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The potential role of H_2 production in a sustainable future power system

An analysis with METIS of a decarbonised system powered by renewables in 2050

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Contents

Abstract

The operation of a future highly decarbonised (95% CO_2 emissions reduction vs 1990) power system, as defined with JRC-EU-TIMES in 2050, is analysed with METIS. The power system is dimensioned in order to provide adequate electricity to a fleet of electrolysers, whose purpose is to produce hydrogen at quantities adequate to supply industrial processes and transport. The analysed power system deviates from current practices in that demand takes over the role of power generation in balancing the system and setting the wholesale market price. The segment of the market where competitive forces set the price shifts from production to demand. Under the assumption of adequate competition between the electrolyser operators the resulting prices could, in most EU member states, arrive at a sustainable equilibrium. This equilibrium – not present in all member states – depends on the ratio between flexible load (electrolyser capacity) and variable renewable generation.

Foreword

The efforts to mitigate risks stemming from climate change are gradually intensifying, with Europe leading the way. According to the European Commission's recently published strategic long-term vision for a climate-neutral economy by 2050, the current policies and actions are projected to achieve reductions of greenhouse gas emissions of around -45% by 2030 and around -60% by 2050.

Achieving the long-term temperature goals set in the Paris Agreement would require additional effort. The road to a net-zero greenhouse gas economy may be paved on several building blocks stretching to all sectors of the economy. The contribution from the power sector can be significant through maximal deployment of renewables and the use of electricity as the main element to fully decarbonise Europe's energy supply.

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Executive summary

The present work explores the potential role of electrolysers in a future largely decarbonised power system and uncovers the reasons why this technology may be an important building block towards the transition to a stable, sustainable and fully renewable power system.

The JRC-EU-TIMES was used as the starting point to evaluate Power-to-X technologies, given the potential to cover the entire energy system. The scenario selected for analysis with METIS is one where Carbon Capture and Storage (CCS) is not widely adopted, or accepted and electrolysis is the main process for producing hydrogen.

This incarnation of a future European power system in 2050 is designed to produce carbon-free fuels and feedstock for the industry, while maximising the deployment of renewable energy power generation. This scenario would require a nearly tenfold increase of installed capacity of solar and wind power generation in 2050 compared to the EUCO30 scenario for 2030 as electricity is the primary source for producing hydrogen. The key new component of the examined energy system is the reversible electrolyser.

The introduction of hydrogen as a new energy carrier would unlock new possibilities for cross-sectoral system integration and eventually, enable the gradual replacement of conventional thermal generators in their function of ancillary services and capacity providers with electrolysers.

Initially, electrolysers will operate on excess power from variable renewable generation. Later, as soon as Power-to-X (P2X) is more widely adopted as a process for generating synthetic liquid fuels, electrolysers will develop a critical capacity that will enable this technology to become price-setters. Electrolyser demand will constitute such a significant fraction of the total load that their role could expand to functions currently performed by conventional centrally dispatched power generation.

Although the primary function of the electrolysers is to supply hydrogen to the downstream sectors, they are also expected to be able to perform two additional and perhaps even more important functions:

- To contribute significantly to the technical stability of the power system and
- To restore a price (in the sense that during times of surplus they can set a price higher than zero) to the power market dominated by prime movers with close to zero variable cost.

By simulating the above functions, perhaps surprisingly, we arrive to the conclusion that the operation of the future decarbonised power system (and market) may be conceptually much closer to current power system than one would expect. The main market actors can still operate in an environment where supply and demand define the wholesale price of electricity, while competition among them can still serve the interests of consumers and producers alike.

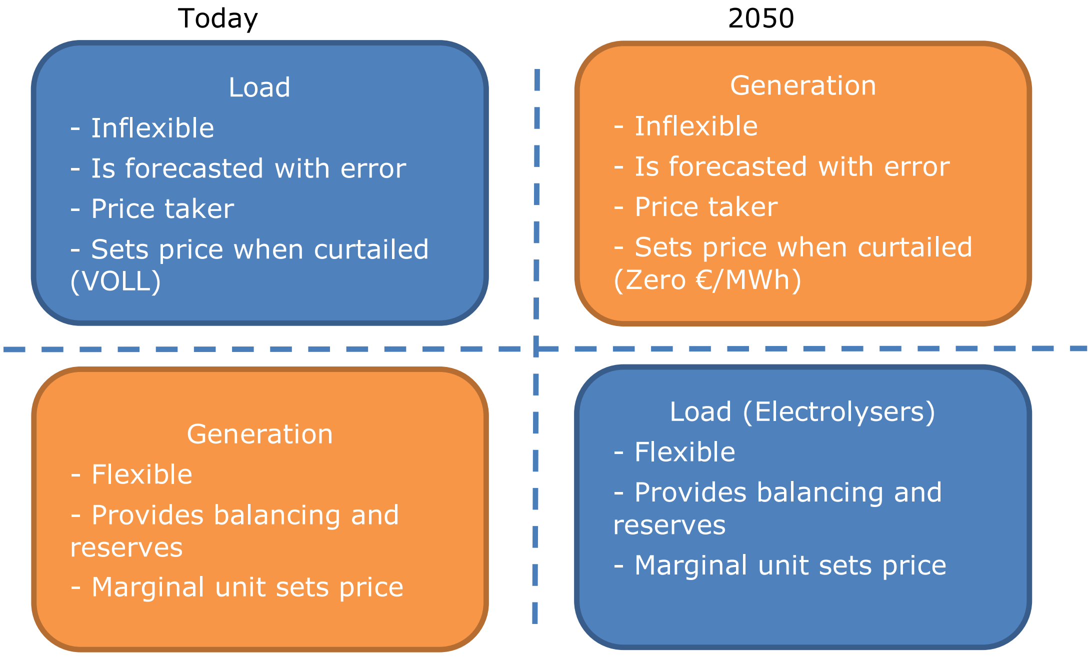
However, due to the intrinsic characteristics of the two main technologies, (renewable generation is variable and electrolysers are dispatchable load) a switch of roles will take place: In contrast to current practice, the demand side (primarily the electrolysers) will be providing energy and the essential services for balancing the power system, while the production side (mostly renewables) will represents the inelastic part of the equation, reminiscing more the characteristics of demand in the current power system.

Some quantitative results of the present analysis are summarised below:

- Due to the periods with low electricity prices, a bidding price of 60 €/MWh from the electrolyser translates into an average price of 27-35 €/MWh for the electricity paid for most countries.
- This translates into a hydrogen production cost of approximately 3€/Kg.

- Operating hours for the electrolyser are between 2 000 and 7 500 hours. Countries with more than 4 500 hours had the following conditions:
    1. Total electricity production was at least 2.5 times the net electricity demand (meaning at least 60% of the electricity demand was from the electrolysers);
    2. Wind was the dominant VRE technology with at least a 2.5 wind to solar production ratio;
    3. The electrolyser is sized between 16 and 24% of the VRE installed capacity.

The electrolyser operation and the VRE operation has such a catalytic effect on the power market operation that generation and demand in 2050 switch roles and mirror today's participants as shown in the figure below.



<u>Conclusion</u>

The METIS model is used to analyse a potential evolution of the European energy system in 2050 where electricity is the primary source for producing synthetic fuels. The scenario favouring electrolyser deployment was selected in order to analyse the technical and economic viability of such a deployment, given the very important challenges posed by VRE integration at levels beyond 50%.

The analysis demonstrates that electrolysers may be considered one more key component towards the transition to an almost fully renewable power system which is stable and very close to being sustainable.

It further demonstrates that the electrolysers required for producing the volumes of hydrogen required by the downstream sectors can play two (potentially three) additional and perhaps even more important functions:

- They can play a role in maintaining the technical stability of the power system and
- They can restore a price to the power market dominated by prime movers with close to zero variable cost.
- They could eventually completely substitute legacy gas fired units by reversing into production mode (fuel cells).

Therefore the electrolyser, as a centrally dispatched variable load unit, can be the vehicle to restore, balance not only to the power system, but also to the day-ahead market.

Moreover, the analysed scenario has very good chances of achieving sustainability: In most countries hydrogen production with electrolysis has the potential to be competitive compared to the main alternative technology (SMR with CCS/U).

At the same time all three Variable Renewable Energy generating technologies could, in most countries, recover all or most of the capital investment cost from the day-ahead power market. Two discount rates were used to assess the CAPEX recovery: The lower value (5%), is closer to a social discount rate used for assessing public infrastructure projects and a higher (9%) is closer to values used for assessing commercial investments. The economic performance of all three technologies (offshore and onshore wind and solar) comfortably exceeds the lower discount rate in most countries but only onshore wind shows potential for higher project economic performance.

1 Introduction

The decarbonisation of the electricity sector is fundamental to reach a low carbon energy system. Wind and Solar power generation technologies are main elements on the path to this goal (referred henceforth as VRE for Variable Renewable Energy). Their short term variability can be compensated by batteries, while Power to X (P2X) can act as potential seasonal storage. P2X implies the production of hydrogen from electrolysis and potential conversion downstream to synthetic fuels as final energy carriers. The main advantages of the technology can be summed up in the following: (1) it can exploit the use of existing infrastructure for transporting and storing hydrogen and synthetic fuels; (2) it can provide an energy vector with the potential to decarbonize other sectors; (3) it supplies hydrogen that can be used in combination with CO2 from biogenic sources (or even air) to produce synthetic fuels and feedstock for chemical industry. The high cost of electrolysers (currently at 1000-1500 €/kW[1]) is the main barrier to overcome.

The present study soft-links two models to assess the potential effect Power to Gas (PtG) can have in a future (2050) energy system. One model is an energy model (called JRC-EU-TIMES [1–3]). Its main advantages are: (1) it makes trade-offs among flexibility options (where PtG is in direct competition with storage, Power to Liquid (PtL), power to heat and demand side management); (2) it calculates prices endogenously based on supply and demand curves; (3) capacity expansion is considered, leading to the optimal PtG capacity being an output of the model. The other is a power model (called METIS) which is able to determine the optimal operation of the installed capacities. The main gap from JRC-EU-TIMES that METIS covers is the temporal resolution (hourly for METIS vs. 24 time slices for TIMES), which is important to capture VRE fluctuations and potential hours with surplus. The main gap JRC-EU-TIMES covers is the link with the rest of the energy system, potential downstream use of hydrogen and effect of its price.

Previous work [4,5] on P2X with JRC-EU-TIMES, analysed over 120 scenarios to tackle the uncertainty on the potential evolution of the energy system. This report focuses on one potential future where Carbon Capture and Storage (CCS) is not widely accepted or adopted. In the particular scenario hydrogen plays a key role (to still reach the CO_2 reduction target of 80-95% vs. 1990 by 2050) and a significant (~1000 GW) capacity of electrolysers is required.

