and more important as the production increases, until they dominate the total production cost.

Our algorithm determines the production profiles $\{P_i^k(t)\}$ which minimize the total, annual generation cost

$$\mathrm{W}(\{P_i^k(t)\}) = \sum_{i,t} W_i(t) \, ,$$

under certain technical constraints. We already mentioned above that each production cannot exceed its maximal planned installed capacity. Further constraints are given by finite ramp rates, specific to each production type, which limit the rate at which given productions increase or decrease. Effective ramp rates, r^k, for each production types are listed in Table 2. They are smaller than the maximal technically allowed values, which can be attained only in ideal conditions which should be monitored plant by plant. This information is however lost in our aggregated model. Our effective ramp rates have been calibrated so that production profiles reproduce historical data qualitatively, if not quantitatively. The associated constraint on the flexible productions read

$$-r^k P^k_{\max i} \leq P_i^k(t) - P_i^k(t - \Delta t) \leq r^k P^k_{\max i} \, .$$

Production type, k	Marginal cost a^k [GWh^{-1}]	Repulsion cost b^k [$\mathrm{GWh}^{-1} \cdot \mathrm{Pmax}^{-1}$]	Ramp rate r^k [h^{-1}]
Dam	90	18	1.00
Gas	60	60	1.00
Nuclear	25	20	0.20
Hard Coal	35	35	0.20
Lignite	20	20	0.10

Table 2. Effective parameters describing the different flexible productions.

Further constraints are related to the aggregated thermal limit power on interregional lines. We discuss them next.

2.3 Power flows

Electric power production is equal to consumption at all times at the European level, but not at the level of individual nodes. We calculate the resulting electric power flows between regional nodes using standard power flow methods in the DC lossless approximation.[16] Aggregated lines have admittances obtained via a standard reduction method[6] and thermal limits given by the sum of the physical lines they represent. Norway and Sweden are not synchronous with the European grid with which they are connected via DC lines. The flows on DC lines are in principle controlled via power electronics by TSOs. There are therefore arbitrary up to the extent that they should not violate any of the constraints already mentioned, nor should they exceed the thermal limit of the line that carries them. In our model, we represent DC lines as modified production or consumption at the nodes they connect.

2.4 Dam hydroelectric power plants

Beside ramp rates discussed above, production from dam hydroelectric plants is constrained by the finiteness of their reservoir and the annual water intake into the latter. This means that production must stop before reservoirs are empty and that it should increase before reservoirs overflow. Additionally, the annual production corresponds more or less to the potential energy added by the annual water intake. In our model, we impose that production and intake are equal. Production profiles are more precise for Switzerland, for which we found more precise time series for energy intake into the reservoirs.[18] Pumped-storage (PS) plants produce at times of high electricity prices and consume (pump) when electricity is cheap. To model this, we base the operation of PS plants on the total European residual consumption. The latter is expected to be a good indicator of electricity "prices" as it measures the demand for flexible productions. We found, but do not show here, that there is indeed a high correlation between residual consumption and day-ahead electricity prices. In our model we assume that PS plants have the same pump and turbine power, which is constrained at each time by the PS installed capacity, individually in each region. The filling $S_{\mathrm{PS}i}(t)$ of PS reservoirs evolves at each time step as

$$S_{\mathrm{PS}i}(t+\Delta t) = S_{\mathrm{PS}i}(t) + \eta P_{\mathrm{p}i}(t) \, \Delta t - \eta^{-1} P_{\mathrm{t}i}(t) \, \Delta t,$$

with a pump/turbine efficiency of $\eta = 0.9$ and the pump/turbine powers $P_{\mathrm{p}i}(t)$ and $P_{\mathrm{t}i}(t)$. The filling cannot exceed the maximum reservoir level. Because we could not find a complete list of storage capacities, we used $S^{\max}{}_{\mathrm{PS}i} = 40P^{\max}{}_{\mathrm{PS}i}\,\Delta t$, based on an average value over the data available and an optimization study to be presented below.

2.5 Implementation and remarks

We found that our dispatch algorithm leads to significantly larger flows, often too close to the thermal limits of the lines. TSOs would not let this happen in real life and to solve this problem, we introduced a *flow cost* that penalizes situations where the power flows are too close to their limits.

