Dispatchable Operation of Multiple Electrolysers for Demand Side Response and the Production of Hydrogen Fuel-Libyan Case Study

by

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A thesis submitted in partial fulfilment of the requirements for the degree of

Doctor of Philosophy

November 2018

Abstract

Concerns over both environmental issues and about the depletion of fossil fuels have acted as twin driving forces to the development of renewable energy and its integration into existing electricity grids. The variable nature of RE generators greatly affects the ability to balance supply and demand across electricity networks; however, the use of energy storage and demand-side response techniques is expected to help relieve this situation. One possibility in this regard might be the use of water electrolysis to produce hydrogen while producing industrial-scale DSR services. This would be facilitated by the use of tariff structures that incentive the operation of electrolysers as dispatchable loads.

This research has been carried out to answer the following question: What is the feasibility of using electrolysers to provide industrial-scale of Demand-side Response for grid balancing while producing hydrogen at a competitive price?

The hydrogen thus produced can then be used, and indeed sold, as a clean automotive fuel. To these ends, two common types of electrolyser, alkaline and PEM, are examined in considerable detail. In particular, two cost scenarios for system components are considered, namely those for 2015 and 2030. The coastal city of Darnah in Libya was chosen as the basis for this case study, where renewable energy can be produced via wind turbines and photovoltaics (PVs), and where there are currently six petrol stations serving the city that can be converted to hydrogen refuelling stations (HRSs). In 2015 all scenarios for both PEM and alkaline electrolysers were considered and were found to be able to partly meet the project aims but with high cost of hydrogen due to the high cost of system capital costs, low price of social carbon cost and less government support. However, by 2030 the price of hydrogen price will make it a good option as energy storage and clean fuel for many reasons such as the expected drop in capital cost, improvement in the efficiency of the equipment, and the expectation of high price of social carbon cost. Penetration of hydrogen into the energy sector requires strong governmental support by either establishing or modifying policies and energy laws to increasingly support renewable energy usage. Government support could effectively bring forward the date at which hydrogen becomes techno-economically viable (i.e. sooner than 2030).

Declaration

This is to certify that the work in this thesis consists of original work undertaken solely by myself. Information taken from the published work of others has been referenced. The material described in this thesis has not been submitted for the award of a higher degree or qualification in any other university.

Abdulla Rahil

Leicester, 2018

Acknowledgments

First and foremost, I am grateful to Almighty God for enabling me to continue with this hard journey.

A debt of gratitude must be paid to my supervisors Dr. Rupert Gammon and Dr. Neil Brown for their support during the course of my PhD and for knowing when to direct me and when to let me go my own way.

My acknowledgment would not have sense if I did not provide my thanks to my beloved wife, {Asma}. You are the best wife in the world; I could not make this work without your support. Also my children, Nasseb , Hoor and Sama. I would like to express my deepest gratitude to my mother, Mabroka Saleh, for her support and love during my PhD journey. Moreover, my father in other life, your prayers and belief in me have made this journey possible.

Last, but not the least, I also wish to express thanks to my brothers, sisters and parents-in-law all for their love, encouragement, patience and support over the years.

I gratefully acknowledge the funding source that facilitated my PhD work. I would like to express my deep gratitude to the Ministry of Higher Education / Libya, the Libyan cultural attaché /London and Omar Al-Mukhtar University/Libya for their support.

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List of Abbreviations

Notation	*Description*
DSR	Demand Side Response
AC	Alternating current
BES	Battery energy storage
Bop	Balance of plant
CH_4	Methane
CH_3OH	Methanol
CAES	Compressed air energy storage
CF	Capacity factor
CO	Carbon monoxide
CO_2	Carbon dioxide
CP	Daily central electrolyser price
CSP	concentrating solar power
DC	Direct current
DOE	Department of Energy
DSR	Demand Side Response
DTC	Daily total cost
EC	Electricity cost
EP	Daily energy price
ESS	Energy storage system
FES	Flywheel energy storage
GDP	Gross Domestic Product
GECOL	General Electricity Company of Libya
HES	Hydrogen energy storage
HHV	Higher heating value
HTS	Higher temperature superconducting
KOH	potassium hydroxide

LHV	Lower heating value
LiCoO2	Lithium cobalt oxide
LiNiO2	Lithium nickel dioxide powder
LTS	Lower temperature superconducting
LYD	Libyan dinar
I_{DC}	Total return of investment
NOC	National Oil Corporation
NOX	Nitrogen oxides
NREL	National renewable energy laboratory
PEM	Polymer electrolyte membrane electrolysis
PHES	Pumped Hydroelectric Energy Storage
$Pt - Mo$	platinum-molybdenum
PV	photovoltaics
R&D	Research and Development
RE	Renewable energy
REAOL	Renewable Energy Authority of Libya
RTP	Real-time pricing
S2P	Station 2 daily released price
S3P	Station 3 daily released price
S5P	Station 5 daily released price
SCC	Social carbon cost
SCES	Supercapacitor energy storage
SHC	solar heating and cooling
SMES	Superconducting magnetic energy storage
SOEC	Solid oxide electrolyser cell
SPE	Solid polymer electrolyte
T&D	Transmission & Distribution
TES	Thermal energy storage
TOU	Time of use
UNFCCC	United Nations Framework Convention on Climate Change

WC	Water cost
WTO	World Trade Organization
ZnBr	Zinc bromine
ZrO2-Y2O3	Yttrium zirconium
$\boldsymbol{\sigma}$	standard deviation
$\boldsymbol{\Gamma}$	gamma function
$\boldsymbol{E_{pf}}$	energy pattern factor
$\boldsymbol{a}$, $\boldsymbol{b}$	coefficients of straight line
$\boldsymbol{D_{HP}}$	Daily hydrogen production (kg/day)
$\boldsymbol{E_S}$	Electrolyser size (kg/day)
$\boldsymbol{R_P}$	Required power (Kw/day)
$\boldsymbol{E_{TC}}$	Total electrolyser cost (£)
$\boldsymbol{E_C}$	Electrolyser cost (£/kW)
$\boldsymbol{S_{TC}}$	Total storage cost (£)
$\boldsymbol{S_C}$	Storage cost (£/kW)
$\boldsymbol{S_S}$	Storage size (kg)
$\boldsymbol{C_{Tc}}$	Total compressor cost (£)
$\boldsymbol{C_c}$	Compressor cost (£/compression system)
$\boldsymbol{C_S}$	Compressor size (kg/day)
E_F	Electrolyser energy requirement (kWh/kg H2)

List of Publications

1. *Journal publications*

A. Rahil and R. Gammon, "Dispatchable hydrogen production at the forecourt for electricity demand shaping," Sustainability, vol 9, no 10, pp. 1785, 2017, (Chapter 7).

RAHIL, A., GAMMON, R. and BROWN, N. (2018) Techno-economic assessment of dispatchable hydrogen production by multiple electrolysers in Libya. Journal of Energy Storage, 16, pp. 46-60, (Chapter 8).

Rahil, Abdulla, Rupert Gammon, and Neil Brown. "Flexible operation of electrolyser at the garage forecourt to support grid balancing and exploitation of hydrogen as a clean fuel." Research in Transportation Economics (2018), (Chapter 7).

Madziga, Miriam, **Abdulla Rahil**, and Riyadh Mansoor. "Comparison between Three Off-Grid Hybrid Systems (Solar Photovoltaic, Diesel Generator and Battery Storage System) for Electrification for Gwakwani Village, South Africa." Environments 5 (2018): 57), (Different project).

2. *Conferences publications*

A. Rahil, R. Gammon, N. Brown. "Demand Side Management from Electrolytic Hydrogen Production", UK Energy Storage Conference, University of Birmingham/November 25-27, 2015 **(poster)**, (Chapter 4 and Chapter 5).

A. Rahil, R. Gammon, N. Brown. "Hydrogen fuel production from renewable sources and its role in balancing the grid in Libya", H2FC SUPERGEN 2015 Research conference, University of Bath/December 14-16, 2015 **(poster),** (Chapter 4 and Chapter 7).

A. Rahil, R. Gammon, N. Brown. "Onsite Hydrogen Production at the Forecourt to Support Grid Balancing", The 1st Faculty of Technology PGR Students Conference, De Montfort University, Leicester,UK/ June8, 2016 **(oral presentation /paper),** (Chapter 7).

A. Rahil, R. Gammon, N. Brown. "Dispatchable Hydrogen Production at the Forecourt for Electricity Grid Balancing" TMREE16 Int'l Conf. Fall Meeting, Paris-France/November 16-18, 2016 **(oral presentation /paper) ,** (Chapter 7).

A. Rahil, R. Gammon, N. Brown. "Dispatchable Hydrogen production by multiple electrolysers to provide clean fuel and responsive demand that facilitates renewable energy integration in Libya", H2FC Researcher Conference, Ulster University, Belfast/ December 12-14, 2016 **(oral presentation),** (Chapter 8).

A. Rahil, R. Gammon, N. Brown. "Techno-economic Comparison between Multiple Forecourt Electrolysers and Central Hydrogen Production", Fuel Cell & Hydrogen Technical Conference University of Birmingham/31st May- 1st June 2017, (**oral presentation),** (Chapter 9 and Chapter 10).

A. Rahil, R. Gammon, N. Brown. "Dispatchable Hydrogen production by multiple electrolysers to provide clean fuel and responsive demand in Libya" The 9th International Renewable Energy congress, Hammamet, Tunisia /March 20-22, 2018, **(poster presentation /paper)** (Chapter 8).

Chapter 1: Introduction

1.1 Background

Energy production has offered a mixture of benefit and problems for society (Tezcakar, 2010). Starting with the fast growth and diffusion of electrification, the internal combustion engine and the rapid R&D achieved in the development and exploitation of fossil fuels, the energy industry has expanded and become the spine of countries' economic activity. The first three quarters of the 20th century concentrated on the exploiting and growth of energy whereas the final quarter focused on problems associated with the industry such sustainability and pollution issues. The 1970s oil crisis and increased awareness of environmental issues caused by fossil fuels acted as the catalysts for the considerable changes in this field. The main effect of oil crises was that complete and finite depends on fossil fuel as the engine of the economy is not tenable and cannot be predicted for long-term reliability (Tezcakar, 2010).

Because of the above issues, exporting countries start looking for the ways to reduce the dependency on fossil fuels to meet the 2030 climate & energy framework from one side and to have sustainable economic from another side (European commission, 2017). Moving away from fossil fuel is not an easy task since this action requires finding ideal alternatives fuels to the electricity and transport sectors as one of the most polluting and harmful to the environment. All these reasons led to rapid growth in the renewable energy industry until reached nearly 19% of total world energy use (Bhattacharya et al., 2016; Helm, 2016). The international Energy Agency (IEA) revealed that nearly 46% of global electricity can be produced from renewable sources by 2050 (Gazey, 2014). British petroleum (BP) forecasted that the fossil fuel industry growth is going to drop from 83% in 2011 to 64% in 2050 of total energy share in favour of renewable sources (Ruehl and Giljum, 2011).

Many countries start depending on the renewable energy as a main source of energy. For example, Germany target is achieving 18% of total energy consumption and 30% of total electricity consumption from renewable energy sources by 2030(Abdmouleh, Alammari and Gastli, 2015). However, on Sunday, May 8, 2016 electricity prices became negative for many hours, meaning commercial consumer were being paid to absorb electricity due two unexpected of high renewable energy generation(Geier, 2016). This is one of the main drawbacks of renewable energy sources. Intermittency and variability are the main issues of renewable energy sources (Ehteshami and Chan, 2014). Instalment a large size of storage devices can solve these issues. Many types of energy storage can be used with advantages and disadvantages for each technique. Hydrogen as an energy storage medium has the ability to store excess energy for reuse as electricity. Electrolysis also has the option to sell both oxygen and hydrogen as commodities. Hydrogen has the ability to use as a chemical gas for industry purpose or as fuel for transportation sector, thus hydrogen could treat the main sources of CO_2 emissions by consuming surplus of renewable energy and replace the fossil fuels (Gazey, 2014).

The oil prices has significantly dropped from $125/b to less than $55/b between 2012 and 2016 due to many reasons such as over-supply, economic stagnation and renewable energy sources development (Yoshino and Taghizadeh-Hesary, 2016). These prices in the long-term will affect oil rich countries which depend on the oil as a main source of income.

Libya is one of the oil-rich countries in Africa which clearly affected by the oil price drop since Central bank forex reserves were $76.6 billion at the end of 2014 in contrast with $105.9 billion in 2010 (Bosalum and Laessing, 2015). This country should follow importing oil countries steps to be renewable energy exporter rather than fossil fuel exporter since all circumstances support the possibility of the country to be one of the highest renewable energy producers. Country location and weather data are very promising to produce and export renewable energy to Europe. Hydrogen also can be used as a Demand side response tool, and can be used locally as a fuel or exporting via pipeline (Elamari, 2011).

Much attention has been paid to renewable energy resources and current target is to deliver the energy stably and cheaply. However, hydrogen applications as energy storage or as fuel need to be investigated. Moving toward hydrogen economy requires studying external factors which affect the options of decision-makers in energy, the interaction between several subsystems of energy and hydrogen industry as well as the relation between the other energy options and hydrogen choice (Tezcakar, 2010).

Because of the advantages of hydrogen, which include the different energy sectors applications such as electricity, transportation and heat. In addition, it can be produced from many sources with high efficiency such as natural gas, fossil fuels renewable energy as well as water. Finally less CO_2 emissions based on the source of hydrogen, the research has been concentrated of hydrogen industry and the expectation was that research and development (R&D) efforts will reduce the hydrogen cost (Dincer and Acar, 2015; Nicoletti et al., 2015). High efficiency of hydrogen energy (as a fuel or as electricity applications) and its ability of reduce the GHG could compensate the high price in contrast with other energy sources (Dutta, 2014).

1.2 Thesis aim and objectives

The main aim of this thesis to investigate the ability of hydrogen to work as grid balancing tool with high penetration of renewable energy and as a clean fuel instead of fossil fuels in Libya. In other words, to shift away from traditional economy (carbon based economy) to hydrogen economy. The electrolysis will operate as demand side Response tool, consuming electricity at off-peak times and produce hydrogen for transportation sector. The main engine of this work is the economic aspect. Hydrogen should be produced with reasonable price to be competitive with traditional fuel. However, some particular objectives were determined at the beginning of the research to avoid the risk of such a large undertaking lacking focus and becoming unmanageable. These objectives were to:

1- Data collection. In a country such as Libya, collection of data requires time and effort since there is no trust of sources except in the official government Institutions. Some Institutions have their websites but not all information can be found. For example, the electricity demand cannot be found except in the general electricity company and a lot of procedure you have to follow to gain these resources.
2- Analysis of weather data and build a software model to analyse the wind and solar data characteristics
3- Develop a software model to calculate the potential wind and solar power based on the weather data for the research location (Darnah city, Green Mountain, Libya). Weather data also collected by different ways such as commercial websites, NASA or airports.

4- Sizing the renewable energy sources based on the research area demand and extract the surplus energy during the year. After the renewable energy investigation in Step 3, renewable energy will be sized based on the Green Mountain demand. This renewable energy should meet demand most days, after which any excess energy will assumed and used by the electrolyser to produce hydrogen. Any deficiency in hydrogen supply can be met via conventional fuel (this point is outside the scope of this research).
5- Wide discussion about the fuel consumption in Libya and specially focus on Darnah fuel consumption and then simulate the hydrogen fuel consumption based on some characteristics of hydrogen and fossil fuel and engines such as lower heating values , higher heating values and engines efficiencies.
6- Build a software model based on optimisation tools to test the effect of electricity price on the hydrogen price before start focusing on the main electricity type in the research which is off-peak electricity. All these calculation will be done under two cost scenarios, 2015 and 2030, and two common types of electrolysers will be investigated technically and economically.
7- Create a new way of electricity price, which depend on the participation between the supply (energy availability side) and demand (hydrogen demand side).
8- Build the main model of the work, which will focus on the techno-economic assessment of hydrogen. Different mode of operations under different cost scenarios with different types of electrolyser will be tested.
9- General comparison between all the operation models will be given at the end of the work.

While many of these cases have been investigated in several studies and field test previously, this aims to be the first electricity mechanism technique, which considers the price decision between supply and demand sides at the same time. This research completely new in terms of the locations. Most previous study focus on the analysis study based on the surveys or interviews with the expert on this field without modelling or calculations. Some studies focused on the potential renewable energy in many regions in the country but without integration or even off-grid systems.

1.3 Methodology

This section discusses the various techniques used in this study. There are different techniques such as a questionnaire, interviews, and practical or software work to answer the research question, realise the main aim and evaluate the result of the research subject. The methodology includes data collection and the method used.

1.3.1 Data collection

The collection of data in this research include the electricity demand data, fuel consumption data and weather data. Weather data (wind and solar) were collected from commercial websites, NASA and as well as airports (Nasa, 2016; weatherspark team, 2014). Electricity demand was extracted from general electricity company of Libya in daily pattern and this is the reason for using daily calculation for the work (GECOL, 2012). Some history background about renewable energy projects and the future planned project information is taken from renewable energy authority in Libya (Mohamed Ramadan Zaroug, 2012). Finally, fuel consumption data is extracted from daily record of stations consumption since our work focus in small city. Regarding oil prices and government subsides, bank loans, interest: they are extracted from Libyan central bank and national oil corporation (Central Bank of Libya, 2014; The National Oil Corporation (NOC), 2017).

1.3.2 Research technique and tools

Matlab software has been used to formulate all parts of the research model but with different tools. Matlab code has been designed to analysis the weather data. Some Matlab tools was used such as probability distribution, Weibull parameters with many different commands. Then the system sizing model was created to extract the surplus power after comparing the demand and supply. Linear programming was used in Chapter 7 to optimise the hydrogen cost based on the time and price of energy. Some economic equations were used to assess the system economically such as retune of investment and payback period formulas. Finally, the long code with different operation modes has been build using Matlab to test different mode of operations with different cost scenarios and with different types of electrolyser. Generally, the main model is flexible and can deal with any region and any mode of time like day or hours. The input of the model are the electricity and fuel demand and weather data and the output are average price of hydrogen per refuelling station, the energy consumption and the satisfaction of hydrogen demand. The model consists of numerous steps, with the main input being the weather data (wind speed and solar irradiance) and the fuel and electricity demand. A number of steps had to be taken before running the main model, which would produce the hydrogen and suggest the average hydrogen price; these were the main outcomes of the model. Other results can be extracted, such as the surplus power absorption, the deficiency in meeting hydrogen demand and the cost of hydrogen. Based on the weather data, the wind turbine and PV system were chosen. This process requires various calculations; for example, the wind speed had to be converted into a daily pattern, then a suitable wind turbine based on the wind speed data had to be selected, and finally the capacity factor had to be computed to determine how many turbines would need to be installed to meet the demand. The last process, the sizing system, mainly depends on the PV system sizing, the wind turbine sizing and average demand. Due to the absence, to date, of an extensive hydrogen market, the hydrogen demand calculation cannot be computed with any great degree of accuracy. The widespread uptake of hydrogen markets will rely initially on the availability of a hydrogen-based infrastructure, particularly a hydrogen station infrastructure and hydrogen-fuelled cars. The data for petrol stations is not available from any official source; only annual fuel consumption can be extracted from the National Oil Corporation or Central Bank of Libya. However, after the introduction of the new system, which would the manager or owner the power to control their own station, unofficial daily reports would be performed to determine costs and revenues, as well as any shortage of oil components. As a result, fuel consumption data were obtained from the station owners' daily records. The rest of the model was written using the Matlab software suite, using many of the toolboxes and equations therein. For example, when analysing the input data of the model, Weibull disruption was used to analyse wind speed. Some tools were used to remove outlier values from solar radiation and wind speed, others were used to convert the hourly data to daily data, and additional code was written to estimate the hydrogen demand based on conventional fuel demand, and the system sizing model was designed. All these steps were taken to determine the excess power that might be available for electrolysis, which was the main goal of the previous work. Then, a large section of code, which made use of a considerable number of tools and commands, was written to simulate all hydrogen production scenarios. Different scenarios were posited under two different cost assumptions using the two main types of electrolysis currently available. All these steps are presented in detail in appendices.

1.4 Thesis structure

The remainder of this thesis is organised as follows:

Chapter 1, this chapter, presents the global energy history and introduces the fossil fuel problems and then move to the taken steps by countries to reduce the reliance on the fossil fuel and the issues that could face this transition for importing and exporting oil countries. Hydrogen has been given as asolution with some techno-economic issues. Second part of this chapter was the main aims and objectives of the research. Finally the research methodology including the data collection and research method was briefly disused.

Chapter 2 introduces general overview of current energy storage with explanation of the construction, the operation way and the limitation then current applications of energy storage and future installation plan of some energy storage has been presented. Finally, general comparison between all energy storage based on different aspects has been presented.

Chapter 3 focuses on hydrogen storage method. First comparison between hydrogen and conventional fuels was presented followed by hydrogen production methods which widely discussed with explanation about the production process and the advantages and disadvantages of each production way. Then hydrogen storage methods was presented with intensive discussion in terms of requirements, positive and negative points for each storage method. Last part of this chapter explained the applications of electrolytic hydrogen as a demand side response. Electrolyser had been tested for different purposes such as end-user energy management, transmission and distribution and wholesale market services.

Chapter 4 introduces electrolysis technology staring with history of this technique, the operation mechanism and the main components of the electrolysis. Second part covers electrolyser cell arrangements including the type of arrangements and advantages and disadvantages for each type. The electrolyser types is presented and discussed in details.

Electrolysis benefits and challenges which could face this industry. Last part was the electrolysers cost which presented with intensive discussion and some examples.

Chapter 5 presents the general idea about energy production and consumption in Libya, which includes information about the oil and natural gas reserves in the country, current situation of oil and natural gas industry and current local consumption of energy. Then electricity production and consumption in Libya is discussed which covers the different aspects such as current and forested demand, consumption per sector and production based on energy source. Furthermore, Libyan environments situation had been presented in this chapter followed by the Libyan electrify prices issues, finally current renewable energy projects, and future prospective are disused in details.

Chapter 6 discussed the project region from different angles, starting with the region location then the electricity demand of the region followed by potential wind production of the region based on the weather data. After that, the project calculation had been started by calculating the potential renewable energy then sizing the system and finally extracted the surplus energy during the year. Then fuel consumption history had been presented with more information about the fuel station in Libya, fuel prices and at the end, fuel consumption of the project area was presented.

Chapter 7 tests different price of energy under optimisation method to reduce the hydrogen cost. The main goal of this chapter to see whether the change of electricity price depend on the time of operation could make a considerable change in hydrogen price. Two cost scenarios had been applied 2015 and 2030 cost scenarios and two different types of electrolysers was used.

Chapter 8 investigates the possibility of on-site hydrogen production to work as a grid-balancing tool and replace a fossil fuel in research region. On-site hydrogen production could include some scenarios such as increase the size of the system and adding central electrolyser to deal with the rest of surplus and meet any hydrogen meet shortage. All operation scenarios had been tested under two cost assumptions 2015 and 2030 and for two common types of electrolysers: PEM and alkaline. Techno-economic assessment of each scenario is presented in details with general comparison between all scenarios.

Chapter 9 investigates the possibility of central hydrogen production to operate as a demand side response tool and produce a clean fuel could be used as an alternative fuel. Two different types of electrolysers (PEM and alkaline) will be tested under two cost assumptions 2015 and 2030.

Chapter 10 shows the comparison between the onsite hydrogen production scenarios and central production scenario in terms of energy absorption, hydrogen required meet and the average hydrogen price under two cost assumptions 2015 and 2030. Comparison between two options of renewable energy integration based on the fossil fuel usage when renewable resources satisfy the same amount of energy. Like in first one, this comparison will be under two cost assumptions 2015 and 2030.

Chapter 11 then summarises the work done in this research, together with further work recommendations, which can enhance the development of hydrogen industry as a suitable way for renewable generation constraints.

Chapter 2: General Review of Energy Storage

2.1 Introduction

There are many reasons for installing energy storage such as mitigating the imbalance between power demand and supply due to high penetration of renewable sources, deferring the upgrade of distribution and transmission systems, power quality, efficiency, and improvement of conventional sources like coal, nuclear and off-grid system applications. Power produced from renewable sources has many advantages, which include it being clean, sustainable, and the sources having a long lifetime (e.g., wind turbines and PV panels may last 20-25 years) (Singh et al., 2017), and low operating and maintenance costs (Martin et al., 2016). Furthermore, the time for construction is very short compared with other kinds of power station. On the other hand, the main disadvantage of most renewable energy sources is that their output is completely dependent on the weather (e.g., wind and sun), which creates two problems: unpredictability and intermittency of output. To increase the penetration of the power generated from such sources, an energy storage system (ESS) can be applied to accommodate temporary surpluses and deficits in generated power. In addition to solving the practical problems of intermittency and variability, ESSs can be economically attractive (Sahay and Dwivedi, 2009). There are many types of energy storage, such as batteries, super-capacitors, flywheels, flow cells, pumped hydro and compressed air. This chapter provides a general review of ESS techniques based on their various different aspects including cost, efficiency, advantages and disadvantages, and applications. Some energy stores are not suitable for systems with a high penetration of renewable power because of their relatively short life cycle such as capacitors and lead-acid batteries (Carmo et al., 2013). The variability of wind power output, for example, can leads to the accelerated degradation of the energy storage device, of which the clearest example is batteries. Different kinds of energy storage can utilise the excess energy from renewable energy systems to store energy in different forms such as hydrogen, pressure, mechanical, and electrostatic storage (Hebner, Beno and Walls, 2002). For example, some methods of energy storage, such as the flywheel, have excellent characteristics for short storage cycles, but by contrast face numerous issues regarding long storage cycles due to self-charge losses (Chen et al., 2009). Most means of energy storage can deal with short storage cycles with few or no disadvantages. However, the requirements of long storage are complex, and not all energy storage methods are efficient in this manner (Schoenung, 2001). For instance, few energy storage methods are suitable for when up to seven days' worth of storage is required, such as batteries, CAES, and hydrogen. The first two storage methods are restricted by degradation of the battery and the requirements regarding the location at which CAES can be constructed (Luo et al., 2015), respectively. Hydrogen storage has received considerable attention over the last few years due to its excellent properties regarding long energy storage and the multiple applications of hydrogen, such as in transportation and electricity (Sevilla and Mokaya, 2014).

2.2 Energy storage methods

A number of factors are taken into consideration when choosing the ideal size for energy storage such as power density, life cycle, cost, efficiency and, most importantly, storage time. Figure 2.1 below shows the relation between the annual cost and the time of storage of different types of storage devices; here, it is clear that increased storage time will lead to an increased annual cost of energy (Schoenung and Hassenzahl, 2007).

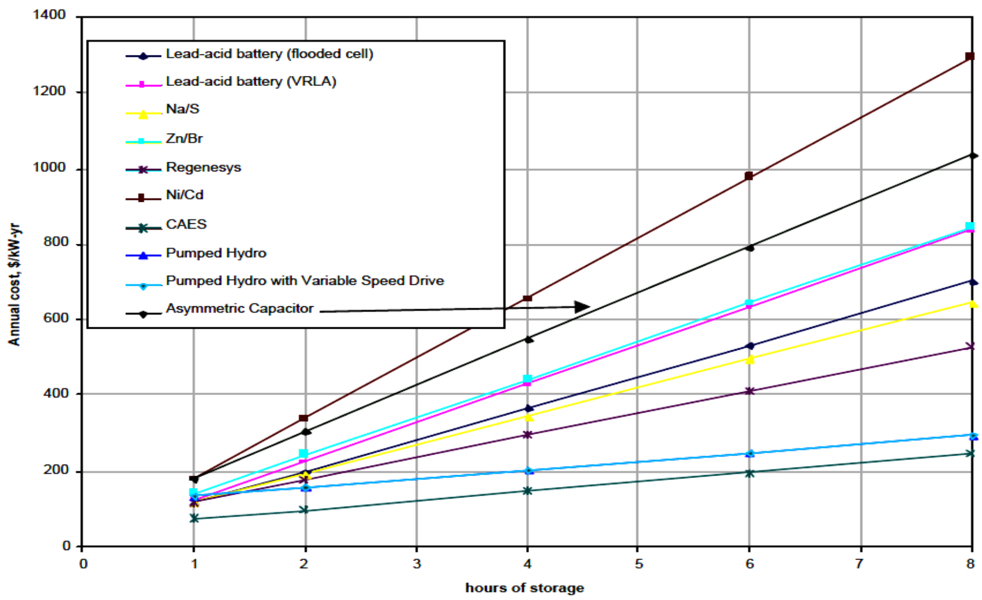


Figure 2.1: Annual cost versus hours of storage for different energy storage techniques

Generally, the longer the storage time, the greater the challenge and therefore the more expensive the solution. Furthermore, choosing a suitable storage device will depend on the application for which it will be used, including power stabilization of the grid, time-shifting of the load, arbitrage and frequency regulation.

2.2.1 Pumped hydroelectric energy storage (PHES)

In Pumped Hydroelectric Energy Storage (PHES), water is pumped from a lower reservoir to a higher one during the charging stage and released from the higher reservoir to the lower one through a generator in the discharging stage (Rehman, Al-Hadhrami and Alam, 2015; Yang, 2014). Figure 2.2 below shows the PHES process, which tends to involve the use of natural resources such as rivers or lakes. More recently, a number of new methods have been introduced; in Japan, for example, the sea has been used as the lower reservoir and it has been suggested that a surface reservoir could be used as the upper reservoir in conjunction with an underground reservoir, possibly directly underneath it, as the lower reservoir. PHES is a well-established, highly durable technology that is used worldwide. It is usually of between 100 MW and 3000 MW power capacity with nearly 70–85% cycle efficiency and a lifetime of 40 years. Suitable storage time for large PHES installations can be hours, months or even much longer-term storage (Luo et al., 2015). Around 200 units and nearly 100 GW of PHES are distributed across Europe (which accounts for 32 GW), Japan (21 GW) and the USA (19.5 GW) as well as in Asia and Latin America (van der Linden, 2003; Bruninx et al., 2015). The largest such facility in Europe is Dinorwig in the UK, which has an 1800 MW capacity, generating more than 5,885 GWh/year and achieving maximum output from zero within only 16 seconds. Some components of older systems, particularly the turbines, can be retrofitted to improve their efficiency. There are some disadvantages to PHES, however, including restrictions regarding where they can be located, lengthy lead times for their build, environmental issues such as the alteration of normal water flow disrupting the aquatic ecosystem, and high start-up costs (Inage, 2009; Táczi and Szorenyi, 2016).

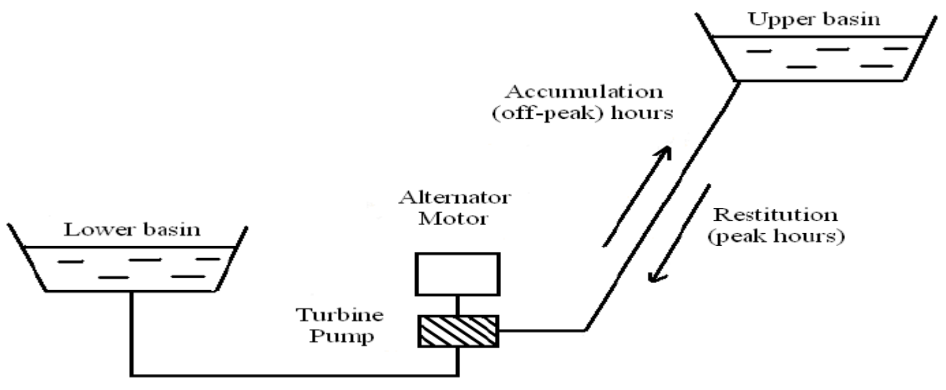


Figure 2.2: Illustration of the PHES process

2.2.2 Compressed air energy storage (CAES)

Compressed air energy storage (CAES) is a means of storing energy as compressed air in an underground cavern. Its operating pressure fluctuates between 40-70 bars at ambient temperature. The efficiency of commercial-scale systems of this nature is limited as heat is radiated into the atmosphere during the compression stage. The first CAES system, which had a 220 MW capacity, was installed in 1978 in Huntorf, Germany (Ferreira et al., 2013; van der Linden, 2003). There are five main components in a CAES system: the compressor train; the motor, or generator; the turbine expander train; the recuperator; and the cavern. To absorb surplus power, the motor drives the compressor to compress the air, which must be cooled down and then stored in the cavern. When there is a need for power to be generated, it is necessary to pre-heat the air in the recuperator before mixing it with a small amount of oil or gas; this is then burned in the combustor. Electricity is generated by expanding the hot gas in the turbine. The entire process takes only a few minutes, so the start-up time of 10 to 12 minutes is one of the main advantages of this system as it has relatively long storage times (Fertig and Apt, 2011; Guney and Tepe, 2017). Figure 2.3 summarizes the construction and operation of CAES:

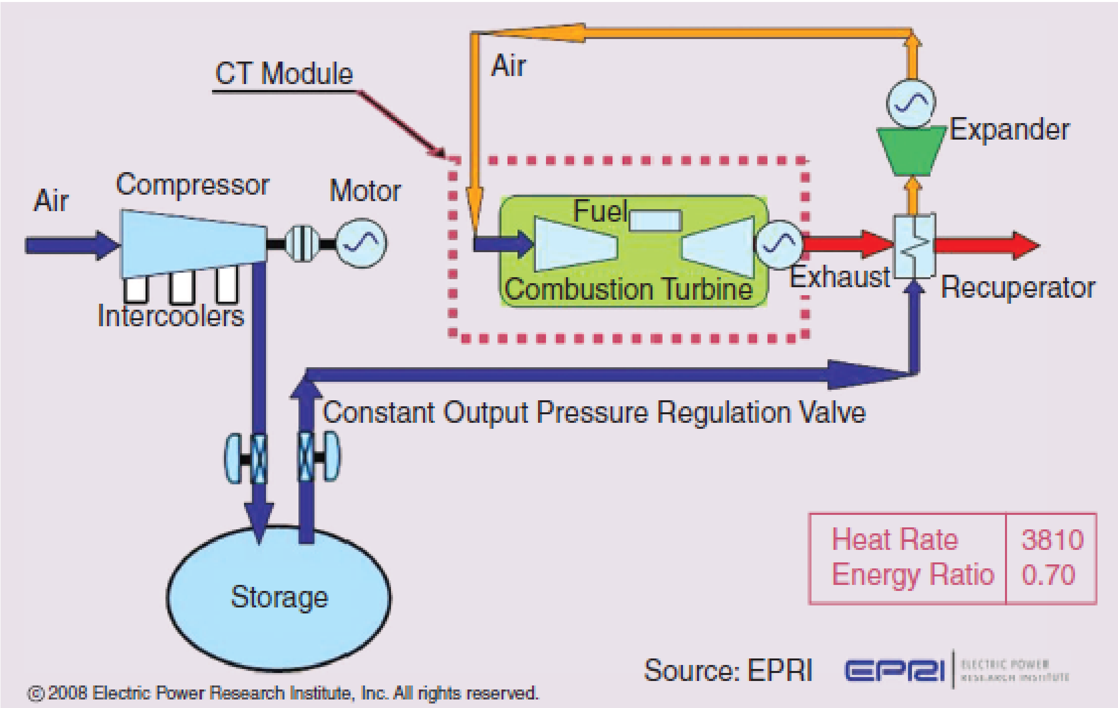


Figure 2.3: Main sections of a CAES plant

Both PHES and CAES are preferable for storing large amounts of energy for long periods. CAES has lower efficiency than PHES (the round-trip efficiency is about 42-54%). The usage of CAES is still limited for conventional applications and has a similar limitation to PHES in terms of location (Luo et al., 2015).

2.2.3 Hydrogen energy storage (HES)

Long-term storage requires a stable storage medium that can be scaled up but which is not reliant on specific locations, as in the case of PHS and CAES. In addition, the rate of self-charge and the degradation of the storage equipment should be low. Hydrogen meets all these conditions. The electricity can be stored as hydrogen for a long period without any degradation, and hydrogen can be stored in different forms such as the gaseous or liquid states, or in some cases in the solid form, in the case of the metal hydride storage technique (Gahleitner, 2013). Hydrogen has many applications, for example for long-term energy storage, as an energy carrier that can be converted repeatedly to electricity using fuel cells, or as an industrial feedstock in many areas such as fertilizer production or food processing. One suggested usage of hydrogen is as a fuel since it creates no greenhouse gas emissions (Mansilla et al., 2013; Johansson, Franck and Berntsson, 2012; Preuster, Alekseev and Wasserscheid, 2017). An electrolytic hydrogen system can be operated as a controllable or deferrable load with smart grid systems. Generally, large industrial and commercial systems can effectively participate in the balancing of the grid through the intelligent use of their loads during the production process. There are many hydrogen production systems in the world; Tessenderlo, for instance, uses one of the largest hydrogen electrolytic systems (Maisonnier et al., 2007) to maintain grid balance, operating at a low price per kWh to allow the distribution network operator to change its production (hydrogen and oxygen). The distribution network operator makes these adjustments based on changing demand within the electrical grid using the DSR method. In other words, Tessenderlo will reduce the hydrogen production in the case of high demand and low energy production and increase hydrogen production in the case of low demand and high energy production (Crockett, Newborough and Highgate, 1997). Further explanation regarding hydrogen storage will be presented in the following chapters.

2.2.4 Thermal energy storage (TES)

A thermal energy storage system comprises a reservoir as the storage medium, a packaged chiller system, piping, pumps and a controller. Regarding temperature operation, there are two types of TES, low temperature and high temperature (Chen et al., 2009; Ferreira et al., 2013). The former is most appropriate for peak shaving and industrial cooling loads and normally uses the water/ice and reheating process, whereas the latter exploits the change of a material from one state to another and uses energy absorption or emission in a liquid-solid at a constant temperature. The TES stores a large amount of energy with very small daily self-charge loss (~0.05-1 %). It is commercially available with a low capital cost ($3-60/kWh). However, the TES has a low cycle efficiency of only ~ 30-60% (Demirbas, 2006; Sharma et al., 2009). Figure 2.4 shows the TES system integrated with wind power generation.

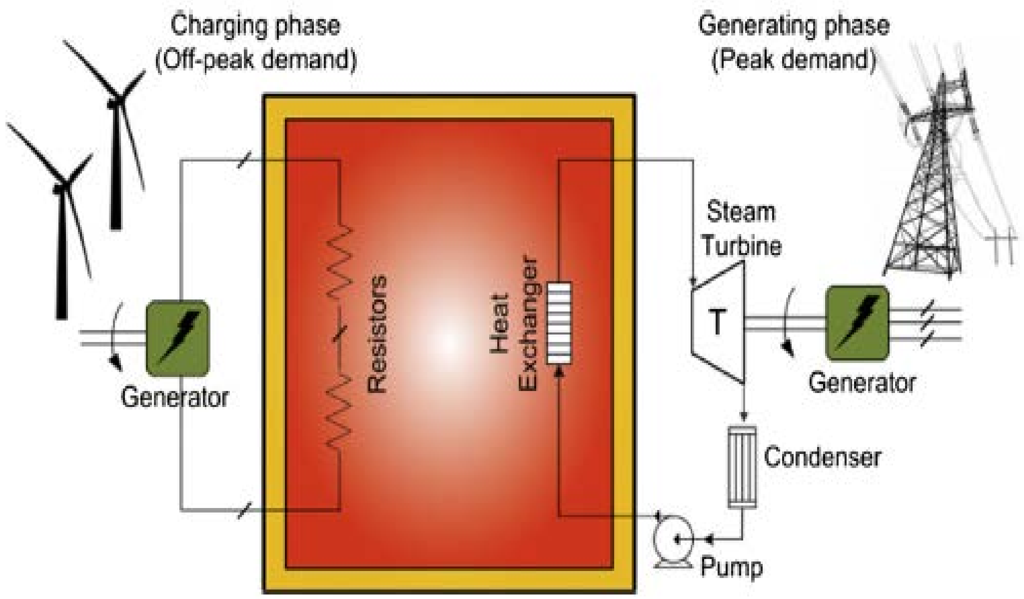


Figure 2.4: TES system integrated with wind power generation

2.2.5 Battery energy storage (BES)

Nowadays, rechargeable batteries are one of the most commonly used EES's in both industry and in daily life (Luo et al., 2015; Akinyele and Rayudu, 2014). The main components of battery storage systems are a DC/AC converter, charger, transformer and AC switch gear. The battery stores the energy in chemical form. Figure 2.5 presents a typical battery operation scheme.

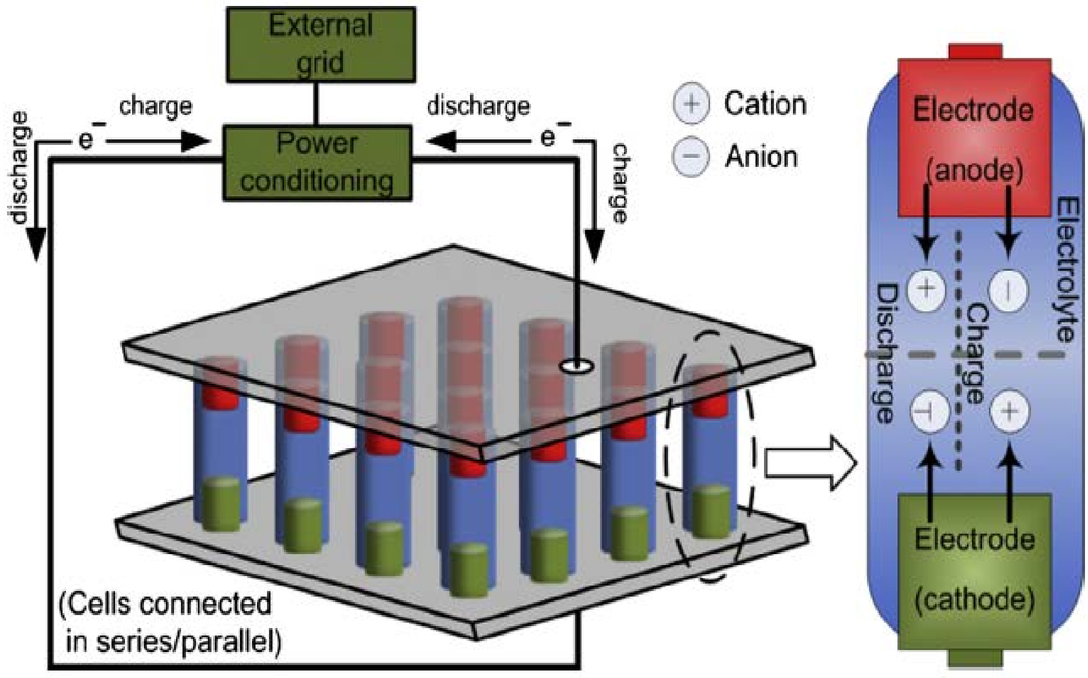


Figure 2.5: Battery energy storage system operation

Batteries are made up of parallel or in-series cells, each having an anode and a cathode and a solid, liquid or viscous electrolyte material. (Waghorne, 2001; Song, Wang and Wan, 1999). There are many kinds of batteries, which can operate in a variety of situations, such as lead-acid, nickel-metal hydride, lithium-ion, sodium-sulphur, alkaline and nickel-cadmium (Willis, 2000). A number of new types of batteries currently are attracting a considerable amount of interest in terms of research. These include high temperature, metal-air, and flow batteries (Van den Bossche et al., 2006; Luo et al., 2015; Dong et al., 2016). The battery most commonly used commercially worldwide is the lithium-ion battery. The zinc-bromine (ZnBr) flow battery will also be considered below in terms of its use as a future battery technology.

a) Zinc Bromine flow battery (ZnBr)

This is a hybrid flow battery system which has two electrolytes in two external tanks based on zinc and bromine. The two electrolytes flow through the cell stack consisting of carbon-plastic composite electrodes with compartments during the charge and discharge modes (Chen et al., 2009; Rajarathnam and Vassallo, 2016).

The main advantages of the ZnBr flow battery are that its energy density (~ 30-65 Wh/l) and cell voltage (1.8 V) are both relatively high, in addition to which it offers deep discharge and good reversibility. The module size ranges from 3 kW to 500 kW with a 10-20 year lifetime, and the discharge period is up to almost 10 hours (Schoenung, 2001; Arai et al., 2008). Its drawbacks are corrosion of materials and a low cycle efficiency (about 65%-75%) in contrast with other batteries, which reduces its use in many applications, and, finally, the ZnBr can normally only operate within a narrow temperature range (Tong, 2010).

b) Lithium-ion battery

The lithium-ion battery has been around for almost 40 years and is widely used in electronics and transport, in particular for plug-in hybrid electric vehicles (PHEVs), and power grid applications (Whittingham, 2012; Akinyele and Rayudu, 2014). The main advantages of this battery are:

1- Higher efficiency (up to 97 %) compared with other BESs,
2- low self-charge,
3- Life cycle of nearly 10000 cycles,
4- Higher energy density (75-2000 kWh/kg) compared to lead–acid, Ni–Cd and Ni–MH batteries,
5- Cell voltage of 3.6 V compared to ∼1. 2 V and 2.0 V for nickel and lead–acid technologies, respectively,
6- No memory effects.

The positive electrode of the lithium-ion battery is made from a ‘lithiated’ metal oxide such as lithium cobalt oxide ($LiCoO_2$), lithium nickel dioxide powder ($LiNiO_2$) or lithium manganese dioxide ($LiMnO_2$), etc., with graphite used in the negative electrode (Chen et al., 2009; Abbas et al., 2013).

A lithium salt such as lithium hexafluorophosphate ($LiPF_6$) or lithium perchlorate ($LiClO_4$), etc., is used as the electrolyte. The lithium cations move to the node during the charging mode and to the cathode during discharging – a form of ‘intercalation’ of chemical reactions. Figure 2.6 shows a schematic of a Li-ion battery (Kebede et al., 2014; Yang et al., 2010).

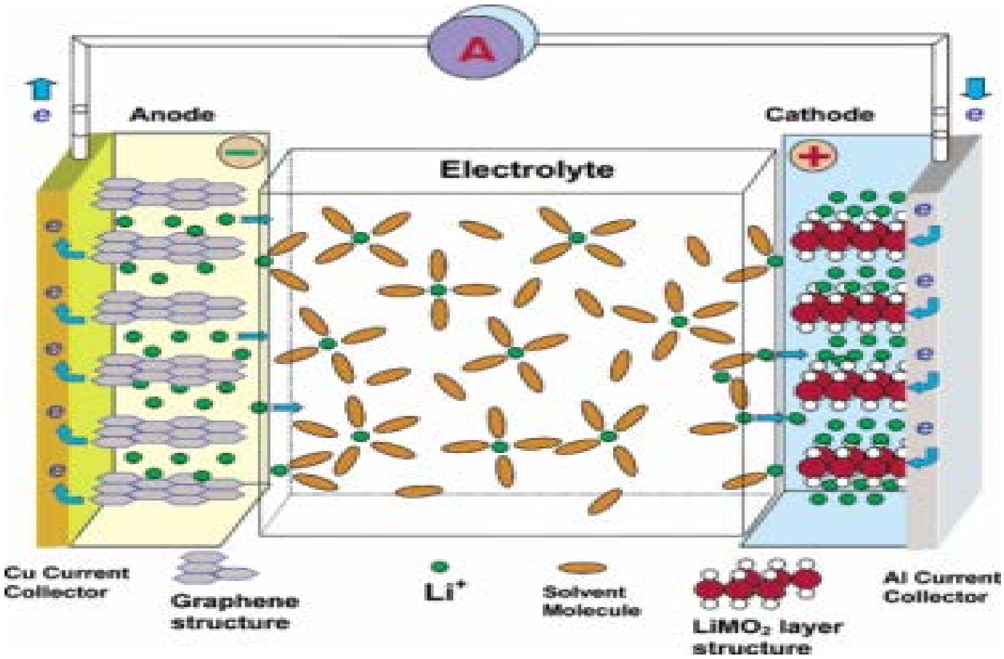


Figure 2.6: Schematic diagram of a Li-ion battery

2.2.6 Supercapacitor energy storage (SCES)

Supercapacitor energy storage (SCES) is relatively new and is considered one of the best ways to deal with voltage regulation (Sevilla and Mokaya, 2014). In SCES, the energy is stored as an electrical field between two electrodes.

Due to the limitations of electronic circuits, (they cannot meet the requirement of energy storage regarding volume and weight), new research should focus on the development of high energy density supercapacitors (Burke, 2000; Dong et al., 2016).

Figure 2.7 shows a supercapacitor with double layers. The main advantages of supercapacitors are that they provide high efficiency (approximately 95%), operate at low temperatures, maintenance cost is zero, and they offer a quick response and good durability. However, supercapacitors are still expensive and under development for large systems and are not yet available for commercial applications, in addition to having low energy densities and a high self-discharge rate (nearly 5% per day) (Sevilla and Mokaya, 2014).

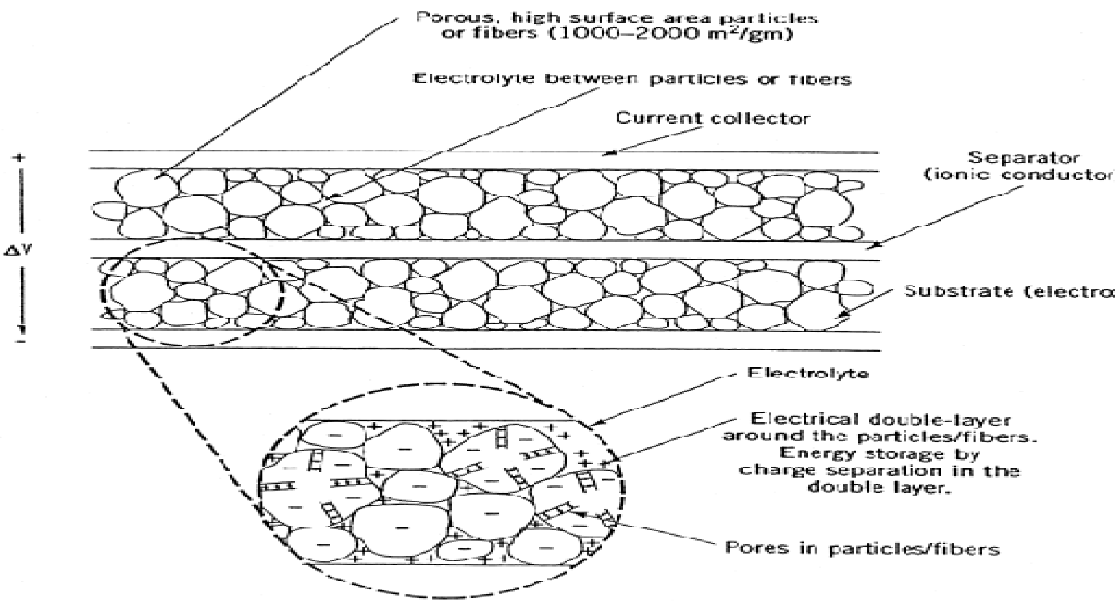


Figure 2.7: Double layer supercapacitors

Supercapacitors are faster than batteries in terms of charge rate, and can be used for power quality systems similar to the flywheel (Huang, Liang and Chen, 2012; Ibrahim, Ilinca and Perron, 2008).

2.2.7 Superconducting magnetic energy storage (SMES)

The ideal SMES consists of three components: a superconducting coil unit, a power-conditioning subsystem and a vacuum refrigeration subsystem (Díaz-González et al., 2012; Ali, Wu and Dougal, 2010).

The electrical energy in the SMES system is stored in the magnetic field produced by the direct current in the superconducting coil. It is essential to cool the superconducting coil to below superconducting critical temperature. The resistance of the coil would usually cause the power to dissipate as heat when it passes through it.

Power can be stored when coils are produced from materials such as mercury or vanadium and operated in a superconducting state at very low temperature. Niobium-titanium, with a 2.9 K superconducting critical temperature, is commonly used for this purpose. When discharging, the SMES returns the stored energy to the electricity network via an inverter, which converts its DC output to AC (Chen et al., 2009). The components of an SMES are shown in Figure 2.8.

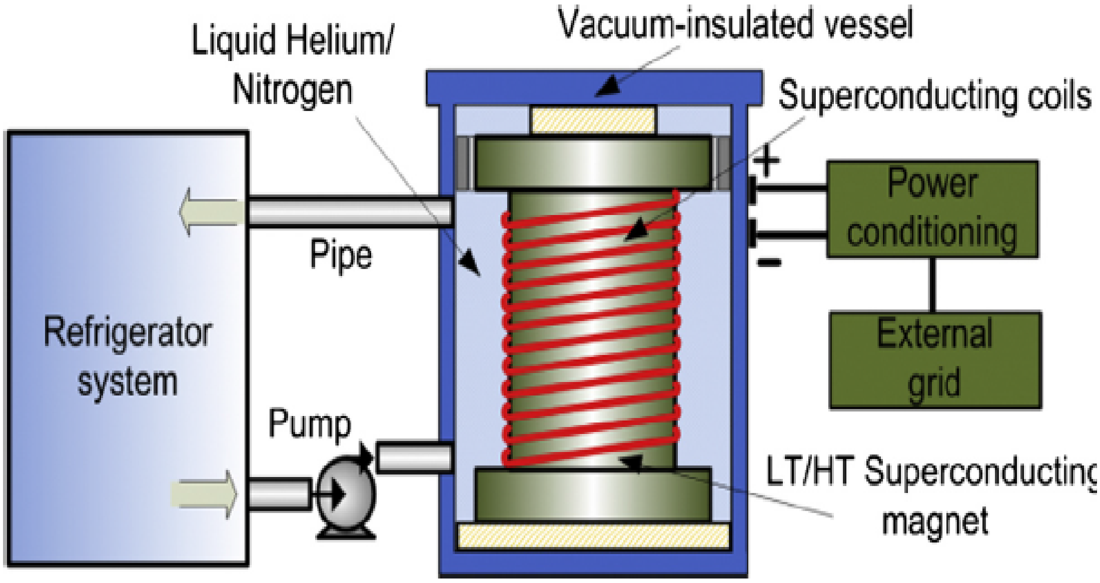


Figure 2.8: Superconducting magnetic energy storage

There are two types of superconducting material: low temperature superconductors (LTC), which can work at nearly 5 K, and high temperature superconductors (HTC), which work at about 70 K. Nowadays, LTCs are commercially available, whereas HTCs are still in the development stage (Díaz-González et al., 2012). On the one hand, SMESs tend to be relatively high in power density (up to p4000 W/L), as well as having a fast response time (millisecond level), together with a rapid full discharge time (less than 1 min), higher cycle efficiency (95–98%) and long lifetime (up to 30 years). However, they can have negative effects on the environment because of the strong magnetic fields inherent to the process, the cost of capital can reach $10,000 /kWh, $7,200/kW, and their self-discharge can extend to 10-15% per day. Currently, research into such units is focussed on two areas: reducing the high cost of the coils and other systems, and developing the HTC material (Schainker, 2004; Smith, Sen Sr and Kroposki Sr, 2008; Schoenung, 2001; Liu, Zhang and Zhang, 2016).

2.2.8 Flywheel energy storage (FES)

Kinetic energy is stored in a Flywheel Energy Storage (FES) system, with the absorbed electricity driving the motor to boost the flywheel's velocity. Then, by running the motor as a generator, electricity is generated and, as a result, the flywheel slows down (Dell and Rand, 2001). Flywheels can be classified into low-speed and high-speed types. The price, and other features of the flywheel, relate to their speed, which means that low-speed flywheels are cheaper, but have limited energy storage capacity in comparison with high-speed flywheels. Their main application is in remote electrical systems, allowing additional renewable energy penetration, while their main advantages are that they offer good high-speed dynamics, have long life cycles and are highly efficient (Ferreira et al., 2013). A systematic description of FES is presented in Figure 2.9.

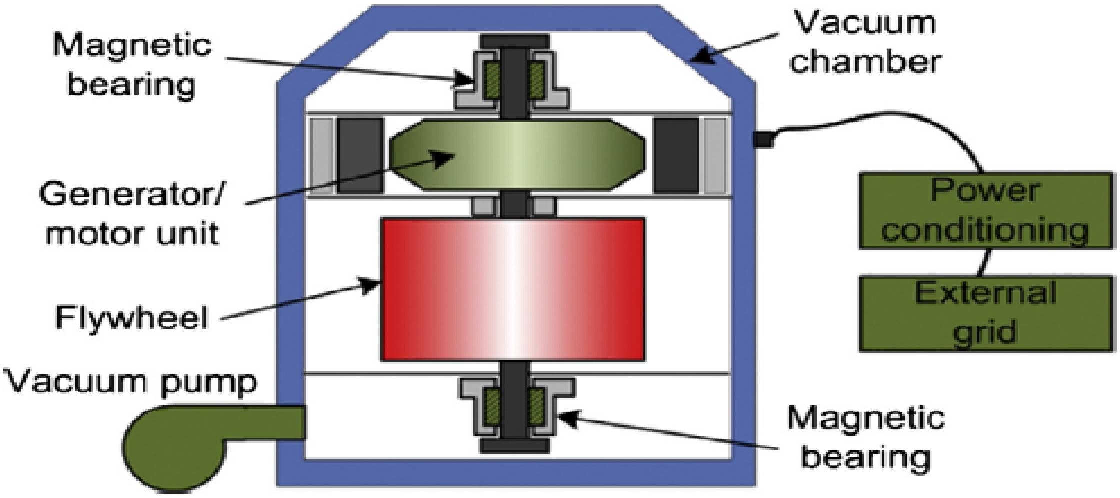


Figure 2.9: Flywheel energy storage system

The energy storage in the flywheel can be determined using Equation (2.1).

$$E = \frac{1}{2} I\omega^2 \quad (2.1)$$

Where E is the energy, I is the moment of inertia, and ω is the rotational velocity (Fleming, 1999). For an electrical power system, a large flywheel is required. The tensile strength of the flywheel material determines the maximum energy which can be stored, Steel is used for low-speed FES units and can be rotated to $6 \times 10^3\ rpm$, while for a high-speed FES, advanced composite materials such as carbon-fibre can be used, which can reach $10^5\ rpm$. Low-speed FES are normally suitable for short-term and medium/high power applications. The energy capacity of a low-speed FES is in the region of $5Wh/kg$, whilst for a high-speed FES this figure is nearer $100\ Wh/kg$. The need for composite materials in the latter case could lead to a higher price compared with conventional FES systems. The main advantages of flywheels are that they offer relatively high power densities, have high cycle efficiency ($\approx 95\%$ at rated power), no depth-of-charge limit, and they are easy to maintain. Nowadays, research and development in this regard is centred on the materials used for flywheels so as to increase rotational speed, the power density and the bearing capacity (Luo et al., 2015).

2.3 Energy storage applications

Energy storage has been applied in many areas throughout the world and for different purposes, mostly to achieve two main targets:

1- Increase the penetration of renewable energy sources by storing excess energy,
2- Satisfy demand at any given time using power that is already stored

Applications of flywheel storage systems can be found in various areas of the world. Beacon Power began the commercial operation of a 20 MW modular power plant in New York in June 2011; it is considered to be the most advanced ESS in North America. Its main purpose is to regulate voltages by providing nearly 10% of the total frequency regulation of the state (Sebastián and Alzola, 2012; Luo et al., 2015). Active Power Company established a 100/150 kW unit, 20 MW/5 MW h plant to satisfy targets in frequency regulation, power quality, and voltage support. Another application was 100 kW/5 kW h, HT magnetic bearings built by Boeing Phantom Works to achieve power quality and peak shaving. There are other applications of FES managed by Japan Atomic Energy Centre, Piller Power Systems Ltd., and the NASA Glenn Research Centre for various purposes (Long and Zhiping, 2008; Pena-Alzola et al., 2011; Hadjipaschalis, Poullikkas and Efthimiou, 2009; Mulcahy et al., 2001).

The first CAES was installed in Germany in 1978 at a rated power of 290 MW. The main aims of this plant were to provide black start power to nuclear plants, back-up to local power systems and to produce more electricity to meet demand as necessary. Another two 110 MW CAES have been built in McIntosh, United States, and a 25 MW in Sesta, Italy (Eckroad and Gyuk, 2003; Greenblatt et al., 2007). SMESs are in the development stage with many studies and research still ongoing, and thus they have not yet been widely used in commercial energy storage applications. Table 2.1 shows various SMES projects (ZHANG, Qiu and LAI, 2008; Ali, Wu and Dougal, 2010; Yuan, 2011; Hassenzahl et al., 2004).

Country	Data	Details
Proof principle tested in a grid in Germany	5 KJ, 2 s to max 100 A at 25 K	World first significant HTS-SMES, by ASC
Korea Electric Power Corporation, Hyundai	3 MJ, 750 kV A	Improving power supply quality for sensitive loads
Superpower & others, University of Houston	20 kW, up to 2 MJ class	UHF-SMES, voltage distribution
Upper Wisconsin by American Transmission	3 MW/0.83 kW h, each 8 MVA	Power quality application reactive power support
Nosoo power station in Japan Improve	10 MW	Improving stability and efficiency of the system
Germany, Bruker EST	2 MJ	High-temperature superconductors
Japan, Chubu Electric Power Co.	7.3 MJ/5 MW and 1 MJ	Provide comparison to transient voltage

Table 2.1: Some SMES projects

There are many SCES projects including an EPSRC-funded project in the UK. The target of this project is to develop a high-performance supercapacitor, some results from which were published in 2013 (Markoulidis, Lei and Lekakou, 2013). Table 2.2 presents some SCES utility applications (Sharma and Bhatti, 2010; ZHANG, Qiu and LAI, 2008)

Organization	Location	Details
CAPXX, Supercapacitor	Australia	Single cell 2.3–2.9 V, up to ~2.4 F, 233- 358 K
Maxwell, Ultracapacitor/ Boostcap	USA	Single cell 2.2–2.7 V, 1–3000 F, UPS, pulse, transportation
Gold capacitor, Panasonic	Japan	Single cell 2.3–5.5 V, 0.1–2000 F
TVA company, Supercapacitor,	USA	200 kW, supporting the start of high power dc machines
Supercapacitor, Siemens	Germany	21 MJ/5.7 W h, 2600 F, metro distribution net application
Supercapacitor,	Japan	NEC 3.5–12 V, 0.01–6.5 F, power quality

Table 2.2: Some SCES utility applications

Thermal energy storage has been used in the UK since 2010 at Scottish and Southern Energy's 80 MW biomass plant, built by Highview Power in 2014 with £8 million having been paid to fund the 5 MW/ 15 MWh LAES project (Gent, 2013). Some TES projects have been installed in offices in the US and Beijing, which could decrease the peak electric consumption of 6100 kWh per month (Sharma et al., 2009). Another 15 MW plant has been built in Spain to store heat energy. Due to the diversity of battery design and uses, it is difficult to note all the associated advantages, disadvantages and applications in just a few pages, so our comparison in this regard will be limited to the most commonly used batteries. Table 2.3 shows the advantages and disadvantages, and some applications, of four types of battery (Chen et al., 2009; Díaz-González et al., 2012; ZHANG, Qiu and LAI, 2008; Hodson, 2013; Semadeni, 2003; Walawalkar, 2008; Kothari, Buddhi and Sawhney, 2004; Luo et al., 2015).

Properties / **Battery**	**Advantages**	**disadvantages**	**Applications**
Lead Acid	1-Established technology. 2. Recognised. 3. Economical. 4. Readily available.	1-Lead-acid batteries show poor performance at low temperatures. 2-Durability issues. 3-Environmental concerns.	Automobile and UPS/ Telecom/ Substation reserve power
Lithium-ion	1-High efficiency (85-90%), 2-Good reliability, 3-Low self-discharge rate (0.1-5 h) 4-Very high energy density (200-600 Wh/L). 5-Energy capacity could reach 30 MWh.	1-For medium and large applications, these batteries are still expensive. 2- Deep discharging has a detrimental effect on lifetime.	Phones/ Computers / Cameras/ Medical purposes/ electric cars/ storage in grid
Sodium Sulphur	1-Very fast adverse action between charge and discharge modes. 2-High operational efficiency (75-90%). 3-The cost of maintenance is low, and they are long lasting.	1-The high temperature of operation (300^{o}C). 2- Safety issues. 3- Expensive.	Peak shaving/ upgrade deferral and levelling load applications
Nickel–Metal Hydride	1-Has a higher energy density (140-435 Wh/L) 2- mature 3- has long life cycle	1-The construction of the battery requires use of scarce materials. 2-High self-discharge rate.	Utility / Telecom backup and consumer electronics

Table 2.3: Advantages and disadvantages of different types of battery

Electrolytic hydrogen storage systems are currently receiving a great deal of attention due to their many advantages. US companies made 80% of the total of such investment in

2012 (Department of Energy, 2016). The first state unit of hydrogen was built in Norway, which produced power with high efficiency (Nakken et al., 2006). One of the largest hydrogen stations was established in California (2.8 MW) (*DFC3000 (2.8 Megawatts MW)*) to convert biogas into electricity. Currently, there are a number of projects at the testing stage such as IdealHy (the Netherlands), RE4CELL (Spain), Sapphire (Norway), SmartCat (France), etc. Figure 2.10 and Figure 2.11 compare different properties of a number of ESSs.

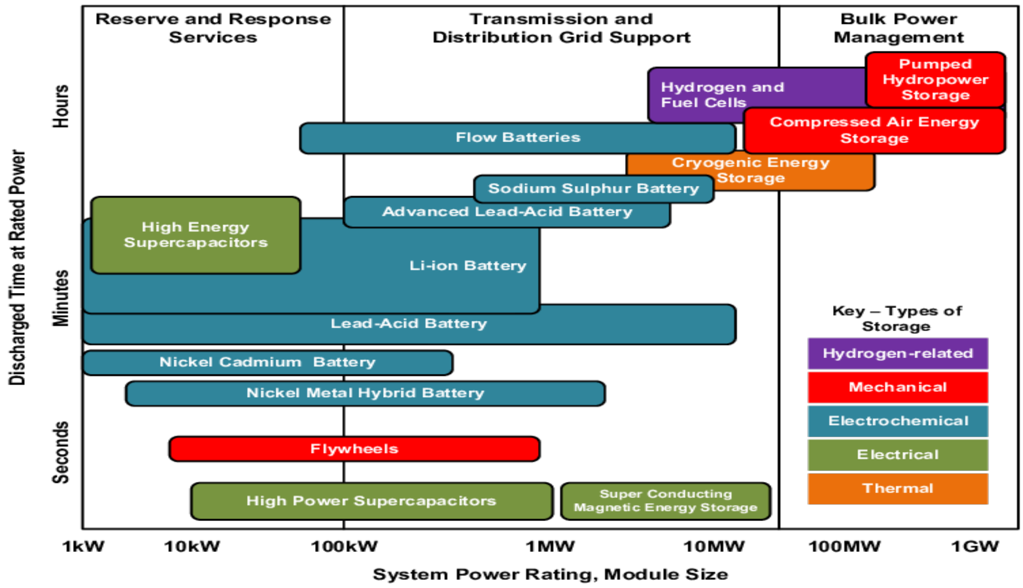


Figure 2.10: Comparison of discharge time vs. system power rating for ESSs (Luo et al., 2015).

