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Comparative energy scenarios: solving the capacity sizing problem on the French Atlantic Island of Yeu

Rodica Loisel¹, Lionel Lemiale²

Abstract

Remote island communities face problems caused by the continuity and reliability of their power supply, which tend to be exacerbated when they rely on fluctuating renewables. In this paper the sizing of supply-demand-storage schemes is addressed in respect of their economy and feasibility. In the case of the French Atlantic Island of Yeu, high electricity peaks are common, due to tourism and to the seasonal use of second homes. A power plant dispatching model is used to simulate energy scenarios in 2030, subject to the supply-demand power equilibrium and the requirements of hydrogen-powered boats. Interconnected Yeu Island could accommodate 30 MW of renewables without curtailment, ensuring an electricity independence rate of 86% and renewable energy generation rate of 131% in the load, made up of wind (42%), solar (10%), tidal (21%), wave energy (25%) and biomass (2%). Excess energy could be exported through bidirectional cables, which are also the key adjustment variable in the reserve margins. Energy transition costs amount to 112 M€ in renewable-hydrogen projects, and 3 M€ for demand-side measures achieving a 2.7% reduction in load. An island self-sufficient power system with Yeu load characteristics would require at least 40 MW of variable renewables and 1 GWh energy storage capacity, at costs of 1.15 Bln€.

Keywords

renewables; islands; hydrogen; modelling; curtailment

Highlights

- Interconnected Yeu Island could accommodate 30 MW of renewables without curtailment.
- Investment costs are about 112 M€ to ensure 86% electricity independence.
- Two fishing boats would need 1.1 MW of electrolyser and 130 kg H₂ of storage.
- Production cost is 11 €/kg H₂-to-mobility made of 78% capital costs and 2% power costs.
- In isolation, Yeu Island would need at least 40 MW of renewables and 1 GWh of battery storage.

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1. Introduction: Drivers for energy transition on islands

European islands are home to 10 million energy customers and 286 territories spread out over the European Union (Eurelectric, 2012). The energy transition of these islands is part of the overall EU strategy for energy efficiency, renewables, and carbon emission targets (European Commission, 2014). However, the attributes of island life make their energy schemes different from those found on the mainland, with local environmental commitments and specific policies of governance and finance.

Traditionally, islands have relied heavily on an external energy supply, and many of them opted for diesel as fuel for power generation (Eurelectric, 2012). This has proven to be unsustainable, due to local and global pollution, and costly due to the severe risk of oil price volatility and economic vulnerability (Notton, 2015). The energy mix on an island is driven by specific attributes such as land area and population, remoteness, economic structure, and the capacity to develop interconnections. For instance, Spanish islands are isolated from the mainland grid system due to the volcanic topography of the seabed which makes difficult the installation of submarine cables (Petraokopoulou et al., 2016). The renewable energy potential of biomass, wave, tidal, solar, and wind could contribute to sustainable development and reduce carbon footprint, though not without challenges in terms of capital cost, system balancing, tourism threat, local opposition, and weak economies of scale (Moller et al., 2012).

From the perspective of energy policy, energy dependency covers several areas, such as a dependency on a single supplier with a monopoly as the usual form of competition; a dependency on one supply route or interconnection; a dependency on one major energy resource and an attendant vulnerability in the case of resource disruption; and a dependency on fossil fuels. An energy-independent system would guarantee autonomy when based only on local resources. Alternative options for power systems are autarky (so-called stand-alone systems or electrical island; Rae and Bradley, 2012, Pillai et al., 2011), or interconnection with the mainland and the export of excess power (autonomous systems, such as the Scottish Orkney Islands; Wright, 2016). From the carbon content point of view, energy independence could be sustainable when generation is based on renewables, or it could have different degrees of resource exhaustion when based on fossil fuels.

The literature on scenarios for islanded power systems is broadly made up of three work categories: studies addressing the energy transition on islands, works handling the renewable-storage sizing problem, and works on energy modelling in support to capacity planning.

The first literature type addresses the issue of islands as test cases for new technologies in attempts to prove feasibility, and islands which have already moved on from the testing phase to the commercial phase, adopting full-scale technologies (Erdinc et al., 2015; Kuang et al., 2016). A growing number of works present lessons learnt in terms of cost, energy mix, technology availability, and demand-side options: Notton (2015) and Selosse et al. (2014) on French islands; Giatrakos et al. (2009) on Crete; Krajacic (2009) on the Croatian island of Mljet; Demiroren and Yilmaz (2010) on the Turkish island of Gökceada; Pina et al. (2012) on the Portuguese Azores; Nielsen and Jørgensen (2015) and Pillai et al. (2011) on Danish islands.

The contribution of this paper provides orders of magnitudes of the scale of renewable energies required to meet the demand on islands with similar climate conditions and tourism factors as the Atlantic Island of Yeu. To that, a detailed description of the load is performed by usage, by day and by season, along with a detailed method for load energy management such as to anticipate social and technological load changes. In general, works on long-term projections of energy capacity assess the way the demand could accommodate the variable

power supply through demand-side management (Praene et al., 2012, Giatrakos et al., 2009). Load management methods are used to assess the gains of appliance efficiency and the behavioural changes, but also the flexibility capability of the demand to face a variable energy-based supply (Critz et al., 2013).

Secondly, a relative large number of studies deal with the issue of sizing the storage and renewables in remote communities. An extensive review of literature on approaches and on the current status of renewables in islands is presented in Kuang et al. (2016), Cross et al. (2017), Rodrigues et al. (2014), Lin et al. (2016), Goel and Sharma (2017), Blechinger et al. (2014) etc. The usual forms of energy storage are batteries, compressed-air, pumped-storage hydroelectricity and hydrogen for long-term applications, and flywheels and supercapacitors for grid power quality control. The on-island power generation can relate to a single technology type or to a mix of technologies, see for instance 100% renewable scenario on a small remote island made of wind, PV, hydro power, batteries and hydrogen storage in Kennedy et al. (2017).

Island power systems are typically characterised by a high ratio of total installed capacity over peak load and a low capacity factor (Cross et al., 2017). For orders of magnitude, Ogunjuyigbe et al. 2016 size the capacity requirements to meet the load of one household and find that 100% renewables' scenario could be effective with PV panels with nominal capacity of 570% of the user's maximum instantaneous load requirement and batteries with 30 days storage autonomy; or with wind turbines sized to 490% of the user's peak load and the same storage capacity as for the PV. A hybrid scenario would require capacities for PV, wind and diesel generators sized at 172%, 164% and 120% of the peak load respectively, and with battery storage of 6 days of autonomy.

Rodrigues et al. (2015) size NaS (sodium sulfur) battery energy storage to wind power in Crete Island and find that 170 MW wind plant would require 288 MWh/40 MW of storage to optimally reduce the power curtailment and the annualized cost, e.g. the battery capacity is 23% of the nominal capacity of the wind plant.

Pflaum et al. (2017) propose battery sizing with PV panels that provide guaranteed expected revenue in the French regulatory context. The energy is remunerated at flat tariff of 0.10 €/kWh, while penalties apply to deviations from the day-ahead predictions of PV energy injected into the grid. The optimal battery size maximizing the profit will depend on the battery cost, such that 5 MW PV plant would need a battery capacity of 200 kWh if the storage capacity cost is of 100 €/kWh, and no battery at all at higher capacity costs. That is, providing accurate variable renewable power leads to a PV:battery sizing ratio of 1:0.04 or a battery capacity of 4% of the PV nominal power. The ratio varies with the modelling choices, such as the proposed regulatory penalties for forecasting deviations (soft constraints) versus technical ramping rates (hard constraints) leading to a larger battery capacity such as 30% of the PV capacity in de la Para (2015).

This paper contributes to this literature with quantitative comparisons for given technology mix scenarios allowing stakeholders to select the renewable-storage combination that best fits policies and targets in terms of renewables' integration support, curtailment avoiding, utilisation factors of storage, and investment cost.

Finally, quite a lot of works address the issue of building scenarios for the generation capacity planning. The classical formulation of the optimal investment strategies is the cost-minimisation programming of building and operating power plants over the long term (10-40 years) or the cost-efficient dispatching by allocating installed power plants in a short term (1 day or several weeks, up to 1 year). While the former models are used to plan the best technology mix, the later type is used to check the feasibility of the obtained best mix and to

draw a detailed operation pattern of power plants due to specific cycling and load-following features (Oree et al., 2017, Pereira et al., 2017).

Works dedicated to energy planning modelling are reviewed by Sadeghi et al. (2017), Oree et al. (2017), Saboori et al. (2017). Some of the reviewed studies highlight the advantage of modelling the uncertainty of investment strategies by means of scenarios with respect to multi-criteria decision-making objectives. The most relevant indicators for renewable integration assessment are the overall system costs, emissions, the expected energy not supplied, the external energy dependency, the system reliability, the firm capacity added to the system, the forced outage rate of conventional units and capacity factors of power plants.

