Market designs for a 100% renewable energy system

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Preface

This research was conducted within the Neo-carbon energy project, funded by Tekes, the Finnish Funding Agency for Innovation. The research work was carried out between December, 2015 and June, 2016. The objective of the research work was to propose and simulate market design options for a 100% renewable energy system.

Olga Gore, Dmitry Bogdanov, Kaisa Salovaara, and Samuli Honkapuro

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1. Introduction

Mitigation of climate change is increasingly pushing energy systems towards decarbonization. Often, this is achieved by increasing the proportion of renewable energy production (wind, photovoltaics, biomass, and biogas) in the system. Transformation into a 100% renewable electricity system (RES) will require markets to accommodate the operational specifics of renewable energy generation. Numerous studies have shown the potential and technical feasibility of 100% RES in different regions. These studies apply a regulatory model and provide a vision of a cost-minimum 100% RES, yet do not specify a transition path to it. Models on country-specific renewable systems of various degrees have been made for Australia [1], Denmark [2], Finland [3, 4], Germany [5], Ireland [6], Portugal [7], and even on a global scale [8]. However, as long as most of the electricity markets are deregulated, the question remains: what kind of a market design is feasible in the fully renewable system?

The existing deregulated electricity markets can mainly be classified as energy only markets or energy plus capacity markets. Energy only markets trade electricity (€/MWh) and, without regulatory intervention such as price caps, are believed to provide adequate cost recovery [9]. Renewable production technologies have typically a low marginal cost and a high volatility, which reduces the price level and raises concern over capacity adequacy. A high proportion of variable renewable energy production needs complementary flexible capacity in order to maintain power balance. In addition to dispatchable generation such as biomass plants, demand-side management [10], energy storages [11, 12], and enhanced use of transmission connections [13] are often assumed to be the main sources of flexibility. If markets fail to attract sufficient capacity to meet certain reliability standards, capacity mechanisms could be introduced. The purpose of capacity mechanisms is to ensure the profitability of the existing power plants and to guarantee or at least support investments [14]. There are different forms of capacity remunerative mechanisms ranging from capacity auctions and capacity payments to strategic reserves (SR) [15].

To the authors' knowledge, the literature fails to acknowledge simulations on fully renewable markets to understand if the current energy only market or the energy plus capacity markets are suitable to provide investment incentives and operate 100% RES reliably and economically. Some studies focus on analyzing the possible effect of renewables on the wholesale prices [16–18], yet do not contribute to the question of the preferred market design. [18] provides qualitative analysis of market design options for the 100% RES and concludes that the current energy only model may be suitable for a fully renewable system by adopting certain market rules. The study also discusses more radical market design options such as compensating generators by the average production or long-term marginal costs while maintaining the marginal-cost-based dispatch or introducing long-term feed-in tariffs or technology-specific auctions with an obligation to supply power. However, with the long asset lives of the electricity industry, the viability of different market options has to be carefully evaluated quantitatively.

This paper fills the research gap and tackles the question about the market designs that provide cost recovery and continuous investments in the 100% RES. The European policy discussions seem to focus on developing energy only markets instead of the more radical design options [20–22]; therefore, we rather focus on testing the feasibility of existing market design models in the 100% RES. By using a dynamic power market model based on a behavioral simulation approach, numerous existing market models are tested numerically and analyzed with respect to the short-term operation of the technologies and the long-term development of the generation mixes in the 100% RES, and compared in terms of reliability and costs for the consumers. The paper is structured as follows. Section 2 details the modeling approach we have used to test the market design options numerically. Section 3 presents the input data. The results are given in Section 4, while Section 5 provides a conclusion and policy implications.

2. Methodology

Energy system models can be divided into market and regulatory models. Regulatory models provide an optimal cost-minimum energy system structure without taking into account the market mechanisms. Considering market models, an example could be agent-based models, which usually apply a behavioral simulation approach, and the final structure of the system depends on the market rules applied to the agents and their corresponding behavior. The system resulting from these models may not be optimal, and is strongly driven by the set of market rules applied and assumptions made on the market behavior of different agents in the system. A behavioral simulation approach has been widely used to understand the long-term dynamics of liberalized electricity markets and analyze the impact of energy and environmental policies as well as market designs on the long-term evolution of power systems [23–26].

This paper presents a dynamic power market model developed by the lead author in Matlab R2013b. The model was developed to analyze and understand the impact of market design rules and policies applied to market players on the short-term operation and long-term development of the 100% RES. The model reflects realistic markets conditions and is close to real-world short-term operating and long-term investment decision-making processes.

At this stage, we are not proposing radical market design changes as described in [19]. We rather focus on testing the feasibility of the existing market design models in the 100% RES. Table 2 provides an overview of the market design options considered in the paper. In the following chapters, we present the methodology used to numerically test the market design options in the 100% RES.

Table 1. Market design options

	MARKET DESIGN	ELECTRICITY MARKET	CAPACITY MECHANISMS
EO	”ENERGY ONLY” MARKET	POOL WITH Marginal pricing	No
EO-CA	”ENERGY-PLUS-CAPACITY” MARKET	POOL WITH Marginal pricing	Pay-as-bid Capacity Auction
EO-SR	”ENERGY-PLUS-STRATEGIC RESERVE” MARKET	POOL WITH Marginal pricing	Strategic reserve

2.1. Model description

The main principle of the model is given in Figure 1. The model comprises several modules: an electricity market model, where the power producers make their short-term hourly decisions on electricity sell volumes and prices; a capacity market module, where the producers sell their availability or capacity; an investment module, where the producers make their long-term decisions while assessing the profitability of new investments. Thus, the model has hourly and yearly resolution. The financial and technical characteristics of the technologies, the demand patterns, the fuel prices, and the capacity factors of wind and solar are given exogenously. There are six independent agents in the model, each representing a particular renewable energy technology: solar, wind, biomass, biogas, waste, and battery storage. The regulator represents a separate agent responsible for setting the market rules and ensuring reliability requirements if needed.

The simulation starts with an initial cost-minimum 100% RES for the reference year 2030. The initial system is a result of a regulatory energy system optimization model developed at the Laboratory of Solar Economy of Lappeenranta University of Technology. The model is based on a linear optimization of the system parameters under a set of applied constraints with the assumption of a perfect foresight of renewable power generation and power demand. For more details about the model, see [27]. We do not specify how the 100% RES would be achieved by 2030; it is outside the scope of the paper to model a roadmap and market policies designed to achieve the 100% RES. Rather, we are interested in analyzing what market designs will advance this scenario, that is, provide incentives for further investments and enable reliable operation of the 100% RES at the lowest possible costs for consumers. In other words, we want to simulate the possible market dynamics of the 100% RES showing possible and realistic short-term and long-term behavior of market players, market prices, and evolution of generation mixes over years depending on the market rules applied.