The current analysis aims to provide answers to following questions regarding the functioning of the power system described previously:

- What would the power market look like, in comparison to today and what could the possible roles of the main participants be? Could the current market arrangements still be relevant?
- How would the electrolyser fleet participate in the power market and what would its impact be on the operation of the electricity system (i.e. electricity prices and effect on surplus)?
- To what extent could demand substitute conventional power generation in providing balancing services and in setting the day-ahead market price?
- What would be the operating profile of the electrolysers?
- Would the resulting electricity market price adequately support the renewable generation investments?
- At the same time would the electricity price allow hydrogen production at a competitive cost with respect to the current alternative technology?

[1] FCH-JU, Development of Water Electrolysis in the European Union, February 2014, http://www.fch.europa.eu/node/783

2 Methodology

The present analysis aims to provide insight into the workings of a power system well ahead into the future. This analysis is performed in two steps. In the first step the future energy system is defined by means of a long term energy model called JRC-EU-TIMES (See Annex 1 for a description). The optimal energy system defined in step 1 is used as input in a power system model in order to study to a much higher detail the operation and performance of the various components of this new power system.

2.1 2050 scenario by JRC-EU-TIMES

The starting point to evaluate Power-to-X technologies was JRC-EU-TIMES, given it's potential to cover the entire energy system, to choose inherently among the most suitable energy carriers for satisfying a service (e.g. electricity or gas for heating), to calculate endogenously commodity prices within a multi-annual capacity expansion optimisation process (previous studies [6–8] that look only at the operational component).

The model was used to evaluate the role of Power-to-Methane [4], Power-to-Hydrogen and Power-to-Liquid [5], where the potential for the latter two is the highest mainly for transport (hydrogen for heavy-duty trucks and electro-fuels [9] for aviation and marine transport) and industry (steel). Electrification (demand over 5000 TWh for some scenarios), energy efficiency (30-40% reduction in residential and transport) and CO_2 storage preferred over CO_2 use were among the most notorious trends.

2.1.1 Competing technologies for H_2 production

Over 100 scenarios were created following a parametric analysis. In total over 20 parameters were varied to analyse their influence on hydrogen and downstream use. The parameters found to be most influential are underground CO_2 storage, biomass, VRE potential and technology performance (i.e. electrolyser and downstream liquid production). The fewer technology options the system has to reach the desired target, the higher the CO_2 price is and more hydrogen is needed.

In scenarios where CO_2 storage is considered possible, the main technology (>95%) used is steam reforming with CCS, thereby limiting the requirement for electrolysers (~80 GW). On the other hand, in scenarios where CCS is not widely adopted or accepted, electrolysis is the predominant technology and the system requires more hydrogen, due to the additional constraints. This results in significant electrolyser capacities (~1000 GW).

2.1.2 A power system based on electrolysers

To put this in perspective, current global capacity of electrolysers is around 8 GW [10]. If we assume this is distributed by regions proportional to hydrogen demand (EU demand is 7 out of 50 mtpa globally), EU should have close to 1 GW of installed capacity. On the one hand, to reach 80 GW of an unrestricted scenario (95% CO2 reduction) implies an annual growth of almost 15 % a year, which is similar to the growth that wind has experienced in the 2007-2017 period (18 % a year [11,12]). On the other hand, a capacity of 1000 GW requires a 24 % growth per year, which is still less than the 32 % observed for PV in the 2012-2017 period [11,12]. Attaining this level of sustained growth for the entire period until 2050 would require significant investments in electrolyser manufacturing capability in Europe. The feasibility of realizing this cost-effectively and in a timely fashion, as well as the policies and incentives necessary to make it happen are outside the scope of the present report.

In this study, the scenario of electrification of the entire hydrogen production in Europe is analysed in order to understand the impact on the electricity system. The main assumptions for this scenario can be found in Annex 1.

2.2 The 2050 power system into METIS

Output from JRC-EU-TIMES was used as input for METIS (scenario dependent) and underlying assumptions have been aligned between both tools (scenario independent, e.g. fuel prices). An overview of these parameters is provided in Table 1. Limited feedback from METIS to JRC-EU-TIMES has been done.

Table 1. Parameters taken from JRC-EU-TIMES used to modify input to METIS.

Parameter	Level of detail	Scenario dependent	Notes
Installed generating capacity	By country, by technology	y	Some technologies (e.g. CHP, geothermal, tidal) were not available in METIS and aggregated in a similar category
Load	By country, peak and average	y	Demand was available by sector, but the version of METIS[2] used did not include sectoral demand profiles. Therefore, total demand time series were used.
CO2 price	One for the entire system	y	This is the marginal and not the average price
Fuel prices	Oil, gas, coal by country	n	Aligned with reference scenario 2016 [21]
Techno-economic data for generators	By technology	n	Cost (CAPEX, OPEX) and efficiency for different types of generator

The analysis of the power system with METIS was conducted at an hourly resolution, which meant that the following additional input not available in JRC-EU-TIMES, was required:

- Hourly load profile (by country)
- Hourly capacity factors for wind and solar (by country)
- Hydrological data for pumped hydro storage
- Reserves

Time series data from METIS EUCO30 2050 were used since this was identified as the closest scenario to the ones modelled. METIS demand time series were rescaled to match JRC-EU-TIMES annual demand, while the hourly profiles from METIS were used to update JRC-EU-TIMES annual capacity factors, and ensure consistency between both tools (since this affects potential electricity surplus and levelised cost of electricity).

[2] METIS v1.3

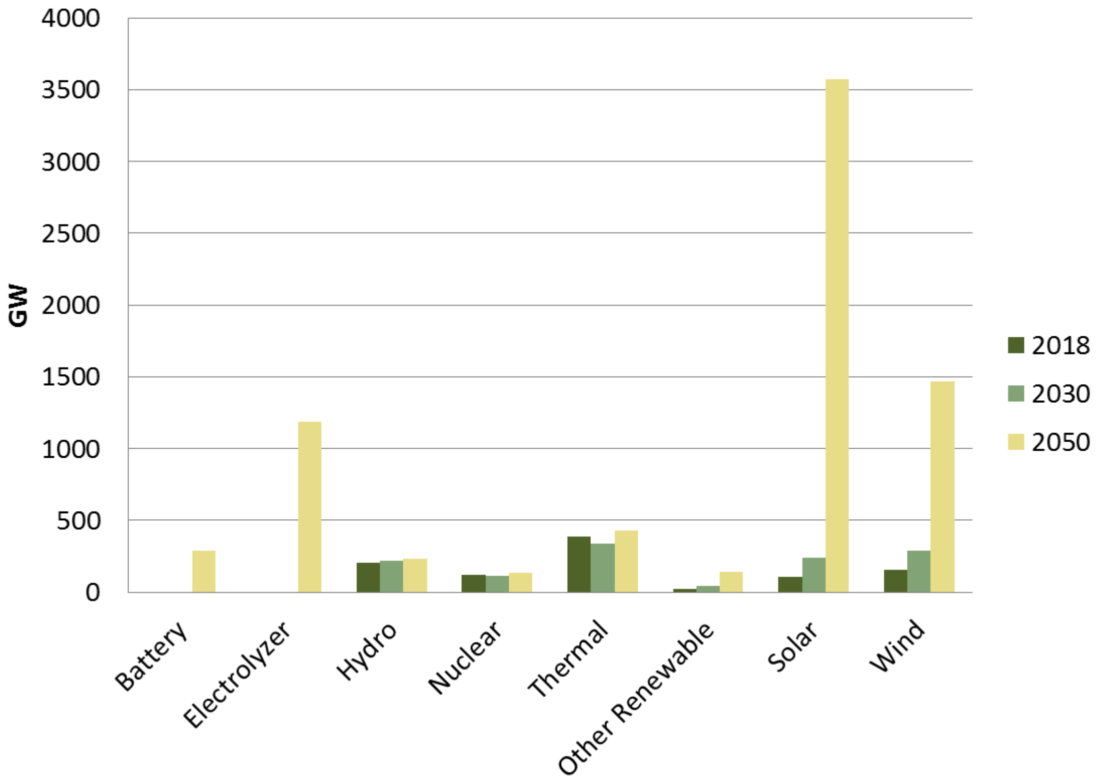
3 The 2050 renewable-based power system

The scenario chosen represents a favourable case for hydrogen in 2050 and hence is appropriate for studying the electrolyser role in balancing the power system.

3.1 Installed capacities

The figure below provides the total installed capacity of generating and consumption assets (electrolysers) in 2050, compared to current and expected installed capacity in 2030 according to a central policy scenario[3]. More than 1000GW of electrolysers are required to produce the volumes of hydrogen needed to supply a decarbonised (primarily steel) industry, and processes to produce synthetic fuel volumes for aviation, shipping and long-haul road transport.

Figure 1. Installed capacities pf generation and consumption assets in 3 time frames (2018 – 2030 – 2050)



Source: JRC, ENTSO-E, METIS EUCO30 2030.

The necessary solar and wind generation capacity figures are 5 to 10 times higher compared to the central policy projections for 2030 (EUCO30). Existing studies on the total renewable generation potential in Europe provide evidence supporting the technical feasibility of the level of capacity increase considered for wind [28]. (See Annex 2 for a comparison of the renewable installed capacities with the respective potentials).

[3] The EUCO30 scenario has been developed to reach all the 2030 targets agreed by the October 2014 European Council (at least 40% reduction in greenhouse gas emissions with respect to 1990, 27% share of RES in final energy consumption and 30% reduction in the primary energy consumption) and the 2050 decarbonisation objectives, continuing and intensifying the current policy mix. The 'EUCO' scenario has been developed by ICCS-E3MLab with the PRIMES energy system model.