Combining both long and short-term planning decisions is usually done by soft linkage within an iterative approach or by means of integrating economic dispatch or unit commitment modules in the long-term investment schedule. For instance Pereira et al. (2017) assess future mixes of power plants by means of an integrated model able to evaluate the hourly impact of renewables on thermal power plants efficiency. Integrated models usually solve a largescale, non-linear discrete and dynamic optimisation problem in highly constrained environments, which increases the computational time (between 10 and 18 hours in the later study). For this reason, only representative days are simulated over the year. In line with this complexity, Maizi et al. (In Press) develop the Reunion-TIMES model to evaluate the French Reunion Island's power system. To reach 100% renewable energy in 2030, several measures are required such as strengthen power grid capacities, demand-side programs to flatten the load curve, and on-grid storage technologies in support to frequency controls. By providing sound options for the long-term development based on a technology-rich representation, the model depicts the short-term by selecting only representative time-slices for an average day for each season every year over the entire simulation period.

In general, the computational time limit binds the modeller to make a trade-off between detailed long-term representation of the power plant capacity planning and detailed short-term depiction of power plant operation. Combining both would necessarily limit the explanatory power of one of them in order to reduce the computational complexity. The model built in this study belongs to the short-term dispatching model category that consists of testing several scenarios of generation capacities and selecting a set of possible optimal solutions constrained by political objectives. The model uses a detailed time decomposition to cover a huge diversity of loads of RES availability and power demand values, which seems to best describe the demand chronology over the year. By making a high temporal resolution, the model proposed is able to fully capture the renewable input availability and the generators operation. This choice is adapted to model the energy storage in particular, with respect to operational constraints. The storage dynamics described here over 8760 hours is driven by the demand and renewables' loads and needs no hypothetical starting and ending storage filling values between two consecutive days as in models with representative time-slices. This eliminates the drawback of limited duration curves which assume a set of theoretical initial and terminal conditions of the state-of-charge of the storage or a desired state-of-charge pattern (Pflaum et al., 2017).

Relatively few contributions to our knowledge combine all three topics related to the load management and the assessment of a set of scenarios with storage and variable renewables (VRES) by means of dispatching modelling. The final outcome is the formulation of a multi-criteria approach that enable the policy maker to consider multiple objectives in the decision process. Energy planning becomes a challenge when the lack of economies of scale leads to capacity oversizing and reduced investor profitability. The example of the French Island of Yeu represents a useful test bed for regulation, business, and technology due to its ambitious energy transition objectives, its energy potential diversity and its complex load profile

(Section 2). An optimisation model is built to simulate power production and consumption on the island (Section 3). Successive runs are used to compute the level of electricity independence and to describe the impacts on the power system (Section 4). Finally island specific market mechanisms for the island are designed (Section 5).

2. The case study: Yeu Island

The Island of Yeu is a French territory located in the Atlantic Ocean, with an area of 23 km² and 5,000 regular inhabitants, or 40,000 in summer. The annual final energy consumption is 77 GWh (2012), of which electricity is 54% and oil is 46%. Yeu is interconnected to the mainland grid via 27 MW submarine distribution cables, which fully meet both demand and reserve margin (see the location of the island at Fig.1, at 25 km from the mainland).

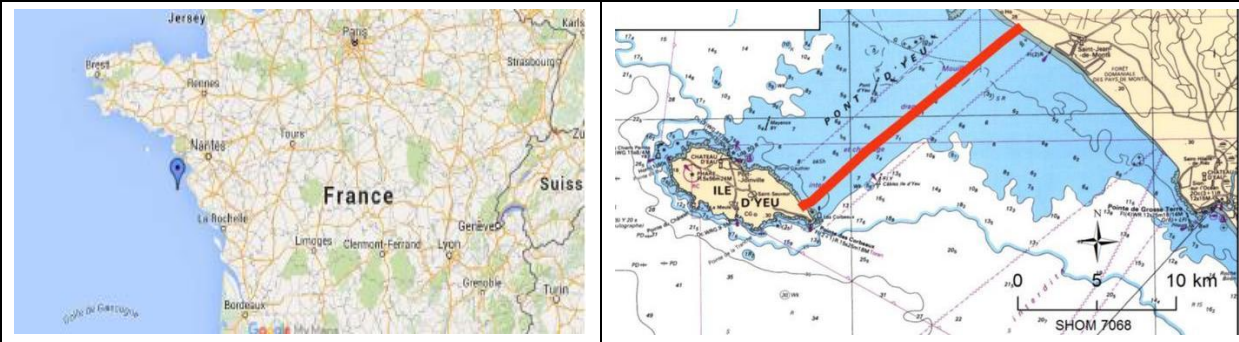


Fig. 1. Location of the Island of Yeu related to the French mainland

Sources: <http://data.shom.fr>, <https://maps.google.fr>

Electricity demand comes from households (71.3%, of which 51% is seasonal housing³), services (18.3%), public administration (6.5%), and industry (3.9%). The average daily load was of 113 MWh in 2012 with a peak of 10 MW. The annual load exhibits seasonal variations reflecting the climate, accounting also for the effects of tourism and secondary and seasonal homes (Fig.2). The hourly peaks in load exhibit some periodicity. Fig. 2 illustrates four average daily load profiles with four peaks⁴: two night-time peaks, around midnight and at 3 am, mostly a result of the deferral of electric appliances such as water heaters, and two day-time peaks, one of which is long-lasting at around midday and one of which is evening peak. Fig. 2 smooths out the load over the month such as the peak times do not show up at the maximum level of 10 MW as announced above.

³ The figure is based on authors' calculations (see section 3.1).

⁴ On Yeu a Time of Use tariff applies, with four time frames (TF). TF1: 0-8am, TF2: 1.30-7.30 am and 12.30-2.30 pm, TF3: 10.30 pm-6.30am and TF4: 11.30 pm-7.30 am.

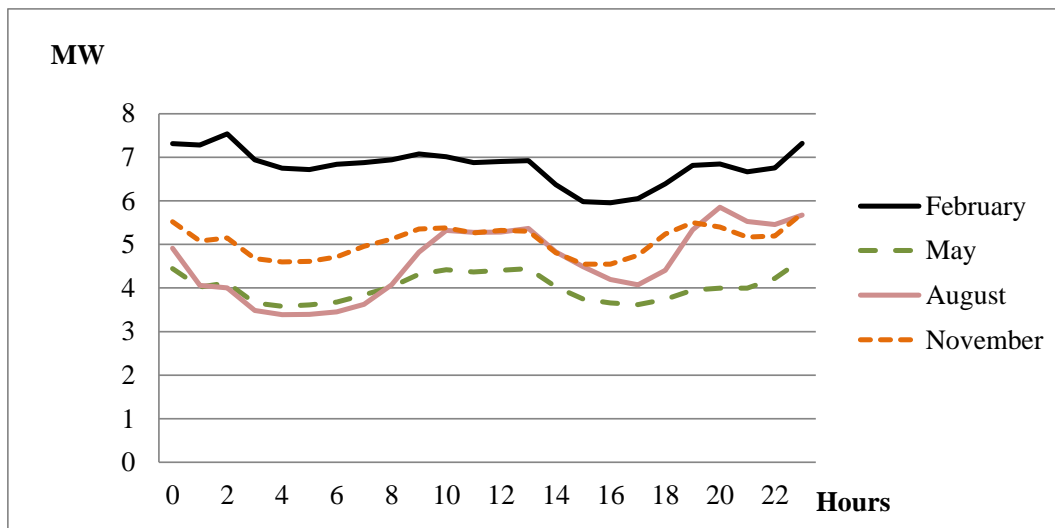


Fig.2. Representation of the average daily demand profile of Yeu Island

Source: Enedis database (2010-2014)

In 2010 the island authorities drew up an energy roadmap with ambitious commitments, targeting the deployment of electrical vehicles, hydrogen-powered cars, solar panels, sustainable tourism and agriculture, and citizens' involvement in deploying offshore wind farms (*Energy Transition, Yeu 2030*; PCET, 2015). They committed to develop the hydrogen economy on the island and started demonstration projects of three electric cars with hydrogen fuel cell range-extendors (Renault, Kangoo Z.E.) fuelled by a 5 kW distribution hydrogen plant (MEDDE, 2015). Other projects are under evaluation, such as an electric mini-bus with hydrogen fuel cell and a hydrogen-powered fishing vessel (MH2, 2015).

While Yeu has the potential to set up renewable energies, at present only 0.2 MW of solar panels are installed, with further projects under evaluation. Industrial-scale deployment faces constraints related to urban planning and to environmental *Natura 2000* site-specific restrictions (OJ, 1992). Marine energies could also be restricted by the tourism and fishing sectors. The island is faced with many challenges common to all remote systems, and tailor-made solutions are required to account for its particular characteristics in terms of economic infrastructure, location, and its legacy as a protected natural site.

3. Methodology

The Island energy transition roadmap addresses both the demand and supply sides. Demand management combines measures of energy savings, peak shaving, and consumption reporting. Literature and expert evaluation are used to produce a load projection (3.1) and hydrogen mobility needs (3.2). The supply side covers a wide range of technologies based on the local energy potential. A power-plant dispatching model is used to quantify the hourly energy generation by technology type (3.3).

3.1. Electricity demand in 2030

Two scenarios are built to project the load in 2030, based on different assumptions documented by the French Transmission Operator (RTE, 2014). These scenarios are likely to draw the evolution of the load by 2030 in the absence of regulatory incentive measures, taking into account technological progress and behavioral structural changes:

- The Low Demand (LD) scenario assumes a low electricity demand in 2030 due to economic growth rates of 1.2% per year, low usage of electrical appliances, and investment in insulation. The demand is 17.6% higher in 2030 than in 2012, e.g. 7.4 GWh more.
- The contrasting High Demand (HD) scenario assumes economic growth of 1.5% per year, a high penetration of electrical appliances (100% electrical space and water heating equipment for permanent residents), but also higher efforts of insulation. Here the demand obtained is 35.4% higher in 2030 than in 2012 (see Table 1).