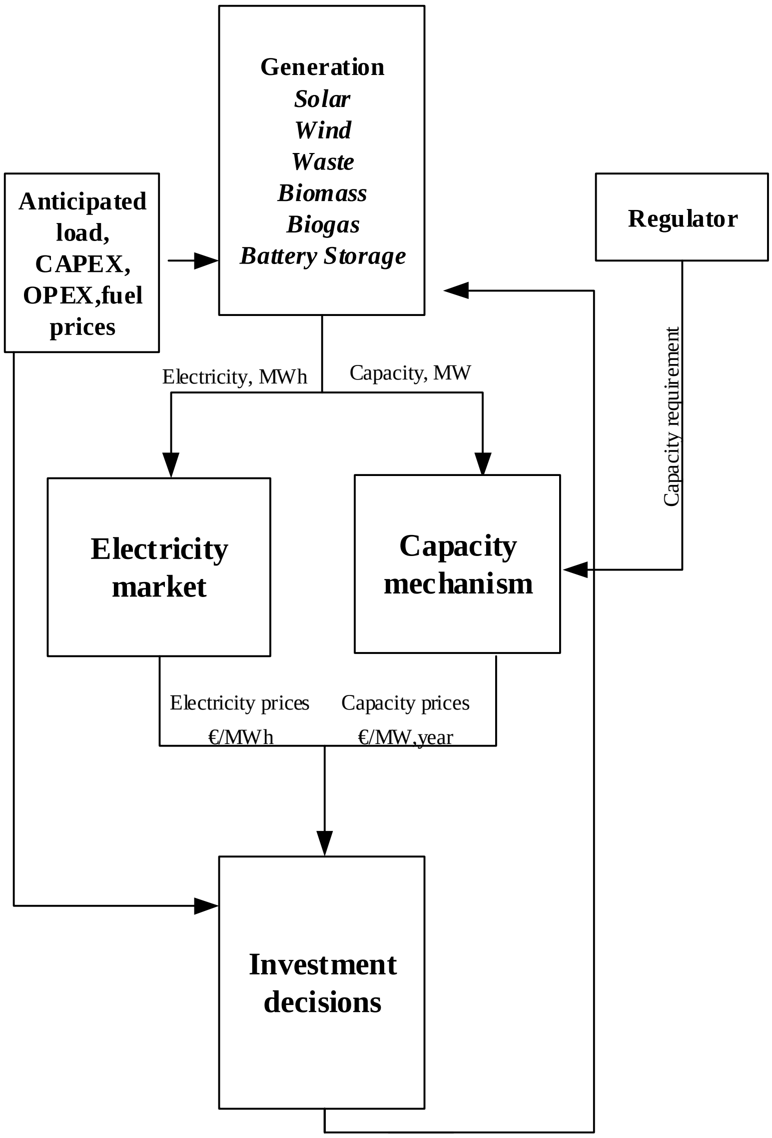

Fig. 1. Principle of the model

2.1.1. Electricity market

Electric energy is traded in pool-based electricity markets, where generators offer their hourly production at a bid price. Renewable energy technologies are divided according to their market behavior into two groups: undispatchable (wind, solar) and dispatchable (waste, biomass, biogas, battery storages).Undispatchable technologies offer energy irrespective of market prices; in the case of excess generation, solar and wind production is curtailed. All technologies, except battery storage, are assumed to bid at their marginal costs. The model does not consider minimum startup/shut down and ramping rates, which is a reasonable assumption because of the absence of large thermal power plants such as coal and nuclear. The marginal costs of wind and solar are assumed zero. We assume that feed-in tariffs will be provided on top of the marker price for solar producers. The marginal costs of biomass and biogas are defined by the costs of the corresponding biofuel. The battery storage is considered either a consumer or a producer depending on the demand/supply situations. The battery storage buys electricity at a low price when there is excess generation and sells it at a higher price in tight supply and demand situations. It has a complex bid curve in the market represented by both sell and buy bid curves given in Figure 2. The bid price of the battery storage depends on the stored energy available against the technical storage capacity in a given hour, reflecting the willingness to buy at the lowest possible market prices when the stored energy is high and avoiding being dispatched when the stored energy is low and other generation technologies are available. It allows the storage to produce whenever it is most profitable, thus saving the energy for the periods of tight supply. All other consumers are assumed to be completely inelastic, thus bidding at the highest possible market price or price cap.

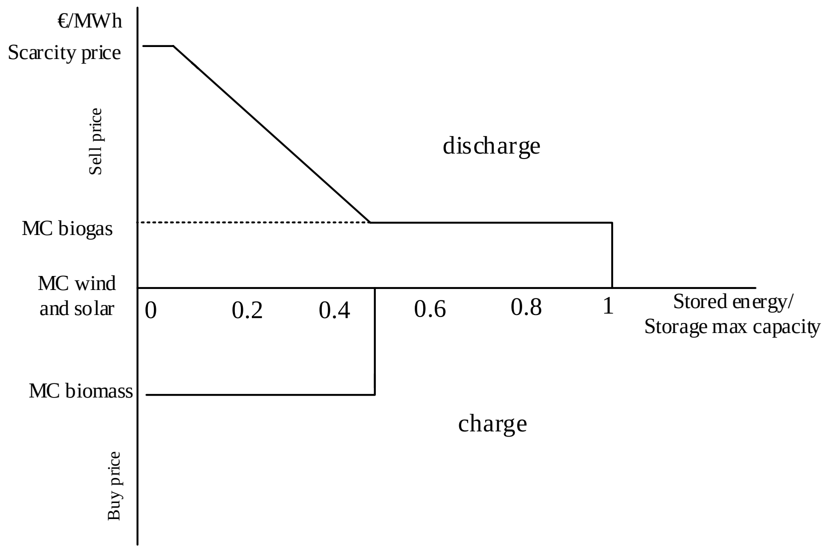

Fig. 2 Bid curve of a battery storage

Based on the bid curves of producers and consumers, the regulator runs the market clearing algorithm, that is, combines the supply- and demand-side bids and maximizes the total welfare by using the equations below. Market clearing optimization produces optimal sell and buy volumes and market clearing prices for each hour t. The market prices are set by the marginal cost of the most expensive producer that clears demand and supply.

$$\max \sum_{j=1}^{k} P_j(t) \cdot Q_j(t) - \sum_{i=1}^{n} P_i(t) \cdot Q_i(t) \quad (1)$$

$$\sum_{i=1}^{n} Q_i(t) - \sum_{j=1}^{k} Q_j(t) = 0 \qquad \text{(1a) power balance}$$

$$0 \le Q_i(t) \le Q_{i,max} \cdot cf_i, \quad \forall\, i \ne battery \qquad \text{(1b) production constraints}$$

$$S(t+1) = S(t) - Q_i(t)/\eta_{discharge} + Q_j(t) \cdot \eta_{charge}, \quad \forall\, i,j = battery \qquad \text{(1c) stored energy balance constraint}$$

$$Q_i(t) \le \min(\mathrm{S(t)} \cdot \eta_{discharge};\ Q_{i,max} \cdot \eta_{discharge}),\ \forall\, i = battery \qquad \text{(1d) discharge capacity constraint}$$

$$Q_j(t) \le \min((Q_{j,max} \cdot E_P - \mathrm{S(t)})/\eta_{charge};\ Q_{j,max}/\eta_{charge}),\ \forall\, j = battery \qquad \text{(1e) charge capacity constraint}$$

With:

i : index of producers

j: index of consumers

n : total number of producers

k: total number of consumers

$P_i(t)$: bid price of producers (€/MWh) at hour t

$P_j(t)$: bid price of consumers (€/MWh) at hour t

$Q_i(t)$: sell volume of producer i (MWh) at hour t

$Q_j(t)$: buy volume of consumer j (MWh) at hour t

$Q_{i,max}$: maximum sell capacity (for a battery storage: maximum discharge capacity)

$Q_{j,max}$: maximum buy capacity (for battery storage: maximum charge capacity)

$cf_{i,max}$: availability coefficients (or capacity factors for solar and wind)

$S(t)$: battery storage level at hour t (MWh)

$\eta_{discharge}, \eta_{charge}$: discharge/charge efficiency of a battery storage

E_P: energy-to-power ratio or charging rate of a battery storage (hours)

The constraints are power balance constraint (1a): in hour t, the total production should equal the total consumption; production constraint (1b): the production should not exceed the available capacity of a power technology and be negative. The available capacities of wind and solar in every particular hour are limited by their capacity factors, that is, the ratio of the actual energy that can be produced to the nominal capacity. The capacity factors depend on the solar irradiation and wind speed in the region, and are given exogenously in the model. Constraints 1c–e represent the battery storage constraints; these are stored energy balance constraint (1c); discharge capacity constraint (1d): the storage sell volume should not exceed the minimum between the stored energy available and the maximum discharge capacity; battery charge constraint (1e): the storage buy volume at hour t should not exceed the minimum between the available storage capacity and the maximum charge capacity. The sell and buy volumes are constrained by the maximum charging (discharging) rates, the hours within which it can store (withdraw) energy from zero (maximum battery energy capacity) to the maximum battery energy capacity (zero).