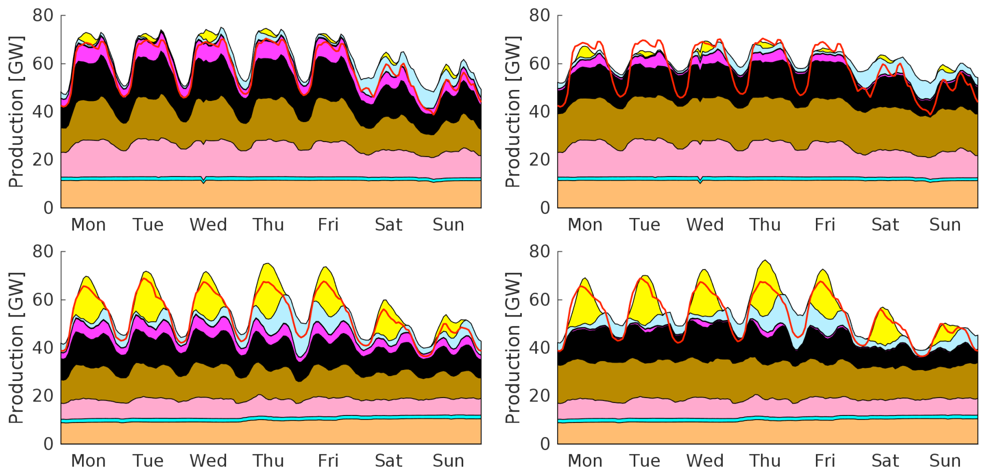


Fig. 2. Dispatched (left) and actual 2015 (right) production of Germany for a winter (top) and a summer (bottom) week. Production types are: nuclear (orange), RoR (cyan), miscellaneous (pink), lignite (brown), hard coal (black), gas (purple), dam (blue), wind (light blue) and PV (yellow). The red curve indicates the 2015 national consumption.

All previously presented variables form an optimization vector. Each feature of the model (cost or constraint) can be expressed via either a vector or a matrix acting on the optimization vector. Our dispatch algorithm is thus a quadratic programming problem which is solved with a dedicated software. We used the Gurobi solver.[19]

Our dispatch algorithm assumes a single pan-European electricity market, which differs from the current situation. Deregulation and liberalization are however expected to unify European electricity markets in the future making it closer to our model.

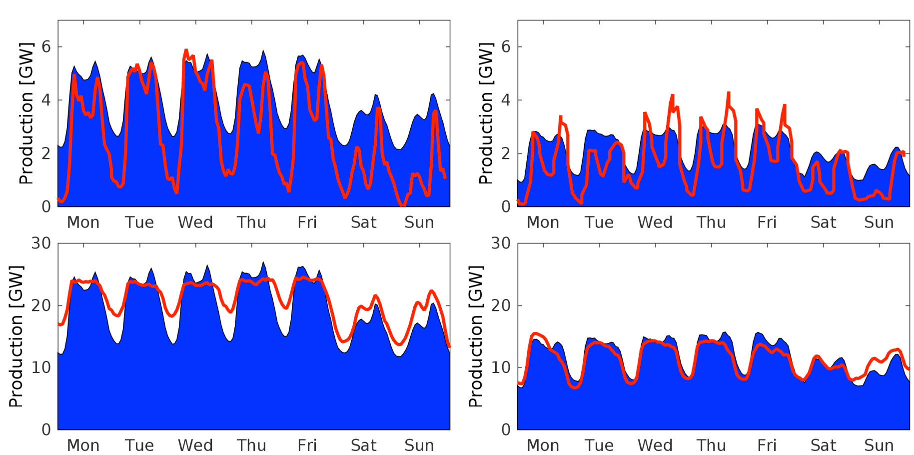


Fig. 3. Dam production of Switzerland (top) and Norway (bottom) for a week in winter (left) and summer (right) in 2015. Dispatched productions are displayed in blue and actual 2015 production profiles are in red.

3. Model Calibration

To calibrate the parameters in our model we try and reproduce 2015 production data. In Fig.2 we show the result for a winter and a summer week in Germany. The agreement between dispatched and actual production is excellent, with small discrepancies emerging from overestimated variations in lignite and hard coal productions. It seems that the flexibility of these two production types is currently not used, probably because their production costs are very small anyway. We have found, but will show elsewhere, similar degrees of agreement between dispatched and actual productions for all other countries with very different production mixes.