Each scenario tests two options: one with no demand-side management (DSM), and one with voluntary DSM measures such as to assess the cost range of energy saving efforts. The focus is on modelling the patterns of behaviour of permanent residents, to which DSM measures could easily be applied, due to the regularity of their consumption pattern. The growth rates of the load by sector are included in the Annex A3.

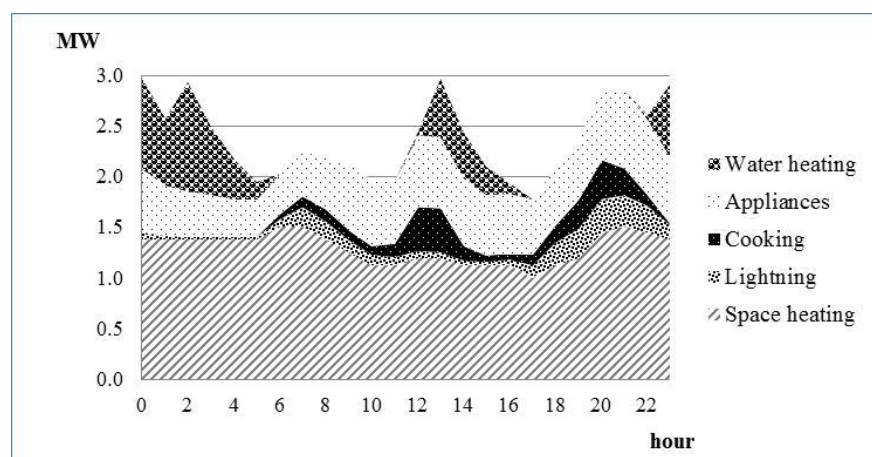
Table 1. Demand scenario characteristics

Scenario	Reference	Scenario Low Demand 2030		Scenario High Demand 2030	
		Without DSM policy LD	With DSM policy LD-DSM	Without DSM policy HD	With DSM policy HD-DSM
Indicator	2012				
Load, GWh	41.5	48.8	47.5	56.2	53.9
Peak load, MW	10.1	12.3	11.6	14.3	13.2

The main assumptions on load variation relate to the pattern of households' load by usage and to DSM measures.

Electricity load decomposition. In a first step, permanent⁵ households load is split into eleven usage types by applying standard coefficient of households consumption, issued from hourly consumption national and international assessments and databases (CEREN, 2015; ADEME, 2013; Pigenet, 2009; ENERTECH, 2004, INSEE 2015). Then the hourly load is rebuilt for 12 typical days.

Data show that space heating and electrical equipment count for 78% in the annual load, and water heating for 15% (see the Annex A1). Fig. 3 displays the load profile for a typical day in February and shows that peak loads with mainly water-heaters and cooking would allow shaving the peak by shifting the water-heating only such as not to alter the utility. In the following, most of the DSM would be obtained from device efficiency savings.



⁵ Despite a large share of secondary residences (59% of the total housing stock), the consumption by usage seems difficult to model, because of the irregularity of the demand. This consumption is then the residual load of the total consumption net of the permanent residents' load.

Fig. 3. Daily load constructed by usage type for permanent resident households

Source: authors' calculations.

In a second step, socio-economic considerations are used to assess the evolution of the load.

Regarding the housing type, it should be noted that the residential consumption is highly correlated with the housing stock. It is assumed that the number of the main residences remains stable while the stock of the seasonal housing rises by 1.1% per year until 2030 (INSEE, 2015).

By usage, the space heating decreases by 50% in 2030 due to a better insulation which is triggered by State incentives (SEURECO, 2013). By scenario, the renovation rate varies with the uncertainty of these State budget-supportive measures in the long term (0.3% per year in the LD case with no renovation incentives and 1.2% per year in the HD scenario with incentives). Yet, loads by scenario evolve with the rate of the electric device equipment: lower loads in the LD scenario and higher in the HD case where households totally substitute the fuel for the domestic use with electricity (see the Annex A2).

To summarize, the second homes' load increases by 0.8% per year in LD scenario and by 1.3% in HD, due to different rates of second homes in the total housing stock and to different electrical appliances equipment.

DSM measures. Measures cutting either aggregate load or peak load aim at reducing the cost of investment in the generation capacity. Three policies are assessed such as the housing renovation, smart metering and load shifting.

An active building insulation policy would strengthen the rate of renovation of permanent residences by up to 2% per year in each scenario. The demand for space-heating decreases by 12% in the Scenario LD-DSM (0.6 GWh) and by 15% in the Scenario HD (1.4 GWh). Smart metering and the informational feedback are assumed to change the consumer behaviour, reducing the load by 5% (Lund et al. 2015, Kendel, 2015). Peaks are partially shaved by homogenously distributing the water-heating start time throughout the day. Taken together, the DSM measures reduce the permanent resident load by 9.5% in the Scenario LD-DSM and by 11.7% in the Scenario HD-DSM. With an average cost in the range of 9-18 k€ per house for insulation investment (SEURECO, 2013), and 200 € per deployed smart meter (Bergantze et al., 2014), the DSM cost, discounted at the 6% rate, amounts to 2.9 M€ in the Scenario LD-DSM and 7 M€ in the Scenario HD-DSM.

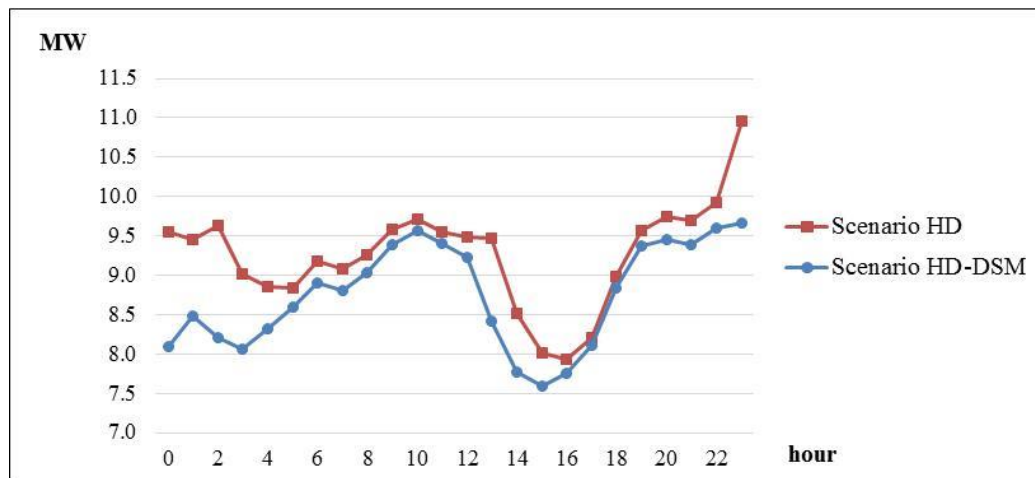


Fig. 4. Aggregate load profile

Source: authors' calculations.

Including all household types, DSM measures reduce the aggregate load by 2.6% in the Scenario LD-DSM and by 4.1% in the Scenario HD-DSM. In amplitude, the DSM smooth the daily profile and reduce the night peak (see Fig.4), such that the annual peak load is lowered by 5.7% in LD-scenario and by 7.7% in HD-scenario.

3.2. Mobility demand scenario

Hydrogen-based mobility choice is justified where there is a requirement for great autonomy. In small island communities such as Yeu, however, there are other arguments to support the deployment of hydrogen-based vehicles, such as the substitution of locally polluting diesel-fuelled boats and cars, and the possibility of producing clean hydrogen using local renewables. The hydrogen economy could bring significant benefits, such as clean production and local short-circuits between production and consumption.

- Hydrogen demand is calibrated assuming that the hydrogen-driven fleet comprises on a regular basis 5 cars, 1 minibus, and 1 delivery van. The annual distance covered by an islanded car is around 5,000 km, and 1 kg of H₂ is required to drive it 100 km. The minibus covers about half of the distance as on the mainland and consumes 20 kg H₂ daily. Cars refuel every two weeks, e.g., 1 car per day by assumption, while the bus and the delivery truck must refuel every day.
- The hydrogen demand of fishing vessels covers 2 boats in 2030, of the 32 boats currently registered at the harbour. Both hydrogen boats are assumed to be small with 24 hours of fuel autonomy and daily recharging needs. The boats' departures take place at the same time, making refuelling simultaneous. Refuelling takes a rather long time, about 8 hours, and is estimated at 65 kg H₂ per day.
- Scheduling the refuelling of cars and boats could be optimised to minimise the size of the hydrogen system. The island has significant control over the vehicle and ship fleets together with a high informational capability specific to remote areas. This leads to the assumption that the daily hydrogen-related activity could be split into two timelines, such that H₂ refuelling takes place at 10 am and 8 pm, with 25 kg and 130 kg respectively.
- The refuelling demand of cars and boats is exogenous in the model and contractually corresponds to fixed commitments to deliver the H₂ at precise times during the day. This constrains not only the capacity sizing so as to minimise the storage capacity but also the generator type supplying power to the electrolyser so as to guarantee the security of supply. The hydrogen operator cannot rely on variable renewables alone and needs a guaranteed supply from the grid as well. The algorithm describing the hourly demand of hydrogen for mobility ($D_{H2_mobility}$) over the year is as follows:

$$D_{H2_mobility}_h = \begin{cases} 25kg, h = 10a.m. \\ 130kg, h = 8p.m. \\ 0, h \neq 10a.m., 8p.m. \end{cases} \quad (1)$$

- The hydrogen system for mobility application sized at Yeu needs of 155 kg of H₂ per day will comprise an electrolyser with polymer electrolyte membrane of 1.1 MW (with an efficiency of 60%), a compressor fuelling a high pressure storage tank (efficiency of 88%), and electronic components ensuring the operation of the hydrogen production-storage system (efficiency of 90%). The round-trip efficiency of the hydrogen station is 43% (=60% x 88% x 90% x 90%; see Table 5 for a description of components). The system cost is estimated at

around 6 M€, based on vendors catalogue such as Areva and on experts' views. To the cost of the electrolyser (around 2 M€) add the cost of the compressor at 350 bar (up to 1 M€) and the cost of the storage tank (around 2 M€), plus significant expenditures with electronic devices for command and control, safety systems and civil works (1 M€). Other documents estimate the cost of similar refuelling stations with on-site electrolyser at around 5 M€ at early development stage (NREL, 2013).