2.1.2. Capacity remunerative mechanisms

The energy plus capacity markets are separated between electricity and capacity trading: electricity markets are used for trading electric energy production (€/MWh) and to cover the variable cost of power production while capacity mechanisms are used to trade availability (€/MW) and provide additional revenue stream required to cover fixed costs. There are different types of capacity mechanisms ranging from strategic reserves, capacity payments, and capacity auctions. This paper focuses only on capacity auction and strategic reserve.

Capacity auction

For a capacity market, we assume that capacity auction is held only for new capacity. On the demand side, the regulator determines the required new capacity by taking the given peak demand plus the reserve margin and subtracting capacity of the existing power plants. The reserve margin is set by the regulator as required capacity that is needed on top of the expected peak demand to ensure generation adequacy. Producers sell their capacity certificates to the common capacity market pool. Capacity certification of new and existing power plants is performed by the regulator. By multiplying the normative capacity factors by the nominal capacities (installed capacities) of power plants, it defines their available capacity during peak hours. For dispatchable resources such as biomass, waste, and biogas power plants, normative capacity factors are equal to one minus the forced outage rate. The normative capacity factors of wind and solar are assumed zero. The normative capacity factor of the storage is assumed to be one, thus certifying 100% of its maximum discharge capacity for sale in the capacity auction.

On the supply side, the regulator collects all certified bids and subsequently, all bids are put in an ascending order to generate the supply curve that is matched with the capacity demand. The objective of the capacity auction is to minimize the total costs of capacity subject to the required new capacity constraints given by:

$$\min \sum_{i=1}^{n} Cbid_i \cdot IC_{i,new} \cdot CF_i \tag{2}$$

$$D_{peak} \cdot (1 + RR) - \sum_{i=1}^{n} IC_{i,exist} \cdot CF_i = \sum_{i=1}^{n} IC_{i,new} \cdot CF_i \tag{2a}$$

With:

i : index of a technology

n : total number of technologies

$Cbid_i$: capacity bid price (€/MW) of new power plants

D_{peak}: peak demand (MW)

RR: reserve ratio

$IC_{i,exist}$: installed capacity of an existing power plant (MW)

$IC_{i,new}$: installed capacity of a new power plant (MW)

CF_i: normative capacity factors of power technologies

$Costs(EO)$: strategic reserve annual costs from buying electricity

$Revenue(EO)$: strategic reserve annual revenue from selling electricity

Capacity auction is a pay as bid auction, where every accepted capacity receives the price of its capacity bid. We assume that investors bid the annuity of the profitability gap given in equation below. In other words, a capacity price of each project equals an annual payment necessary to increase the negative net present value (NPV) to zero. The capacity market ensures a payment at the level of the auction clearing price over multiple years.

$$Cbid_i = \max\left(0; -\frac{NPV_i}{\sum_{t=1}^{T}(1+r)^{-t}}\right) \tag{3}$$

With:

i : index of a technology

T : years of guaranteed capacity payments

NPV_i: net present value of new investments

Strategic reserve

The goal of a strategic reserve is to ensure that a certain amount of reserve capacity is available to safeguard the security of supply. While the main part of the market remains energy only, a strategic reserve is contracted in addition to the market capacity and is withheld from the spot market in favor of a central dispatch. The strategic reserve (SR) dispatched at the dispatch price is defined exogenously by the regulator. Setting the proper dispatch price is an essential element in designing the strategic reserve. For our analysis, we set the dispatch price at a price slightly higher than the marginal cost of the most expensive unit in the system in order not to decentivize market capacity from producing in the electricity markets. The required volume of strategic reserve is tendered by the regulator, which is typically the transmission system operator (TSO). The generators in the strategic reserve are provided with fixed capacity payments, which are collected from the end-users through transmission tariffs. We assume that the SR consists mainly of battery storages. The battery storages of SR buy and store energy when there is an excess of solar and wind generation and sell it back at the dispatch price when there is no market capacity available to meet the demand. The target volume of SR for the next year is defined as the expected peak demand increased by the required reserve margin minus the existing market capacity multiplied by the normative capacity factors given by:

$$SR = D_{peak} \cdot (1 + RR) - \sum_{i=1}^{n} IC_{i,exist} \cdot CF_i \tag{4}$$

The revenue mismatches resulting from selling electricity at the dispatch price in the electricity market and the total costs (annualized fixed costs plus costs of buying electricity) are compensated for by collecting capacity payments from consumers estimated by:

$$CP_{SR} = FCosts_{SR} + Costs(EO) - Revenue(EO) \qquad (5)$$

With:

$FCosts\_SR$: annualized fixed costs of strategic reserve

$Costs(EO)$: strategic reserve annual costs from buying electricity

$Revenue(EO)$: strategic reserve annual revenue from selling electricity

2.1.3. *Investment decisions*

In the investment decision block, each agent assesses the profitability of new investments by estimating the net present value (NPV) of a new investment over the entire economic lifetime given by:

$$NPV^g = -Capex^g + \sum_{t=1}^{Lifetime_i} \frac{(P_t^g - Opex_t^g)}{(1+r)^t} \qquad \text{for } g = 1: N_i \cdot k_i: N_i \cdot k_{i,max} \qquad (6)$$

With:

i : index of a technology

g : size of a potential new investment

N_i : nominal capacity of a technology i

k_i : number of power blocks of a technology i

$k_{i,max}$: maximum installable number of blocks of a technology i

NPV^g : net present value of a new investment

$Capex^g$: investment costs of a new investment g of a power technology i (€)

P_t^g : total revenue of investment g from the market in year t (€/year)

$Opex_t^g$: annual operating and maintenance costs of investment g (€/year)

$Lifetime_i$: lifetime of power technology i (years)

r: discount rate

For a new investment with the size ranging from the number of power blocks with nominal capacities N_i from one to $k_{i,max}$, the agent runs forecast dispatches for the whole lifetime of new investments to obtain electricity prices and estimate the expected revenues from selling electric energy to the market. $k_{i,max}$ is constrained by the maximum number of blocks that are technically possible to install because of the limited fuel availability in the region or other technical limitations. Among all possible investments, the agent selects the number of blocks that give a positive and the highest NPV. At the second step, the investment is added to the installed capacities of the previous step with the construction time lag. We do not model mothballing decisions of existing power plants in the case of intermediate negative profitability. In the case of an energy plus capacity market, the agent calculates the NPV in order to estimate the profitability gap of the energy market, based on which it estimates the capacity bid prices for a new investment.

3. Input data

We used the power system data of Israel to generate an initial baseline 100% renewable generation mix in 2030 and simulate market designs. The perfect solar resources of the eastern Mediterranean make the idea of the 100% RES in Israel very promising. Moreover, as we do not model interconnectors, Israel with its quite isolated power market is a suitable case to perform the analysis. The input data used in the model can be divided into three categories:

- hourly profiles for electricity demand and capacity factors for wind turbines and solar PV
- technical characteristics assumptions for power generation and energy storage technologies included in the system
- capital expenditures, operational expenditures for all technologies included in the system

3.1. Power demand, wind and solar capacity factor profiles

The demand profile is based on the synthetic generated load data, calculated using historical temperature profiles, and data of work weeks and public holidays. This demand profile is upscaled to fit the annual electricity consumption of Israel [28, 29]. An example of the load profile for Israel is presented in Figure 3.