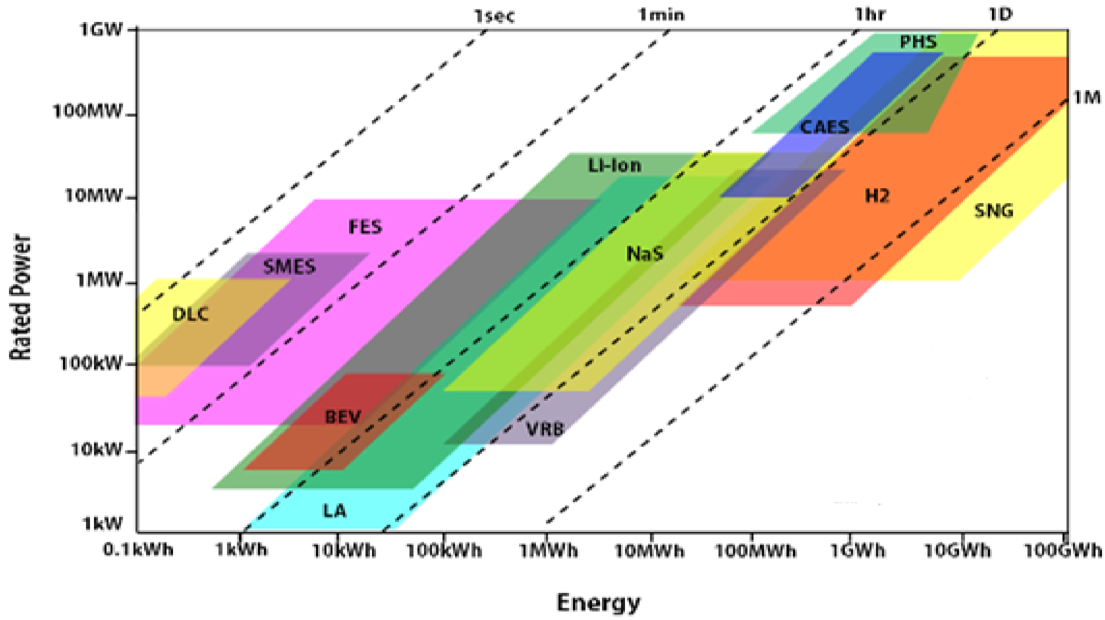


Figure 2.11: Comparison of capacity of rated energy vs. rated power with period of discharge for ESSs.

2.4 Summary of the chapter

This chapter has provided an overview of recent technological developments in EESs, both in academia and in industry. Relevant technical and economic data were used in order to carry out a comprehensive comparison of different aspects of these technologies, with the aid of tables and figures. The potential applications of energy storage systems were discussed in detail in terms of current EES features and through the specifications of each application. The overview has provided an up-to-date view of significant EES technologies which could be used as a basis for further research and development in this area and to assess EES technologies in terms of implementation. The review showed that PHS plants have been utilised globally as a result of being an established technology. Their main use is as stationary, large-scale energy storage units because of their relatively low power/energy densities whereas the Li-ion battery, on the other hand, with its relatively high power/ energy densities and specific power/energy, is used mainly in small-scale EES applications. In terms of cycle efficiency, continuous improvements have been made to EES technologies. This has led to technological breakthroughs and, as a result, most commercialized techniques tend to have medium-to-high cycle efficiencies. The main factors in choosing a suitable storage duration are energy capacity and the self-discharge of the energy storage system. The overview indicated that, at least currently, no suitable commercial-scale technology exists for seasonal energy storage, although a number of EES technologies could potentially be applied in this manner, including Pumped Hydroelectric Energy Storage, fuel cells, and thermal energy storage. Various factors need to be considered when choosing which EES to implement. The main priority for the national regulator would be the level of technological maturity, reliability and potential environmental impacts (such as the toxic chemical materials used in batteries) whereas cost-effectiveness may not be particularly important; these factors would also be important to end-users (customers) or local (private) networks, but the investment cost and the economic gain would be additional concerns. Hydrogen energy is more suitable for large-scale, long-term storage than other mature storage methods and has the advantage of being environmentally friendly. It is used for seasonal energy storage, despite being very low in efficiency as hydrogen is able to store energy for several months with little loss. It can be released by either a combustion engine or a fuel cell, is the latter being the more efficient but more expensive of the two. It is also much more suitable for demand side response applications. Due to the advantages discussed above, hydrogen was selected for further investigation in this thesis.

Chapter 3: Overview of Hydrogen Storage Method

3.1 Introduction

Hydrogen is extremely light when compared with various traditional types of fuel (such as diesel, petrol, methane (CH_4) and methanol (CH_3OH)), having zero emissions (when renewable energy is used) and a high energy density. In addition, hydrogen is available in vast quantities in nature, as mixed with other elements. Hydrogen can be produced in various different ways such as electrolysis and steam reforming, etc. Table 3.1 below gives a comparison between hydrogen and various other fuels (Kuang et al., 2005; Nicoletti et al., 2015; Lee, Speight and Loyalka, 2014).

Type of fuel / **Properties**	**Hydrogen (H_2)**	**Methane (CH_4)**	**Methanol (CH_3OH)**	**Gasoline**
Molar mass (g/Mol)	2	16	32	100~105
Carbon percent (%)	0	75	37.5	85~88
Energy Density (MJ/kg)	143 (electrolytic hydrogen)	50	19.9	44.4

Table 3.1: Comparison between hydrogen and other traditional fuels

All these comparisons are made under standard conditions, where the operating temperature and pressure are 25℃ and 1 bar, respectively. The thermal physical properties of hydrogen in its liquid and gas states are compared with natural gas and petrol in Table 3.2 (Najjar, 2013a; Suleman, Dincer and Agelin-Chaab, 2015).

Fuel / **properties**	**Hydrogen**		**Natural gas**	**Gasoline**
	Gas	**Liquid**		
Intensity($g/\ cm^3$)	0.84×10^{-4}	0.71×10^{-1}	0.78×10^{-3}	0.73
Point of boiling (℃)	-235		-156	30~204
Energy density gravimetric (KJ/kg)	12.5×10^4		4.8×10^4	4.45×10^4
Limits of flammable (% in air)	4-75		5-16	1.4-7.6
Speed of blaze (m/s)	3.45		0.41	0.4
Temperature of blaze (℃) in air	2045		1875	2197
Temperature of ignition (℃)	585		540	257
Blaze shines	Low		Medium	High
Volume of energy density (KJ/m^3)	10.4×10^3	8.52×10^6	37.3×10^3	32×10^6

Table 3.2: Thermos physical properties of hydrogen (gas and liquid), NG and gasoline

From the properties in the table above, hydrogen's weight for a given energy is nearly one-third that of gasoline and it has a higher limit of flammability, and higher flame speed, which is inherent to its use as a fuel for internal combustion engines, gas turbines and jet engines. Hydrogen is a 'safe' fuel in terms of it's the higher ignition temperature and low flame luminosity. Moreover, it is also a non-toxic and recyclable gas (Sharma and Ghoshal, 2015; Lowry, 2017). It is not possible to call hydrogen a primary energy source because it is, rather, an energy carrier, and thus would more correctly be called a secondary energy source. An additional comparison between hydrogen and other traditional fuels is shown in Figure 3.1.

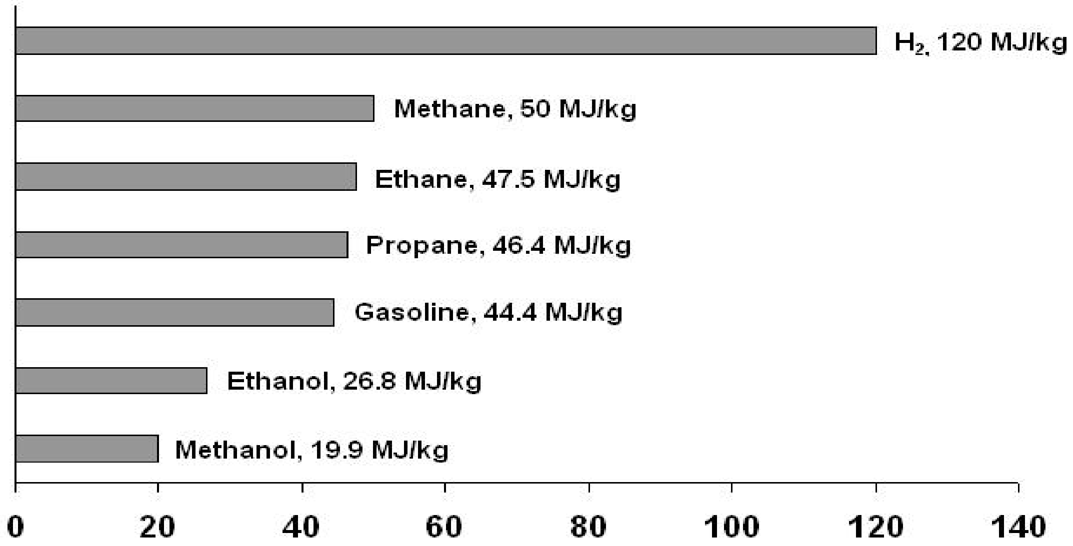


Figure 3.1: Content of heating energy by mass of many types of fuel

From Figure 3.1, it is clear that hydrogen has the highest energy density at 120 MJ/kg (nearly three times that of fossil fuels), with a very low energy density volume of about 0.01006 MJ/L. Nowadays, hydrogen represents a promising means of energy storage and a future environmentally-friendly fuel. Hydrogen can be used in various applications such as transportation, electricity generation and energy storage (Kuang et al., 2005; Pudukudy et al., 2014). The main drawbacks of hydrogen as a fuel are its low energy density, which means that a huge volume is required for any practical purposes. The intensive application of hydrogen in mobile applications, however, will almost certainly lead to further research to solve this problem. To clearly demonstrate this issue, Figure 3.2 shows the comparison between hydrogen and certain other fuels (petrol, liquid hydrogen, compressed hydrogen, and metal hydrides) based on the volume of these fuels required to generate 1 GJ of energy (Salvi and Subramanian, 2015; Ball and Weeda, 2015).

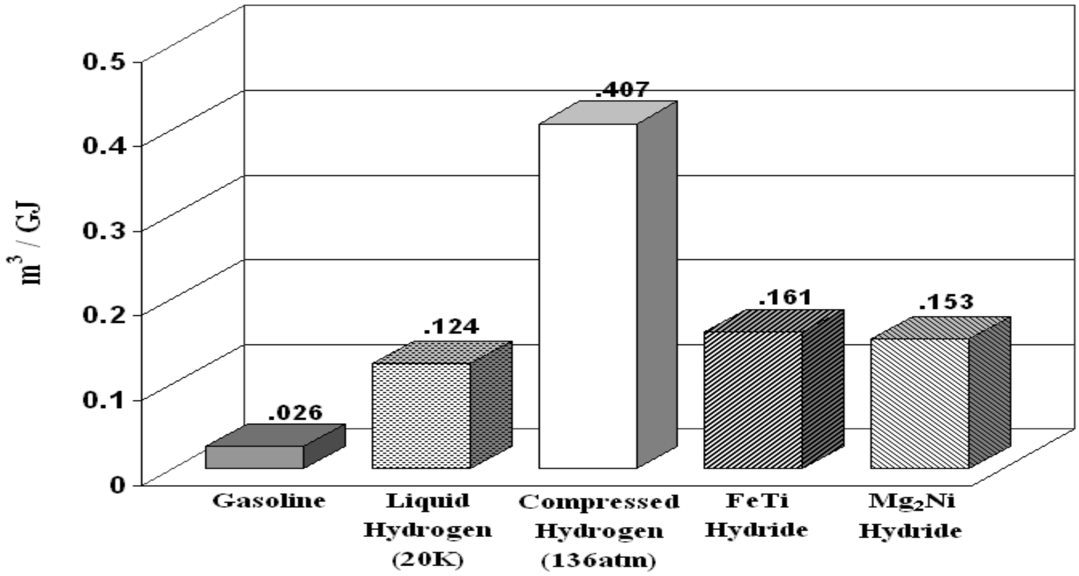


Figure 3.2: Volume of different fuels occupies for producing 1 GJ of energy

From Figure 3.2, it may be noted that all forms of hydrogen need a significantly greater volume than gasoline to produce the same amount of energy. Hydrogen fuel can be applied in three main kinds of energy conversion system: steam turbines to generate electricity, the production of electricity via fuel cells, and finally in the internal combustion engine (ICE) for mechanical and electrical power (mobile applications).

3.2 Hydrogen production methods

Hydrogen is available in vast quantities; whilst it is the most abundant element in nature, it cannot be found as a 'pure' element. Its extraction or production process requires a prodigious amount of energy (Kothari, Buddhi and Sawhney, 2004; Dincer and Acar, 2015). Nearly half of the total production of hydrogen is used in the subsequent production of ammonia, whilst the remainder is used in the petrol industry (about 37%), and in the production of methanol (around 8%) (Ramachandran and Menon, 1998; Salvi and Subramanian, 2015). Hydrogen can be produced from three different sources, namely water, biomass and fossil fuels. Around 90% of hydrogen is produced from fossil fuels using the steam reforming technique (Hassmann and Kühne, 1993; Nikolaidis and Poullikkas, 2017). This is achieved by mixing light oil or natural gas with steam at high temperature. The production of hydrogen through the electrolysis of water and the gasification of coal are the two other principal means used to produce hydrogen. Figure 3.3 illustrates the percentage of hydrogen produced by each energy source.

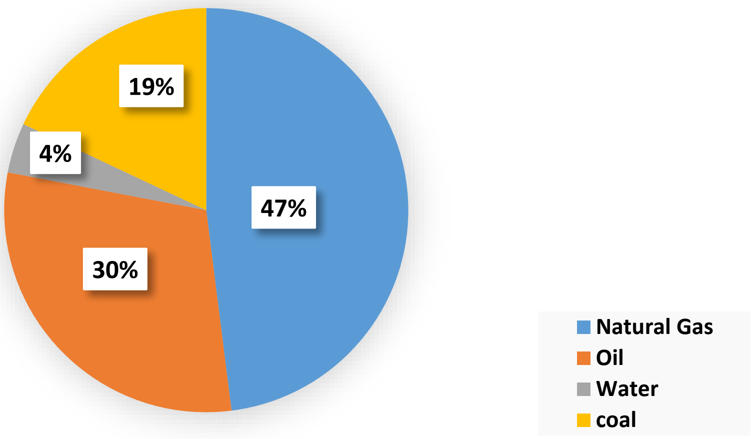


Figure 3.3: Hydrogen production based on energy sources(Hassmann and Kühne, 1993; Nikolaidis and Poullikkas, 2017)

Natural gas has the highest associated percentage, which is nearly half of total hydrogen production. Only 4% of global hydrogen produced is derived from water, allowing for significant reductions in CO_2 emissions if electricity is derived from renewable or nuclear sources. The reason for this percentage is due to the economic competitiveness between renewable and fossil fuel sources.

3.2.1 Hydrogen production from fossil fuels

a) Steam reforming

Currently, hydrogen production worldwide is predominantly achieved via steam reforming. This method generates hydrogen from CH_4 and other hydrocarbons, releasing carbon monoxide in addition to hydrogen, using a catalyst with steam. The process temperature is in the range 700-850℃ at a pressure of 35 bar (Abánades, Rubbia and Salmieri, 2013; Kothari, Buddhi and Sawhney, 2008). The catalyst in this reaction is usually made from nickel. This reforming process of methane (CH_4) can be summarised as per Equation (3.1).

$$H_2O\ (g) + CH_4\ (g) \rightarrow \quad 191.7\ kJ\ /mol + 3H_2\ (g) + \qquad (3.1)$$

The energy absorbed by this reaction is 191.7 kJ/mol, which is gained from the ambient environment. More hydrogen can be produced by adding water at low temperature (around 130°C). 40.4 kJ/mol of heat will be released during this process. Equation (3.2) shows this reaction.

$$H_2O\ (g) + CO\ (g) \ \rightarrow \ \ H_2\ (g) - 40.4\ kJ/mol + CO_2\ (g) \qquad (3.2)$$

This method can be divided into several steps: first, produce hydrogen from methane by separating the hydrogen from the carbon by passing it through high-temperature steam; this reaction produces carbon monoxide. In the second stage, the reaction between the carbon monoxide and steam generates hydrogen and carbon dioxide. In economic terms, steam reforming is highly efficient, but unfortunately releases a huge amount of CO_2, which is not in line with modern environmental standards.

b) Partial oxidation of hydrocarbons

The reaction in this process is exothermic, and hence there is no for an external source of energy. At moderately high temperature and speed, oxygen (incomplete combustion state) is used. The reaction occurs with a blaze temperature of 1300-1500°C (Ramachandran and Menon, 1998; Villa et al., 2015). The process can be summarized as per Equation (3.3).

$$H_2O\ (g)\ +\ 2\ C_8H_{18}(l)\ + 23/2\ O_2\ (g) \rightarrow\ 19\ H_2\ (g) + 8\ CO\ (g)\ +\ 8\ CO_2\ (g) \qquad (3.3)$$

The by-product in this reaction is methane (CH_4). The amount of CH_4 can be controlled via the temperature and pressure used for the reaction. If the operating pressure is limited, increasing the temperature can lead to a reduction in methane production.

c) Thermal cracking of natural gas

Thermal cracking is an advanced method for producing hydrogen from natural gas. It is a very old technique with the simplicity of a petroleum refinery process. In thermal cracking, a firebrick is heated to 1400°C using a methane-air blaze. The methane will decompose to hydrogen and carbon, and the air is then turned off until the temperature of the firebrick has dropped to around 800°C. The hydrogen and methane are isolated, and then transferred to a hydrogen purification process (Abánades, Rubbia and Salmieri, 2013).

d) Coal gasification

Coal gasification is one of the more popular ways by which to produce hydrogen. It also requires extensive energy consumption. This method proceeds via various chemical reactions, and is rather complex compared to the previous methods discussed above. The main advantages of this method are high efficiency and reliability and low cost (Stiegel and Ramezan, 2006). Coal gasification was stopped for a time due to the advantages of other methods (natural gas and oil) from an environmental perspective. Steam or oxygen with a temperature of more than 700℃ and pressure of 30 bar is passed over coal to generate a gaseous mixture of H_2, CO, and CO_2. Increasing the pressure leads to increased methane production. By adding the CO_2 acceptor, the CO_2 can be removed; this is achieved by adding the mixture to lime or calcium oxide (CaO), where the reaction between CaO and CO_2 produces $CaCO_3$, which is then heated to evolve CO_2. The hydrogen released can be purified to around 99.5% using pressure swing adsorption (Pant, Gupta and Gupta, 2009; Verma, Olateju and Kumar, 2015).

3.2.2 Hydrogen production using biological methods

There are many different biological methods for hydrogen production. Biological components, a bioreactor, and sunlight can all be used. Currently, an algal strain is the biological element used in many such applications. Biological components can be divided into two types: biomass and microbial (Bridgwater, 2002).

a) Biomass

Hydrogen can be generated from biomass using the biophotolysis method, which is abundant, renewable and clean. There is a diversity in the biomass resources such as animal waste, sewage, trees, crops and certain kind of industrial waste. This process is based on heating the biomass in water to a temperature of 700℃ to decompose it into CO_2 and H_2, followed by a purification stage to obtain pure hydrogen (Parthasarathy and Narayanan, 2014; Abuadala and Dincer, 2012).

b) Microbe

This technique was first investigated by (Weaver, Lien and Seibert, 1980) through the production of hydrogen from the photosynthesis of bacteria, and which can be undertaken in the dark. Hydrogen can be produced from microorganisms through photosynthesis (Gest and Kamen, 1949). The metabolic processes of these micro-organisms produce hydrogen. Generally, there are two methods: anaerobic, and photosynthetic. The production of hydrogen from microbes uses fermentation via anaerobic organisms (Schlapbach and Züttel, 2001; Han, 2007).

3.2.3 Hydrogen production from water

Hydrogen can be produced from water in large quantities since water is almost always easily available (lakes, rivers, and oceans). Oxygen is generated as a by-product in addition to hydrogen. Hydrogen production from water is an abundant and promising option due to its environmental advantages. Regarding the study of (Markillie, 2013), the cost of hydrogen was projected to be £4.19/kg in 2013, a reduction of 32.7% compared with the value of £6.23/kg from previous years under identical operating conditions. Table 3.3 shows the conditions required to produce reasonably priced hydrogen.

Electrolyser capacity	446 kg/day
Period of Amortisation	10 years
The price of Electricity	£0.035/kWh
Price of water	0.13 p/litre
Conversion rate	55 kWhr/kg
Yearly Service	5% of sale price
Capacity factor	70%

Table 3.3: ITM power details for £4.19/kg of hydrogen price

a) Direct thermolysis

This is also called the steam process or high-temperature electrolysis. Hydrogen and oxygen can be generated by the direct decomposition of water at a temperature of 2200℃ (Balta, Dincer and Hepbasli, 2010; Yılmaz and Balta, 2016). At the industrial level, this temperature is not feasible. Electricity and heat can be employed in the same process (hybrid) to decompose water into hydrogen and oxygen and, as a result, the temperature required for the process can be decreased to 800℃ (Brisse, Schefold and Zahid, 2008). Because the energy for high-temperature electrolysis is derived from a hybrid system (heat and electricity), it is considered more efficient than room temperature electrolysis since the energy for the latter system must be generated electrically (Yu, 2013). Furthermore, the reaction in high-temperature electrolysis is more active than normal electrolysis temperature, and the average number of steam molecules being splitting is also increased. This process can be demonstrated as per Equation (3.4), below:

$$H_2O\ (l)\ +\ Heat\ \rightarrow a\ H_2O\ (g)\ +\ bH_2\ (g)\ +\ CO_2\ (g) \qquad (3.4)$$

Where a, b and c are mole fractions. The temperature required to split the water into hydrogen and oxygen can be produced using a solar oven. This technique reduces the usage of electricity in contrast to normal-temperature electrolysis, and leads to a greater reduction in the overall cost of the method. There is the further advantage that a catalyst is not required, the method is environmentally friendly, and the amount of hydrogen produced from this process is very high (Arashi, Naito and Miura, 1991).

b) Thermo-chemical process

In the thermochemical method, the dissociation of water into hydrogen and oxygen is achieved through the use of a catalyst. Water is heated to a moderate temperature. The process efficiency fluctuates from 17.5% to 75.5% (Kothari, Buddhi and Sawhney, 2004; Dincer and Acar, 2015), and the associated chemical reactions are presented as per formula (3.5) below, in which AB is catalyst:

$$\begin{gathered} AB +\ H_2\ O\ (l) +\ heat\ \rightarrow A\ H_2\ (g) + BO \\ A\ H_2 + heat\ \rightarrow A +\ \ H_2\ (g) \\ 2BO +\ heat \rightarrow\ 2B + O_2\ (g) \\ A\ + B + heat\ \rightarrow AB \end{gathered} \qquad (3.5)$$

c) Solar energy

Energy from the sun is, obviously, free. There is no need for more fuel, there is no immediate cost, and there are no associated emissions. Solar energy is abundant, clean and free, and can be exploited to decompose water into hydrogen and oxygen. There are many different solar energy methods that can be used, such as photochemical, photoelectrochemical, photolysis and photovoltaic-electrolysis (Momirlan and Veziroğlu, 1999). Under normal conditions, $285.57\ KJ$ is required to split a mole of water into oxygen and hydrogen (Ohta, 2013). A photocatalyst is needed for the photolysis method. The ideal catalyst is titanium dioxide (TiO_2)(Zheng et al., 2009). As mentioned earlier, this method is simple, direct and clean, but has a very low efficiency.

The photolysis process can be summarized as per Equation (3.6), X is standard for photocatalyst (Thomas, 2000):

$$\left.\begin{array}{c} H_2\,O\,(l) + X + Light \rightarrow Reduced\,X + 2H_- + 1/2O_2(g) \\ Reduced\,X + 2H_- \rightarrow X + H_2\,(g) \\ H_2\,O\,(l) + X + Light \rightarrow H_2\,(g) + 1/2O_2(g) + X \end{array}\right\} \quad (3.6)$$

Photovoltaic-electrolysis is a combination of a photovoltaic device and an electrolyser used in the generation of hydrogen. Sunlight is converted directly into electricity, which is then used to drive the electrolysis of water; the associated reaction will be disused in the water electrolysis method section later in this study (Sun et al., 2013; Bak et al., 2002).

d) Direct electrolysis

William Nicholson and Anthony Carlisle first apply this method in 1800. Water is directly split into hydrogen and oxygen using electricity. The energy source is connected to two electrodes, the anode and the cathode. Both are placed in a sink of water. During the reaction, the hydrogen molecules accumulate at the cathode, whereas the oxygen accumulates at the anode. An electrolyser is a direct current-low voltage device (Kumar, 2015; Fingersh, 2003). Figure 3.4 shows a water electrolysis device.

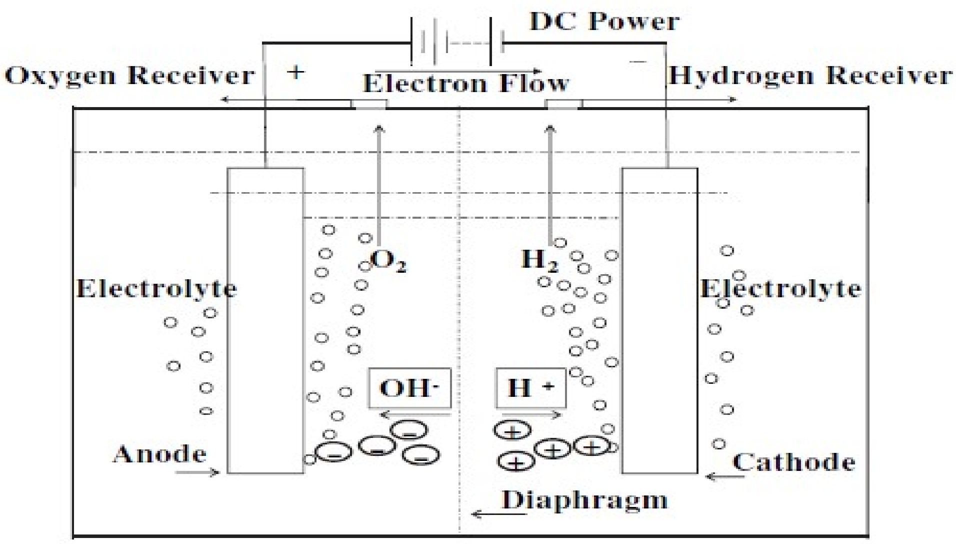


Figure 3.4: Water Electrolysis device

The amount of hydrogen produced is proportional to the injected current. The nominal voltage of an electrolyser is 1.23 V, but in real operation, the voltage is higher than the nominal value, around 1.65 V - 2.20 V (Bossel, Eliasson and Taylor, 2003; Gutiérrez-

Martín and Guerrero-Hernández, 2012). The hydrogen produced from electrolysis can be extremely pure. The reaction for this process is presented in Equation (3.7.

$$\left.\begin{array}{r} Reaction\ of\ cathode\colon\ H_2\,O\,(l) + 4e^- \rightarrow 2\,H_2\,(g) + 4OH^- \\ Reaction\ of\ anode\colon H_2\,O\,(l) + 4e^- \rightarrow 2\,H_2\,(g) + 4OH^- \\ Overall\ formula\colon 4\,H_2\,O\,(l) + Electricity \rightarrow\ 2\,H_2\,(g) + O_2\,(g) +\ heat \end{array}\right\} \quad (3.7)$$

The reduction reaction occurs at the cathode. Hydrogen ions will accept the electrons at the anode (oxidation reaction). The electrode material affects the general efficiency of the electrolyser. Reducing the energy consumption leads to increased system efficiency. Energy consumption depends on the ionic activators; in other words, hydrogen evolution could be improved by developing the physical characteristics of the cathode material. The cathode can be manufactured from various different elements. Platinum-molybdenum $(Pt - Mo)$ alloys have been tested as good candidates for the cathode material. Molybdenum-platinum $(MoPt_2)$ and titanium-platinum $(TiPt)$ have also been investigated as cathode materials. The cost of alkaline, proton exchange membrane and solid oxide methods range from US$ 400-600/kW, US$ 2000/kW and US$ 1000-1500/kW, respectively (Padró and Putsche, 1999). If pure water is used, the electrolysis reaction becomes very slow because of the low conductivity of the medium. Seawater can be used for this technique at high efficiency and low cost. Indeed, the efficiency can reach 75% and might be further improved at higher pressures and temperatures. This efficiency drops to around 30-45% if the process of converting heat into hydrogen is taken into consideration (Kato et al., 2005). This method consumes a large amount of energy (energy intensive process), where 53.4-70.1 kWh is required to produce 1 kg of hydrogen (Haryanto et al., 2005; ITM Power, 2013).

3.3 Hydrogen storage methods

Although hydrogen has many advantages, such as its abundance, cleanliness and high energy density, it is still the lightest substance. Hydrogen storage remains a huge challenge in contrast with other conventional fuels. The hydrogen phase diagram is presented in Figure 3.5.

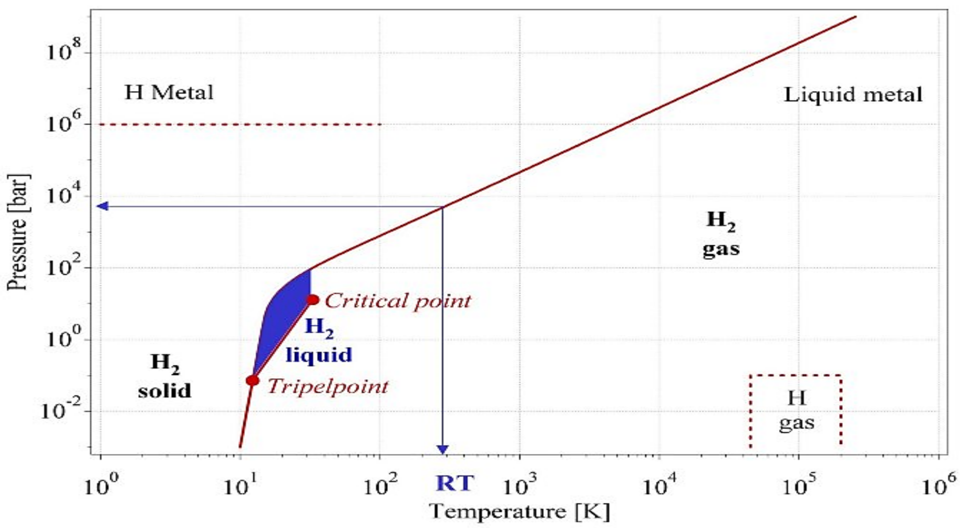


Figure 3.5: Diagram of hydrogen phase

The hydrogen molecule, H_2, can be seen in different forms as reliant on pressure and temperature, as given in the figure above. Hydrogen is a solid at extremely low temperature with a density of 70.6 $kg.m^{-3}$ at $-262°C$, and in the gas state at higher temperatures, with a density of 0.089886 $kg.m^{-3}$ at $0°C$ and a pressure of 1 bar. A small area starting at the triple point and finishing at the critical point shows the formation of liquid hydrogen with a density of 70.8 $kg.m^{-3}$ at $-253°C$. Hydrogen can be stored via different methods such as compression, liquefication using cooling processes, storage in insulated tanks, using complex compounds and by absorption on interstitial sites in a host metal, or physisorbed in carbon. A comparison of these storage methods is given in Table 3.4 (All data in this table is under standard conditions 25℃ or 298K, and 1 bar):

Methods of storage	**Gravimetric density (%)**	**Volumetric density**$(kg\frac{H_2}{m^3})$	**Operation temperature** ℃	**Pressure (bar)**
Complex compounds	Less than 18	150	More than 100	1
Gas (high compressed)	12	Less than 4	Room temperature	800
hydrogen Adsorbed	Nearly 2	20	-80	100
Liquid	Depend on size	70.8	-252	1

Table 3.4: Comparison between the storage methods

3.3.1 Hydrogen compression storage

Hydrogen's density is 70.6 kg/m^3 at a temperature of -262℃ in the solid phase, whilst in the liquid phase the density is 70.8 kg/m^3 at 253℃, whilst at a pressure of 1 bar in the gas state. However, the problem of the lowest energy density creates an additional burden for hydrogen storage (Trevisani et al., 2007; Parks et al., 2014). The most popular method of hydrogen storage for many years was in a high-pressure gas state. Compressed hydrogen can be stored in a container and delivered to a consumption area using pipelines, which requires the diffusion of hydrogen. This technique is a simple method of storage with a high efficiency of about 90% (Niaz, Manzoor and Pandith, 2015). High pressure is needed for this method, which can create safety problems. For standard applications of hydrogen, steel tanks are preferable since weight is important. At less than 3,000 psi (200 bar), a high pressure compressed gas cylinder at a density of 14.5 kg $/m^3$ is considered a commercially viable means of storing hydrogen. Increasing the pressure leads to increased capacity, and currently the highest pressure that can be obtained is around 800 bar (12000 psi) and with a density of nearly 36 kg/m^3(Züttel, 2004; Trevisani et al., 2007). The losses in the compression process mainly arise from operational and permeation losses (Takeichi et al., 2003).

3.3.2 Liquid hydrogen storage

This technique is a highly energy-intensive process. The energy required for liquefying is equal to nearly one-third of the energy stored in the liquefied hydrogen (Züttel, 2007; Lai et al., 2015). The liquefying process principle is similar to the hydrogen compression method. The liquid state of hydrogen can only be obtained at very extremely low temperatures of about -252℃ (-423.17°F or 20.27 K) at standard pressure. After the liquefying process, hydrogen can be stored as a liquid in a pressurized and cooled container, which needs to be extremely large because of the relatively low energy density of the liquid state of hydrogen. The energy utilization efficiency of this method is low; even though it has a high storage capacity due to losses during the liquefication process. The volume occupied is relatively small in contrast with the gas compression process. Liquid hydrogen's volume capacity is 0.070 kg/l, in contrast with 0.03kg/l for gas tanks at 700 bar. The purity of the hydrogen available from this technique is very high (Niaz, Manzoor and Pandith, 2015). There is a small but continuous leakage of hydrogen due to evaporation (Schlapbach and Züttel, 2001; Peschka, 1983; Scott, Denton and Nicholls, 2013). This method is extremely expensive in contrast with other methods due to its temperature and pressure requirements. Combining cryogenic storage and high-pressure gas requires a hybrid tank, as investigated by (Han, 2007). These hybrid tanks are lighter than hydrides and are more compact than the high-pressure vessels required for room temperature storage. The temperature required is not as low as for liquid hydrogen, there is less energy loss (less paid penalty) and less leakage in hybrid tanks.

3.3.3 Physisorption in carbon

Physical adsorption, or physisorption, occurs on the surface of solid elements. The concept underlying this method is one of boosting the density of hydrogen at the solid interface. Carbon is a good candidate material for hydrogen storage because of its non-polar surface properties (Mudassir et al., 2011; Sevilla and Mokaya, 2014; Noh, Agarwal and Schwarz, 1987). Carbon can be found in different forms such as active graphite, meso-carbon and nanotube. Hydrogen is concentrated in tubes, pores and internal layers of carbon. The nanotube method was first investigated in 1997 (Jones and Bekkedahl, 1997; Dalebrook et al., 2013). The storage capacity relies on many factors, such as the surface area, pore size distribution, and pore geometry of the nanotubes, and the storage temperature and pressure (Züttel, 2003). The main advantages of this method are low cost, low operating pressures and straightforward operation. However, the hydrogen energy density relatively is low, and the reaction can only occur at room temperature (25℃). Another disadvantage of this method is the difficulty one encounters in its control and optimization. Numerous pore volumes and the large surface area of the activated carbon make it one of the best absorbents of gaseous species (Darkrim, Malbrunot and Tartaglia, 2002). Carbon nanofibres and nanotubes storage capacities, which are below 0.7 $wt\%$ at 25℃ and a pressure of 100 bars, is less than the capacity of activated carbon (Takagi et al., 2004). However, herringbone-type graphite nanofibers were investigated and it was shown that such a structure can absorb hydrogen until 0.67 wt% at a temperature of 27℃ and high pressure (about 101 bar) (Chambers et al., 1998). These results cannot be recreated in recent studies since most published research showed that the maximum storage of hydrogen by non- carbon materials fluctuated between 0.1-

0.2 $wt\%$ (Barbir and Gomez, 1997; Kirubakaran, Jain and Nema, 2009)(Hirscher and Panella, 2005; Rouquerol et al., 2013; Liu et al., 2016).

3.3.4 Complex hydrides

Obviously, AlH_3, NH_3 and BH_3 are constituted of very light elements and are covalently bonded hydrides. They are difficult to handle safely and will decompose to stable forms, namely Al, N_2 and B, which are very challenging to refuel with hydrogen when on board a vehicle. All three compounds readily react with ionic hydrides, e.g., alkaline MH, forming $LiBH_4$, $NaAlH_4$ and $LiNH_2$ (David et al., 2007; Friedrichs et al., 2009). This class of material contains stable solids which are more convenient to handle, and consist of an electropositive counterion and a coordination complex where hydrogen is covalently bonded, i.e., $[BH_4]^-$, $[AlH_4]^-$ and $[NH_2]^-$. A significant paradigm shift occurred in the mid-nineties when (Bogdanović and Schwickardi, 1997) observed hydrogen release and uptake for titanium-catalysed sodium tetrahydridoalanate, $NaAlH_4$ (often denoted sodium alanate), under 'reasonable' physical conditions. Reversible nitrogen-based complex hydrides, e.g., as based on $LiNH_2$–Li_2NH–LiH, were discovered by (Chen et al., 2002), while (Züttel et al., 2003; Soulié et al., 2002) were the first to test metal tetrahydridoboranates, e.g., $LiBH_4$. This class of materials is known as metal borohydrides.

3.3.5 Metal hydrides

Hydrogen can be reacted with various alloys and metals spontaneously. The most reactive elements are electropositive elements such as the lanthanides, the actinides, Sc, Yt and members of the groups containing Ti and Va. Metal hydrides have the ability to repeatedly store and release the hydrogen at low pressures and temperatures. This property can be exploited in many applications such as laptops, boats and vehicles (Züttel, 2003) (David, 2005). Over 50 metals can absorb hydrogen. These experimental observations were achieved by placing solid materials with condensed hydrogen inside into containers (Holladay et al., 2009). In contrast with other storage methods, metal hydrides have several advantages such as high storage capacity, it is a reversible storage method with no self-discharge, and a high purity of the gas does not require a complex container. However, the majority of metal hydrides are easily oxidised, difficult to activate and are expensive (Liu et al., 2013; Shang et al., 2004). Figure 3.6 compares the principal properties of a number of complex hydrides, carbon nanotubes and metal hydrides. The comparison depends on volume density, ρ_v, and the mass density of hydrogen, ρ_m.

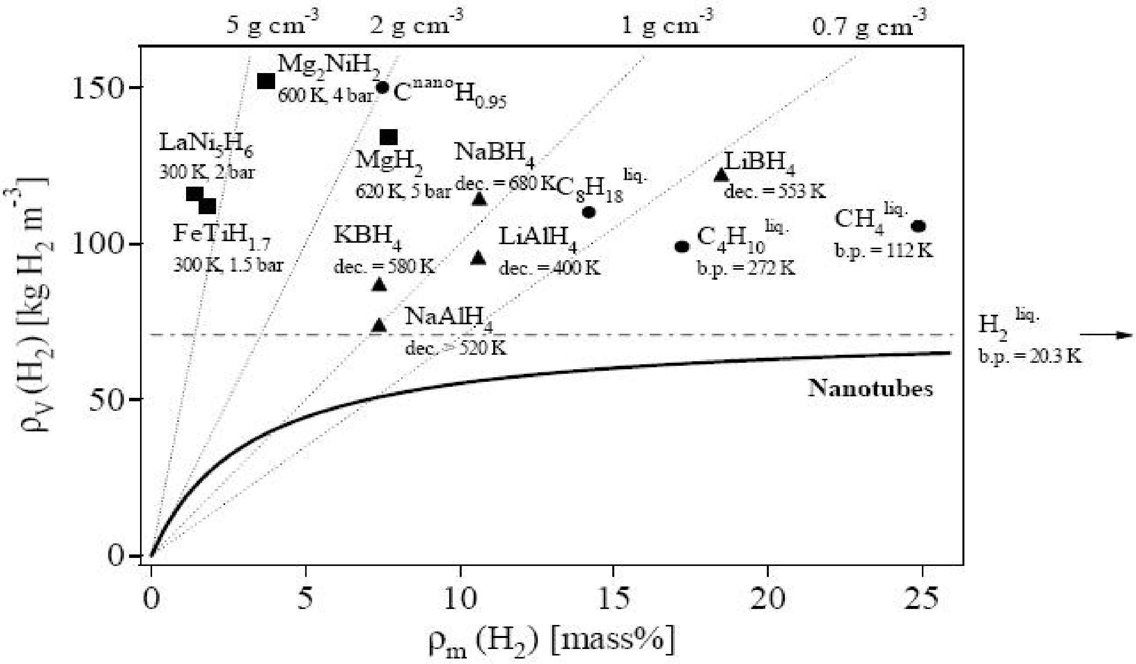


Figure 3.6: Capacities of hydride hydrogen

There are two main applications of hydrogen: transportation and stationary. Both applications have different requirements and constraints. The transportation field is expected to be the first use of hydrogen in the future hydrogen energy market. The storage requirements for the hydrogen transportation sector are more complex and rigorous than those for stationary hydrogen applications. The requirements for hydrogen storage for the transportation sector can be summarised by the following points:

1- Multicycle reversibility of release and absorbed hydrogen (nearly 500 cycles)
2- Operating pressure should be low, less than 4 bars
3- Absorption/release of hydrogen kinetic energy should be rapid
4- Volumetric densities and gravimetric of hydrogen should be relatively high (greater than or equal to 70 g/l for system storage and up to 9 $wt\%$)
5- Hydrogen cost should be less than £1/kg

3.4 Hydrogen safety issues

Hydrogen is a promising clean fuel with a number of advantages such as versatility, efficiency, less pollution and renewability. It has a quality as an energy carrier, which can be used with great efficiency with zero emissions at the point of use (Grigoriev et al., 2009; Dagdougui et al., 2018). Hydrogen cannot be found alone so it requires energy to extract it and then deliver it to the p-point of use. The main issue related to the acceptance of hydrogen as a fuel for public use is its safety, both in the production, storage and transportation stages and in its applications stage (for example, vehicle fuel or in-home use) (Allston and Press, 2016). There are three classifications of hazard relating to the use of hydrogen:

1- Physiological
2- Physical
3- Chemical

For more than a century, the safety record for the production and use of hydrogen for many applications in industrial and commercial purposes such as refinery, rocket propulsion and chemical process has been good. However, hydrogen is not as popular as other fuels mainly due to its history of serious accidents which have caused significant economic and societal cost. These include the Hindenburg disaster in New Jersey in 1937, hydrogen released during maintenance in Houston in 1989, and a pressurized hydrogen tank rupture in Frankfurt in 1991 (Najjar, 2013b). The main causes of hydrogen accidents can be classified as follows:

1- Material or mechanical failure
2- Corrosion
3- Over pressurisation
4- Enhanced embrittlement of storage tanks at low temperatures
5- Boiling liquid expanding vapour explosion
6- Rupture due to impact by shock waves and missiles from adjacent explosions
7- Human error.

Hydrogen is a good choice of clean fuel and energy storage, however some issues related to its safety have to be considered and some steps have to be taken to deal with hydrogen in a safe environment (Pasman and Rogers, 2010). The summary of this section is presented in the following points

1- Hydrogen has physical hazards such as causing embrittlement of metals which leads to degradation and failure.
2- Chemical hazards are related to wide flammability and detonability ranges, low ignition energy, high flame velocity. However, it is relatively safe in terms of having highe buoyancy and diffusion rates
3- Physiological hazards are related to asphyxiation, overpressure injury, thermal and cryogenic burns (hypothermia)
4- There are hazards with storage, especially leaking and ventilation which result in mixing hydrogen with air hence, burning
5- Hydrogen has problems with transmission. It requires relatively more power to transmit. High-pressure output electrolysers have been recently used
6- Reliable and economic sensors are needed for for early detection of leaks
7- Hydrogen safety is extremely important in vehicular applications especially fire, explosion and toxicity. It is safer than gasoline in open fires
8- It is essential to achieve a high degree of safety before any progress in applications toward hydrogen economy.

3.5 Demand Side Response using electrolysis

Since the aim of this research is to use the electrolyser as a Demand-Side Response (DSR) mechanism to absorb surplus power during off-peak times, the rest of this chapter will focus on the application of the electrolyser as a DSR technique. Most types of electrolysers being developed and improved involve the use of a solid alkaline electrolyte (SAE), liquid alkaline electrolyte (LAE), solid oxides (SOEC) and proton exchange membrane (PEM) electrolysers. Currently, PEM and alkaline electrolysers are being produced in different capacities, ranging from the low kilowatts to megawatts. Solid oxide (SOES) electrolysers have a promising future due to their higher efficiency, even if their technology is less mature in contrast with liquid alkaline electrolyte and proton exchange membrane technologies (Bhandari, Trudewind and Zapp, 2014). Hydrogen can be used in many applications such as petroleum hydrocracking, removal of sulphur via the hydrodesulphurisation process, hydrogenation of oil, ammonia production, cryogenics, the generation of power in a fuel cell mobile, combustion devices, and stationary applications. The transport sector is currently paying particular attention to this area since it has highly promising environmental advantages. In addition to hydrogen production, an electrolyser can contribute in many electrical sectors, such as end-user management, transmission and distribution (T&D), renewable energy integration, and wholesale electricity market services. There are very few studies in the literature on the operational flexibility of electrolyser methods. The use of electrolysers comes with the possibility of being able to provide considerable value to a number of related parties including facility owners, transmission and distribution system operators. Furthermore, increasing the integration of renewable energy into the grid leads to further challenges in terms of controlling the grid and gaining the flexibility necessary to do so. For short storage applications, many methods can be used and with less prices than hydrogen. However, the issue will be critical when the long energy storage is needed.

3.6 Large-scale and long-term storage options

For short storage applications, there are various methods that can be implemented that cost less than hydrogen. However, this has to be considered in light of the need for longer term energy storage. As it is mentioned in Chapter 2, CAES and PHES are preferable for storing large amounts of energy for long periods, so in this section, the practicalities of hydrogen storage will be contrasted in a technical and economic sense with these other long-term storage methods.

One of the most difficult challenges that the energy industry is dealing with is the requirement of storing huge amounts of energy for long periods as well as seasonal times in an attempt to bridge the gap between the actual demands and the non dispatchable and fluctuating power generation by means of solar and wind resources which is not likely to be achieved through conventional technologies. In the current fossil- based energy production industry, the fossil fuels storage is used for the compensation in shut downs and shortages, strategic reserves and seasonal fluctuations, e.g. both France and Germany have reserves that can cover demands for approximately two months.

Meeting the storage capacity requirements by fossil fuels is highly unlikely due to the fact that the most dominant supply in the future industry is electricity which means an electrical energy long term storage capacity will necessarily be much longer than an hour. In the last few years, for levelling out the fluctuation inherent to wind and Photovoltaics (PV) feeds into the transmission grids, compressed air energy storage (CAES) and hydro pumps systems (PHES) were exclusively the only two suitable methods. However, the most recent investigations, specifically, the comprehensive research study by (Energiespeicher, 2009) pointed out some significant drawbacks and limitations to the previously mentioned storage techniques, in respect to the total storage capacities in particular. It is only hydrogen that can solve the issue of the storage of huge amount of energy to balance long time of poor wind power supply and its longer-term, seasonal fluctuations.

Large-scale of hydrogen storage, at least currently, appears to be the only long-term means to provide electrical energy in quantity and with a quality that consumers are accustomed to, in parallel to the downscaling of major capacities from fossil power plants and nuclear power stations. However, the large volumes of hydrogen which will need to be stored can most likely only be accommodated underground in large geological formations, primarily in man-made salt caverns.

In the case of hydrogen, storage is based on chemical principles, which are associated with much higher volumetric storage densities. The disadvantage to date is the lower conversion efficiency (electricity-to-electricity,) less than 40%, for converting electricity into hydrogen by electrolysis, and its subsequent storage and conversion back to electricity when used to drive a gas turbine. However, even despite these efficiency restrictions, hydrogen is the only storage option, which allows for the storage of large amount of electrical power. In addition, there are a considerable number of suitable geological salt formations that can be used as hydrogen caverns in comparison to Compressed air energy storage caverns because hydrogen caverns can be installed at much more depths (Schindler et al., 2006). Figure 3.7 shows the potential timescales for the storage of energy using different long-term storage options.

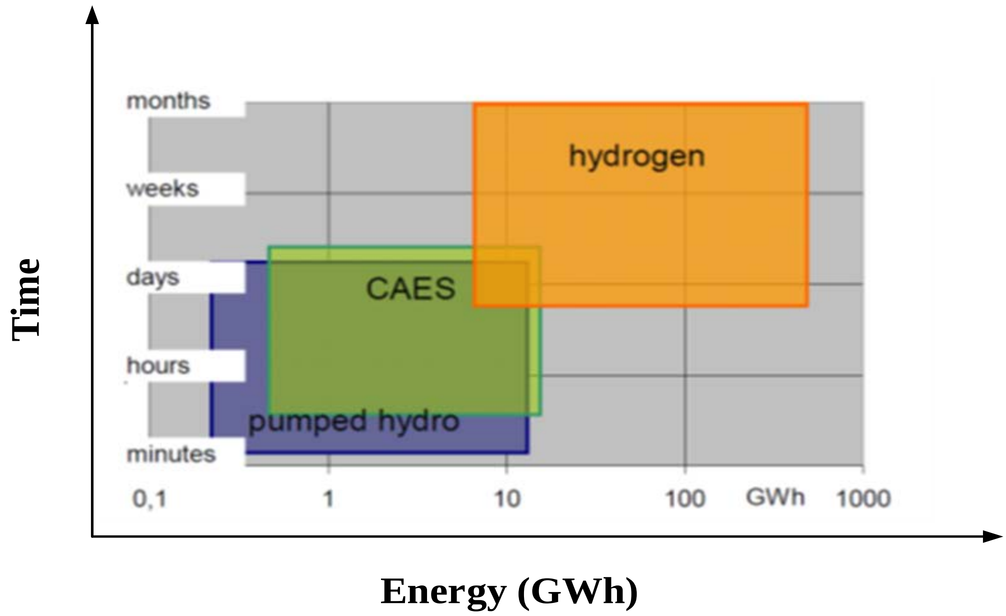


Figure 3.7: Most suitable timescales for large-scale storage options

3.7 Economic aspects of large-scale storage options

The VDE ETG study (Energiespeicher, 2009) further calculated the storage costs for the three large-scale storage alternatives. The results shown in Figure 3.8 demonstrates the load levelling needed in the two set-ups to balance short-term oscillations while the amount of energy for long-term storage are determined over a long period of time. However, the parameters taken into consideration are power plants output and storage capacities. In terms of short-term energy storage, pumped hydro and CAES power plants have similar low costs than hydrogen storage. This is basically dependent on the high investment costs on the aboveground systems and the ineffective operating cost is linked to the overall lower efficiency in the hydrogen storage case. The circumstances are reversed when long-term storage is considered. Hydrogen storage becomes more attractive when long-term storage is associated with the number of storage caverns needed. In effect, lower storage cost for hydrogen depends on its higher storage density, which reduces the required cavern volume by about 60 (Díaz-González et al., 2012). In conclusion, a crucial advantage associated with hydrogen as energy storage model for large energy volumes required to balance power usage over a long period do not depend solely on technical aspects. Underground hydrogen storage also allows for much large volume energy storage at lower costs.

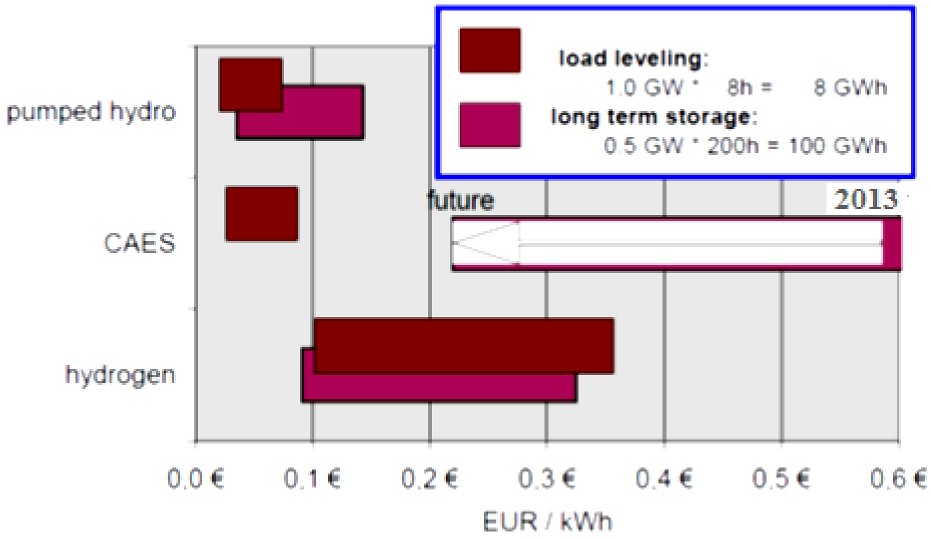


Figure 3.8: Costs (range) for storing one kWh electric power

3.8 Summary of the chapter

In contrast with conventional fuels, such as methane (CH_4), methanol (CH_3OH) and gasoline, hydrogen has the lightest weight, no carbon content and the highest mass of energy density. These features make it a good candidate for storing energy. Hydrogen can be produced from different sources such as fossil fuels, biological components, and water. Different hydrogen production and storage methods were studied in this chapter. Since this research will deal with applications of an electrolyser as a DSR, the rest of this chapter focuses on the use of electrolyser in electricity market applications. It shows that electrolysers working as demand response device can respond sufficiently rapid and for long enough periods to contribute in the management of energy on the utility scale and at end-user facilities. Therefore, the next chapter will cover the cost of the electrolyser in details and present the effect of the electricity price on the hydrogen price.

Chapter 4: Water Electrolysis Technology

4.1 Introduction

Electrolysis has been applied for nearly 100 years for producing hydrogen. A large electrolyser was built in 1927 by Norsk-Hydro in Norway for this purpose. Many electrolysers have been established in 1940, and, since 1945, some plants, with capacities of more than 33,000 Nm^3/h of hydrogen, have been erected in different areas (Koponen, 2015).

Only approximately 4% of the world's current hydrogen need is produced from electrolysis. The remainder is extracted from hydrocarbon sources, predominately using steam reforming and partial oxidation of natural gas (nearly 80% of total hydrogen production), followed by extraction from coal and naphtha.

Even the use of coal and naphtha is likely to change in the coming years due to both increases in costs and a reduced availability of natural gas and oil, as well as other environmental issues. The principle behind the electrolysis process is to apply a DC current through two electrodes submerged in an electrolyte.

Oxygen is separated at the anode and Hydrogen is collected at the cathode. There is a directly proportional relationship between the amount of current flowing between electrodes and the rate of hydrogen production (Paidar, Fateev and Bouzek, 2016). The general formula for the chemical reaction within a water electrolysis system can be given as per Equation (4.1), below.

$$H_2O(l) \rightarrow H_2(g) + {}^1/_2\, O_2(g) \tag{4.1}$$

Where l refers to the liquid state and g the gas state. A commercial electrolysis system consists of three main components, as shown in Figure 4.1.

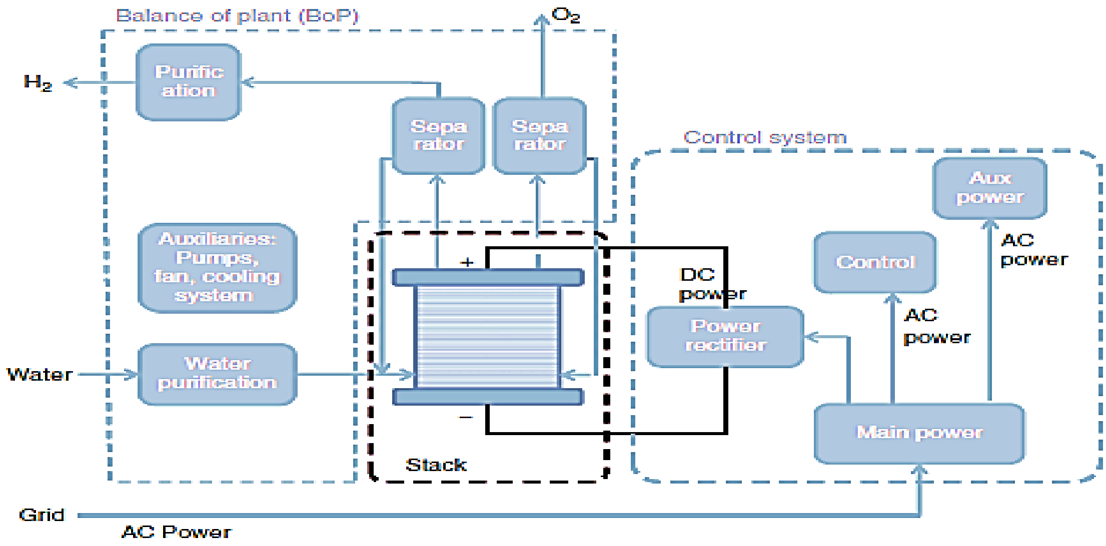


Figure 4.1: Water electrolysis diagram(Gandia, Arzamend and Diegnez, 2013)

1- The stack: this is the main element of the electrolysis system, where the water-splitting process occurs. A single electrolyser can be composed of one or several stacks. Stacks are made up of a group of cells in stacked configuration. (Mohandas, Sanil and Rodriguez, 2002).
2- The system control: this is an electric system supplying power and controlling the electrolysis process. In terms of the system control, many different architectures are available but, for many electrolysis systems, there is a master control and individual controls for each stack (Godula-Jopek, 2015).
3- The balance of plant (BOP): this term refers to the rest of the parts of the electrolysis system. These elements include gas-liquid separation units, the cooling system, water pumps, etc.

4.2 Electrolyser cell arrangements

There are two main cell arrangements for an electrolysis device: bipolar and unipolar. Figure 4.2 andFigure 4.3 show these configurations. Electrolysis cells in a monopolar arrangement are connected in parallel to build large cell stacks. U_M and I_M are the voltage and the current of electrolysis module, respectively. Since the cells in a monopolar arrangement are connected in parallel, the voltages between individual pairs are equal to the total voltage of the cell. Hence the name monopolar; each electrode has a single polarity. The current of the module (I_M) is the sum of the currents in each cell.

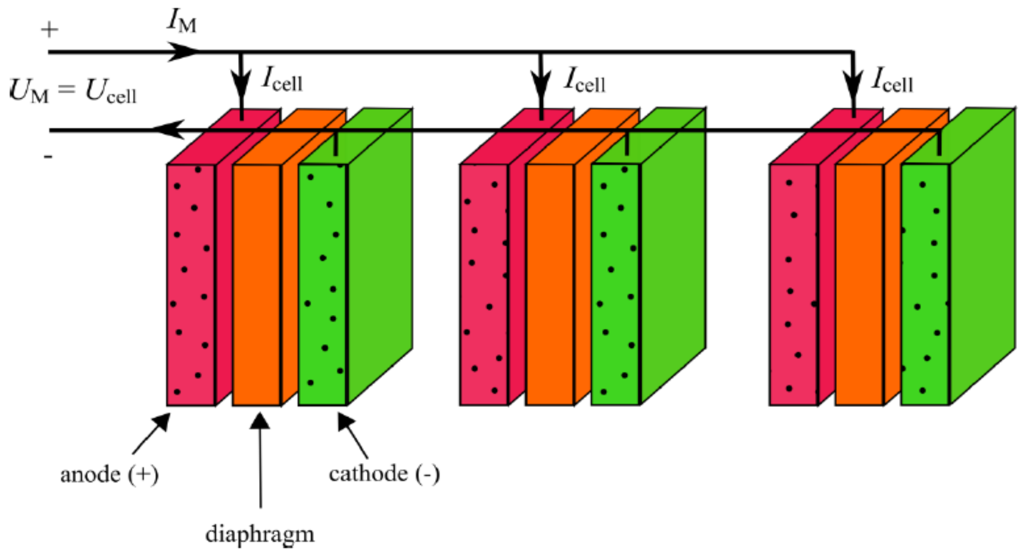


Figure 4.2: Monopolar cell arrangement(Carmo et al., 2013)

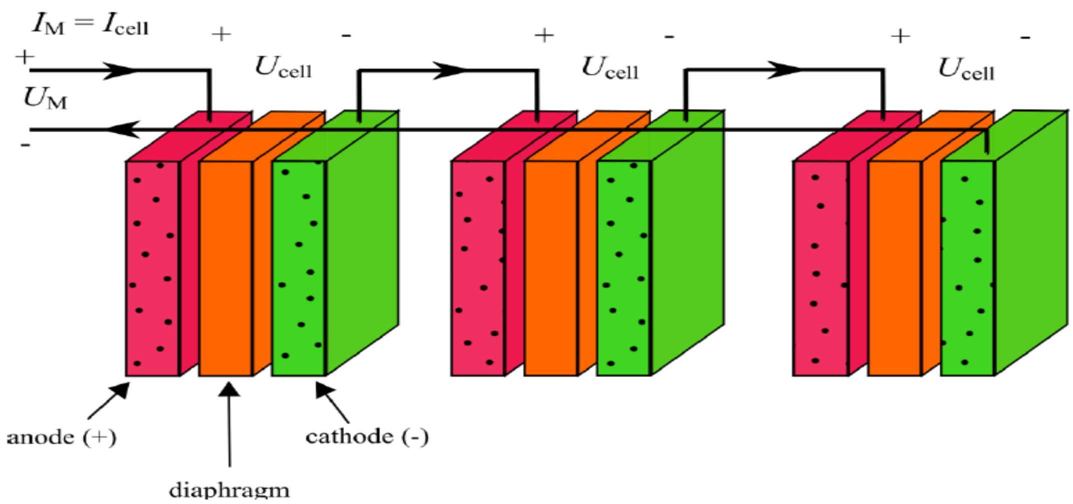


Figure 4.3: Bipolar cell arrangement(Carmo et al., 2013)

In a bipolar arrangement, the direct current connects only to the end two electrodes as the cells are placed back-to-back in direct contact with each other. In fact, the cathode of each cell is the anode of the next, so they are just 2 sides of a single bipolar plate.

The voltage (U_M) is the sum of the individual cell voltages in the bipolar module. Cells in a bipolar module are characterised by their low cell voltages, which is because of the shorter current paths in the electrodes (Tilak et al., 1981).

Many companies have upgraded their electrolysis systems to bipolar modules since these are considered more efficient than monopolar modules for the production of hydrogen due to their significantly lower losses (especially ohmic losses) (Lehner et al., 2014;

Albert et al., 2015). Additionally, parallel, series, and mixed connections of modules can be added to basic bipolar and monopolar module configurations to meet required production levels. The production of hydrogen by an electrolysis plant also needs other components for purification, gas cooling, storage and compression.

An electrolyser also requires power sources, suitable power conditioning, and control and safety systems (Ursua, Gandia and Sanchis, 2012). Table 4.1 below gives the advantages and dis advantages of bipolar and monopolar cell modules (Tilak et al., 1981; Carmo et al., 2013).

Advantages	
Monopolar	**Bipolar**
Design is simple and tough	Voltage of cells is low
Relatively cheap parts	Current density is high
Fabrication method is simple	Optimisation of rectifier cost is straightforward
Checking individual cells is easy	Easily works at high temperature and pressure
Maintenance is easier due to simplicity of isolating cells	Easy to control the whole system
Filters and pumps are not required	Requirements for spare parts are few
Circulation of internal gas lift is simple	Frame of each cell can be very thin, leading to a huge gas output from each part of the machine and Possible to work at high current density
Disadvantages	
Achieving small inter-electrode gaps is difficult	Complex design and manufacturing methods are needed
Inter-cell bus bar is heavy	Parasitic currents lower overall current efficiency
Temperatures and pressures of cell are limited by mechanical design	External equipment (cooling, filtering pumping and filtration) are needed
Observe the temperature, electrolytic rate, purity of gas must be monitored for each cell	Electrolyser stack must dismantled to fix a single unit cell

Table 4.1: Advantages and disadvantages of bipolar and monopolar cell modules

A crucial drawback of monopolar electrolysers is their large surface area which means they require more space, are unable to operate at high temperatures because of heat losses and there is an increased risk of potential drops in cell hardware. Bipolar electrolysers are more compact and generally more efficient, which makes them more common in industrial applications. They can work at higher current densities and at higher pressures and temperatures. This nevertheless introduces more challenging design issues for preventing electrolyte and gas leakage between cells (Yakdehige, Sanath Kumara De Silva, 2017).

4.3 Electrolyser types

4.3.1 Alkaline electrolyser

Alkaline electrolysers are the most technology means of water electrolysis. Anthony Carlisle and William Nicholson performed the first separation of hydrogen from oxygen using electricity in 1800. Alkaline electrolysers represent the majority of electrolysers installed worldwide. The size of a commercial alkaline water electrolyser system is between 1.8 and 5300 kW. The rate of production of hydrogen for commercial applications is 0.25 – 760 Nm^3/h (Bhandari, Trudewind and Zapp, 2014; Briguglio and Antonucci, 2015). Presently, alkaline water electrolysis is the most appropriate choice for large-scale hydrogen production applications. The principle of operation of an alkaline electrolyser cell is shown in Figure 4.4.

