Modeling and sizing of a hydrogen bus refueling infrastructure – a case study for Reunion Island

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Abstract

In order to achieve energy autonomy in island systems, the heavy mobility sector is considering hydrogen in order to reduce its dependence on fossil fuels and its emissions. This paper shows that hydrogen could be integrated on Reunion Island to decarbonise a fleet of 100 buses and assesses the impacts of such an integration. Through a novel methodology for the sizing of hydrogen refueling stations, the modelled stations are integrated into the island's overall electricity network. Three scenarios on the number of stations to be installed are presented in order to analyse their impact. The results show a total need of 7.6 MW of electrolyser, 5.3 MW of compressor and 951 kgH_2 of hydrogen storage distributed among the installed stations. Installing four stations on the island would imply higher storage needs. The choice between installing two or three stations can be made according to cost, regulations or footprint criteria.

1 Introduction

As dependence on fossil fuels becomes more and more problematic, public transport is undergoing a real revolution. Worldwide, new energy sources are being studied to decarbonize the sector. Hydrogen (H_2) is one of them [1, 2]. Hydrogen buses are being developed in parallel with electric buses; they allow a faster recharge and a better autonomy, two important characteristics for a public transport network.

More and more publications focus on this transition. The hydrogen solution is often compared with a battery one, with different points of comparison: costs [3, 4], emissions [5–7], or both combined with other criteria like primary energy consumption [8, 9]. The study of fuel cell buses is often done via an implementation comparison, without simulation or optimization of the operation or impact on the electrical network infrastructure. Some articles stand out by focusing on the optimization of a refueling station and/or a fleet using a

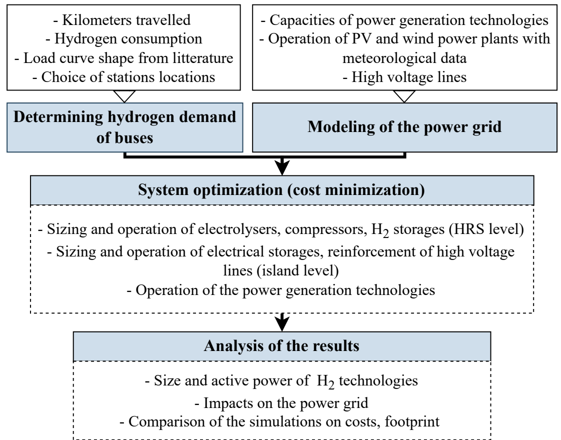

Figure 1: Flowchart of the proposed methodology.

more complete energy system modeling. While all of them focus on hydrogen production with wind power, [10] optimizes the share of the fleet switching to hydrogen as well as the power production facilities, [11] evaluates the power supply of a mini-bus fleet and [12] evaluates the different operating modes of the electrolyser.

The case study described in this paper is Reunion Island, located in the South West of the Indian Ocean and defined as a non-interconnected area. The territory is largely dependent on fossil imports for electricity production and mobility. Indeed, the inhabitants are rather dependent on private cars, no train or tramway is to be counted on the island, and the various ports and airports of the island imply a significant additional consumption. Following a national law, the island has set the objective of energy autonomy in 2030. In this study, it will be aimed for 2050. Indeed, the territory has reached a near-record energy dependence of 88.2 % in 2021, with 35 % of fossil fuels consumed going to the road sector alone [13].

The objective of this study is to evaluate the possibility of a transition of a bus network currently running entirely on diesel to hydrogen, produced by electrolysis using electricity from the power grid. To do so, a novel methodology of sizing the stations (summarized in Fig. 1) is presented, and their operation over a year is studied. The hydrogen demand will first be estimated, the local power system containing several Hydrogen Refueling Stations (HRS) will be modeled and then optimized via a system cost minimization. The applied methodology can be replicated to any non-interconnected area with a bus network willing to detach from fossil fuels.

2 Methodology

The bus network studied in this paper is Car Jaune, the island's intercity network. Five other more local bus networks exist on the island, with much lower average kilometers traveled per line. The autonomy offered by the batteries is sufficient for the buses of these networks. The map of the one studied can be seen in Fig. 2. In 2017, buses on this 17-line network traveled a total of almost 8 million kilometres [14].