3.3. Power plant dispatching model

An optimisation model is built to minimise the short-run system cost to generate and to import the power under a set of constraints. Technological constraints relate to power plant operation subject to efficiency parameters, technology availability, installed capacity, and natural inflows, e.g., wind speed, solar irradiance, wave, tidal cycles and biomass potential. Economic constraints are the variable cost of different generation options and the hourly demand in terms of volume. The model uses linear programming implemented in the Gams software with the Cplex solver.⁶ The model is dynamic with 8,760 time slices, simulating a local market, hour-by-hour. The results are the flows of the electricity generated by each technology on an hourly basis.

The model is a partial equilibrium model, built to select power supply technologies endogenously. The power demand is fixed and non-constant at each hour and includes the aggregated power consumption from households, services and industry, from electrical vehicles and hydrogen production for mobility. Imports and exports are adjusted by the model, as a function of the system-balancing requirements.

For a given amount of installed capacity, the model determines the most cost-efficient combination of installed technologies that meets the demand. The supply aggregates the power generated locally (see Table 2), the interconnection to the mainland, and when needed the hydrogen storage in the discharging mode (power-to-power). The model reproduces the electricity market operation by ordering the technologies from the lowest to the highest short-run marginal cost. Renewables have close-to-zero marginal costs due to free cost inputs, in this case wind, solar and marine energy, and have variable operation and maintenance costs. In contrast biomass has costly inputs and enters the order curve after the exhaustion of fluctuating renewables because of its dispatchable nature, but ahead of imports from the mainland, because of the feed-in tariffs allowed for cogenerating technologies.

It should be noted that the dispatching model developed here is not an investment model in support to decisions of the technology type to invest in. The selection of technologies is political and social in essence, based on the local energy potential and on projects' profitability. The scope of the model is to present the interaction between different power generators and the overall cost and profit rates. Different sizes are tested such as to cover large autonomy objective range and these orders of magnitudes could further support policy decisions and local energy roadmap building. The relevant constraints set in the model are the natural energy hourly flows, the hourly local demand, the interconnection cable limit to export the excess, and the renewable energy capacities installed, while exogenously facing the market price. The renewable energy operators are not price responsive, firstly because the variables costs are very low, which means that activating the power generators is

⁶ The General Algebraic Modeling System (GAMS) is suitable for modelling linear optimization problems, being especially useful with large database (<https://www.gams.com>). The GAMS solver Cplex is designed to solve large, difficult problems quickly. These advantages are fully exploited here to solve the power system specific problem of capacity sizing under hourly constraints over the year. Cplex optimizer helps setting the optimal solution of this detailed time decomposition model (more than 177,000 variables) in a short execution time (less than one minute).

economically interesting even for very low market power prices; and secondly, an operator cannot speculate on the wholesale market due to the negligible role played on the market, and to the fatal nature of the energy inputs.

The program minimises the annual system cost of operating power generators, which is the sum of the variable costs, such as the fuel costs, the variable operation and maintenance costs, and the import costs. The transmission loss rate is set at 2.5%. **The objective function** represents the yearly system cost minimisation:

$$Fobj = \sum_{h=1}^{8760} \sum_{tech} Generation_{h,tech} (CostVOM_{tech} + CostFuel_{tech} / eff_{tech}) + Pelec_h Imports_h \quad (2)$$

The **power market equilibrium** is set every hour (in terms of volume):

$$\sum_{tech} Generation_{h,tech} + Imports_h + Storage_out_h = Demand_h + Exports_h + Losses_h + Storage_in_h \quad (3)$$

The power generation by production type is constrained by the maximum load factors, describing the use of a technology limited by natural resource inflow and plant unavailability due to maintenance.

When the local potential of renewables exceeds the local demand, the energy operators make a trade-off between selling the flow to the mainland or to the hydrogen operator. However, when the grid line is saturated, the energy flow is freely transferred to the hydrogen operator. This arrangement could be a strong motivation for the hydrogen operator to produce in a remote system of this kind. When all demand, grid line, and storage capacities are saturated, the remaining energy is curtailed and the power generators are disconnected from the grid.

$$Curtailement_h = \sum_{tech} EnergyPotential_{h,tech} - Demand_h - Grid_capacity - Storage_capacity_h \quad (4)$$

Curtailement is the accumulation of all technology output suppressions, expressed as the residual part of the theoretical fluctuating energy resource potential, and the generation fed into the power grid or used to produce the hydrogen.

Storage operation. The dynamic operation of the hydrogen production-storage-discharge system is based on perfect foresights of the power prices and of natural inflows of wind, solar, tidal energy and waves over one year. Storage is adapted to the use of the hydrogen as a fuel compressed at 700 bars, and as a power vector compressed at 200 bars.

$$Storage_h = Storage_{h-1} + Charging_h / (eff_prod + eff_charg) - Discharging_h * eff_disch \quad (5)$$

Charging for the storage has two sources, the island local potential and the mainland energy supply via distribution cables. Discharging responds to locally high power prices to supply the power, and to fixed commitments to supply fuel for mobility. Storage occurs when there is an excess of power or when the market prices are foreseen to increase over the medium term.

A power-to-power application includes an electrolyser and one or several storage tanks at low pressure with a round-trip efficiency assumed to be 25% in 2030. The size of the electrolyser and the storage is determined endogenously by the model. As orders of magnitude, the hydrogen plant installed in the French Island Corsica in support to solar energy, comprises an electrolyser with nominal power of 50 kW, inverters, converters, two H₂ storage tanks at 35 bars of a cumulated capacity of 1.75 MWh, a fuel cell of 100 kW and transformers allowing the injection in the electrical distribution grid (Poggi et al., 2014).

Project costs and finances. Cost projections for 2030 are based on the assumptions that further research and demonstrator projects that are either planned or ongoing worldwide will reduce costs and will enhance the reliability and the durability of the components, especially

when operated intermittently. Table 2 reports the main cost and technology assumptions for the power plants.

Table 2. Assumptions made on the characteristics of renewable power plants

Technology	Capex	Opex	Technical lifetime	Capacity factor
	€/MW	€/MWh	years	%
Power plants				
Off-shore wind	6 000 000	2	25	30%
On-shore wind	1 800 000	2	25	19%
Solar panels	1 700 000	0.1	30	12%
Wave energy	4 480 000	1	25	30%
Tidal stream energy	3 400 000	1	25	24%
Biomass	3 000 000	0.5	30	50%

Source: NREL (2015)

Table 2 shows unitary costs which will be applied to the power plants depending upon the scenario. The model results in terms of power volume are extrapolated to the entire technical lifetime of technologies in order to reproduce the investors' business model. The economics of each energy project is assessed by calculating the Levelised Cost of Energy (LCOE), by summing up all overnight and discounted costs and dividing by the quantity of energy generated (EG) discounted at rate r :

$$LCOE = \frac{INV_0 + \sum_t \frac{CostVOM_t + CostFuel_t}{(1+r)^t}}{\sum_t \frac{EG_t}{(1+r)^t}} \quad (6)$$

Renewable energy investors are assumed to share the total amount of capital between the company's own capital and debt, due to the capital intensive nature of the project. The Weighted Average Cost of Capital (WACC) makes it possible to compute the additional cost induced by borrowing capital, and represents the minimum return that the investors must earn on the expected asset base. The WACC rate is set at 10%, as is the discount rate.

Power prices are documented by the Epexspot market.⁷ They are on average rather low (35 €/MWh in 2014), with negative values in some periods (-23 €/MWh) and maximum values of 108 €/MWh.

The hydrogen-to-power plant cost needs to be considered for the overall system, since it is difficult to isolate the precise cost by component. However the model sizes each component to the power system needs, according to the renewable energy capacity installed. The H₂ plant cost is considered next 1 M€/MW for the electrolyser, 500 €/kg H₂ for the low pressure storage (DoE, 2014) and 5 M€/MW for the fuel cell (NREL, 2016). To this adds the cost of converters, inverters and balance of plant, which could amount to 20% of the plant cost.

3.4. Scenarios on power plant capacities

The installed generation capacities in 2030 are based on two scenarios, the first setting the optimal level of energy independence, and the second simulating an islanded power system.