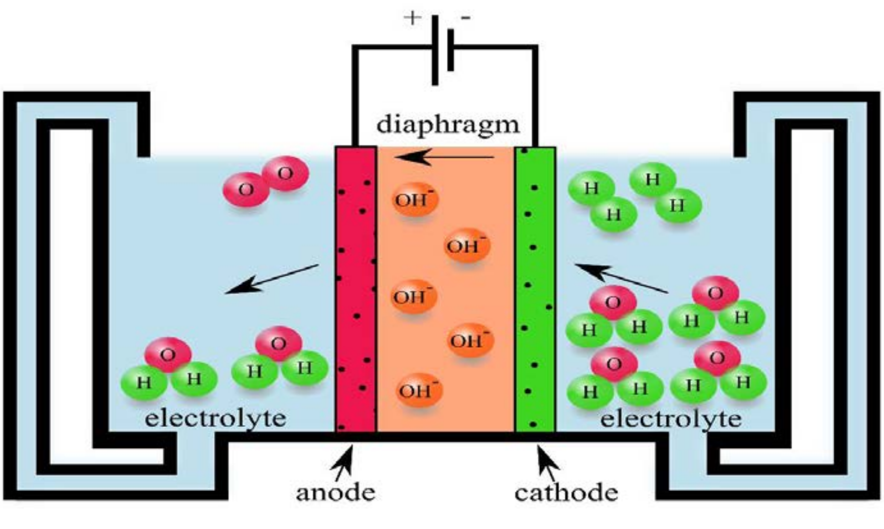


Figure 4.4: Principle operation of alkaline electrolyser(Godula-Jopek, 2015)

The principle behind the electrolysis process is to apply a DC current through two electrodes submerged in an electrolyte. Oxygen is separated at the anode and Hydrogen is collected at the cathode. The electrolysis cell consists of two electrodes (cathode and anode) isolated by a gas-tight diaphragm.

These are immersed in the electrolyte, which is normally a high concentrate aqueous solution. The electrolyte is usually a $20\text{–}40$ wt% solution of potassium hydroxide (KOH). Ignoring physical losses, the electrolyte is not consumed. Since water is consumed in the water electrolysis process, it has to be added regularly (Lehner et al. 2014). The chemical processes in alkaline electrolysis at the anode and the cathode, respectively, are as follows (Ursua, Gandia and Sanchis, 2012).

$$2H_2O + 2e^- \rightarrow H_2(g) + 2OH^- \quad (4.2)$$

$$2\mathrm{OH}^-(\mathrm{aq}) \rightarrow 1/2\mathrm{O}_2(\mathrm{g}) + \mathrm{H}_2\mathrm{O}(\mathrm{l}) + 2\mathrm{e} - \quad (4.3)$$

Hydrogen is accumulated at the cathode where water is consumed, as per Equation (4.2). Hydroxide anions pass through the diaphragm to the anode. The purity of hydrogen typically reaches 99.5–99.9 % (Bhandari, Trudewind and Zapp, 2014).

The main characteristics of an alkaline electrolyser are listed in Table 4.2 below (Lehner et al., 2014; Carmo et al., 2013).

Maturity	Commercial
Density of current	$0.2\text{–}0.4\ A/cm2$
Area of each cell	$<\ 4\ m^2$
Pressure of output hydrogen	$0.05\ –\ 30\ bar$
Operating temperature	$60\ –\ 80\ °C$
Minimum load	$20\ –\ 40\%$
Overload	$<\ 150\ \%\ of\ nominal\ load)$
Minimum load to maximum(full) load ramp-up	0.13-10 % full load
Starting up time from cold to maximum load	$20\ min\ –\ hours$
Purity of hydrogen	99.5 % without dioxo and driver 99.9% without dioxo and driver
Efficiency (HHV)	68 – 77 %
Indicative cost of the system	$1.0 – 1.2$ €$/W$
Size range of the system	0.25 – 760 Nm^3/h 1.8 – 5300 kW
Stack lifetime	$60000 - 90000\ h$

Table 4.2: The main characteristics of an alkaline electrolyser

In terms of cost, alkaline electrolysis is considered the cheapest of all electrolysis techniques to produce hydrogen. The cost ranges between 1200 - 1300 € kW^{-1} with efforts being made towards achieving 800 € kW^{-1}(Godula-Jopek, 2015). The main advantages of an alkaline electrolyser in contrast with other water electrolysis methods are as follows:

1- Comparatively lower capital cost due to the use of cheap cell materials (anode, cathode and diaphragm);
2- Proven method with well-established operational costs;
3- Large capacity units;
4- Raw water can be consumed directly during operation without the need for a specific purification process.

There are some disadvantages, however, which include:

1- The diaphragm does not completely prevent the product gases from cross diffusing through it. The diffusion of oxygen into the cathode chamber reduces the efficiency of the electrolyser, since oxygen will be catalysed back to water with the hydrogen present on the cathode side;
2- Low maximum achievable current density, due to the high ohmic losses across the liquid electrolyte and diaphragm. (Rosa, Santos and Da Silva, 1995; Carmo et al., 2013).
3- A high purity of hydrogen product requires additional purification steps such as deoxo and drying. This leads to an increase in general cost of hydrogen (Rosa, Santos and Da Silva, 1995; Carmo et al., 2013).

4.3.2 Proton exchange membrane water electrolysis (PEM electrolyser)

The current density of a PEM electrolyser is higher than that of the alkaline. Therefore, the effects of overvoltage concentration could be more significant. Hydrogen overvoltage may be defined as the difference of potential that exists between a reversible hydrogen electrode, and an electrode, in the same solution, at which hydrogen, H_2, is being formed from hydrogen ions.

The Nernst Equation below can be applied to calculate the overvoltage concentration.

$$U_{con} = -\frac{RT}{ZF}\ln\left(1-\frac{i_d}{i_{lim,d}}\right) \tag{4.4}$$

Where i_d is the current density diffusion, and $i_{lim,d}$ is the current density diffusion limit, which is directly proportional to reagent concentration. The overvoltage concentration can be ignored once the current density is less than $1A/cm^2$ (Nieminen, Dincer and Naterer, 2010). Generally, the overvoltage concentration is only significant at high current densities. Hence, the possibility of observing this phenomenon in commercial applications is actually relatively high (García-Valverde, Espinosa and Urbina, 2012). The operational current density of a PEM electrolyser normally fluctuates from 0.6 to 2.0 A/cm^2.The operational principle of a PEM electrolyser is explained in Figure 4.5.

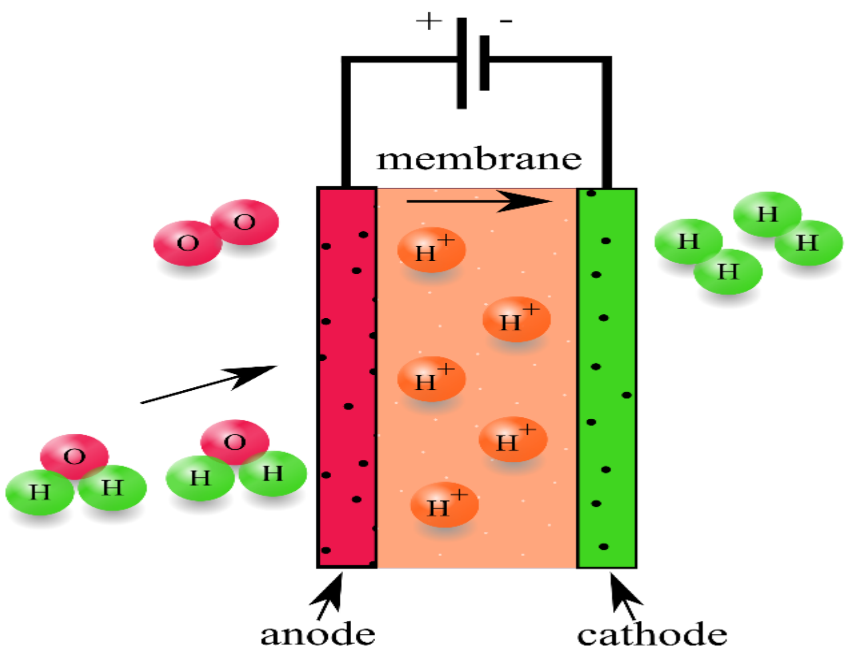


Figure 4.5: Principle operation of PEM (Godula-Jopek, 2015)

Rather than using a liquid electrolyte as in an alkaline electrolyser, a solid polymer (proton conducting membrane of $50-250\mu m$ thickness) is used in a PEM electrolyser. This polymer has a strong acidic character and is strong mechanically (Lehner et al., 2014). It is common to use sulphonated fluoropolymers, generally fluoroethylene, for this purpose; the most commonly used polymer is Nafion™. Polyethylene is adjusted by replacing a hydrogen atom with a fluorine atom in the molecule and then sulfonating by mixing with a side chain group ending with sulphonic acid (HSO_3). Thus, a polymeric electrolyte is created. An important property of sulphonic acid is that it can attract water, which is important because the polymer electrolyte membrane conductivity is reliant on hydration - decreasing water content decreases conductivity. The blending of water and the ionic bonding of the sulphonic acid group enable the movements of the H^+ protons through the molecule's structure (Larminie, Dicks and McDonald, 2003).The first water electrolysis based on a PEM electrolyser was performed in 1966, with commercialisation beginning in 1978 (Ursua, Gandia and Sanchis, 2012). Nowadays, PEM systems are used as a commercial method of electrolysis only at small and medium scale (Briguglio and Antonucci, 2015). There is only one exception to this, which is that of Siemens AG, who are establishing a huge-scale PEM electrolyser system in Germany with a capacity rating of 6MW which is officially lunched on July 2015(Martini, 2015). The chemical reactions taking place at the anode and cathode, respectively, in this system can be summarised in the Equations (4.5) and (4.6) below.

$$H_2O(l) \rightarrow \frac{1}{2}O_2(g) + 2e^- + 2H^+(aq) \quad (4.5)$$

$$2H^+(aq) + 2e^- \rightarrow H_2(g) \quad (4.6)$$

The main characteristics of the PEM electrolyser are listed in Table 4.3 below (Lehner et al., 2014; Carmo et al., 2013; Godula-Jopek, 2015):

Maturity	Commercially available at the small and medium scale size
Current density	$0.6 - 2.0\ A/cm^2$
Area of the cell	$< 0.3\ m^2$
Pressure of hydrogen output	$10 - 30\ bar$
Temperature of operation	*50-80*℃
Minimum load	$5 - 10\%$
Overload	$< 200\%\ of\ nominal\ load$
Minimum load to full load ramp-up	$10 - 100\%\ of\ full\ load/second$
Start-up time (from cold to minimum load)	$5 - 15\ min$
Purity of hydrogen	$99.9 - 99.99999\%\ with\ drier$
Efficiency of the system	$62 - 77\%$
Indicative cost of the system	$1.9 - 2.3€/W$
Size range of the system	$0.01 - 240\ Nm^3/h\ 0.2 - 1150\ KW$
lifetime	$\geq 25{,}000h$

Table 4.3: The main characteristics of the proton exchange membrane water electrolyser

From an economic viewpoint, the cost of low-capacity electrolysers (less than 100 $Nm^3 hr^{-1}$) is close to 2000 € kW^{-1}. Now, the research and development (R&D) target is to develop large-scale electrolysers up to megawatt capacities with a cost in the range of 1200-1400 € kW^{-1}. By 2020, the target is 700–800 € kW^{-1} (Godula-Jopek, 2015). The main advantages of the PEM electrolysis system are as follows:

1- The possible operation of the cells at high current densities;
2- The usage of de-ionized water as the sole reactant; leads to high-purity of hydrogen production;
3- High efficiencies can be achieved (even at high current densities); due to the thin zero-gap cells used in the PEM electrolyser, ohmic losses are reduced and system efficiency is increased due to reduced screening of the electrodes by gas bubbles;
4- Dynamic range is high (from zero to 100% hydrogen production rate can be achieved within less than 50 ms) (Tsiplakides, 2012).

The main disadvantages are:

1- The capital cost is high due to the membrane electrode assembly and the requirement for other expensive cell materials such as titanium;
2- Higher purity of water is required leading to additional cost;
3- Limitations for large-scale applications ($> 100 Nm^3/h\ H_2$) (Grigoriev, Porembsky and Fateev, 2006).

A comparison between PEM and alkaline electrolysers is presented in Table 4.4 below (Stojić et al., 2008; Kordesch and Cifrain, 2010; Godula-Jopek, 2015).

	Alkaline water electrolysis	**PEM water electrolysis**
Electrolyte	Caustic solution	Polymer
Normal current density	$0.45\ A/cm^2$	$1.0\ A/cm^2$
Consumption of energy	$4.35 KWh/Nm^3$ @ $0.45\ A/cm^2$	$4.35 KWh/Nm^3$ @ $1 A/cm^2$
Max. current density	$0.8\ A/cm^2$	$10\ A/cm^2$
Pressure of H_2 delivery	$up\ to\ 30\ bar$	$up\ to\ 700\ bar$
Purity of H_2 (dry state)	$\geq 99.5\%$	$\geq 99.9\%$
Stack lifetime	$\geq 60000h$	$\geq 25000h$
Dynamic range	$10 - 100\%$	$0 - 100\%$

Table 4.4: Comparison between PEM and alkaline electrolysers Solid oxide electrolyte electrolysers

4.3.3 Solid oxide electrolyte electrolysis (SOE)

SOE is the third important electrolysis technique currently in use besides PEM and alkaline methods. SOE electrolysis is the latest version of the three main electrolysis technologies, and is still in the research and development phase (Gandia, Arzamend and Diegnez, 2013). It is not really a modern technology because pioneering work on such systems was actually finished in the late$1960s$. Solid oxide electrolyte technology is attracting increased interest due to its potential for improving the efficiency of water electrolysis through operation at high temperatures, e.g. in the range of $700 - 1000$℃ (Ursua, Gandia and Sanchis, 2012). Figure 4.6. Shows the principle operation of SOE. Due to the high temperatures, this water electrolysis technology is, effectively, steam electrolysis. However, fast degradation of cell components occurs due to the high operating temperatures, and this explains why such devices are currently still at the development stage. The reasons behind this degradation are still not well understood (Moçoteguy and Brisse, 2013). To obtain thermal stability of the materials, research is concentrating on SOE systems working at around $500 - 700°C$. For the same reasons, $0.3 - 0.6\ \mathrm{A/cm^2}$ current densities are being used.

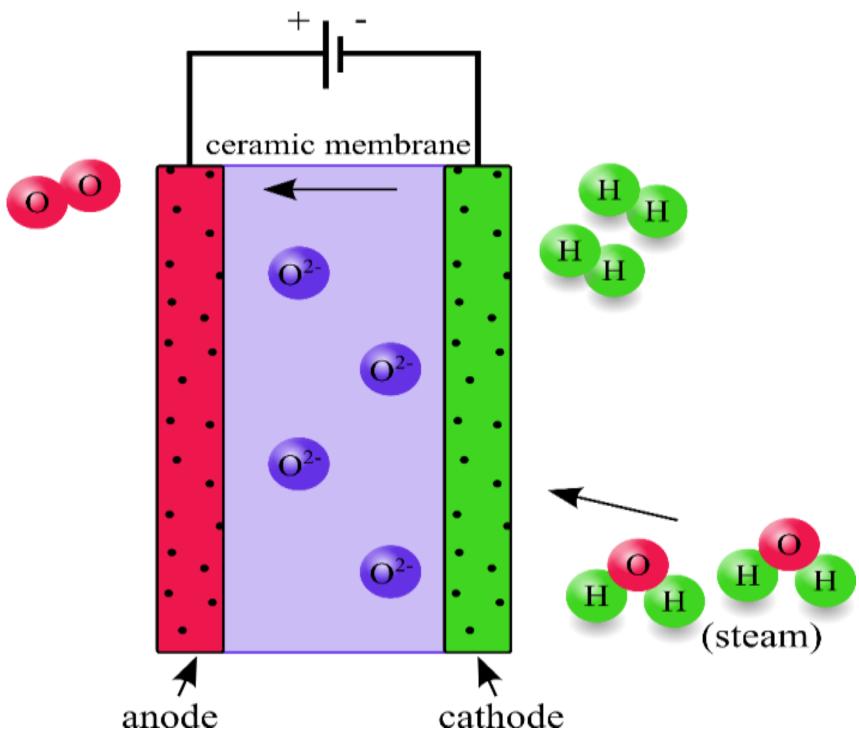


Figure 4.6: Principle operation of solid oxide electrolyte electrolysers (SOE)(Godula-Jopek, 2015)

The chemical reactions taking place at the cathode and anode, respectively, can be summarised as per the Equations below:

$$H_2O(g) + 2e^- \rightarrow H_2(g) + O^{-2} \quad (4.7)$$

$$2O^{-2} - 2e^- \rightarrow O_2 \quad (4.8)$$

Water vapour is injected at the cathode where it is separated into hydrogen and oxygen according to Equation (4.7). Oxide ions move out of the electrolyte to the anode, where they interact to produce oxygen molecules, as per Equation (4.8). The main disadvantages of this technology is the severe corrosion that takes place at both anode and cathode during oxygen evolution due to the high operating temperatures required. More research is needed to overcome these issues; for example (Ohmori, Mametsuka and Suzuki, 2000) and (Arai et al., 2006) have used different materials to improve the efficiency and characteristics of the electrolysis technology. Commercial applications of SOE are relatively few as the technique is still at the development stage. The main features of a number of commercial applications under development, as of 2016, are summarised in Table 4.5 below.

Manufacturer company	**region**	**Power rating (kW)**	**Pressure (bar g)**	**Energy consumed** $kWhNm^{-3}, \Delta H\ efficiency$
Ceramatec	U.S.A	20-100	10	~3.0 (~60)
SunFire	Germany	200	< 30	~3.0 (~60)

Table 4.5: The main features of various commercial products of SOE

4.4 Electrolysis benefits and challenges

Electrolysis is a technology by which clean hydrogen could be generated from renewable energy resources. Other technologies require the use of conventional fuels, like natural gas and coal. These technologies also have the disadvantages of releasing a diversity of greenhouse gases such as CO_2, CO, NOX and other pollutants, which, from the standpoint of climate change scientists, represent a significant problem and need subsequent filtering steps and usage of carbon sequestration methods to clean up (Utgikar and Thiesen, 2006; Ball and Wietschel, 2009). The decomposing of water via electrolysers, particularly when connected with renewable resources, has very little environmental impact compared to fossil fuel sources of hydrogen production. Electricity is required for the electrolysis process, so it is effectively the electricity source that determines the cleanliness level of the operation and the hydrogen fuel thus produced (dos Santos et al., 2017). The hydrogen cost is a crucial factor for its diffusion and adoption as a promising energy carrier (Eichman, Townsend and Melaina, 2016; Olateju, Kumar and Secanell, 2016). In conjunction with the increasing penetration of renewable energy supplies in to the gird, hydrogen might represent a clean fuel that also could support the deployment of variable energy sources such as solar and wind power, but only if the price is reasonable. Hydrogen is a secondary energy source, or a so-called 'energy carrier', but it is not a primary energy source as it is extracted from other energy sources via various techniques. It has characteristices that span those of an energy carrier, a conventional fuel, and electricity. unlike electricity, hydrogen can be compressed and stored in large quantities and dispatched as needed, which must be exploited as it is produced as difficult to store at large-scale. Hydrogen, as an energy carrier, poses some unique problems in its use. 1 kilogram of hydrogen has an energy content equivalent to that of 1 gallon of petrol. This means that storage with high-density choices is required in some applications such as transport (Gupta, 1982). There are several important factors might accelerate the transition towards hydrogen fuel. First, the potential for greater local production of energy, thereby increasing the export or reducing the import of oil depending on the country resources . A further reason is the growing attention regarding the impact of man-made CO_2 in the air and climate change. Hydrogen as a fuel has the possibility to be used relatively cleanly, either by thermochemical reaction in fuel cells or by combustion, where in both cases water is the main by-product. Hydrogen could be used particularly in fuel cells, for electricity generation and for transport applications or a fuel for heating purposes. For these features, it can be called a sustainable and clean fuel. Water electrolysis is a method by which electricity is injected to decompose water into hydrogen and oxygen. Under typical conditions, nearly 39.4 kWh of electricity and around 8.9 liters of water are required to produce 1 kilogram of hydrogen (under normal conditions at 25°C and 1 atm). This explains the hydrogen higher heating value (HHV), which involves the total amount of energy (electrical and thermal) to split water under normal conditions. Some studies and equipment have used the lower heating value of hydrogen (LHV) to compare efficiency in which the value value of the equivalent energy input is about 33.3 kWh/kg of hydrogen under normal conditions. The efficiency of the system is the ratio between the heating value (LHV or HHV) and the actual input energy in kWh/kg. Based upon the LHV, the maximum efficiency is nearly 82%, while the efficiency of the system has a theoretical maximum of 100% based upon the HHV (Hosseini and Wahid, 2016). The maximum system efficiency can never be satisfied because the process is never completely perfect due to thermodynamics and the physical limitations of materials. Electrolyser efficiencies currently range between 52% and 82% (HHV) (Chen, 2011). As mentioned earlier, the main obstacle facing hydrogen deployment is cost, since it is expensive to produce in contrast to fossil fuels (Nistor et al., 2016), which is the main point of this research. The next part of this chapter will discuss the cost of electrolytic hydrogen production in detail.

4.5 Electrolytic hydrogen cost

The price of hydrogen is affected by two main factors: capital cost and the operational cost (mainly the price of electricity), which are mostly affected by the size of the electrolyser. In other words, for a small electrolysis plant, the capital cost is the greatest factor, whereas for a large plant it is the price of electricity (Ivy, 2004).

4.5.1 Capital cost of electrolyser

Decreased cost and improved efficiency will lead to greater deployment of hydrogen production in the energy market. For a small-sized electrolyser system, the capital cost represents nearly 60% of the cost (Melaina and Penev, 2013). In general, an electrolyser system consists of the following parts:

1- Electrolyser stack
2- Power electronics
3- Control unit
4- Water and gas conditioning units
5- Water circulation unit
6- Cooling system.

It is not easy to determine real costs of electrolysers from manufacturers due to commercial sensitivity. Most research tries to use various examination methods to estimate the investment cost based on historical data or company surveys. The estimates, therefore, include some scale-up to commercial electrolysis units and extrapolation. Estimating the cost of the electrolyser cell stack depends on limited experience and normally on smaller cells and a fewer cells per stack. Experience of pricing for the purchase of components is based on laboratory or pilot-scale procurement, thus requiring electrolyser manufacturers to negotiate with sellers to determine prices for greater volumes. One formulation, based on the nonlinearity relationship between the production capacity of plant and its cost, was presented by (Genovese et al., 2009) as follows:

$$C = W^n \tag{4.9}$$

Where C the plant capital cost, W the plant capacity (e.g., kg per day), and n is a constant value that fluctuates between 0.6-0.8 depending on the plant type. For a greater total capacity, units must be installed in parallel and the cost relationship in such an instance could be linear, or at least nearly so (n approaches 1). The capital cost at each size level was scaled via Equation (4.10) from the National Renewable Energy Laboratory (NREL) Milestone Report (Ivy, 2004), where y, the plant capital cost in thousands of dollars, and x is in kgH_2/h. The authors of this report found a good match between capital cost of electrolyser and the collected cost data from the literature and seller surveys, and it is precise for sizes from $0.1\ \mathrm{kg/hr}$ to $100\ \mathrm{kg/hr}$, which fall into the size ranges being tested here.

$$y = 224.49x^{0.6156} \tag{4.10}$$

The H2A model from the NREL explains the total hydrogen cost per kg in detail. The capital cost in H2A is divided into direct and indirect capital cost. The direct capital cost includes the stack cost (41%) and the balance of the plant cost (BOP) (59%). The BOP itself consists of these parts(Saur et al., 2013):

1- Hydrogen gas management system (anode system side) (9%)
2- Oxygen gas management system (cathode system side) (3%)
3- Power electronics (21%)
4- Control and sensors (2%)
5- Mechanical balance of plants (plumbing/copper cabling/dryer valves (5%))
6- Item breakdown-assembly labour (2%)

7- Water reactant delivery management system (6%)
8- Water delivery system (5%)
9- thermal management system (5%)
10- Other items (1%).

The indirect capital cost consists of site preparation; engineering and design; project contingency; process contingency; on-time licensing fees and up-front permitting costs. In addition, there are non-depreciable capital costs that could add to the capital cost, such as land cost. Most studies rely on company and vendor questionnaires and use the cost of the power required to produce 1 kg of hydrogen to determine the capital cost of electrolyser (Saur et al., 2013). The estimate of the cost of the alkaline electrolyser system is in the region of 1000–1200 €/Kw for alklaine, and 1860–2320 €/kW for PEM electrolysers. To sum up, the real cost of electrolysers is difficult to estimate, so this research, like other studies before it, will depend on recent capital cost estimation, which will be presented in the coming chapters. E4tech and Element Energy have published an important report which discusses electrolysis theory from many perspectives (Bertuccioli et al., 2014). The capital cost of alkaline and PEM electrolysers was discussed in this report, as were expected costs from 2015 to 2030. These costs are very close the values presented in many recent studies (Bertuccioli et al., 2014). Figure 4.7 and Table 4.6 below show the current and future cost details of PEM and alkaline. Table 4.7 and Figure 4.8 shows the current and future energy consumption of PEM and alkaline (central and range size)

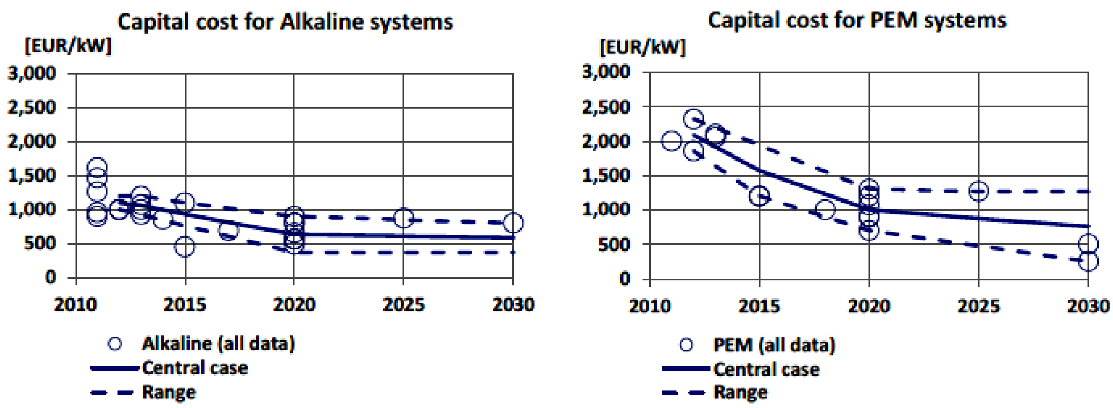


Figure 4.7: Current and future expected capital cost of alkaline and PEM systems (Bertuccioli et al., 2014)

Electrolyser cost			Today	2015	2020	2025	2030
EUR /kW	Alkaline	Central	1100	930	630	610	580
		Range	1000-1200	760-1100	370-900	370-850	370-800
	PEM	Central	2090	1570	1000	870	760
		Range	1860-2320	1200-1940	700-1300	480-1270	250-1270

Table 4.6: Current and future expected capital cost of alkaline and PEM systems

Electrolyser cost			Today	2015	2020	2025	2030
EUR /kW	Alkaline	Central	54	53	52	51	50
		Range	50-78	50-73	49-67	48-65	48-63
	PEM	Central	57	52	48	48	47
		Range	50-83	47-73	44-61	44-57	44-53

Table 4.7: Current energy consumption and future expected consumption of alkaline and PEM (Bertuccioli et al., 2014)

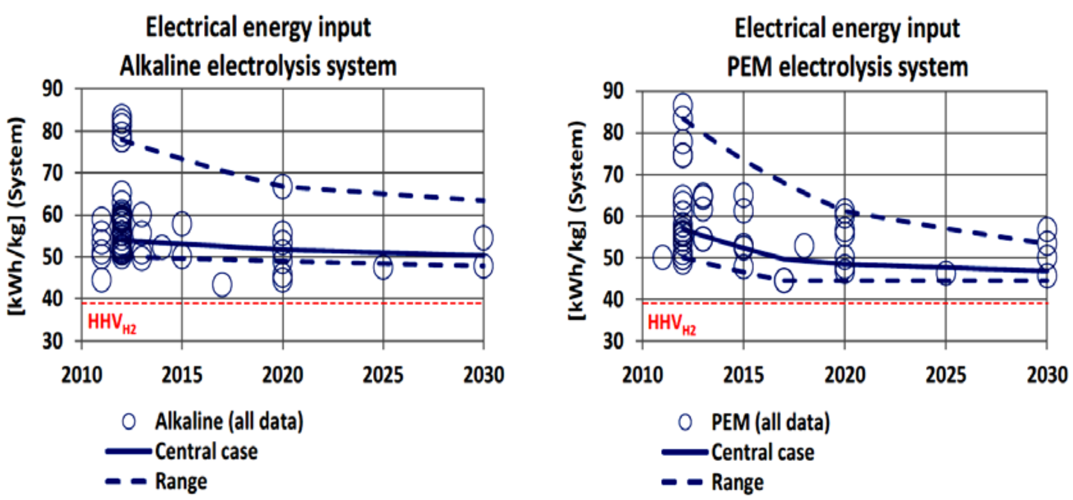


Figure 4.8: Current energy consumption and future expected consumption of alkaline and PEM systems (Bertuccioli et al., 2014)

4.5.2 Operational cost of electrolysers:

Operational costs can be classified as either variable or fixed costs. Fixed operating cost includes maintenance and repair costs (materials and production), salaries of workers, property taxes and insurance (Saur et al., 2013). Generally, fixed costs are, relatively speaking, small. Thus they are neglected in many studies. The main expense arises from the variable costs, which include electricity and water. Between 9 and 11 litres of water are needed to make 1 kg of hydrogen, so how much water and the cost per litre can be straightforwardly determined based on the size of electrolyser and the price of water. As in fixed costs, the price of water is not so high that it can be ignored (Ebaid, Hammad and Alghamdi, 2015; Gutiérrez-Martín, Ochoa-Mendoza and Rodriguez-Anton, 2015). The main part of the variable cost is the feedstock price (electricity price), which represents the highest cost of the whole system in large-scale electrolysis (Saur, 2008). In addition to its importance in terms of cost, electricity plays a key role in determining the 'cleanliness' of the hydrogen produced, and is based on the source of electricity. Recently, most hydrogen studies have focused on two main topics: the role of hydrogen in balancing the grid (demand-side management) using hydrogen production (Guinot et al., 2015; Bennoua et al., 2015; Kaldellis, Kavadias and Zafirakis, 2015) and the applications of hydrogen as a fuel (Singh et al., 2015; Yan and Hino, 2016). The cost of hydrogen in large-scale electrolysis depends only minimally on the price of electricity. To investigate the impact of price of electricity on the total cost of hydrogen produced in normal operation, the Equations below have been determined on the basis of production capacity and current density rating as follows(Gutiérrez-Martín et al., 2009):

$$C_1 = 8.36/u \times \left[E_0 + {kJ}/{P_w}\right]^{0.21} J^{-0.32} \tag{4.11}$$

$$\mathrm{C}_2 = 26.8 \times p_i(\mathrm{E}_0 + \mathrm{kJ}) \tag{4.12}$$

$$C = C_1 + C_2 \tag{4.13}$$

Where u is the utilization factor, p_i is the electricity price(£/kwh), J is the current density(A/m^2), P_w is the rated power of the electrolyser(MW), E_0 is the voltage (1.5V), k is the resistance(7.5×10^{-3} mΩ m^2), C is the total cost (£/kg), C_1 is the annual capital cost (£/kg), and C_2 is the energy cost (£/kWh). MATLAB code has been prepared to calculate the total cost with different energy prices to show the importance of this factor, especially for large electrolysis systems. The total hydrogen cost will be tested under three different prices at peak time (£0.12/kWh), off-peak (£0.05/kWh), and between on- and off-peak (£0.07/kWh) with the same capacity factor (40%). Figure 4.9, Figure 4.10 and Figure 4.11 show the impact of changing the energy price on the total hydrogen cost. Changing the energy cost from £0.12 /kWh to £0.07/kWh reduces the hydrogen cost from nearly £6/kg to nearly £4/kg and to £3/kg in the case of £0.05 / kWh. Further explanation about the Equations (4.11), (4.12) and (4.13)above can be found in (Gutiérrez-Martín et al., 2009).

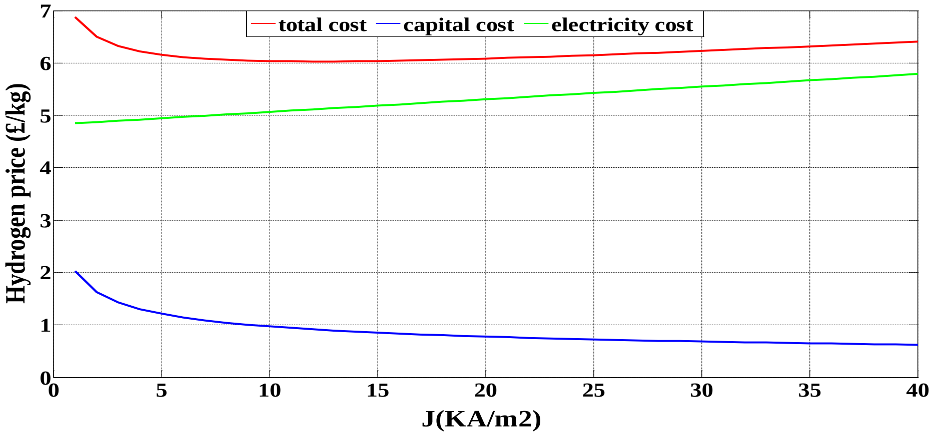


Figure 4.9: Hydrogen price cost (£/kg) at on-peak (£0.12/kWh)

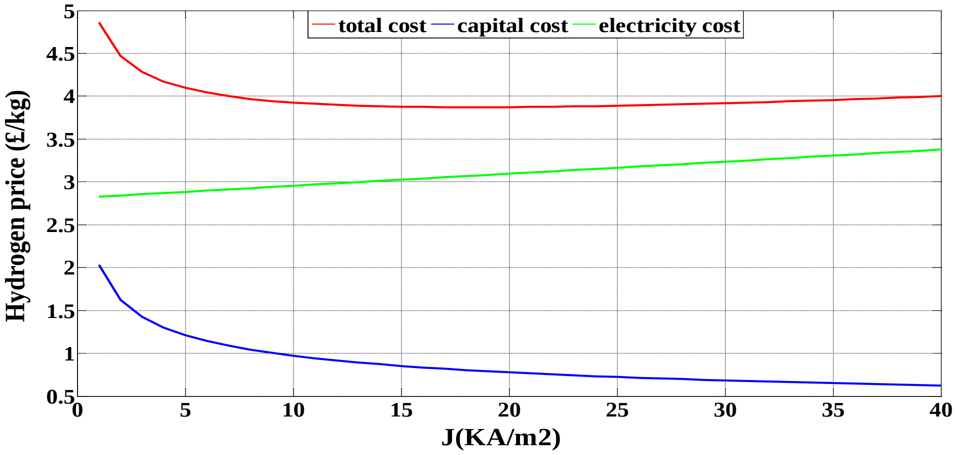


Figure 4.10: Hydrogen price cost (£/kg) at £0.07/kWh

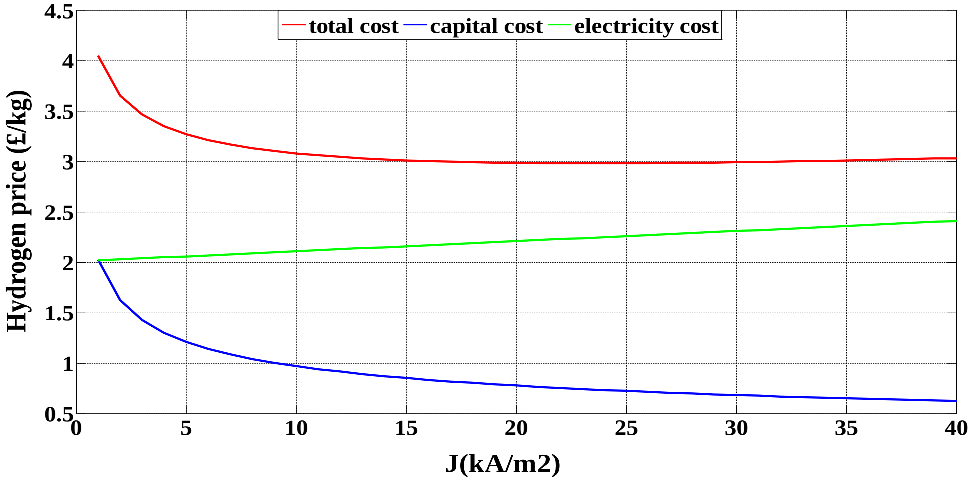


Figure 4.11: Hydrogen price cost (£/kg) at off-peak (£0.05/kWh)

Regardless the other cost components, the cost of electricity could allow for a significant reduction in the cost of hydrogen, especially if production is concentrated during off-peak periods. In this research, only power surpluses times of off-peak demand will be used to produce hydrogen. Few studies concentrate on flexible operation of the electrolyser in order to increase the benefits of lower electricity prices (Levene, 2005; Gutiérrez-Martín, Ochoa-Mendoza and Rodriguez-Anton, 2015; Mansilla et al., 2013). Instead, all these studies focus only on the hydrogen production stage, and do not consider the hydrogen application stages. The different applications of hydrogen require different physical conditions such as pressure, storage, and delivery; however, the main point, as ever, is the price. For example, the operating conditions of hydrogen as a fuel differ from those required in the food industry, and this will lead to a change in cost, based on the storage type and pressures required. Other studies focus on hydrogen production from renewable energy, such as wind and solar, as a main aim either on-grid or off-grid.

4.6 Summary of the chapter:

This chapter has explained the electrolysis process from different perspectives. First, it has considered the history of the electrolysis industry, followed by a detailed examination of the main components of various types of electrolyser. The second part concentrated on electrolysis cell arrangements and presented the advantages and disadvantages of each type. The most commonly used types of electrolyser have been discussed in terms of their operational processes, construction, their advantages and disadvantages, and comparison has been made between them. Some description has been given of the benefits and challenges that face the electrolysis industry, in particular the control of cost. The cost of electrolysis was focused on at the end of this chapter, in which the most significant costs of each part of electrolysis was discussed. This will be considered further in this study to investigate whether research techniques can overcome these issues.

Chapter 5: Energy Production and Consumption, the Electricity Network and the Renewable Energy Situation in Libya

5.1 Introduction

Libya has a small population of nearly 6.5 million (as of 2010) and does not have a heavy agricultural potential or a wide industrial base like its neighbouring countries such as Algeria, Morocco, Tunisia and Egypt. On the other hand, Libya has abundant energy resources with large reserves of oil and gas. For instance, Libya leads the African countries in terms of proven reserves of crude oil (U.S. Department of Energy, 2014), as shown in Figure 5.1 below:

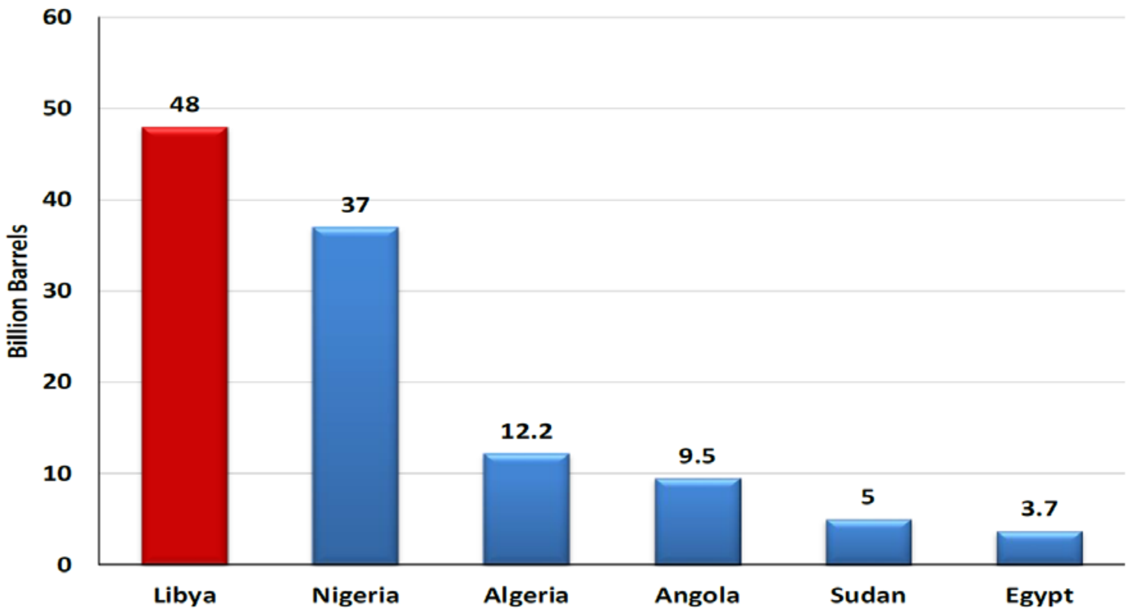


Figure 5.1: Top African countries by proven reserves of crude oil, 2014

In terms of natural gas, Libya's proven reserves were measured at 55 trillion cubic feet in 2014, which is one of the highest reserves in Africa, as we can see in Figure 5.2 below (U.S. Department of Energy, 2014). Nearly 70% of Libyan Gross Domestic Product (GDP) comes from the oil-exporting sector, having increased from nearly 50% in 2002 in line with the increasing price of oil (Mbendi, 2016). Oil and gas production and energy consumption in Libya will presented in detail in the following sections.

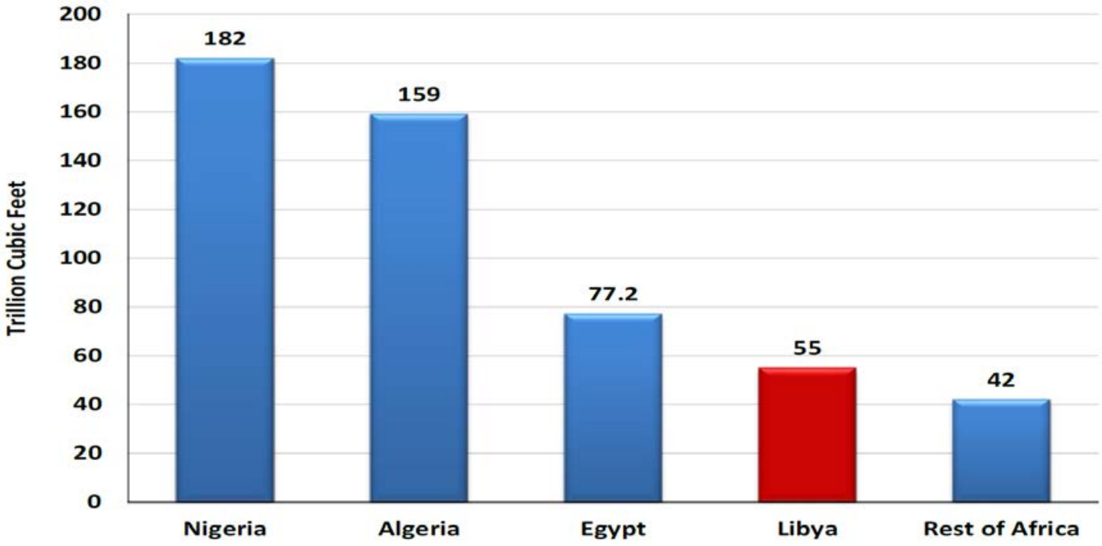


Figure 5.2: Top African countries by proven reserves of natural gas, 2014

5.2 The current situation regarding Libyan energy

Libya relies completely on fossil fuel to produce its energy. Natural gas and oil are the main sources of energy. Libyan power plants currently rely on oil, though there has been an increasing move towards natural gas power plants over recent years. The status of oil and natural gas is summarised in the next two subsections.

5.2.1 The current situation regarding oil production in Libya

Libyan oil production is one of the largest across the North Africa countries and is currently at about 1 million barrel/day, in contrast with 1.68 million barrel/day before the 'Arab Spring' revolution in February 2011. Proven reserves of crude oil in Libya are measured at nearly 47.1 billion barrels (Kuuskraa, Stevens and Moodhe, 2013). The last five years of oil production are shown in Figure 5.3.

Oil production was dropped due to the war that started in February 2011 and continued for eight months (Kuuskraa, Stevens and Moodhe, 2013). Oil production has subsequently improved between 2012 and 2013 and reached 1.4 million barrel/day due to the country becoming more internally stable. Oil production was suspended again in mid-2013 because certain military groups took control of the main oil harbours and refinery regions in the country.

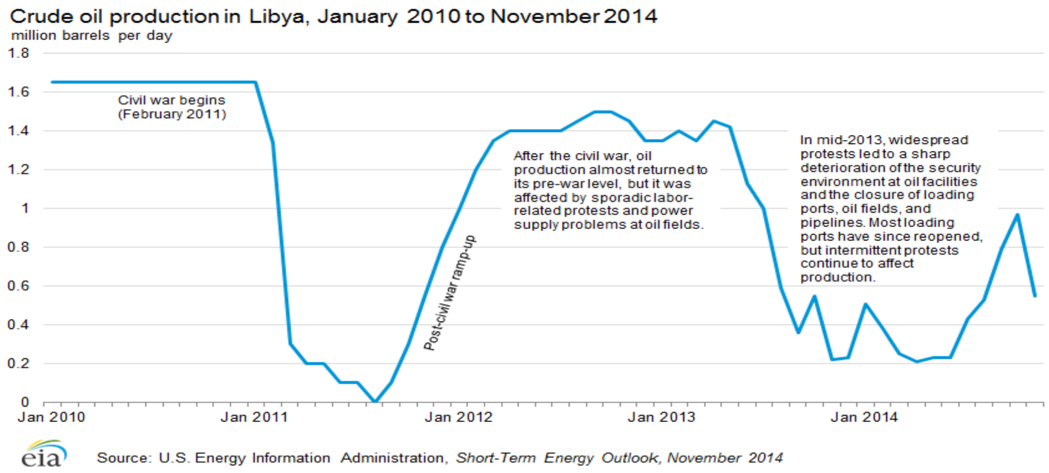


Figure 5.3: Libyan crude oil production, Jan/2011-Nov/2014.

Before the war in February 2011, the main controller of the oil industry was the National Oil Corporation (NOC), which was entirely state-owned. The NOC had a production goal of 2.5 million barrel/day by 2015, but this goal cannot now be reached until oil production rates return to their 2011 pre-war levels. This recovery requires a stable and secure political environment in order to encourage international companies to return to work in the Libyan oil industry. The eastern part of the country has the largest quantity of oil (75% of the total), in a region called the Sirte Basin; the remaining 25% of the country's reserves are in the southern region, the Murzuk Basin (Asheibe and Khalil, 2013), as presented in Figure 5.4.

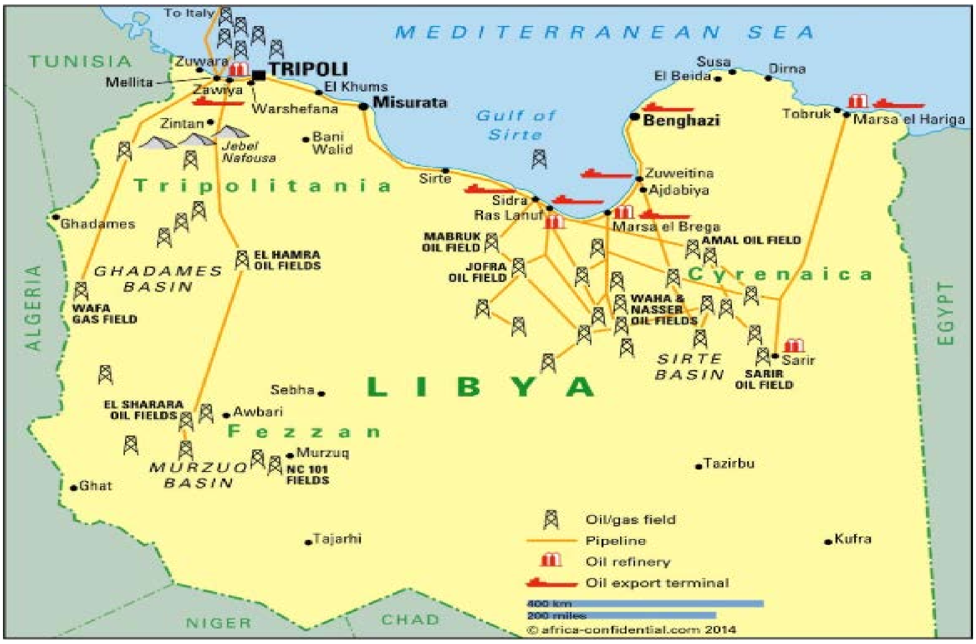


Figure 5.4: Libyan oil reserve distribution.

Net production of oil in Libya is around 1.65 million barrel/day, with around 330,000 barrel/day consumed locally for electricity production (as of 2010). Due to the dramatically surging demand for energy in Libya due to an inefficient use of energy, this number is expected to increase in the coming years. Figure 5.5 below shows oil production and consumption in Libya between 1980 and 2013 (U.S. Department of Energy, 2014).

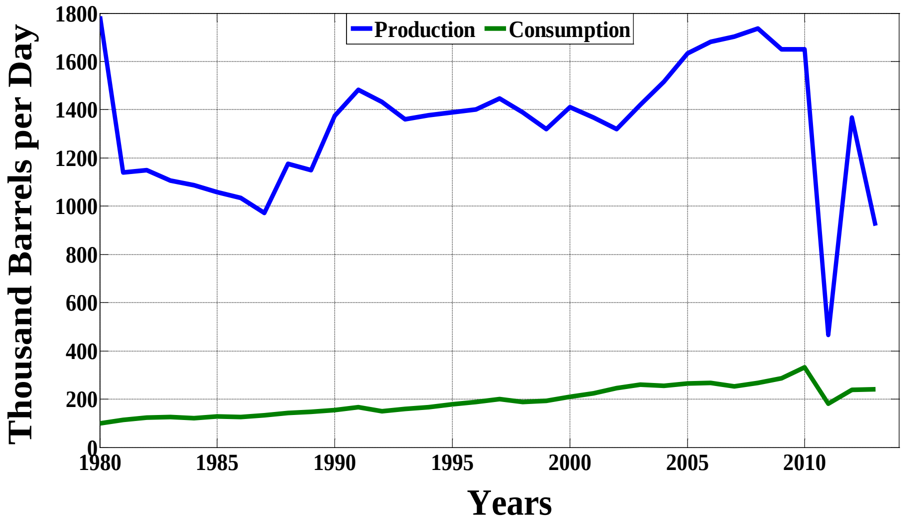


Figure 5.5: Libyan oil production and consumption (1980-2013) (U.S. Department of Energy, 2014).

5.2.2 The current situation regarding natural gas in Libya

The second-most important source of energy in Libya is that of natural gas. The proven natural gas reserves are 52.8 trillion cubic feet (as of 2012). Figure 5.6 shows the production and consumption of natural gas in Libya between 2000 and 2013.

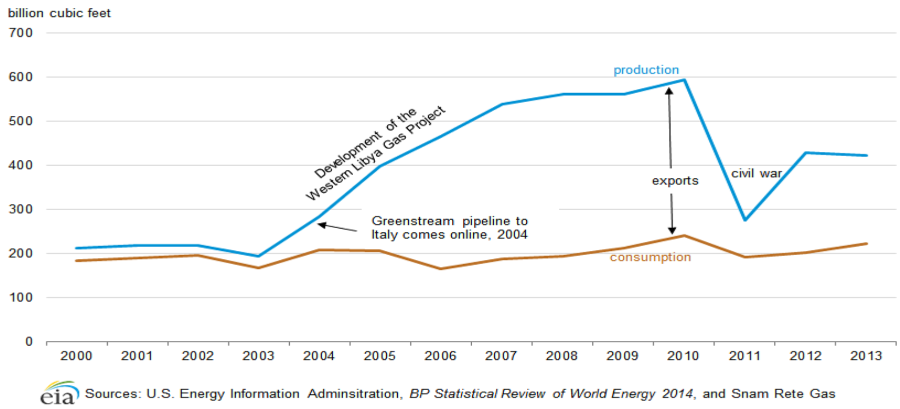


Figure 5.6: Production and consumption of natural gas in Libya (2000-2013) (U.S. Department of Energy, 2014).

As shown, most of the natural gas produced goes into exports. The large-scale growth of the gas industry in Libya began with the construction of the ‘Greenstream’ gas pipeline between Libya and Italy, with most of Libya’s natural gas being exported to Italy via this pipeline (U.S. Department of Energy, 2014). The increase in consumption of gas in Libya in recent years is due to the replacement of many oil-fired electricity stations by ones fired by natural gas (Kuuskraa, Stevens and Moodhe, 2013).

A discussion of the oil and gas industry will help the reader to understand the advantages and disadvantages of these resources, such as instability of the price and demand variation from the importer countries after investment in the renewable energy industry has begun. Libyan oil reserve distribution is presented to show the effect of ceasing to produce oil from the Sirte Basin on the total production of the country, as happened in 2013 when military groups took control of the main oil harbours and refinery regions in the country.

5.3 Electricity production and consumption in Libya

The power generation capacity in 2010 was 5759 MW with 32 TWh of energy generated. Currently, Libyan power stations are generally oil-fired, though many have been changed in recent years to natural gas (GECOL, 2010). Electricity demand in Libya is increasing rapidly (6-8% annually) and is expected to be around 8 GW in 2020.

Figure 5.7 and Figure 5.8 below show the actual annual demand and the growth rate over recent years (2003-2012), and further gives the expected load growth rate between 2013 and 2020 (GECOL, 2012) respectively.

The electricity consumption is very high in contrast with the population of this country due to climate change and inefficient use of energy. In addition to the higher growth rate, the war in 2011 led to the destruction of many power stations in different cities across Libya. For these reasons, the Libyan government is now strongly motivated to move towards a greater use of renewable energy sources.

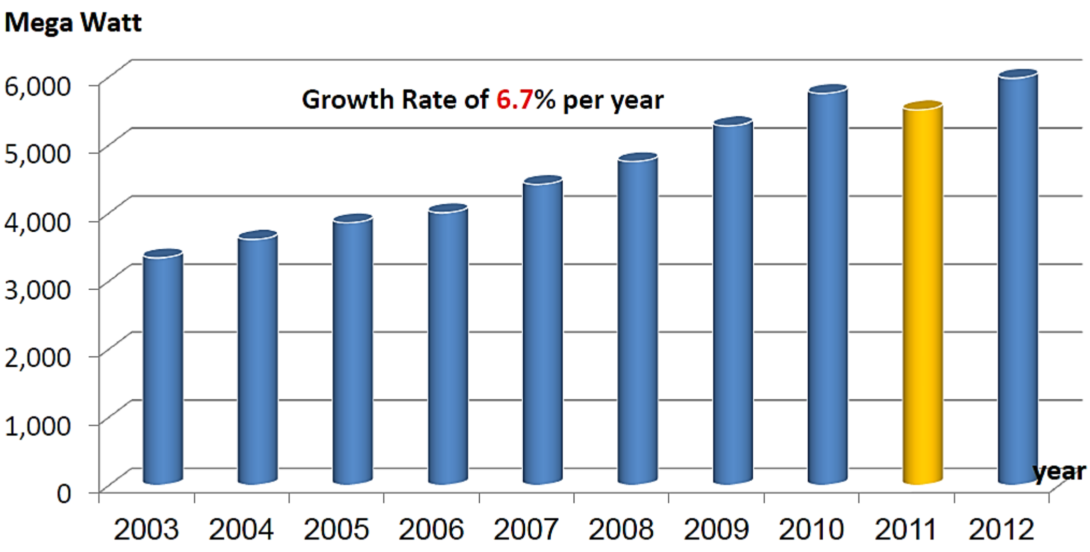


Figure 5.7: Libyan energy load growth rate (2003-2012) (GECOL, 2012)

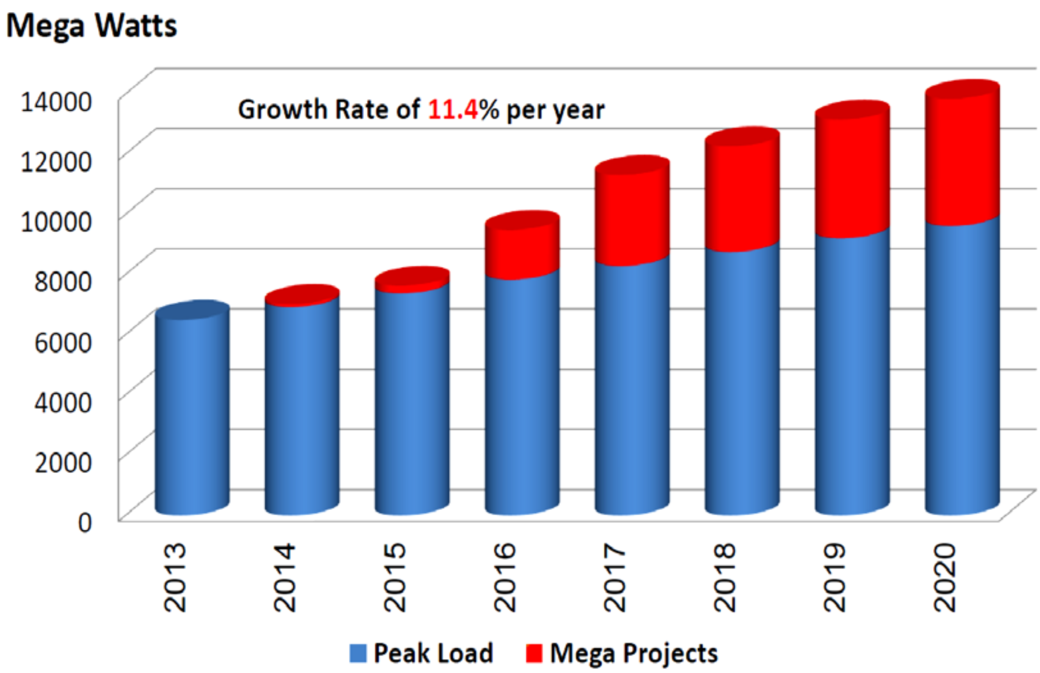


Figure 5.8: Forecasting Libyan load growth rate (2013-2020) (GECOL, 2012)

Where: peak load is the annual peak load of the general grid and mega project is the expected increase in the load based on the yearly growth rate. The residential sector represents the largest area of electricity consumption followed by the commercial and industrial sectors, as can be seen in Figure 5.9 below.

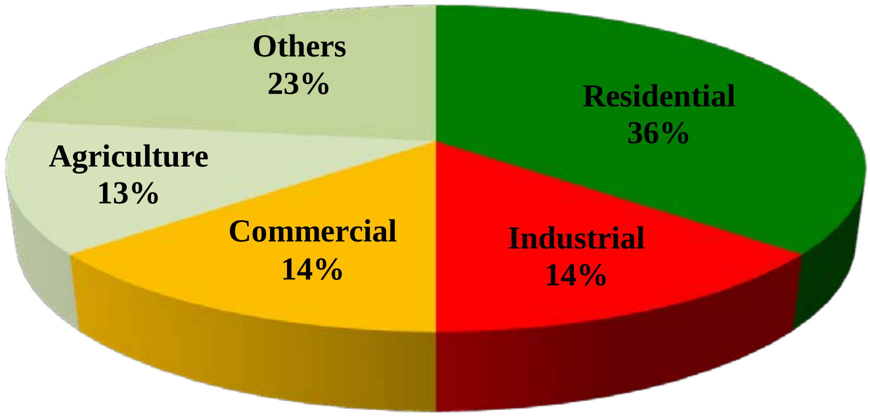


Figure 5.9: Electricity consumption in percent by sector in Libya (2010) (GECOL, 2010).

The general electricity company of Libya (GECOL) manages all electricity power departments (production, distribution, and transmission). The high voltage transmission of Libya about 12,000 km spreads across the country.

This long distance power transmission causes significant efficiency losses (13.5% in 2007) (IEA Statistics, 2014). The energy sector depends on heavy fuel oil, natural gas and light fuel oil. To reduce CO_2 emissions, GECOL has moved toward the use of natural gas stations rather than oil-fired stations. Figure 5.10 below shows the percentage share of conventional energy sources of the Libyan electricity grid (Asheibe and Khalil, 2013).

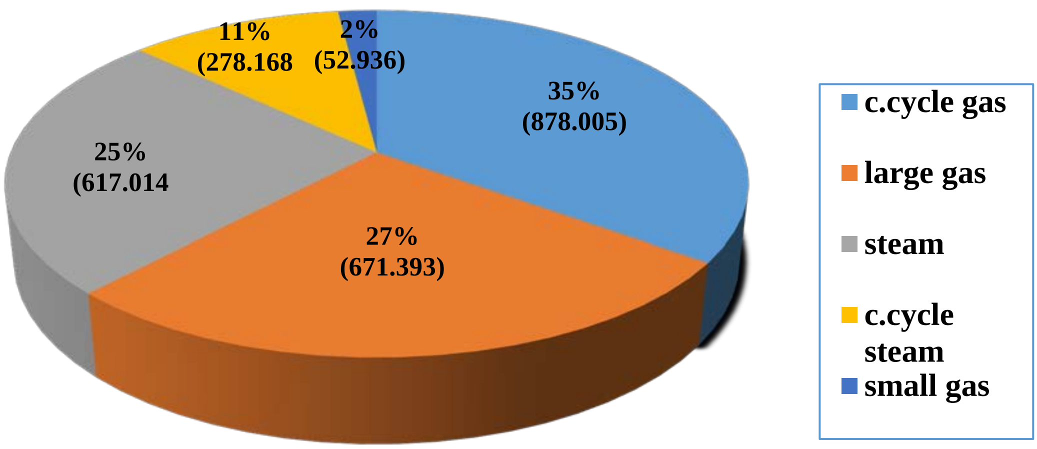


Figure 5.10: Libyan Electricity generation (MWh) in 2010(GECOL, 2010).

As mentioned earlier, the recent use of natural gas as a fuel has increased rapidly, as motivated by a number of advantages in contrast with other traditional fuels, as shown in Figure 5.11 below.

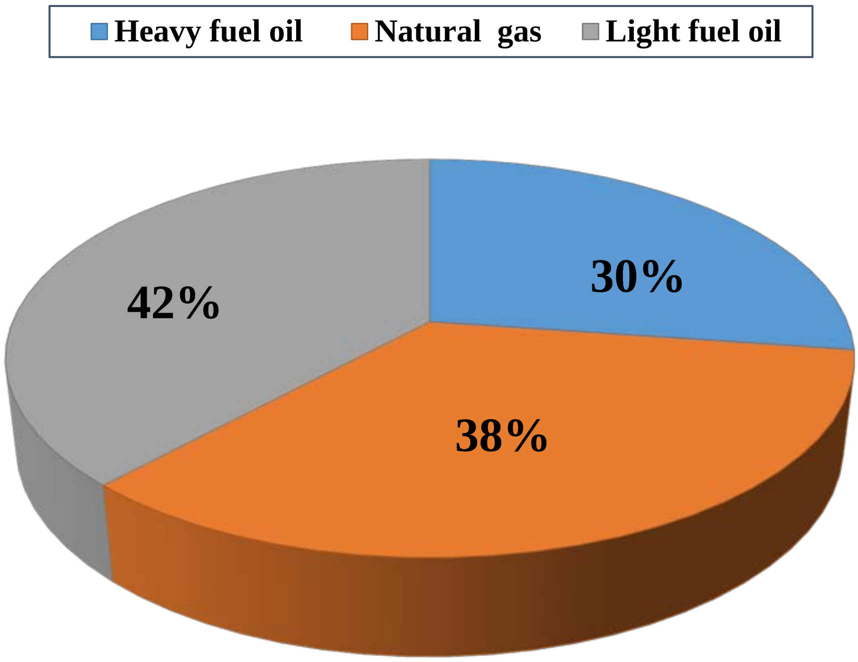


Figure 5.11: Electricity generation by fuel type in Libya 2010(GECOL, 2010).

5.4 Transmision network and constraints in Libya

High voltage power transmission lines in Libya extend to almost all places where industry exists and is expanding and where people live.

Prior to 2006 the highest voltage used in Libya was 220 kV, but in Sept. 2006 the General Electrical Company of Libya (GECOL) commissioned the first 400kV, which extends over 460km from Gumas to Benwaild and Gamra 1 system, with single, and double circuits with triple bundled conductors. Figure 5.12 below shows the new Libyan 400-kv network (Khalil et al., 2009).

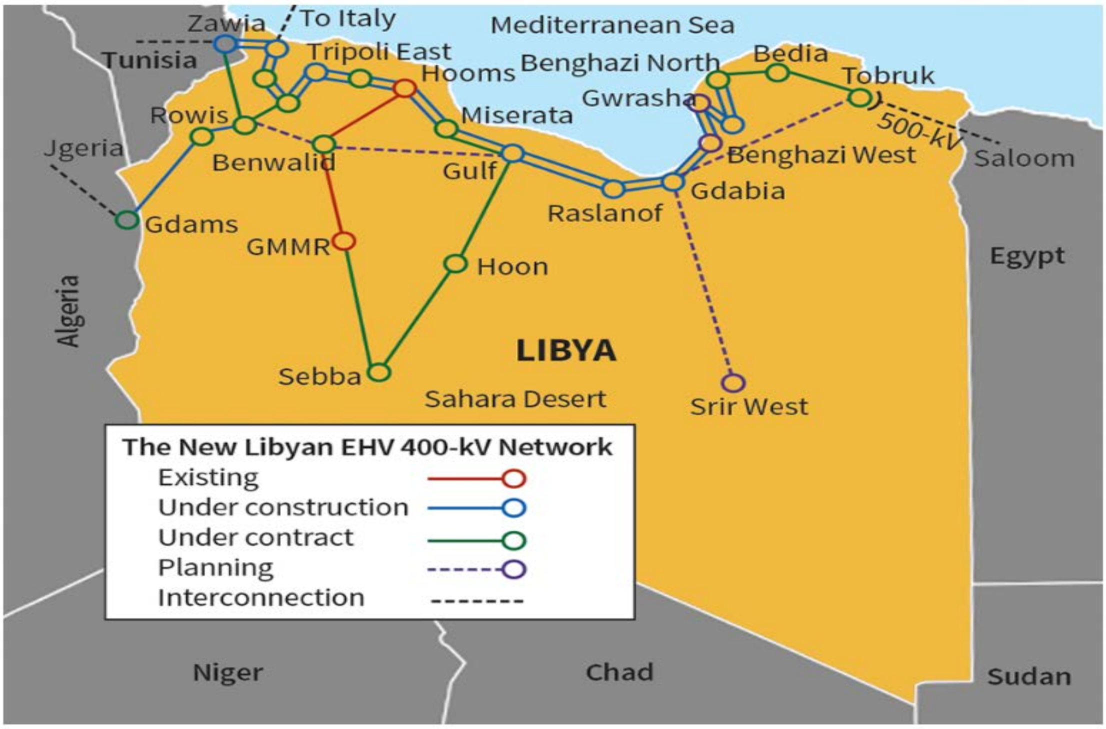


Figure 5.12: The new Libyan transmission system and outlines what is existing and under construction (Daloub, 2017)

As a result of Libya's ongoing civil war, which began in July 2014, various events have caused damage to numerous 400-kV, 220-kV and 66-kV transmission lines and substations, resulting in the transmission system now operating as four islanded systems. The current separate transmission systems have reduced generation capacity in the most populated area in the northwest (Tripoli), which now has an electricity demand that is higher than the installed generating capacity. (Daloub, 2017). Conversely, there is now excess generating capacity connected to the remaining three islanded transmission systems that supply the large cities of Benghazi, Adjdabia and Ghadams. A geographically large state, Libya shares borders with six neighbouring countries, four Arab states (Egypt, Sudan, Algeria and Tunisia) and two African states (Chad and Niger) (GECOL, 2012). Currently, Currently, Libya is only electrically interconnected with Egypt and Tunisia on its eastern and western borders, respectively. Since the circuits were first commissioned, more than 600 MW of energy have been exchanged commercially through the tie lines in each direction. The 220-kV double-circuit interconnection with Egypt connects the Tobruk substation in Libya — approximately 165 km (103 miles) from the border — with the Salum substation in western Egypt, close to the city of

Alamin. This transmission line extends across the Egyptian desert before reaching the areas of high-energy consumption and load centres, namely the Mediterranean city of Alexandria. The transmission systems of GECOL and the Tunisian National Company of Electricity and Gas (STEG) are interconnected by two 220-kV transmission lines. The first cross-border link, known as the coastal line, is a double-circuit 220-kV transmission line that interconnects the Abukamash substation in Libya with the Madneen and Abushama substations in Tunisia (Faraj, 2009). The overall length of this circuit is 380 km (236 miles), with 26 km (16 miles) in Libya and 354 km (220 miles) in Tunisia. The second 220-kV circuit, known as the Sahara line, is a single circuit connecting the Rouais substation in Libya with the Tataween substation in Tunisia. This circuit is 298 km (185 miles) long, with 37 km (23 miles) in Libya and 261 km (162 miles) in Tunisia. . Figure 5.13 below The existing Libyan transmission system comprises both 400-kV, 220-kV overhead lines and interconnected with Egypt and Tunisia(Daloub, 2017).