3.1.1 Thermal capacity vs reversible electrolysers

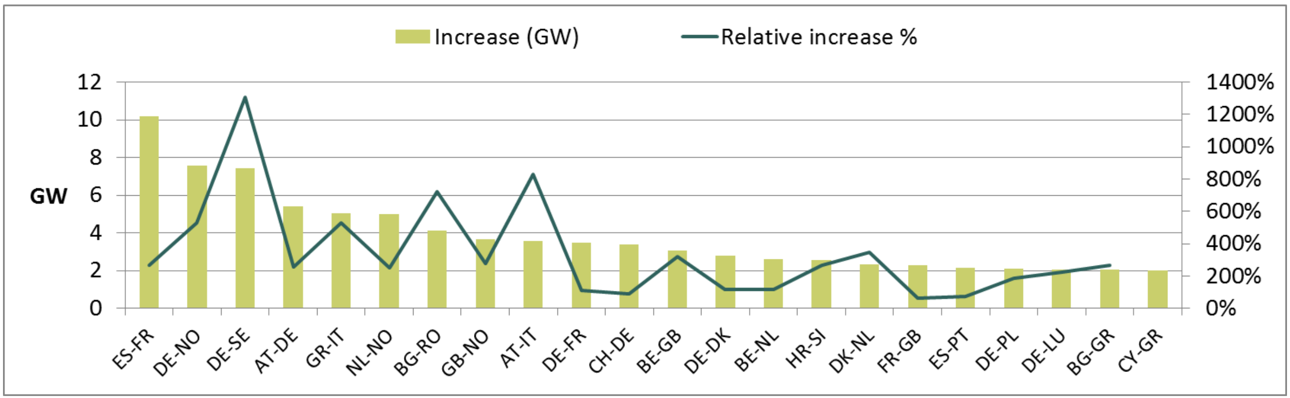
It is surprising at first that the installed capacity of thermal power plants is somewhat above current levels (400 GW). Approximately half (190GW) are peaking plants (open cycle gas turbines), 80 GW are coal fired power plants fitted with CCS/U, while the rest are combined cycle gas turbines. The latter two are based on the JRC-EU-TIMES results. However, the peaking plant capacity (OCGTs) is the result of the calibration of the METIS scenario during initial runs of the model in order to reduce the occurrence of any loss of load below 3 hours/year.

The gas-fired power plants in the system would be the legacy power plants installed during the transition period. They could eventually be entirely replaced if one third of the installed capacity of the electrolysers is reversible.

3.2 Interconnections

The interconnection capacity between EU-28 member-states and Switzerland and Norway was based to a large extent to the results stemming from the e-Highway 2050 project[4] that studied 100% RES scenarios with high share of wind and solar. The figure below provides the most important interconnection capacity upgrades between neighbouring member states until 2050. Detailed information on the interconnection capacity values is provided in Annex 3.

Figure 2. Interconnection capacity increase between EU-28 member states (2020 – 2050)



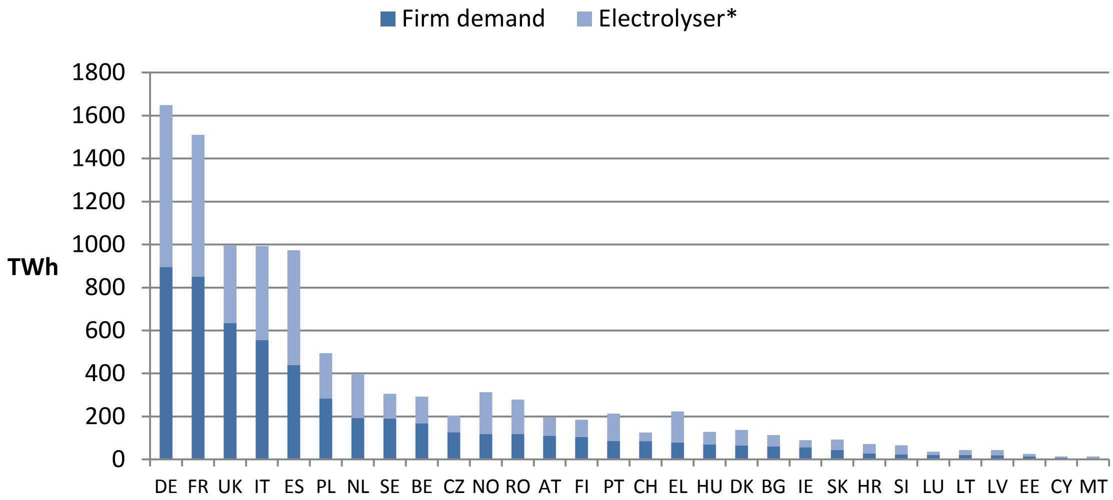
3.3 Demand

Demand time series were generated by scaling of the existing demand time series of the METIS EUCO30 2050 scenario in order to match the annual total demand calculated by JRC-EU-TIMES.

A flat demand profile dimensioned according to the electrolyser installed capacity was then added to the resulting time series. The potential consumption of the electrolysers impacts significantly on demand. A mid-merit electrolyser operation of 4000 hours would double the electricity demand in most member states (see Figure 3 below).

[4] http://www.e-highway2050.eu/results/

Figure 3. Firm (other than electrolyser) vs potential electrolyser demand



*assuming an average operation of 4000 hours of the electrolysers.

3.3.1 Modelling the electrolysers

The electrolyser demand load-following ability was modelled as an equivalent generating unit with a variable cost equal to the maximum acceptable power or Willingness to Pay (WTP) price by the electrolyser operator. The WTP was set at 60€/MWh. This value is based on the reasoning presented in the following paragraph. Electrolyser fleets across the EU were modelled with the same WTP price and hence identical bidding behaviour.

It was also assumed that hydrogen production has access to a large-scale storage (otherwise the electricity consumption would have to follow the hydrogen demand).

3.3.2 Discussion on deriving the willingness to pay (WTP) price

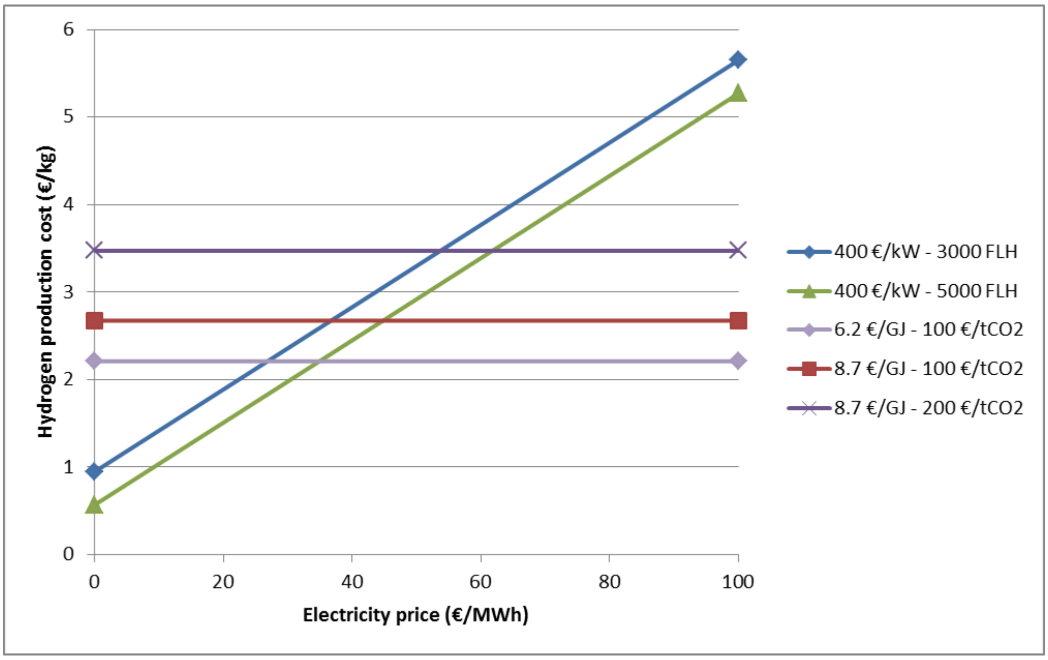
The competing technology for hydrogen production is the basis to estimate the electricity price below which electrolysis is competitive. This is assumed to be steam methane reforming (SMR) with CCS. This technology still has some CO_2 emissions (90% capture assumed), but the main cost contributor is the gas used as feed. The assumed gas price is 8.7 €/GJ, corresponding to the import price for 2050 in the 2DS (2 ºC) scenario from IEA ETP [13]. Given the low carbon nature of the future scenario, a CO_2 price of 200 €/tonne is used. This can be seen as high compared the current (February 2019) EU ETS CO_2 price, which is close to 20 €/tonne. However, it is much lower than marginal prices seen with JRC-EU-TIMES, that are 300 €/tonne of CO_2 for the most flexible scenarios and can be as high as 1000 €/tonne for the most restricted [4]. This is also in line with estimates with PRIMES that range between 230 and 310 €/tonne [14] or prices above 1000 €/tonne that have been observed in studies looking at hydrogen penetration in energy system models at a global level [15]. These assumptions give a hydrogen production cost of almost 3.5 €/kgH_2.

The hydrogen production cost through electrolysis will directly depend on the operating hours that affect the CAPEX contribution to total cost. Since the hours are not known ex-ante, an average of 4000 hours was used (also using as indication the output from JRC-EU-TIMES). The future (2050) CAPEX for the electrolyser is highly uncertain (400 – 1000 €/kW [5,16]). A specific CAPEX of 400 €/kW was used[5], in line with the large (1000 GW) capacity deployed in this scenario and assessments that estimate that the CAPEX for the PEM electrolyser could be as low as 290 €/kW in high hydrogen deployment scenarios

[5] The lower value was chosen considering the potential economies of scale under the massive scale up of electrolyser installations considered in the present scenario.

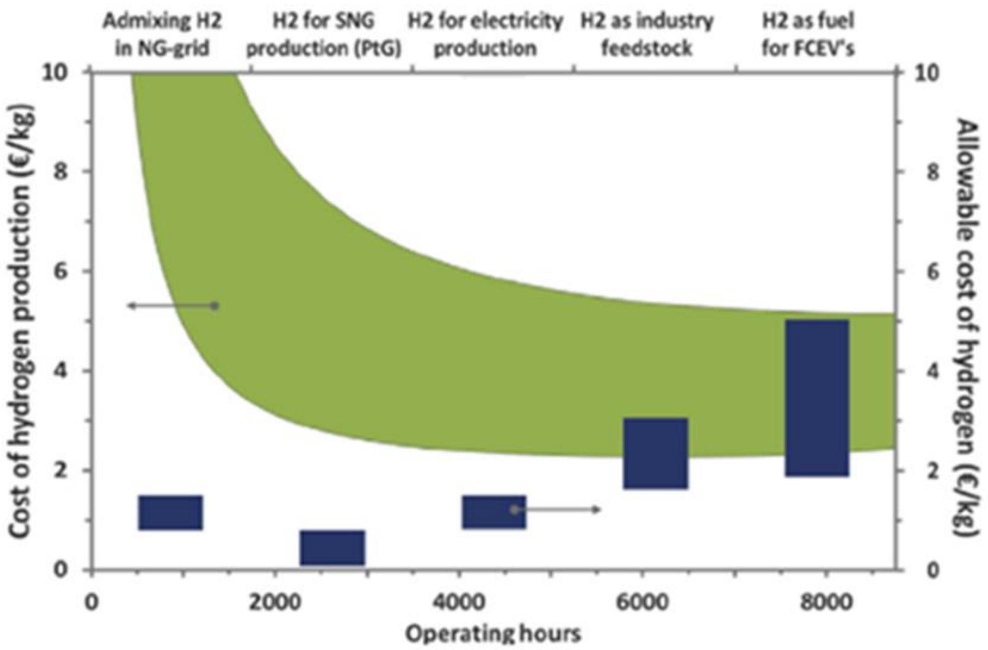
[17].The influence of the different parameters on hydrogen production cost is shown in **Figure 4**.