⁷ Epexspot is the platform where French power exchanges occur:
http://www.epexspot.com/fr/donnees_de_marche/

Several cases are tested, in order to select the best technical-economic combination of energy projects, based on their investment cost and usage rate.

Scenario of cost-efficient electricity independence. Small remote areas generally have a low profusion (smoothing-out) effect, and present limited uncorrelation in the degree of variability of renewables. This increases the risk of curtailing the power in surplus. Because the island of Yeu is interconnected to the main grid, the risk of curtailment is limited up to a certain level. Scenario sizing then becomes an exercise in how much local supply is necessary to match the demand, with minimum generation curtailment, such that the excess could be exported to the mainland via submarine cables. Three cables are operational today, two small cables with a capacity of 6 MW each and a larger one of 15 MW. It is assumed that the large cable is used daily while the small cables provide back-up during periods of maintenance of the large cable.

Scenario of islanded power system. This case study highlights the complexity of a system in which an islanded power system is composed of a large proportion of variable renewables. Removing the island interconnection will necessarily lead to plant overcapacity. Intuitively, the curtailment rate will be very high, affecting the profitability of investments and maintenance operations causing frequent shut-downs of the power plants. Three scenarios are used: one case assuming 100% renewables and hydrogen storage, one with renewables and natural gas turbines, one combining renewables, hydrogen storage and gas turbines. The gas-fired technology can be a simple cycle gas turbine due to the small size of the scheme (<15 MW).

Data calibration of the renewable potential is based on hourly inflow.

- The wind energy potential is based on data collected at the weather station located on the island of Belle-Ile-en-Mer, about 100 km from Yeu, and 15 km from the mainland, this choice being justified by the availability of the data.⁸ Under the physical limitations of wind availability, energy conversion, component efficiencies, and mechanical losses, an annual capacity factor of 36% is obtained. Potential error estimates are considered by downsizing the capacity factor to 30%, but accounting for the same wind profile on the both Atlantic Islands. For wind farms located on-shore, the capacity factor is further downsized to 19%. The maximum installed capacity is set at a hypothetical level of 10 MW for each offshore and onshore wind technology type, i.e. 10 MW being the load peak on the Island.
- Solar hourly potential is a function of the hourly French photovoltaic energy market data (RTE, 2012), which is the power sold nationwide in 2012. This implies that the variability is smoothed out across the different locations specific to large balancing areas. The database is adapted to the monthly average irradiance potential on Yeu, with a capacity factor of 12%. Given the small size of the island and the scarcity of space, the maximum capacity potential is estimated at 6.8 MW, this being the sum of the current 0.2 MW panels already installed, 4.2 MW roof-based solar panels on 1,100 buildings of 20 m² each, and one single 2.6 MW ground-based photovoltaic facility. Simple solar panels are considered, driven by the fact that only the electricity demand is modelled, while in practice more efficient systems could meet power and heat or air conditioning demands, e.g. solar reverse cycle air conditioners or solar heat pumps.
- Tidal energy potential is based on five-minute tides data documented by the French Hydrographic and Oceanic Marine Service. The variability is such that for 3-4 hours each day there is near-zero power generation. Unlike solar and wind power, tidal energy

⁸ http://fr.windfinder.com/windstatistics/pointe_du_talut. Data are collected at an altitude of 34 m and relate to wind speed, temperature, relative humidity, and air pressure.

variability is highly predictable, with accurately predictable daily, weekly and annual cycles. No evaluation has yet been made of the exploitable potential of tidal energy for Yeu. Assumptions on the capacity to install are purely hypothetical and are not on the local agenda; here it is supposed to set the highest capacity related to the island load, e.g., between 6 and 10 MW for tidal energy installation. A maximum 10 MW of tidal capacity is assessed at the load peak on the Island, e.g. 10 MW, such as to avoid curtailing the tidal energy over the year.

- Wave energy potential is a combination of tidal energy and off-shore wind potential. Since waves are produced by winds blowing across the surface of the ocean, the wave energy has similar variability as the off-shore wind energy with however a higher predictability due to foreseeable tidal currents. The model databases contains deterministic data, hence does not integrate the uncertainty of the forecast, and builds the hourly potential based on real data on the off-shore wind and tidal energy potential. The average capacity factor amounts to 30%, in between rates documented by JRC (2015), e.g. from 20% to 36%.
- Biomass potential is based on surveys of the municipality of Yeu and covers both forest wood potential and local waste. The total potential amounts to 2,300 tons per year, which would fuel a biomass plant with a maximum capacity of 0.5 MW (Naldeo, 2014).

4. Model results and analysis

4.1. Electricity independence scenario

In this scenario the demand load is as described in the Scenario LD-DSM, and the sensitivity of the results to the Scenarios HD and HD-DSM is tested.

The results for this scenario are presented in terms of the plant capacity and cost for each wind, solar, wave, tidal and biomass technology, and their interaction over one year.

Power system sizing. Several tests are run for different plant sizes, successively set at 0, 1, 2, 4, 6, 8, and 10 MW by technology type, leading to total capacities ranging from 0.2 to 47.3 MW.

Table 3. Inputs-outputs of the model for different plant size scenarios, Sce LD-DSM

Inputs, installed capacity MW							
Scenario	Sce 0MW	Sce 1MW	Sce 2MW	Sce 4MW	Sce 6MW	Sce 8MW	Sce 10MW
Solar panels	0.2	1	2	4	6	6.8	6.8
Wind Onshore	0	1	2	4	6	8	10
Wind Offshore	0	1	2	4	6	8	10
Wave energy	0	1	2	4	6	8	10
Tidal stream energy	0	1	2	4	6	8	10
Biomass	0	0.5	0.5	0.5	0.5	0.5	0.5
Total capacity	0.2	5.5	10.5	20.5	30.5	39.3	47.3
Outputs, Scenario Low Demand, LD-DSM							
Generation rate							
Production / Demand, %	0%	29%	50%	91%	131%	170%	205%
Curtailment							
Prod VRES / Potential, %	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	1.3%
Export / Demand, %	0%	0%	0%	10%	37%	70%	102%
Import / Demand, %	108%	79%	58%	28%	14%	8%	5%
System cost, M€	0.3	19	36	71	106	138.7	170.1
RES Unit Generation Cost, LCOE, €/MWh	128	89	95	101	103	103.1	104.0
Electricity independency, 1 - Import/ Demand, %	-	21%	42%	72%	86%	92%	95%

The selection of the reference scenario is based on the highest capacity level at which the power system can absorb the energy flow of variable renewable energies, e.g., where the curtailment rate is zero. A 6 MW plant is the maximum size by technology, because the system cannot accommodate any further capacity. The reference scenario comprises 30 MW of installed variable renewable capacity, an annual export flow of 18 GWh, imports of 7 GWh, and a power generation rate of 131% of the island load. The power generation rate is the percentage of the local power generation (consumed and exported) in the total power load (the local electricity consumption). A higher than 100% proportion of the generation in the total electricity demand means that the excess is exported to the mainland, and that the island is a net exporter of electricity. A similar indicator is used for the Scottish Orkney Islands, i.e. the generated renewable output has been equivalent to 104% of its electrical demand in 2014 (OREF, 2016).

The electricity independence is 86%, calculated as the inverse of the electricity dependency ratio:

$$\text{Electricity independence} = 1 - \text{Imports/Demand} \quad (7)$$

A high electricity independence ratio comes with high costs, which in the reference scenario amount to 106 M€ for power generators, and represent an average generation cost of 102.8 €/MWh (see Table 4).

Table 4. Power plant inputs/outputs in the Scenario 6MW by technology

Power Plants	Inputs				Outputs	
	Installed capacity	Technical lifetime	Capex	Total Investment cost	Capacity factor (model)	LCOE
	MW	years	€/MW	€	%	€/MWh
Off-shore wind	6	25	6 000 000	36 000 000	30%	122
On-shore wind	6	25	1 800 000	10 800 000	19%	62
Solar panels	6	25	1 700 000	10 200 000	12%	129
Wave energy	6	25	4 480 000	26 880 000	30%	76
Tidal stream energy	6	25	3 400 000	20 400 000	24%	131
Biomass	0.5	30	3 000 000	1 500 000	35%	92
Total RES Investment Cost, M€		105.8				
RES Generation Average Cost, LCOE, €/MWh		102.8				

The hourly power generation is calculated based on the size and the availability of the installed capacity and the hourly natural inflow described at the section 3.4, under the constraint of the demand which has to be met at each hour.

The hydrogen system is calibrated for mobility use only, because the power-to-power vector presents a close to zero capacity utilisation rate. The presence of the cable and the low curtailment rates of renewables make the hydrogen power-to-power less useful, due to losses (see a low round-trip efficiency of 25%) and to zero curtailed renewables which could be stored. The power system structure is different in the scenario where the island would be disconnected from the mainland grid and the hydrogen-to-power can become attractive (see section 4.2).

The size of the hydrogen-to-mobility system remains stable among scenarios because it is triggered by fixed fuel demand. The component sizes are shown in Table 5, and are obtained using successive runs until minimum sized is obtained for each component.