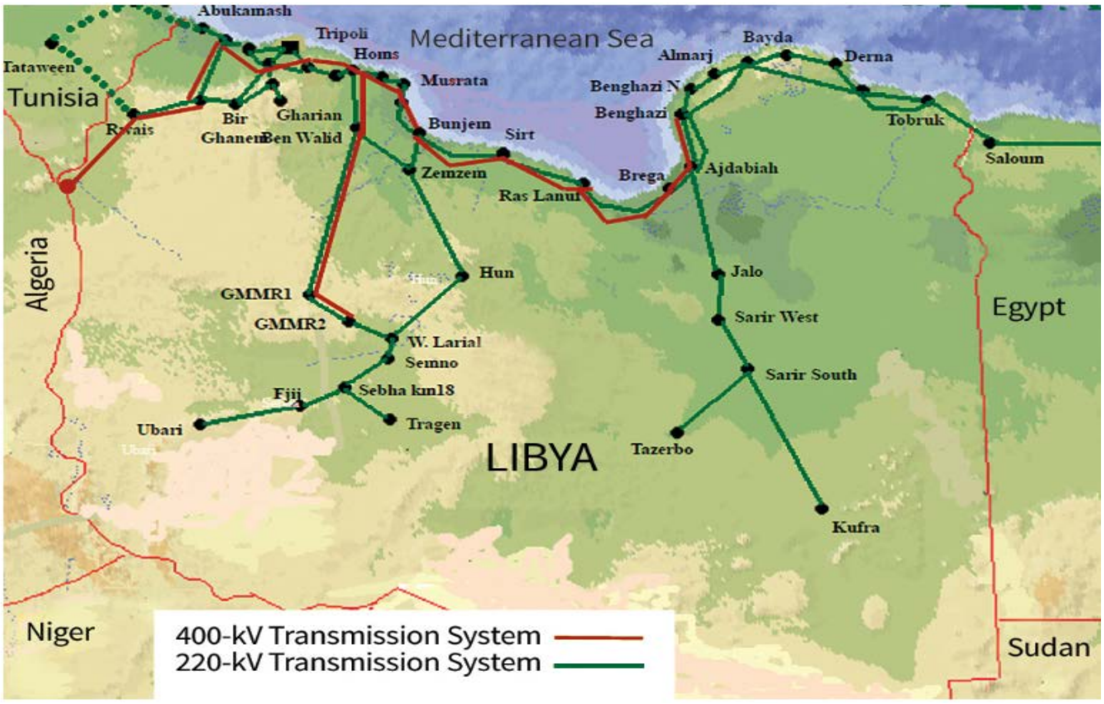


Figure 5.13: Exsisting 200-kv and 400-kv in Libya and the interconnection with neighbour countries (Daloub, 2017)

Electrolysers play a vital role in this regard as they can respond within minutes for a set point or full shut down. This rapid response allows for Transmission and distribution (T&D) planners to utilize electrolysers located on congested lines to reduce transmission line congestion by lowering the electric demand from the electrolysers. Responsive devices on a line can possibly delay or even remove the need for additional transmission lines if the devices have sufficient capacity to alleviate congestion. Alternatively, electrolysers can be applied to encourage the authorities to work on a smart grid system under high penetration of renewable energy, by solving the issue of energy storage. However, in this research because of the lack of data, transmission and distribution issues are not covered since the research focuses on small city as smart grid system. In addition, the idea of this research is to solve the issue of long-term (days) and large-scale energy storage. For the T&A, the required response time fluctuates between minutes to hours for several hours.

5.5 Libyan environmental issues

A significant current global trend is towards reducing greenhouse gas emissions, both in terms of current and future energy generation (UNFCCC, 1997). Current scientific assertions are that the effects of a rapidly-changing climate will put considerable strain on environmental, social and economic sustainability. Experts currently warn of the risk of worldwide climate change in this regard as a result of increasing greenhouse gas emissions into the atmosphere, mainly from fossil fuel use. The United Nations Framework Convention on Climate Change (UNFCCC) adopted the Kyoto Protocol in 1997 (see www.unfccc.int), as signed by 84 states, under which all major industrialised countries must ultimately limit their greenhouse gas emissions to 1990 levels, or lower (UNFCCC, 2014). The Human Development Report (HDR) 2007/2008 indicates that the annual increase in CO_2 emissions was around 4.2% between 1999 and 2004. Furthermore, this same report indicated that Libya was responsible for 0.2% of international emissions, which equates to around 9.3 tonnes of CO_2 per person (Watkins, 2007). In terms of the various international environmental conventions, Libya has signed and ratified numerous agreements such as the Vienna Convention in 1990, the United Nations Framework Convention on Climate Change in 1999 and the Kyoto Protocol in 2006 as a Non-Annex I party (Watkins, 2007; UNFCCC, 2014). Thus, Libya has the opportunity to implement emissions reduction policies such as the Emissions Trading Mechanism. Well-defined emissions reduction policies and environmental regulations are key mechanisms by which to address the issue of climate change. Libya is the world's 11th largest oil producer (Pratten and Abdulhamid Mashat, 2009) and ,as a consequence of rising petroleum production and the associated revenues (accounting for about 95% of export earnings and contributing more than 54% of its GDP), Libya has seen a significant increase in greenhouse gas emissions, particularly those of CO_2 (Elhage et al., 2005). Oil and cement manufacture are the principle culprits for greenhouse emissions in Libya. As with most other countries that have seen significant increases in their greenhouse emissions, this can be related to both economic and industrial growth. High levels of urbanisation also contribute in this regard in the larger urban centres of Northern Africa. Libya, however, has seen the highest per capita increase in CO_2 emissions in comparison to its neighbouring countries, including CO_2 produced from the consumption of solid, liquid, and gaseous fuels and gas flaring (Mohammed, 2010). The main sources of air pollution in Libya are related to the use of petroleum derivatives as fuels in many manufacturing, industrial and transport fields (Abdul-Hakim, 2006), with CO_2 mostly originating from the burning of various fuels by the power production sector (38%), fuel for the transport sector (20%) and industry (8%), with other sectors representing the remaining 34% (R.Zaroug, 2012; Lawgali, 2008). Oil factories are a major atmospheric polluter because of the emission of various harmful or hazardous gases. Primarily, these are carbon compounds, hydrocarbons, sulphurs and nitrogen oxides, which are released from refineries and oil fields. As well as the air, however, these gases will also have an adverse effect on the surrounding residential and maritime areas. In 2003, petroleum was responsible for more than 60% of Libya's CO_2 emissions, with natural gas accounting for the remaining 40% (Ramelli et al., 2006; R.Zaroug, 2012). In 2010, two thirds of electricity in the world was produced from burning fossil fuels; in the same year, Libya produced about 60 million tons (Mt) of CO_2, in comparison with 50 Mt in 2002. Libya's energy-related CO_2 emissions rose by more than 78%, from less than 18.7 million tonnes of oil equivalent (Mtoe) in 1980 to about 50 Mtoe in 2003, mostly because of increasing demand for power (Ekhlat, Salah and Kreama, 2007). The amount of emissions per unit energy varies depending on fuel type (i.e., coal, oil or natural gas), and therefore the move towards the increased use of natural gas should ultimately help to lower CO_2 emissions (Mohammed, 2010). Because of rising energy demand, CO_2 emissions are expected to more than double in the coming years, reaching around 104 Mt in 2030. The annual average growth in emissions has been estimated to be 3.3% over the outlook period, although one piece of good news is that this is lower than the original forecast (3.6%

growth in demand) due to the move towards gas-fired power stations. The daily data recorded for CO_2 emissions includes fuel intake and energy production from different producing units, particularly combined cycle units, which account for about 37% of the total energy produced in the Libyan network. (Khalil et al., 2009; Mohamed, 2016).

5.6 Libyan electricity tariff and governments subsidies

One of the critical issues in the Libyan power system is government subsidies, which have currently allowed for lower electricity price tariffs nation-wide and reduced the efficiency of consumption. To understand this point, we consider that 1 Dinar = 1000 Dirham; the current exchange rate between the Pound and Dinar is 1 Pound ≈ 2 LYD. A higher tariff is paid for commercial consumption in Libya, which is set at 0.068 LYD/KWh (£0.04/KWh) (GECOL, 2010). Even with these prices, GECOL is struggling to persuade people or companies to pay for their usage.

GECOL has prepared a report to explain the difference between the real cost of electricity based on international fuel prices and local fuel prices, which reveals that the real cost of one-kilowatt hour is around 0.467 LYD /kWh (£0.25/ kWh) in terms of international fuel prices, whereas the current electricity prices are around 0.02 LYD/kWh (£0.01/ kWh), which means that the local price represents only 4% of the unit cost. If the system works with the local fuel price, the unit cost is 97 Dirham/kWh with the same price of electricty (20 Dirham/kWh) (Agha and Zaed, 2013).

Furthermore, the Libyan government does not give any incentive to encourage people to regulate or decrease consumption, yet frequent “rolling blackouts” occur at many times of the year, and can last for several hours (reaching 12 hours at peak summer and winter consumption) (El-Werfelli et al., 2008). These could be mitigated by such price incentives.

Table 5.1 and Table 5.2 below show the profit and losses for the year 2012 in terms of international fuel prices and local fuel prices (Agha and Zaed, 2013).

Category	Total Sales of energy	Expenditure	Unit Cost	Unit Price	Income	Different (subsides)
	MWh	(M.LD)	(Dirham\KWh)		(M.LD)	
Residential	7,441,077	3,476	467	20	148.8	-3,327.5
Agriculture (small)	1,039,526	462	444	30	31.2	-430.5
Agriculture (Large)	1,393,150	410	294	32	44.6	-365.3
Light Industrial	910,450	345	379	42	38.2	-307.2
Heavy Industrial	900,274	261	290	31	27.9	-233.4
Commercial	2,507,157	1,089	434	68	170.5	-918.8
State Offices	3,695,736	1,367	370	68	251.3	-1,115.8
Street Lighting	3,075,149	906	295	68	209.1	-696.6
Total	20,962,519	8,317	397	44.0	921.6	-7,395.1
				Different		-89%

Table 5.1: Income and losses for the year 2012 for international fuel prices

Category	Total Sales of energy	Expenditure	Unit Cost	Unit Price	Income	Different (subsides)
	MWh	(M.LD)	(Dirham\KWh)		(M.LD)	
Residential	7,441,077	718	97	20	148.8	-569.3
Agriculture (small)	1,039,526	86	83	30	31.2	-54.7
Agriculture (Large)	1,393,150	68	49	32	44.6	-23.5
Light Industrial	910,450	64	70	42	38.2	-25.4
Heavy Industrial	900,274	42	47	31	27.9	-14.3
Commercial	2,507,157	201	80	68	170.5	-30.2
State Offices	3,695,736	238	64	68	251.3	13.3
Street Lighting	3,075,149	183	59	68	209.1	26.2
Total	20,962,519	1,599	76	44.0	921.6	-677.8
				Different		-42%

Table 5.2: Income and losses for the year 2012 for local fuel prices

In the current oil price scenario (less than $50/barrel) and the slump in demand (nearly 300,000 barrel/day compared with 1.400,000 before 2011 and $120/barrel), the Libyan government has to take serious steps to reduce subsidies. This action will be applied in stages over a 1-5 years periods until a zero rate of subsidy is achieved, which will lead to increased electricity tariffs and open the door to investment in renewable energy companies within the Libyan electricity market. (Agha and Zaed, 2013). GECOL have published some important recommendations that could improve and develop the electrical grid in Libya. These recommendations include:

1. The higher electricity consumption per capita is an obvious sign of poorly considered use of electricity and low efficiency; the low efficiency can be due to two main reasons:
    a. Low price (tariff) for electricity.
    b. Low efficiency of devices and equipment used in the Libyan electricity market due to a failure to enforce standards in the supply of these appliances.
2. Investment in electricity projects is an important element for development. However, the ability of the country to continue to bear the costs of these investments comes with some considerable risk due to fluctuations in oil prices. It is noticeable that the state spends on all investments in the electricity sector and has funded the expense of overhauling large production plants, covering financial differences between selling prices, the power unit, and the actual cost to the general electricity company and its investors. The government should develop policies to reduce the financial burden on public finances.
3. Continuing to provide the company with fuel and natural gas prices below international prices leads to inefficient allocation of resources in the industry and does not encourage good performance or rationalisation of energy consumption.
4. The government should follow recommendations to replace subsides of goods and oil by cash support to the citizen, which will lead to relief of the state's consumption and customer's inefficient use of energy.
5. Allow for investment in renewable energy sources, increased energy efficiency and demand-side management through the development of new standards for electrical goods, street lighting and industrial sites.
6. Work on the rationalization in spending and improve the efficiency of the sector workers by distributing tasks and employees in an appropriate manner and reducing expenses, since in recent years it has been observed that the number of employees in the company has steadily increased in a manner inconsistent with the number of customers. This will result in an increased burden on the company, poor productivity underuse of the workers. For example, there is an average of 34 consumers per employee of the company, and if we compare this with

electricity production facilities in Saudi Arabia, we find an average of about 173 consumers per employee.

5.7 Renewable energy resources in Libya (current utilisation and future prospective)

Many Middle East countries, especially oil-rich countries like Libya, try to diversify their economies and their decrease the reliance on oil as their main source of energy and income in order to achieve more sustainable economies. Finding alternative and secure sources of income and energy is becoming particularly important for these countries if they wish to maintain their living standards for coming generations and reduce the negative environmental impacts of pollution and carbon emissions from fossil fuels (Ramli, Alarefi and Walker, 2015; Mohamed, Al-Habaibeh and Abdo, 2013). Libya has a high potential for the use of renewable energy from wind and solar sources according to currently-available information. Libya has a massive land area of around 1,759,540 km^2, with a very long coastline of nearly 2000 km, and 88% of the country is desert. Figure 3.1 a map of Libya. This high potential for renewable energy can be realised concentrating solar power (CSP), solar heating and cooling (SHC) and via photovoltaics (PV). Furthermore, it has been calculated that, every year, one square kilometre of the desert in the Middle East and North Africa area receives energy equal to 1.5 million barrels of oil.

Figure 5.14: Libyan location on the map

This high potential for renewable energy can be realised through the deployment of 300 concentrating solar power (CSP), solar heating and cooling (SHC) and via photovoltaics (PV). Furthermore, it has been calculated that, every year, one square kilometre of the desert in the Middle East and North Africa area receives energy equal to 1.5 million barrels of oil. Figure 5.15 below shows the annual normal direct solar radiation in $\mathrm{kWh/m^2}y$; this information was derived from data collected by the German Aerospace Centre (DLR) in 2007 (Faraj, 2009; El-Osta and Kalifa, 2003; Mohamed, Al-Habaibeh and Abdo, 2013).

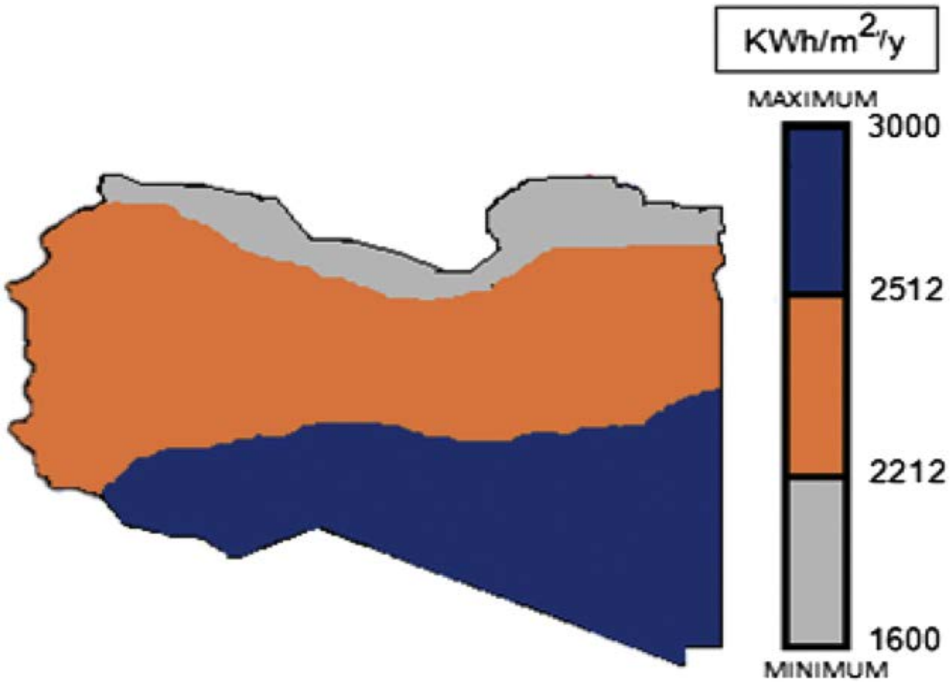


Figure 5.15: Annual average solar irradiance estimates for Libya

In terms of wind power sources, the data provided by Wind Atlas of Libya (version 1.0 3/2008) is shown in Table 5.3.

The mean wind speed in different regions of Libya is given. Generally, average wind speeds fluctuate between 5 and 10 m/sec in the majority of regions in Libya (Abohedma and Alshebani, 2010).

In addition, Libya's neighbouring countries have launched a considerable number of projects aimed at exploiting wind resources through various demonstration and commercial-scale projects (Khalifa, 1998).

Region	Average speed
Chat	5-5.5 m/sec
Sabah	6-6.5 m/sec
Tarakin	6.5-7 m/sec
Tubruq	7-7.5 m/sec
Al magrun	7-7.5 m/sec
Tukra	7-7.5 m/sec
Jbalzaltan	7.5-8 m/sec
Al-Fattaih-Darnah	8-8.5 m/sec

Table 5.3: Average wind speeds in various regions of Libya

5.8 Motivation toward adoption of renewable energy in Libya

There are many reasons for pushing a country towards starting large-scale investment into renewable energy resources, which include:

1. Based on data from U.S. Energy Information Administration, nearly 34% of oil production was going into local consumption in 2010. By moving to renewable energy resources, additional amounts of oil can be exported rather than locally consumed in Libya, thereby contributing further to the country's economic growth (U.S Energy Information Administration, 2015).
2. It could reduce Libya's dependence on fossil fuels and help it transition from being an oil exporter to an RE exporter – much of this potentially via hydrogen pipelines.
3. Reducing CO2 emissions via renewables could support Libya's approach to the issue of global warming.
4. Since 88% of the country is a desert, this is potentially a good candidate area for solar energy production. At the same time, these areas might be considered remote, with the majority of the population concentrated on the coast. Therefore, solving the energy problem in remote areas could limit emigration to the more crowded city areas. Power to gas techniques could save money, and time since the hydrogen can be used as a fuel.
5. The strategic location of the country gives it primacy in exporting power to Europe since there are a number of such projects that have already been established, such

as the natural gas pipeline that runs from Libya to Italy. This trade will support the penetration of renewable energy since it has a very strong connection with European countries, which can accommodate vast amounts of energy.

5.9 Applications of renewable energy resources as a power supply in Libya

The first renewable energy project as a power supply was developed in 1976. This used a photovoltaic power system to fed a cathodic protection station for an oil pipeline in the Dahra field with the port of Sedra; these projects are still running today (Mohamed, 2016). In 1979, PV panles used four experimental telecommunication stations as energy sources during the day and times of power shortage. A water-pumping system was started at Al-Agailat in 1983 for the purposes of irrigation, and a PV pumping system was used for this purpose. According to data produced by the Planning and Studies Depatrment of Renewable Energy Authority ofLibya (REAOL) in February 2011, the target for the share of renewable power should be up to 30% by 2030. This energy will be derived in the main from wind power, photovoltaic systems (PV), solar water heating (SWH) and concentrating solar energy systems (CSP), as shown in Figure 5.16. However, this target is very unlikely to be achieved because of the current security issues in Libya, and it could well be significantly postponed or even suspended.

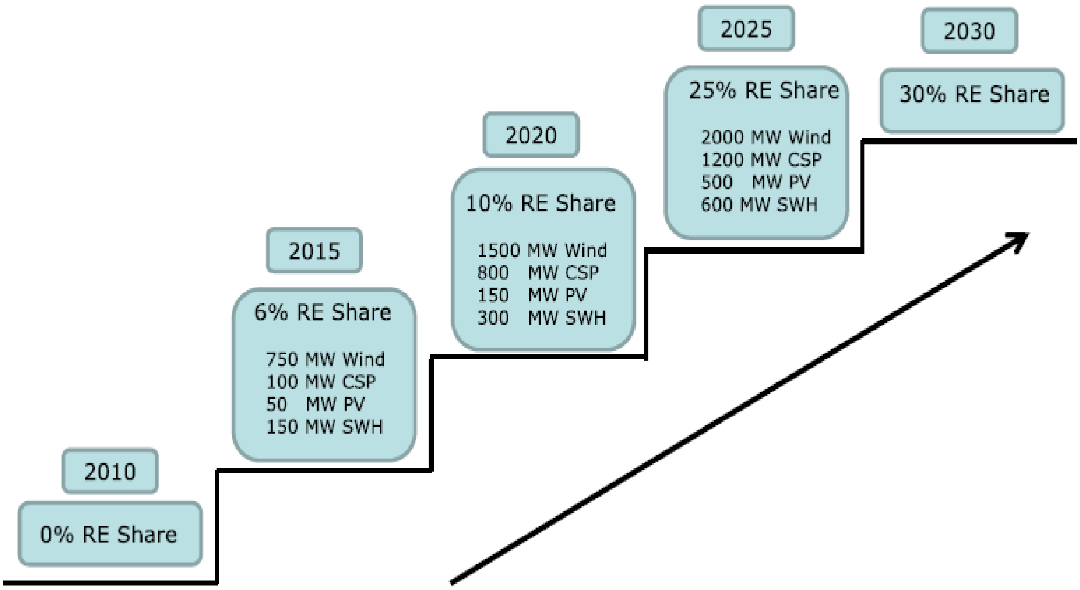


Figure 5.16: Deployment of renewable energy sources as planned by the Renewable Energy Authority in Libya.

The wind speed is acceptable in many areas for wind power generation. At around 5 m/sec average speed in most cases, this wind speed can potentailly be exploited economically. Wind energy can play a significant role in coming years in contributing to energy supply and to meeting total demand of electrical energy. Recent data regarding wind speed has been collected from 4 stations out of sixteen meteorological stations over a time of three months; these stations have been in operation since 2010. Figure 5.17 presents the average wind speed over time between 30/11/2010 and 20/01/2011, as recorded every 10 seconds (Mohamed, 2016).

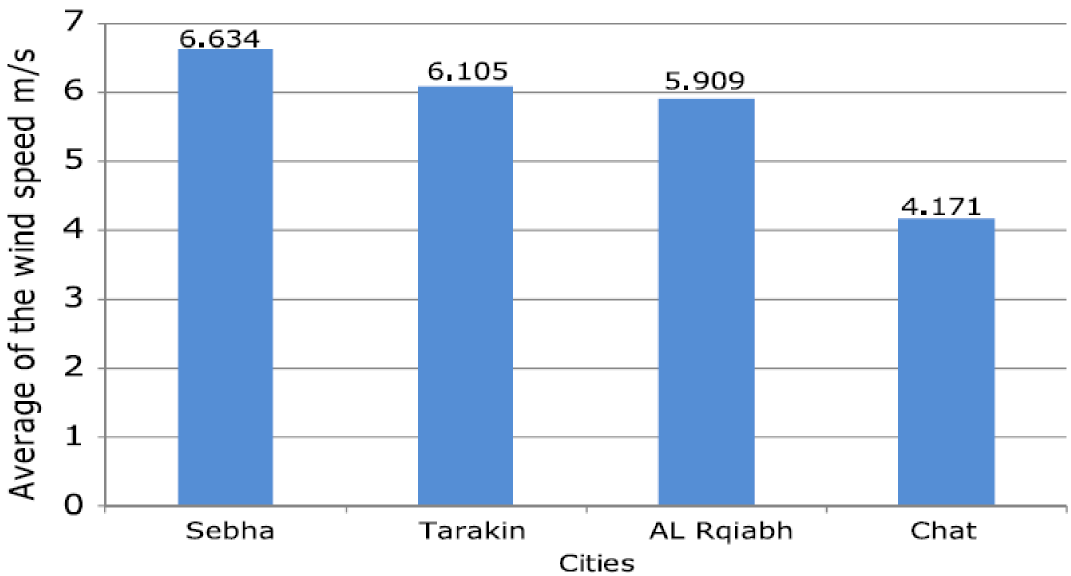


Figure 5.17: Average wind speed in four cities.

Solar energy could be the most important source of renewable energy in Libya. The annual average solar irradiance in various regions in the country is shown in Figure 5.18. Solar power can be seen to be one of the important renewable resources because of Libya's location on the Tropic of Cancer, so the the sun is always available throughout the year for at least several hours a day. 7.1 kWh/m^2day has been found as the mean daily solar irrdiance in the coastal region in the north, and 8.1 kWh/m^2day in the southern region, with the annual average amount of sunshine at more than 3500 $h/year$ (Mohamed, 2016).

REAOL argued that the average number of hours of sun is about $3200h/year$ with an average daily solar irradiance is 6 $kWh/m^2/day$. This is approximately equal to $10^6 \times {}^{1.5}/_{365} \approx 4110$ barrels/day of oil. Therefore, if just 0.1% of the country's area could be used for solar power, this could lead to $0.001 \times 1.7 \times 10^6\, barrel$ and this would be the equal to $1.7 \times 10^6\, km^2 \times 0.001 \times 4110 = 6.986 \times 10^6$ barrels/day of oil in terms of collected energy.

This is six times higher than current Libyan oil production. Therefore, solar and wind energy could be considered excellent candidates to satisfy peak energy demands. And this, in turn, couild be considered an excellent motivation for encouraging renewable energy projects within the country.

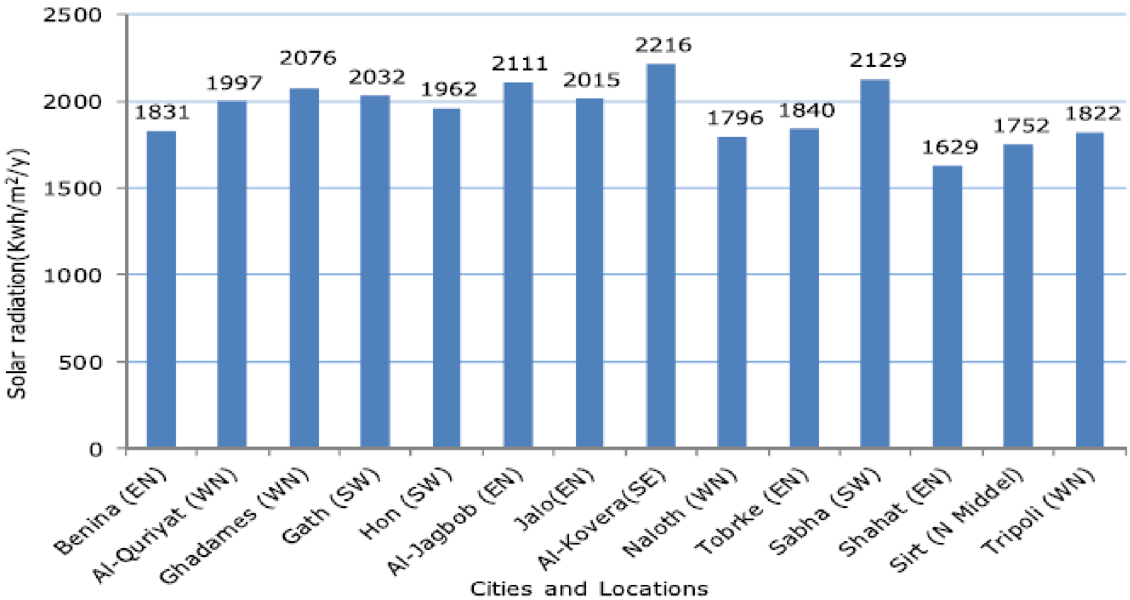


Figure 5.18: Mean annual solar irradiance in various regions in Libya.

5.10 Current and potential future renewable energy projects in Libya

Libya, like other oil-rich countries, has created a diversity of means of income instead of completely relying on the oil industry. Such steps will result in many advantages such as saving money, reducing emissions and increasing the durability of the country's economy. Libya has started many renewable energy projects, which differ in the size and purpose of application (Mohamed et al., 2013). These projects can be summarised as follows (Zaroug, 2013):

5.10.1 Wind farm projects

1. Darnah wind farm (60 MW) should have been completed in the period between 2008-2012, with another 60 MW capacity due to be installed in the near future. However, the war in 2011 postponed this project.
2. Al-Maqrun wind farm (120 MW) was founded by the Libyan government, and there is an additional privately-funded 120 MW capacity in the development stage.
3. There is a 250MW project under development in the western part of the country.

5.10.2 PV power plants in operation

1. 725 kWp for rural electrification
2. 15 systems of 75 kWp capacity for street lighting
3. 1,859 kWp for mobile phone antennae
4. 67.2 kWp Wadi-Marsit Centralised PV system
5. 120kWp for water pumping
6. 950kWp for communication stations
7. 42 kWp connected to the grid

5.10.3 PV power plants under construction

1. 14 MW PV power plant in Hun city

5.10.4 PV power plants in feasibility and negotiation stages

1. 40 MW PV in Sabha city
2. 15 MW in Ghat
3. 40 MW in Shahat
4. PV rooftop systems (3 MW)
5. Electrification in rural areas (2 MW).

5.11 Solutions to obstacles to renewable energy penetration in Libya

As mentioned above, Libya has the target of reaching 30% of its total energy production from renewable sources by 2030. In the first stage, this integration requires serious steps to change government policies and regulations. These changes include removing or significantly reducing government subsidies and creating appropriate incentives to attract renewable energy investors to the country. Currently, most economic policies and regulations in Libya are motivated by two main issues: the oil price crisis (with the price of oil dropping from $120 to less than $50) and World Bank recommendations (The elimination of food and energy subsidies) (Araar, Choueiri and Verme, 2015). Changing the country's regulations will open the door to investment for companies to start studying and searching for renewable energy resources in Libya. The second issue is completely technical in terms of the main obstacles that will face the integration of renewable energy systems into the grid. These issues include intermittency and variability of renewable energy resources, difficulties in forecasting energy loads in the short or long term, and, finally, grid department problems (generation, transmission, and distribution). Demand-Side Response (DSR) is one of the most promising solutions to address all these issues. For example, DSR can overcome the energy resource problem by consuming the power in off-peak demand periods and release it during on-peak periods. As a result of this technique, it would be possible to deal with load-forecasting issues and maintain the balance between supply and demand (Warren, 2014). As discussed earlier, DSR can be achieved through the use of many tools and techniques. Hydrogen production from electrolysis during off-peak periods is one of these methods, which will be investigated in detail over the coming chapters. The location of Libya and the weather characteristics, such as high wind speed and high solar radition in many regions in the country, are the main reasons for selecting this technique. For instance, hydrogen can be used as a fuel which can solve oil supply problems in remote areas by using onsite hydrogen production (e.g. at the garage forecourt) and also can be used as a means of electricity production (by fuel cell). Producing hydrogen in large quantities could provide an opportunity for Libya to export hydrogen to Europe via pipeline as the distances involved are not too great. The use of hydrogen as a clean fuel is a concept that receiving considerable attention at the moment and might soon become economically available (Firak and Đukić, 2016), which enhances its chances of Libya making a serious investment in its production.

5.12 Summary of the chapter

Libyan electricity demand is dramatically increasing at a rate of 6.5-8% per annum. Meeting this demand from fossil fuels will eat into Libya's export revenue because the income of the country greatly depends on the export of oil and natural gas. Now, nearly

30% of fossil fuel production goes to meeting internal energy demand, and this wappears to be growing each year. The solution to increasing export revenue is for Libya to move towards the use of renewable energy sources to satisfy increases in internal demand and create new, alternative sources of income. Ideal weather and a large land mass makes Libya a candidate to become one of the most important countries worldwide in terms of renewable energy generation. Wind and solar could very well be the main sources of renewable energy in Libya. Demand side Response can be applied to overcome the disadvantages associated with integrating renewable energy into the current electricity grid. Hydrogen is one of the best options for DSR techniques. Bold policy measures are needed to reduce emissions and to provide a sustainable economic future for oil-producing nations such as Libya in a post-fossil fuel era. In particular, this means strong support for renewable energy and hydrogen markets. Libya should make signiciatn steps towards use of renewable energy resources by following various recommendations from different studies, which include:

1. Focusing the populace's attention on the short- and long-term negative effects of ineffecient energy use. The media could be used effectively to these ends.
2. Enforce the use of low-power appliances, which can be achieved by establishing new legislation and laws for use of electricity, leading to more efficient power consumption.
3. The taxation system must be changed to limit wasteful power consumption
4. Attract renewable energy investors into the Libyan electricity market. This aim relies on political stability within the country.
5. Start training and education programs to increase the number of individuals with expert knowledge in the area of renewable energy.
6. One of the challenges of developing renewable electricity project is the difficulty in obtaining data such as solar irradiance, wind speed, and other weather data. Establishing small projects with data logging could be useful at this time.
7. R&D issues: despite such a huge area of the country avilable, there is only one centre of research, which is located in the western part of the country. Libya requires many more centres of research to enhance renewable energy penetration.

Chapter 6: System Design for Green Mountain Region

6.1 Introduction

The Libyan electrical grid is completely owned by the government through the general electricity company of Libya (GECOL). All power plants in Libya have been installed by GECOL since its establishment in 1984 (GECOL, 2007). Most Libyan power plants were established at this time with very few maintenance programmes in place. All other information about the Libyan electricity system is discussed in detail in Chapter 5. Libyan researchers inside or outside the country trying to investigate and add improvements to the Libyan electricity systems face many associated issues, most of which are due to a lack of information. The General Electric Company of Libya has attempted to explain the situation regarding the Libyan electrical system through its annual reports (GECOL, 2007; GECOL, 2012). However, these reports only contain general information, and the latest was published in as long ago as 2012. Based on the above, this research will consider only a small area of the country, which we will investigate in part to allow for further research that covers the rest of the country. The area of our investigation, however, will be restricted to a region called Green Mountain. Green Mountain is located on the eastern Libyan coast, with an area of 7800 $km^2$and a population of 206,108 as of 2006. The general electricity company divided the country into various areas depending on the number of customers, number of stations, and number of its employees. The consumption of the Green Mountain region represented nearly 6% of the total consumption of Libya during the period 2000-2007 (Zaroug, 2013), as shown in Figure 6.1.

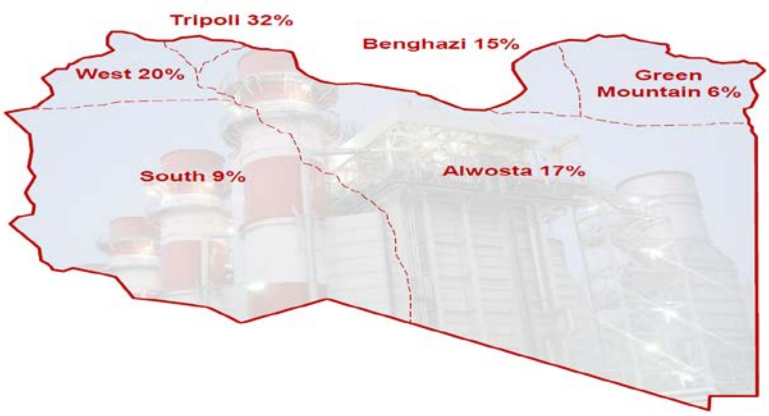


Figure 6.1: Libyan load density (2000-2007)

The Green Mountain area, as with other regions, suffers from a lack of associated data. However, there are some advantages to choosing this region as the subject of this research. For example, as there have been a number of renewable energy projects started in this area, especially in the city of Darnah, and there are some useful generation and consumption data available (Elansari, Musa and Alssnousi, 2012; Ahwide, Spena and El-Kafrawy, 2013).

6.2 Power demand in Green Mountain

Data on the Libyan demand for power is only available as daily or monthly data; in some reports, hourly data can only be found for one day of the year (GECOL, 2010). These data are not sufficient to calculate, or to at least even gain an accurate forecast of hourly demand, which is one of the main factors used in this research to analyse the Libyan electrical grid. The options for calculating the hourly demand are very limited in this case, due to this lack of availability of data. One option to overcome this issue is to use data on other countries' loads after performing appropriate sizing and scaling processes. However, the neighbouring countries' demands, especially those of Tunisia and Egypt, are not available for research purposes (at least, not for overseas students) (Madziga, Rahil and Mansoor, 2018). Another option is to use estimation and forecasting tools even though this will result in a considerable degree of error because of the limited data available. With all these options, the results will be of variable accuracy, which could affect the cost calculations subsequently determined by this research. Figure 6.2 below shows the daily demand of Green Mountain in 2012 after scaling.

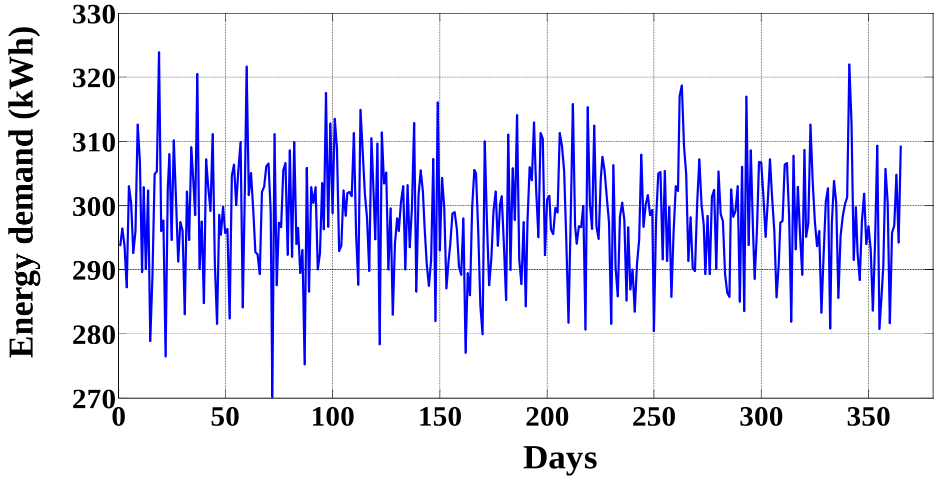


Figure 6.2: Green Mountain daily demand

6.3 Energy generation from renewable resources in Darnah

Currently available information suggests that Libya has a high potential for renewable energy generation through wind and solar power. Libya has a massive land area of around 1,759,540 (km^2) of which 88% is dessert and nearly 2000 km of coastline (Faraj, 2009; El-Osta and Kalifa, 2003; Mohamed, Al-Habaibeh and Abdo, 2013). In this research, renewable energy generation is based on wind and solar radiation data for Darnah city. Darnah is a small city in the east coastal region of the country (32°46′ N, 22°38′ E). It has a unique environment amongst Libyan cities, as it is located between three different weather areas, the Mediterranean Sea, the Green Mountains and the desert. The city's population was between 100,000 and 150,000 in 2011 (Wetterdienst, 2014). As a potential renewable energy producer, the city used as a case study sees favourable wind speeds of 8-8.5 m/s based on the data taken from the Renewable Energy Authority of Libya (REAOL). Furthermore, solar radiation levels are also very promising at around 5.03 kWh$/m^2/$day. Some wind energy projects have already been established (generating nearly 60 MW), although due to the recent civil war, testing in the area had to be stopped. Figure 6.3 shows the location of Darnah within Libya.

Figure 6.3: Darnah's location in Libya

This area is relevant to the main issues targeted by this research, namely those related to renewable energy resources. In other words, the wind speed and solar irradiance levels at Darnah will be used as the weather data for this research, but the production of energy and consumption details considered will be those applicable to the Green Mountain area.

Since the surplus power will be converted into hydrogen that can be used as a fuel instead of fossil fuels, the fuel details will be extracted from this area and hydrogen consumption levels will then be formulated based on the fossil fuel consumption of Darnah. This process is more illustrated in Figure 6.4:

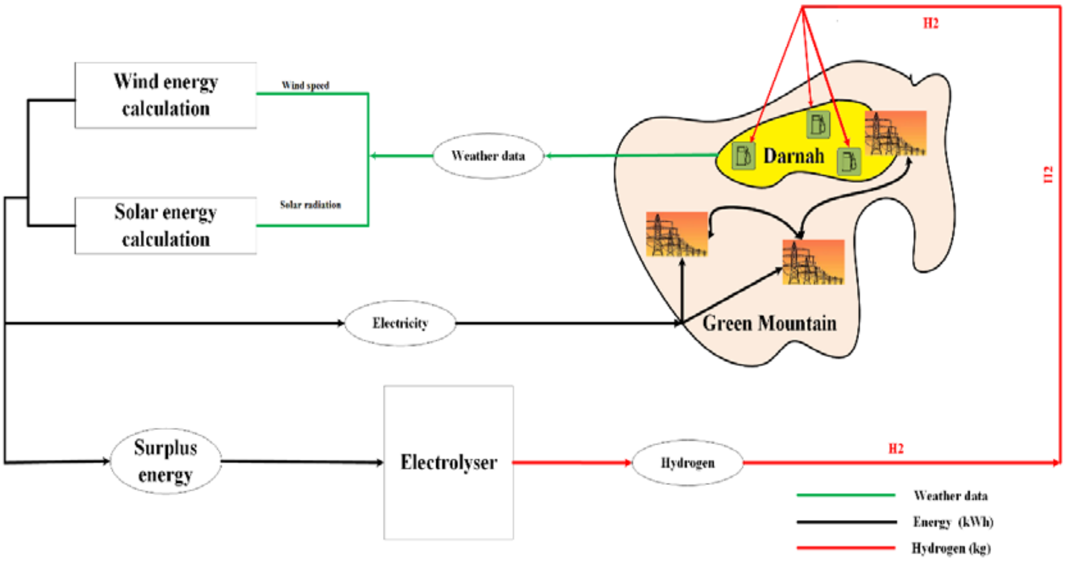


Figure 6.4: General overview of the concept

The process shown in Figure 6.4 is run as part of the Libyan grid rather than as an off-grid system, as can be seen in Figure 6.5.

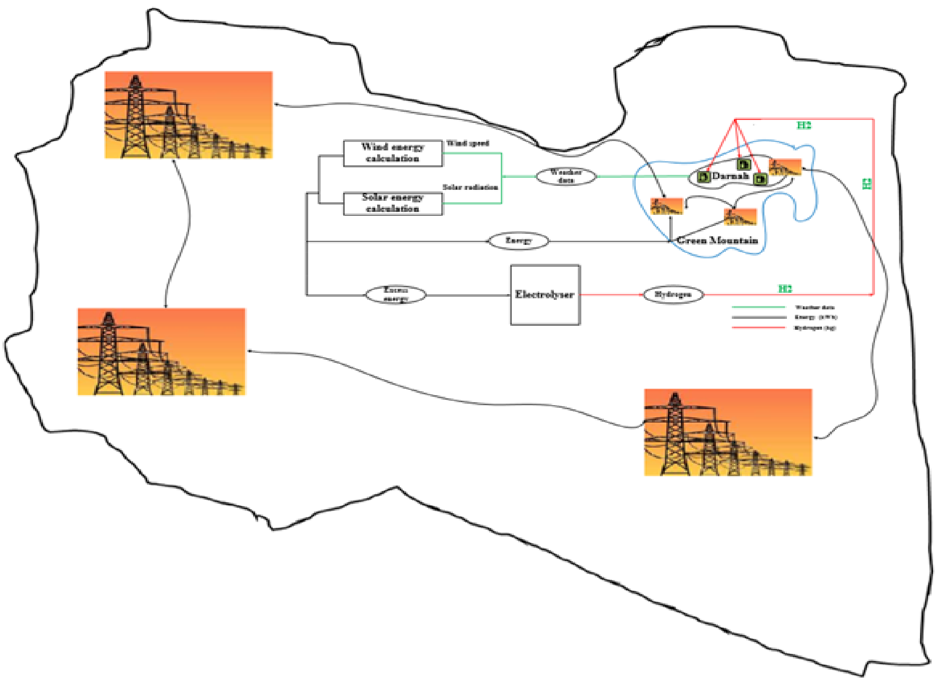


Figure 6.5: Research system as a part of the Libyan electricity grid

6.4 Wind speed and power potential in Darnah

Darnah has a higher wind speed than other regions of the country at around 8 m/s, according to data collected and investigated in many previous studies (Tjahjana, Dominicus Danardono Dwi Prija et al., 2016; Al-Behadili and El-Osta, 2015). This research agrees on the possibility of being able to produce a huge amount of wind power in this region (Ahwide, Spena and El-Kafrawy, 2013).

6.4.1 Wind data analysis

Hourly wind speed data for Benina Airport in Libya from 2013 was used for this research. There are a large number of weather stations in Libya that not only gauge wind speed but also air, pressure, temperature, rainfall, and so on. Wind speed is normally taken at 10 m height. These data were collected from Benina International Airport at a height of 10 m above ground level (weatherspark team, 2014). Raw hourly wind data from the Met Office is taken for wind speeds 10 m above the ground; however, wind turbine hub is much higher than this level, and wind speed changes with height, and friction from the terrain, buildings, etc., that can cause a slowing of airflow plus high variability due to turbulence. The mean wind speed can be easily calculated using Equation (6.1) (Ahwide, Spena and El-Kafrawy, 2013):

$$V = \frac{1}{N}\sum_{i=1}^{N} V_i \qquad (6.1)$$

Where: V is the wind speed and $N =$ number of data.

There are two methods by which to calculate wind speed at the hub heights of wind turbines (Archer and Jacobson, 2003):

a) Power law profile

The wind speed as a function of height has the form below:

$$V(z) = V(z_r)\left(\frac{Z}{Z_r}\right)^n \qquad (6.2)$$

Where $V(z_r)$ is the measured wind speed at 10 m height, $V(z)$ is the adjusted wind speed at the wind turbine hub height, Z is the wind turbine hub height, which can reasonably be supposed to be 80 metre (from the project data), Z_r is the measured height of wind speed (10 m). For the raw wind speed data and n is the frictional coefficient (which varies from 0.09, when the wind is very unstable, to 0.41 when it is very stable). The stability factoe also related to the turbulence.(Van den Berg, 2004); a value of n = 1/7 is used in this research.

b) Logarithmic law

The logarithmic law can be described as in Equation (6.3):

$$V(z) = V(z_r)\left(\frac{\ln\left[\frac{Z}{Z_0}\right]}{\ln\left[\frac{Z_r}{Z_0}\right]}\right) \tag{6.3}$$

where $V(z_r)$ is the measured raw wind speed at 10 m height, $V(z)$ is the adjusted wind speed at the turbine hub height, Z is the hub height, reasonably assumed to be 80 metres, Z_r is the measurement height (10 metre) for raw wind speed data, and Z_0 is the roughness length, typically 0.01 m (Archer and Jacobson, 2003). Roughness length Z_0 is not a physical length; it is a parameter, which can be considered as a length-scale of the roughness of the surface of the ground(Rahil, Gammon and Brown,). The power law profile is used in this research to convert the measured wind speed at 10 metre height to the speed at an 80 m hub height. Figure 6.6 presents the wind speed at 10 metres and 80 metres.

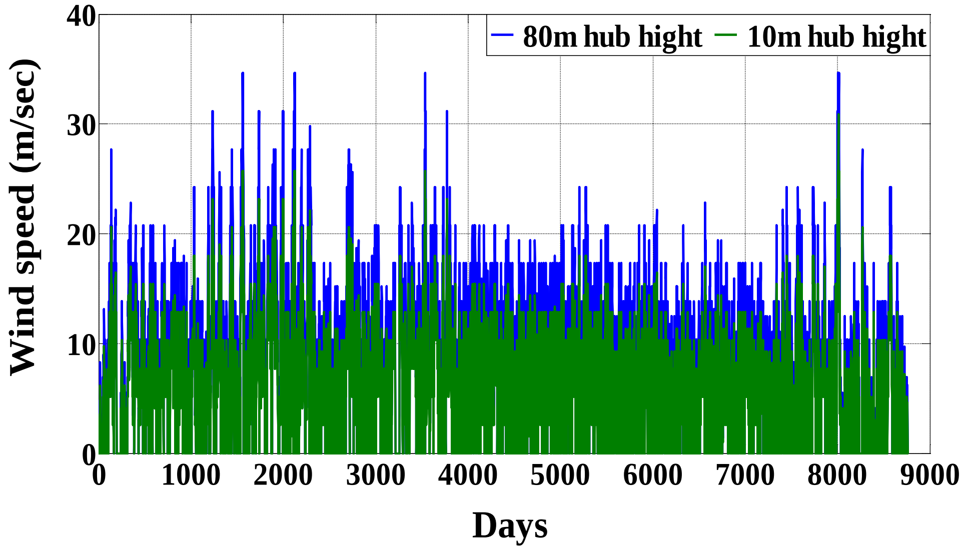


Figure 6.6: Hourly wind speed at different heights (10 m and 80 m) in Darnah, Libya, in 2013.

6.4.2 Calculating the wind turbine power

The wind turbine output power can be calculated using the formula below (Nistor et al., 2016):

$$\boldsymbol{P}(\mathbf{t}) = \begin{cases} \mathbf{P_{rated}} \times \dfrac{\mathbf{V(t) - Vin}}{\mathbf{Vr - Vin}} & \mathbf{Vin \leq V(t) \leq Vout} \\ \mathbf{P_{rated}} & \mathbf{Vr \leq V(t) \leq Vout} \\ \mathbf{0} & \mathbf{V(t) < Vin \cup V(t) > Vout} \end{cases} \quad (6.4)$$

The wind turbine output is is determined by the power curve and each turbine has its own power curve. In this research, the power curve for M. Torres TWT 1.65-82 turbines will be used since they have already been installed for the pilot project. The technical details for this turbine are given in Table 6.1 (Bauer, 2016):

Rated power (P_{rated})	1.65 MW
Cut-in wind speed (V_{in})	3 m/sec
Rated wind speed (V_r)	15 m/sec
Cut-out wind speed (V_{out})	25 m/sec
Survival wind speed	52.5 m/sec
Rotor Diameter	82 m
Rotor swept area	5,365 m²
Wind turbine hub height	70/80 m
Number of blades	3

Table 6.1: Technical details for the M. Torres TWT 1.65-82 Turbine.

The M. Torres (TWT 1.65-82) turbine power curve is presented in Figure 6.7:

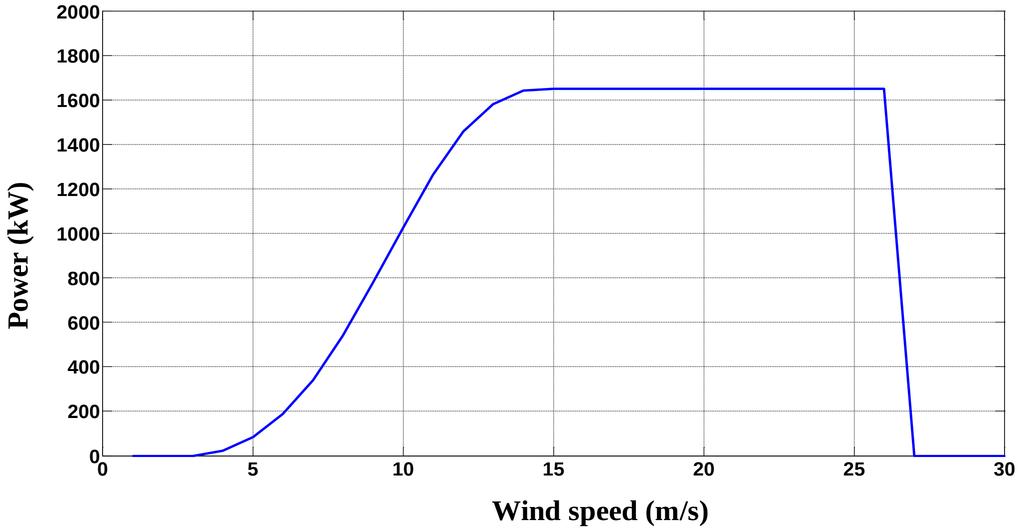


Figure 6.7: Wind turbine power curve with wind speed.

The capacity factor is important in the determination of how much energy can be produced by the turbine. This can help an engineer to decide whether installing wind turbines in a specific area is economically worthwhile. The simple definition of capacity factor is the actual generated energy over a given time divided by the total energy the turbine would produce if it ran continuously at its rated output throughout the same period. It can be calculated using this equation using Equation (6.5) (Albadi and El-Saadany, 2009):

$$CF = \frac{\mathbf{exp}\left[-\left(\mathbf{V}_{in}/\mathbf{c}\right)^{k}\right] - \mathbf{exp}\left[\left(\mathbf{V}_{r}/\mathbf{c}\right)^{k}\right]}{\left(\mathbf{V}_{r}/\mathbf{c}\right)^{k} - \left(\mathbf{V}_{in}/\mathbf{c}\right)^{k}} - \exp\left[\left(V_{out}/c\right)^{k}\right] \tag{6.5}$$

Where V_{in} is the cut-in speed, V_r is the rated speed, V_{out} is the cut-out speed, and k, the shape factor, and c, the scale factor (m/s), are the so-called Weibull parameters. The next section will give a broad discussion of the calculation of Weibull parameters using various different methods.

6.4.3 Statistical analysis of wind speed

The Weibull probability distribution function method is widely used in the analysis of wind speed (Sathyajith, 2006). The Weibull distribution function is given by:

$$P(V) = (k/c)\left(\frac{V}{c}\right)^{k-1} exp^{-(\frac{V}{c})^{k}} \tag{6.6}$$

Where $P(V)$ is the frequency or probability of occurrence of a given wind speed, c is the Weibull scale parameter, with identical units to wind speed, and k is the unitless Weibull shape parameter. Higher values of c indicate that the wind speed is higher, while the value of k gives indication of wind stability. The cumulative Weibull distribution function, $P(V)$, gives the probability of the wind speed. It is expressed by:

$$P(V) = 1 - exp^{-(\frac{V}{c})^{k}} \tag{6.7}$$

However, before using the Weibull equations, scale and shape factor parameters must first be determined. There are many methods by which this can be achieved; in this research, different methods will be applied to verify the accuracy of our calculations (Akdağ and Dinler, 2009). Table 6.2 below shows the Weibull parameter formulae and values of the parameters above as determined by the various different methods. MATLAB code is used to calculate the Weibull parameters using these methods. Maximum likelihood method was used in this research.

Method	k and c equations	10 m		80 m	
		k	c	k	c
Graphic method	$k = a$ $c = \exp(\frac{b}{a})$	2.4	9.93	2.4	13.4
Maximum likelihood method	$k = \left(\frac{\sum_{i=1}^{n} v_i^k \ln(v_i)}{\sum_{i=1}^{n} v_i^k} - \frac{\sum_{i=1}^{n} \ln(v_i)}{n}\right)^{-1}$ $c = \left(\frac{\sum_{i=1}^{n} (v_i)^k}{n}\right)^{\frac{1}{k}}$	2.3	9.8	2.3	13.2
Moment method	$k = \left(\frac{\sigma}{\bar{V}}\right)^{-1.086}$; $1 \leq k \leq 10$ $c = \frac{\bar{V}}{\Gamma(1+\frac{1}{k})}$	2.3	9.8	2.33	13.1
Power density	$k = 1 + \frac{3.69}{(E_{pf})^2}$ $c = \frac{\bar{V}}{\Gamma(1+\frac{1}{k})}$	2.2	9.8	2.2	13.2

Table 6.2: Weibull parameters calculation

After calculating the Weibull parameters, the wind turbine capacity factor can be determined as per Equation (6.5). The capacity factor for these turbines, as based on the wind turbine curve and Weibull parameters, is 0.35. Thus the energy that can be generated from this turbine on an annual basis is:

$$E_{annual} = CF * 8760 * P_r \tag{6.8}$$

$$E_{annual} = 0.35 * 8760 * 1.65 = 5058.9 \text{ MWh/year}$$

Where P_r is the rated turbine power (1.65 MW for this particular turbine).This research will deal with the daily pattern of generation for various reasons, such as the pool of the data, especially hourly demand, being difficult to determine accurately from renewables, especially in the Libyan case here, and, additionally, due to the period available for research, as recording and analysing data for an hourly pattern would require considerably more time and effort. In this research, PV systems are used only to fill gaps in wind power output, hence the wind data can only be considered intermittent and variable. Figure 6.8

and Figure 6.9 show the energy produced from one turbine over one year in hourly and daily patterns, respectively.

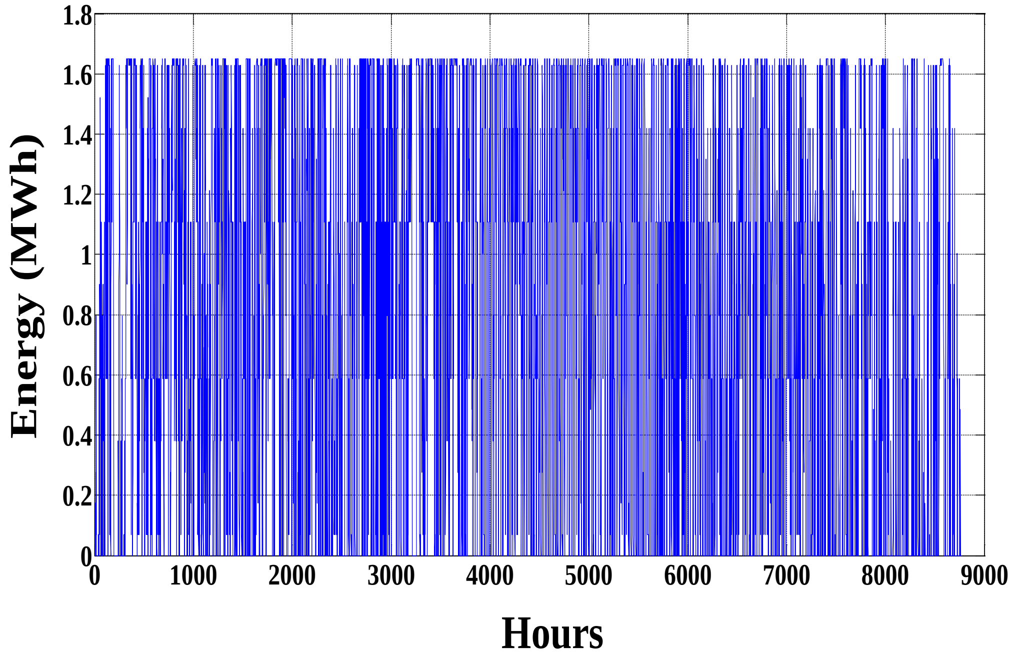


Figure 6.8: Yearly energy from one turbine (hourly pattern)

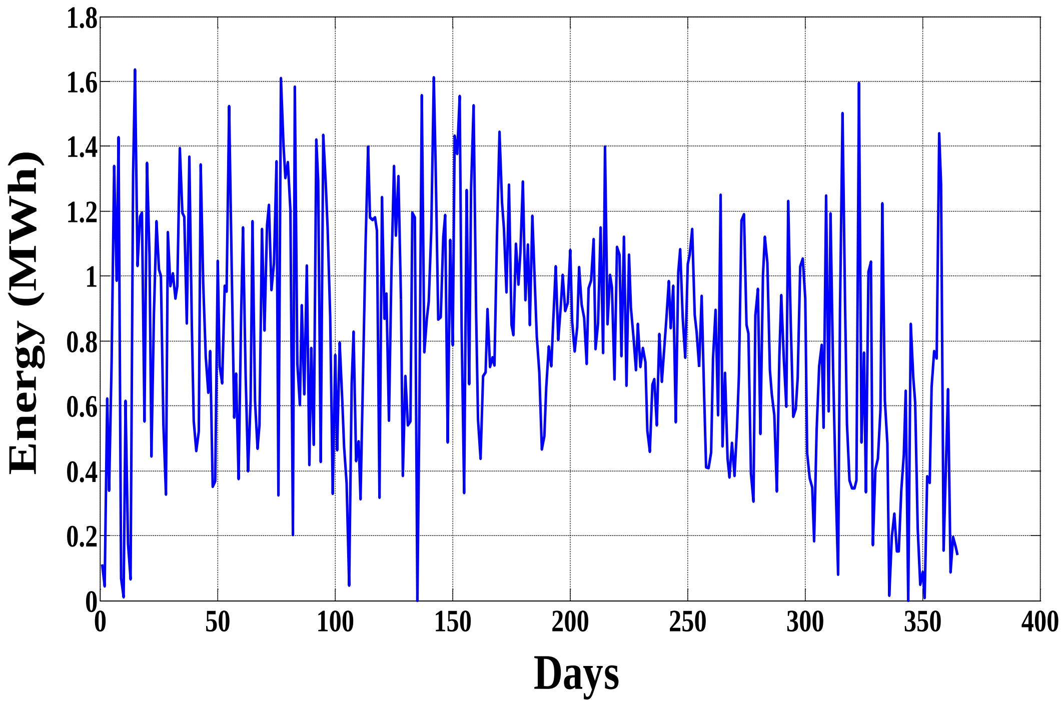


Figure 6.9: Daily energy production for one turbine throughout the year

6.4.4 Solar irradiation and photovoltaic power potential in Darnah

Based on the data made available by the renewable energy authority and NASA, Darnah has a promising solar resource. Figure 6.10 shows the annual average solar irradiance estimates for Libya (kWh/m^2 /y) whilst Table 6.3 shows the monthly averaged insolation incident on a horizontal surface (kWh/m^2 /y) over a 22-year average.

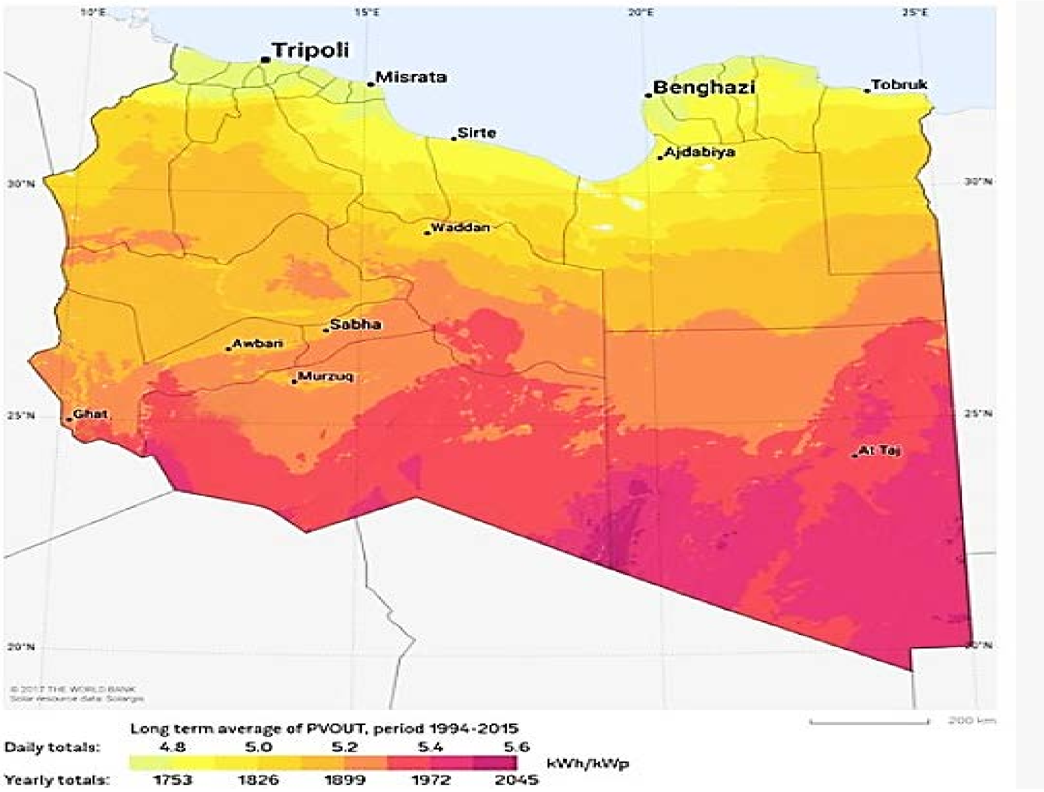


Figure 6.10: Annual average solar irradiance estimates for Libya

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solar Radiation (kWh/m^2 /day)	2.67	3.66	4.93	6.27	7.17	7.95	7.93	7.08	5.86	4.26	3.06	2.40

Table 6.3: Monthly average solar radiation

In 2012 a 14 MW facility was installed in Jufra District, Hun (Mohamed Ramadan Zaroug, 2012). In this research, it is assumed that this 14 MW is integrated into the grid. Value for parameters, such as the PV panel cost and lifetime, in this research will be equivalent to those of the Hun project, so only the location and solar irradiance data will be different. The technical parameters of the PV panels used herein are presented in Table 6.4:

Parameter	Value
Cell type	Crystalline PV module
Power	Different power ratings: 230 – 245 Wp
Number of modules	~57,140 – 60,870
Module efficiency	14.1 – 15.1 %
Maximum rated current series	15 A
Power tolerance	+/- 3 %
Maximum power voltage	29.4 – 30.7 V
Plant load factor	18.87 %

Table 6.4: Technical details of the PV panels used in this project

The hourly solar radiation for Darnah can be obtained from the national renewable energy Laboratory data and the NASA website. Figure 6.11 shows the solar radiation in Darnah over a year.