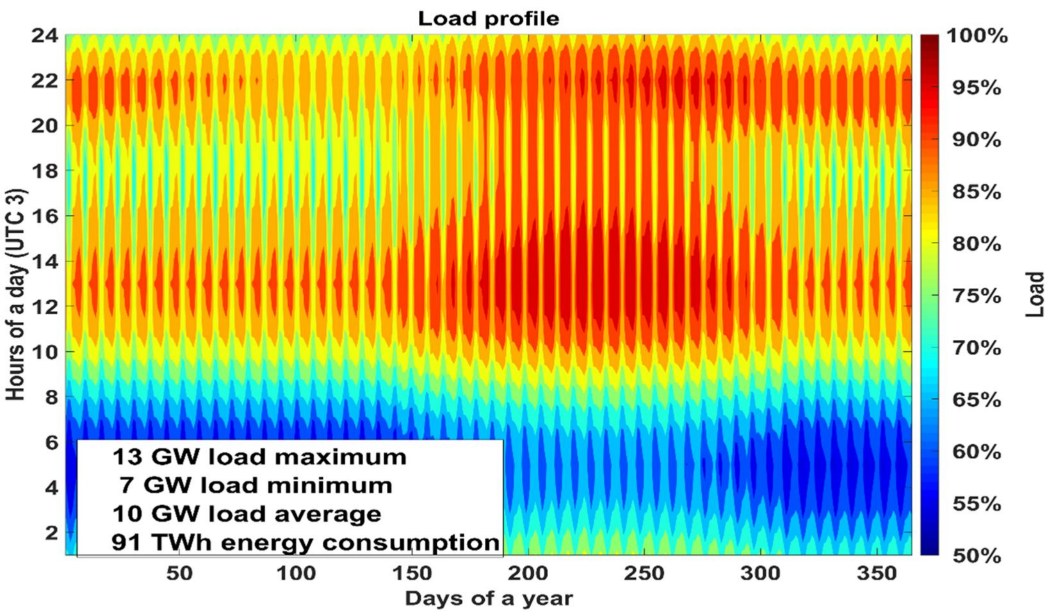

Fig. 3. Synthetic load profile for the year 2030

The capacity factors for optimally tilted PV and wind turbines are calculated based on the data for direct and diffuse solar irradiation, wind speed, temperature, and surface roughness for the year 2005, provided by NASA [30, 31], and reprocessed by the German Aerospace Center [32]. The wind turbine capacity factors are calculated for a 3 MW wind turbine at a hub height of 150 m. The capacity factors are calculated in a 0.45˚x0.45˚ spatial and hourly temporal resolution for the actual weather conditions of the year 2005. The aggregated profiles of the solar PV and wind energy power generation normalized to the maximum capacity averaged for Israel are presented in Figure 4.

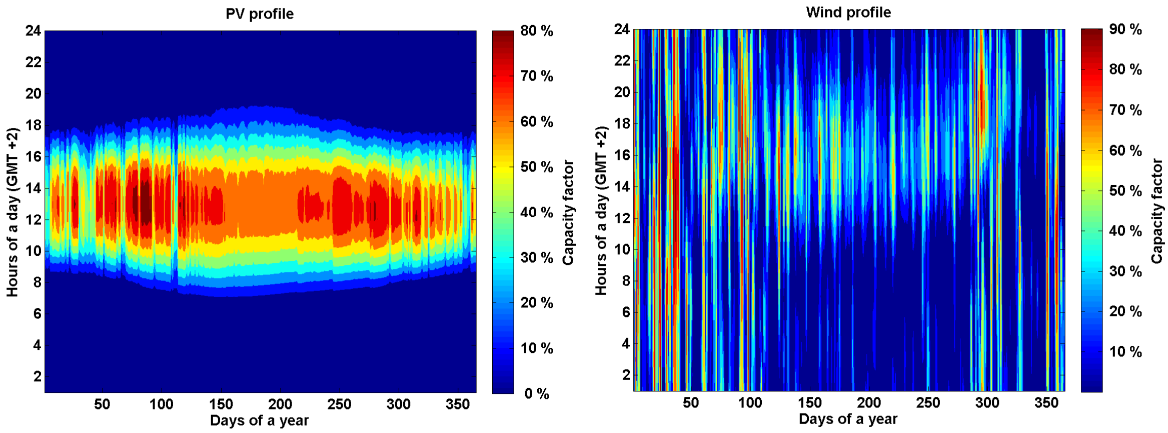

Fig. 4. Aggregated capacity factors for optimally tilted PV (left) and wind power plants (right)

3.2. Financial and technical assumptions for power generation and energy storage technologies

The financial assumptions for the energy system components for the 2030 reference year are presented in Table 2 (the investment cost (capex) and operation and maintenance (opex) values refer, in general, to a kW of electrical power). The financial assumptions for storage systems refer to a kWh of electricity. The assumptions are mainly taken from [33] but also from other sources: Li-ion batteries [34–36], silicon-based PV cost development [37, 38], biomass and biogas technologies [39], and waste-to-energy [40]. The technical assumptions concerning power to energy ratios for storage technologies and the efficiency numbers for generation are presented in Table 3.

Table 2. Financial assumptions for energy system components

Technology	Capex [€/kW]	Opex [€/kW]	MC [€/kWh]	Lifetime [a]
PV	550	8	0	30
Wind onshore	1000	20	0	25
Biomass CHP	2500	175	0.065	30
Biogas CHP	370	14.8	0.085	30
Waste incinerator	5240	235.8	-0.015	20
	Capex [€/kWh]	Opex [€/kWh]	MC [€/kWh]	Lifetime [a]
Battery	150	10	-	10

Table 3. Efficiencies and energy to power ratio of the storage technologies

Technology	Efficiency charge [%]	Efficiency discharge [%]	Energy/Power Ratio [h]
Battery	85	85	6

Biomass and waste resource potentials are taken from the German Biomass Research Center [40]. All biowaste is divided into three components: solid waste, solid biomass, and biogas sources. Solid waste is comprised of municipal and industrial used wood; solid biomass includes straw, wood, and coconut residues; biogas sources are excrement, municipal biowaste, and bagasse.

3.3. Baseline generation mix

For the preparation of the baseline generation mix, the regulatory energy system model was applied. The model was optimized to reach a minimum annual energy system cost for the given constraints: demand and capacity factor constraints and the financial and technical assumptions. The result gives the mix of installed capacities and operation profiles for the optimal technologies, which provides the minimum cost of guarantee energy supply for every hour of the year. The optimal baseline generation mix for the year 2030 is given in Table 4.

Table 4. Optimal baseline generation mix for the year 2030

Technology	Baseline generation mix [MW]
PV	32997
Wind onshore	6978
Biomass	5222
Biogas	1512
Waste	28
Battery	10368

4. Results and discussion

For all scenarios, the model generates hourly supply-demand profiles, storage charging and discharging, spot market prices, and wind, solar and demand curtailments. On the annual basis, the model provides installed capacities, annual production by technologies, reliability, and economic indicators such as consumer bill, capacity margins, and the number of lost load occasions. We report results for a 20 year time frame (2030–2050). A policy analysis, comparing all three market design scenarios in terms of reliability and affordability, is presented in Section 4.3.

4.1. Operating profiles

Figures 5 and 6 illustrate example summer and winter supply–demand profiles and hourly market prices for EO scenario. The summer and winter profiles illustrate how different technologies operate at an hourly level to accommodate the variability of demand, solar and wind.