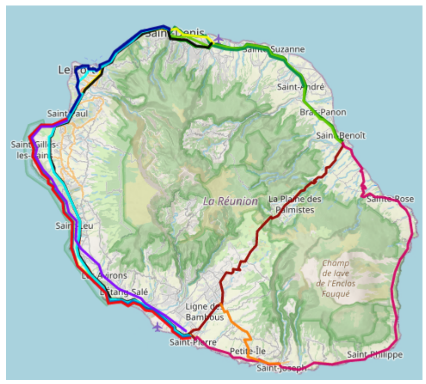

Figure 2: Map of the lines of the studied network.

2.1 Bus network evolution

In this study, only the 2050 horizon will be simulated, with the objective of energy autonomy. By then, public transport will have to evolve to reduce the dependence of the island's inhabitants on the private car. In 2020, there were nearly 400 000 private cars in Reunion Island, i.e. one car for every two inhabitants [13]. This leads to numerous traffic jams and heavy congestion on the roads during rush hours.

Based on the current network, a possible evolution for 2050 is determined. Only the frequency of the buses has been increased, in order to reach a 12.5 % increase in the distance travelled by buses per day. The specifics of the network are shown in Table 1. The values displayed are for the entire fleet. Kilometers per day were set up in particular by taking into account journeys until 10 or 11 pm, an hourly frequency, or more passage on Sundays and public holidays. The number of buses in the fleet has consequently been increased.

2.2 Load profiles

Using the daily kilometric data from Table 1, a hydrogen demand can be obtained. For almost all the lines, a hydrogen consumption of the buses at $9\,\mathrm{kgH_2}/100$ km has been considered, assuming a decrease of the consumption in

Table 1: Comparison of the network specifics.

Horizon	Annual kilometers	Kilometers on a weekday	Kilometers on a Sunday	Number of buses
Current	7.917 M [14]	24 000	11 200	94 [14]
2050	8.980 M	27 000	12 600	100

the long term, but a higher consumption locally due to the use of air conditioning in the buses (average temperature of 24°C). For three lines, the consumption was taken at 10 kgH_2/100 km because of a more marked relief on their route (up to 1 600, 400 and 700 meters of altitude).

Load curves can then be defined to simulate the hydrogen demand of the model. First, the model given by [10] is used: charging at night, mostly between 8pm and 2am. It is assumed that the operators on Reunion Island agree to work under these conditions. The curve is then adapted to the data of this case study. Considering a normal fuelling rate at 3.6 kgH_2/min [15] and an average requirement of 25 kgH_2 per bus, a bus will take about 7 minutes to be recharged. A maximum of six buses charged per hour on a single dispenser is assumed. In this study, only one dispenser per station is considered. Considering the number of buses of the modeled network, two HRS would be needed. The global load curve for the two stations can be seen in Fig. 3, drawn in blue. On public holidays and Sundays, only half of the fleet will be mobilised, thus only the morning section of the weekday curve is kept. In order to remove the night charging for the operators, two additional load curves will be tested, corresponding to a model with three and four HRS (in green and orange on Fig. 3).

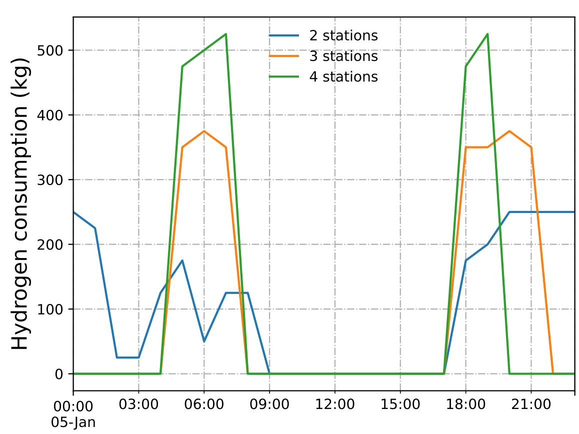

Figure 3: Load curve for a weekday depending on the number of HRS.

2.3 Refueling locations

The locations of the different HRS within the island's electrical network must be defined. First of all, the network will be modeled by its different substations. Indeed, in this study, hydrogen will be produced by electrolysis using surplus renewable electricity from the grid. It is therefore necessary to first present the local electrical model used.