Figure 4[6]. Hydrogen production cost for steam methane reforming and electrolysis as a function of electricity and gas prices



An alternative approach for the WTP for electricity could be to estimate this value, based on the WTP for the hydrogen by the different sectors either as fuel or feedstock (see **Figure 5**), which can be as high as 7-8 €/kg in the case of transport [19].

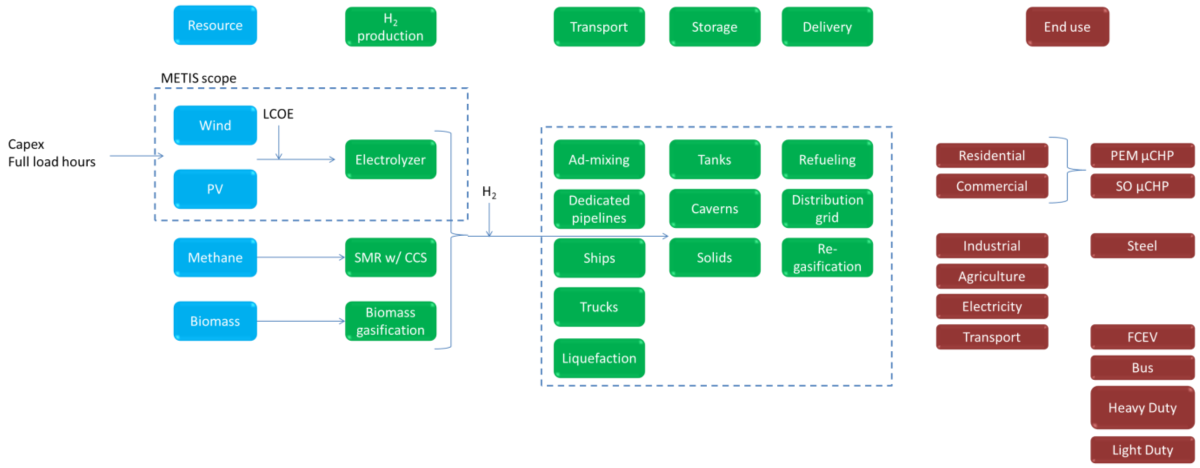
Figure 5. Hydrogen production cost vs WTP from various sectors (from [18])



[6] Discount rate: 7%; lifetime: 30 years; efficiency (LHV): 70.9% [27], hydrogen storage of 8 hours (480 €/kg), 25% installation factor; SMR Capex: 580 €/kW (including CCS)

This demand driven approach would probably favour the case for hydrogen, however, at present the uncertainty regarding the evolution of hydrogen distribution costs and competing technologies to satisfy those same end services (both pathway dependent) is considerable. Since the present analysis with METIS focuses on the power sector, (see **Figure 6**) it was decided to use the competing technology approach, as more conservative and involving less exogenous assumptions.

Figure 6. Hydrogen pathways in comparison to METIS scope



From the point of view of the electrolyser, the WTP will be as low as possible, in order to have the lowest production cost. However, lower WTP also translates into lower average electricity prices, which decreases the average revenues of the renewable generators thereby making them unprofitable. At the same time, given that the average electricity paid by the electrolyser is lower than the maximum WTP, the final electricity costs are lower, due the fact that the electrolysers will only operate when the day-ahead price is lower than the WTP.

Following the above discussion the WTP value of 60 €/MWh was adopted as a conservative and balanced first estimate.

3.4 Summary

The 2050 power system specified in the present analysis is essentially an evolution of the current power system where derivatives of existing VRE technologies (Wind and Solar) dominate the energy mix. Three quarters of the annual power generation are provided by these technologies. Enabling this level of VRE penetration into the power system would require addressing challenges stemming from the stochastic generating patterns of these technologies. One further complication stems from the fact, that the variable production cost is almost zero. Inevitably the following questions would need to be addressed:

1. How will the power system be balanced?
2. What will the day-ahead market price look like?
3. How will power generators recover their investment costs?

The following sections attempt to provide some insight on the above questions by modelling the electrolysers as another asset participating in a competitive power market.

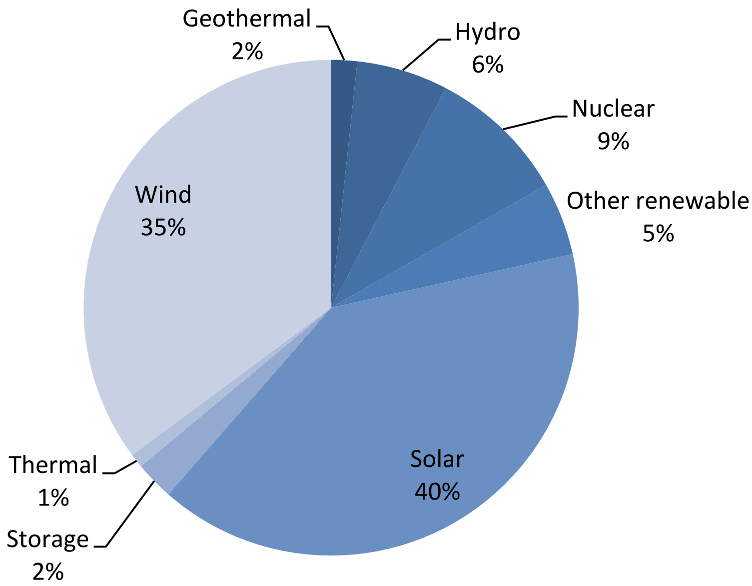
4 Modelling results

The operation of the power system described in the previous section was simulated with METIS, by performing an optimal dispatch of the power system at hourly resolution for one year.

4.1 The fuel mix

The figure below provides the share of electricity generated by each category of generating technologies, across the modelled area. Wind and solar dominate, providing around three quarters of the total generation. Nuclear and hydro contribute together a further 15%, while the role of thermal power plants and storage is limited to providing energy and reserves at times of scarcity.

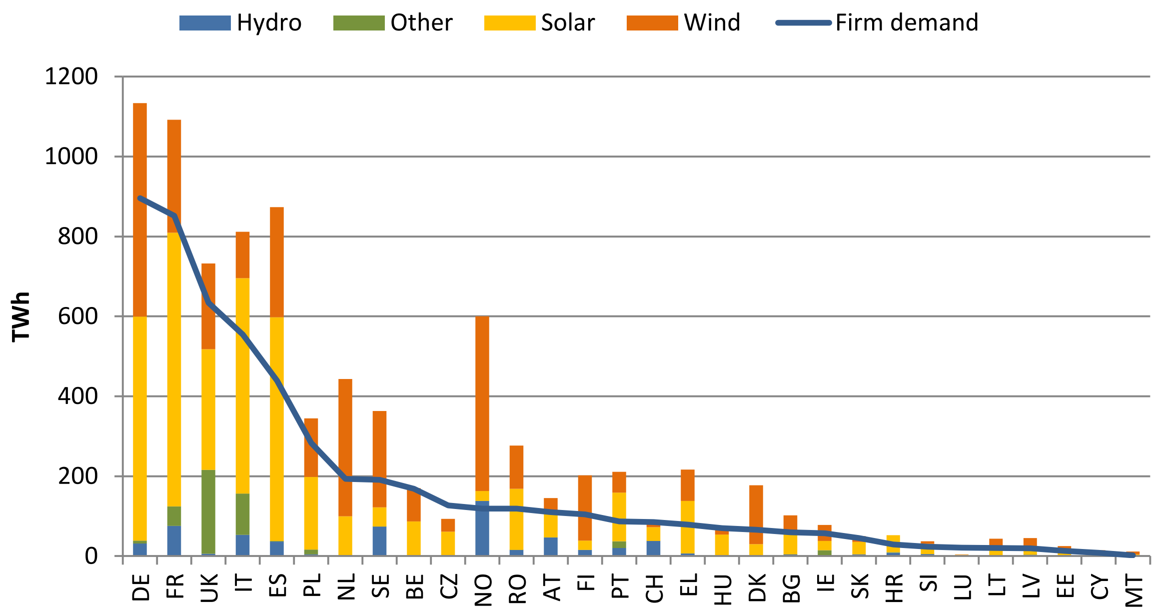
Figure 7. Contribution of each technology category to the total electricity generation



4.2 Renewables production and curtailment

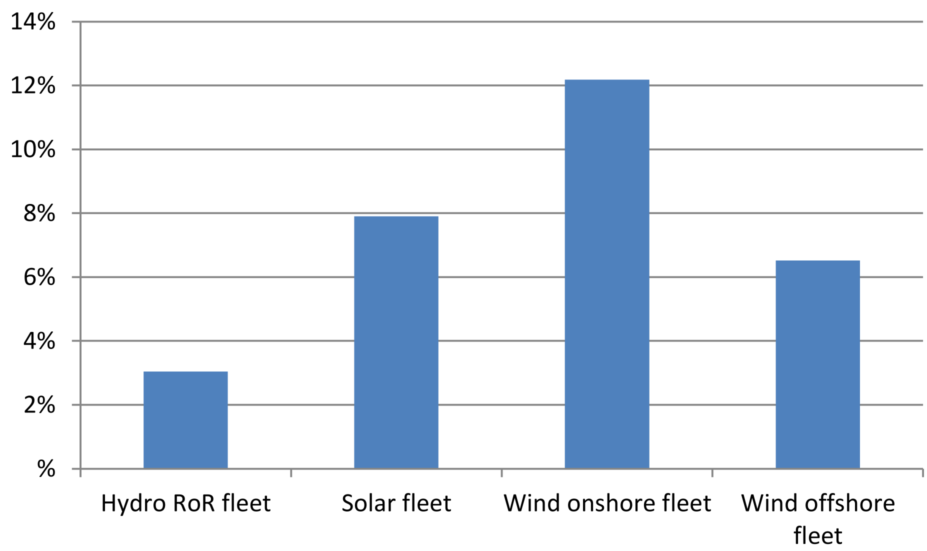
The T95_2050 scenario is a power system dominated by renewables and in particular VREs. The figure below provides the annual production for each member state from renewable generation per source, stacked. The solid line provides the total demand in each member state, also used in **Figure 3**. The production surplus is evident, but not uniform among the member states. The surplus is higher in countries where the climatic conditions favour the development of VRE generation. This surplus is a major part of the energy feeding the electrolysers.