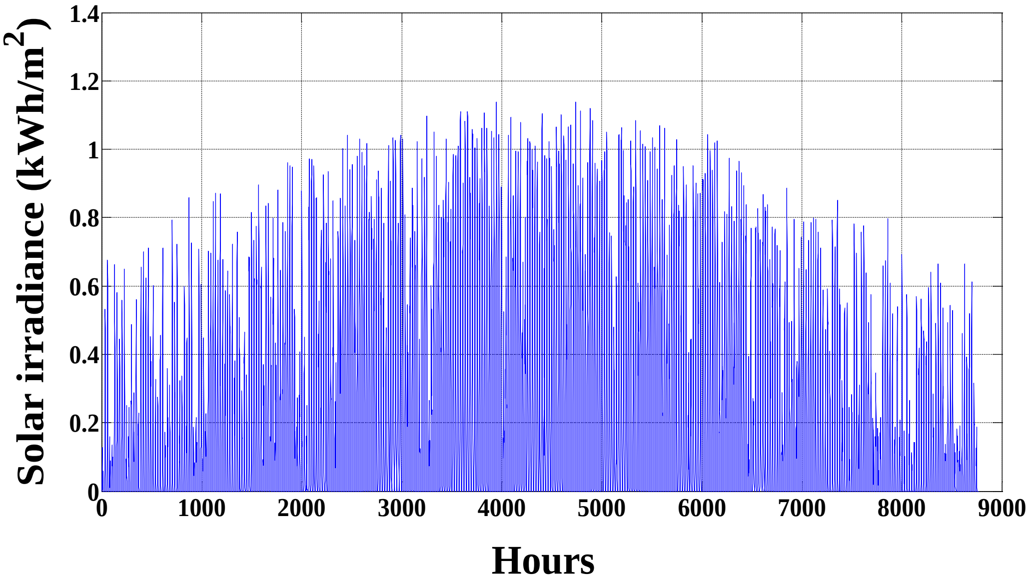


Figure 6.11: Hourly solar irradiance in Darnah, Libya

The total energy produced from a 14 MW system can be computed using the formula below:

$$E = A \times r \times H \times Pr \tag{6.9}$$

Where E is the total energy produced (kWh), A is total solar panel area (m^2), r is solar panel yield(%), Pr is the performance ratio and H is daily solar irradiation($kWh/m^2 day$). The total area of the panels can be calculated as follows:

1. Number of panels used $(14\ MW) = \frac{14\times10^6}{rated\ power\ of\ panel\ (240)} \approx 58334\ panel$

2. Total area required= 58334×1.6 (area per panel) $= 93334\ \text{m}^2$
3. The yield of the solar panels is given by the ratio of electrical power (in kWp) of one solar panel divided by the area of one panel, i.e.: (240/1000)/1.6=15%.
4. The performance ratio (PR), which ranges between 0.5 and 0.9, and is given a default value of 0.75 herein.

The performance ratio is very important in terms of evaluating the quality of a photovoltaic installation because it gives the performance of the installation independently of the orientation/inclination of the panel; it includes all losses. Many losses contribute to the PR value such as Inverter losses (4% to 15%), temperature losses (5% to 18%), DC cable losses (1% to 3%), AC cable losses (1% to 3%), Shading (0% to 80%), Weak radiation losses (3% to 7%), and losses due to dust, snow, etc. (2%). The capacity factor of the PV system can be calculated by dividing the actual energy production by the rated energy of the system, as in the formula below:

$$CF = \frac{actual\ energy(kWh)}{rated\ energy\ of\ the\ system(kWh)} \qquad (6.10)$$

$$CF = \frac{19{,}826{,}751}{8760 \times 14000} = 16\%$$

Figure 6.12 and Figure 6.13 show the energy generation in hourly and daily patterns, respectively, from a 14 MW PV system:

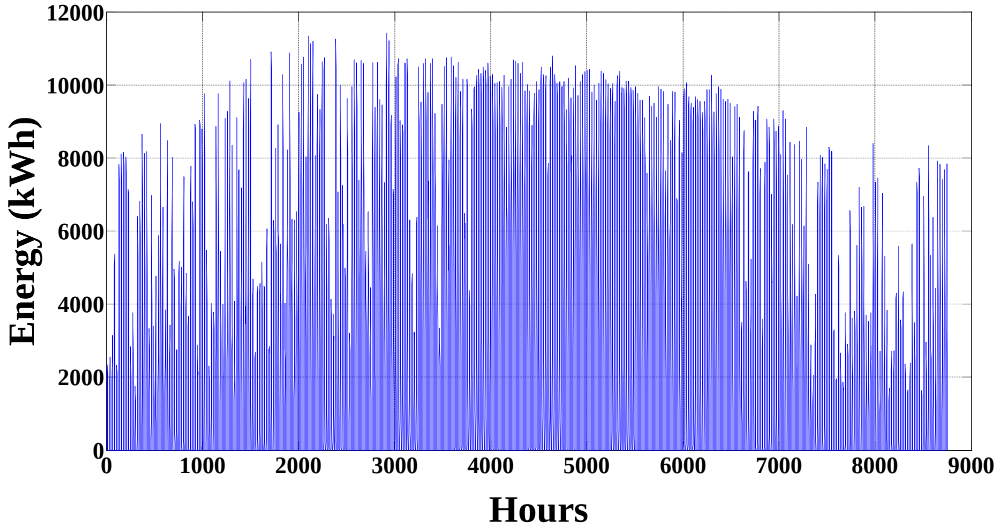


Figure 6.12: Hourly AC energy produced from 14 MW PV energy system

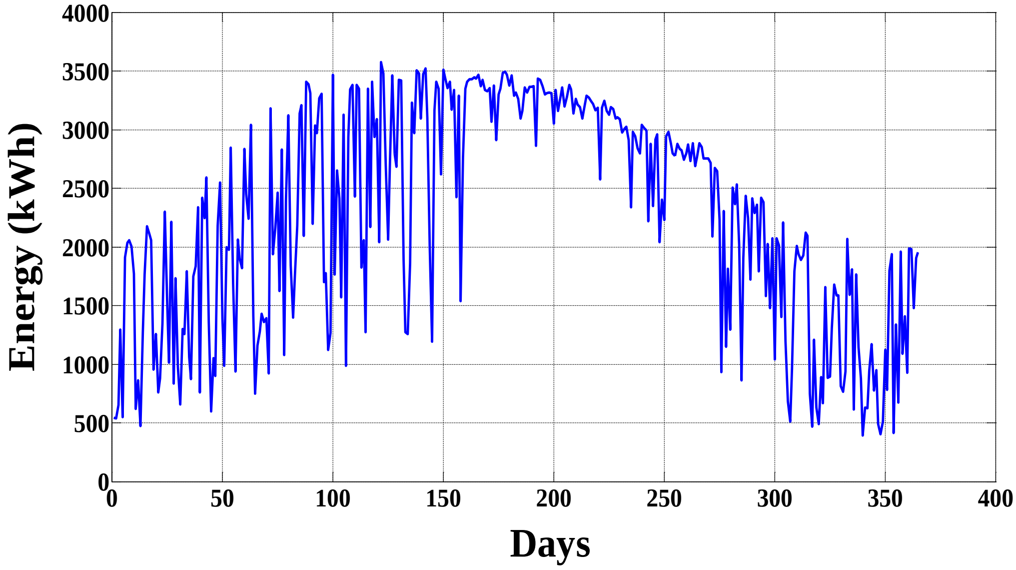


Figure 6.13: Daily AC energy produced from 14 MW PV energy system

6.5 Sizing a wind turbine and solar photovoltaic cell

There are many examples of analytical systems that have been used to design hybrid power systems. These are normally used with wind and diesel and hybrid systems utilising batteries as storage for any temporary surplus of power generated by renewable sources. Furthermore, most previous models have been simulated or designed for standalone/off-grid systems (Torreglosa et al., 2014; Valverde, Bordons and Rosa, 2016; Petrollese et al., 2016). Most of the available commercial or academic software has two main problems: the input requirement is very large and substantial computational resources are required to dimension a system size (Gazey, 2014). In this chapter, a novel, simple tool that leads to sizing on-grid hybrid systems is proposed.

This model will work only in the case of surplus power. In other words, any shortfall from renewables will be supplemented by fossil fuelled generators or the grid, but these are out of the scope of this work. Therefore, this model will focus on supplying the case-study area from renewable energy sources (wind and PV) and any surplus will be available for electrolysers to produce hydrogen. The input for this system is the wind power data, PV system data and the demand data. This model been developed using MATLAB software. The sizing part of the model is shown in Figure 6.14.

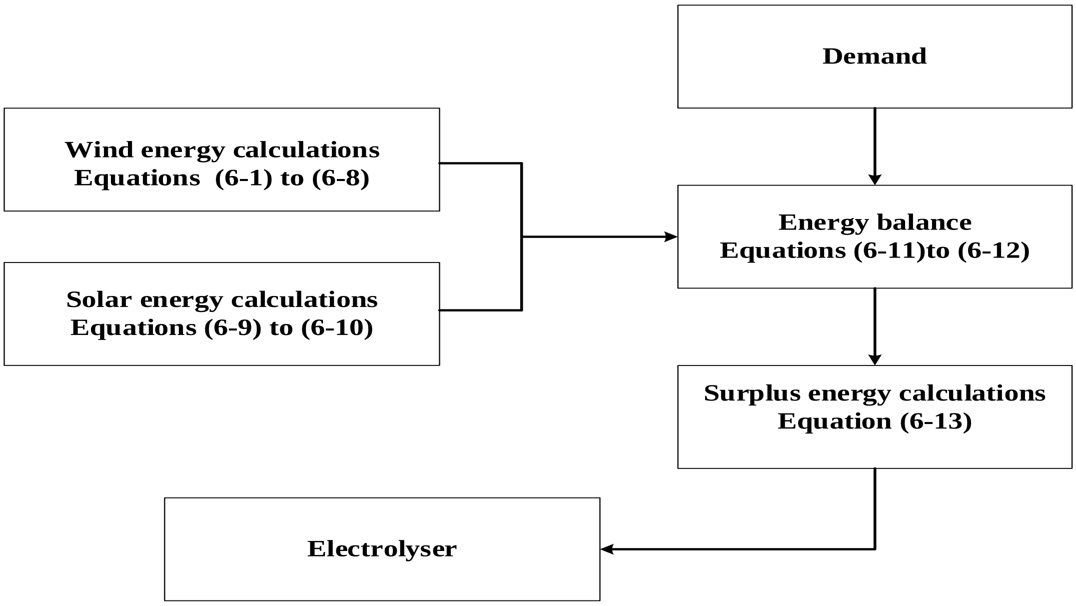


Figure 6.14: Proposed sizing system steps

The sizing process flow can be summarised as per the points below:

1. Sizing the PV system: since the 14 MW system is assumed to be installed with a capacity factor of 16%, there is no further need to do any further calculations for this system because the PV system is fixed and daily energy can be calculated as per Equation (6.9)
2. Sizing the wind turbine: the characteristics of the wind turbine used in this research were based on real-world data from the Darnah project to make this work as close as possible to genuine data calculations. The next step is to estimate the needed power in the Green Mountain area. Average demand will be as calculated in Equation (6.11):

$$P_W = \frac{\overline{P_{dem}} - CF_{PV} \times P_{pv}}{CF_W} \tag{6.11}$$

where P_W is wind power, $\overline{P_{dem}}$ is average demand, CF_{PV} is the solar system capacity factor, P_{pv} is the solar system rated power and CF_W is the wind turbine capacity factor. The previous step will give the total energy required to satisfy the demand from renewable energy based on the weather situation.

In other words, some days this system will be unable to meet demand, with the deficit then being supplied by non-renewable sources. By dividing the required amount of power by the rated power of each wind turbine, the number of turbines required will be known, as per Equation (6.12):

$$N_W = P_W / r_P \tag{6.12}$$

Where r_P is the rated power of the chosen turbine ($1.65MW$). Based on the calculations in Equations (6.11) and (6.12), the total energy required from the wind system is $808.1677\ MWh$, and the number of wind turbines required to produce this amount of power is ≈ 490.

Figure 6.15 shows the total energy produced from the system verses the energy demand in a daily pattern.

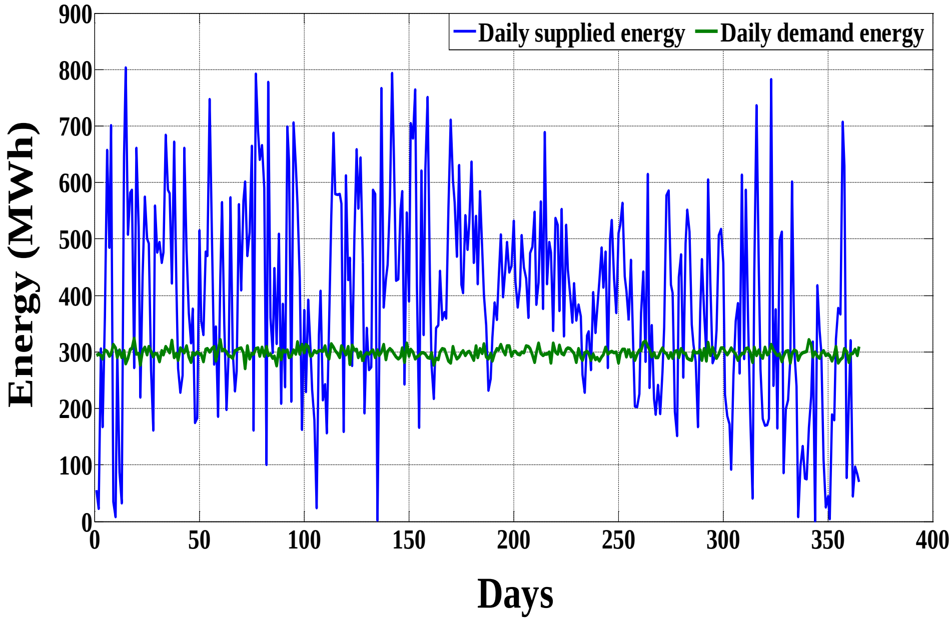


Figure 6.15: Green Mountain daily demand in contrast with energy production after sizing process

Surplus energy can be calculated using Equation (6.13):

$$E_{daily-surplus} = (E_1 - Demand_1) + (E_n - Demand_n) + \cdots\cdots\cdots\cdots + (E_{365} - Demand_{365}) \tag{6.13}$$

Where: E is the daily energy production(kWh), $Demand$ is the daily demand (kWh), $E_{daily-surplus}$ is the daily surplus energy and n is the number of days during the year. Figure 6.16 presents the daily surplus energy in MWh.

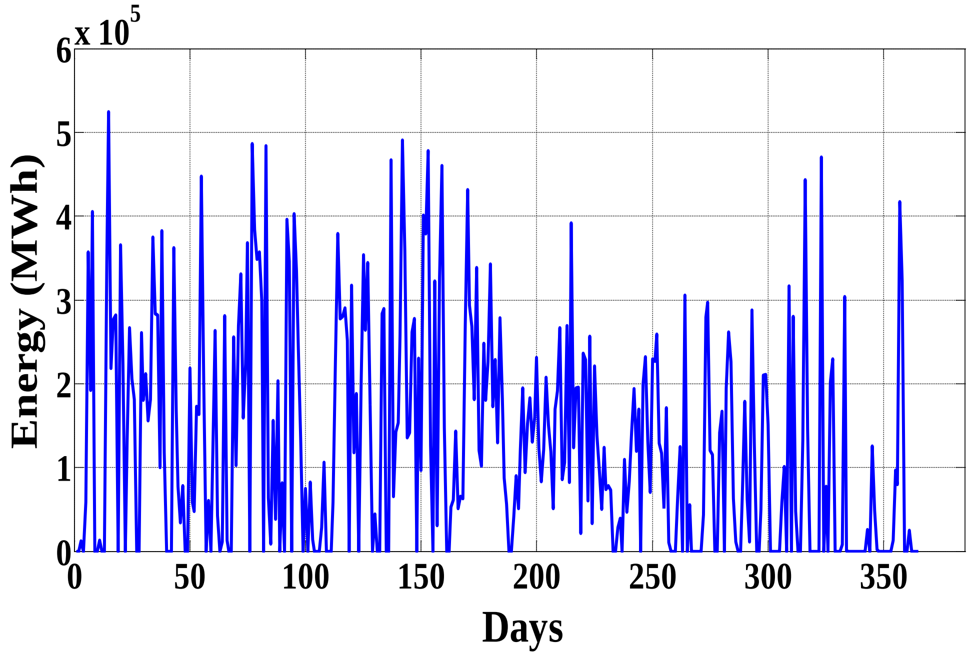


Figure 6.16: Daily surplus energy after the comparison between demand and supply

The temporary surplus energy represent 33% of the total energy produced. However, temporary periods of deficit mean that 12% of the total demand cannot be met without input from non-renewable sources. However, the surplus power can be stored and reused at times of shortage.

Daily energy surpluses fluctuate from zero to 524.5 MWh, which gives a strong indication that energy storage could be used in overcoming any intermittency and keeping the grid balanced.

6.6 Hydrogen demand

6.6.1 Introduction

The transport sector in Libya has consumed the largest amount of energy across all sectors over recent decades.

For example, transport represented nearly 46% of the total energy consumption between 1988 and 1990 (El-Osta and Zeghlam, 2000). Figure 6.17 shows the share of energy consumed by the transport sector between 1973 and 1993.

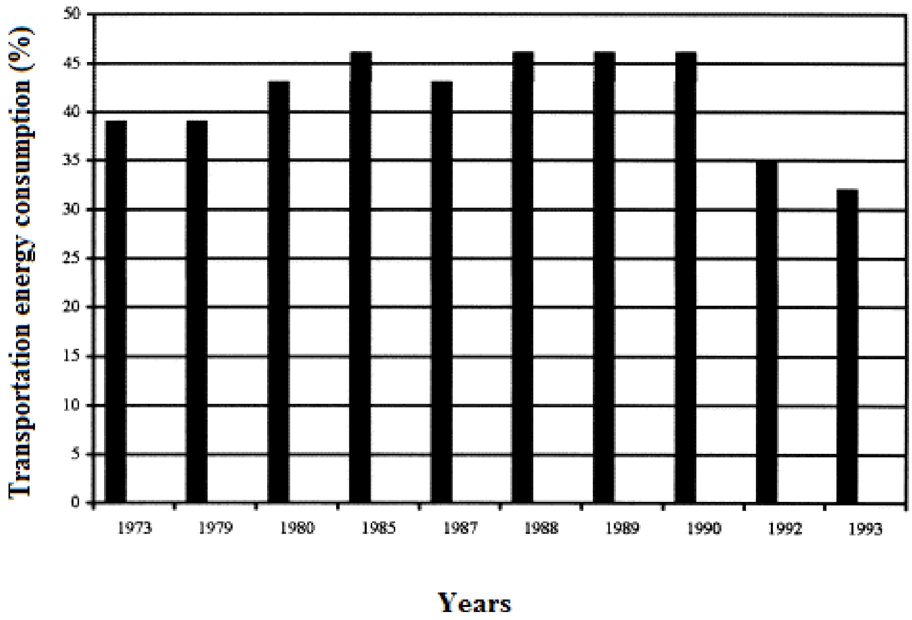


Figure 6.17: Percentage of energy consumption in the transportation field as a fraction of total demand of energy

There is a strong link between the population size and energy use. In Libya, the population growth rate is very high, which means that energy consumption will dramatically increase in coming years. Figure 6.18 presents the population and the population growth rate of Libya between 1985 and 2050.

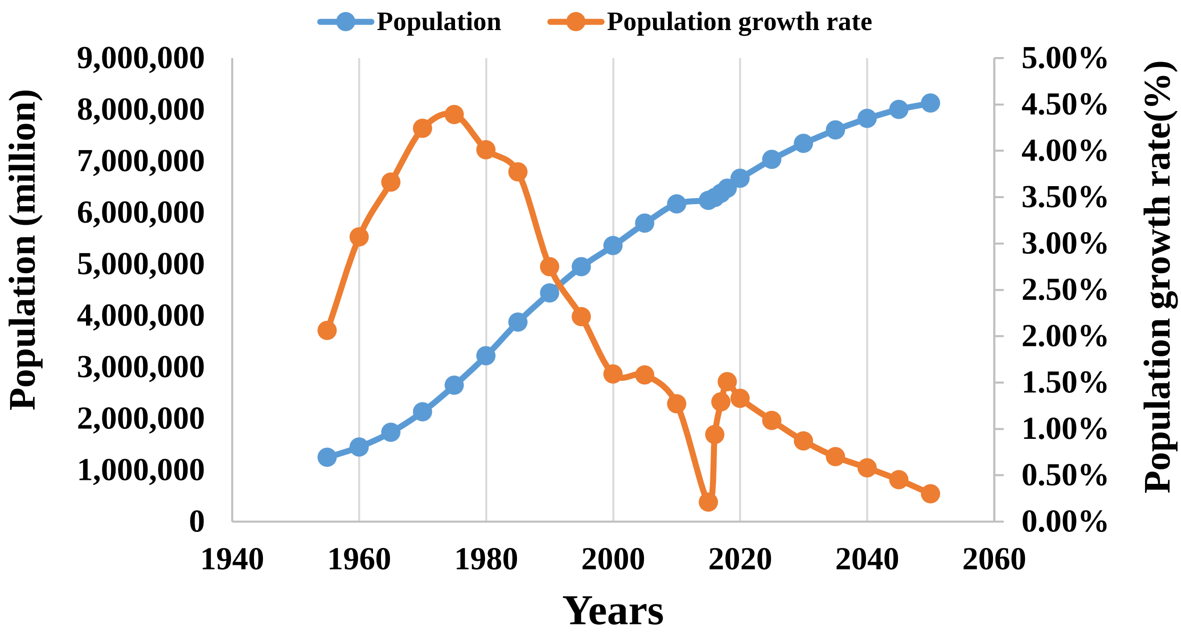


Figure 6.18: Libyan population and population growth rate between 1985 and 2050

6.6.2 Moving from fossil fuel to hydrogen fuel in Libya

The use of hydrogen in the Libyan transport sector will likely begin with the transition towards the use of hydrogen as an alternative fuel worldwide. The main target of this research is to present the advantages of using hydrogen as a fuel and as a grid-balancing tool with a real-world example to encourage the Libyan authorities to adopt this approach. Obviously, many challenges have to be addressed before a complete move towards hydrogen fuel can occur. These issues include the building of a hydrogen-based infrastructure and reducing the price of hydrogen. In addition, bold policy measures are needed to reduce emissions and to provide a sustainable economic future for oil-producing nations such as Libya in a post-fossil-fuel era. In particular, this means strong support for renewable energy and hydrogen markets. Priority should be given to the transport sector in terms of hydrogen applications since this constitutes the largest proportion of local energy consumption. Fuel consumption for transpor increased by a factor of two over 15 years (from nearly 1 million in 1975 to 2 million in 1990). Table 6.5 presents the yearly fuel consumption (metric tonnes) between 1975 and 1996.

Year	**Gasoline (tonnes)**	**Kerosene (tonnes)**	**Diesel (tonnes)**
1975	447 200	166 200	389 222
1980	832 324	299 630	584 669
1985	969 643	310 521	847 741
1990	1 262 464	265 838	859 164
1991	1 378 947	264 302	792 614
1992	1 495 542	152 887	801 525
1993	1 525 463	84 930	848 346
1994	1 546 930	74 196	808 458
1995	1 566 171	76 123	770 371
1996	1 521 105	78 286	735 510

Table 6.5: Annual fuel consumption (metric tons) in transportation sector between 1975 and 1996

Based on low local prices of fuel and the growth in population and number of cars, the fuel consumption of the transport sector is anticipated to dramatically increase by up to 3090 kTOE/ annum of gasoline and 1178 kTOE/ annum of diesel in 2020 (El-Osta and Zeghlam, 2000).

6.6.3 Petrol stations in Libya

The precise number of petrol stations in Libya is difficult to know because recently the National Oil Corporation (NOC) in Libya gave permission for many private petrol stations to be built to solve the problem of bottlenecks at current petrol stations. Generally, petrol stations built prior to 2007 were completely controlled by the NOC, which is responsible for forecourt construction, and the transportation and selling of fuel (The National Oil Corporation (NOC), 2017). Three companies were established pursuant to decision number 291 of 2007 and they commenced activities in the field of oil derivatives marketing. These companies are Alrahila Oil Services, Oil Libya Company and Sharara Oil Services Company and are responsible for building fuel stations and delivering the oil product. Figure 6.19 shows some of the forecourts owned and operated by these companies, whilst

Figure 6.20 shows the distribution of Alrahila and Sharara fuel stations across the country before 2011. Even for private f, they should belong to one of the three companies that is controlled by the NOC to to be able to offer all services. Recently, as forecourt owners, these companies have dealt directly with station managers, and are responsible for all worker salaries. In other words, these fuel stations operate as small companies. (Alrahila, 2017; Sharara Oil Services Company, 2017; Oil Libya company, 2013).

Figure 6.19: Some examples of petrol stations in Libya

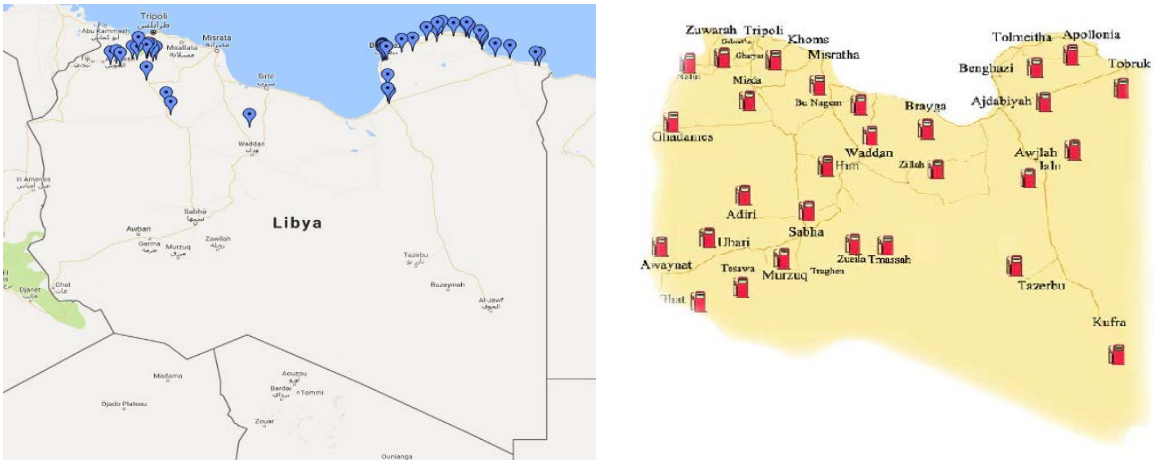


Figure 6.20: Distribution of Alrahila and Sharara stations in Libya (The National Oil Corporation (NOC), 2017)

6.6.4 Libyan fuel prices

The aim of this section is to discuss the current price of fuels in Libya due to their direct impact on both the economic and financial placement of Libya worldwide, and in turn on the standard of living of Libyan people. The financial value of government subsidies is 14.8 billion Libyan Dinars (7.4 billion pounds), which represents nearly 13.8% of the gross domestic product (GDP) of the country. Fuel, electricity and food represent the bulk of this subsidy (*Libya: Selected Issues* 2013). Figure 6.21 shows the comparison between subsidies and government spending on health and education.

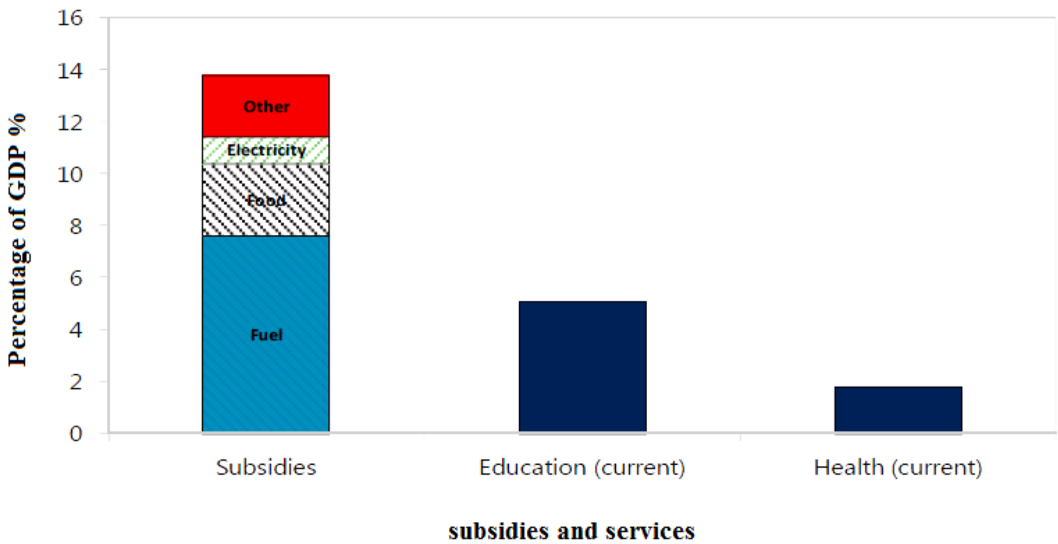


Figure 6.21: Comparison between Libyan subsidies and spending on other services

The fuel subsidies represent nearly 70% of the total cost of fossil fuel in Libya, as in Figure 6.22:

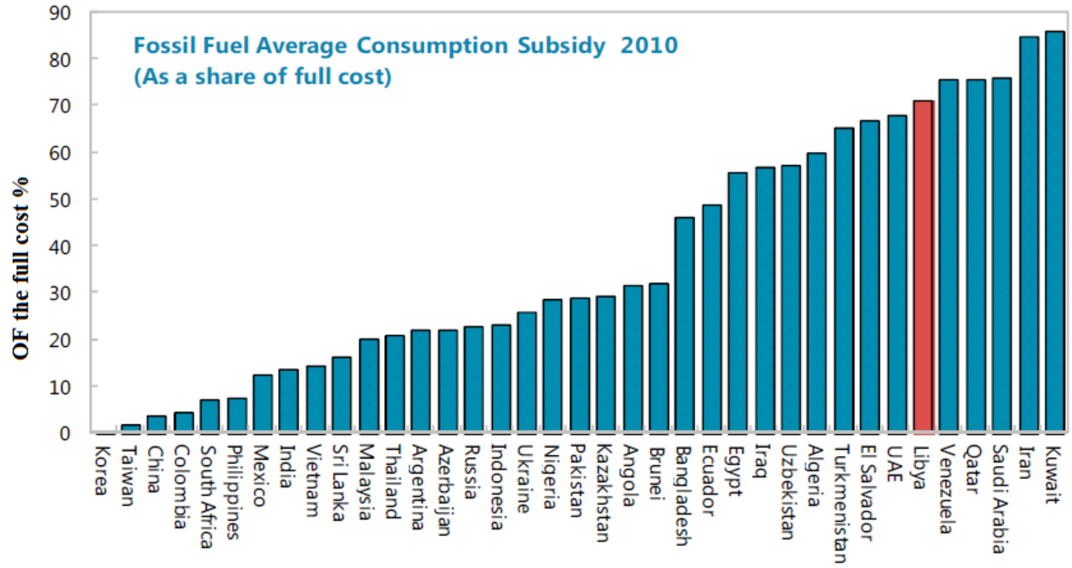
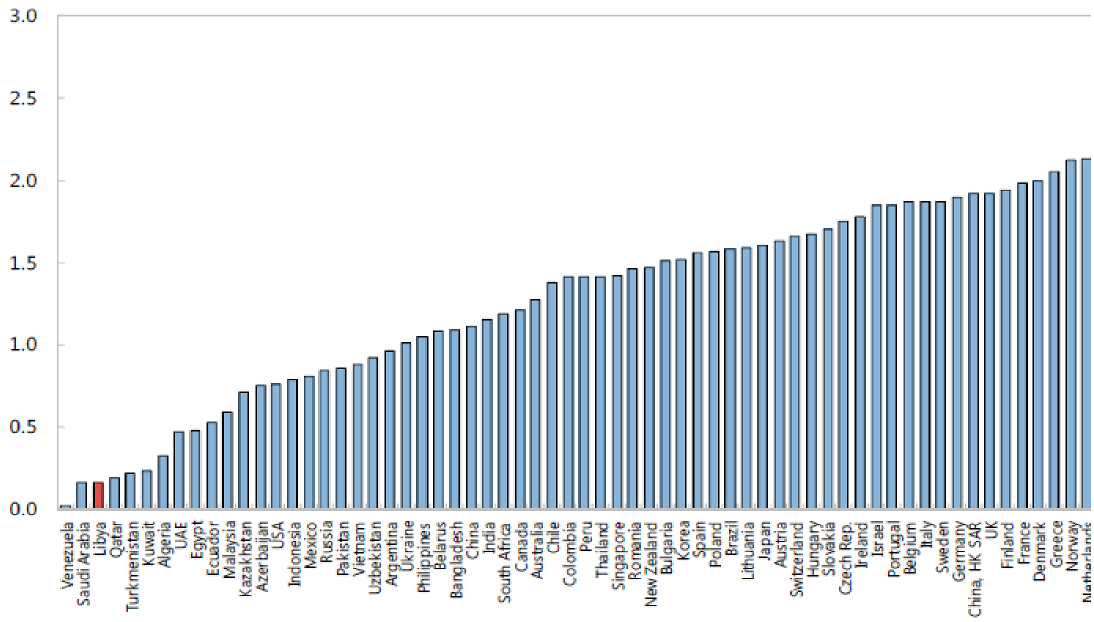


Figure 6.22: Fuel subsidy as a percentage of total cost in various countries

Fuel prices are heavily subsidised in Libya, with fuel prices amongst the cheapest in the world. At the end of 2010, Libyan fuel retail prices were less than half those of fuel in the majority of neighbouring countries and less than one-tenth of the price being charged in Italy. Figure 6.23 shows the retail fuel price for various countries in 2010.



Sources: FAD database on cross-country gasoline prices, Deutsche Gesellschaft für Technische Zusammenarbeit, and Libyan authorities.

Figure 6.23: Fuel prices in various countries

Fuel subsidies are equal to nearly 11% of GDP, about 2100 LYD per capita. Beyond the financial cost, however, subsidies on fuel prices have led to the inefficient use of energy by customers. Furthermore, the fuel subsidy tends to favour high-income customers rather than those on low incomes. Consumer diesel prices average 17 Dirham/litre, whilst consumer gasoline prices average 20 Dirham/litre. The current fuel prices are given in Table 6.6:

fuel	Price at sale point (Dirhams/litre)	Price at sale point (£/litre)
Gasoline	17	0.09
Diesel	20	0.10

Table 6.6: Libyan fuel prices (Libyan and UK currencies)

Currently, the government plan is to replace food and fuel subsidies with cash payments to citizens, to relieve some of the burden on public finance, which have badly affected by dwindling oil revenue. These steps will be applied in stages and, after five years, the government subsidy should be entirely removed (Elumami, 2015; Donati and Shennib, 2013).

6.6.5 Hydrogen consumption estimation

Because of the absence to date of an extensive hydrogen market, the hydrogen demand calculation cannot be computed with any great accuracy. The widespread uptake of hydrogen markets will rely initially on the availability of hydrogen-based infrastructure, (particularly the hydrogen refuelling station infrastructure) and hydrogen-fuelled cars (Dagdougui, Ouammi and Sacile, 2012). Due to the associated uncertainty, scenario planning can be deemed as the only systematic method of estimating the size of hydrogen supply chain. Optimal design configuration will rely extensively on presumed scenarios. In this research, estimates of hydrogen demand and thus the number of hydrogen refuelling stations (HRSs) is based on the current supply of oil products to present conventional petrol stations. The data related to conventional petrol stations is useful in estimating potential hydrogen consumption and the required electrolyser capacity and based on these calculations, different scenarios will be investigated. According to the U.S. Department of Energy data, the energy content of 1 kilogram of hydrogen is equal to that of one gallon of gasoline. A typical gallon of gasoline contains nearly 114,000 BTU of energy, with one BTU equal to 0.000293071 kWh; hence, one gallon of gasoline is the equivalent of 33.140 kWh of electricity (Chu, 2013). This assumption has been used in many previous studies in the literature (Gutiérrez-Martín et al., 2009; Lamy, 2016; Allston and Press, 2016).

Another means of estimating the hydrogen consumption on the basis of fossil fuel consumption is presented (Dagdougui, Ouammi and Sacile, 2012; Greiner, KorpÅs and Holen, 2007). Lower and higher heating values and the conversion efficiencies of hydrogen and fossil fuel engines were used to calculate associated hydrogen consumption, as per Equation (6.14):

$$Q_{H_2} = \frac{Q_{ff} \times LHV_{ff} \times \mu_{ff}}{LHV_{H_2} \times \mu_{H_2}} \tag{6.14}$$

where Q_{H_2} is the hydrogen demand (kg), Q_{ff} is the estimated fossil fuel demand (kg) at a fossil fuel forecourt, LHV_{ff} is fossil fuel's lower heating value (kWh/kg), μ_{ff} is the efficiency of a fossil-fueled engine, LHV_{H2} is the lower heating value of hydrogen, and μ_{H2} is the efficiency of the hydrogen engine. In this research, the second option will be applied for greater accuracy. The values for the data in Equation (6.14) above are given in Table 6.7(Gillingham, 2007; Greiner, KorpÅs and Holen, 2007; U.S. Department of Energy, 2006).

Parameter	**Value**
LHV_{ff}	43.448 MJ/kg≈12.06kWh/kg
μ_{ff}	20%
LHV_{H_2}	40-60%
μ_{H_2}	120.21 MJ/kg≈33.33kWh/kg

Table 6.7: Properties of fossil fuel and hydrogen engines

The data for petrol stations is not available in any official form; only annual fuel consumption can be extracted from the the National Oil Corporation or Central Bank of Libya. However, after the recent introduction of a new system, which gives the manager or owner the power to control their own station, unofficial daily reporting has been performed to determine costs and revenues, as well as any shortage of oil products. As a result, fuel consumption data were obtained from each fuel stations owner's daily records.

6.6.6 Fuel consumption in Darnah

There are six fuel stations across the city with heavy daily consumption. As discussed above, the fuel consumption data was obtained from the stations owners' daily records. Figure 6.24 shows the locations of these stations.

Figure 6.24: Petrol station locations in Darnah, Libya

Estimated average daily fuel consumption for these forecourts was 6787.247 litres/day, 9681.243 litres/day, 20263.316 litres/day, 12429.996 litres/day, 33216.344 litres/day, and 16827.954 litres/day for fuel stations 1 to 6, respectively. The daily record for fuel consumption was recorded in litres/day, but Equation (6.12) requires data to be in kg/day. The appropriate conversion can be achieved based on 1 litre = 0.7489 kg (Greenwood and Earnshaw, 1998). Figure 6.25 shows the yearly consumption for fuel stations 1 to 6.

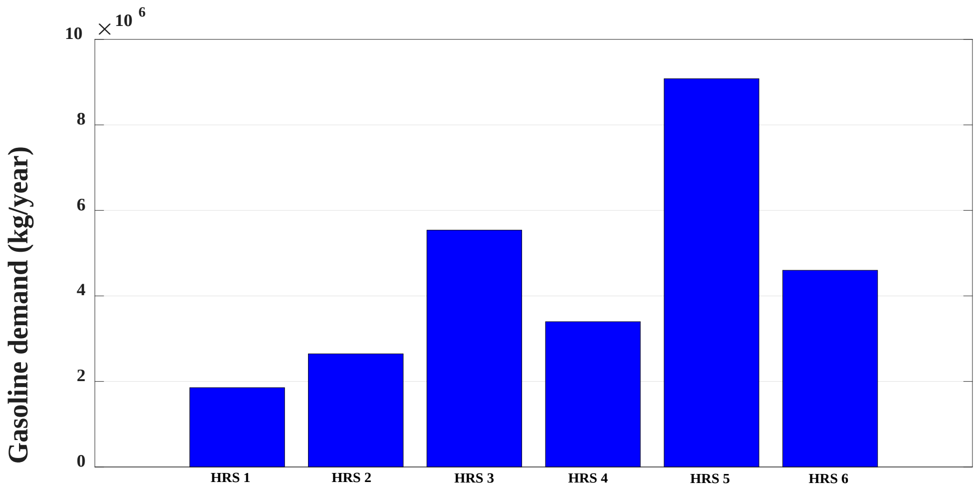


Figure 6.25: Gasoline consumption for all fuel stations (kg/year)

The consumption between days is considerably different, as based on various factors. For example, on many days, there are power cuts for several hours, so many families have diesel-fuelled backup generators whose fuel consumption will contribute to overall fuel consumption figures. However, it is not possible to recognise whether cars or diesel generators are consuming the fuel. Fuel consumption over several days is shown in Figure 6.26.

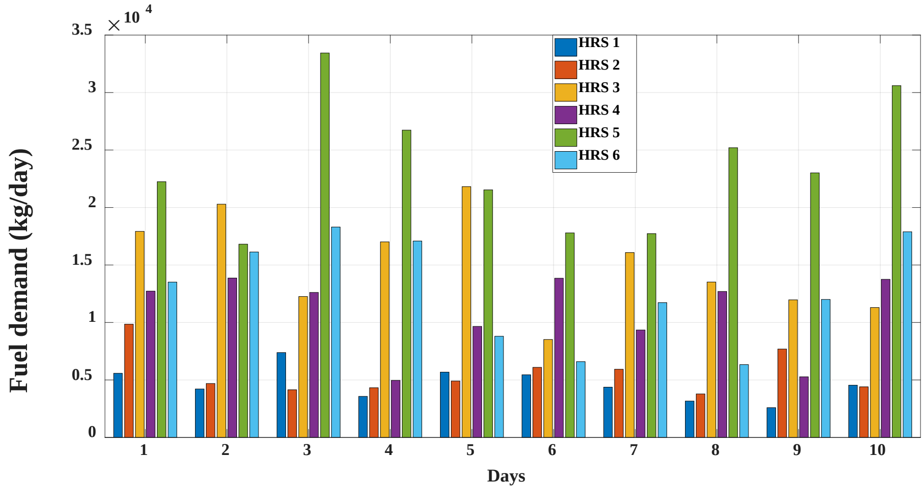


Figure 6.26: Several days' fuel consumption in stations 1 to 6

Daily average estimates of hydrogen demand from these fuel stations were 734.864, 1048.2109, 2193.94, 1345.811, 3596.374, and 1821.983 kg/day for fuel stations 1 to 6, respectively. Figure 6.27 below shows the total yearly demand for fuel stations 1 to 6.

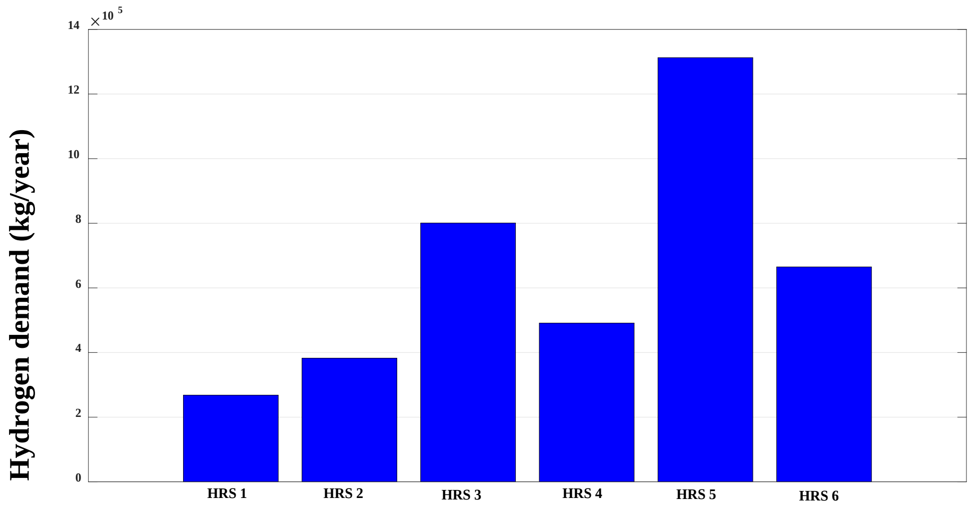


Figure 6.27: Hydrogen consumption per station (kg/year)

Since the hydrogen demand calculation is based on gasoline demand, the hydrogen consumption profile should be the same as that of gasoline. Figure 6.28 shows the daily hydrogen demand of a selection of days during the year.

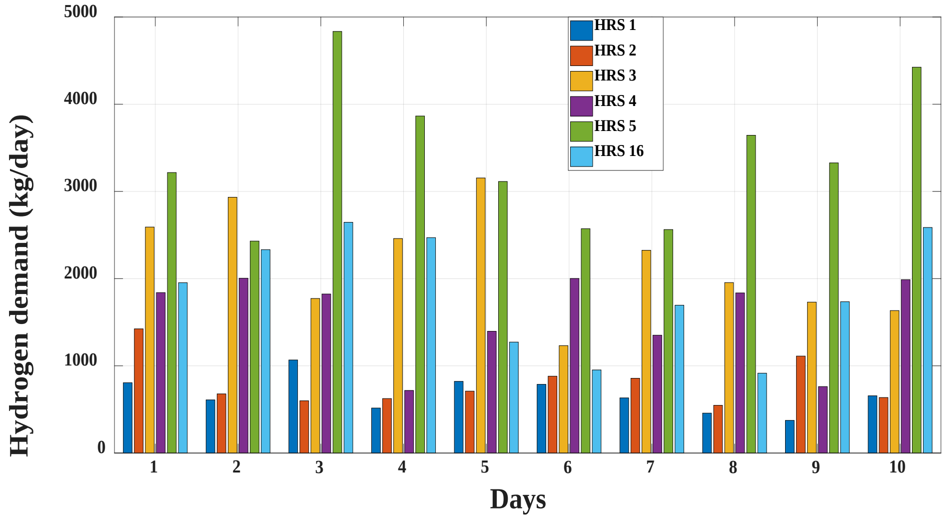


Figure 6.28: Several days' hydrogen demand for fuel stations 1 to 6

This makes it clear that substituting 100% of fuel demand with hydrogen will be very difficult to achieve. The total hydrogen demand for all fuel stations during the year was 3920525.23 kg, and the total surplus energy was 47488392.43 kWh/year. The efficiency of the electrolysis system in this research was found to be 54.6 kWh/kg, so the maximum possible hydrogen production from the surplus power is 869750.78 kg/year. This value represents just under 22% of the total hydrogen demand. As a result, 20% of the total hydrogen demand will be tested.

6.7 Summary of the chapter

This chapter summarises how to make use of surplus energy that can be used to produce hydrogen by electrolysis. Harvesting this surplus energy requires multiple steps and calculations. The first step is to analyse the opportunities for renewable energy production from wind and solar sources, to size the renewable energy generators to accommodate the Green Mountain region's demand and then amount of surplus energy available as a result of the mismatch between demand and supply during times of high production and low demand. The calculation of wind and solar energy passed through several stages, which included analysis of differences in wind speed at the height it was measured and the turbine hub height, followed by the use of various different methods to calculate the Weibull parameters. These were used to calculate the capacity factor, which is vital to any estimate of the amount of wind energy produced from a specific region. Contributions from solar power were also calculated after determining its capacity factor, as based on the ideal production and actual production of the system. The second section included details on how to estimate hydrogen consumption based on the real-world stations' sales of fossil fuel. This section included the fossil fuel consumption of Libya, in particular the city of Darnah, and explored opportunities for the Libyan state to exploit hydrogen as a clean fuel. The coming chapters will include analyses of the use of hydrogen as a grid-balancing mechanism and as a promising clean fuel. This study will be extensive, and will consider multiple cases and scenarios.

Chapter 7: Investigation of Hydrogen Price under Different Electricity Tariffs

7.1 Introduction

Environmental issues and the depletion of fossil fuels have motivated the rapid growth of renewable energy (RE) generation and its integration into electricity grids. For the same reasons, an alternative to hydrocarbon fuels is needed for vehicles; hence, the anticipated uptake of electric and fuel cell vehicles. High penetrations of RE generators with variable and intermittent output threaten to destabilise electricity networks by reducing the ability to balance electricity supply and demand. The use of hydrogen as a fuel carries major environmental advantages because there are a number of ways of producing it by low-carbon methods. When electrolysis is used, additional benefits are obtained by flexible operation that offers the opportunity to reduce the cost of hydrogen production by absorbing electricity during off-peak hours, and stopping operation during peak hours. This can also act as a tool in support of balancing electrical systems. Many studies have analysed the concept of applying electrolysers to counteract variable renewable energy generation, to supply grid services, and derive revenue from differences in peak and off-peak electricity prices (Saur and Ramsden, 2011; Steward et al., 2009; Biegel et al., 2014a; Biegel et al., 2014b; Petrollese et al., 2016; Valverde, Bordons and Rosa, 2016). These studies reveal that there are possibilities for electrolysers to absorb off-peak (lower cost) electricity for hydrogen production through the use of different electricity markets and electricity rate structures, as well as consuming surplus renewable energy. Hydrogen production from electricity systems with high wind energy penetration has been widely investigated, since such systems require a high level of flexibility to accommodate the fluctuations of wind power generation (Olateju and Kumar, 2011; Sánchez et al., 2012). Hydrogen is commonly proposed as a means of energy storage that can support the integration of renewable power sources into electricity networks (Carton and Olabi, 2010). Producing hydrogen from surplus energy was investigated for use in Ireland by Troncoso, Newborough and Gonzalez et al. (Troncoso and Newborough, 2011b; Troncoso and Newborough, 2011a; González, McKeogh and Gallachoir, 2004). Gonzalez et al. (2004) indicated that a cheap electricity price and an expensive hydrogen sale price is required to create a profit, whereas Troncoso and Newborough (2011) point out that profitability can be achieved if a certain amount of on-peak electricity is also absorbed to better amortize the device's costs.

7.2 Electricity tariff structure

Tariff structures can be used to incentivise the operating of electrolysers as controllable (dispatchable) loads. Part time (flexible) operation of electrolyser could meet both; possibility to reduce the hydrogen production cost (by absorbing energy during off-peak times, and stopping the operation during peak times) and also act as a tool in support of balancing electrical systems. The aim of this research is to investigate the opportunity of using electrolysis as a demand side Response technique and at the same time exploit the produced hydrogen as fuel with competitive price without any interruption of fuel supply at garage forecourts. Based on these aims this chapter compares the cost of hydrogen production by electrolysis at garage forecourts under both dispatchable and continuous operation, while ensuring no interruption of fuel supply to fuel cell vehicles. An optimisation algorithm is applied to investigate a hydrogen refuelling station in both dispatchable and continuous operation. Three scenarios are tested to see whether a reduced off-peak electricity price could lower the cost of electrolytic hydrogen. These scenarios are:

1. "Standard Continuous", where the electrolyser is operated continuously on a standard all-day tariff of 12p/kWh;
2. "Off-peak Only", where it runs only during off-peak periods in a 2-tier tariff system at the lower price of 5p/kWh;
3. "2-Tier Continuous", operating continuously and paying a low tariff at off-peak times (5p/kWh) and a high tariff (12p/kWh) at other times.

These tariffs (5p/kWh and 12p/kWh) have been extracted from actual data from large electricity companies in the UK such as British Gas, EDF Energy, E.ON, Npower, Scottish Power and SSE. All these companies' electricity tariffs are very similar and close to the suggested values in this research.

7.3 Hydrogen refuelling station (HRS) design

There are two types of hydrogen production facilities to be considered:

1. Centralised plants
2. Decentralised plants (Estermann, Newborough and Sterner, 2016).

The latter being at the point of retail sale. From centralised facilities, the hydrogen is transported to the hydrogen filling station via rail, truck or pipeline. With on-site decentralised production, hydrogen can be produced, stored and fed into the station at the same location. Installing a huge central electrolyser could minimize the production cost of hydrogen due to economies of scale. However, hydrogen density is low in contrast with conventional fuels such as gasoline and natural gas, so to deliver the hydrogen at the same energy density of fossil fuel, the transportation cost between the central electrolyser and the hydrogen filling station would be costly and bulky. Since the decentralised hydrogen production option eliminates the requirement of building a large central electrolyser and the associated challenges in distributing the hydrogen to end-user, it becomes a preferable option before a fully mature hydrogen-fuelled vehicle market is established. Figure 7.1 below shows a completed hydrogen refuelling station with on-site electrolysis. It consists of five main parts: production (electrolyser), compression, storage, dispensing and ancillary equipment (Xu et al., 2016)

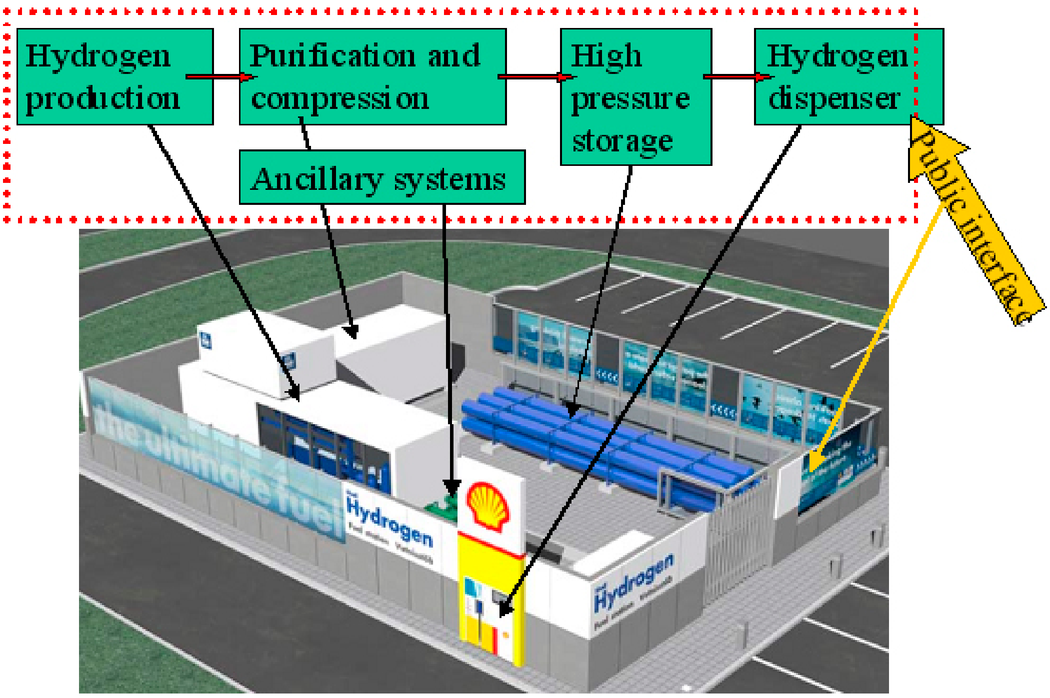


Figure 7.1: Hydrogen filling station parts

7.4 Cost component assumptions

As it is discussed in Chapter 4, it is difficult to obtain accurate costs from companies, due to commercially sensitive nature of the information.

Most research in this area tries to use the analysis methods to estimate the investment cost that are based on some historical data or company surveys. The estimates, therefore, include some extrapolation to scale-up the costs to commercial electrolysis units. This research, like other studies before, will depend on recent capital cost estimations and two types of electrolysers will be used (alkaline and PEM).

Two cost scenarios for each electrolysis system will be applied. These scenarios are the 2015-Cost scenario and the 2030-Cost scenario. The 2015-Cost and 2030-Cost assumptions are derived from many studies and reports (Menanteau et al., 2011; Bertuccioli et al., 2014; Li et al., 2017; Parks et al., 2014; Levene, 2005). Only the electrolyser price will make a difference between the electrolysis systems since other component prices will be equal. A summary of these scenarios are presented in Table 7.1 and Table 7.2 below.

Alkaline Scenarios	**2015**	**2030**
Electrolyser Cost ($\boldsymbol{E_C}$) ($£/kw$)	900	500
Electrolyser Energy Requirement (E_F)($kWh/kg\ H2$)	54.6	50
Storage Tank Cost (S_S) (£/kw)	586.39	258
Compressor Cost ($\boldsymbol{C_c}$) , 1500 kg ($£/compression\ system$)	387070	240,000
Compressor Electricity requirement ($kWh/kg\ H2$)	3.3	2.66
Dispensing Cost (D_C)(£) for a system with 3 dispensers)	43223	29000
Control and Safety Equipment (£)	19,000	15,000

Table 7.1: Cost assumptions different scenarios of the hydrogen refuelling stations (Alkaline electrolyser)

PEM Scenarios	2015	2030
Electrolyser Cost (E_C) ($£/kw$)	1800	800
Electrolyser Energy Requirement (E_F)($kWh/kg\ H2$)	54.6	47
Storage Tank Cost (S_S) (£/kw)	586.39	258
Compressor Cost (C_c) , 1500 kg ($£/compression\ system$)	387070	240,000
Compressor Electricity requirement ($kWh/kg\ H2$)	3.3	2.66
Dispensing Cost (D_C)(£) for a system with 3 dispensers)	43223	29000
Control and Safety Equipment (£)	19,000	15,000

Table 7.2: Cost assumptions different scenarios of the hydrogen refuelling stations (PEM electrolyser)

The target of this research is building a model with flexible control of input; this means accurate data can be added easily to the system once they are obtained without reconfiguration the model. The system cost can be divided into: capital cost, fixed cost and operation cost. Exchange rate was 1 GBP = 1.5501 US. The component cost is based on the costs presented in Table 7.1 and Table 7.2.

7.4.1 Capex of the HRS at the garage forecourts

The capital cost of the hydrogen system components at the garage forecourts includes the cost of electrolyser, storage, compressor and dispenser. All costs based on the 2015-Cost scenario are presented in Equations (7.1) to (7.6) below (Saur et al., 2013).

$$R_P = D_{HP} \times E_F/24 \quad (7.1)$$
$$E_{TC} = R_P \times E_C \quad (7.2)$$
$$S_{TC} = (S_S \times E_F/24) \times (S_C) \quad (7.3)$$
$$C_{Tc} = (C_S/1500) \times C_{mc} \quad (7.4)$$
$$D_C = 43223\ £ \quad (7.5)$$
$$C_C = E_{TC} + S_{TC} + C_{Tc} \quad (7.6)$$

Equations 7.1 to 7.6 summarise the total capital cost of the forecourt, which include the costs of the electrolyser, storage, dispenser and compressor. Equation 7.1 calculates the required system power; equation 7.2 calculates the electrolyser capital cost; equations 7.3 and 7.4 calculate the required storage size and the storage cost respectively; and equations 7.5 and 7.6 calculate the dispenser cost and compressor cost respectively.

7.4.2 Fixed cost

These costs are not high and have been ignored for many research studies. It includes the general and administrative (G&A) rate (% of labour cost), G&A ($/year) Licensing, Permits and Fees ($/year), Property tax and insurance rate (% of total capital investment/year), Property taxes and insurance ($/year), Rent ($/year), Material costs for maintenance and repairs ($/year), and Production Maintenance and Repairs ($/year). The fixed cost is extracted from the H2A model after some scaling steps (Saur et al., 2013). In all these scenarios, the capex and fixed cost will be financed by bank loans with a 5% interest rate over seven years. This year is one of the seven years of the loan period. The total return of investment after 7 years per station can be calculated using Equation (7.7) below:

$$I_{DC} = (C_C + fixed\ cost) \times (1 + ir)^Y \tag{7.7}$$

Since the simulation is only for one year. The cost should be annualised and the daily cost can be calculated as a follows:

$$Y_P = I_{DC}/7 \tag{7.8}$$
$$D_P = Y_P/N_D \tag{7.9}$$

Where: ir is the interest rate is assumed to be 0.05. These values of interest are determined by the central bank of Libya since most Libyan banks are controlled by the government so this value is constant between all banks. Y is the numbers of the years to pay back the loan to the bank with its interest which is 7 years, (medium period)(Central Bank of Libya, 2014). N_D is the number of days per year. In addition, the research year is one of the first seven years which means all components will be in a good condition. Based on these reasons, the maintenance cost will be excluded in this research. In this research, investment cost defines as the capital cost plus loan services.

7.4.3 Variable cost

The main part of this cost is the price of feedstock, which includes water, but is mainly electricity. In large electrolyser sizes the highest cost of the total comes from electricity, especially if the operation is during the whole day (on peak and off peak times) (Saur, 2008). The rest of these costs are water and compressor electricity. In terms of water, 11.8 litres of water are required to produce 1 kg of hydrogen based the assumption in the H2A model and a price per litre of £0.0029 /litre (Ebaid, Hammad and Alghamdi, 2015) so the cost of water (WC) can be computed as in Equation (7.10):

$$W_C = 11.8 \times 0.0029 \times D_{HP} \tag{7.10}$$

Based on the cost assumptions in Table 7.1, the electricity cost (EC) (electrolyser + compressor) can be computed as in Equation (7.11) below.

$$EL_C = E_P \times D_{HP} \times ((2.9 + 54.6) \tag{7.11}$$

Where 2.9 is the compressor electricity consumtion per 1kg of hydrogen.The daily total (DTC) cost can be calculated by using Equation (7.12) (Saur et al., 2013).

$$D_{TC} = I_{DC} + W_C + EL_C \tag{7.12}$$

The daily cost process can be summarised in the model below (Rahil, Gammon and Brown, 2018):

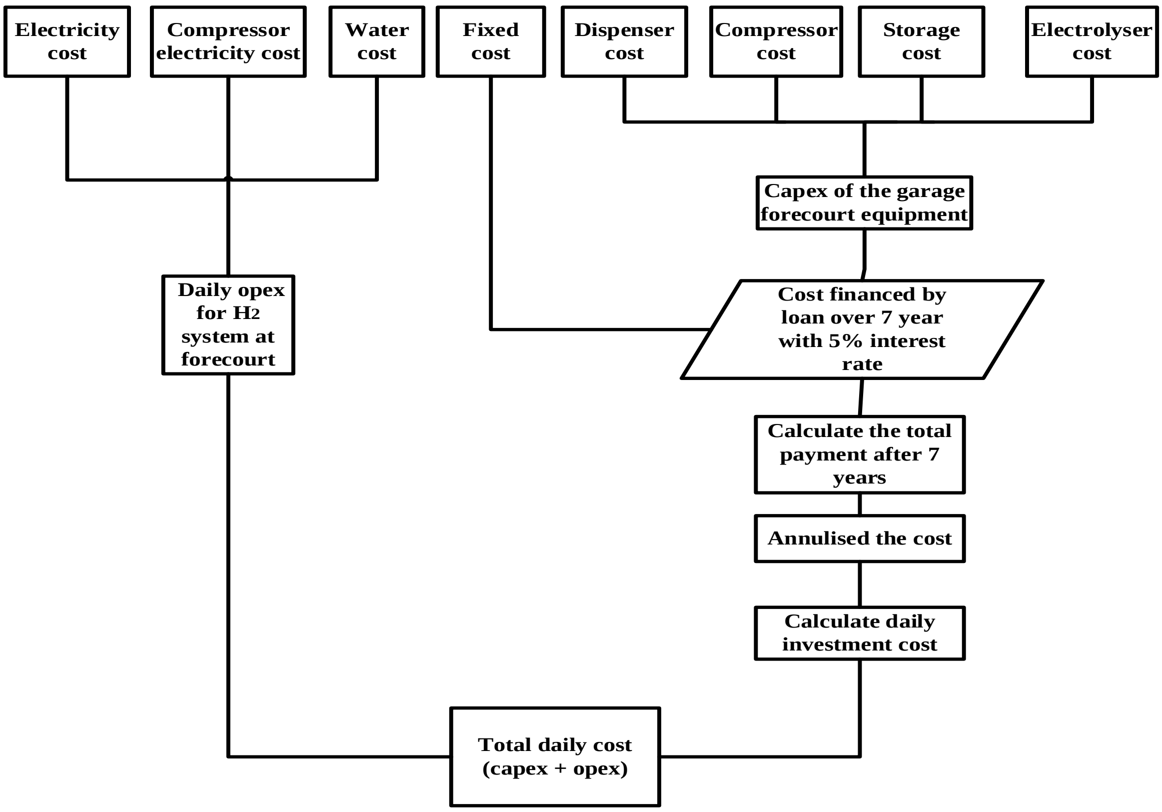


Figure 7.2: Summary of the system cost process

7.5 Optimisation

An optimisation problem is a problem in which certain parameters (design variables) need to be determined to achieve the best measurable performance (objective function) under given constraints. There are many applications of an optimisation system, which include:

1. Design: selecting the best parameters for the design, which lead to the best characteristics of a system, device or process
2. Planning, including:
   - Production plan: focusing on reducing the cost of the product
   - Financial plan: increasing the profit of the business
   - Task planning: reaching best performance
3. Manufacturing and control: achieving bets performances
4. Mathematical modelling: surface fitting or curve of the data to reduce the error.

There are multiple solutions of the problem and the best solution has to be sought. Also, there are one or more objective has to be achieved. Constraints should be imposed during the optimisation based on the system or process situation to guarantee best result (Pourmousavi et al., 2010; Marzband et al., 2014; Rahil, Gammon and Brown, 2017; Rahil and Gammon, 2017).

The main target of the process in this chapter is to reduce the hydrogen cost. Since the investment cost is fixed, the optimisation will focus on variable cost to reduce the hydrogen price. In this study, there are two sources of electricity with different prices, so the optimisation should focus on cheap electricity price as much as possible to achieve the target. There are some constraints such as electrolyser size, storage size and demand. Meeting the demand could be added as another objective of the optimisation. The optimisation target is to reduce the hydrogen cost by maximising the operation at cheap electricity price in Case 2 and Case 3 which have the opportunity to buy the surplus power at a reduced price. However, for Case 1, the system will run continuously at fixed price and the cheap hydrogen price will come from the small system size in contrast with other cases. All system objectives and constraints are linear, so linear programming can be used to solve the optimisation problem in this chapter.

The objective function is similar in all three scenarios, but electricity prices and energy sources may be different.

For example, in Case 1, the price is fixed at 12p /kWh so the energy source has no affect in this scenario but for Case 2, the price is different based on the energy source and time.

In Case 3, only surplus power will be used at 5p /kWh. MATLAB software is used to solve this problem.