The 2050 horizon will be simulated with a scenario where each local renewable electricity generation sector is at its maximum potential (see Table 2). These potentials come from [16, 17]. Three sectors not yet exploited today on the island have been considered: ocean thermal energy conversion (OTEC), geothermal energy and offshore wind. These three fields have significant potential on the island and are currently being studied. The installed power at each source station is distributed using data from [16]. To determine where to locate the HRS, the substations with the largest installed power generation capacities are paralleled with the areas with the most network line termini. These are consistent with the location of the bus company's facilities. In the case of this study, when two stations are modeled, one is placed in the north of the island, while the other is in the south. With additional stations, the additional locations alternate between south and north on the remaining substations.

Table 2: Installed power generation capacity for the 2050 horizon.

	Capacity (MW)
Photovoltaic (PV)	1200
Hydropower	233
Onshore wind	146
Offshore wind	40
OTEC	30
Geothermal energy	15
Biomass	303

2.4 Modeling

The energy system can then be modeled. In particular, the modeling of the HRS will be described.

Each substation is represented by data on electrical production, consumption and storage. These are connected to each other by the 63 kV high voltage transmission network. To the substations where a HRS is installed, an electrolyzer, a compressor, a H_2 storage and a H_2 demand are added. Two H_2 flows are defined in each HRS, one at 30 bar and the other at 350 bar. Fig. 4 shows the modeling of a substation with a refueling station.

Other assumptions must be taken into account for the overall system modeling. First, regarding the electrical demand, a load profile has been modeled

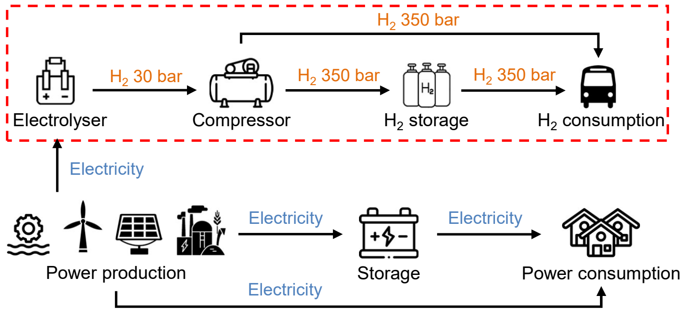

Figure 4: Proposed model of a substation with a HRS (framed in dots).

using available data for the tertiary sector and data from the main residence, occupancy and use of domestic appliances [18] for the residential sector.

Second, as energy autonomy is the goal of this study, the electrification of the individual vehicle fleet is considered with data from [19]. These were distributed to the substations according to the demography of the island. However, the electrification or the switch to hydrogen of the other bus networks were not considered, as well as the needs of the maritime and aviation sectors. Indeed, the transition of the latter two sectors is still uncertain, and their impact on the electricity grid in 2050 is difficult to assess. It will therefore not be considered in this study.

Finally, the operating models of the PV and wind power plants have been determined beforehand and validated with experimental data. All these data have been established for one year with hourly resolution. The curves of the electrical demand, PV production and wind production for a typical day in 2050 for the whole island can be seen in Fig. 5.

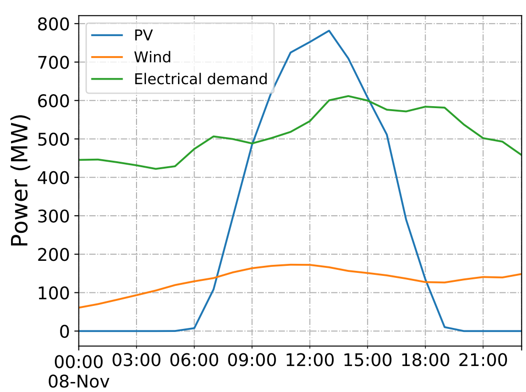

Figure 5: Simulated curves of the electrical demand, PV and wind production for the whole island for a day in 2050.

2.5 Optimization

Knowing the model and its data, the optimization can be proceeded. The following notations are adopted: n for the substations, k for the refueling stations, l for the electrical lines, t for the timesteps (every hour of year 2050) and s for the different generators, storage, electrolyzer or compressor at a substation. The input data are: the hourly electrical and H_2 consumptions ($d_{n,t}$ and $dh_{k,t}$ in MW), the nominal powers of the electrical generators ($\bar{g}_{n,s}$ in MW), as well as the necessary technical and economical data, like the efficiencies of compressors and electrolysers (η) and meteorological data (wind, temperature, radiation) for the operation of the PV and wind power plants. All technical and economical parameters used for H_2 technologies can be seen in Table 3. Compressor efficiency is taken as the average compression ratio over the whole range.