Figure 8. Stacked renewable annual production vs firm electricity demand[7] at country level



A power system based on VREs (75% of the annual generation) would expose these technologies to significant levels of curtailment if the necessary infrastructure, capable of absorbing the excess power, were not present. In the T95_2050 scenario the installed electrolyser capacity can provide the ramp-down reserve capability to minimise curtailment of variable renewable generation. The figure below provides the calculated curtailment as a percentage of the total available potential.

Figure 9. Curtailed production as % of total generation potential from variable generation



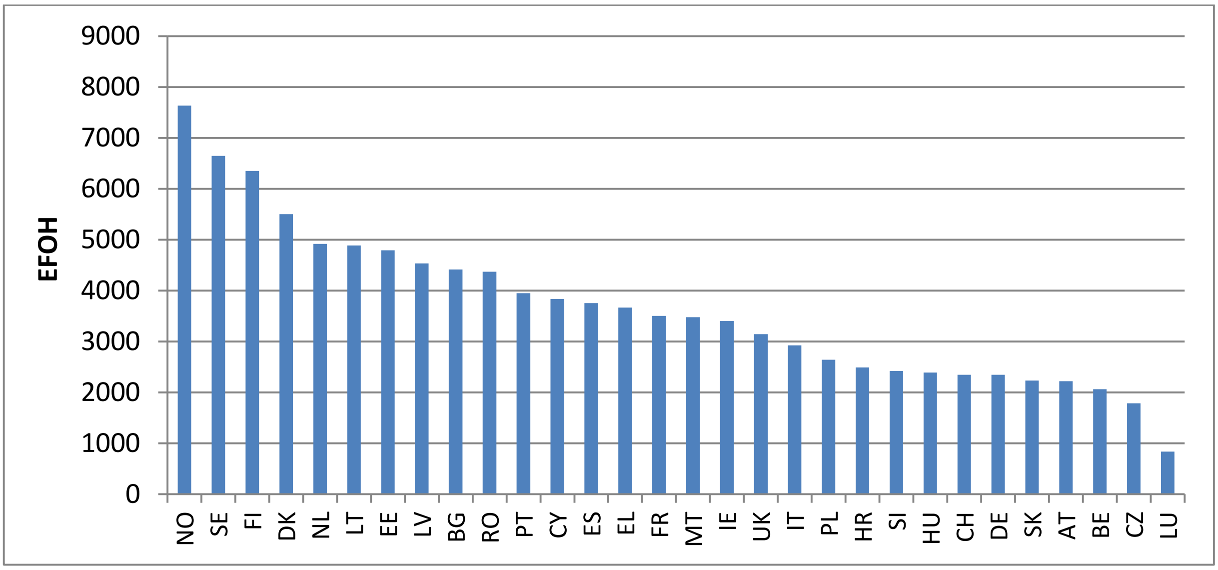
The observed higher curtailment of generation from wind is partially explained by the fact that generation from wind is curtailed before solar and run of river with the default model parameters[8].

[7] In this case excluding demand from the electrolyser fleet
[8] Wind generation is modelled as generating at a variable cost slightly above zero €/MWh

4.3 Electrolyser operation

The equivalent full operating hours (EFOH) for all the countries are shown in the figure below. Although it is not the sole affecting factor, the surplus (observed in **Figure 8**) is related to the EFOH of the electrolyser fleet increase.

Figure 10. Electrolyser operation (EFOH)

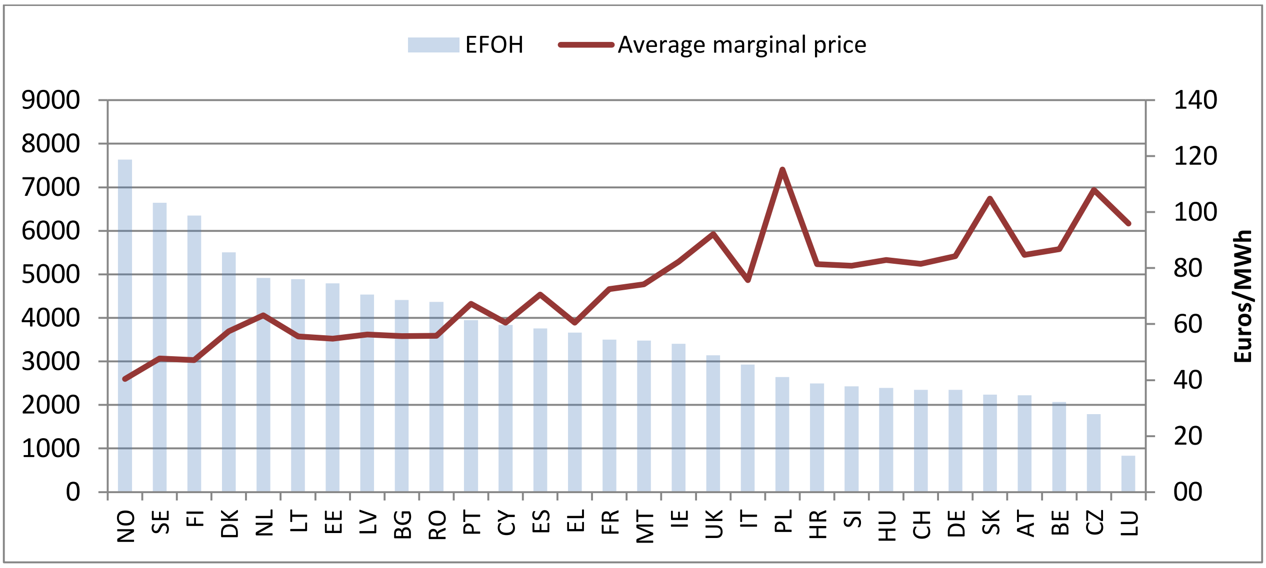


4.4 Marginal electricity prices

A major challenge posed by increased shares of variable renewable generation is the effect on electricity day-ahead market prices. During hours of expected high injections of power by wind and solar prices tend to drop to zero. In markets where rules allow it negative prices can occur.

One of the outcomes of the present analysis is that the electrolyser, as a centrally dispatched variable load unit, can be the vehicle to, not only restore balance to the power system, but also to the day-ahead market. The figure below (red line) provides the average marginal price for every country during one year plotted against the background of the EFOH provided in **Figure 10**.

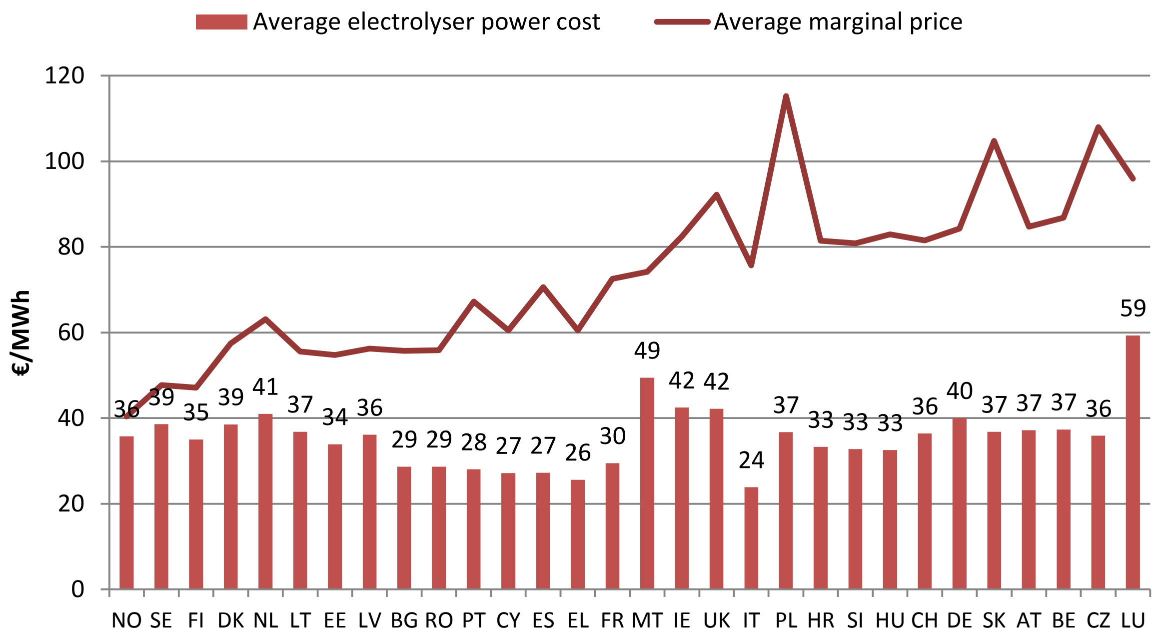
Figure 11. Average marginal price of electricity



The patterns observed in the above figure allude to a market-driven operation of the electrolysers. Their operators bid for power at their highest acceptable cost or Willingness to Pay (WTP), set at 60 €/MWh. Whenever the marginal price is higher than 60 €/MWh, the area is facing scarcity and the electrolysers are not operating. Whenever the marginal price is lower than 60 €/MWh, the electrolysers are operating at full load. When the electrolysers are operating at part load the marginal price is 60€/MWh (The electrolysers are the marginal technology).

Under the above market arrangement and assumed electrolyser operator bidding behaviour, the cost of electricity procured by the electrolysers is always lower than the average marginal price. The figure below illustrates that the difference between the two widens in countries with low EFOH of the respective electrolyser fleet.