Table 5. Hydrogen system inputs/outputs

Hydrogen refuelling station	Installed capacity	Technical lifetime	Efficiency		Load factor (model)
	MW	years		%	%
PEM Electrolyser, MW	1.1	20		60%	27%
Compressor 350 bar, MW	1.3	20		88%	27%
Storage 350 bar, MWh	4	20	Efficiency storage_in	90%	55%
Storage 350 bar, kg	120		Efficiency storage_out	90%	
Hydrogen station Investment cost, M€		6			
Hydrogen production-storage Variable cost, M€		0.01			
H2 for mobility -Unit Cost, €/kg		11			

The production cost of hydrogen amounts to 11 €/kg, composed of 78% of fixed capital costs at current hydrogen cost rates, 20% fixed costs for operation, maintenance and safety, and a 2% yearly electricity cost. Hydrogen production is based on electricity which is paid for at the wholesale power market price calibrated using data for the year 2014. In this scenario, there is no power in excess so there is no power for free flow for the hydrogen operator. When fees are added to the market power price, such as grid fees and public service provision taxes, the selling power price can double, leading to a production cost of hydrogen of 12 €/kg, 10% more than initially. Within alternative contractual arrangements, e.g., power fed in for free (Loisel et al., 2015), the cost would decrease to 9 €/kg H₂ (or 15% less).

Power system operation. Figure 5 shows the operation of the island power system over two days in the selected reference scenario, with 6 MW for each variable renewable energy. Export flows represent the amount above the demand curve (bold curve), and, as a reminder, there is no curtailment in this scenario.

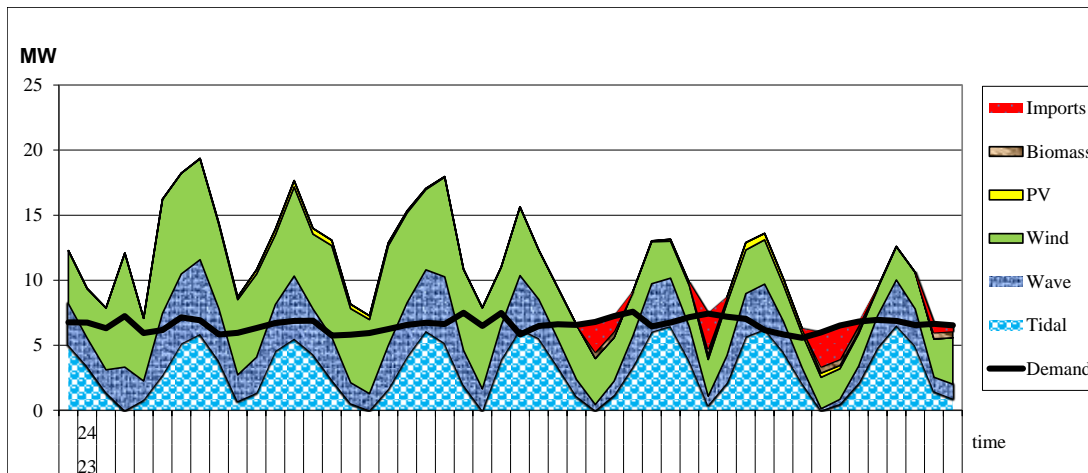


Fig. 5. Model results for power plant dispatching over two days

Variability of renewables is dealt with in a deterministic way, with perfect foresights of future inflows and no extreme weather conditions or unforeseen disruption. Any power plant could be replaced using the back-up reserve cable, which is as large as any two large power plants of 6 MW each.

The short-run operation cost is close to zero for more than 5,500 hours, meaning that for more than 60% of the time the marginal technology is a local one.

Table 6. Statistics on imports and variable energy (VRES) flows: amplitude and frequency

Imports, MW	#hours	VRES, MW	#hours
>15	0	>15	191
[14,15[0	[14,15[146
[10,14[2	[10,14[1484
[5,10[157	[5,10[3831
[3,5[598	[3,5[1986
[2,3[643	[2,3[702
[1,2[876	[1,2[365
[0,1[932	[0,1[55
=0	5552	=0	0

Table 6 shows that the cable is used most of the time for imports of less than 5 MW (during more than 3,000 hours over the year), and it is only used for more than 5 MW during 160 hours. The cable remains essential to grid stability, nevertheless its sizing could take better account of options for peak shaving, resulting in its possible downsizing from 15 to 10 or even 5 MW for imports only. Above 5 MW of the cable capacity, the grid is essentially used for exports as shows the number of hours recording large variable renewable energy generation.

Energy resource diversity considerations. Within each energy technology category, the smoothing effect of intermittency is weak, due to the small size of Yeu Island. The diversity of the resources instead show some complementarity, as seen for instance in the number of hours with no imports at all and in the low number of hours when the usage rates of the import cables is high. It should be noted that there are no zero-energy events, and that the firm capacity is of 0.5 MW. Fig 6 shows the monthly generation mix in terms of percent of the final demand. Each variable energy-based technology contributes to the monthly load, with PV fluctuating the most. The wind share is quite stable at around 50% of the demand. It should be noted that the overgeneration is uncorrelated with the load. The generation rate can be 100% in months with high or low loads, e.g., February and August, and more than 150% during the highest load months such as November. The net export flows, as the difference between overgeneration and demand, follow the same trends.

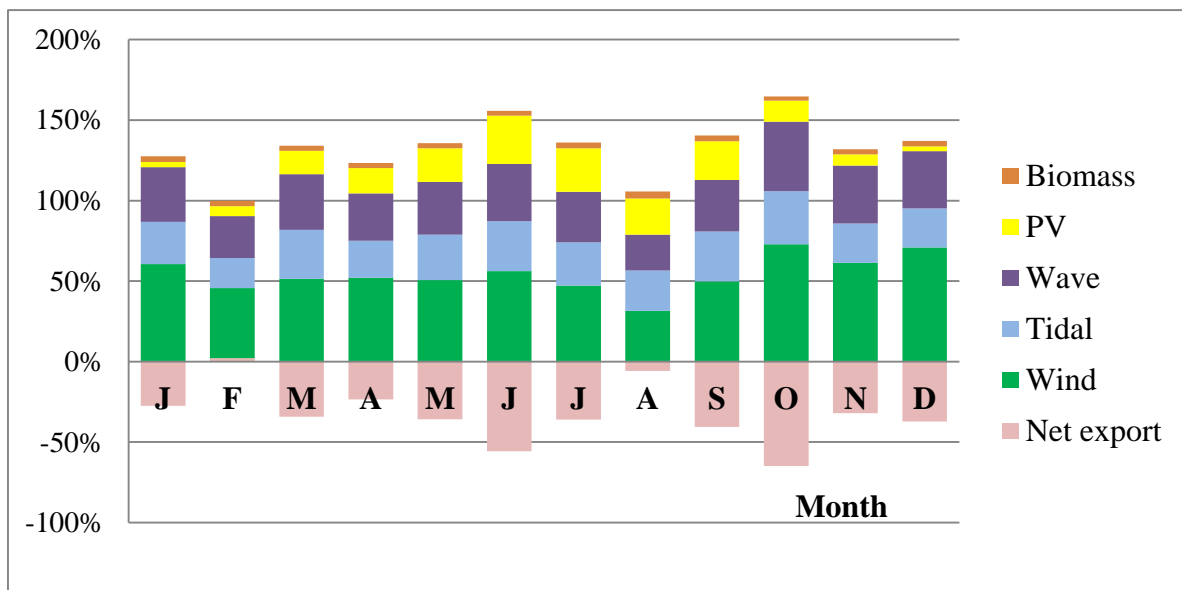


Fig. 6. The diversity of the energy mix, in the 6 MW Scenario

At an aggregated level, the reference 6MW scenario's yearly load is composed of 38% wind, 19% tidal, 23% wave, 9% photovoltaic, 2% biomass and 10% imports.

Hydrogen system operation. The hydrogen system is sized to minimise the investment cost, net of operational cost. In this way, the storage capacity is relatively low and allows few price arbitrage opportunities for the operator. Figure 7 shows that hydrogen production is price responsive, because production occurs mostly when prices are low, and the storage capacity is full during times of peak price.

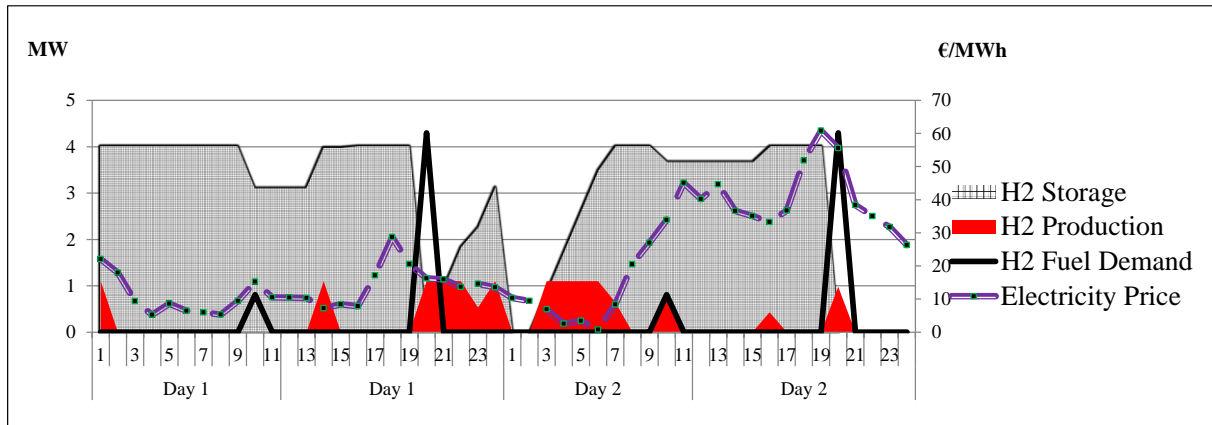


Fig. 7. The operation of hydrogen production-storage for mobility: model results

Hydrogen production occurs discontinuously, in 66% of the hours over the year. Over the two days shown above, there are seven shut-downs and rapid start-ups which could alter the technical lifetime of the system (Clarke et al., 2013). The electrolyser with polymer electrolyte membrane responds quickly to the power input, however, and is suitable for supporting variable renewable energy integration (Carmo et al., 2013).