Table 3: Data used during the modeling.

Parameter	**Unit**	**Value**	**Ref.**
Electrolyzer efficiency	kWh/kgH_2	45	[20]
Electrolyzer fixed O&M	%	2.8	[21]
Electrolyzer variable O&M	€/kWh	0.12	[21]
Electrolyzer CAPEX	€/kW	585	[21]
Compressor efficiency	-	0.75	[11]
Compressor fixed O&M	%	6	[11]
Compressor CAPEX	€/kW	2400	[11]
H_2 storage variable O&M	%	2	[10]
H_2 storage CAPEX	€/kgH_2	1350	[15]

The optimization variables are: the nominal power of the electrolyzers and compressors and their hourly dispatch ($\bar{gh}_{k,s}$ and $gh_{k,s,t}$ in MW), the nominal energy of the storages ($\bar{e}_{n,s}$ and $\bar{eh}_{k,s}$ in MWh), their hourly dispatch ($h_{n,s,t}$ and $hh_{k,s,t}$ in MW) and stored energy ($e_{n,s,t}$ and $eh_{k,s,t}$ in MWh), as well as the hourly operation of the power generation technologies ($g_{n,s,t}$ in MW) and the potential reinforcements of the power grid (F_l in MVA). The hourly operation of intermittent power generation technologies is not optimized; all the possible energy produced is recovered.

The constraints of the problem are defined in (1) to (7):

$$\sum_{s} g_{n,s,t} + \sum_{s} h_{n,s,t} - \sum_{l} K_{nl} f_{l,t} = d_{n,t} + \frac{gh_{k=n,ely,t}}{\eta_{ely}} \tag{1}$$

$$gh_{k,ely,t} \times \eta_{comp.} + \sum_{s} hh_{k,s,t} = \sum_{s} dh_{k,t} \tag{2}$$

$$\tilde{gh}_{k,s,t} * \bar{gh}_{k,s} \leq gh_{k,s,t} \leq \bar{gh}_{k,s,t} * \bar{gh}_{k,s} \tag{3}$$

$$\sum_{s} gh_{k,s,t} \geq \sum_{t} 1 \times CF \times \bar{gh}_{k,s} \tag{4}$$

$$eh_{k,s,t} = eh_{k,s,t-1} - hh_{k,s,t} \tag{5}$$

$$eh_{k,s,tinitial} = eh_{k,s,tfinal} \tag{6}$$

$$|f_{l,t}| \leq F_l \tag{7}$$

Equation (1) represents the satisfaction of the electrical demand, with the power flow $f_{l,t}$ in MW and K_{nl} the incidence matrix of line l at substation n, while (2) represents the satisfaction of the H_2 demand.

The operation of electrolyzers and compressors is described by (3), with $\tilde{gh}_{k,s,t}$ and $\bar{gh}_{k,s,t}$ two time-dependent parameters restricting the dispatch (per unit of nominal power). This equation is also valid in the case of electrical generators. Moreover, (4) imposes a minimum operation of the electrolysers and compressors according to a capacity factor CF taken here at 0.8. The hydrogen storages operation is described by (5) and (6): the first equation determines the stored energy (standing losses are considered zero) and the second equation determines the cyclic state of the storage over the simulated temporality. The same constraints are defined for electrical storages. The reinforcement of power lines is defined by (7). The current limit of the apparent power that can pass through the lines was defined with data from [16].

The objective function, minimizing the investment costs on electrolyzers, compressors, hydrogen and electric storages ($c_{n+k,s}$) and power lines (c_l), as well as the operating costs of generators, electrolyzers, compressors and storages ($o_{n+k,s,t}$) is defined in (8):

$$\begin{aligned} min \sum_{n,s} [c_{n,s}\bar{g}_{n,s} + c_{n,s}\bar{e}_{n,s}] \\ + \sum_{k,s} \left[c_{k,s}\bar{gh}_{k,s} + c_{k,s}\bar{eh}_{k,s}\right] + \sum_{l} c_l F_l \\ + \sum_{t} \sum_{n,s} [o_{n,s,t} g_{n,s,t} + o_{n,s,t} h_{n,s,t}] \\ + \sum_{t} \sum_{k,s} [o_{k,s,t} gh_{k,s,t} + o_{k,s,t} hh_{k,s,t}] \end{aligned} \tag{8}$$

The modeling was implemented with PyPSA [22] and the optimization problem was solved with Gurobi.