Figure 12. Average electrolyser power cost



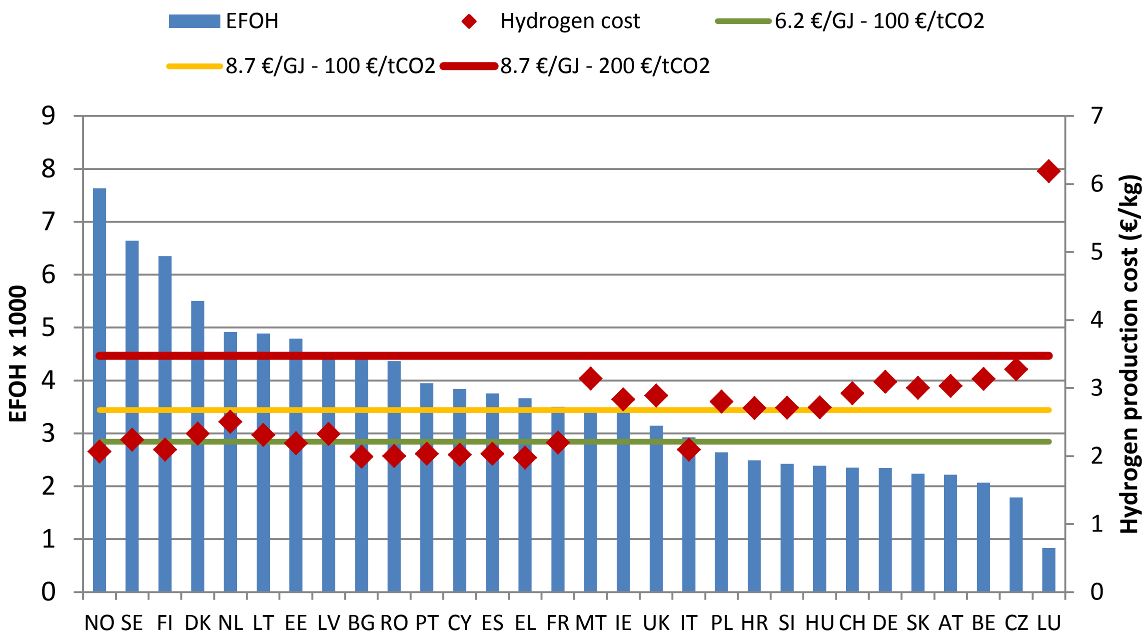
With the exception of two outliers (LU and MT) and the triad IE, NL and the UK which is marginally above 40€/MWh, the cost of electricity powering the electrolysers is below 40€/MWh. By combining the above results and the factors presented in paragraph 3.3.2 (CAPEX and efficiency), we may derive the resulting average production cost of H_2 in each country.

4.5 Production cost of H_2

The average production cost of H_2 is, as explained in paragraph 3.3.2, a function of the CAPEX value of the electrolyser infrastructure, the equivalent full load operating hours (**Figure 10**) and the average electrolyser power cost. Other factors being equal between countries (CAPEX and electrolysis efficiency) this cost will vary depending only on the variation of the EFOH and the cost of power. The figure below provides this variation between countries.

The results indicate competitiveness of H_2 production with electrolysis in countries where the EFOH are above 3500 hours. Small deviations from this rule are observed were the cost of electricity is close to or above 40 €/MWh (NL, DK, MT and IE).

Figure 13. Average electrolyser power cost vs alternative technology production costs and EFOH



4.6 Generator income vs Electrolyser cost

The electrolysers are setting the price in the power day-ahead market during a considerable number of hours. For most countries this number of hours ranges between 2000 and 5000. This restorative effect of electrolysers on the market price directly affects the revenues of generators. After establishing in the previous paragraph that the electricity price paid by the electrolysers is, with a few exceptions, below the threshold of 40 €/MWh, and the resulting ex-factory price of hydrogen below 3€/kg, we need to ascertain that the other end of the market can recover the investments costs.

Hydrogen electrolyser operators receive income, through a presumably established hydrogen market. Therefore, the hydrogen price sets the willingness to pay for the electricity by the operators of the electrolysers, which in turn increases VRE revenues.

Figure 14. Offshore wind generator income

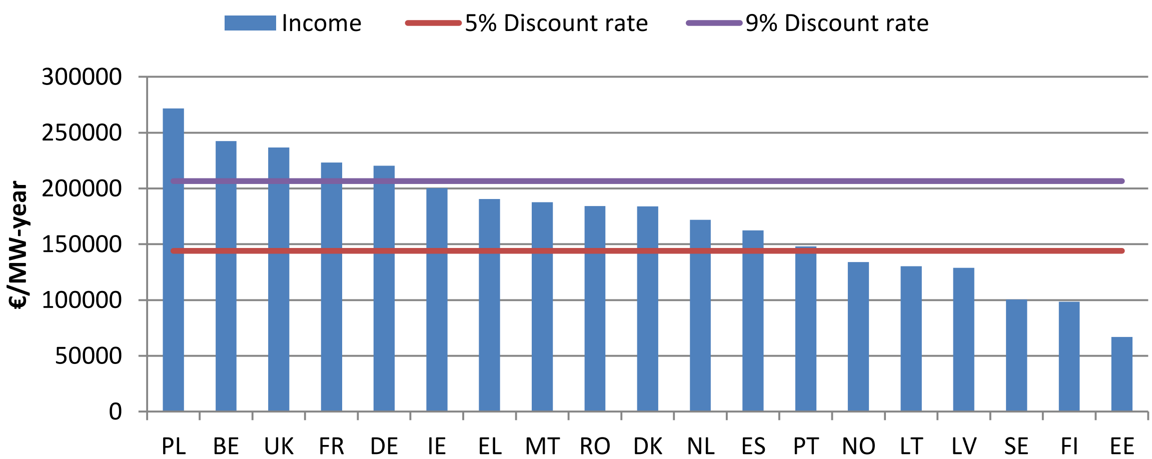


Figure 14 provides the calculated annual income of offshore wind generators vs the annuity of the technology estimated with the two discount rates.

Generator revenues are calculated based on the hourly production and hourly marginal prices for each country. A simplified quick assessment of the viability of the offshore wind investments can be conducted by comparing the annual income of each VRE technology with the respective required annuity calculated for 2 discount rates: a low value at 5% and a higher value at 9%. The annuity for each technology is based on CAPEX values of 1200 €/kW, 2030 €/kW and 400 €/kW for onshore wind, offshore wind and PV respectively.

Similarly the projected annual incomes for onshore wind generating and solar generating technologies are provided in the figures below.

Figure 15. Onshore wind generator income

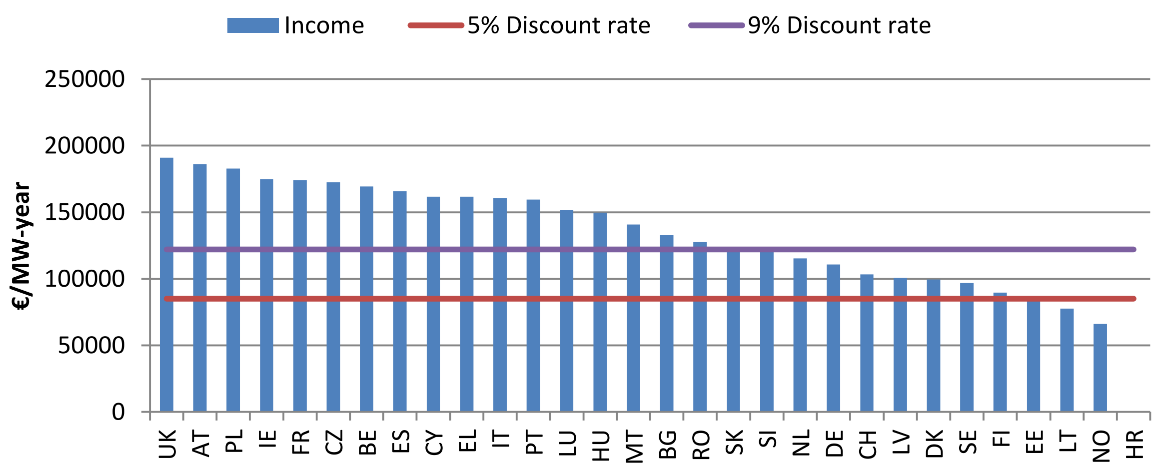
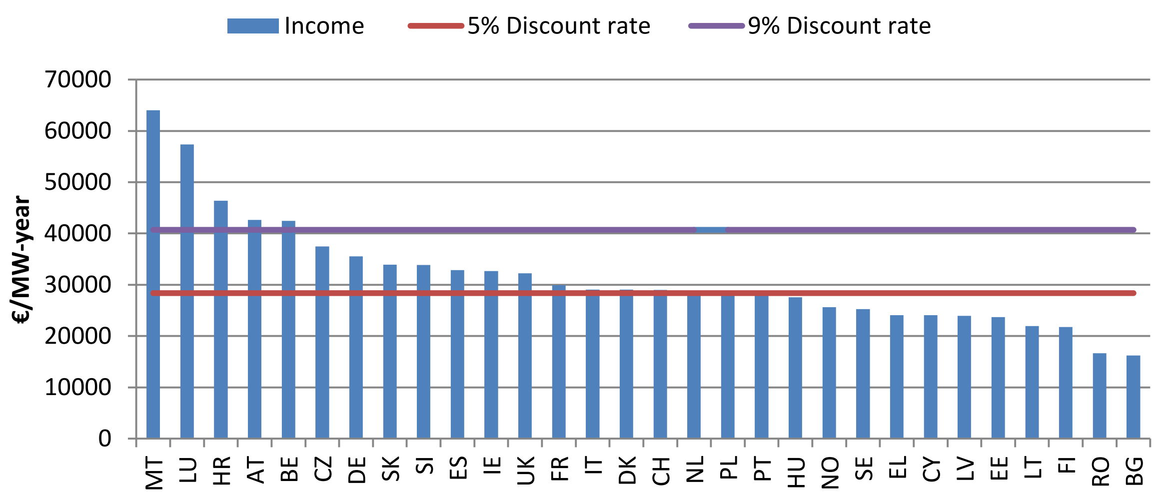


Figure 16. Solar generator income



The results presented above indicate that on-shore wind power generation in the climatic year assessed in the present study would generate in almost all countries income above the lower discount value threshold. Lithuania and Norway are two exceptions, suggesting overcapacity in onshore wind. Similarly Romania and Bulgaria are two examples where solar generating capacity is higher than justified by the market or system needs.

4.7 Summary and conclusions

The power system simulation of the T95_2050 scenario with METIS provided insight into the possible operation of a future power system based on VREs and hydrogen.

The system defined with the energy model (JRC-EU-TIMES) presents a significant variation in VRE production surplus (available energy over firm demand) among the countries. This in turn leads to a significant variation both in the electrolyser operating hours and the resulting electricity prices. Therefore there is room for further optimisation of the electrolyser and VRE fleets.

However, under the assumptions of the present analysis, the T95_2050 based power system appears potentially sustainable. The results indicate that in most countries hydrogen production with electrolysis could be competitive to the main alternative technology (SMR with CCS/U). At the same time they indicate that all three VRE generation technologies (some better than others) could in most countries, depending on the discount rate applied, recover all or most of their investment requirement from the day-ahead power market.

Identifying the reasons for a lower performance in some countries and optimising capacities to improve this could be an area of further work.