Sensitivity tests. This part highlights the importance of the DSM strategies, which previously allowed the calibration of the supply to reduced loads, namely by 2.7% related to projections in 2030. To understand the impacts of higher loads and higher peaks, the Scenario High Demand is next simulated with and without demand management strategies (see Table 7).

- Results of the study case of High Demand without energy efficiency measures show that power independence rate is 4 points lower in the 6 MW Scenario High Demand with DSM compared to the case of Low Demand with DSM, e.g., 86% versus 82%.
- The scenario with DSM highlights the different options for achieving greater energy independence. In the reference scenario of 6 MW per power plant, i.e., having 1 point more electricity independence (82% with DSM instead of 81% without DSM) would cost 7 M€ invested in DSM measures. Further, keeping the initial independence rate of 86% as in the LD-DSM scenario could be achieved with an extra cost of 17 M€ in additional generation capacity (7 MW instead of 6 MW) and 4 M€ for DSM investments.

Table 7. Inputs-outputs of the model for different plant size scenarios, Scenario HD without and with DSM

Inputs, installed capacity MW	6	7	8	6	7	8
PV	6	6.8	6.8	6	6.8	6.8
Biomass	0.5	0.5	0.5	0.5	0.5	0.5
Wind Onshore	6	7	8	6	7	8
Wind Offshore	6	7	8	6	7	8
Wave	6	7	8	6	7	8
Tidal	6	7	8	6	7	8
Total capacity	31.3	35.3	39.3	31.3	35.3	39.3
Outputs	Scenario High Demand without DSM			Scenario High Demand with DSM		
Generation rate, Prod/Demand %	112%	129%	144%	116%	134%	150%
Curtailment, %	0.0%	0.0%	4.0%	0.0%	0.0%	7.0%
Export/Demand, %	23%	36%	49%	26%	40%	54%
Import/Demand, %	19%	15%	12%	18%	13%	11%
System cost, M€	105.9	123.0	138.7	105.9	123.0	138.7
VRES LCOE, €/MWh	102.4	102.7	102.7	102.5	102.8	102.8
Electricity independency, %	81%	85%	88%	82%	87%	89%

4.2. Scenario of islanded power system

This scenario aims at calibrating a hybrid storage-renewable energy system, and assumes the island in isolation by disconnection from the mainland grid. It should be noted that isolating an island such as Yeu, which is already connected, is not on the agenda and would not be rational, especially that variable renewables are better integrated with the interconnectivity support offered by the grid. Our simulations are purely hypothetical such as to give orders of magnitudes of storage and generators needed in self-sufficient power systems.

The hydrogen infrastructure is calibrated for mobility only. For the electricity needs, alternative storage technologies are used to absorb the excess of renewables, such as Lithium-ion batteries which are more suitable than hydrogen at small scales due to higher round-trip efficiency and negligible discharge. The conversion efficiency is set at 80% over the entire life-time of the battery which is set at 15 years, and the investment cost is set at 1,000 €/kWh per usable capacity (Pena-Bello et al., 2017).

The LD-DSM scenario is used next, and local generators are required to cover the demand plus margins assumed here to be 25% of the load. This margin reserve factor is higher in Maizi et al. (In press), e.g. 69% of the average demand on the Reunion Island in 2008. Methods are different here, e.g. the first rate applies to peak as well, while the former is computed on average loads.

Results of simulations show that generating power with only variable energies requires large installed capacities of power generators and energy storage, and leads to significant energy curtailed. All projects simulated hereafter are over-sized compared to the yearly island needs, but adapted to peak loads. They also ignore the political and social local strategy and acceptability for large-scale renewables.

Three scenarios are built: 1) 100% Renewables and Storage; 2) Renewables and Gas Turbines; and 3) Renewables plus Storage and Gas Turbines. The first scenario, 100% Renewables and Storage, means that there is no fossil fuel in the electricity mix. It should be noted that the terminology *100% Renewables* could inappropriately be used to designate that occasionally a power system can fully satisfy the demand with renewables, even if, absent wind and solar power, the system can rely on conventional resources. The term could also mean that the system is fully capable of absorbing the renewable potential (Duic et al., 2008). For instance, the Spanish island of El Hierro is designated as being 100% renewable despite a diesel component in the electricity mix (at least 24% of production in the total island generation, Rodrigues et al., 2014).

Results show that an autarkic system would entail at least 40 MW of generators and almost 1 GWh of storage, or 10 hours of continuous full power provision, with a maximum cumulative capacity of batteries of 14 MWh. Below 40 MW of power generators, the generation volume is not sufficient to produce and store energy despite infinite storage-tested capacity (see Table 8). In Duic et al. (2008), the capacity of a hydrogen facility is estimated at two weeks to cover the demand of the Portuguese island of Porto Santo, with a comparable population and peak load size to Yeu. Nevertheless this large storage need is due to one single resource-based system, wind energy.

Table 8. Model results for successive renewable energy capacity sizes

RES capacity	Curtail	Storage Batteries	Inv Cost, Power Generation	Inv Cost, Battery Storage	Usage rate of Batteries	Gas turbine	Gas turbine, Load factor	LCOE RES	LCOE RES-Storage-Gas	Energy independency
MW	%	MWh	M€	M€	%	MW	%	€/MWh	€/MWh	%
100% Renewables + Battery Storage										
39	<i>Infeasible</i>									
40	24%	993	155	993	0.1%	-	-	141	4 067	100%
50	43%	594	215	594	0.1%	-	-	189	2 556	100%
Renewables + Gas Turbine										
1	0%	2	1.1	-	-	16	45%	-	-	89
5	0%	-	9	-	-	15	0	68	68	8%
10	0%	-	18	-	-	15	0	77	77	20%
20	3%	-	68	-	-	14	22%	107	107	55%
50	57%	-	207	-	-	14	5%	236	236	90.6%
Renewables + Battery Storage + Gas Turbine										
5	0%	10	9	10	1.1%	15	41%	69	319	18%
10	0%	10	18	10	0.01%	15	37%	77	227	30%
20	0%	185	68	185	0.09%	14	21%	103	1 320	68%
50	50%	300	207	300	0.22%	10	0.4%	213	1 419	99.5%

A 100% renewable system needs large capacities for both generators and storage, and therefore high investment. The lowest level of generators of 40 MW which could meet the island demand would cost some 155 M€, plus 1 Bln€ for energy storage with batteries. The storage capacity would decrease for higher levels of renewables, but with only a limited interest in building these due to high curtailment rates (e.g., 43% for 50 MW of generators). The higher is the renewables' installed capacity, the lower is the need for storage, but the higher is the cumulative batteries' capacity, triggered by large amount of power in excess. Figure 8 shows the inverse relationship between the renewables' installed capacity and the storage size, along the curtailment rate computed as the energy deleted over the total potential.

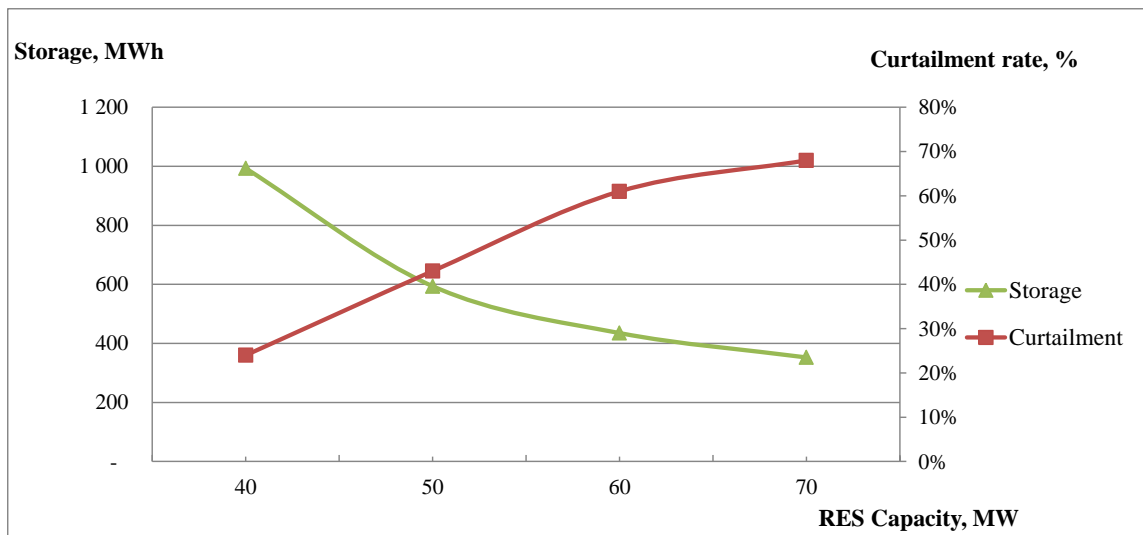


Fig. 8. Results of simulations for different variable renewables installed capacity

The analysis of storage filling and discharging shows low average usage values over the year. Security and system reliability come with high investment costs. Decreasing the target of 100% renewables in the favour of conventional generators, such as natural gas turbines, would decrease the investment cost and improve the usage rates of both variable renewables and energy storage systems.

