HYDROGEN GRID AND OPERATING MODES : CRUCIAL MODELING CHOICES

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Overview

Especially after the Paris Agreement and the publication of "A Clean Planet for All" (European Commission, 2018), all European countries have set new targets to go further in decarbonizing energy. This often involves significant electrification (Ministère de la Transition Ecologique et Solidaire, 2018) and decarbonization of electricity. However, the other energy vectors (methane, hydrogen, heat) must also be decarbonized in order to decarbonize all energy sectors (industry, transport, residential, tertiary, agriculture) and could represent an major source of flexibility for the electrical system. Consequently, many initiatives are turning towards sector-coupling and cross-vector integration. (Clegg & Mancarella, 2015) jointly models methane and electricity but is limited to Great Britain. (Blanco, Nijs, Ruf, & Faaij, 2018) uses the TIMES tool to simulate several scenarios of the European energy system in trajectory from 2010 to 2050, but, according to (Alimou, Maïzi, Bourmaud, & Li, 2020), not using an hourly time step model to simulate the electricity supply-demand balance may result in an underestimation of investment costs by up to 28%.
For these modelings, many questions arise around hydrogen, which is currently little used compared to its future prospects[1]. In particular, there is almost no energy use of hydrogen at the moment (material use only). The importance of the network was highlighted in (Enagás, et al., 2020): ambitious hydrogen consumption requires a hydrogen grid, but it is very difficult to predict how far it will be developed. Location is also uncertain: will the electrolyzers be near the renewables or near the hydrogen consumption (which would imply a reinforcement of the electrical network)? At the same time, and as a crucial factor in the development of the hydrogen and electricity networks, several electrolyser operating modes have been considered (RTE, 2020): a base load mode (for industrial needs), an self-generation mode (with dedicated PV farms) and a marginal mode (optimized operation with the whole energy system therefore when electricity prices are low).
In order to understand the impact of these issues, using the open-source Antares tool[2], we modeled the electrical system coupled to the methane and hydrogen vectors on an hourly timestep. We raised two questions: what is the influence of the hydrogen grid in the results of the system modeling? and what does a different choice of electrolyser production mode entail? The geographical scope cover most of european load[3] and the time horizon is 2050.

Methods

To model the three energy vectors of electricity, hydrogen and methane, we used target from (Ministère de la Transition Ecologique et Solidaire, 2018) for France. Abroad, the target is from (Entsog & Entsoe, 2019) and the national strategies or European Commission's specific studies for Germany, the Netherlands, Spain, Italy, Portugal and the United Kingdom.
The modeling for electricity vector was taken from RTE's Generation Adequacy Report. We will not go into details of this part here, but it takes into account all electricity production technologies (solar, wind, run-of-river and lake hydraulics, gas, oil, coal, biomass, nuclear)[4]. Electricity consumption includes a specific part (lighting, multimedia...), electric heating and electric vehicles. Storage includes pumped hydro, batteries and vehicle-to-grid. Each country is represented by a node (except Denmark, Italy, Norway, Sweden), which implies that the electricity grid is highly meshed at the national level, and connected to its neighbours via an interconnector modelled as a Net Transfer Capacity.
In the context of this paper, we have focused on modeling the other energy vectors. Methane has a specific profiled consumption, at a daily time step, and is linked to hydrogen via steam reforming and to electricity via methanation and methane power plants, which are ways of transforming energy. We accounted for different sources (anaerobic and gasification methane, imports), storage (aquifers and depleted reservoirs) and the grid was considered sufficiently sized to simplify the methane system into a single European node.
Hydrogen is dedicated to industry, e-liquids and heavy transport consumption. Industry and e-liquid consumption is assumed to be constant over time and the heavy transport load curve is managed in a similar way to that of electric

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[1] The gas and electricity system operators expect hydrogen consumption for 2050 to be around 1000 TWh (Entsog & Entsoe, 2019) while its current use is 339 TWh, according to (Hydrogen Europe, 2019).
[2] (Doquet, Fourment, & Roudergues, 2011) and https://antares-simulator.org/
[3] Austria, Belgium, Switzerland, Czech Republic, Germany, Denmark, Spain, France, Great Britain, Ireland, Italy, Luxembourg, Northern Ireland, Netherlands, Norway, Poland, Portugal, Sweden
[4] More details on the assumptions and modelling on the website https://www.concerte.fr/

vehicles, and outside the scope of this study. Hydrogen can be produced from methane (steam reforming), electricity (electrolysis) or imported. European saline storage is assigned to hydrogen. Each country is considered a distinct node. We have modeled three options for a hydrogen network. The first one is a non constrained Europe-wide hydrogen network, but would overestimate the flexibility of hydrogen, which could conceal the problems of electrical storage and network. The second possibility is one hydrogen node per country, which assumes a highly meshed national hydrogen network but no cross-border interconnections of these networks, which seems unlikely given the expected volumes of hydrogen. For the third possibility, we did not find any source describing a prospective hydrogen network covering the whole of Europe, so we opted for an intermediate network between the previous configurations, based on the existing capacities of the methane network and assuming a partial retrofitting. Although the exact values used must therefore be considered with caution, this possibility seems more realistic in terms of general behaviour.
Following the work of (RTE, 2020), we considered three operating modes for the electrolyzers. The first one, subsequently called "base", is a base load operation except in situations where the electrical system is under strain. This mode allows a large number of operating hours to make the high investment costs of the electrolysers profitable, without penalizing the electrical system too much during peak periods. The second operating mode is called "self-generation". It is decentralized and operated in Southern European countries (France, Italy, Spain, Portugal) on dedicated solar farms PV with 10 times more capacity than the electrolyzers in order to have a higher electrolyser load factor. If a self-generation mode were to develop in Northern Europe, it would rather be assigned to offshore power plants, therefore with a profile closer to the "base" mode, which is why we have we have not modelled it explicitly. Finally, the "marginal" mode is the only non-fatal mode. It is activated in a way that is optimized for the energy system, when hydrogen consumption requires it and electricity prices are low. Unlike (RTE, 2020) which used contrasting scenarios to illustrate the associated caracteristic effects, we have simulated the 3 modes together, in order to represent the different initiatives that will emerge rather than a uniform development.
The two issues of hydrogen networks and their operating mode are related: the self-generation business model favours a location of electrolysis unit where there is a good potential for renewable energies rather than where hydrogen is consumed. In this context, interconnections would be required to transport hydrogen from the production sites to the consumption sites, increasing the total hydrogen costs.

Results

We found that the more interconnected the hydrogen system was, the less need there was for sources of flexibility (network, storage, flexible production facilities) in the electrical system. It will also reduce the need for hydrogen storage and make hydrogen balancing easier. We also found that the three electrolyzer production modes had very different production schedules and therefore different impacts on the electricity system and on gas-fired power generation. To produce the same volume as the other modes, the "marginal" mode, which operates in far fewer time steps, requires much more electrolyser capacity. It is therefore the mode for which the investment costs are the highest, but also the one for which the operating costs are the lowest. It has the best overall economic performance from a system-wide perspective.

Conclusions

We have studied different scenarios for the development of the hydrogen network (infinite, null and intermediate) and different electrolyser operating modes (base, self-generation and marginal). We found that these issues have an impact not only on the hydrogen system but also on the entire energy system, which makes modeling choices crucial. Work is underway to further understand the interactions between the different energy vectors by including heat networks in our models.

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