At on-peak time, the system size will be small since the energy is available at any time and no need to have a large storage to store hydrogen as in off-peak operation, which requires a huge store for the hydrogen.

The objective function of the system should meet the following goals:

1- Fully utilise the surplus power;
2- Minimise the hydrogen cost;
3- Serve all customers without running out of fuel.

The constraints are as follows:

1- Capacity of the hydrogen tank, where the minimum value of the storage is the allowed minimum level in tank and the maximum is the maximum capacity of hydrogen tank;
2- Capacity of electrolyser, starting from zero until the full capacity of electrolyser.

According to the objectives and constraints, the formulation of the optimization problem is(Xiao et al., 2011):

$$f = min(C * (P)) \tag{7.13}$$

ST: $$0 \leq (P) \leq (cap_{electrolyser} \times 54.6)$$

$$Tank\_min \leq H_{intank} \leq Tank\_size$$

$$H_{intank} = H_{intank} + Hy_{pro} - Hy\_cons$$

$$Hy_{pro} = (P)/54.6$$

Where: C is electricity cost (£/kWh), P is the daily required energy (kWh), Hy_{pro} is the hydrogen production (kg) in day , Hy_cons is hydrogen consumption (kg) in day, $Tank\_min$ is allowed minimum level in tank (kg), $Tank\_size$ is Hydrogen storage size (kg), H_{intank} is current amount of hydrogen in tank (kg), $cap_{electrolyser}$ is the electrolyser size (kg/day). The required power will change based on the time (on-peak or off-peak) and the price will change as well.

The main difference between the optimisation technique in (Xiao et al., 2011) and in this research is that in this research due to the ambiguity of the electricity price in Libya because of government subsides , the ambiguity of the electricity price in Libya due to government subsidies, means that three different electricity tariffs have been used. These tariffs were extracted from large electricity suppliers in the UK in 2015 and were totally dependent on the time of use.

The second difference is the time pattern. In this research a daily pattern was used since the target was a long-term large-scale storage technique. Another point was added into this research in the number of stations.The test was carried out for only one station but in the current research six stations were considered and the demand supplied is shown in order of hierarchy from the highest to the lowest

7.6 HRS simulations with PEM electrolysis

Two cost scenarios will be tested for PEM electrolysis: 2015-Cost scenario and 2030-Cost scenario. The difference between these scenarios is the system components cost and electrolysis efficiency.

7.6.1 2015-Cost scenario

Three scenarios of energy price will be checked under the 2015-Cost scenario. The test will include the hydrogen demand satisfaction, the average hydrogen price and surplus energy absorption.

7.6.1.1 Standard Continuous scenario (all day tariff 12 p/kWh)

In this scenario all electrolysers are operated continuously on a standard all-day tariff (12 p/kWh). The Overall system configuration of this scenario is given in Figure 7.3 below.

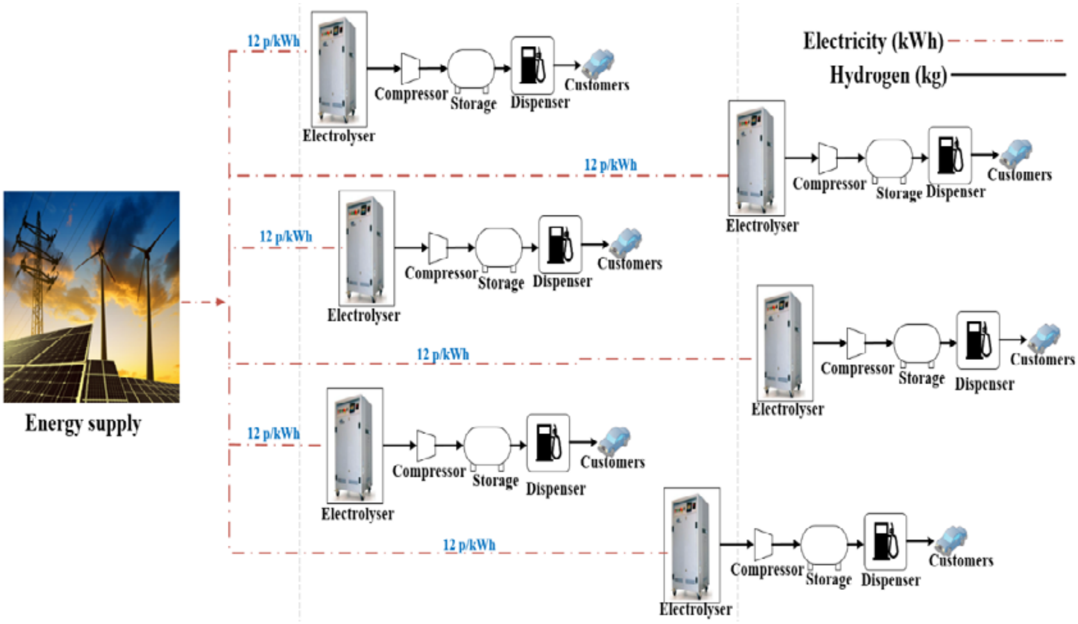


Figure 7.3: Overall of the system when standard tariff is applied

The choice of electrolyser capacity is based on the average consumption for each garage forecourt. Since the electrolysers are operating continuously, the storage tank size is equal to daily electrolyser output. As result, the difference in cost between these scenarios will be driven by both electricity price and storage tank price. The amount of hydrogen in the tank at the starting point is equal to 80% of the tank capacity and the allowed minimum level in tank is 20% of the storage size. Details of the six garage forecourts in this scenario are presented in Table 7.3 below:

Components / HRSs	Electrolyser capacity (kWh/day)	H_2 Storage tank (kg)			Compressor (kg/day)	Number of dispensers
		Max	Initial value	Min		
HRS 1	8120	149	111.75	29.8	150	3
HRS 2	12320	230	172.5	46	225	3
HRS 3	24500	450	337.5	90	450	3
HRS 4	15400	280	210	56	285	3
HRS 5	40600	740	555	148	745	3
HRS 6	20300	374	280.5	74.8	375	3

Table 7.3 : garage forecourts details when Standard Continuous scenario is applied (2015-Cost scenario)

The hydrogen production in Standard Continuous scenario for all hydrogen refuelling stations (HRS_S) is given in Figure 7.4 below.

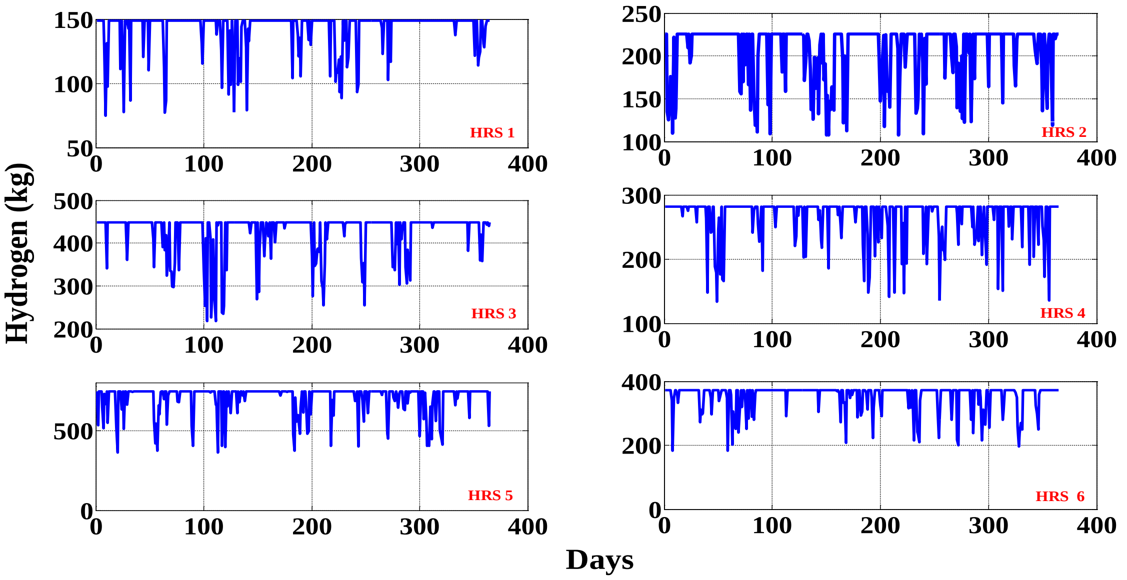


Figure 7.4: Hydrogen production per electrolyser throughout the year when Standard Continuous scenario is applied (2015-Cost scenario)

The capacity factor in this scenario is very high for all electrolysers since the operation is continuous. The capacity factor of all 6 electrolysers was 96%, 92%, 95%, 95%, 95%, and 95% for HRSs 1, 2, 3, 4, 5 and 6 respectively.

The storage is very small (only one-day storage) just to meet variations in demand throughout the day (24h period). The amount of hydrogen in the tank for all HRSs during the year is presented in Figure 7.5 below.

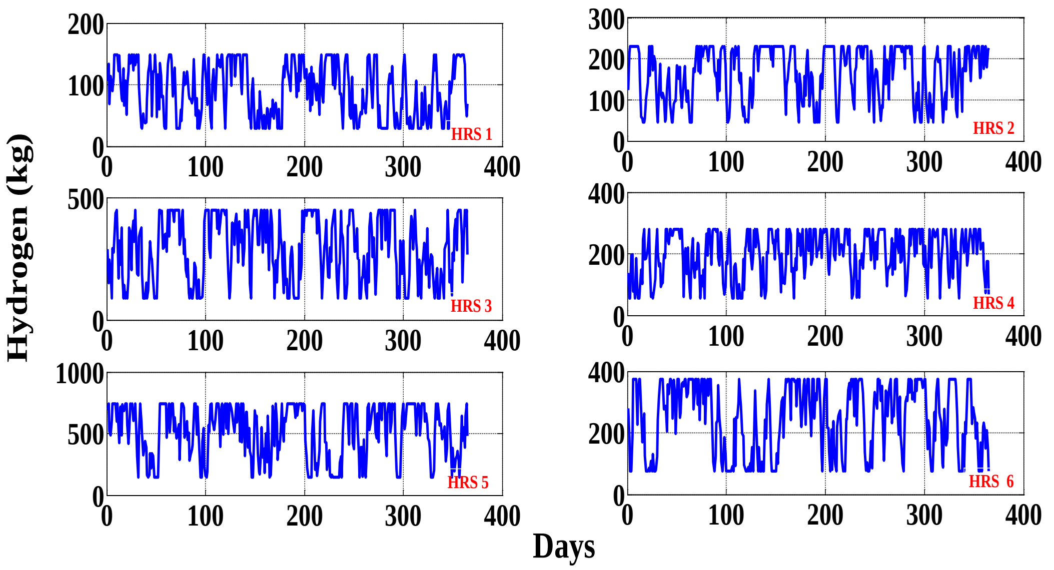


Figure 7.5: Hydrogen in tank per electrolyser throughout the year when Standard Continuous scenario is applied (2015-Cost scenario)

The assessments of this scenario will focus on two main parts: the degree to which hydrogen demand is satisfied and the hydrogen price. Hydrogen demand satisfication means the production should meet the HRSs demand throughout the year and at the same time the price should be competitive with the conventional fuel price. Figure 7.6 below shows the total hydrogen consumption and production during the year for all HRSs.

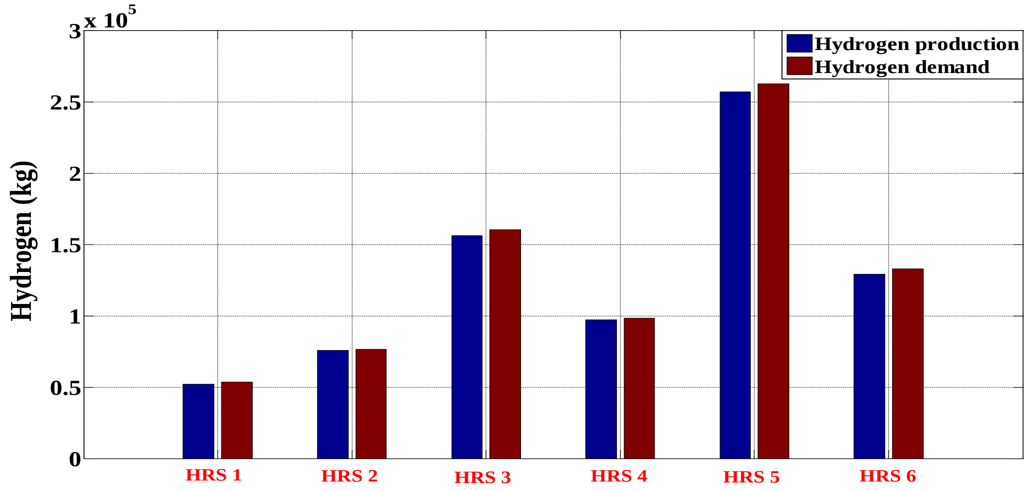


Figure 7.6: Total hydrogen production and consumption throughout the year

Nearly 97%, 99, 97%, 99%, 98%, and 97% of hydrogen consumption for HRSs 1, 2,3,4,5 and 6 respectively are met during this scenario. The rest of consumption can be met via an external source or by increasing the storage size to accommodate exceptional hydrogen production. However, increasing the size of storage to cover such rare shortages is not an economic option and this shortage should be consider as a planned shortage for maintenance. The hydrogen cost calculation is summarised in Table 7.4.

Cost / **HRSs**	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average electricity cost** (£/kg)	**Average hydrogen price** (£/kg)
HRS 1	181,292	1,783	20,634	341,394	52,105	6.60	10.50
HRS 2	271,624	2,593	30,011	496,546	75,785	6.60	10.60
HRS 3	529,592	5,346	61,861	1023514	156,214	6.60	10.40
HRS 4	335,347	3,331	38,544	637721	97,332	6.60	10.40
HRS 5	870,367	8,790	101,721	1683023	256,872	6.60	10.40
HRS 6	440,601	4,414	51,081	845156	128,992	6.60	10.40

Table 7.4: Hydrogen production cost details for each HRS when Standard Continuous scenario is applied (2015-Cost scenario)

The cost details for all HRSs are shown in Figure 7.7 below.

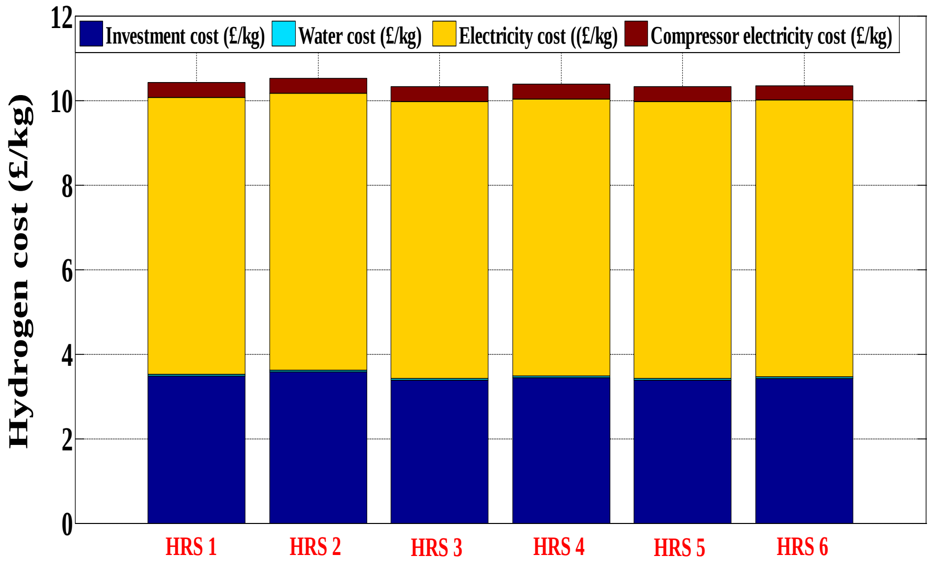


Figure 7.7: Hydrogen cost breakdown per kilogram at each HRS when Standard Continuous scenario is applied (2015-Cost scenario)

The electricity cost in the Standard Continuous Scenario (12 p/kWh) represents nearly 63% of the total hydrogen production cost for all HRSs.

7.6.1.2 "2-Tier Continuous", operating scenario

In the "2-Tier Continuous" Scenario, the electrolyser operates operating continuously and pay low tariff (5 p/kWh) at off-peak times and a high tariff (12 p/kWh) at other times. Figure 7.8 shows the details of the system in this scenario.

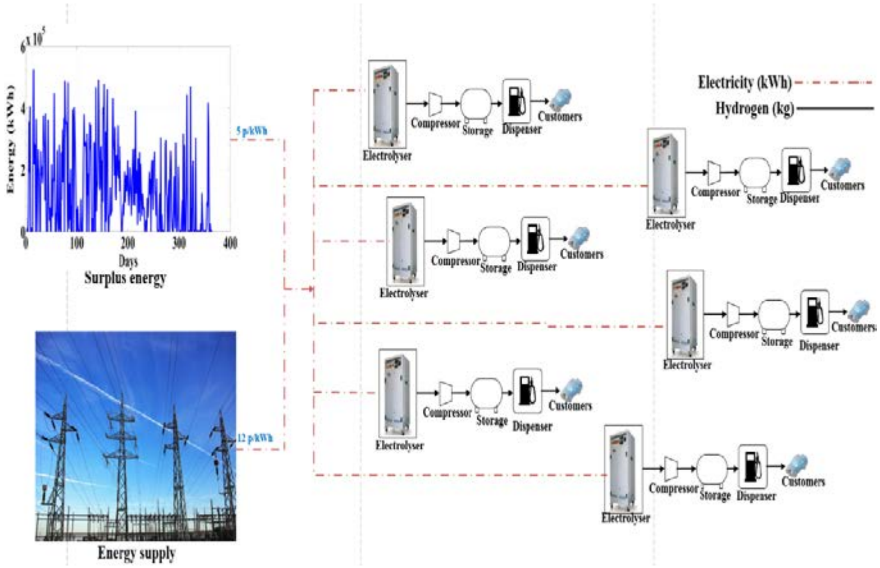


Figure 7.8: Overall system in 2-Tire Continuous scenario (2015-Cost scenario)

The optimization model in this scenario will focus on absorbing the energy at off-peak times and storing the rest to avoid buying expensive electricity during the on-peak times. However, this technique will lead to an increase the storage size, which will directly affect the capital cost of the system.

The cost assumptions and size of components is still the same as in Table 7.1 and Table 7.2. Only storage size will be increased to accommodate the surplus power absorption. The storage size is four times the capacity of each electrolyser, because many times during the year there are five following days without any surplus power. The amount of hydrogen in the tank at the starting point is equal to 80% of the tank capacity and the allowed minimum level in tank is 20% of the storage size. The system components are given in Table 7.5.

components / **HRSs**	**Electrolyser capacity** (kWh/day)	**H_2 storage tank** (kg)			**Compressor** (kg/day)	**Number of dispenser**
		Max	**Initial value**	**Min**		
HRS 1	8120	594.9	475.9	119	150	3
HRS 2	12320	902.6	722.1	180.5	225	3
HRS 3	24500	1794.9	1435.9	359	450	3
HRS 4	15400	1128.3	902.6	225.6	285	3
HRS 5	40600	2974.4	2379.5	594.9	745	3
HRS 6	20300	1487.2	1189.7	297.4	375	3

Table 7.5 : The garage forecourts details when 2-Tire Continuous scenario is applied (2015-Cost scenario)

All previous equations will be applied in this scenario taking into account the electricity price differentiation because it consists of two values based on the used energy (on or off) peak and also the cost of storage will be higher in this scenario.

The optimisation system will focus on importing surplus power as much as possible to avoid buying at on peak times. The demand supplied is shown in order of hierarchy from the highest to the lowest. Figure 7.9 and Figure 7.10 show cumulative energy consumption at garage forecourts during on- peak and off-peak periods respectively. The design of this optimization will focus on reducing variable cost (mainly electricity) to reduce the total hydrogen cost. At off-peak times, there are no clear criteria by which to choose the first HRS to be supplied. Because of the fixed price of electricity at off-peak times (5 p/kWh), the HRS with the highest demand will be provided for first each day.

This criterion allows for the interpretation of the case shown in Figure 7.10, which is that the HRS with the highest consumption absorbs the largest amount of surplus energy.

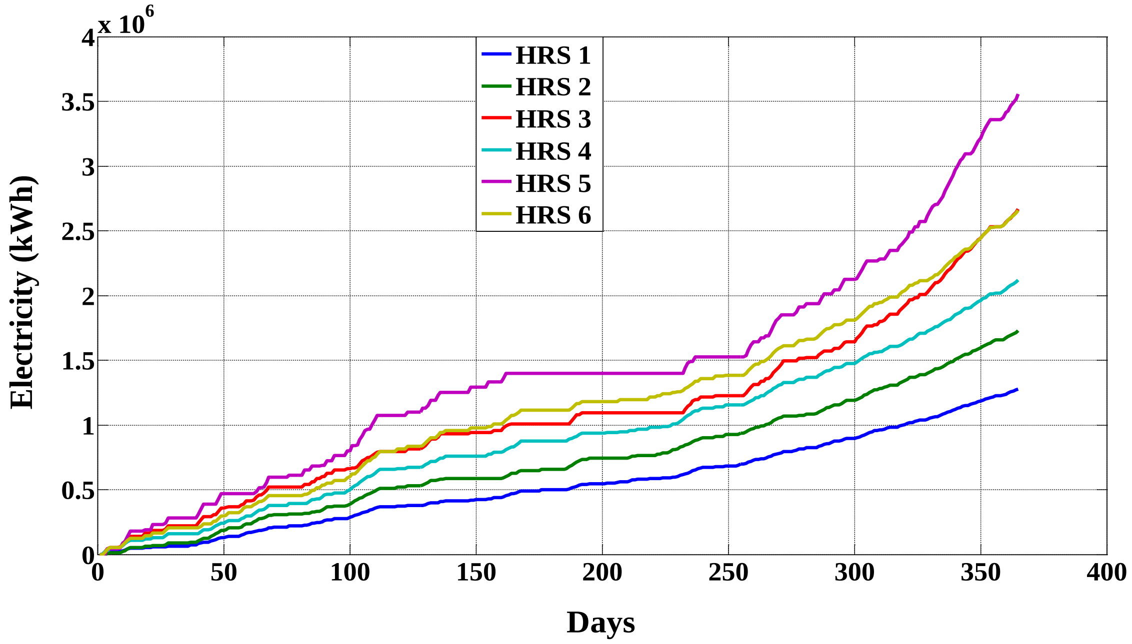


Figure 7.9: Cumulative on-peak energy consumption for each HRS

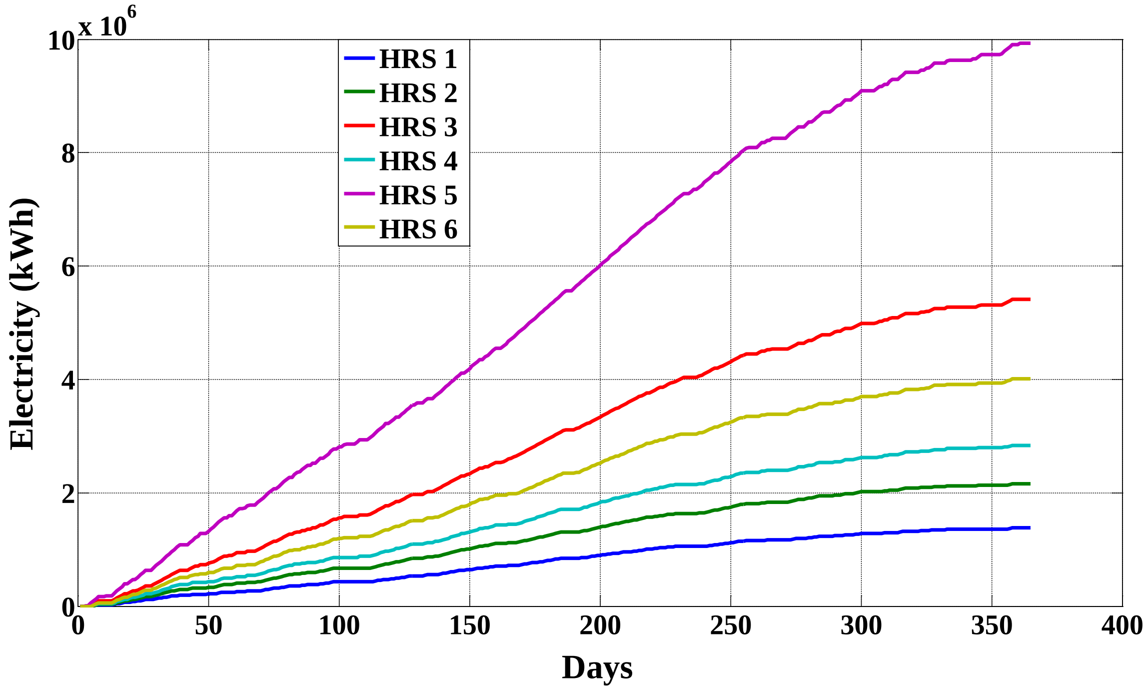


Figure 7.10: Cumulative off-peak energy consumption for each HRS

Figure 7.11 shows the total hydrogen production (on-peak and off-peak) during the course of the year.

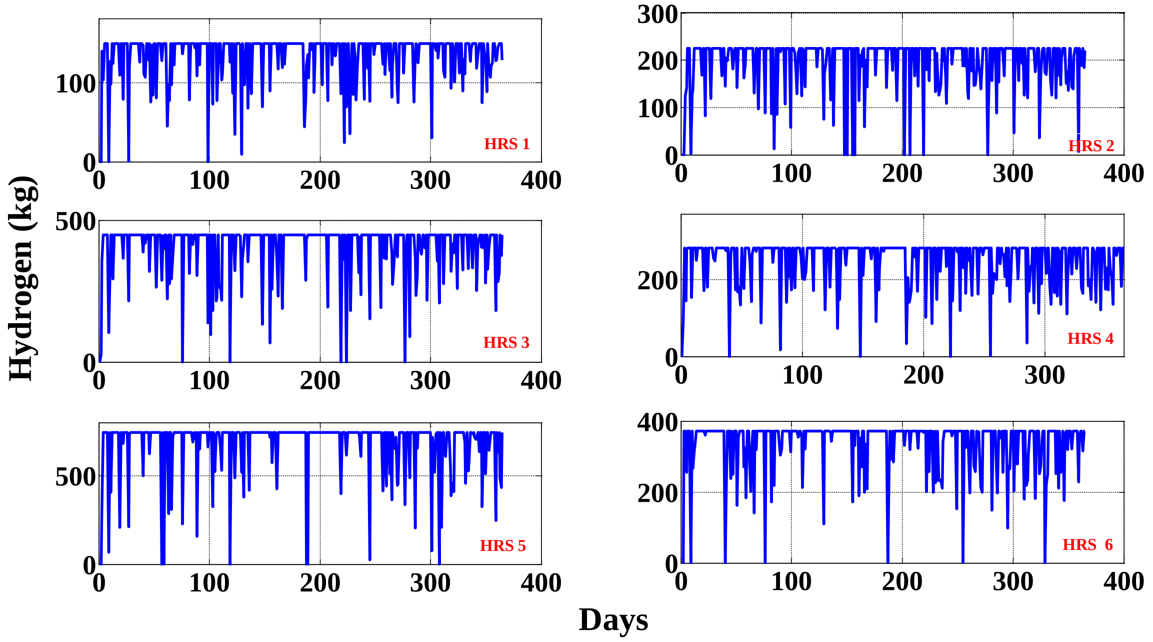


Figure 7.11: Hydrogen production throughout the year when 2-Tire Continuous scenario is applied (2015-Cost scenario)

Hydrogen storage variation in the tank for each garage forecourt is shown in Figure 7.12 below.

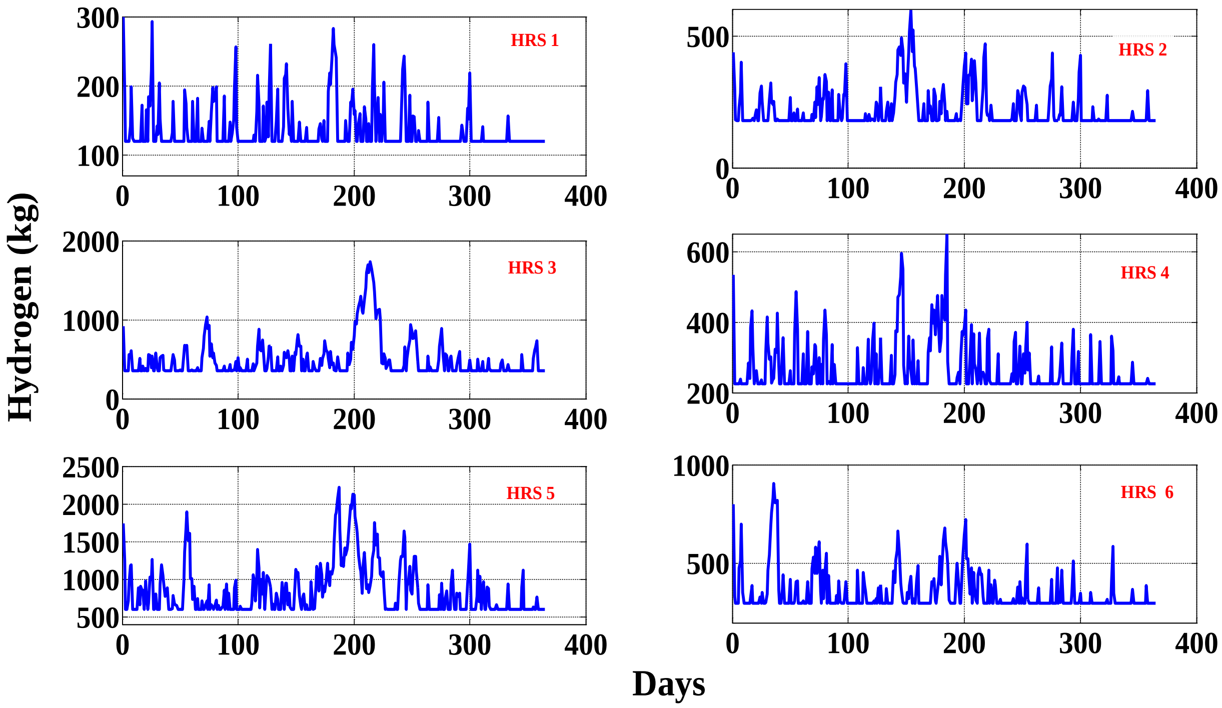


Figure 7.12: Storage variation throughout the year for all garage forecourts when 2-Tire Continuous scenario is applied (2015-Cost scenario)

The total hydrogen production, in contrast with the total consumption during the year, is similar to the Standard Continuous scenario but with different hydrogen price since the electricity price in this scenario is variable. Nearly 97%, 99, 97%, 99%, 97%, and 96% of hydrogen demand for HRSs 1, 2,3,4,5 and 6 are met during this scenario. The hydrogen cost details can be seen in Table 7.6 below:

Cost / **HRSs**	**Investment cost** (£/year)	Water cost (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average electricity** cost (£/kg)	**Average hydrogen** price (£/kg)
HRS 1	300,858	1,666	13,438	222,334	48,676	4.60	11.00
HRS 2	451,980	2,439	19,063	315,403	71,260	4.40	11.00
HRS 3	890,233	5,062	35,694	590,573	147,936	4.00	10.20
HRS 4	562,802	3,107	23,955	396,345	90,799	4.40	10.90
HRS 5	1,469,535	8,454	55,802	923,271	247,056	3.70	9.90
HRS 6	739,112	4,179	31,400	519,535	122,125	4.30	10.60

Table 7.6 : Hydrogen production cost details for each HRS when 2-Tire Continuous scenario is applied (2015-Cost scenario)

The average electricity cost dropped in this scenario from nearly £6/kg at standard continues price to nearly £4.5/kg. However, the total cost is increased because of the storage cost (increased 4 times). The details of the hydrogen cost are given Figure 7.13 below.

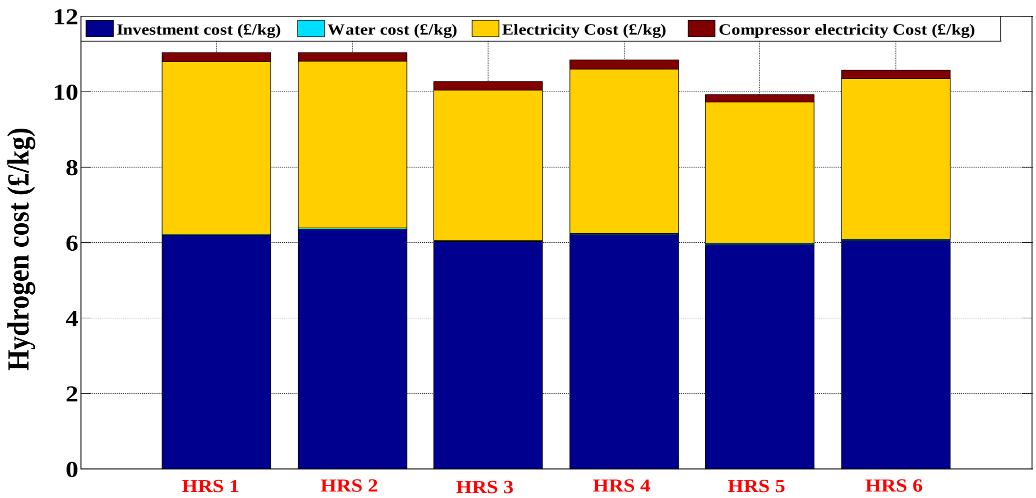


Figure 7.13: Hydrogen cost breakdown per kilogram at each HRS when 2-Tire Continuous scenario is applied (2015-Cost scenario)

The electricity cost in this scenario represents nearly 42%, 40%, 39%, 41%, 37%, 41 of the total hydrogen produced cost at garage forecourts 1, 2,3,4,5 and 6 respectively in contrast with nearly 63% in last scenario. Figure 7.13 shows that the cheapest hydrogen price is in HRS 5. One of the main reasons for this is the huge amount of surplus energy consumed at cheap price as is shown in Figure 7.10.

7.6.1.3 "Off-peak Only" scenario

In this scenario electrolysers run only during off-peak periods at the lower price of 5 p/kWh. Figure 7.14 below shows the overall system.

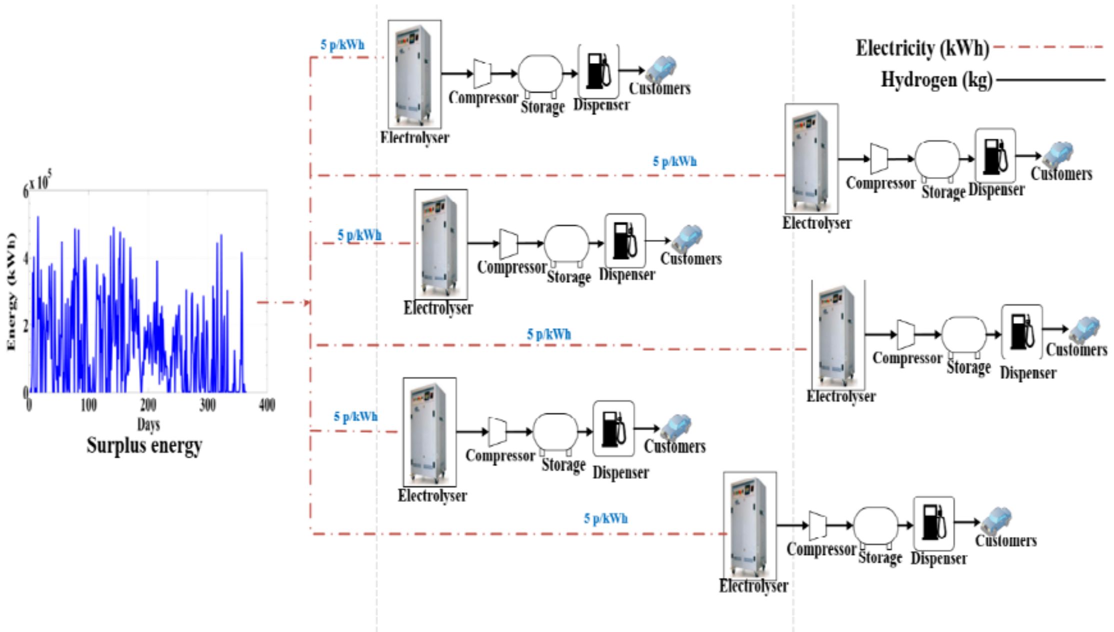


Figure 7.14: Overall system in Off-peak only scenario (2015-Cost scenario)

All assumptions of components and costs in in Table 7.1 and Table 7.2 will be applied as well as Equations (7.1 - 7.12). In this scenario, the electrolyser capacity will be the same but the storage tank will be optimized based on the daily production and consumption. This means the electrolysers will be operated as long as there is surplus energy and under the electrolyser capacity limits. Only storage size will be increased to accommodate the surplus power absorption. The storage size is four times the capacity of each HRS. Nearly 80% of initial value is in the tank at the beginning of the simulation and minimum limit in tank is 20% of the storage size. Storage tank size is related to the most continuous shortage of surplus energy between days. The system components details are given in Table 7.7 below.

Components / HRSs	Electrolyser capacity (kWh/day)	H_2 Storage tank (kg)			Compressor (kg/day)	Number of dispenser
		Max	Initial value	Min		
HRS 1	8120	594.9	475.9	119	150	3
HRS 2	12320	902.6	722.1	180.5	225	3
HRS 3	24500	1794.9	1435.9	359	450	3
HRS 4	15400	1128.3	902.6	225.6	285	3
HRS 5	40600	2974.4	2379.5	594.9	745	3
HRS 6	20300	1487.2	1189.7	297.4	375	3

Table 7.7 : The garage forecourts details when Off-peak Only is applied (2015-Cost scenario)

Figure 7.15 below shows the off-peak energy consumed at each garage forecourts throughout the year.

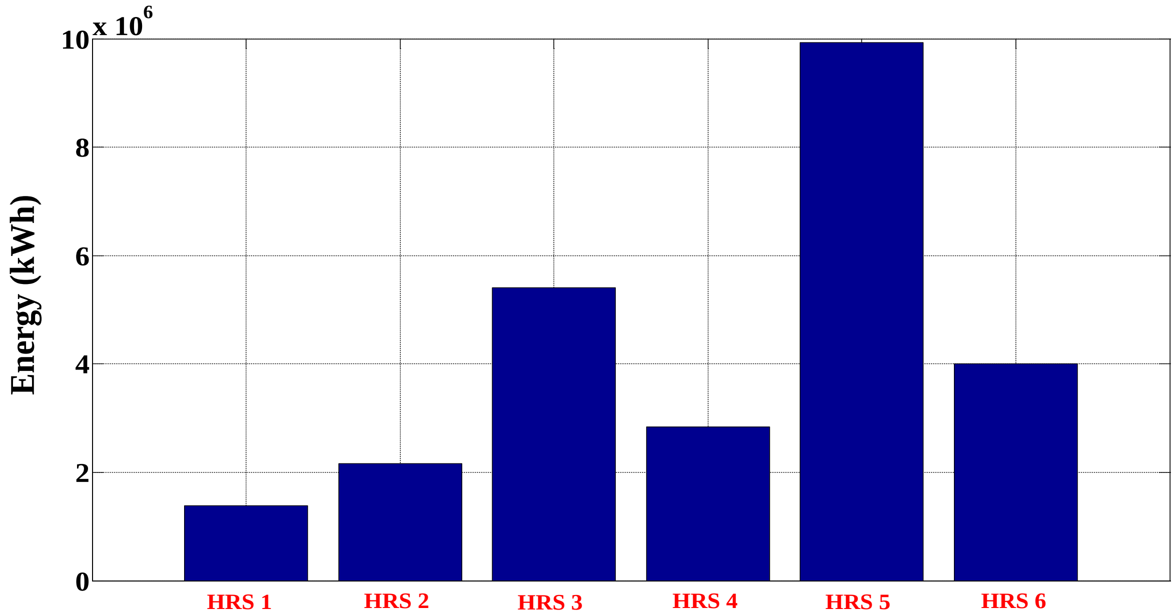


Figure 7.15: Total energy consumed via garage forecourts throughout the year when Off-peak Only is applied (2015-Cost scenario)

This energy represents nearly 54% of the total available surplus energy, which means that other energy storage method such as batteries can be used to absorb the rest, and this may be sold to HRSs at times of power deficit. Alternatively, a central electrolyser could be added to the system to consume the rest of the surplus energy and produce hydrogen for times of shortage at the garage forecourts but in both cases (battery storage and central electrolyser) will lead to an increase the hydrogen price. Hydrogen production in comparison with hydrogen demand is shown in Figure 7.16 below.

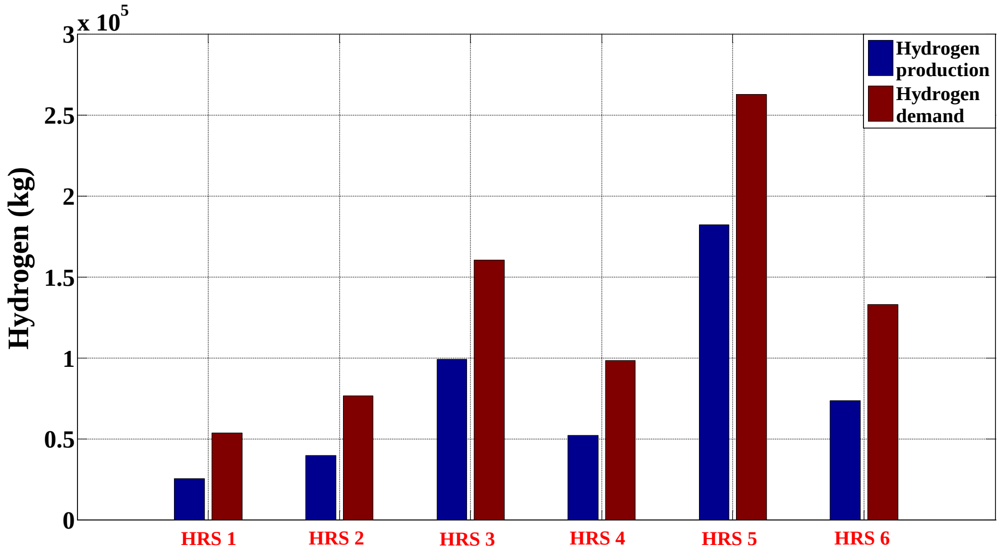


Figure 7.16: total hydrogen production and consumption throughout the year when Off-peak Only is applied (2015-Cost scenario)

Hydrogen production in this case can meet 47%,52%,62%,53%,69%,55% of the hydrogen demand of HRSs 1,2,3,4,5,6 respectively. However, the rest of the surplus power is quite enough to meet the demand totally. Figure 7.17 shows the garage forecourts' hydrogen production throughout the year (only off-peak production scenario)

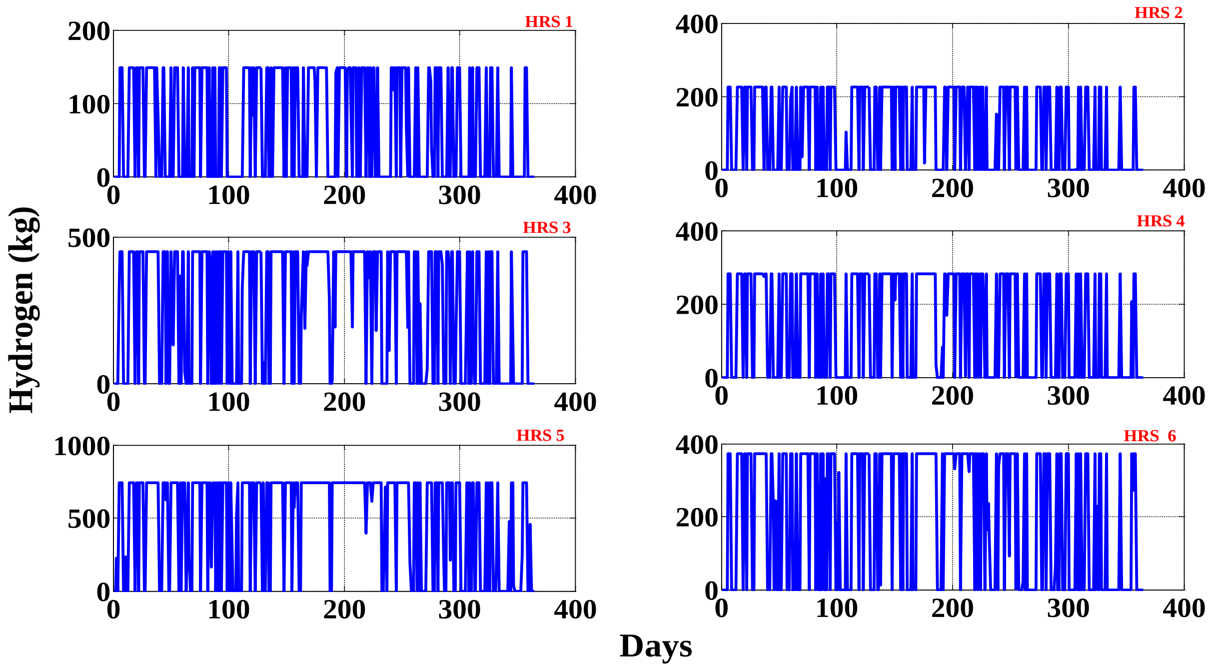


Figure 7.17: Hydrogen production per electrolyser throughout the year when Off-peak Only is applied (2015-Cost scenario)

Hydrogen level variation in the tank throughout the year is given in Figure 7.18 below.

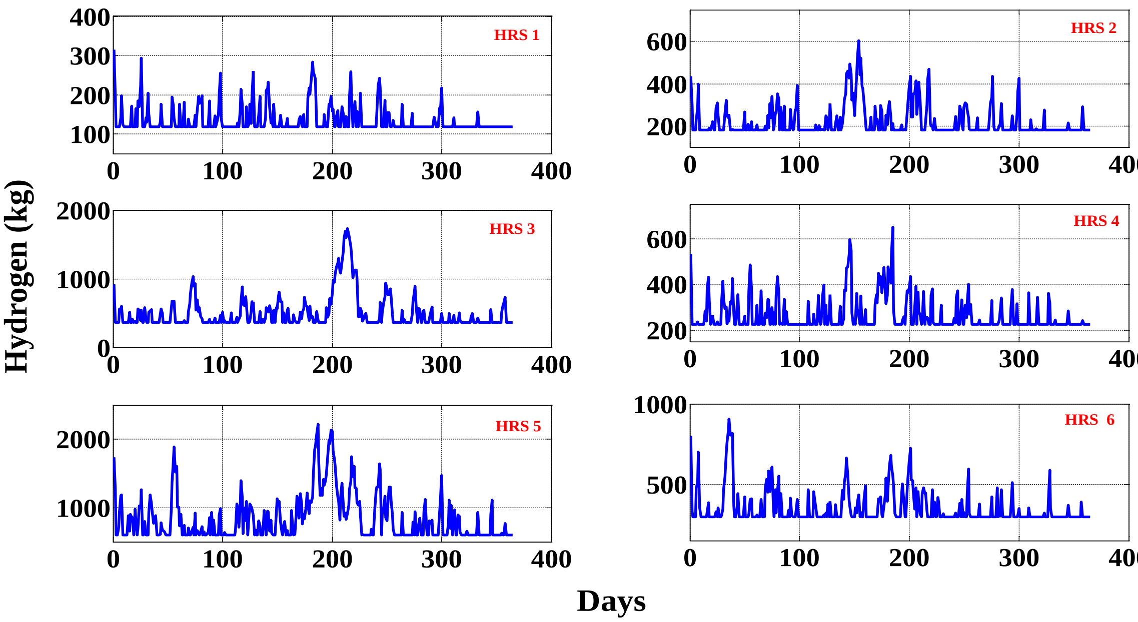


Figure 7.18: Storage variation throughout the year for all garage forecourts when Off-peak Only is applied (2015-Cost scenario)

Any deficient must be met using an external source or the electrolyser size can be increased but this will dramatically increase the investment cost. More work will be applied in coming chapters to focus on satisfying the demand at periods of shortage. Table 7.8 shows the details of hydrogen cost.

Cost / HRSs	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity off-peak) cost** (£/year)	**Hydrogen production** (kg/year)	**Average electricity cost** (£/kg)	**Average hydrogen price** (£/kg)
HRS 1	300,858	865	4,170	68,994	25,273	2.73	14.80
HRS 2	451,980	1,356	6,540	108,210	39,637	2.73	14.30
HRS 3	890,233	3,391	16,349	270,502	99,085	2.73	12.00
HRS 4	562,802	1,778	8,572	141,834	51,954	2.73	13.80
HRS 5	1,469,535	6,227	30,023	496,743	181,957	2.73	11.00
HRS 6	739,112	2,513	12,115	200,450	73,425	2.73	13.00

Table 7.8 : Hydrogen production cost details for each HRS when Off-peak Only is applied (2015-Cost scenario)

In this scenario, the electricity price per kg is the cheapest among the three scenarios. However, the average hydrogen price at some HRSs is a bit expensive, which is logical since the hydrogen production is less than in the other two scenarios. The challenge of this work is to meet the hydrogen demand without interruption at competitive price. The share of each component in the total cost of hydrogen is given in Figure 7.19 below:

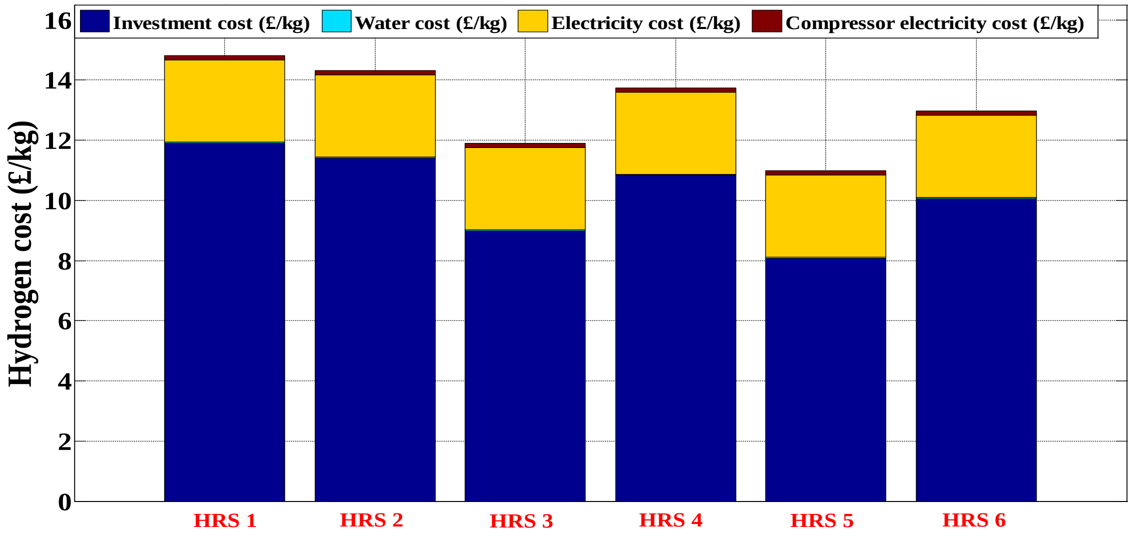


Figure 7.19: Hydrogen cost breakdown per kilogram at each HRS when Off-peak Only is applied (2015-Cost scenario)

The electricity cost share in this scenario represents 18%, 19%, 23%, 20%, 25%, and 21% for HRSs 1, 2, 3,4,5,6 respectively, which are the cheapest prices between all scenarios. The highest share in the hydrogen cost becomes the investment cost, rather than electricity cost, in contrast with the other two scenarios. The average hydrogen price is still in between the prices of the other two scenarios. However, the problem with this scenario is that these system component sizes cannot fully meet the hydrogen demand. A general comparison between the three scenarios in terms of average electricity price per kg and the average hydrogen price for each HRS is given in Table 7.9

Scenarios	Standard Continuous		2-Tier Continuous		Off-peak Only	
	Average electricity price (£/kg)	**Average hydrogen price** (£/kg)	**Average electricity price** (£/kg)	**Average hydrogen price** (£/kg)	**Average electricity price** (£/kg)	**Average hydrogen price** (£/kg)
HRS 1	6.60	10.50	4.60	11.00	2.73	14.8
HRS 2	6.60	10.60	4.40	11.00	2.73	14.3
HRS 3	6.60	10.40	4.00	10.20	2.73	12.00
HRS 4	6.60	10.40	4.40	10.90	2.73	13.80
HRS 5	6.60	10.40	3.70	9.90	2.73	11.00
HRS 6	6.60	10.40	4.30	10.60	2.73	13.00

Table 7.9 : Three scenarios average electricity and hydrogen price per kg for each HRS

7.6.2 2030-Cost scenario

In this scenario, the estimated cost of 2030 will be used. Generally, this scenario will directly affect the investment cost since the cost of expensive parts of the hydrogen system will be reduced. The 2030-cost scenario is presented in Table 7.2 . The same price of electricity scenarios will be tested in 2030-cost scenario. This scenario will affect two main parts: the energy consumed and the average price of hydrogen. In terms of energy, the production will be increased with less consumption of energy due to the electrolysis efficiency improvement. Hydrogen price will be reduced due to the lower price of components in future.

7.6.2.1 Standard Continuous scenario (all-day tariff of 12-p/kWh)

In this scenario, all electrolysers are operated continuously on a standard all-day tariff (12 p/kWh). The size assumption will be the same as in 2015-Cost scenario. The cost and the electrolyser efficiency of the 2030-Cost scenario is given earlier in Table 7.1. Hydrogen production will be increased since the electrolysers' efficiency improved (from 54.6 kWh/kg to 47 kWh /kg) as shown in Figure 7.20.

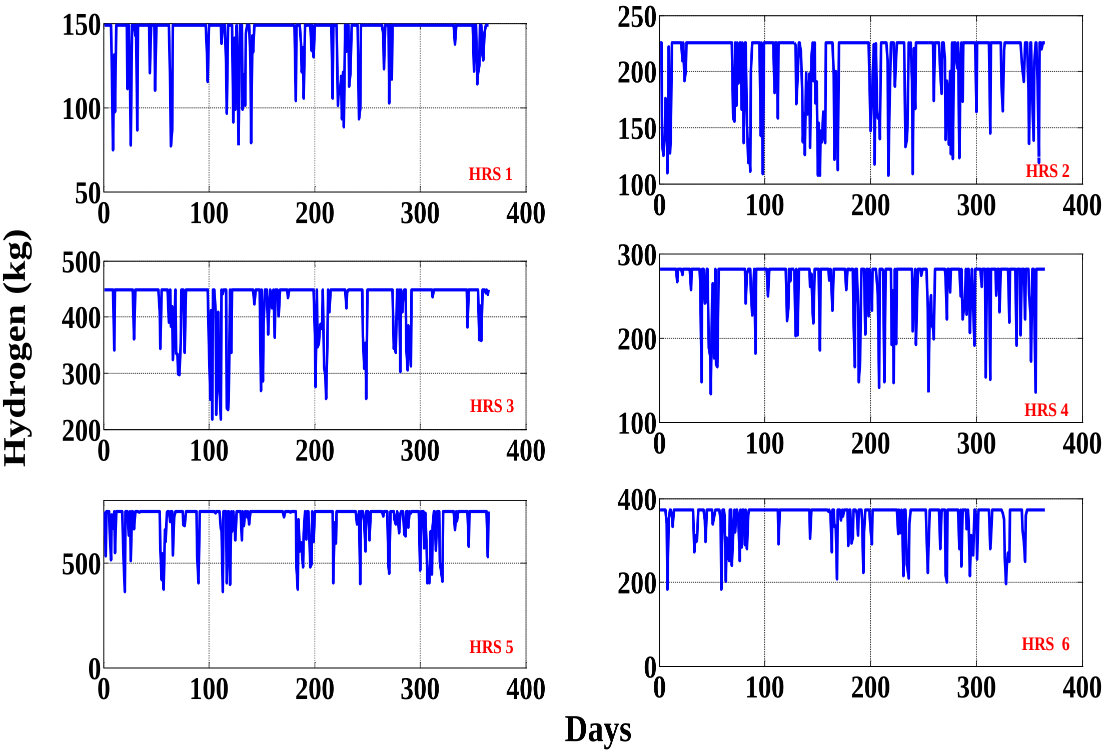


Figure 7.20: Hydrogen production for each electrolyser throughout the year (Standard Continuous under 2030-cost scenario)

The capacity factor of electrolysers in this scenario is very high and higher than the 2015-Cost price scenario because of the efficiency improvement for all electrolysers since the operation is continuous.

The capacity factor of the six electrolysers was 96%, 91%, 95%, 95%, 95%, and 95 % for HRS 1, 2, 3, 4, 5 and 6 respectively.

The storage capacity is very small (only one-day storage) just to meet any temporary peaks in demand that could happen any time within a 24-h period.

The hydrogen in the tank for each HRS throughout the year is presented in Figure 7.21 below.

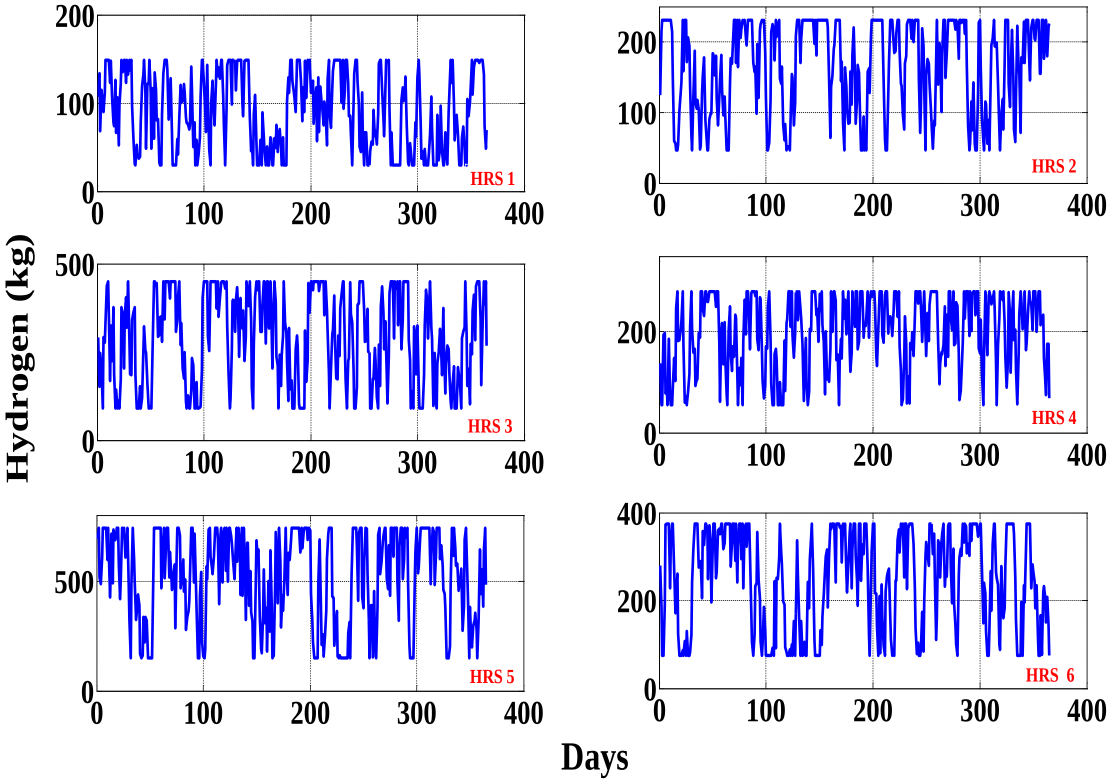


Figure 7.21: Hydrogen in tank for each HRS throughout the year (Standard Continuous under 2030-cost scenario)

The same objectives should be meet in the 2030 scenario, which are to meet the fuel demand throughout the year without interruption and at a competitive price compared with conventional fuel.

Figure 7.22 below shows the total hydrogen consumption and production throughout the year for each HRS.

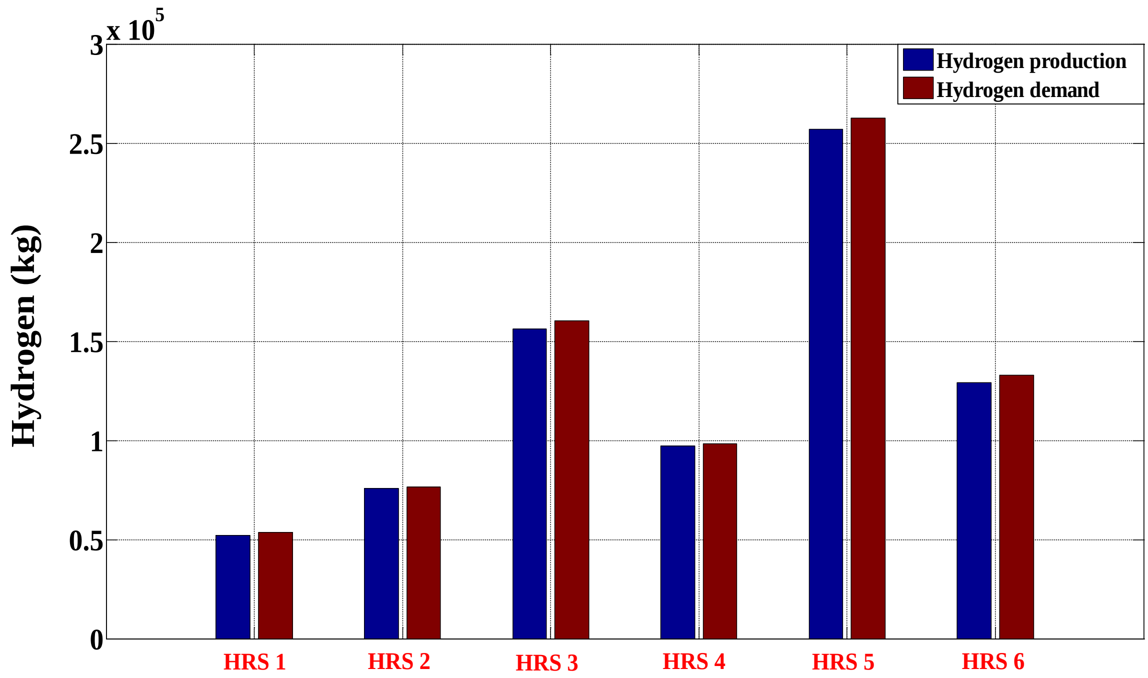


Figure 7.22: Total hydrogen production and consumption throughout the year

Hydrogen production can meet 97%, 99%, 98%, 99%, 98% and 97% of the hydrogen demand of HRS 1, 2,3,4,5 and 6 respectively.

This value is a bit higher than the same case in the 2015-Cost scenario due to the anticipated efficiency improvements. The hydrogen cost calculation is summarised in Table 7.10.

Cost / **HRSs**	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average electricity cost** (£/kg)	**Average hydrogen price** (£/kg)
HRS 1	74,565	1,785	16,648	294,149	52,154	5.64	7.40
HRS 2	111,881	2,607	24,319	429,696	76,187	5.64	7.50
HRS 3	213,414	5,353	49,928	882,189	156,417	5.64	7.40
HRS 4	135,030	3,324	31,004	547,823	97,132	5.64	7.40
HRS 5	347,264	8,775	81,848	1,446,193	256,417	5.64	7.30
HRS 6	178,341	4,425	41,276	729,306	129,310	5.64	7.40

Table 7.10 : Hydrogen production cost details for each HRS (Standard Continuous under 2030-cost scenario)

In this case, the electricity represents the highest part of the total hydrogen cost (around 76%) due to the investments cost reduction shown in Figure 7.23 below.

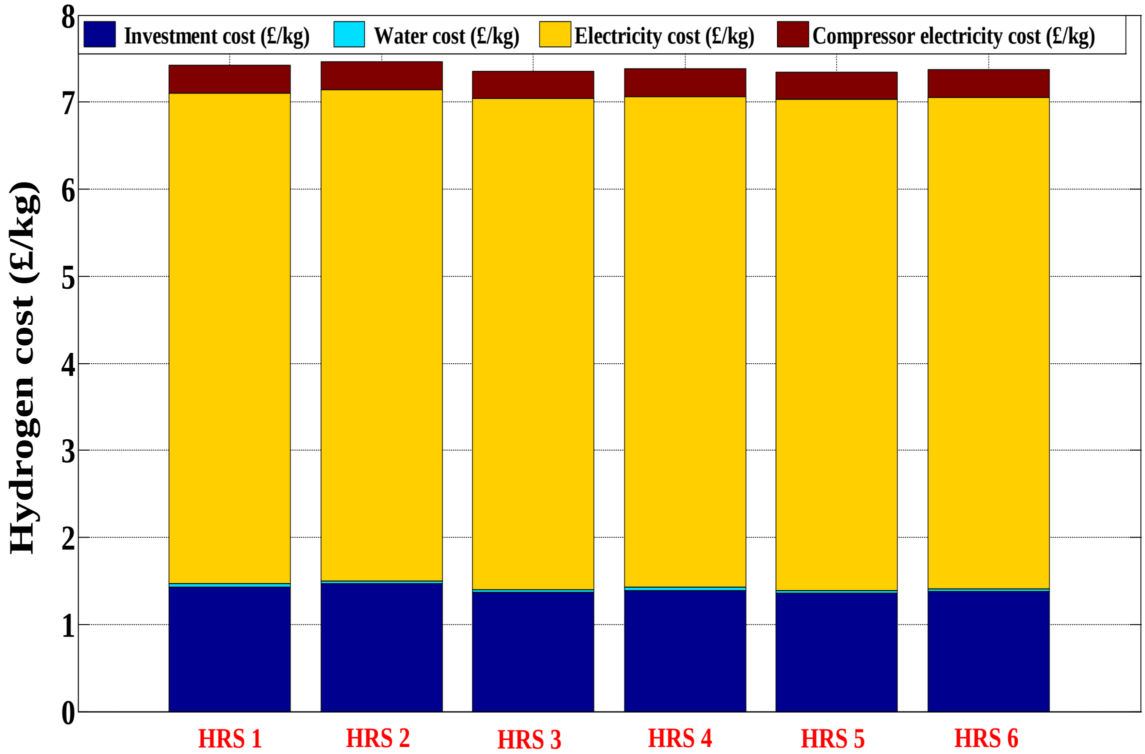


Figure 7.23: Hydrogen cost breakdown per kilogram at each HRS (Standard Continuous under 2030-cost scenario)

In the 2030 scenario, the hydrogen price is highly dependent on by electricity price because of the dramatic drop in HRS component costs.

7.6.2.2 "2-Tier Continuous", operating scenario

In the "2-Tier Continuous", scenario the electrolyser operates continuously and pay a low tariff (5 p/kWh) at off-peak times and a high tariff (12 p/kWh) at other times.