3 Results and discussion

The system modeled above was thus optimized for three scenarios, one case with two HRS for H_2 buses, one case with three stations and one case with four. The general results are shown in Table 4. For each simulation, the results for the H_2 installations sizes are identical for each station. The total installed is specified in brackets. For the electrical storage at each substation, only the total installed has been specified. Indeed, in each simulation, electrical storage would be installed at each substation, ranging in size from a few megawatt-hours to almost 300 MWh. Two values are displayed for the investments in the power grid; the same two power lines are concerned for each simulation, one line in the south, the other in the north.

Table 4: Results of the optimizations; for the H_2 technologies, the result per station is given, the total for the island is specified in brackets.

	Electrolyzers nominal power	**Compressors nominal power**	**H_2 storage nominal energy**	**Electrical storage nominal energy (total)**	**Power grid reinforcement (on two different lines)**
Two stations	3.78 MW (7.56 MW)	2.65 MW (5.3 MW)	15.88 MWh (31.72 MWh)	1 980 MWh	+5 MVA and +2 MVA
Three stations	2.52 MW (7.56 MW)	1.76 MW (5.28 MW)	10.58 MWh (31.74 MWh)	1 980 MWh	+4 MVA and +2 MVA
Four stations	1.89 MW (7.56 MW)	1.32 MW (5.28 MW)	9.52 MWh (38.08 MWh)	1 980 MWh	+3 MVA and +2 MVA

3.1 Electrolyzer and compressor

As expected, the size of electrolyzers and compressors decreases with the growing number of installed charging stations. Indeed, the same total H_2 demand is distributed according to the number of stations.

Fig. 6 shows the typical active power of the electrolyzer and the compressor of a station from the simulation with three HRS. The operation of the compressor following the electrolyzer is well demonstrated, as well as the satisfaction of the demand by the compressor, completed by the storage. Once this demand is satisfied, the electrolyzer and the compressor continue to operate to fill the storage.

To satisfy the H_2 demand of a fleet of 100 buses in Reunion Island, the electrolyzers needed will not be larger than 4 MW and the compressors will not be larger than 3 MW. With the constraint (4) defined earlier, the two technologies

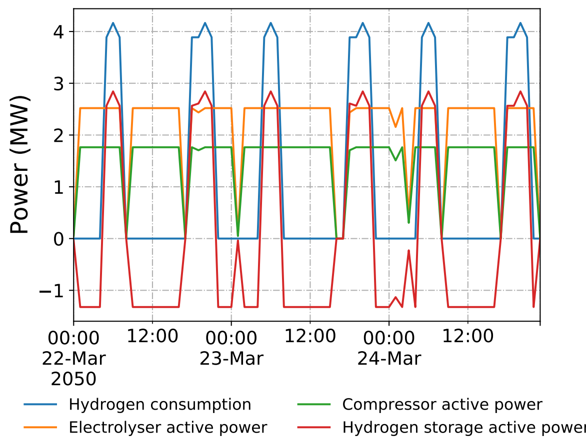

Figure 6: Hydrogen production over three days on a station of the simulation with three HRS.

are solicited 80 % of the time, i.e. 7 000 hours. Thus, these technologies could last at least 14 years by 2050 [20].

The impact of the hydrogen consumption of the buses has been evaluated on the scenario with two HRS: for a 12 % decrease in the hydrogen consumption over one day, a 12 % decrease in the size of the installations is noticed on each station, whether it is for the electrolyzers, the compressors or the hydrogen storages. Similarly, a 10 % increase in daily consumption resulted in a 10 % increase in facility size.

3.2 Hydrogen storage

Regarding H_2 storage, the same remark as before can be made: as expected, the size of the storage decreases with the number of refueling stations installed. However, it can be noted that, in the case of four installed stations, the total H_2 storage requirement will be greater. This is due to the location of the last HRS. In order to distribute two stations to the south and two to the north, the last station was placed on the second northern substation connected to the largest power generation. However, this substation is connected to less power generation than the other three (76 MW against more than 150 MW). Thus, in the case of Reunion Island, installing a maximum of three hydrogen bus charging stations would be preferable in order to reduce storage requirements.

Another difference lies in the use of these storages. While the hourly active power shows two peaks per day for three HRS, as can be seen in Fig. 6, one peak is observed per day for two stations, but with a higher intensity. This is due to the influence of the different modelled load curves.