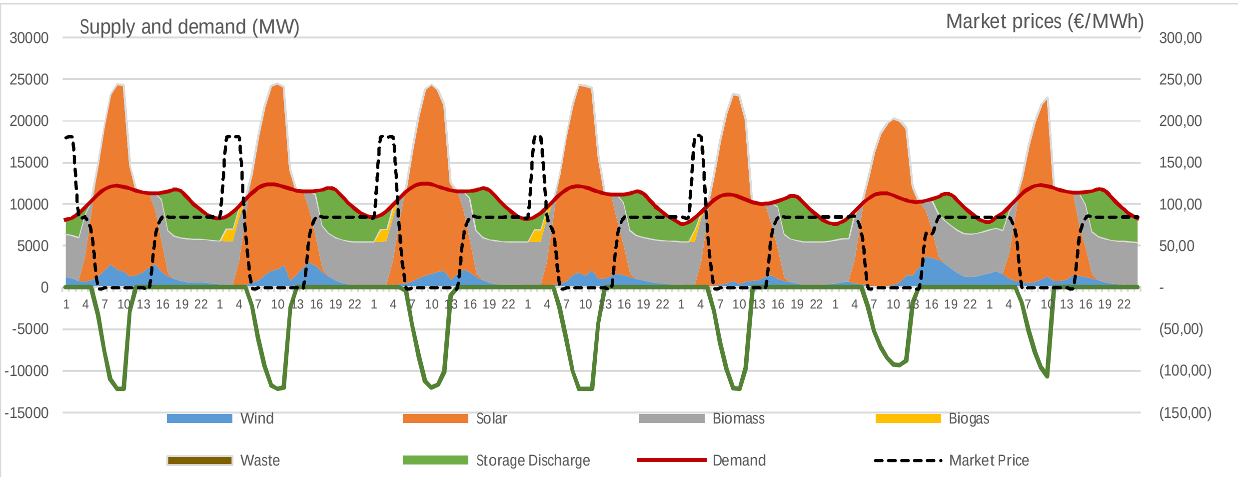

Fig. 5. Summer supply–demand profile and hourly market prices

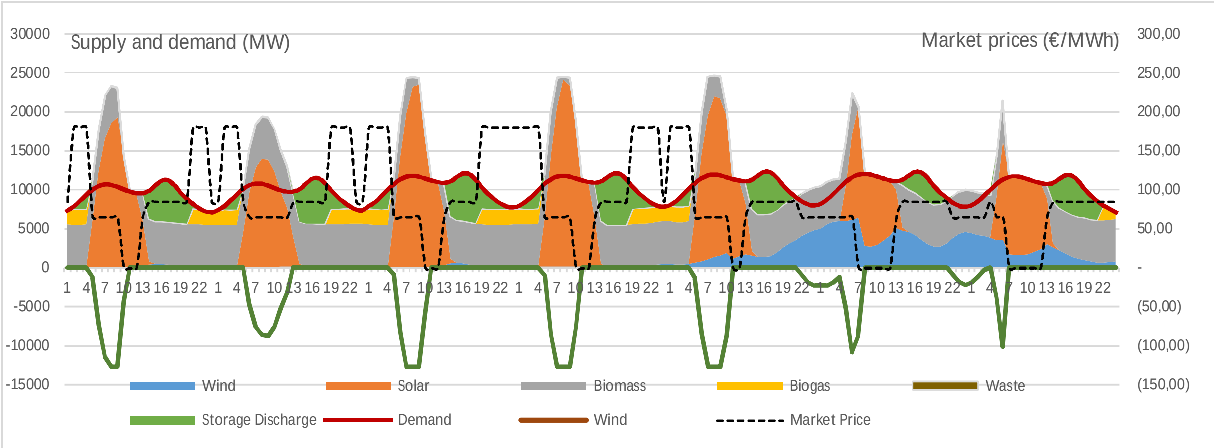

Fig. 6. Winter supply–demand profile and hourly market prices

The simulation provides a number of insights into the opportunity of constructing and operating a 100% renewable energy system in regions with high solar resources. In the 100% RES, where almost 70% of inflexible generation (wind and solar) has no fuel costs, the market prices are often set to zero if the variable generation is sufficient to meet the demand. Only flexible generation is able to contribute to positive hourly market prices: biomass and biogas power plants by fuel costs, and storage plants bidding opportunity costs.

In summer, the high correlation of the solar availability with the daily peak demand (between 6:00 and 16:00) and the high generation from PV (ten hours of sunshine) allow meeting the peak demand only with solar generation at almost zero prices. During these periods, the storage is actively buying excess zero-cost PV generation for charging. During some hours in summer, because of the limited charge capacity of the storage and high PV generation, the excess PV and wind generation has to be curtailed to meet the demand. This occurs in particular when the wind and solar availability correlate highly. We can see the cutbacks in PV production during some hours in Figure 5. Instead, in times of an empty battery storage and insufficient production of biomass and biogas to meet the demand, there might be power shortfalls and the load would be curtailed to match the supply. In this case, the power market price will rise to the value of the lost load. The evening reduction in PV generation is managed by flexible technologies. For this purpose, biomass provides effective baseload power. Battery storage discharging and sale of the stored energy becomes profitable during the evening peak demand. Owing to the most expensive fuel costs, biogas is mainly used when no stored energy is available or when the storage capacity is low and the storage bids an opportunity cost (higher than the marginal costs of biogas).

In winter, because of the lower solar availability and intensity than in summer (eight hours of sunshine instead of ten), and the poor wind conditions of the region, the production of PV and wind is not sufficient to charge the storage at full. For this reason, to maintain the desired level of stored energy to be able to provide energy during evening peaks, apart from PV, the storage has to buy energy from biomass. In this case, the market prices are set by the marginal cost of biomass. Other than zero, the power market prices during daily peak demand produce inframarginal rents, which benefit solar producers and help to recover their fixed costs. Sometimes, high wind production occurring before the daily peak of PV generation as well as a bounded rationality of the battery storage regarding the availability of solar and wind may produce quite high solar curtailments, which can be observed in the two last days of the winter profile in Figure 6. Thus, efficient operation of flexible resources, particularly storages and demand-side resources together with accurate forecasts of production of inflexible resources, will continue to play a key role in the operation of the 100% RES economically and reliably. In this paper, we consider only one type of storages. However, a combination of different types of storages from short-term to long-term ones and demand-side resources will help to balance the system better with less energy losses.

4.2. Generation mixes

Figure 7 provides the evolution of installed capacities of different technologies under the EO market design in the years 2030–2050.

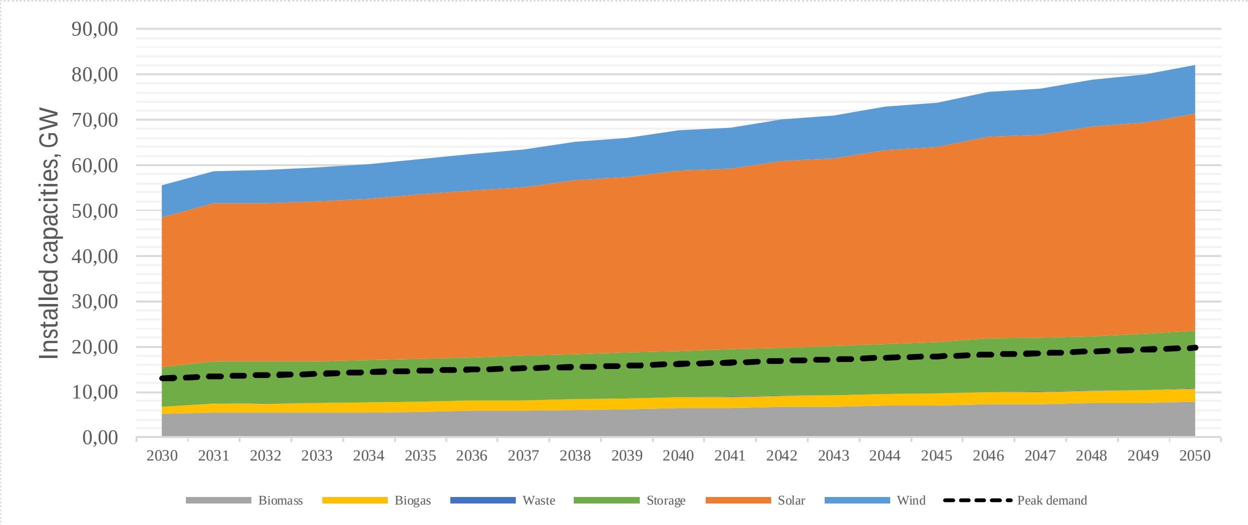

Fig. 7. Evolution of installed capacities 2030–2050 under EO market design

At present, there is around 12 GW of capacity in Israel, mostly composed of gas, coal, and oil generation. This capacity meets a demand that varies from 6 GW to 11 GW. The 100% RES has far more installed capacity (almost 55 GW while the peak demand is 13.5 GW in 2030), with almost 70% of that being wind and solar PV. However, the 100% RES system maintains only 15.5 GW of firm technologies (biomass, biogas, waste, and storage maximum discharge capacity). The amount of firm capacity is sufficient to meet the peak demand even when no solar or wind is available.