5 Participation of the electrolyser fleet in the power market

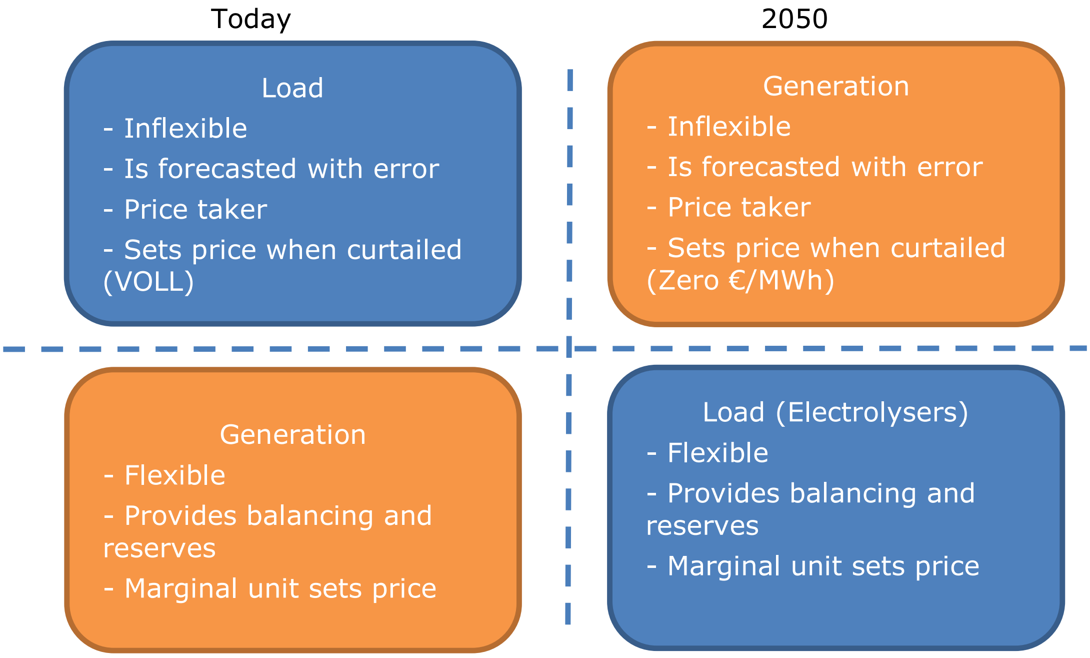
In the preceding paragraphs the operation of a power system based primarily on VRE generation was simulated, assuming an optimal dispatch of all generating technologies bidding at their variable cost. The VRE generation installed capacity is very high, much higher in fact than the level required for supplying the electricity demand. Without the electrolysers participating in the market, a significant proportion of time during the year (a few thousand hours) a generation surplus would be present, forcing VRE generation curtailment. During these hours market prices, assuming they are based on the prevailing marginal price, would be zero.

5.1 Mirroring the current power system to 2050

The electrolysers are present in the simulated 2050 power system with an installed capacity in the order of magnitude of the current thermal generation capacity in Europe. Their primary mission is to produce the volumes of H_2 necessary to supply the industrial demand and to feed the synthetic fuel production processes, by absorbing the excess production from VRE generation. However, while doing so, they can also act as balancing service providers. This function can be realized if they have the capability to provide synchronous reserves by adjusting their consumption in a way similar to the current practise of thermal power generators.

Besides producing the hydrogen feedstock required by other sectors and providing balancing and regulation services there is a third, and perhaps more important role, that of a price-setter. A simple way to explain this is by mirroring the current energy system. VRE generation in 2050 mirrors load in the current power system: It varies with time, in a way which is not controllable, but can be predicted with some error, is inflexible, is a price taker and, when curtailed, sets the price, albeit at a minimum (zero), instead of a maximum (VOLL) set by load curtailment today.

Figure 17. Generation and demand in 2050 mirroring today's participants



Similarly, electrolysers in 2050 mirror centrally dispatched power generation units in the current power systems. They are flexible, cycling and ramping as required to balance the system and, while competing to acquire the cheapest electricity, are setting the power market price.

5.2 The electrolyser fleet as a price-setter

It's possible to imagine the electrolyser fleet assuming a price setting role in a deregulated competitive power market, where a sufficiently large number of electrolyser operators (possibly with small differences in plant efficiency) compete to consume the maximum amount of electricity at the lowest possible cost. For each electrolyser operator there is a willingness to pay (WTP) price, set by the plant technical and economic performance, the downstream contracts / and or the prevailing H_2 commodity price (assuming there will be a downstream H_2 market). The WTP price for the electrolyser operators in one country or region will probably be very close to one another, much like the variable cost of generation is for current CCGT operators.

By extending the logic of mirroring today's participants in the power system of 2050, it is possible to understand the factors driving the electrolyser operator participation in this instance of a future power system (and market). Electrolyser operators competing in a power market with a uniform market clearing price would be exposed to very similar dilemmas and options, as today's power plant operators.

Power plant operators today, so long as competition is effective bid at (or close to) their marginal production costs. Similarly, if electrolyser operators participate in the day-ahead market with the same rules as power plants, they would bid for the power they will consume at (or close to) their WTP. If they opt to bid at a lower price they risk being displaced by a competitor, not accessing the power they need for producing the H_2 volumes to fuel their downstream operations.

The WTP for each electrolyser operator will probably vary, depending on the market price of H_2, the stocks, the agreements in place and the efficiency of each installation. The individual WTP and capacity value pairs, when known would be used to generate an electrolyser priced demand curve. The present analysis and power system simulation is considering a flat demand curve, bidding the entire electrolyser capacity in each country at the WTP price of 60 €/MWh.

This assumption may seem simplistic at first, but it may not deviate significantly from reality, if competition is fostered between electrolyser operators via proper regulatory oversight and system planning.

5.3 Fostering competition among electrolyser operators

In the preceding paragraphs the potential role of the electrolyser fleet as a price setter in the electricity market was presented, as well as why this appears to be possible in a deregulated power market. Contrary to the power markets today, where the supply side (generation) is setting the price, in the VRE-based 2050 power market simulated in the present report the electrolysers will be the price setters for a significant amount of time.

This means that the primary concern of ensuring competition in the power market will shift from the production side to the demand side, in particular to the electrolyser operators. The enhanced oversight could involve new indicators and monitoring.

New indicators for assessing the reliability and, more importantly, the viability of the power system should be devised. One such indicator would be the ratio of VRE installed capacity to electrolyser capacity (V/E). Methodologies may be developed for assessing the desired level of the V/E ratio, similar to current adequacy assessments. The thresholds of this indicator would indicate whether the power system is in need of investments in VRE generation or electrolyser capacity.

Monitoring electrolyser operator bids would build upon the current practice of monitoring power plant bids. This task could be carried out by Regulators or Competition Authorities with the mandate to intervene and avert collusion.

6 Conclusions and possible further work

The present analysis demonstrated how a power system model may be used to gain insight and apply concepts, regarding competition and markets, applicable today to a possible future instance of a power system.

The METIS model was used to analyse a potential future scenario of the European energy system in 2050 generated with JRC-EU-TIMES. In this scenario electricity is the primary source for producing synthetic fuels, primarily for transport and hydrogen for energy intensive industries (Steel). The scenario favours electrolyser deployment and was selected in order to analyse the technical and economic viability of such a deployment, given the very important challenges posed by VRE integration at levels beyond 50%.

Thus the electrolyser turned out to be the key component of the envisioned power system in 2050. The analysis demonstrated that this component could enable the transition to an almost fully renewable power system, which is stable and potentially sustainable.

It further demonstrated that the electrolysers required for producing the volumes of hydrogen required by the downstream sectors can play two additional and perhaps even more important functions:

- They can play a role in maintaining the technical stability of the power system and
- They can restore a price to the power market dominated by prime movers with close to zero variable cost.
- They can eventually completely substitute legacy gas fired units by reversing into production mode (fuel cells).

The above roles may be fulfilled if the following conditions are met:

- The electrolysers can be operated in a flexible manner without major degradation of performance.
- The electrolysers participate in the power market providing energy and balancing services on a competitive basis.
- Effective market monitoring is in place to avert collusion and to monitor adequacy indicators for electrolysers and VRE generation.
- Approximately one third of the electrolyser capacity is reversible.

The future power market could be structurally different from the current power market in terms of roles. While supply and demand will have to be met at all times, the two roles will be switched: In contrast to current practise the demand side (primarily the electrolysers) would be providing energy and the essential services for balancing the power system, while the production side (mostly renewables) would represent the inelastic part of the equation, similar to the role of demand in the present power system.

6.1 Possible further work

- Use of the capacity expansion module of METIS to assess the potential for optimisation in T95_2050 system.
- Derive WTP price versus volume curves based on input from the energy model and literature.
- Assessing the optimal V/E capacity ratios for every country.

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List of abbreviations and definitions

CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCU	Carbon capture and usage
EFOH	Equivalent full operating hours
NTC	Net transfer capacity
OCGT	Open cycle gas turbine
OPEX	Operational expenditure
PEM	Proton-exchange membrane
P2X	Power to X
PtG	Power to gas
SMR	Steam methane reforming
V/E	Variable renewable energy capacity to electrolyser capacity ratio
VRE	Variable renewable energy
WTP	Willingness to pay

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Annexes

Annex 1. A description of the models

The JRC-EU-TIMES model

For more detail on the structure and considerations of the model you may refer to [4,5,22–26].

JRC-EU-TIMES model is a partial equilibrium, linear optimization, bottom-up technology model created with the generator from Energy Technology System Analysis Program (ETSAP) of the International Energy Agency [1–3]. Its objective is the satisfaction of energy services demand while minimizing (via linear programming) the discounted net present value (NPV) of energy system costs, subject to several constraints. Energy system optimization is different from doing NPV calculations for analysing the business case of a certain technology. The most important difference is that in an energy system model, prices (e.g. for electricity) are not predefined, but endogenous.

As a partial equilibrium model, JRC-EU-TIMES does not model the economic interactions outside of the energy sector. However, it does capture the most important feedback through the use of price elasticities that change the final energy demand of services. This is a proxy for converting the cost minimization to economic surplus maximization. Moreover, it does not consider in detail demand curves and non-rational aspects that condition investment in new and more efficient technologies.

A key feature of the model is that the end use demand is not defined as power, gas, oil demand, but instead the services that are satisfied with those commodities (e.g. number of houses, space to be heated, materials, traveling distance) and the energy carrier used to satisfy those needs is an endogenous option.

There are common characteristics and limitations of energy system models, specifically with cost optimization. These include in terms of approach: perfect foresight (knowledge in the base year of all the future demand and global prices), central optimization (best decision across sectors, which in reality include many stakeholders), rational behavior (choice for cost optimal alternative without consideration of politics, social acceptance, personal interests) and perfect competition (no market distortions).

The METIS model

For more detail on the structure and considerations of the model you may refer to [29][30].

The METIS model is a modelling tool that can quickly provide robust insights on complex energy related questions, focusing on the short term operation of the energy system and markets.