System size and optimisation objectives will be the same as in the 2015-Cost scenario but with new energy efficiency and new cost details of the HRS components.

Figure 7.24 and Figure 7.25 show cumulative energy consumption at each garage forecourt during on- peak and off-peak periods respectively.

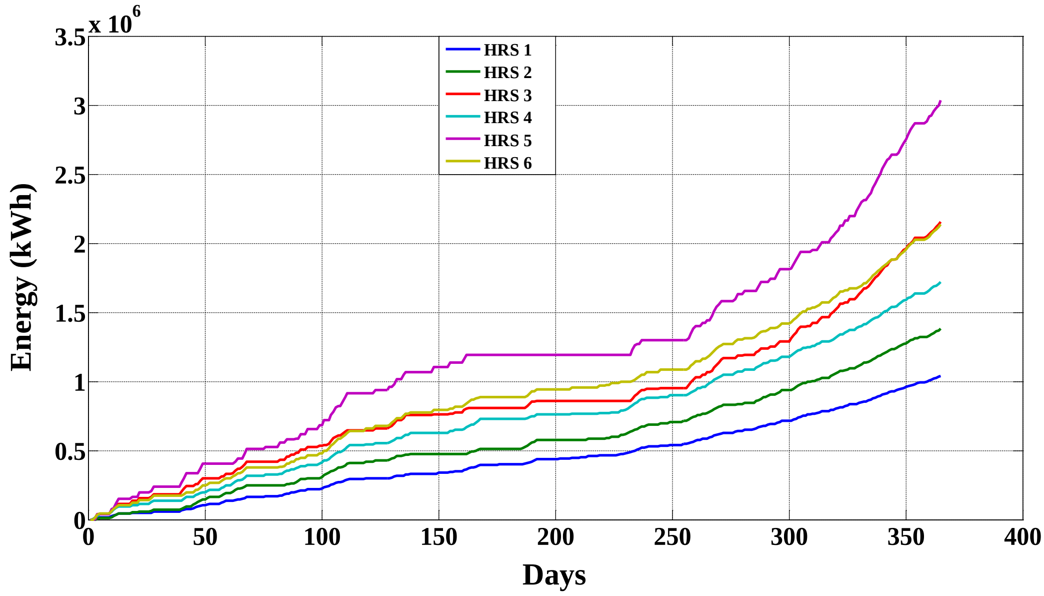


Figure 7.24: Cumulative on-peak energy consumption for each HRS

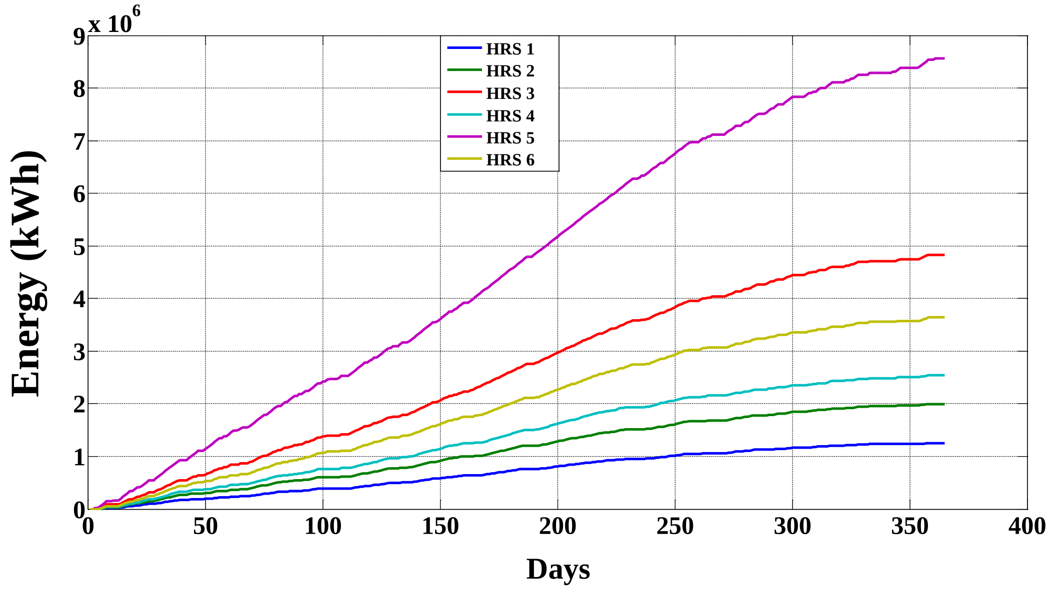


Figure 7.25: Cumulative off-peak energy consumption for each HRS

The energy consumption at each forecourts is reduced due to the energy efficiency improvement. For instance, the consumption of surplus energy at HRS 5 dropped from nearly 10×10^6 kWh to 8.4×10^6 kWh and from nearly 3.55×10^6 kWh to 3.03×10^6 kWh in on-peak case.

This lowering consumption gives other HRSs a chance to absorb more cheap surplus electricity instead of buying expensive energy to meet their demand. This translates into a reduction of consumption of non-renewable power for rest of the HRSs. Hydrogen production throughout the year for each HRS is shown in Figure 7.26 below.

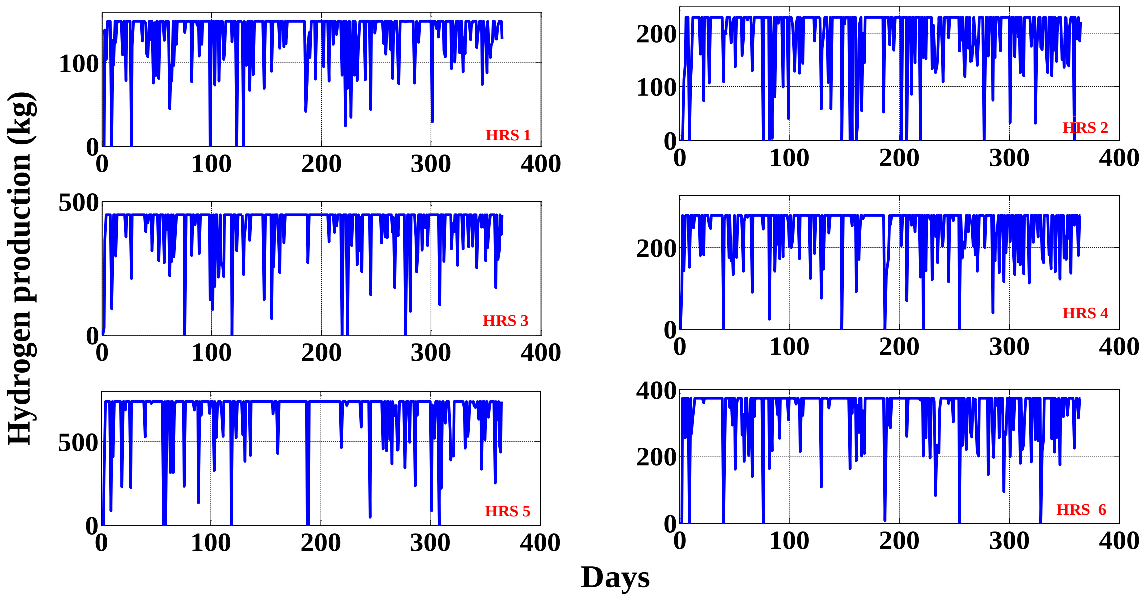


Figure 7.26: Hydrogen production throughout the year (2-Tier Continuous under 2030-Cost scenario)

Variation in Hydrogen storage level in the tank for each garage forecourt is shown in Figure 7.27 below.

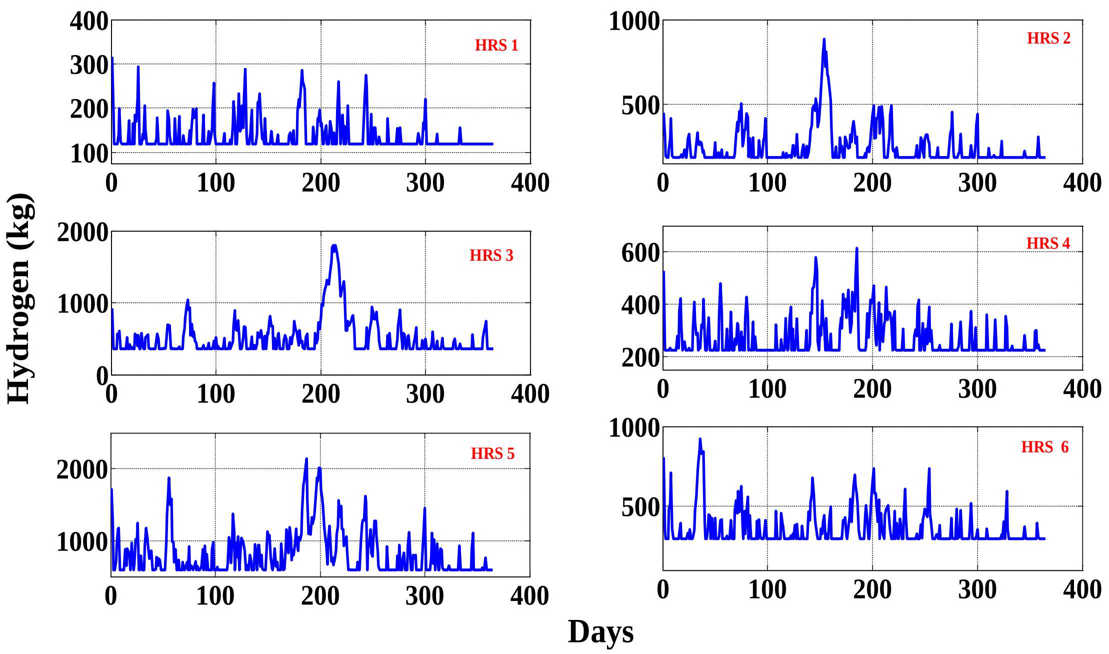


Figure 7.27: Variation in hydrogen storage levels throughout the year for each forecourt (2-Tier Continuous under 2030-Cost scenario)

Like in the Standard Continuous scenario, the hydrogen demand is nearly fully met. The hydrogen cost details can be seen in Table 7.11 below.

Cost	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average electricity cost** (£/kg)	**Average hydrogen price** (£/kg)
HRS 1	119,963	1,670	10,606	187,398	48,806	3.80	6.50
HRS 2	181,960	2,460	15,030	265,572	71,892	3.70	6.50
HRS 3	350,524	5,089	28,320	500,398	148,706	3.40	6.00
HRS 4	220,342	3,108	18,896	333,869	90,817	3.70	6.30
HRS 5	572,733	8,445	44,845	792,378	246,794	3.20	5.70
HRS 6	292,294	4,207	24,813	438,432	122,945	3.60	6.20

Table 7.11 : Hydrogen production cost details for each HRS (2-Tier Continuous under 2030-cost scenario)

The hydrogen cost is reduced in this scenario since much of the electricity is consumed at off-peak times and has lower price. The details of the hydrogen cost are given in Figure 7.28 below. The electricity cost in this scenario represents nearly 59%, 57%, 57%, 58%, 56%, 58 of the total hydrogen production cost at HRS 1, 2,3,4,5 and 6 respectively in contrast with an average of nearly 75 % in the previous scenario. Figure 7.28 reveals that the cheapest hydrogen price is in HRS 5 due to its import of more surplus energy compared with other HRSs.

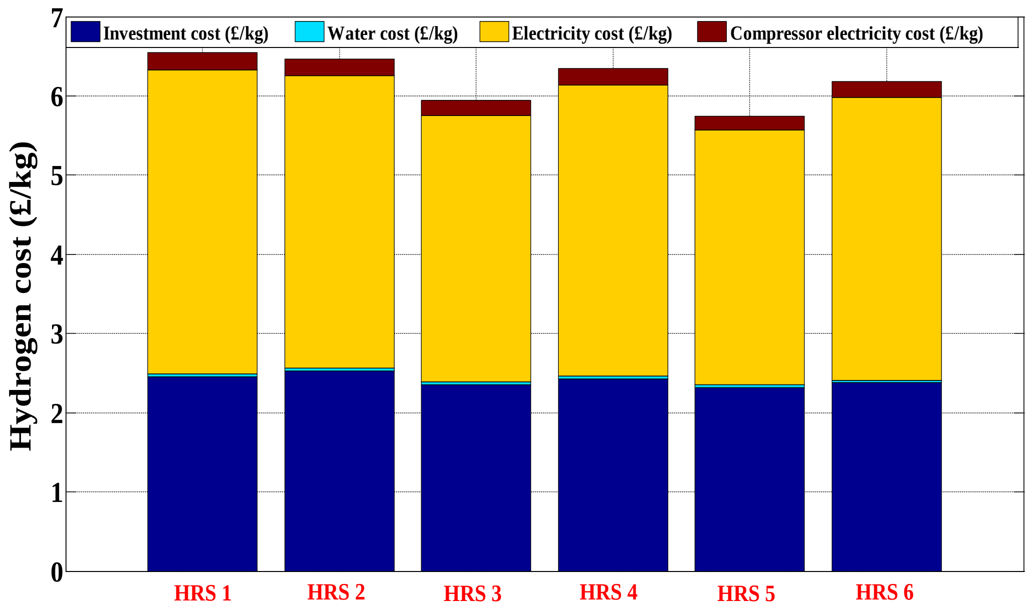


Figure 7.28: Hydrogen cost breakdown per kilogram at each HRS (2-Tier Continuous under 2030-Cost scenario)

7.6.2.3 "Off-peak Only" scenario

In this scenario, electrolysers run only during off-peak periods at the lower price of 5 p/kWh. All assumptions of the size will be the same as in the 2015-Cost scenario. Figure 7.29 below shows the off-peak energy consumed at each HRS throughout the year.

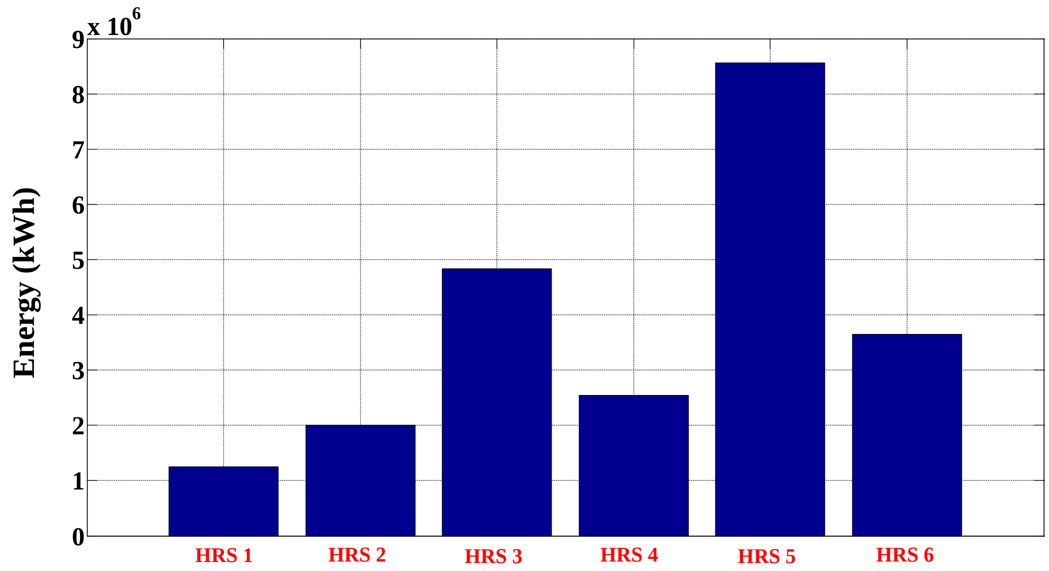


Figure 7.29: Total energy consumed via garage forecourts throughout the year (Off-peak Only under 2030-Cost scenario)

This energy represents nearly 48% of the total surplus energy and the total hydrogen production can satisfy 62% of the demand. Hydrogen production compared with hydrogen demand at each HRS is shown in Figure 7.30 below.

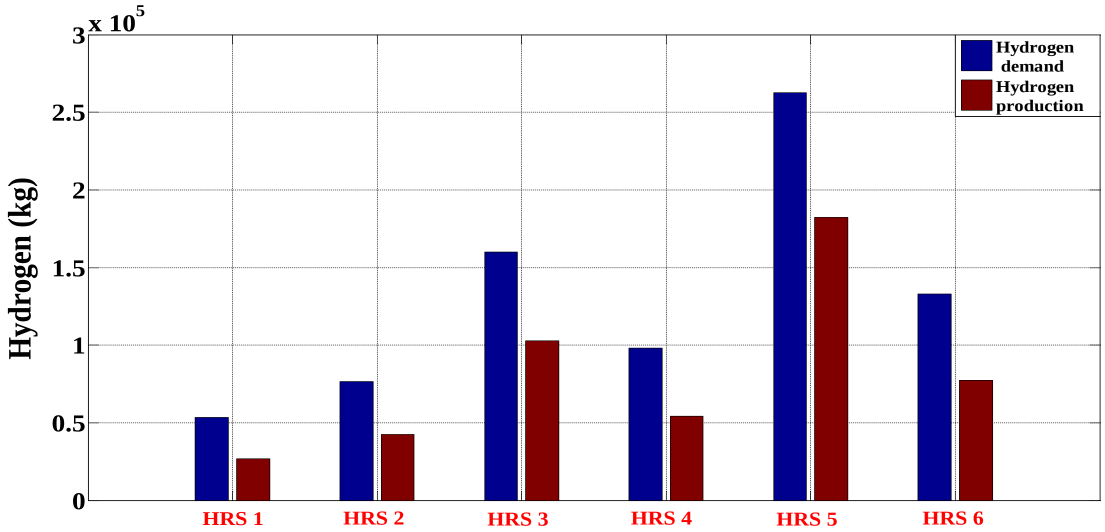


Figure 7.30: Total hydrogen production and consumption throughout the year (Off-peak Only under 2030-cost scenario)

The hydrogen production in this case can meet 50%, 56%, 64%, 55%, 69%, and 58% of hydrogen demand of HRSs 1, 2,3,4,5 and 6 respectively. These values are higher than the results in the 2015-Cost scenario, probably because of electrolyser efficiency improvement. Figure 7.31 shows each garage forecourts' hydrogen production throughout the year (only off-peak production)

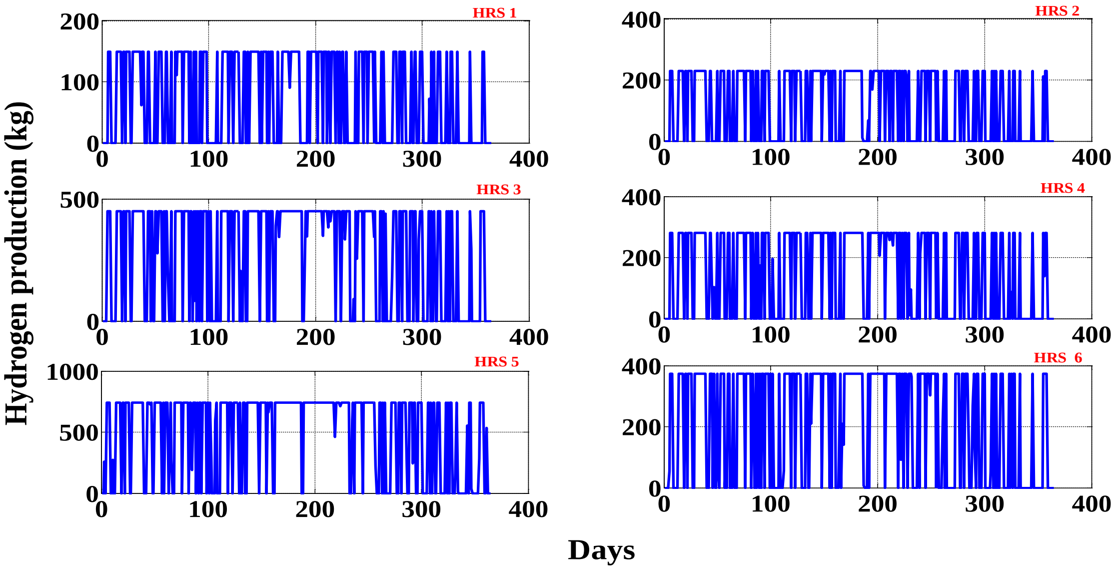


Figure 7.31: Hydrogen production per electrolyser throughout the year (Off-peak Only under 2030-cost scenario)

Variations in hydrogen levels in storage tank at each forecourt throughout the year are shown in Figure 7.32 below.

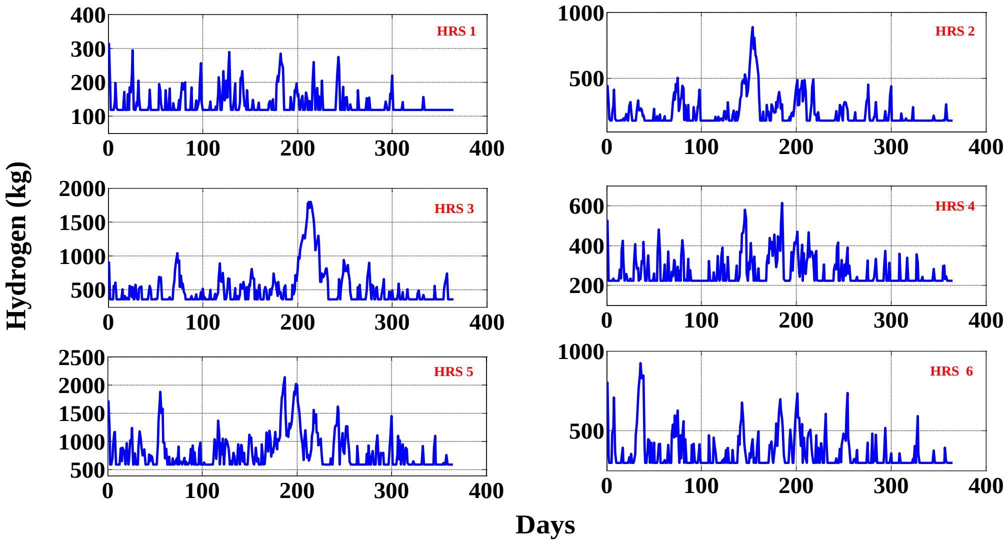


Figure 7.32: Variation in hydrogen storage levels throughout the year for each forecourt throughout the year (Off-peak Only under 2030-cost scenario)

Table 7.12 shows the techno-economic assessment of each garage forecourt.

Cost / HRSs	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity off-peak) cost** (£/year)	**Hydrogen production** (kg/year)	**Average electricity cost** (£/kg)	**Average hydrogen price** (£/kg)
HRS 1	119,963	914	3,552	62,764	26,708	2.40	7.00
HRS 2	181,960	1,455	5,655	99,927	42,522	2.40	6.80
HRS 3	350,524	3,519	13,676	241,907	102,828	2.40	6.00
HRS 4	220,342	1,855	7,209	127,282	54,205	2.40	6.60
HRS 5	572,733	6,236	24,237	428,244	182,231	2.40	5.70
HRS 6	292,294	2,652	10,308	182,126	77,500	2.40	6.30

Table 7.12 : Garage forecourts cost details (Off-peak Only under 2030-cost scenario)

The electricity price per kg is the cheapest of all three of the scenarios, which leads to a reduction in the total hydrogen cost that brings it to a level that is close to being competitive with conventional fuels. The share of each component in the total cost of hydrogen is given in Figure 7.33. The electricity in this scenario represents 34%, 35%, 40%, 36%, 42%, and 37 % for HRSs 1, 2, 3,4,5,6 respectively, which are the cheapest price between all scenarios. In contrast with other scenarios, the highest share in the hydrogen cost is now investment cost (Capex) rather than electricity cost.

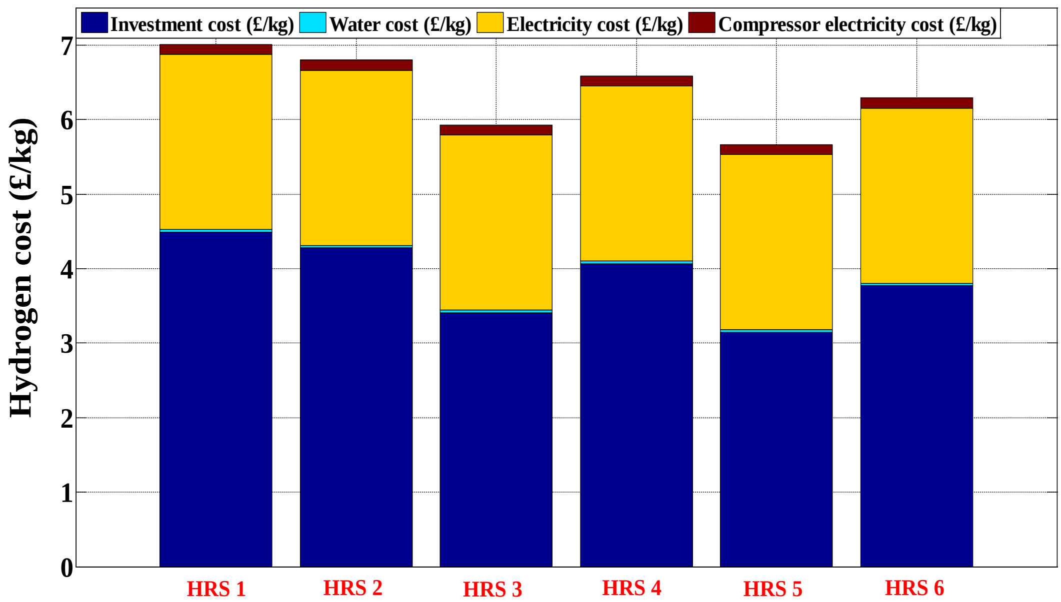


Figure 7.33: Hydrogen cost details per HRS per kilogram (Off-peak Only under 2030-cost scenario)

The average hydrogen price is still in between the prices of the other scenarios. However, the problem with this scenario is that with these component sizes, the system cannot meet the total demand for fuel. The average electricity price and average hydrogen price for all energy price cases in this scenario are less than the 2015-Cost scenario due to the reduction of the investment cost and improvement in electrolyser efficiency. In terms of grid balancing, electrolysers can play an important role in this scenario since the flexible operation of the electrolyser can enable DSR if some incentives such as reduced electricity tariff at times of surplus power availability are offered in order to incentive it. For the hydrogen to be cost-competitive as a fuel, the fossil fuel prices of the future need to be forecasted while taking into account some important points such as the effects of pollution and government subsides. Table 7.13 below shows the comparison between the two cost scenarios in terms of energy price and average hydrogen price using PEME.

Scenarios		HRSs	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Standard Continuous Scenario	**2015-Cost scenario**	Electricity price (£/kg)	6.60	6.60	6.60	6.60	6.60	6.60
		Average hydrogen price (£/kg)	10.50	10.60	10.40	10.40	10.40	10.40
	2030-Cost scenario	Electricity price (£/kg)	5.60	5.60	5.60	5.60	5.60	5.60
		Average hydrogen price (£/kg)	7.40	7.50	7.40	7.40	7.30	7.40
2-Tier Continuous Scenario	**2015-Cost scenario**	Electricity price (£/kg)	4.60	4.40	4.00	4.40	3.70	4.30
		Average hydrogen price (£/kg)	11.00	11.00	10.20	10.90	9.90	10.60
	2030 - Cost scenario	Electricity price (£/kg)	3.80	3.70	3.40	3.70	3.20	3.60
		Average hydrogen price (£/kg)	6.50	6.50	6.00	6.30	5.70	6.20
Off-peak Only Scenario	**2015-Cost scenario**	Electricity price (£/kg)	2.70	2.70	2.70	2.70	2.70	2.70
		Average hydrogen price (£/kg)	14.80	14.30	12.00	13.80	11.00	13.00
	2030-Cost scenario	Electricity price (£/kg)	2.40	2.40	2.40	2.40	2.40	2.40
		Average hydrogen price (£/kg)	7.00	6.80	6.00	6.60	5.70	6.30

Table 7.13 : Average hydrogen price cost in 2015- and 2030-Cost scenarios for PEME test

7.7 HRS simulations with alkaline electrolysis

For both 2015-Cost and 2030-Cost scenarios, only the capital cost of the electrolyser will change which will affect the hydrogen cost. The price of an alkaline electrolyser is cheaper than a PEM electrolyser regardless the operation advantages of PEM.

7.7.1 2015-Cost scenario

The cost assumptions for alkaline electrolysers are presented in Table 7.1. The three energy price scenarios will be repeated with alkaline electrolysis.

7.7.1.1 Standard Continuous scenario (all day tariff of 12 p/kWh)

Based on the recent studies, the PEME cost is nearly double that of an alkaline electrolyser so using alkaline would lead to a reduction in hydrogen price, which enhances opportunities of hydrogen as a fuel.

Table 7.14 shows the summary of the hydrogen cost at standard continuous operation.

Cost / HRSs	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electricity feedstock** (£/year)	**Hydrogen production** (kg/year)	**Average electricity cost** (£/kg)	**Average hydrogen price** (£/kg)
HRS 1	120,084	1,783	20,634	341,394	52,105	6.60	9.30
HRS 2	178,756	2,593	30,011	496,546	75,785	6.60	9.30
HRS 3	344,910	5,346	61,861	1,023,514	156,214	6.60	9.20
HRS 4	219,261	3,331	38,544	637,721	97,332	6.60	9.20
HRS 5	564,323	8,790	101,721	1,683,023	256,872	6.60	9.20
HRS 6	287,578	4,414	51,081	845,156	128,992	6.60	9.20

Table 7.14 : Garage forecourts cost details for Standard continuous (2015-Cost scenario)

The total hydrogen price dropped from nearly £10.50/kg to £9.00/kg when the alkaline electrolyser is used. This drop is driven by the reduction of the electrolyser capital cost.

7.7.1.2 "2-Tier Continuous", operating scenario

Table 7.15 shows a summary of the hydrogen cost at standard continuous operation with peak and off-peak tariff applied.

Cost / HRSs	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electricity feedstock cost (£/year)	Hydrogen production (kg/year)	Average electricity cost (£/kg)	Average hydrogen price £/kg
HRS 1	239,649	1,666	13,438	222,334	48,676	4.60	9.80
HRS 2	359,111	2,439	19,063	315,403	71,260	4.40	9.80
HRS 3	705,552	5,062	35,694	590,573	147,936	4.00	9.00
HRS 4	446,717	3,107	23,955	396,345	90,799	4.40	9.60
HRS 5	1,163,490	8,454	55,802	923,271	247,056	3.70	8.70
HRS 6	586,089	4,179	31,400	519,535	122,125	4.30	9.30

Table 7.15 : Garage forecourt cost details for 2-Tire Continuous operation ((2015-Cost scenario)

The hydrogen price dropped from nearly £10-11/kg to £9-10/kg for 2-Tier Continuous operation when the alkaline electrolyser is used instead of a PEME.

7.7.1.3 "Off-peak Only" scenario

Table 7.16 shows the details of hydrogen cost at Off-peak only operation mode.

Cost / HRSs	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electricity feedstock (£/year)	Hydrogen production (kg/year)	Average electricity cost (£/kg)	Average hydrogen price (£/kg)
HRS 1	239,649	865	4,170	68,994	25,273	2.70	12.40
HRS 2	359,111	1,356	6,540	108,210	39,637	2.70	12.00
HRS 3	705,552	3,391	16,349	270,502	99,085	2.70	10.00
HRS 4	446,717	1,778	8,572	141,834	51,954	2.70	11.50
HRS 5	1,163,490	6,227	30,023	496,743	181,957	2.70	9.30
HRS 6	586,089	2,513	12,115	200,450	73,425	2.70	11.00

Table 7.16 : The garage forecourts details for Off-peak only operation (2015-Cost scenario)

The average hydrogen price per kg was £14.80, £14.30, £12.00, £13.80, £11.00 ,£13.00 for Off-peak only operation of PEM case and became £12.40, £12.00, £10.00, £11.50, £9.30, £11.00 for alkaline of HRSs 1,2,3,4,5,6 respectively.

7.7.2 2030-Cost scenario

In this scenario, the electrolysis efficiency will increase from 54.6 to 50 kWh/kg and thus the operation characteristics of the HRSs will improve, which leads to a reduction in the average price of hydrogen.

7.7.2.1 Standard Continuous scenario (all day tariff 12 p/kWh)

Running the electrolyser continuously with fixed price (12p/kWh) can solve the problem of failure to the fully meeting hydrogen demand but with other issues, such as an increased hydrogen price, could fail as DSR tool.

Table 7.17 shows a summary of the hydrogen cost at Standard continuous scenario.

Cost / HRSs	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electrolyser electricity cost (£/year)	Hydrogen production (kg/year)	Average electricity cost (£/kg)	Average hydrogen price (£/kg)
HRS 1	59,807	1,785	16,648	312,924	52,154	6.00	7.50
HRS 2	89,100	2,607	24,319	457,124	76,187	6.00	7.50
HRS 3	168,842	5,353	49,928	938,499	156,417	6.00	7.40
HRS 4	107,296	3,324	31,004	582,791	97,132	6.00	7.50
HRS 5	273,967	8,775	81,848	1,538,503	256,417	6.00	7.40
HRS 6	141,297	4,425	41,276	775,857	129,310	6.00	7.40

Table 7.17 : Hydrogen cost details Standard continuous operation (2030-Cost scenario)

There is a big difference (from £9.00/kg to £7.50/kg) due to the electrolyser capital cost reduction and efficiency improvement.

This scenario can meet 97%, 100%, 98%, 99%, 98%, and 97% for HRSs 1, 2,3,4,5 and 6 respectively which are similar values to 2030-Cost scenario but with lower hydrogen prices.

7.7.2.2 "2-Tier Continuous", operating scenario

The hydrogen cost details for this scenario can be seen in Table 7.18 below.

n Cost / HRSs	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electrolyser electricity cost (£/year)	Hydrogen production (kg/year)	Average electricity cost (£/kg)	Average hydrogen price (£/kg)
HRS 1	108,103	1,669	10,704	201,203	48,784	4.10	6.60
HRS 2	163,651	2,458	15,152	284,809	71,833	4.00	6.50
HRS 3	314,703	5,082	28,476	535,256	148,512	3.60	6.00
HRS 4	198,054	3,102	19,085	358,739	90,649	4.00	6.40
HRS 5	513,827	8,440	44,876	843,541	246,626	3.40	5.70
HRS 6	262,523	4,206	25,081	471,438	122,921	3.80	6.20

Table 7.18 : Hydrogen production cost details for 2-Tire Continuous operation (2030-Cost scenario)

For the alkaline scenario the price was £9.80, £9.80, £9.00, £9.60, £8.70, £9.30 /kg in the 2015-Cost scenario and, in 2030-Cost scenario became £6.60, £6.50, £6.00, £6.40, £5.70 and £6.20 /kg for HRSs 1,2,3,4,5 and 6 respectively.

7.7.2.3 "Off-peak Only" scenario

The average hydrogen cost and the energy price in this scenario is less than the 2015-Cost scenario due to efficiency improvements and cost reductions as can be seen in Table 7.19

Cost / HRSs	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electricity feedstock** (£/year)	**Hydrogen production** (kg/year)	**Average electricity cost** (£/kg)	**Average hydrogen price** (£/kg)
HRS 1	108,103	895	3,477	65,357	26,143	2.50	6.80
HRS 2	163,651	1,429	5,555	104,423	41,769	2.50	6.60
HRS 3	314,703	3,479	13,521	254,154	101,662	2.50	5.80
HRS 4	198,054	1,810	7,036	132,252	52,901	2.50	6.40
HRS 5	513,827	6,220	24,176	454,440	181,776	2.50	5.50
HRS 6	262,523	2,602	10,111	190,063	76,025	2.50	6.10

Table 7.19 : Garage forecourts cost details Off-peak only operation (2030-Cost scenario)

All hydrogen prices at HRSs in the 2030 price scenario are lower than in off-peak mode operation at 2015-Cost.

The comparison between the 2015-Cost and 2030-Cost scenarios, in terms of energy price and hydrogen cost for alkaline electrolysers, which is presented in Table 7.20 below.

There is a considerable drop in hydrogen price for all cases which suggest that further research should focus on the flexible operation of electrolysis. The price decrease is higher when the off-peak power is used especially for the 2030-Cost scenario.

Scenarios		HRSs	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Standard Continuous Scenario	**2015-Cost scenario**	Electricity price (£/kg)	6.60	6.60	6.60	6.60	6.60	6.60
		Average hydrogen price (£/kg)	9.30	9.30	9.20	9.20	9.20	9.20
	2030-Cost scenario	Electricity price (£/kg)	6.00	6.00	6.00	6.00	6.00	6.00
		Average hydrogen price (£/kg)	7.50	7.50	7.40	7.50	7.40	7.40
2-Tier Continuous Scenario	**2015-Cost scenario**	Electricity price (£/kg)	4.60	4.40	4.00	4.40	3.70	4.30
		Average hydrogen price (£/kg)	9.80	9.80	9.00	9.60	8.70	9.30
	2030-Cost scenario	Electricity price (£/kg)	4.10	4.00	3.60	4.00	3.40	3.80
		Average hydrogen price (£/kg)	6.60	6.50	6.00	6.40	5.70	6.20
Off-peak Only Scenario	**2015-Cost scenario**	Electricity price (£/kg)	2.70	2.70	2.70	2.70	2.70	2.70
		Average hydrogen price (£/kg)	12.40	12.00	10.00	11.50	9.30	11.00
	2030-Cost scenario	Electricity price (£/kg)	2.50	2.50	2.50	2.50	2.50	2.50
		Average hydrogen price (£/kg)	6.80	6.60	5.80	6.40	5.50	6.10

Table 7.20 : Average hydrogen price cost in 2015- and 2030-Cost scenarios for alkaline test

7.8 Summary of the chapter

The optimization of hydrogen production by electrolysis has been implemented to achieve a number of goals: providing the DSR for the grid by absorbing temporary surpluses of renewable energy, reducing the cost of hydrogen by choosing the cheapest electricity tariff; and guaranteeing the uninterrupted supply of hydrogen fuel. Two types of electrolyser (PEM and Alkaline) have been used. In each case, two cost scenarios have been tested: a 2015-Cost scenario and 2030-Cost scenario. Three different modes of operation based on the time of operation and electricity tariff have been investigated in each scenario. In the Standard Continuous Scenario, the electrolysers are operated continuously on a standard all-day tariff of 12 p/kWh, in the 2-Tier Continuous Scenario, they operate continuously, paying the 5 p/kWh tariff at off-peak times and 12 p/kWh tariff at others and in the Off-Peak Only Scenario, they operate only during off-peak periods at a lower price of 5 p/kWh in a 2-tier tariff system.

In the system with PEM electrolysers, for the 2015-Cost scenario, it was found that the cheapest electricity cost per kg of hydrogen produced, was £2.73, which occurred in the

Off-Peak Only Scenario. The next cheapest, at £3.70 - £4.60, was in the 2-Tier Continuous Scenario, and the most expensive was £6.60/kg in the Standard Continuous Scenario. However, in general, the hydrogen price is quite high due to the high price of HRS components. So the hydrogen cost is strongly driven by capital cost which represents the highest share of the total cost.

For the 2030-Cost scenario, the hydrogen price also reduced since the cost of HRS is reduced by nearly 50%. For instance, the Standard Continuous Scenario, the hydrogen price dropped from £10.40 to £7.40 and thanks to the efficiency improvement in this scenario, the electricity price per kg is also decreased from £6.60 to £5.64.

In the alkaline system, the electricity price per kg does not change because the same electricity price assumptions have been applied in both. However, the overall price of hydrogen has been reduced due to the lower price of alkaline electrolysers by comparison with PEM electrolysers. For instance, in the 2015-Cost scenario, the hydrogen cost was reduced in Standard Continuous operation from nearly £10.40 with PEM system to £9.30 with the alkaline system. The same situation is true of the 2-Tier Continues and Off-peak Only operation modes. Also in the 2030-Cost scenario, use of the alkaline electrolyser will lead to more reduction in the cost of hydrogen. Achieving a competitive price for hydrogen will require reductions in the capital cost of the system as well as the operating costs explored in this research. In terms of meeting the demand and balancing grid, which is mainly the target of Off-Peak Only Scenario, more storage tools are needed to consume the rest of the surplus power and provide energy to the electrolysers during times of power shortage. Bold policy measures are needed to reduce emissions and to provide a sustainable economic future for oil-producing nations such as Libya in a post-fossil-fuel era. In particular, this means strong support for renewable energy, hydrogen and other energy storage and DSR markets.

The next chapter will deal with only the surplus power and work to achieve different targets such as keeping the balance between demand and supply by absorbing the surplus energy and convert this energy to hydrogen, which, will be used as a clean fuel. Meeting the hydrogen demand is another challenge of this research, which requires many steps as will be seen in next chapter. Another important point is satisfying the economic requirements since HRSs components will be financed via bank loans, which include interest payment. The production should be enough to pay the bank instalments and variable costs each year and the hydrogen price should be commercially viable in the transport fuel market.

Chapter 8: Techno-Economic Analysis of Dispatchable Operation of Multiple Forecourt Electrolysers for Demand Side Response and Hydrogen Fuel Production

8.1 Introduction

As mentioned in Chapter 7, the cheapest electricity per kg was produced via the Off-peak Only scenario. However, this scenario cannot meet the main objective of grid balancing by absorbing the majority of surplus power, or indeed meet hydrogen demand at an acceptable price. In addition, only one off-peak electricity tariff was applied (5 p/kWh), which limits the means by which electricity can be sold to the garage forecourts. In the last chapter, the demand supplied is done in order of hierarchy from the highest to the lowest (normally, though, this hierarchy remains the same every day). This technique will create problems with the other garage forecourts, especially if the available energy is not sufficient to meet their total demand. In this chapter, the off-peak electricity price will be changed every day, as based on the available amount of energy and the hydrogen required per HRS. This technique could be useful for both on of the HRS and of the energy supplier. Different scenarios will be investigated to examine how the following requirements might be satisfied:

1- The majority of the surplus power should be consumed (at least 90%) to support grid balancing and increase the penetration of renewable resources into the Libyan grid;
2- Meet the required hydrogen demand without interruption;
3- The hydrogen production cost should be competitive compared to fossil fuel prices.

There are many scenarios, which will be tested, but as each scenario is examined and its weakness established, the subsequent scenario will be designed to overcome these weaknesses, in an iterative process. For example, if the first scenario cannot absorb the majority of the surplus energy, the next scenario will be built to address this issue, and so on. In other words, any given scenario should tackle or treat the weakness and problems found with the previous scenario. As in Chapter 7, two common types of electrolyser (alkaline and PEM) will be tested using two different cost scenarios (2015 and 2030).

8.2 2015-Cost scenario with alkaline electrolysers

Different scenarios will be investigated in this section. The main idea behind the work in this chapter is that each HRS has its own electrolyser in order to produce hydrogen for local consumption. Other, subsequent, scenarios will be considered if any scenario currently under consideration cannot satisfy the principle aims of grid balancing, meeting hydrogen demand and producing hydrogen fuel at a reasonable price at the point of sale. The summary of these scenarios are presented in Table 8.1.

Details	Scenario No.	LAE Sc. 1	LAE Sc. 2	LAE Sc. 3	LAE Sc. 4	LAE Sc. 5	LAE Sc. 6	LAE Sc. 7	LAE Sc. 8	LAE Sc. 9	LAE Sc. 10	LAE Sc. 11	LAE Sc. 12	LAE Sc. 13	LAE Sc. 14	LAE Sc. 15
HRSs Electrolyser Size (Kg/day)	HRS 1	149	297	446	446	446	149	149	149	149	149	149	149	149	149	149
	HRS 2	226	451	677	677	677	226	226	226	226	226	226	226	226	226	226
	HRS 3	449	897	1346	1346	1346	449	449	449	449	449	449	449	449	449	449
	HRS 4	282	564	846	846	846	282	282	282	282	282	282	282	282	282	282
	HRS 5	744	1487	2231	2231	2231	744	744	744	744	744	744	744	744	744	744
	HRS 6	372	744	1115	1115	1115	372	372	372	372	372	372	372	372	372	372
HRS Storage size (kg)	HRS 1	560	560	840	1120	1680	560	560	560	560	560	560	560	560	560	560
	HRS 2	630	630	945	1260	1890	630	630	630	630	630	630	630	630	630	630
	HRS 3	1890	1890	2835	3780	5670	1890	1890	1890	1890	1890	1890	1890	1890	1890	1890
	HRS 4	1190	1190	1785	2380	3570	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190
	HRS 5	2464	2464	3696	4928	7392	2464	2464	2464	2464	2464	2464	2464	2464	2464	2464
	HRS 6	1540	1540	2310	3080	4620	1540	1540	1540	1540	1540	1540	1540	1540	1540	1540
HRS Compressor Size (Kg/day)	HRS 1	149	297	446	446	446	149	149	149	149	149	149	149	149	149	149
	HRS 2	226	451	677	677	677	226	226	226	226	226	226	226	226	226	226
	HRS 3	449	897	1346	1346	1346	449	449	449	449	449	449	449	449	449	449
	HRS 4	282	564	846	846	846	282	282	282	282	282	282	282	282	282	282
	HRS 5	744	1487	2231	2231	2231	744	744	744	744	744	744	744	744	744	744
	HRS 6	372	744	1115	1115	1115	372	372	372	372	372	372	372	372	372	372
Central Electrolyser Size (Kg/day)		×	×	×	×	×	1098	1923	3021	4853	2220	1098	1923	3021	4853	2220
Central Electrolyser Storage size (kg)		×	×	×	×	×	5000	9000	15000	24000	11000	5000	9000	15000	24000	11000
Central Electrolyser compressor		×	×	×	×	×	1098	1923	3021	4853	2220	1098	1923	3021	4853	2220
Electrolyser efficiency		54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6
Year of the components cost		2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015

Table 8.1: The summary of the alkaline electrolyser scenarios under 2015-Cost scenarios

Where: **LAE Sc. 1:** Only Onsite alkaline electrolyser without central electrolyser (default sizes) (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 2: Double-sized default electrolyser size and same as the default storage size (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 3: Triple-sized default electrolyser and 1.5 times the default storage size (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 4: Triple-sized default electrolyser and double the default storage size (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 5: Triple-sized default electrolyser and triple the default storage size (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 6: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day alkaline central electrolyser with 5,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 7: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day alkaline central electrolyser with 24,000 kg storage size (sized based hydrogen on production side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 8: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day alkaline central electrolyser with 15000 kg storage size (sized based on production side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 9: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 10: Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day alkaline central electrolyser with 11000 kg storage size (sized based on hydrogen consumption side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 11: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day alkaline central electrolyser with 5,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

LAE Sc. 12: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day alkaline central electrolyser with 24,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

LAE Sc. 13: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

LAE Sc. 14: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

LAE Sc. 15: Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day alkaline central electrolyser with 11,000 kg storage size (sized based on hydrogen consumption side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

8.2.1 Onsite garage forecourts without central electrolyser (LAE Sc. 1)

In this scenario, only onsite electrolysers will consume the surplus power. The optimal energy storage scenario would include a variety of technologies that are complementary to each other, such that the whole range of storage sizes and timescales are covered (e.g. flywheel for frequency response, batteries for medium storage periods and Hydrogen for large scale, long timescale storage). However, in this scenario, there are no other energy storage methods working alongside electrolysis to absorb any unused surplus energy, even to meet any shortage in hydrogen supply. Figure 8.1 illustrates the overall system represented by this scenario.

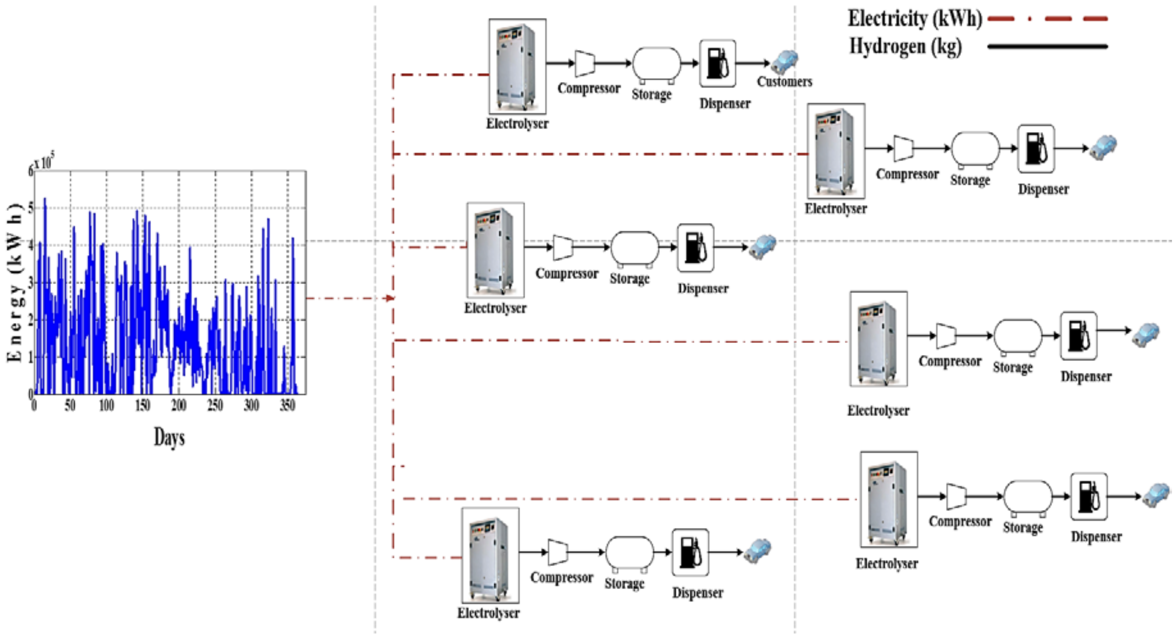


Figure 8.1: Overall system process when Onsite garage forecourts without central electrolyser scenario is applied (LAE Sc. 1) (2015-Cost scenario)

The main three goals have to be satisfied in this scenario. As mentioned in previous chapters, capital costs are one the significant parts of the total hydrogen system cost, so optimal sizing of garage forecourt components can lead to a reduction in the total cost of the system.

8.2.1.1 System sizing

a) *Electrolyser sizing*

Accurate system sizing will lead to an overall reduction in system cost. The system can be sized based on the electricity supply side or hydrogen demand side. Based on the former, the sizing will not be accurate because of the intermittency of the electricity supply (from 0 to 500 MWh) and there is no guarantee of being able to buy electricity every day because of the competition between the HRSs. In the case of the latter, hydrogen demand is also variable, as shown in Figure 8.2. Two options could be used for the demand side: sizing the system based on maximum demand, or the average daily demand.

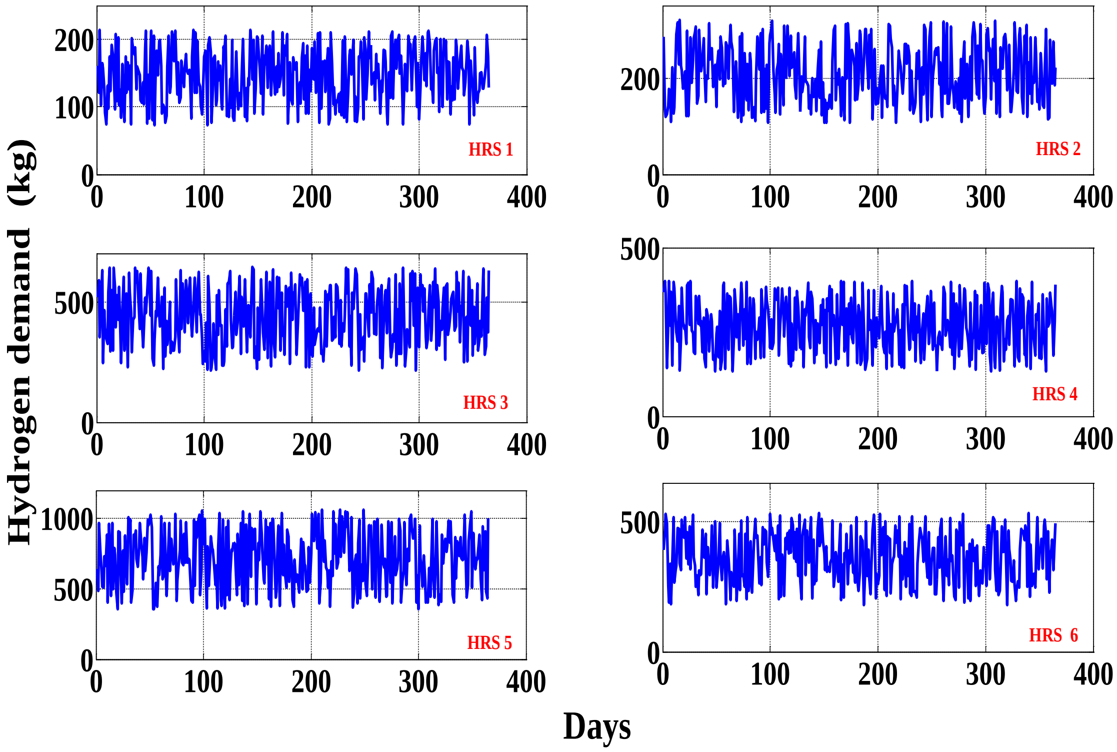


Figure 8.2: Daily hydrogen demand for HRSs 1 to 6 throughout the year

For example, in HRS 1, if the electrolyser is sized based on the maximum hydrogen demand, peak operation of the electrolyser will only be seen twice per annum because maximum demand occurs just twice during the year, a situation that is very similar to that of the other HRSs.

So, average hydrogen demand would be a better means by which to size the electrolyser, as sizing based on average demand will reduce the capital cost of the system.

b) Storage sizing

The storage tank is one of the most expensive components of the HRS systems. Since the scenario is one of running only during off-peak times, the storage should be designed based on times of hydrogen shortage without surplus power in order to absorb as much power as possible, and thus allow for the sale of hydrogen at times of power shortage. The storage size is taken as four times the capacity of each electrolyser, because there are frequently four consecutive days without any surplus power during the year.

c) Compressor

One day of hydrogen production is equivalent to the size of the compression system. Because it is located between the electrolyser and storage, it is sized based on the rate of sale

8.2.1.2 System cost

In this chapter, the assumptions made regarding cost are the same as those described in Chapter 7. All these costs are based on the companies' surveys, quotes, reports and recent studies in the same field (Menanteau et al., 2011; Bertuccioli et al., 2014; Li et al., 2017; Parks et al., 2014; Levene, 2005). Two-cost scenarios will be tested: one at 2015 costs and one at 2030 costs. These costs include the electrolyser, storage, compressor, dispenser, and control system. In addition, the electrolyser efficiency will be taken into consideration, as electrolyser efficiency in particular is expected to improve between 2015-Cost and 2030-Cost scenarios. Two types of electrolyser will be used in the system: an alkaline and a Polymer Electrolyte Membrane (PEM) electrolyser. These two types are commercially available at different prices. A summary of the associated costs and system efficiencies are presented in Table 7.1 and Table 7.2.

8.2.1.3 Electricity pricing mechanism

The cost of the hydrogen will be adjusted daily. The day-ahead market is assumed to have been approved as a contractual agreement between the seller and buyer for the delivery of the following day's energy; the electricity price is set and the trade agreed for the next day. Each HRS must calculate how much hydrogen it needs to produce, based on the expected hydrogen demand for the day and the amount of hydrogen in the tank, taking into account all constraints such as electrolyser size and storage tank parameters (maximum, minimum and initial levels) as per Equation (8.1.

$$Req\_H_2 = max\_H_2 - Curr\_H_2 \quad (8.1)$$

Where: Req_H_2 is the daily amount of hydrogen (kg) required, max_H_2 is the maximum storage tank limit per day (kg) and $Curr\_H_2$ is the currently available hydrogen in tank on a given day (kg). The amount of electricity needed to produce the required hydrogen is known, based on 54.6 kWh/kg for the 2015-Cost scenario and 50 kWh/kg for the 2030 price scenario. Each forecourt operator will have a target selling price for hydrogen, which might vary somewhat each day, but which must remain competitive in the fuel retail market. This target price will be based on the amount of electricity to be consumed, the price of electricity and the need to repay the capital investment costs. Using Equation (8.2, an electricity tariff level can be identified, at which the forecourt operator can afford to buy electricity while still making profit on producing hydrogen that day. This is the forecourt operator's bid price and it will be different for each forecourt and each day.

$$\text{PriceElectric}(£/kWh) = \left(\frac{\text{Hydrogen cost}(£/\text{kg}) \times Req\_H_2(\text{kg}) - \text{InvestmentDaily Cost})(£)}{(Req\_H_2(\text{kg}) \times 54.6(\text{KWh/kg})}\right) \tag{8.2}$$

An accurate cost for the hydrogen should be calculated through the equation above in order to determine the cheapest viable electricity price. Generally, only off-peak power should be used in order to give the garage forecourt owners the chance to choose a hydrogen price that will allow for the purchase of cheap electricity.

In this research, the European cost target for hydrogen generation in 2025, which is £4.40/kg, will be applied. The hydrogen price at the point of sale should be higher than this value so as to ensure the desired economic targets are reached. After calculating the electricity price per HRS, the decision as to how to set the electricity price for that day will be determined at the electricity producer's side.

The energy producer's aim is obviously to sell as much electricity as possible, perhaps up to 90% of the day's surplus energy, but at the highest price it can achieve without losing customers and failing to meet its 90% target. After seeing the bid prices for all HRSs, the decision on where to set the electricity tariff for that day will be determined by the utility company and this is the price that would be paid by all HRSs whose bid price was equal to or above this value. HRSs with bid prices below this level will not purchase energy and will not run their electrolysers on that day. Figure 8.3 below shows the electricity pricing mechanism diagram.

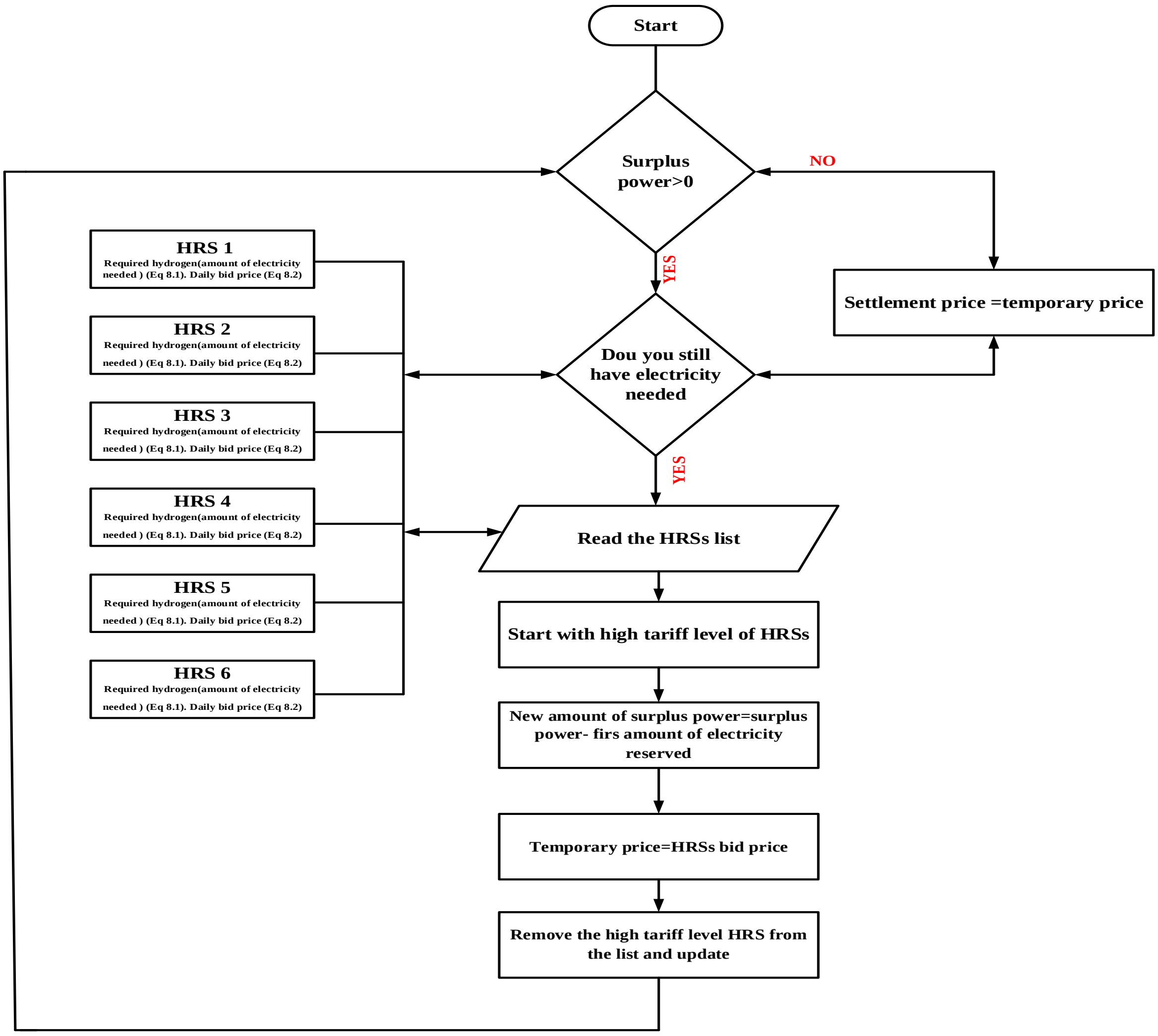


Figure 8.3: Electricity pricing mechanism diagram when the onsite alkaline electrolysers operates without central electrolyser (LAE Sc. 1) (2015-Cost scenario)

The electricity tariff mechanism for selected days of the year is shown in Figure 8.4. On day 44, each HRS releases its bid price based on the calculations from Equations (8.1) and (8.2). The total surplus energy on that day was found to be 168,272 kWh, whereas the energy needed to meet the required hydrogen demand for all HRSs was 121,240 kWh. This means that the surplus power was sufficient to satisfy the needs of all the HRSs, and hence the reason for accepting the lowest bid price for electricity on that day. In other words, the electricity producer started with a high tariff level and adjusted it downwards it until their sale target was satisfied (at least 90% of all energy available). This target would not be satisfied unless the tariff were set at the lowest bid price. The HRSs' consumption represents nearly 72% of the available surplus energy, which calls for another source to consume the rest of energy in order to achieve one of the main targets, namely that consuming 90% of available power. On days 45 and 46, the surplus energy was not sufficient to meet all the HRSs' requirements.

On day 45, the surplus energy was only 72,520 kWh, whereas the total required energy was 121,240 kWh; hence, the surplus energy could not meet the demand on that day. The electricity producer will start with an expensive price and lower it until the selling target is satisfied, which, on this day, happened at the HRS 2 bid price. As a result, the HRS 2 bid price is considered to be the selling price for that day. HRSs 1 and 5 did not buy electricity to run their electrolysers on that day because their bid prices were lower than the tariff eventually offered by the utility company.

The same process may be noted on day 46, where HRSs 2, 3, 4, and 6 were running out of hydrogen on that day due to the limited amount of surplus energy available. The selling price was the electricity bid price of HRS 5.

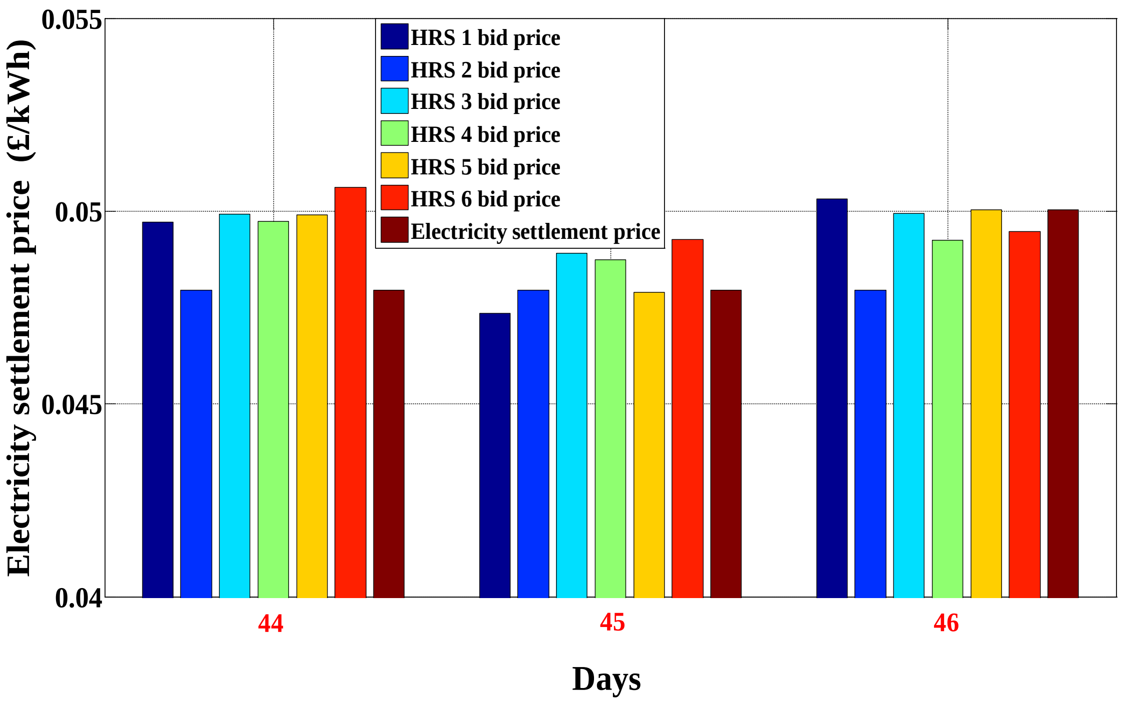


Figure 8.4: The electricity tariff mechanism for selected days of the year (2015-Cost scenario)

Figure 8.5 shows the daily settlement price over the year; zero values are assigned to days without any surplus energy.