One focus of the present manuscript being dam hydroelectricity, we check that we correctly capture this production. Fig. 3 displays the productions of Swiss and Norwegian dam hydroelectric plants during one week in summer and winter. Despite the inherent difficulty to dispatch dam hydro production, we see that our relatively simple model catches most features of the 2015 production qualitatively and almost quantitatively. Production flexibility is slightly underestimated in Switzerland and overestimated in Norway, which perhaps can be attributed to existing mid- to long-term contracts or discrepancies already mentioned in lignite and hard coal productions. Aside from that the agreement between numerically calculated and actual data is excellent. With these tests, we conclude that our model, with the parameters described above and listed in Table 1 and 2, is correctly calibrated and we therefore validate it to forecast 2030 productions. We note that dam hydro is often neglected or at best summarily treated under a number of ad hoc approximation in all studies similar to ours we are aware of. In particular we have never found time series for simulated, dispatched dam hydro productions. That our approach allows to treat hydroelectricity on an equal footing with other productions is its great advantage.

4. Hydroelectric production and the energy transition

We next investigate the role of hydroelectricity in 2030, when the energy transition will have reached some maturity level where RES are one of the main production types, which will make it very problematic to absorb and mitigate the associated fluctuating productions.

Our unified pan-European economic model predicts electricity costs via the European residual consumption. The operation of PS plants depends on their rated power and maximal stored energy. It follows closely electricity prices and we first determine a ratio maximal stored energy/rated power which optimizes the gains a plant can make against the maximal possible gain. Alternatively, this ratio gives the minimum charge/discharge time of the PS plant.

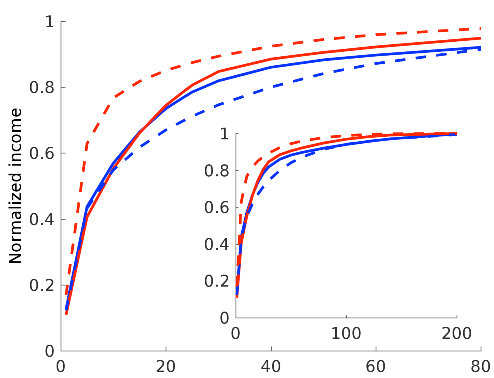


Fig.4. Normalized income of a PS plant as a function of its minimal charge/discharge time. Income calculated using the European residual consumption as cost function. Different curves correspond to winter (blue) and summer (red) periods for 2015 (solid) and 2030 (dashed).

In Fig.4 we show the normalized income (income calculated from the residual consumption divided by maximal income obtained if any opportunity to generate benefits can be seized) vs. the minimum charge/discharge time. It is seen that the income grows with the charge/discharge time, but that a 40 hours charge/discharge time already allows to generate more than 80% of the benefit one would get with an infinite maximal stored energy. While in 2015, the income is essentially the same in summer as it is in winter, one further observes that in the 2030 market, significantly more income is made in summer than in winter at fixed charge/discharge ratio, which we attribute to the daily fluctuations of PV production. Finally, PS plants with charge/discharge times larger than 200 hours effectively act as infinite storages. The soon operating swiss PS plants of Nant-de-Drance and Linthal2015 have charge/discharge times in the range 25-50 hours and are thus optimized for summer production. From the data presented in Fig.4, and in agreement with an average we took over a set of PS plant available to us, we calibrate all PS plants in our aggregated model to a charge/discharge time of 40 hours.

Increasing the penetration of RES changes the operating mode of dam hydroelectricity, in particular, in countries where the RES will be dominated by PV causing high summer and low winter RES productions. Fig.5 shows first that when RES have low production (first five days), dam productions are high to help supplying the demand for electricity. When RES productions are high, for instance during the first four days in the second week displayed, with strong winds in the Germany, dam production is significantly lowered. Note in particular that Switzerland imports a significant fraction of its consumption during several consecutive days, which is never the case nowadays. This illustrates the key role of demand-supply regulator that hydroelectric plants will play in the future pan-European market with strong penetration of RES.