Figure 7 shows that the EO market design provides continuous investments in all technologies following the demand growth, indicating that the market prices are sufficient to cover the costs of producers. Thus, we can conclude that EO market design based on marginal pricing is able to ensure profitable operation of the 100% RES. However, further provision of subsidies to zero marginal cost generation might be required, particularly to solar generation, which is dominating in the generation mix under study. Furthermore, investments in capital-intensive storage technologies become viable only if it is allowed to price energy at opportunity costs rather than at marginal costs. On the other hand, this might initiate strategic behavior among producers, which would pose a risk of high costs to consumers. Therefore, attracting enough flexible resources to the market, that is, different types of storages and demand-side resources, and ensuring appropriate competition among them will play a vital role in the efficient functioning of the 100% RES markets. Another way of attracting sufficient investments in flexible resources is introduction of different forms of capacity remuneration mechanisms that provide stable and predictable revenue streams based on availability.

Next, we will illustrate how investments and generation mixes develop under three market designs. Figure 8 provides the installed capacities MW and the proportions of different technologies in percent of the final generation mix by the end of the simulation period (year 2050) while Figure 9 illustrates the annual generation in TWh and the proportions of annual production in percent of the total production for the year 2050.

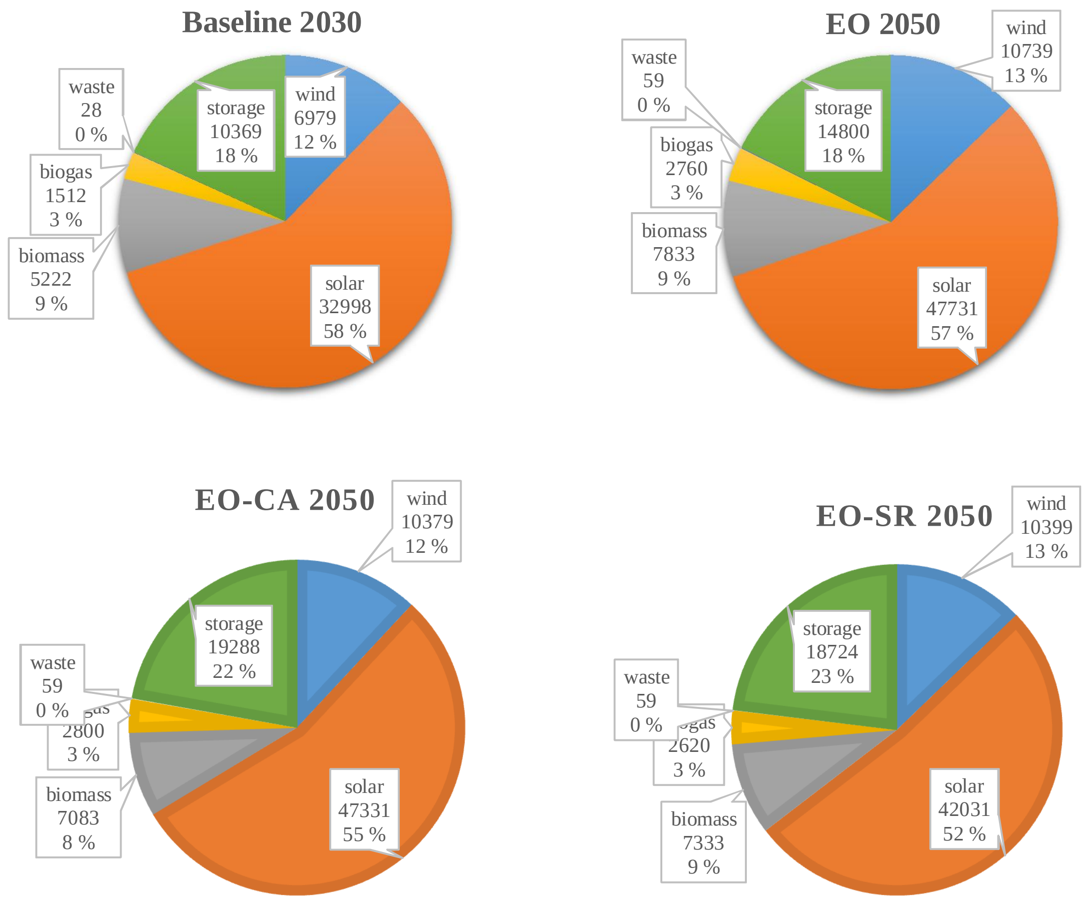

Fig. 8. Installed capacity (MW, in percent of total) by technologies under three different market designs (year 2050)

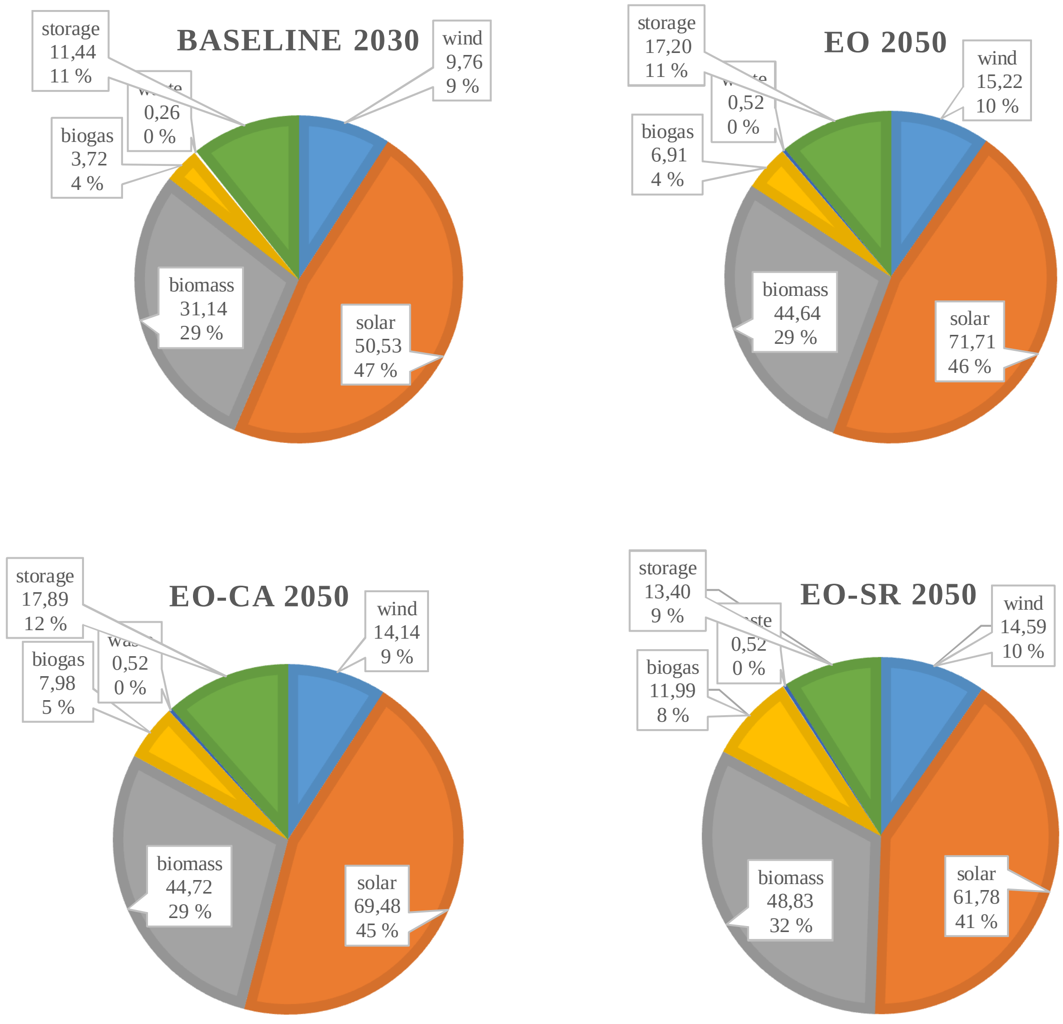

Fig. 9. Annual generation (TWh, in percent of total) by technologies under three different market designs (year 2050)

One important observation is that the proportion of technologies in the final mix in the EO design by 2050 is almost the same as in the optimal baseline generation mix 2030. This means that a competitive EO market design provides the least-cost mix of technologies compared with other market designs under consideration.