The power system module used in the present analysis represents the power system by a network in which each node stands for a geographical zone that can be linked to other zones with power transmissions. Exchanges of energy between nodes are limited by the NTC, which is exogenously defined.

The simulation consists of the optimisation of the operation of the system assets over a year, at an hourly time step by minimizing the overall cost of the system to maintain supply/demand equilibrium at each node. The optimisation problem is linear and is solved using a rolling horizon approach.

In METIS, units of the same technology or using the same fuel in each zone are bundled together into the same asset in a cluster model which simulates the dynamic constraints and starting costs in a relaxed (LP) unit commitment, without using binary variables.

Assumptions for scenario chosen from JRC-EU-TIMES for this study

Table 2. Scenario chosen from JRC-EU-TIMES for analysis in METIS.

Parameter	Value	Reasoning
95 % CO2 reduction	228 Mton of CO2/year for EU28+ by 2050, which represents 95% CO2 reduction vs. 1990	It is expected that PtG will play a larger role as target becomes stricter since there is limited budget for emissions from gas
No underground CO2 storage	Absence of CO2 underground storage (e.g. due to lack of social acceptance)	This has been identified as key option to decarbonize the energy system, especially sectors other than power. Not having CCS will make the need for other technologies larger
High wind and solar potential	Higher PV and wind potential (see Appendix 1)	Initial estimates are conservative. If higher potential is assumed, more VRE deployment will lead to more electricity surplus to deal with and a larger need for flexibility where PtG can play a role
Best PEM (electrolyser) performance	Electrolyser cost of 400 €/kW and efficiency of 86% (including heat recovery) by 2050	Technology is its early stages. Learning curve is dependent on deployment which is in turn uncertain, as well as breakthroughs in research
Limited geothermal potential	Maximum of 300 TWh for EU28+ (see Appendix 1)	There are optimistic estimates from GEOELEC with almost 3000 TWh for EU [32], while geothermal contribution to power is at most 2-2.5% of generation for most of global studies

Annex 2. Renewable potentials

Figure 18. Installed solar power capacity in T95_2050 vs theoretical potential

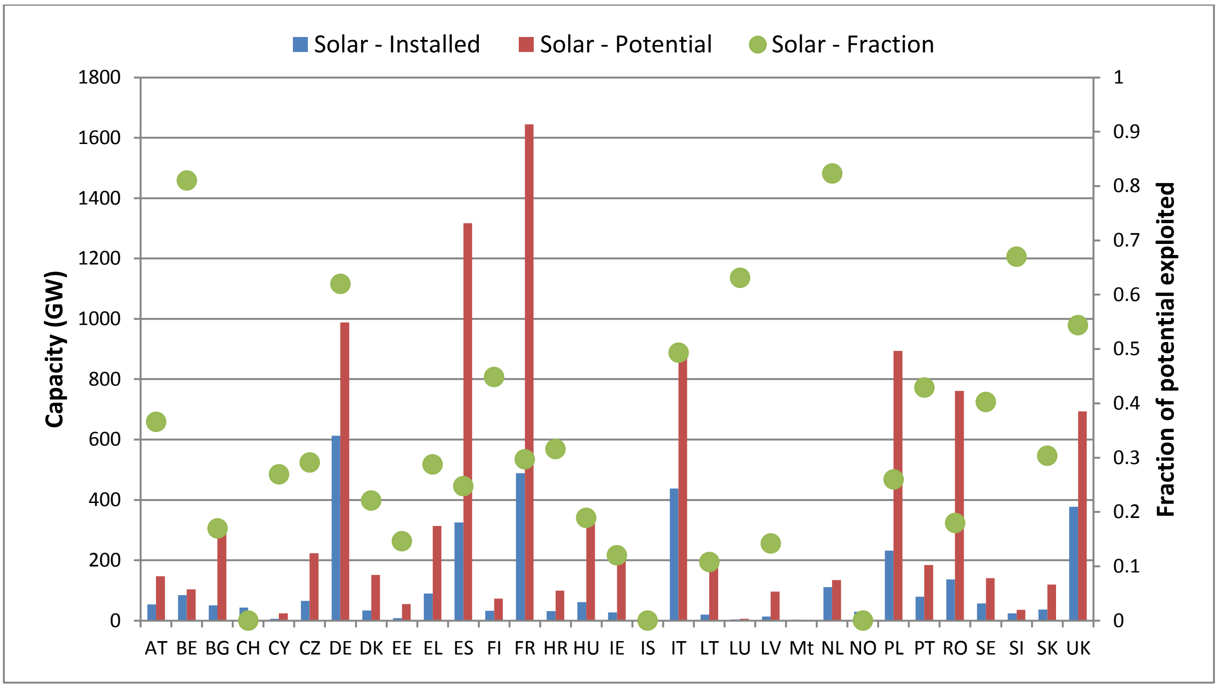
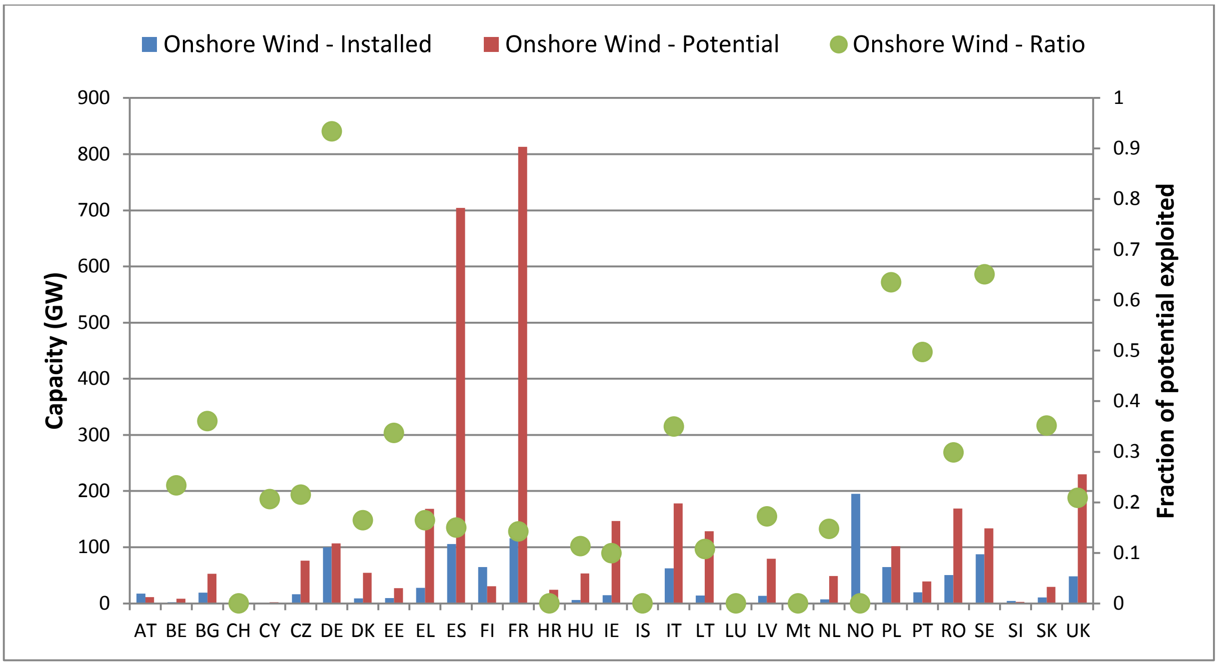


Figure 19. Installed onshore wind power capacity in T95_2050 vs theoretical potential



Annex 3. Interconnection capacities

Interconnection	2020	2030	2050	Relative increase %	Increase (GW)
ES-FR	3.81	4.0	14	267%	10.19
DE-NO	1.43	1.5	9	529%	7.57
DE-SE	0.57	0.6	8	1304%	7.43
AT-DE	2.1	7.3	7.5	257%	5.4
GR-IT	0.5	1.0	6	1200%	5.5
NL-NO	2	2.1	7	250%	5
BG-RO	0.57	4.2	4.7	725%	4.13
GB-NO	1.33	1.4	5	276%	3.67
AT-IT	0.43	1.5	4	830%	3.57
DE-FR	3.14	3.3	6.6	110%	3.46
CH-DE	3.81	7.2	7.2	89%	3.39
BE-GB	0.95	1.0	4	321%	3.05
DE-DK	2.38	3.5	5.15	116%	2.77
BE-NL	2.29	2.4	4.9	114%	2.61
HR-SI	0.95	2.7	3.5	268%	2.55
DK-NL	0.67	0.7	3	348%	2.33
FR-GB	3.62	3.8	5.9	63%	2.28
ES-PT	2.86	4.0	5	75%	2.14
DE-PL	1.14	3.2	3.24	184%	2.1
DE-LU	0.93	1.9	3	223%	2.07
BG-GR	0.76	0.8	2.8	268%	2.04
CY-GR			2	inf	2
HR-HU	0.57	2.55	2.55	347%	1.98
CH-IT	4.04	4.24	6	49%	1.96
AT-SI	0.86	1.51	2.7	214%	1.84
FR-IT	3.57	3.75	5.35	50%	1.78
HU-RO	1.05	1.1	2.8	167%	1.75
IT-SI	0.41	1.32	2.15	424%	1.74
NO-SE	3.43	4.97	4.97	45%	1.54
BE-FR	3.52	3.7	4.97	41%	1.45
FR-IE			1.4	inf	1.4
LT-SE	0.67	0.7	2	199%	1.33
CZ-DE	3.05	3.2	4.26	40%	1.21
FI-SE	3	3.15	4.1	37%	1.1
DK-NO	1.62	1.7	2.64	63%	1.02
DK-SE	1.97	2.86	2.98	51%	1.01
FI-NO	0.1	0.1	1.1	1000%	1
GB-IE	0.86	1.4	1.85	115%	0.99
GB-NL	1.23	1.29	2	63%	0.77
CH-FR	3.05	3.7	3.8	25%	0.75
LT-LV	1.43	2.15	2.15	50%	0.72
DK-GB			0.7	inf	0.7

PL-SE	0.57	0.6	1.2	111%	0.63
AT-HU	0.86	1.46	1.46	70%	0.6
EE-LV	0.76	1.34	1.34	76%	0.58
AT-CH	1.14	1.93	1.7	49%	0.56
EE-FI	0.95	1	1.5	58%	0.55
HU-SI	0.76	0.8	1.2	58%	0.44
AT-CZ	1.71	1.8	2.11	23%	0.4
DE-NL	4.62	4.85	5	8%	0.38
PL-SK	0.76	0.88	0.99	30%	0.23
CZ-SK	2.38	2.5	2.5	5%	0.12
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