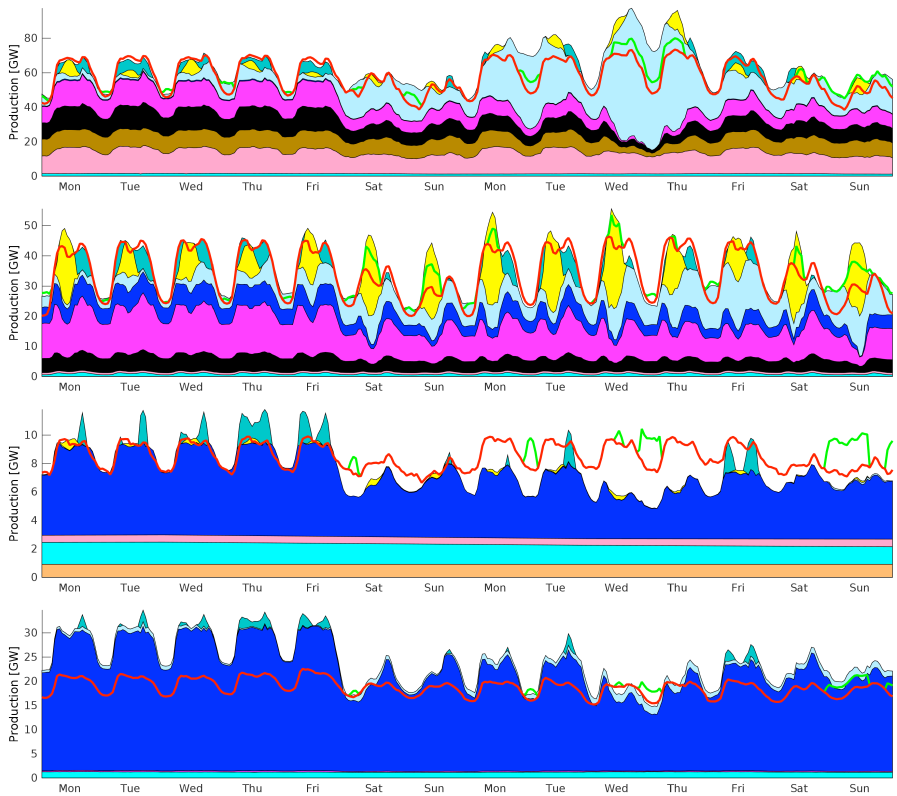


Fig. 5. Top to bottom: electricity productions of Germany, Italy, Switzerland and Norway for one 2030 winter week. Color convention is as in Fig. 2, with additionally, PS production (turquoise) and PS consumption (pumping; green line).

Dams need to absorb the variations of PV production, which are twofold. First, there are seasonal variations, PV producing mode in the summer in the northern hemisphere, and second there are daily fluctuations. We found that Swiss dams can play an important role in absorbing the seasonal fluctuations, being able to shift up to 2TWh of production from summer to winter.[20] In our pan-European model, we found comparing 2015 and 2030 productions that about 1 TWh has been shifted by an optimized dam operation mode.

Fig.6 finally illustrates the role of PS plants in the 2030 pan-European electricity market. During summer weeks, PS plants will work at close to maximal capacity on an almost daily basis, compensating the lack of production before and after the PV production peak and consuming more during that peak. We conclude that PS plants will play a crucial role in mitigating RES daily and relatively short-term fluctuations.

Conclusion

We developed a pan-European electricity dispatch model. Using a mathematically well-defined merit order, we calibrated it so that it reproduces 2015 production profiles. We investigated how productions will change in 2030 and showed that dam and PS hydroelectricity will be invaluable to mitigate the seasonal, weekly and daily fluctuations of RES productions. Hydroelectricity will be a key instrument for the energy transition.

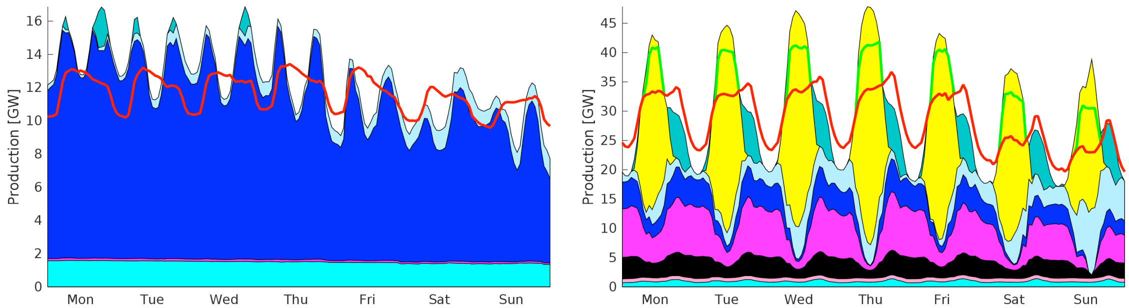


Fig. 6 Electricity productions of Norway (left) and Italy (right) for one week in summer 2030. The color convention is the same as in Fig. 5.

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