The simulation shows that investments in flexible generation increase with the EO-CA and EO-SR designs compared with the EO design because of the provision of stable capacity payments to flexible resources guaranteeing capacity that can be used to meet the peak demand. On the other hand, the lower scarcity prices resulting from the lower price cap and the higher reserve margins in the capacity-based markets make investments in inflexible generation such as wind and solar, which are not getting any capacity payments, less attractive than in the case of the EO design. In the EO-SR there are less investments in biomass and biogas than in the EO design. The dispatch price of the strategic reserve is capping scarcity prices, and thus, decreases the revenues and investment incentives for other technologies, particularly in other flexible technologies such as biogas and biomass. Despite the increased production of biogas and biomass, owing to the strategic reserve that is being dispatched only when no other generation is available in the market, biomass and biogas are getting less inframarginal rents required to cover their fixed costs than in the EO design, which makes their investments less attractive. Thus, to maintain the required amount of flexible resources in the market, decreased investments in biomass and biogas have to be compensated for by increasing the size of the strategic reserve, that is, storage. However, the production of the storage is lowest among all market design scenarios. Again, the reason is its last dispatch, leading to the decreased production and also decreased production of inflexible resources as a result of the storage buying less solar and wind production. In the EO-CA market, the losses of inframarginal rents of biogas resulting from reduced scarcity prices are compensated by capacity payments. Thus, we see more investments in biogas in the EO-CA design than in the EO-SR.

4.3. Affordability and reliability

We compare the three market designs (EO, EO-CA, EO-SR) in terms of affordability and reliability using several metrics presented in Figures 10–12. Figure 10 and 11 present the dynamic development of average wholesale electricity prices and capacity margins under three market designs over the simulation years. The capacity margin is estimated taking into account only the availability of firm capacity in the market, that is, biomass, biogas, waste, and storage maximum discharge capacity in the market. In addition, Figure 12 presents a summary of the results. Firstly, it represents the average values over the whole simulation years of the loss of load expectations LOLE[1], solar and wind curtailments, and electricity and capacity prices. Secondly, it illustrates the consumer bill consisting of energy component, capacity component, and solar surcharge. The energy component corresponds to the annual costs of consumers, and it originates from energy

[1] LOLE represents the number of hours per annum in which supply will not meet demand.

procurement in the spot market, while the capacity component corresponds to the annual costs of consumers, and originates from capacity procurement in the capacity markets. Solar surcharge represents the total financial support from outside the electricity market paid through feed-in tariffs by consumers to solar producers. We could also have considered total welfare as a metric to compare the designs. However, policy makers mostly focus on the consumer bills when deciding upon policy options.