The choice of the most suitable scenario is a function of the final cost, the technology usage rate, the power curtailment, and the policy target in terms of renewables and carbon footprint.

4.3. Policy decision-maker options

Four perspectives characterise a set of distinct and occasionally conflicting interests. The stakeholders involved in the decision-making process are at least the following: the energy investor, the distribution system operator (Enedis), the energy consumer on Yeu Island, and the policy maker on the island. They all influence at different levels the scenario building and the deployment of energy projects.

- **Renewable energy investors** have high financial costs and face generally low average market prices with low income expectations. The return of investment is not analysed here and would need further projections of market power prices for revenue computation. Complementary contracts could be used in addition to spot market payments, including capacity market mechanisms, contracts for difference, and capacity auctions (Newbery, 2016). Allowing for investors to recover their costs, the concern would be to sell the entire energy potential. In the face of power curtailment risks, the investment incentives would diminish and would reduce the provision of installed capacities. The choice criterion among scenarios is the maximum usage rate without curtailment. Among the scenarios with interconnection, 6 MW by technology or a cumulated size of 30 MW is the limiting boundary of the investor choice. For islanded systems, the selection boundary is 10 MW in the case of gas turbine support, or when storage is added.
- **The distribution system operator** (Enedis) is in charge of the control and the stability of the grid in order to balance supply and demand continuously. The operator is faced by the fluctuation of renewables and seeks to ensure grid reliability by means of firm capacity or storage devices. The operator will naturally favour scenarios with interconnection large enough to guarantee grid stability through reserve cables; in islanded cases, scenarios with Li-ion batteries storage or fired-gas units as back-up technologies are preferred. In the

absence of any grid regulation policy on the operator's disconnection, avoiding curtailment could be the objective of the distribution operator for safely dispatching the power plants. However, although voltage control is not analysed here (Chen et al., 2011) this could be a means of orienting operator choice towards relatively low rates of variability of renewables. Among all the islanded system scenarios, 100% renewables could be a challenge for the distribution operator; any scenario up to 10 MW of renewables and gas turbines might be the preferred choice of the operator.

- **The energy consumer** seeks to protect the living environment and the energy consumption-related utility, subject to a limited budget constraint. Two criteria could influence the consumer choice: energy cost minimisation and renewable share maximisation. The household price is around 140 €/MWh in 2016, of which two thirds are taxes and distribution tariffs (CRE, 2016). Installing at least 1 MW of renewables would make the bill increase to 160 €/MWh, based on the LCOE indicator shown in Tables 3 and 8, plus two thirds of taxes. The reference 6 MW scenario shows an indicative cost of 154 €/MWh, while islanded systems show a wide range of final prices of 100-6,000 €/MWh. The willingness of consumers to pay is a function of income and of the acceptability of renewables. Yeu is subject to regulated tariffs and an equalisation tariff system with the mainland, however. The high cost of renewables would be socialized among all consumers nationwide, and this cost increase would only marginally affect the island. The consumer issue is more a question of acceptability of large-scale deployment of energy projects.
- **Policy-makers** are the guardians of social welfare, accounting for the utility of the actors involved. The democratic process of decision-making should weigh up the opinions of all actors, and the policy should then internalize negative and positive effects in terms of energy production, distribution and consumption. These externalities are broadly the grid congestion, carbon emissions, peak load, overcapacity, and resource sharing with other economic activities, etc. Prior to power generation investments, DSM measures and smart grid solutions could help to focus resources first on the management of flexibility to deal with the forthcoming variability of supply. A set of new regulatory provisions is necessary to deal with various intermittent sources, such as new grid codes, the definition of the order of operators' curtailment, and new market compensatory mechanisms in cases of losses (the so called *missing money* issue; Newbery, 2016). These issues are in most cases out of the hands of the island municipality (Sperling et al., 2011), therefore strong links with all energy regulation operators are essential for meeting the transition roadmap targets.

With respect to the foregoing perspectives, the analysis tends to recommend the scenario of 6 MW by technology, with a total of about 30 MW of installed capacity. These large sizes of plants are justified by the fact that energy projects tend not to support incremental investments, due to economies of scale of construction, maintenance and exploitation. In Europe, the orders of magnitudes of installed capacities and costs can be seen in the Maltese projects, of 95 MW of wind farms (300 M€; Eurelectric, 2012); 23 MW of wind-storage on the Spanish island of El Hierro (84 M€); 16 MW wind-storage on the northern European Faroe Islands (19 M€). Ultimately, the key criteria are the total cost of projects and their social acceptability.

5. Conclusions

This research has led to a methodology that integrates island-specific constraints in an attempt to set out energy transition scenarios in support of public selection of energy schemes for the French island of Yeu. Several scenarios are proposed combining complex technologies at

different maturity levels (TRL between 3 and 9)⁹ with demand management solutions, some of which are as common as house insulation, and some more sophisticated such as smart meters. These options are costly to plan, implement, operate and maintain, despite potential positive economic effects in terms of employment, innovation, and growth. The investment allocation programme is a trade-off between costs and expected benefits from supply and demand investments, with the priority being given to load peak-shaving. Next in energy efficiency terms come the projects for local renewable energy production.

Energy scenarios resulting from this optimisation exercise consider the energy flows from local potential resources, from storage and from the mainland, and enable estimates of orders of magnitude of the investment costs. The interconnected system can accommodate up to 30 MW of variable renewables and would cost 112 M€. Hydrogen-to-mobility production has an average cost of 11 €/kg due to the significant investment involved (6 M€). Valuable sizing insights are drawn from simulations of islanded power systems, showing details of variable renewables and the storage needed to balance the demand. The high ratio of storage to renewables shows that the quantities of stored energy are large and should not be underestimated (Lund et al., 2015). All tested scenarios consider the cost of additional devices as well such as inverters in order to support renewable integration and to ensure network synchronisation at both frequency and voltage level.

From a consumer perspective, the most convenient share of renewables in the current interconnected system, would be 130% of the final demand resulting in a final bill of 154 €/MWh. In islanded systems, a satisfactory share of renewables would be 55% of the final demand with the support of gas turbines, given the resulting neutral effect on the final bill among the scenarios (161 €/MWh) or a share of renewables of 30% with the support of both batteries and gas turbines but with a significant increase in the energy bill (341 €/MWh).

These technological options listed by scenario are the first step in the policy decision process. These options should then be ordered by economic importance, in terms of employment and growth effects, by the political value of the energy independence, and by social acceptability in terms of protection of the local economy and natural sites. Weights should be ascribed to the decision criteria and calibrated based on the island's regulatory and policy framework, according to public opinion and national provisions on energy transition.

Islands generally need a regulatory framework that differs from the mainland and which should be tailored according to specific criteria. A real-price policy could reveal the actual cost of the electricity, on an island in particular, and would reflect the high cost of the energy independence and of decarbonated power systems. In practice, applying real prices is a matter of political autonomy for the island, and despite the significant freedoms enjoyed by the municipality of Yeu in managing its territory, it has low administrative and regulatory power in matters of electricity pricing and regulation. Decentralization changes the market rules in any case (Sperling et al., 2011), which must be tailored to the variable nature of renewables and to site-specific impacts.

The energy transition on Yeu Island will probably be achieved through a mix of solutions including renewables and hydrogen. Beyond the technical solutions, political support and the participation of both inhabitants and market operators are key to encouraging investments and promoting clean power production in such remote and sometimes fragile communities.

⁹ TRL (Technological Readiness Level)

http://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf. Cited 16 December 2016

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Annex

Table A1. The breakdown of the permanent household load by usage

Usage type		GWh	%
Space Heating		5.5	38.2%
Water-heating		2.2	15.3%
Lighting		0.7	4.9%
Cooking		0.9	6.3%
Electrical appliances	Refrigeration	1.14	7.9%
	Dish and washing	0.78	5.4%
	Computer	0.7	4.9%
	Drier	0.28	1.9%
	TV	0.36	2.5%
	Others	1.46	10.1%
Total		14.4	100.0%

Source : authors' calculations

Table A2. Assumptions on the load of permanent households by scenario

		2012	2030	
			LD	HD
Space heating	Share of households with electric space heaters	47%	47%	100%
	Efficiency gains in 2030 relative to 2012	-	17%	17%
Water-heating	Share of households with electric water heaters	70%	70%	100%
	Efficiency gains in 2030 relative to 2012	-	23%	23%
Cooking	Share of households with electric cooking apparatus	89%	89%	100%

Sources SEURECO (2013), RTE (2014)

Table A3. The sector load by scenario (GWh)

Sector	2012	LD	LD-DSM	HD	HD-DSM
Permanent resident houses	14.4	14.7	13.3	19.7	17.4
Secondary homes	15.2	17.7	17.7	19.3	19.3
Private services	7.6	8.7	8.8	9.3	9.3
Public services	2.7	3.1	3.1	3.2	3.2
Industry	1.6	1.8	1.8	1.9	1.9
Hydrogen mobility	-	2.8	2.8	2.8	2.8
Total	41.5	48.8	47.5	56.2	53.9

Source : authors' calculation based on Enedis (2013)