It is also possible to evaluate the surface required for H_2 storage. Considering 10-20 $\mathrm{kgH_2/m^2}$ [15], according to the scenarios, the H_2 storage will take between

48 and 34 m^2 in the case of two stations and between 32 and 16 m^2 in the case of three. The electrolysers and compressors also require a large area, bringing the total area required for a station to around 1 000 m^2 depending on the case. Thus, each station will occupy a smaller area as the number of stations installed increases. The area available at the chosen locations may be a determining factor in the choice of one scenario or another.

3.3 Other impacts

Finally, it can be seen that the choice between the number of HRS to be installed has little impact on the overall electricity network. Indeed, the same quantities of electrical storage would be installed, and the same lines would need their capacity increased.

The integration of intermittent energies has also been evaluated. In the modeled system, these consist of PV (1 200 MW), onshore wind (146 MW) and offshore wind (40 MW). On average over the year 2050, in each case the hourly rate of intermittent energy on the total electricity production would be 38.5 % (the rest of the production being provided by hydro, biomass, geothermal or OTEC production). 9 hours at 100 % can be noticed, as well as 5 % of the time at zero intermittent production. This is how the additional storage at each source station finds its relevance, allowing to store this intermittent energy and not to degrade the safety of the system and the quality of supply. In fact, they are generally recharged during the day and emptied in the evening. Their operation is similar for each day of the year. As a comparison, the maximum penetration rate of intermittent energy on the network was 36 % [17] in 2019.

It has been seen that the total power required for the electrolyser, compressor and storage sizes is the same for two or three installed stations. Thus, the economic results of the optimisation of the simulated systems are almost identical (about 1,600 million euros). The main economic difference not taken into account in the optimisation is the cost of the station itself and the dispensers, which is however negligible compared to the cost of the technologies. It is necessary to count between 45 and 65 k€ for an additional dispenser [10] and 33.5 k€ for an additional station (grid connection, construction expenses, power transformer, etc.) [3]. Thus, the first scenario with two stations is economically optimal.

It is also possible to increase the number of dispensers per station in order to charge more buses at the same time and to reduce staff costs as well as the costs of installing an additional station.

However, the advantages of having an additional station can be to relieve the two initial stations, or to have one backup station in case of maintenance or malfunction of a station. Moreover, it is possible that with the evolution of the regulations in France by 2050, a number of three stations would be preferable. Indeed, the installation of two stations today (1 250 kgH_2 dispensed per day) would require more restrictive and longer procedures than the installation of three stations (less than 900 kgH_2 dispensed per day). This last solution would thus contribute to accelerate the island's energy transition.

4 Conclusion

A methodology for sizing the facilities of a hydrogen bus charging station has been presented in this paper. This methodology has been applied to Reunion Island, with the objective of achieving energy autonomy by 2050. The study conducted shows that considering hydrogen to decarbonize heavy mobility on the island is possible. Three different scenarios were simulated, including the installation of two, three or four HRS on the island. The results showed that in this particular case, four stations would not be optimal. On the other hand, while two HRS would be economically advantageous, other aspects may favour three HRS, such as maintenance stops or regulations.

In the further course of this work, the trade-off between electric and hydrogen considerations will be developed for the case study. The number of buses considered will be reviewed: an optimal number for the studied network will be modelled, in order to evaluate if the autonomy brought by hydrogen presents a real advantage compared to battery-powered buses [8]. The flexibility of the modelled hydrogen load curve will also be studied and optimised.

New station models will be tested in parallel, such as multiple dispensers per station or multiple electrolyzers, so that they complement each other during longer downtime, for maintenance for example.

The footprint of hydrogen storage was addressed in this paper. This parameter could be further studied using geographic information system software, in order to verify the available space of the substations mobilised in this study. An additional constraint could thus be added to the optimisation problem presented here.

Finally, hydrogen could also be integrated in the island's isolated sites and their non-interconnected micro-grid [23], or at the global scale of the island, in the form of inter-seasonal storage in each substation. In this case, the hydrogen technologies introduced in this paper for the charging stations could be mutualized, in order to maximize their use on the island.

Acknowledgements

This work has been supported by the EIPHI Graduate School (contract ANR-17-EURE-0002), the ANR HyLES project (contract ANR-20-CE05-0035) and the Region Bourgogne Franche-Comté.

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