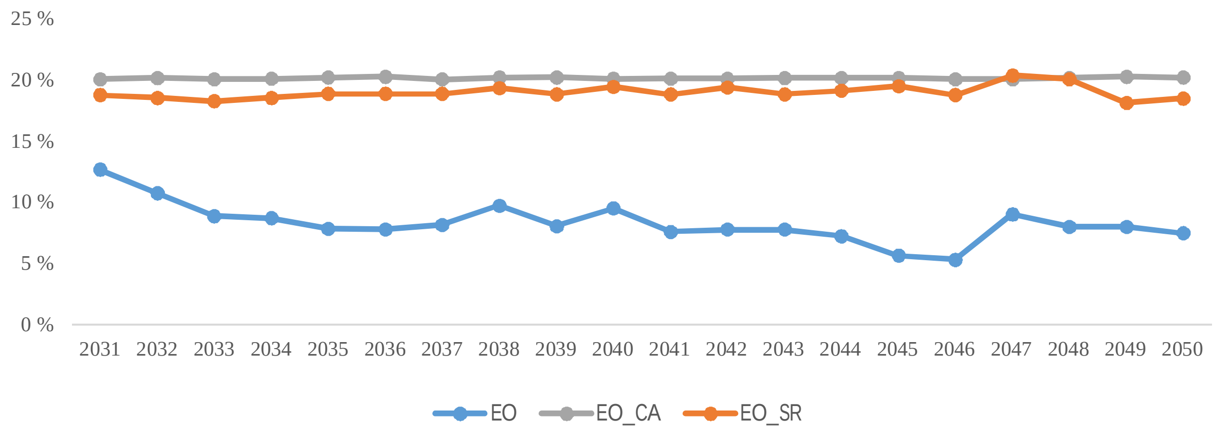

Fig. 10. Capacity margin of the system (%) over years

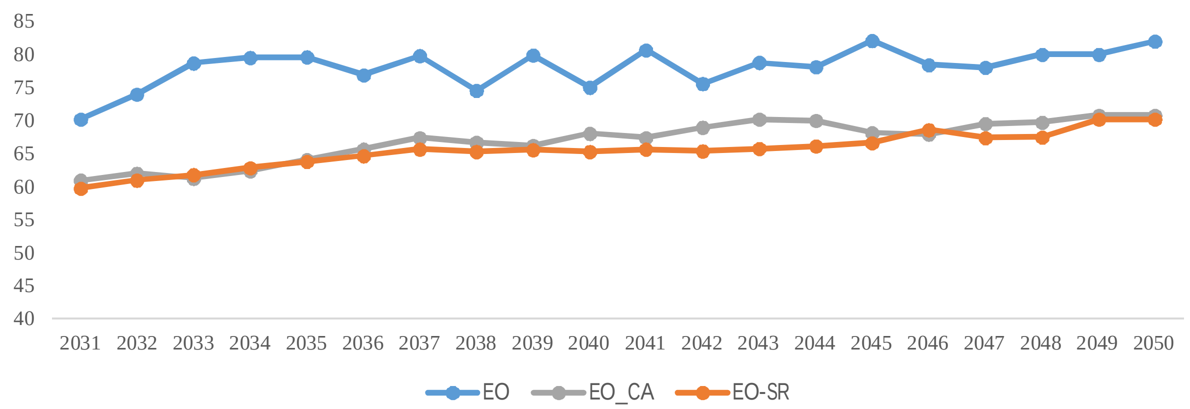

Fig. 11. Average wholesale electricity prices (€/MWh) over years

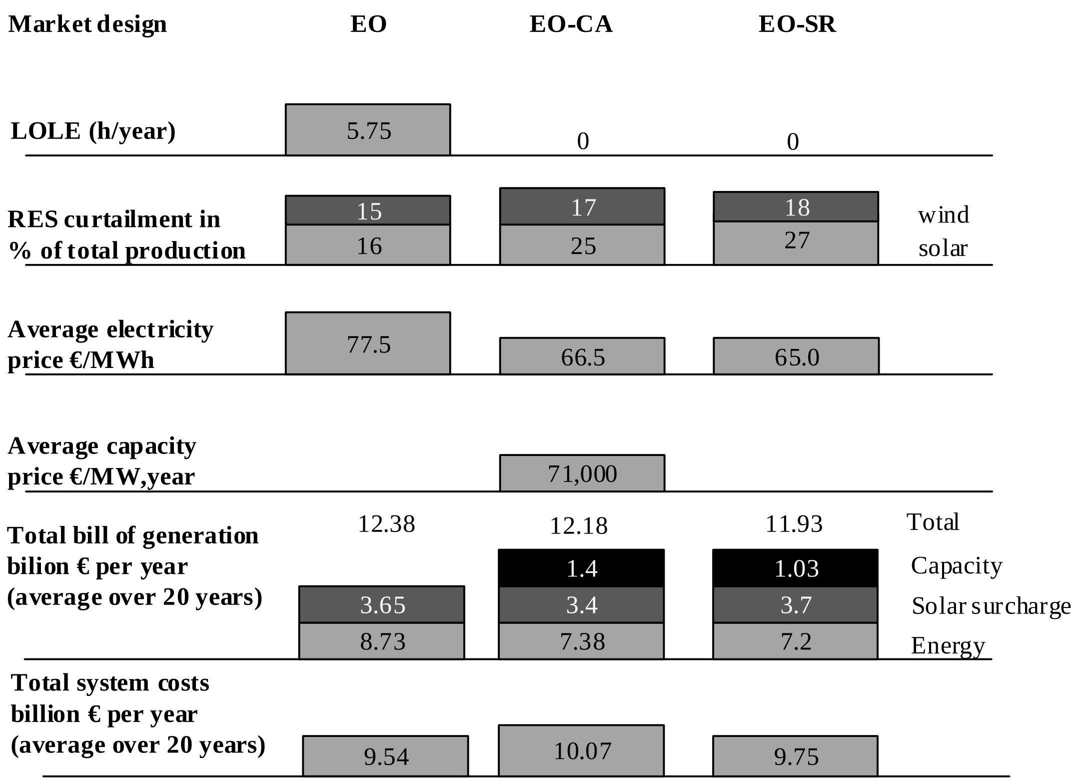

Fig. 12. Summary of the results

In terms of reliability, capacity markets have a positive effect on the market. In Figure 10, this can be seen from the higher and less volatile capacity margins in the EO-CA and EO-SR scenarios than in the EO market design scenario. The number of the loss of load occasions is lower (5.75 hours against 0 in the CA and EO-SR scenarios) as a result of the larger amount of flexible capacity installed in the capacity markets. The capacity margins are estimated taking into account the 100% availability of flexible resources during peak demand. In practice, the availability of flexible technologies, especially storage, is lower.

The average prices vary between 60 and 85 €/MWh depending on the market design. Because of the considerable proportion of flexible resources bidding non-zero prices to the market, the average wholesale prices will not decrease (which is a current concern in the energy only markets), yet they will be double the current average EU-28 market prices. The average market prices and the energy component in the consumer bill are highest in the EO design among all scenarios. Firstly, this can be explained by the more frequent occurrence of the lost load occasions as the investors are providing less flexible capacity. Secondly, a higher price cap provides more incentives for the storage to exercise strategic behavior and bid scarcity prices up to VOLL in tight demand-supply situations. With capacity markets there is always less potential to exercise strategic bidding because of the sufficient capacity and a lower price cap. Moreover, prices are less volatile in the capacity market designs, because the regulator ensures a steady amount of flexible firm capacity in the market, which is not the case in the EO design, where the installed capacities have a more fluctuating development. The average market prices and consequently, the energy component in the consumer bill are lowest in the case of the EO-SR design. As long as the storage belongs to the TSO and receives guaranteed compensation in the form of capacity payments to cover its total costs, it has no incentives to exercise strategic bidding in the energy market. The storage operates as a last resort resource and is dispatched only in the case of scarcity at constant dispatch prices, thereby flattening power prices and reducing the energy component in the consumer bill. However, it is emphasized that withholding the storage from the market makes the competition tighter and increases the possibility for the market flexible capacity to exercise strategic bidding, which could lead to higher prices and consequently, a higher consumer bill than the ones we presented above. The same concerns the assumptions regarding the capacity auction. We assumed perfectly a competitive auction, where generators restore exactly the missing-money from the energy market. If we accounted strategic bidding in capacity auctions, it would lead to higher capacity costs for consumers, and thereby, a higher average consumer bill. To conclude, the assumptions we made with regard to the behavioral assumption of producers and investment decisions may lead to an overestimation of the consumer bill in the case of the EO market design and on the other hand, underestimation in the case of the capacity markets.

Solar curtailments are highest in the capacity market scenarios. In EO-SR market design, nonmarket-based operation of the storage leads to distortions in dispatch of other technologies and thereby to high energy losses of cheap wind and solar generation. Another reason for high solar curtailments in the capacity market scenarios is the willingness of the storage to maintain the required amount of storage capacity to ensure its availability during peak demand in order to be eligible to receive capacity payments, thus making it to buy biomass production in order to reduce its risk of being unfilled in the case of low solar availability.

Another important question is to define whether the markets are able to ensure the cost recovery of the system. Using the capital, O&M, fuel and financing costs, we estimated the annualized system costs of the 100% RES given in Figure 12. The system costs depend on the total installed capacity in the market. In the case of the EO-CA design, we have the highest system costs because of the largest proportion of total installed capacity compared with the other market designs. By comparing the system costs with the total consumer bill, we can see that all market designs are able to provide sufficient revenues to recover the producers' costs. However, the markets generate different surpluses, that is, the difference between the revenues and the costs of producers. Thus, the EO market benefits the producers most. Again, some assumptions we made with regard to the strategic bidding in the EO market or capacity auctions may lead to the over- or underestimation of the producers' benefits.

5. Conclusions and Policy Implications

This paper tackled the question about the market designs that will provide cost recovery and continuous investments to incentivize investments in the 100% RES. Various energy only and energy plus capacity market models were tested numerically taking a behavioral simulation approach. The market designs were analyzed with respect to the short-term operation of technologies and the long-term development of generation mixes, and compared in terms of reliability and costs for consumers. The objective was to examine whether the current energy only market design is suitable to provide investment incentives and operate the 100% RES reliably and economically, or whether an additional capacity remunerative mechanism might be needed as long as the investment problem remains one of the most important issue in the 100% RES.

Our results indicate that with the energy only market design, it is possible to solve the cost recovery and investment incentive problem in the 100% RES if applying certain rules. Cost recovery for variable power plants with zero marginal costs (particularly solar) only from market prices is challenging because of the low market prices at times of their production. Thus, subsidies to intermittent power plants will most likely be kept in the future energy only markets. Note that we did not consider the opportunity of inflexible generation to bid at prices above their marginal costs and leave this question for further research. Moreover, market prices should take account of the opportunity costs of flexible resources, particularly storage or demand-side resources, to enable recovering their capital and operating costs. However, this might involve a high risk of strategic bidding obviously not benefiting consumers. Uncertainties in price developments and the high price volatility in the energy only market make investments in dispatchable generation highly risky, thereby increasing the risk of underinvestment and threatening the security of supply. Thus, capacity remunerative mechanisms might be required to mitigate the risk of insufficient investments.

Our study demonstrates that capacity remuneration mechanisms ensure the required proportion of flexible resources in the 100% RES to meet the reliability standards. This is manifested by the reduced number of lost load occasions and a less volatile and higher capacity margin than in the case of energy only market. Moreover, our study shows that assuming strategic bidding in the energy only market, introduction of capacity markets leads to a decrease in the consumer bill. However, this holds only when assuming prevention of strategic bidding in the capacity markets. Many studies argue that capacity markets improve the reliability of the system at the expense of consumers. However, we found that this is not always the case because of the interlinkage of capacity and energy markets, where a decrease of revenues in one market is compensated in another.

Finally, we want to note that the quantitative results presented above may be limited because of the several assumptions we had to make to keep the model tractable, in particular, with regard to the behavioral assumption of producers and investment decisions. However, we are confident that our main findings on market design options for the 100% RES will hold because the change in assumptions affects all scenarios alike, driving the final results in one direction.

In our future research, we would like to extend our analysis to market designs for the 100% RES by incorporating more flexible resources such as power-to-gas technology and demand response in the model. Further, the study should include the changing demand structure resulting from the growing number of electric vehicles entering the market. Moreover, the feasibility of radical market designs should be considered. Finally, the riskiness of investments depending on market designs should be considered when analyzing the market design options. In addition, it is possible to model a roadmap and market policies designed to achieve the 100% RES with the model presented in the paper.

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