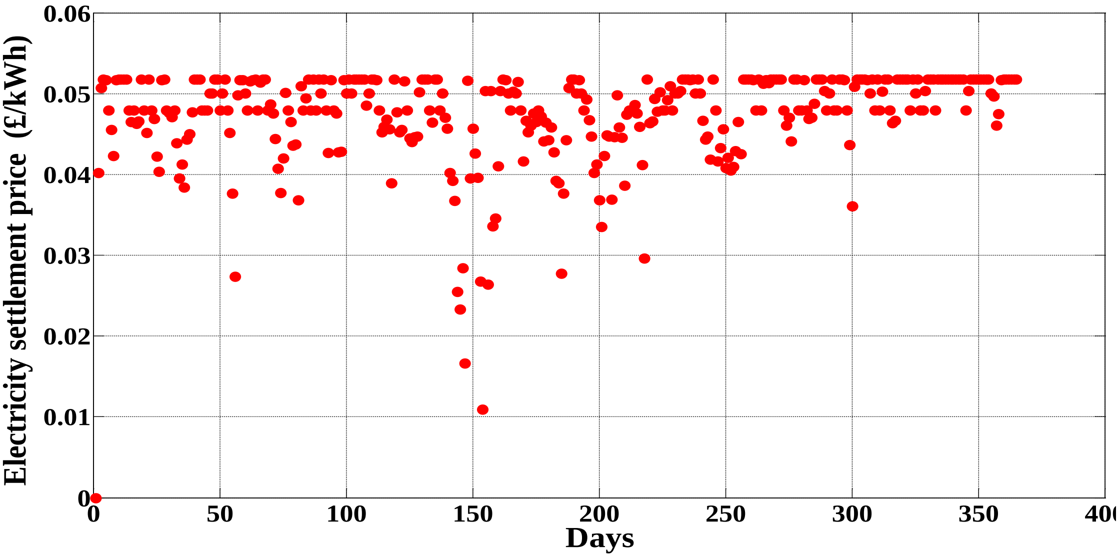


Figure 8.5: Daily electricity settlement price over the year when garage forecourts operate without central electrolyser (LAE Sc. 1) (alkaline, 2015-Cost scenario)

Daily investment costs are explained in detail in the previous chapter; Figure 8.6 summarises the investment cost steps.

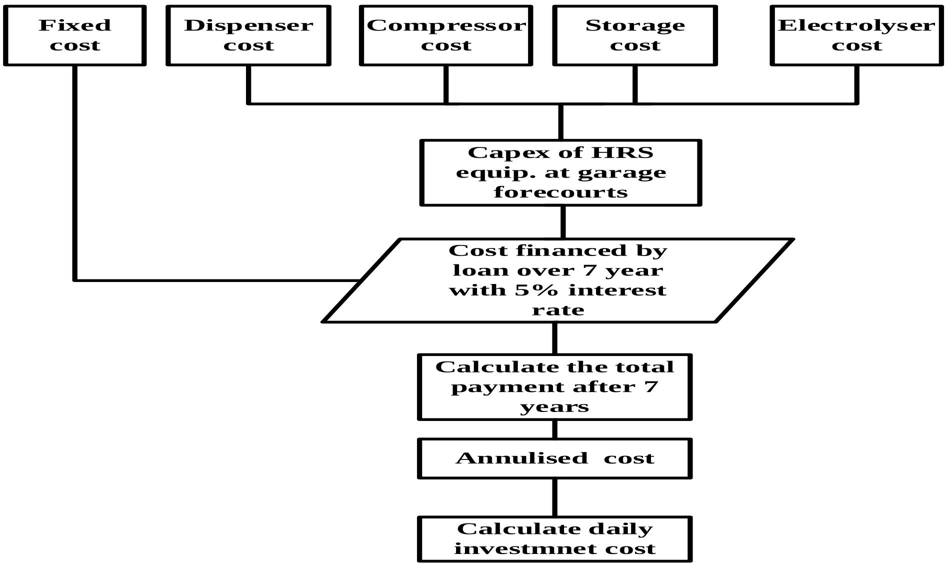


Figure 8.6: Daily investment cost calculation

8.2.1.4 Assessment of the scenario

The assessments will address three main criteria: grid balancing, hydrogen demand satisfaction and the hydrogen price at the point of sale. To avoid large amount of curtailment (wastage), the system should absorb the majority of the surplus power every day to avoid any problems within the system. The six HRSs consume only 53.91% of the total surplus energy during the year in this scenario, as can be seen in Figure 8.7.

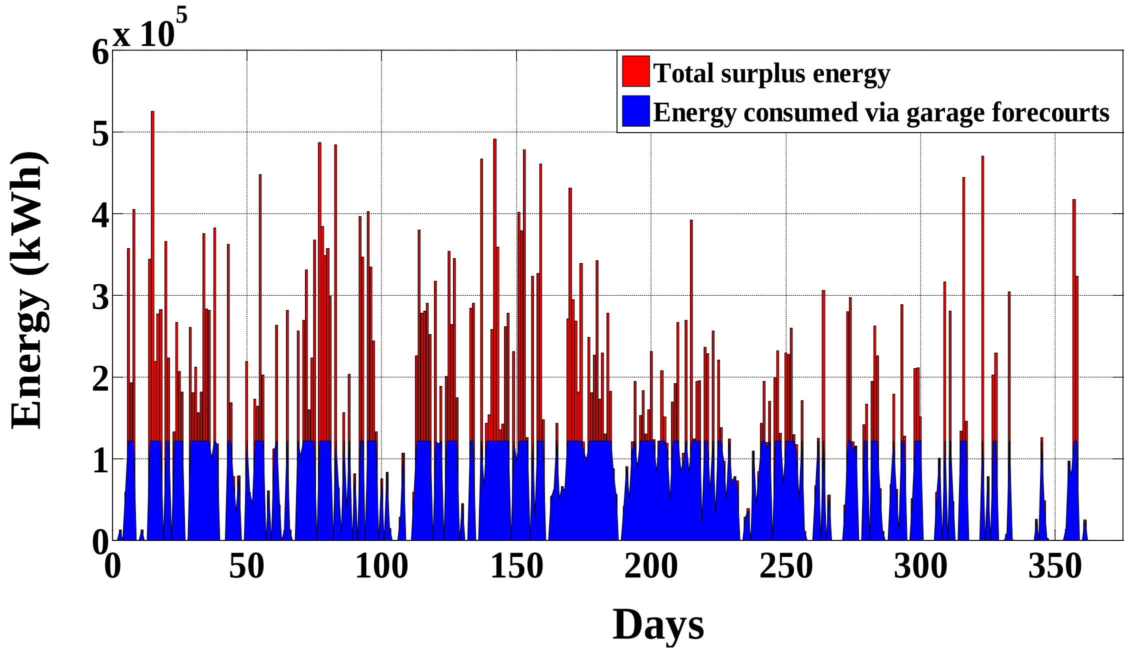


Figure 8.7: Total surplus energy versus energy consumed at the garage forecourts when garage forecourts operate without central electrolyser(LAE Sc. 1) (alkaline, 2015-Cost scenario)

The details of hydrogen production computed to hydrogen demand per HRS throughout the year are shown in Figure 8.8 and reported in Table 8.2.

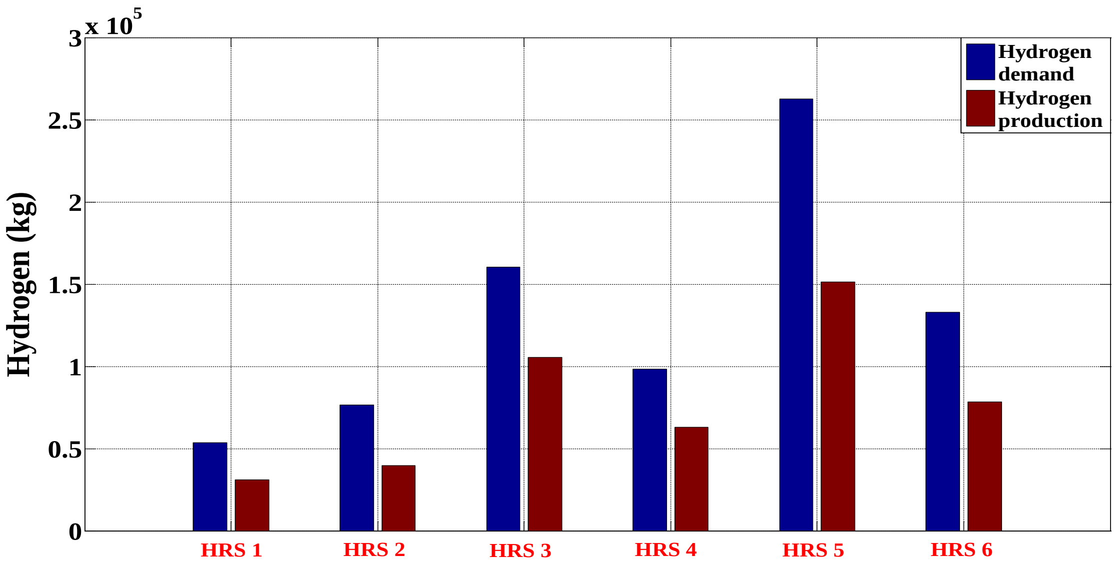


Figure 8.8: Total annual hydrogen demand and production when garage forecourts operate without central electrolyser (LAE Sc. 1) (alkaline, 2015-Cost scenario)

HRS no.	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Hydrogen production (kg/year)	31,082	39,487	105,475	63,122	151,461	78,216
Hydrogen demand (kg/year)	53,645	76,519	160,157	98,244	262,535	133,005
Satisfication of Hydrogen demand (%)	58%	52%	66%	64%	58%	59%

Table 8.2: Comparison between hydrogen production and hydrogen consumption during the year in all six HRSs (LAE Sc. 1) (alkaline, 2015-Cost scenario)

This scenario can nearly meet 60% of the total hydrogen demand in the Darnah area, but this creates another issue in addition to grid balancing (only 53.91%. is consumed). The remaining surplus power can be used to meet the hydrogen demand if another hydrogen production source is added to the system or the sizes of the electrolysers on the garage forecourts are increased. The hydrogen production cost can be calculated based on Equation (8.1).

$$H_2\_Price = H_2\_Cost / H_2\_Production \tag{8.3}$$

Table 8.3 shows the cost summary for this scenario:

Cost / HRSs	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average price** (£/kg)
HRS 1	230,364	1,064	5,011	75,631	31,082	10.00
HRS 2	285,987	1,351	5,843	94,229	39,487	9.80
HRS 3	731,128	3,609	17,443	261,345	105,475	9.60
HRS 4	463,440	2,160	10,435	155,101	63,122	10.00
HRS 5	1,026,705	5,183	23,912	368,025	151,461	9.40
HRS 6	600,420	2,677	13,013	191,272	78,216	10.30

Table 8.3: Hydrogen production cost details when Onsite electrolysers at garage forecourts without external hydrogen sources is used (LAE Sc. 1) (alkaline, 2015-Cost scenario)

The hydrogen sale price should be set between £9-10.5/kg to meet the economic requirements, namely those of the bank repayment instalments and variable costs, regardless of the other drawbacks to this scenario such as being unable to meet hydrogen demands and any shortcomings in achieving full in grid balancing. As can be seen in Figure 8.9, the highest cost arises from the investment cost, followed by the feedstock cost.

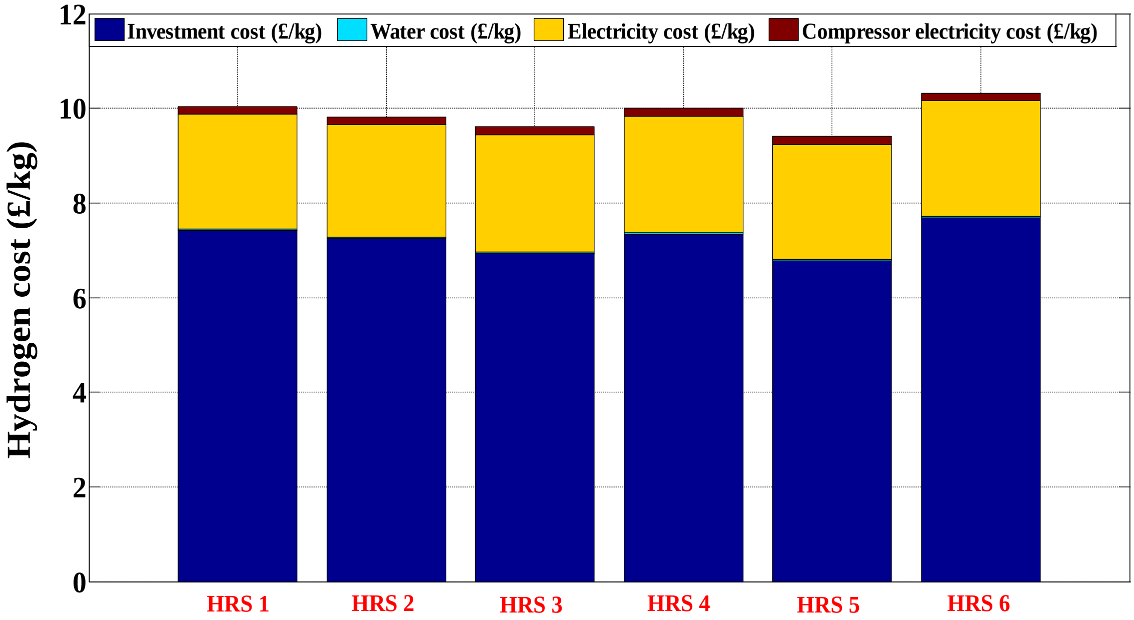


Figure 8.9: Hydrogen cost breakdown per kilogram at each HRS under Onsite electrolysers at garage forecourts without central electrolyser (LAE Sc. 1) (2015-Cost scenario)

Although there is a clear deficiency in hydrogen production, surplus power is still available and can satisfy this shortage. Therefore, the solution from the electricity producer's perspective is to find another customer in addition to the garage forecourts to whom the remaining energy can be sold, and thus avoid an economically difficult option of energy curtailment. The time at which energy is sold to new customers is of particular importance as it directly affects the selling price, since it makes no sense to ask these customers to wait until the garage forecourts have been refuelled and then run without any incentive payments. Importing hydrogen from another source or buying expensive electricity to produce hydrogen could be considered as one possible option to deal with times when supplies are running out at the garage forecourts. Adding another large central electrolyser could allow for the electricity and hydrogen producers to make money and give the central electrolyser the chance to consume electricity and produce hydrogen at profit. Many solutions need be tested in order to achieve the main targets of both sides (both the energy supply side and hydrogen demand side). These can be summarised as follows:

1. Increase the size and storage of all six-garage forecourts. This could be a simple solution;
2. A large central electrolyser with additional storage to provide hydrogen at times of shortage.
3. The first target of the central electrolyser itself is to make money, so the economics of a central electrolyser will be considered in addition to those of the hydrogen refuelling stations (HRSs). The operation time of the central electrolyser will be considered and two modes of operation, as based on running time, will be tested.
4. Import electricity at peak times at a higher price. This scenario will not be explored in any part of this work because there is a lot of surplus power that is not exploited and would otherwise be lost.
5. The electricity supplier could store the remaining power in other kinds of storage, such as a battery, and sell it later during power shortages; however, the price will be determined by the economics of the use of batteries and a central electrolyser. A comparison between a central electrolyser and battery system can be used to determine the best option as DSR (or more accurately "as part of a multi-model storage system).
6. Variable hydrogen price at the HRS. Changes in the price of hydrogen as per the price of electricity could represent one possible solution. The problem with this technique is the inconvenience it represents to the customer, especially if the difference between the daily prices is high.

Applying all, or most, of these techniques at the same time might be the best option because all possible situations will then be taken into consideration. Only the first two options will be investigated in this study because the other scenarios do not support the project goals. The next section will consider the solutions to the shortcomings of the previous scenarios, taking into account two points: the use of the 2015-Cost scenario, and using the alkaline electrolyser.

8.2.2 Increased size of HRS components

The first suggestion to tackle the shortage of hydrogen demand is to increase the size of the HRS components. The main parts of the sizing targeted are the electrolysers, since the production could not fully meet demand in the previous scenario. In terms of storage, Figure 8.10 shows the variation of hydrogen in the tank throughout the year for the previous scenario.

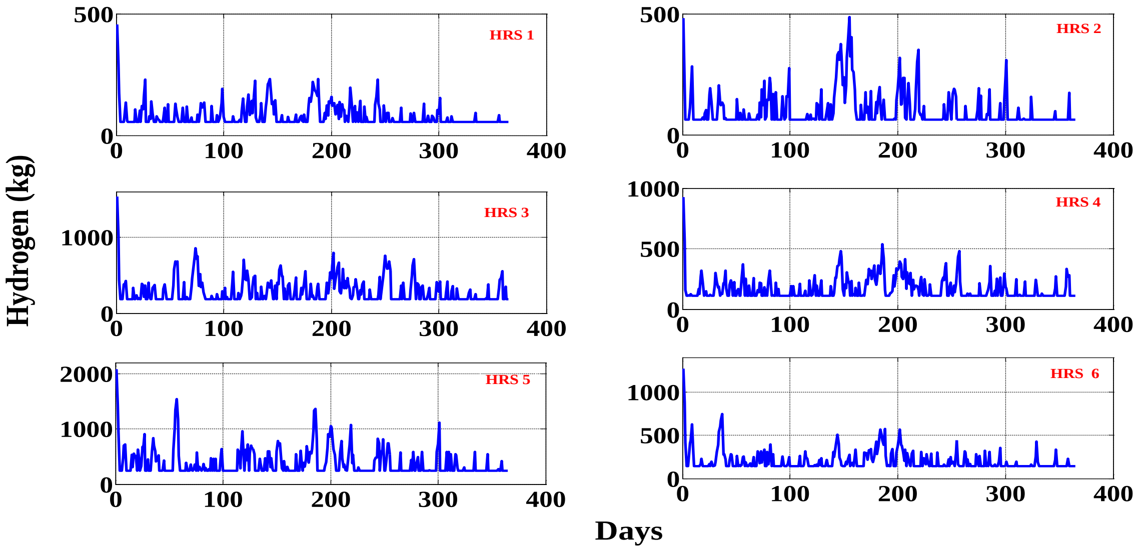


Figure 8.10: Variation in hydrogen storage levels throughout the year for each forecourt of previous scenario (LAE Sc. 1)

As we can see, the hydrogen in the storage tank only rarely reaches its maximum, which means this tank size could accommodate a new bigger electrolyser. Another component whose size would need to be increased is the compressor, since it is located between the production and storage. The compressor should be increased equal to electrolyser increase since all production will pass through the compressor to the storage.

a) Double-sized default electrolyser test (LAE Sc. 2)

In this scenario, the size of electrolysers and compressors will be doubled and the new cost of these components will be taken into account. This scenario will follow the same instructions as the last. For the electricity price mechanism, the same days as in last scenario (LAE Sc. 1) will be analysed. A summary of the electricity price mechanism for these days is given in Figure 8.12. For the first day, the surplus energy available is not sufficient for all HRSs; the bid price of HRS 2 is accepted as the daily selling price with HRS 5 running out that day because its prices were lower than the bid price.

On the second day (day 45), some of the prices were negative. The reason of this was that meeting the hydrogen demand on that day could not meet the economic requirements. Due to the storage constraints that day, the remaining space in the tank was small; this led to a reduction in the amount of hydrogen required, which could not then meet the investment cost.

The investment cost is divided equally over each day of the year, so every day the same amount of money is required to cover this expense. For day 45, the energy available was only just enough to meet the needs of HRS 5, and the price for that day was set the bid-price level of HRS 5. On day 46, the energy available was enough to meet the requirements of two highest bid prices, (those of HRSs 2 and 3), with the daily price being set as the cheapest bid by these two HRSs.

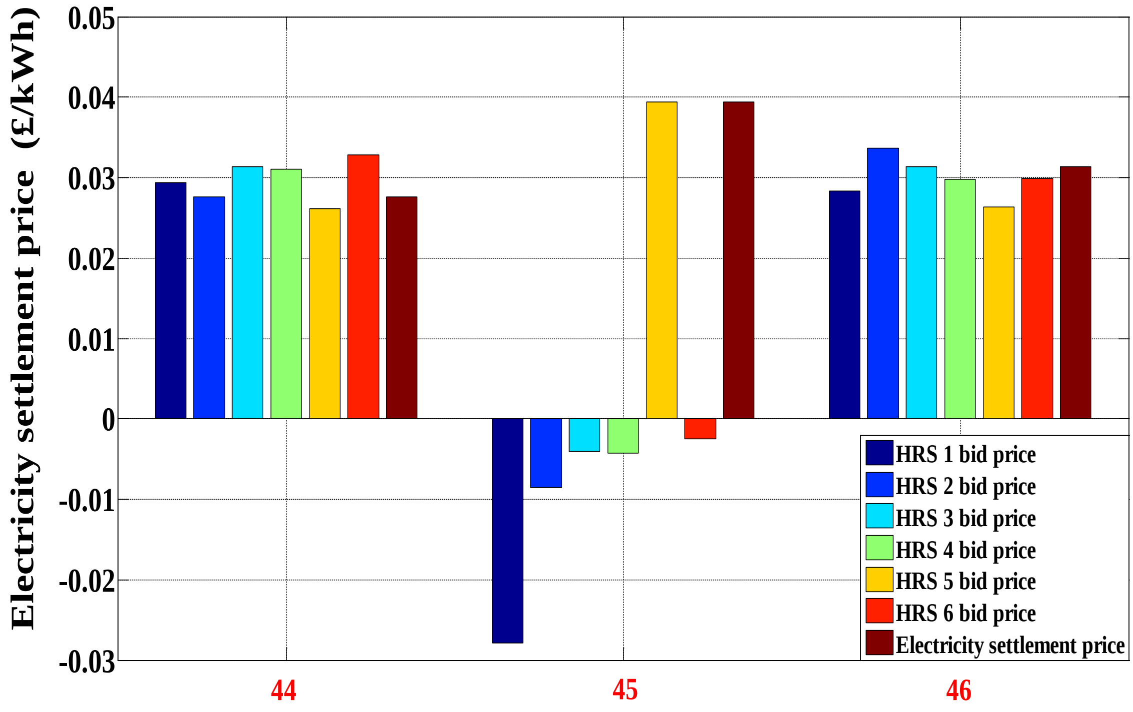


Figure 8.11: The electricity pricing mechanism for selected days of the year double-sized default electrolyser (LAE Sc. 2) (2015-Cost scenario)

The daily electricity prices for the year are shown in Figure 8.12.

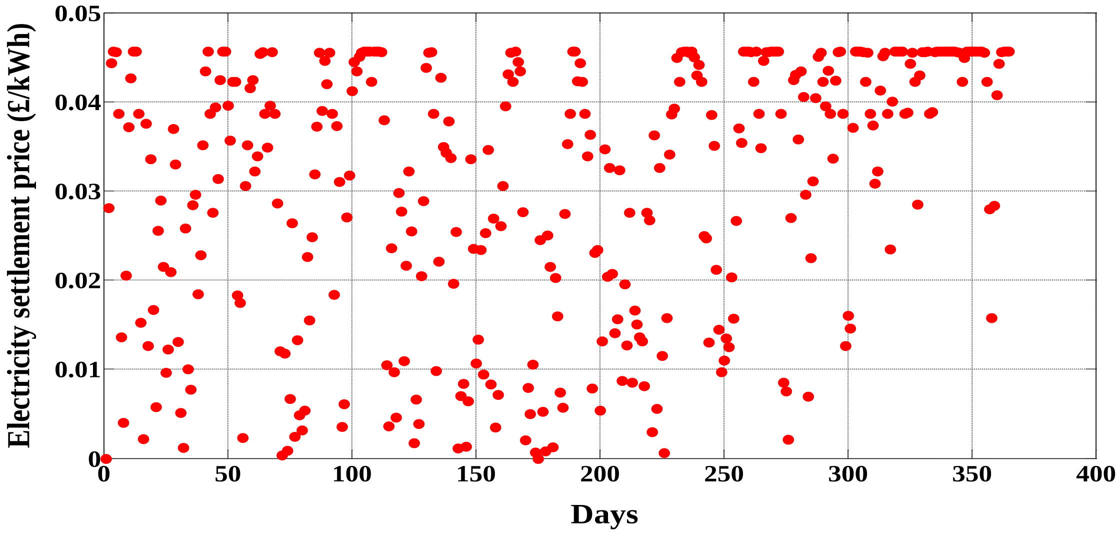


Figure 8.12: Daily settlement price over a year for double-sized default electrolyser LAE Sc. 2 (2015-Cost scenario)

The difference between the last scenario and this one in terms of the electricity price is that the price variability in this scenario is higher. The price was frequently low or close to zero, whereas for the last scenario the variation mostly fluctuated between 5 and 4 p/kWh. This is reasonable since the competition between HRSs will lead to greater differentiation in electricity prices, and a longer investment cost for a particular HRS requires cheaper electricity to achieve a profit. Hydrogen production and demand for this scenario are shown in Figure 8.13 and reported in Table 8.4.

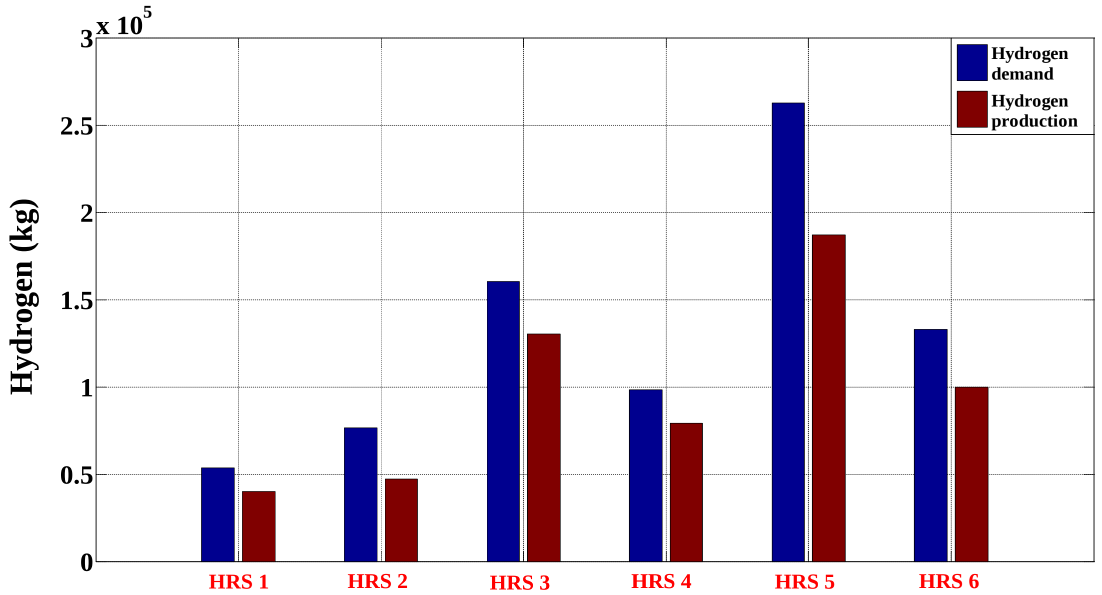


Figure 8.13: Hydrogen demand and production throughout the year for each HRS (LAE Sc. 2)

HRS no.	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Hydrogen production (kg/year)	40,033	47,090	130,076	78,957	186,994	99,759
Hydrogen demand (kg/year)	53,645	76,519	160,157	98,244	262,535	133,005
Satisfication of Hydrogen demand (%)	75%	62%	81%	80%	71%	75%

Table 8.4: Comparison between hydrogen production and hydrogen consumption in all six HRSs throughout the year (LAE Sc. 2)

This scenario can meet around 75% of the total hydrogen demand and around 67% of the total surplus energy can be absorbed.

The economic assessment and average hydrogen cost, as based on costs and production in this scenario (LAE Sc. 2), are given in Table 8.5.

Cost / HRS	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average price** (£/kg)
HRS 1	299,354	1,370	4,233	51,473	40,033	9.00
HRS 2	390,526	1,611	4,479	53,960	47,090	9.60
HRS 3	939,152	4,451	14,459	178,224	130,076	8.70
HRS 4	594,309	2,702	8,601	106,016	78,957	9.00
HRS 5	137,139,4	6,399	18,743	243,724	186,994	8.80
HRS 6	772,894	3,414	11,121	120,035	99,759	9.00

Table 8.5: Hydrogen production cost details per HRS for double-sized default electrolyser (alkaline, 2015-Cost scenario) (LAE Sc. 2)

In this scenario, the average hydrogen prices of the HRSs are similar or less than those in the previous scenario. This reduction is driven by two main issues, namely the production of hydrogen being higher and the reduction in electricity price because of the competition between HRSs.

An increase in the size of the electrolyser and compressor requires more space in the forecourt, which is considered unfavourable. Figure 8.14 shows the cost of the system components as a proportion of the total hydrogen cost.

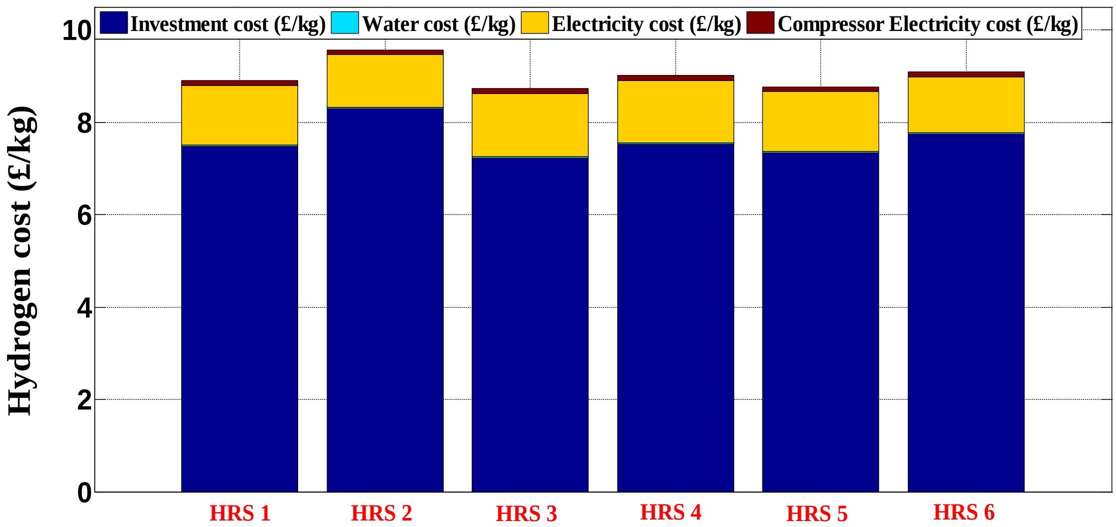


Figure 8.14: Hydrogen cost breakdown per kilogram at each HRS for double-sized default electrolyser (LAE Sc. 2) (2015-Cost scenario)

This scenario, with a new size of electrolyser and compression system, cannot meet the target for the system as only 67% of total surplus energy is consumed and 75% of total hydrogen demand is met. Increasing the size of these components by a factor of three could possibly give better results than seen in this scenario because the average price is still less than the original price in the double-size scenario.

b) Triple-sized default electrolyser test

Increasing the size of the system by a factor of three could help solve the two problems identified above, but issues surrounding the storage tank have to be investigated first. The storage might not accommodate the new production levels with its current size. Figure 8.15 below shows the variation of hydrogen levels in the store for the double-sized scenario throughout the year. All HRSs reached the limit of their tank's capacity many times during the year, which means this storage size is unable to accommodate the production associated with the new compressor size. This will lead to a restriction in production, based on the space in the tank, as the production has to be passed to the storage before consumption. Three different scenarios for the storage have been tested with the triple-sized electrolyser. An increase in system size could partially treat the problem of grid balancing by absorbing more energy and thus reducing the shortage of the hydrogen demand. However, the hydrogen price dramatically increased from £9/kg in the previous (same storage) scenario to nearly £16 /kg (triple-sized electrolyser).

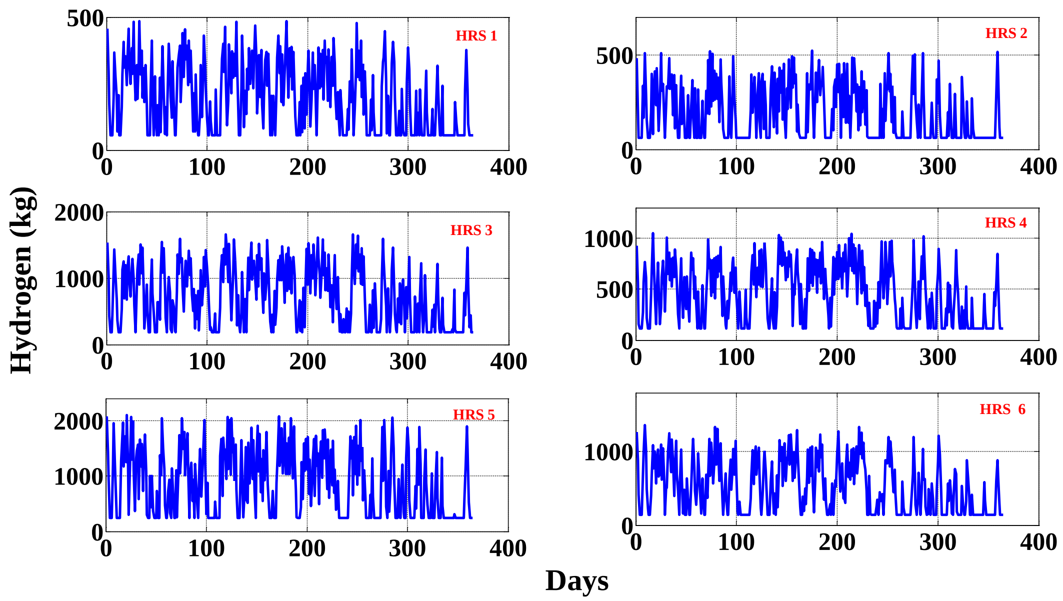


Figure 8.15: Variation in hydrogen storage levels throughout the year for each HRS (LAE Sc. 2)

Clearly, there is still more energy that can be absorbed and some hydrogen demand that needs to be satisfied in all the above scenarios. The electricity price is strongly reliant on the daily investment cost and the hydrogen required to meet demand. The average electricity prices were 17.4p, 019.1p, 20p /kWh for triple-sized electrolyser and 1.5 times storage size, triple-sized electrolyser and double-sized storage size and Triple-sized electrolyser and triple-sized storage respectively. Figure 8.16 below shows the electricity price for all three scenarios throughout the year.

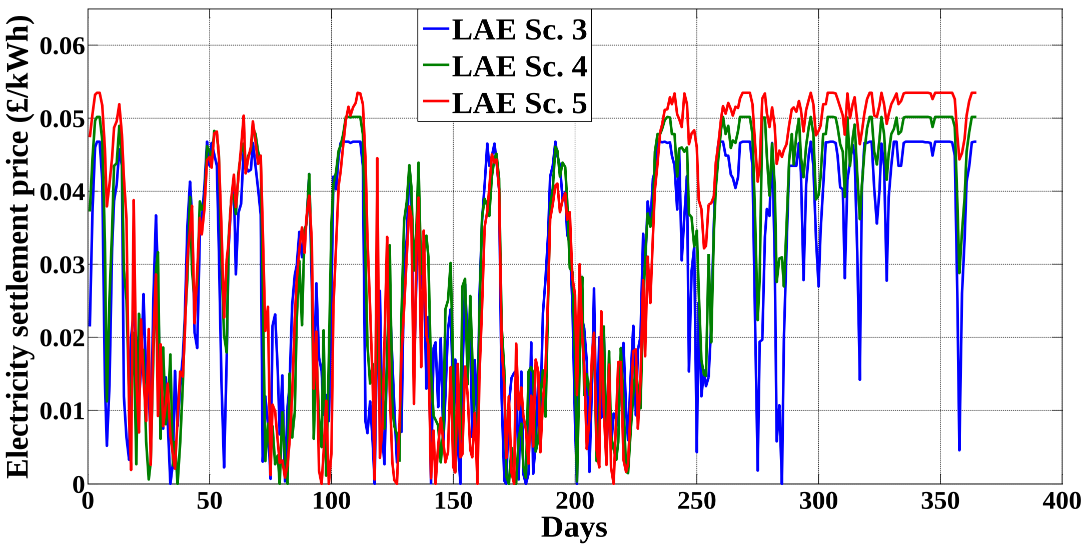


Figure 8.16: Daily settlement prices for different storage size (triple-sized alkaline electrolyser under 2015-Cost scenario)

Table 8.6 presents the techno- economic assessments of the system under different size of electrolyser and different storage sizes.

Scenario \ HRS		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Triple-sized default electrolyser and 1.5 times default storage size (LAE Sc. 3)	Hydrogen demand satisfaction (%)	82	65	87	87	77	83
	Average hydrogen price (£/kg)	11.50	12.80	11.50	11.80	11.50	11.80
	Total hydrogen demand satisfaction (%)	80					
	Total surplus energy consumed (%)	73					
Triple-sized default electrolyser and double-sized default storage size (LAE Sc. 4)	Hydrogen demand satisfaction (%)	85	76	90	90	81	86
	Average hydrogen price (£/kg)	13.00	12.90	13.10	13.40	12.80	13.40
	Total hydrogen demand satisfaction (%)	84					
	Total surplus energy consumed (%)	76					
Triple-sized default electrolyser and Triple-sized default storage (LAE Sc. 5)	Hydrogen demand satisfaction (%)	87	79	92	91	84	88
	Average hydrogen price (£/kg)	16.10	15.30	16.50	17.00	15.40	16.80
	Total hydrogen demand satisfaction (%)	87					
	Total surplus energy consumed (%)	78					

Table 8.6: Techno- economic assessments of the system under different size of electrolyser and different storage sizes (2015-Cost scenario)

8.2.3 Adding a large alkaline central electrolyser to the system

As defined by the US Department of Energy, a central electrolyser can be classified as being either one of central production or semi-central production. The criterion for this classification is merely one of daily hydrogen production: i.e. the hydrogen production of a central electrolyser is defined by the US DOE as being 750,000 kg/day or greater, and will be required in the long term to satisfy a large hydrogen demand (U.S. Department of Energy, 2015). In contrast with distributed production, centralised production needs a greater capital investment cost as well as substantial hydrogen delivery and a transport infrastructure. Semi-central production fluctuates between 5,000–50,000 kg/day and, being located in close proximity (25–100 miles) to the point(s) of consumption, may play a substantial role in the long-term usage of hydrogen as an energy carrier. These facilities can supply not only a level of economy of scale, but also reduce the costs of hydrogen transport and infrastructure (Xiao et al., 2011). The inclusion of a central or semi-central electrolyser will be considered for the Darnah case study in the next section.

8.2.3.1 Methodology of the system

A central electrolyser will be added to the Darnah system to absorb the remaining surplus energy and to supply hydrogen to the garage forecourts shortages appeared in previously tested scenarios. There are two possible modes of operation for the central electrolyser, both of which will be investigated. The first is one where the central electrolyser runs at the same time as the six HRSs and is regulated by the same electricity price mechanism. In this instance, the entire system does not require any power incentives as all garage forecourts and the central electrolyser will ‘play the same game’ in terms of electricity purchasing. However, if the central electrolyser’s settlement price is set after the HRSs, some incentive has to be offered to encourage the central unit to accept such an offer. In this research, the electricity price for the central electrolyser is set at 20% less than the the HRS settlement price (even if not all the HRSs can accept the settlement price on that day). In addition, a percentage of the investment cost could be added to the capital cost to guarantee a favourable economic situation. The central electrolyser is assumed to be financed via a loan set at a rate of 5% interest over seven years in this scenario. Running the central electrolyser after the garage forecourts have been refuelled, however, could lead to economic difficulties, especially on days of little surplus energy. These operational modes for the central electrolyser are connected with the assessment of the garage forecourts; each mode will be investigated to determine the possibility of a given scenario achieving its main objectives, which are grid balancing and meeting hydrogen demand at an acceptable price.

8.2.3.2 Sizing the system

In terms of cost and the size, the same assumptions in as in the previous chapter will be made. However, the central electrolyser components have to be sized. These components include the electrolyser, storage and compression systems.

a) Central electrolyser sizing

The central electrolyser can be sized based on the production side (surplus energy) or consumption side (garage forecourts' maximum production). For the production side, the size should be sufficient to consume as much of the remaining surplus energy as possible after the HRSs have been accounted for. However, in this case, the size will be quite large and there is no guarantee that all the absorbed energy will be sold to the HRSs during shortages. In terms of the production side, the size will be based on the total daily production of the six HRSs. If the target size is dictated by surplus energy side, it is likely to be different to one dictated by the demand side, an assessment of the main objectives must be computed in each case.

Figure 8.17 shows the sizes chosen for the central electrolyser. They are based on the amount of energy consumed, namely 59,971 kWh (LAE Sc. 6) (38% of the remaining energy), 105,000 kWh (LAE Sc. 7) (60% of remaining energy), 165,000 kWh (LAE Sc. 8) (80% of remaining energy), and 265,000 kWh (LAE Sc. 9) (95% of remaining energy).These estimated values for energy consumed for a given size might change depending on certain system constraints, such as storage size and demand.

The average price of hydrogen will be determined for all sizes, where hydrogen demand is met and grid balancing is achieved. If the target size is based on the demand side, the central electrolyser size is equal to the sum of the capacities of the forecourt electrolysers (LAE Sc. 10) (≈ 2200 kg/day).

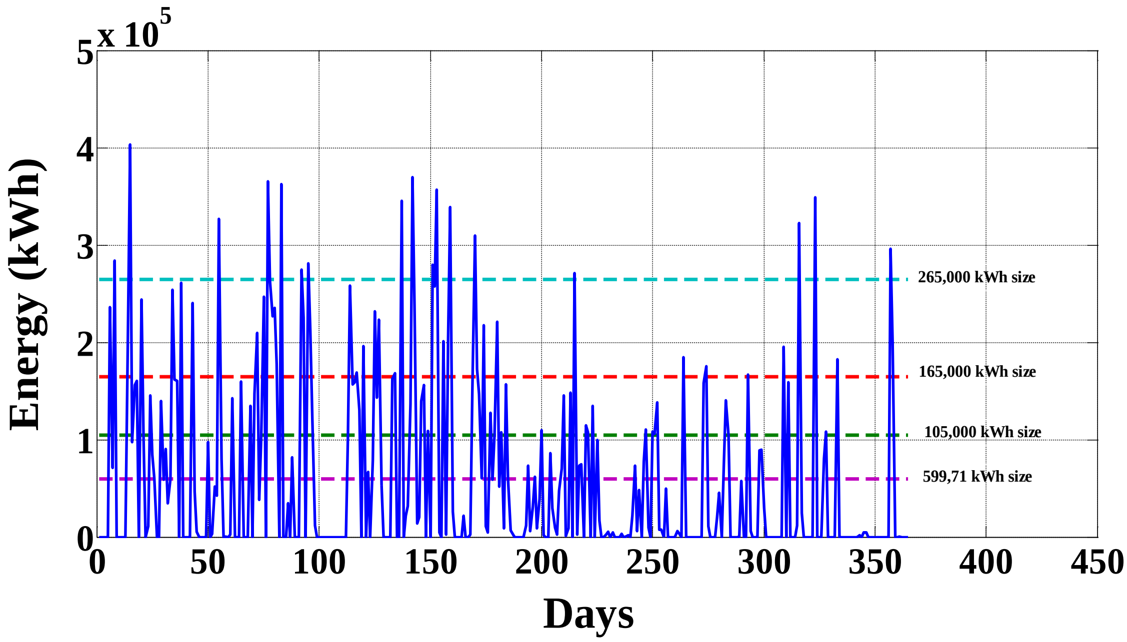


Figure 8.17: Remaining surplus energy after supplying garage forecourts, as compared with the different sizes of electrolysers

b) Storage size

The storage size will critically rely on the production. Each size of the electrolyser requires a specific storage volume. However, we will assume five days of production as being the required storage for each size of electrolyser due to the shortages over several (usually four or five) consecutive days that frequently occur. This chosen size of storage is due to the shortage of power that occur many times during the year (typically no more than five consecutive days) for the consumption side, so it will be sized on the basis of five days of production (10,000 kg/day).

c) Compression system

Nearly one day of production will be assumed for each size because of the location of the compressor between the electrolyser and storage tank.

8.2.3.3 Alkaline central electrolyser sizing based on the production side

Two modes of central electrolyser operation will be tested in this section: the central unit will run in the same way as the garage forecourts, so every day it will release an economic electricity bid price and follow the electricity pricing mechanism, as if it were just another HRS and the electricity settlement price of the HRSs and the central electrolyser are different. In other words, the utility company has to check the bid price of HRSs first and choose the settlement price of all HRSs. After that, another settlement price will be given to the central electrolyser.

a) Central alkaline electrolyser operates under a different electricity settlement price to the HRSs

The electricity settlement price of the HRSs and the central electrolyser are different. In other words, the utility company has to check the bid price of HRSs first and choose the settlement price of all HRSs.

After that, another settlement price will be given to the central electrolyser. If the central electrolyser's settlement price is set after the HRSs, some incentive has to be offered to encourage the central unit to accept such an offer.

In this research, the electricity price for the central electrolyser is set at 20% less than the HRS settlement price (even if not all the HRSs can accept the settlement price on that day). 20% is considered a reasonable profit margin for many economic projects (Investopedia, 2015).

Four different sizes for system components will be tested in the model, and it will be determined at each size whether the main aims can be met.

These sizes are LAE Sc. 6, (this central electrolyser will only take 38% of the remaining energy), LAE Sc. 7 (60% of the remaining surplus energy), LAE Sc. 8 (80% of the remaining surplus energy), and LAE Sc. 9 (95% of the remaining surplus energy).

The price of electricity sold to the HRSs will be the same for all central electrolyser sizing scenarios where the central electrolyser is running after the garage forecourts.

Thus it will not affect the electricity price mechanism decided between the electricity producer and the garage forecourts. Figure 8.18 shows one day of the process that would be applied every day throughout the year.

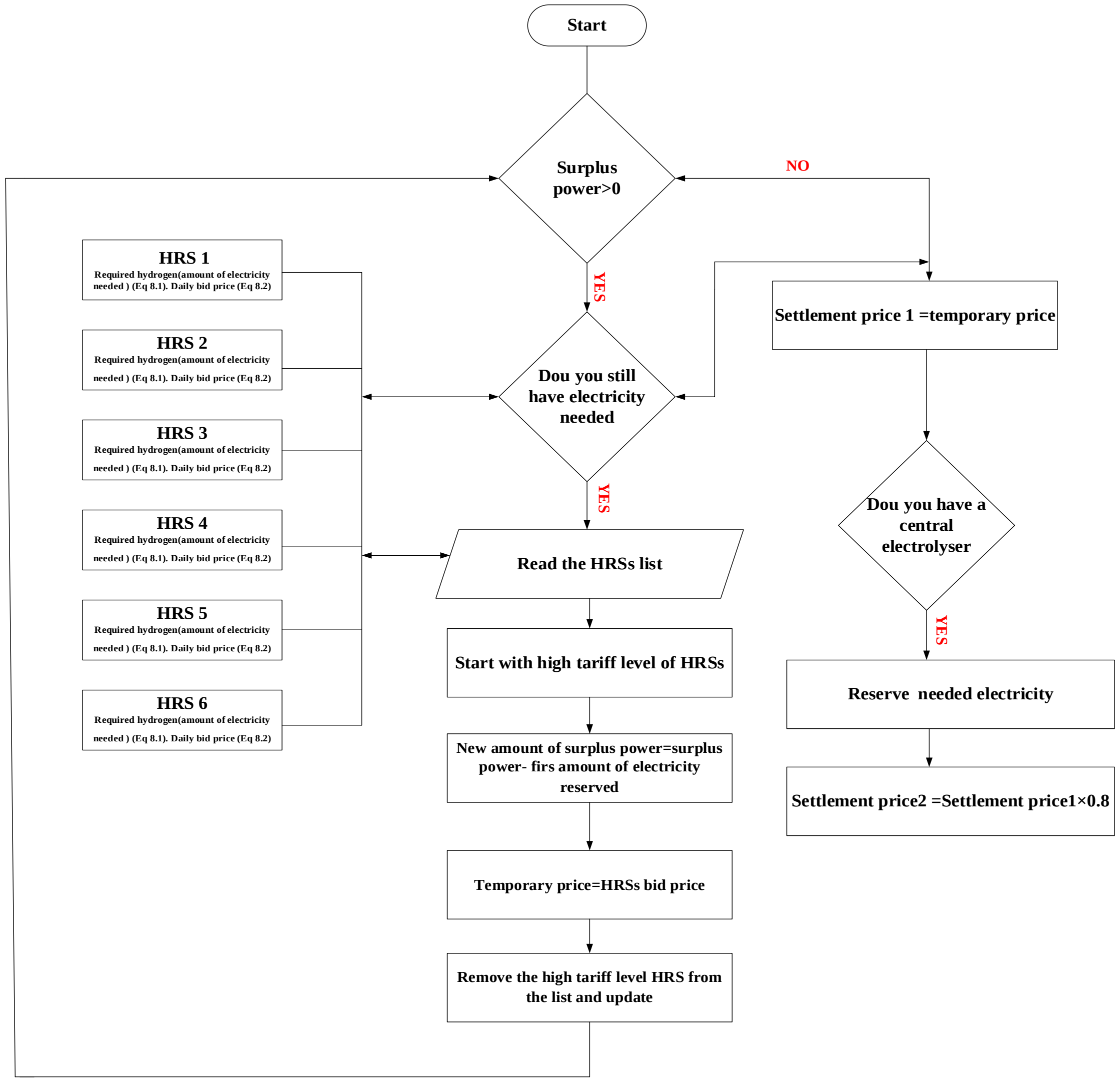


Figure 8.18: Electricity pricing mechanism for one day when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

As we can see, the electricity producer started with an expensive price, which was released by HRS 6, after which the amount of the energy remaining will be checked based on the 90% condition discussed above for the surplus energy (so in other words the remaining energy should be less than 10% before sales are stopped). However, because on this particular day the amount of energy was sufficient to supply all the HRSs, the cheapest price that of HRS 5, was accepted as the price for that day; the remaining surplus energy after all six HRSs absorbed their own requirements is then absorbed via the central electrolyser at a 20% reduction over the HRSs settlement price. The electricity mechanism for the garage forecourts and for the central unit on selected days of the year is shown in Figure 8.19.

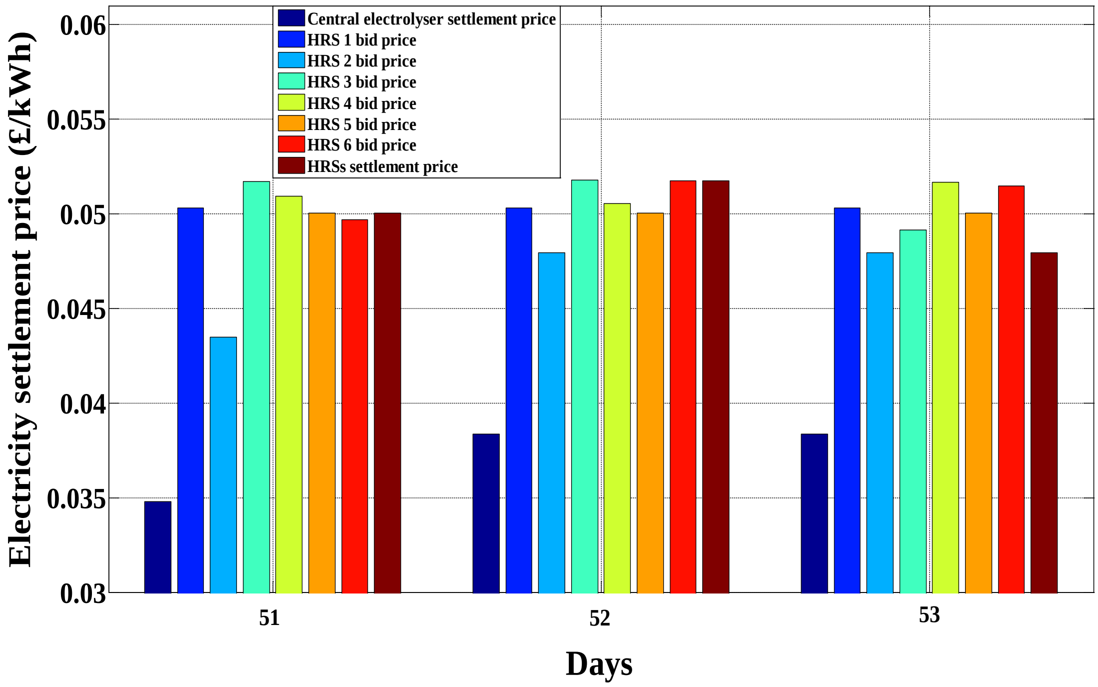


Figure 8.19: Electricity pricing mechanism for certain selected days when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

Three days have been chosen as an illustrative example to explain the electricity price mechanism, which are days 51, 52 and 53.

On day 51, the surplus energy is not sufficient to supply all HRSs, so only four HRSs were refuelled. In addition, HRS 5 was not fully supplied, and so the price at the garage forecourts was set as that of HRS 5 bid price. However, the selling price to the central electrolyser is dependent on the cheapest price, which on this day was set by HRS 2. Hence, the central unit price on day 51 was set as 20% less than that of HRS 2.

On this day, even though the price to the central unit has been determined, central hydrogen production was zero because there was not enough surplus to even supply the forecourts. For the second day (52), only two HRSs were refuelled: HRS 3 and HRS 6, and the selling price to the garage forecourts was set at the bid price of HRS 6.

This leaves less than 90% of the surplus energy having been sold (the condition to stop selling to the garage forecourts), so the remainder will be sold to the central electrolyser at a 20% lower price than HRS 2 bid price (the cheapest bid price set at the HRSs that day). The central electrolyser can absorb any amount of energy, at least within the bounds that the size of the electrolyser and storage tank allow.

On the last day (53), the surplus energy was sufficient to meet all the HRSs' requirements, and so the remainder will be consumed by the central electrolyser.

The cheapest bid price was released by HRS 2, which determines the selling price to all HRSs, whilst at the same time the central price was set at 20% that of the HRS 2 bid price. The main job of the central electrolyser is to absorb the remainder of the surplus energy and deliver hydrogen to the HRSs at the forecourt during shortages. However, the economic target for the central unit still has to be achieved.

The central electrolyser system was financed by a seven year loan at a 5% rate of interest. The hydrogen price should cover the variable costs and the investments costs. Simply put, the average hydrogen price from the central electrolyser should follow Equation (8.4):

$$Average\ hydrogen\ price\ (£/kg) = \left(\frac{Total\ cost\ (£\ /year)}{Hydrogen\ production\ (kg/year)}\right) \tag{8.4}$$

For the garage forecourts, the cost calculations are the same as in other scenarios but with the addition of the cost of hydrogen imported from the central unit. The imported hydrogen cost can be calculated as per Equation (8.5):

$$Imported\ hydrogen\ cost = Central\ average\ hydrogen\ price \times Total\ imported\ hydrogen \tag{8.5}$$

The production and the variation in stored hydrogen in all central electrolyser size scenarios are presented in Figure 8.20 and Figure 8.21, respectively.

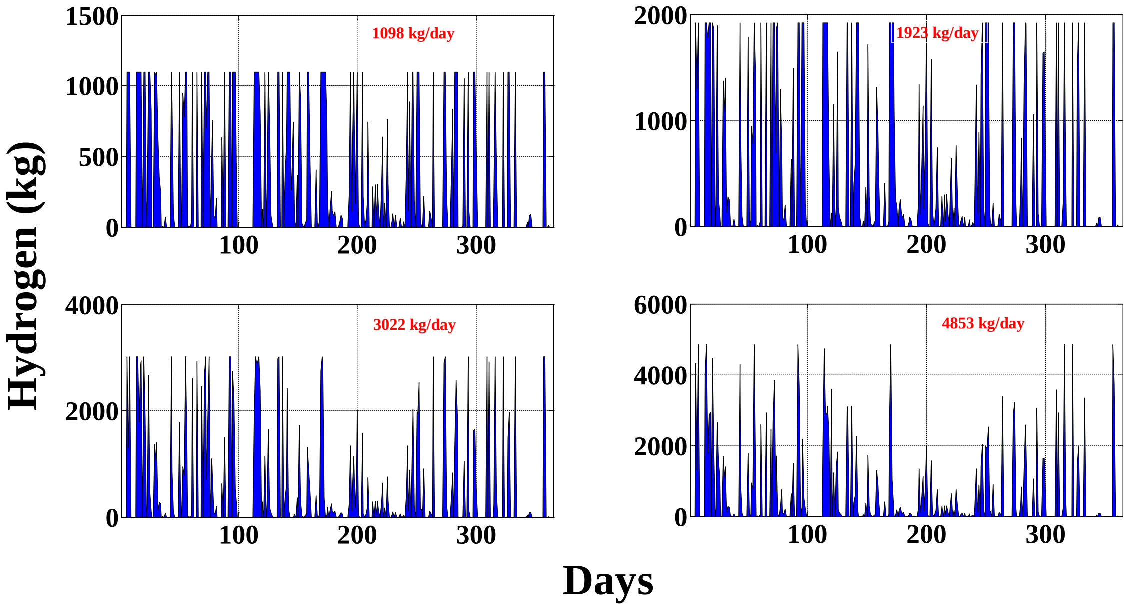


Figure 8.20: Hydrogen production of central electrolyser under different electrolyser sizes when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

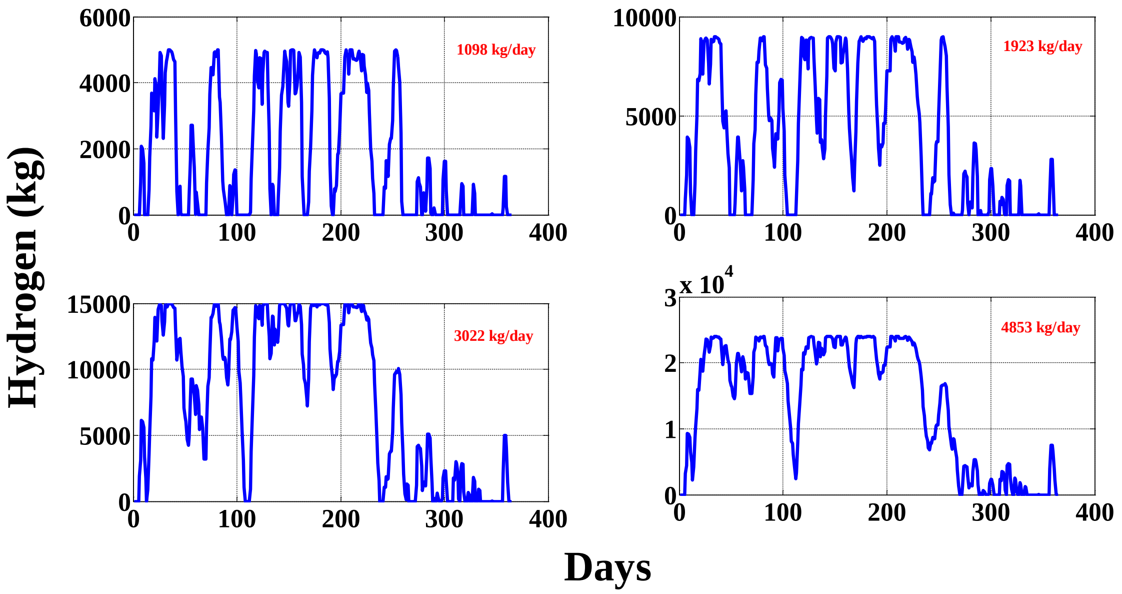


Figure 8.21: Daily variation of Hydrogen level in storage tank throughout the year using different sizes of electrolyser when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

Table 8.7 below summarises the economics and the assessment of each option in terms of achieving the main objectives of the research namely grid balancing support, hydrogen demand satisfaction and hydrogen price target.

Central electrolyser size (kg/day)	HRSs	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
LAE Sc. 6	Satisfaction of hydrogen demand (%)	71	67	77	74	77	74
	Average hydrogen price (£/kg)	12.00	12.40	11.30	11.50	12.40	12.60
	Total energy consumed after adding central electrolyser (%)	68					
	Satisfaction of total hydrogen for HRSs (%)	75					
	Average central electrolyser hydrogen price (£/kg)	21.00					
LAE Sc. 7	Satisfaction of hydrogen demand (%)	77	77	84	81	82	81
	Average hydrogen price (£/kg)	14.00	15.00	13.00	13.30	14.30	14.60
	Total energy consumed after adding central electrolyser (%)	73					
	Satisfaction of total hydrogen for HRSs (%)	81					
	Average central electrolyser hydrogen price (£/kg)	26.00					
LAE Sc. 8	Satisfaction of hydrogen demand (%)	84	82	87	86	87	86
	Average hydrogen price (£/kg)	17.40	19.00	15.50	16.00	17.70	17.80
	Total energy consumed after adding central electrolyser (%)	78					
	Satisfaction of total hydrogen for HRSs (%)	86					
	Average central electrolyser hydrogen price (£/kg)	34.00					
LAE Sc. 9	Satisfaction of hydrogen demand (%)	88	87	89	89	90	89
	Average hydrogen price (£/kg)	22.30	24.60	19.30	20.00	22.70	22.40
	Total energy consumed after adding central electrolyser (%)	80					
	Satisfaction of total hydrogen for HRSs (%)	89					
	Average central electrolyser hydrogen price (£/kg)	46.40					

Table 8.7 Assessments of the system under different central electrolyser sizes when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

In this section, different central electrolyser component sizes, as based on the amount of energy consumed, have been investigated. It can be concluded that a large-sized electrolyser can provide two main benefits, namely those of grid balancing, by absorbing the majority of the remaining surplus energy, and meeting any hydrogen shortages at the garage forecourts. However, because of the high price of the hydrogen thus imported, the average price at the point of sale will be increased considerably, which will reduce the opportunity to compete with conventional fuels.

b) The central alkaline electrolyser operates under the same electricity settlement price as the HRSs

The central electrolyser participates in the electricity pricing mechanism as if it were just another HRS. Therefore, only one settlement price will be set for all the HRSs and the central electrolyser and the central electrolyser will buy electricity at the same settlement price as HRSs. Figure 8.22 shows one day's worth of operation for a capacity of 1098 kg/day, under the pricing mechanism that governs the relationship between the production and consumption sides over the year.

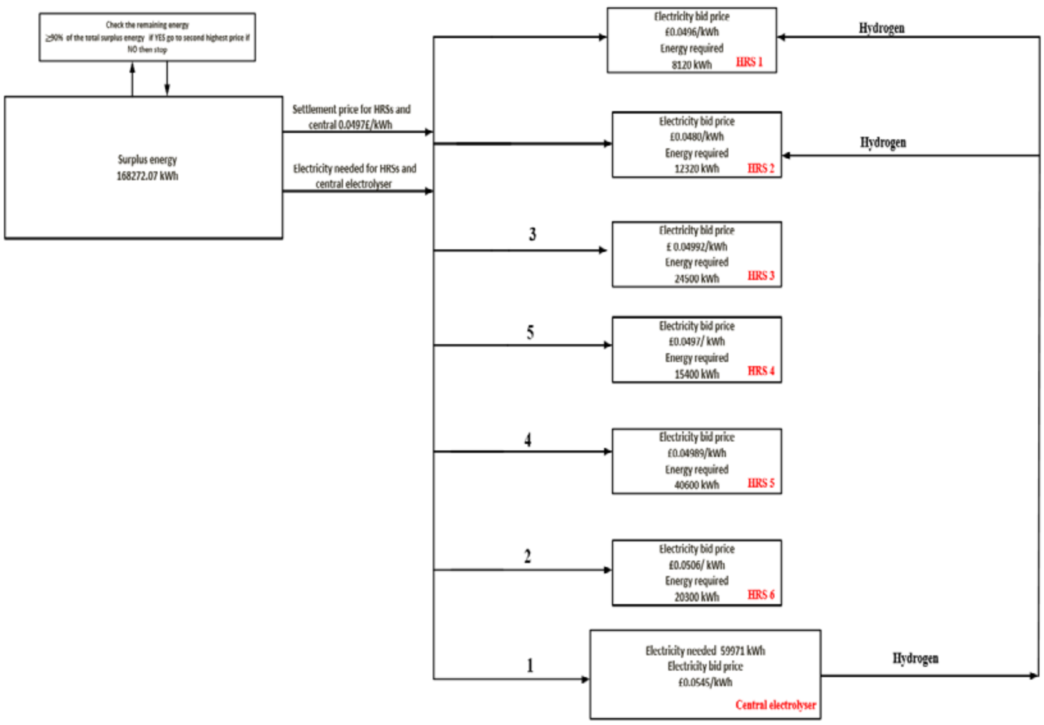


Figure 8.22: One day of electricity pricing mechanism when the central electrolyser runs under the same settlement electricity price as the HRSs (2015-Cost scenario)

For day 44 of the year, as in the previous scenario the electricity producer will start trading at an expensive price as released by the central electrolyser until the power side condition is achieved, which here is at HRS 4; then, HRS 4's price becomes the default price of the system including the central electrolyser. On this day, there were two HRSs that were running out of hydrogen and that could be refuelled by the central electrolyser. The selling price of the electricity price mechanism throughout the year is shown in Figure 8.23 for a system with a LAE Sc. 11:

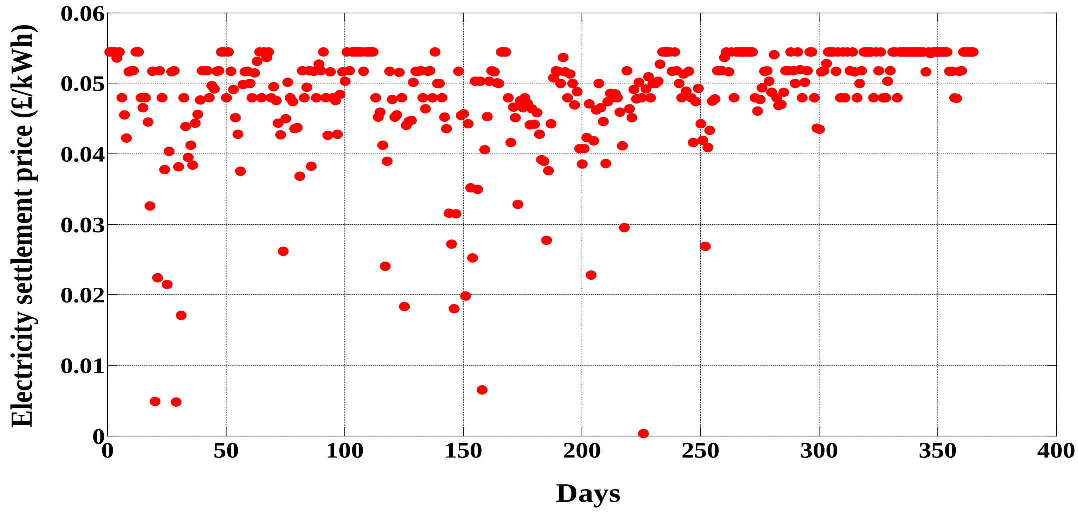


Figure 8.23: Electricity settlement prices to the HRSs and to the central electrolyser when the central alkaline electrolyser runs under the same settlement electricity price as the HRSs (LAE Sc. 11)

The daily hydrogen production and the variation of stored hydrogen for all HRSs including the central electrolyser are presented in Figure 8.24 and Figure 8.25:

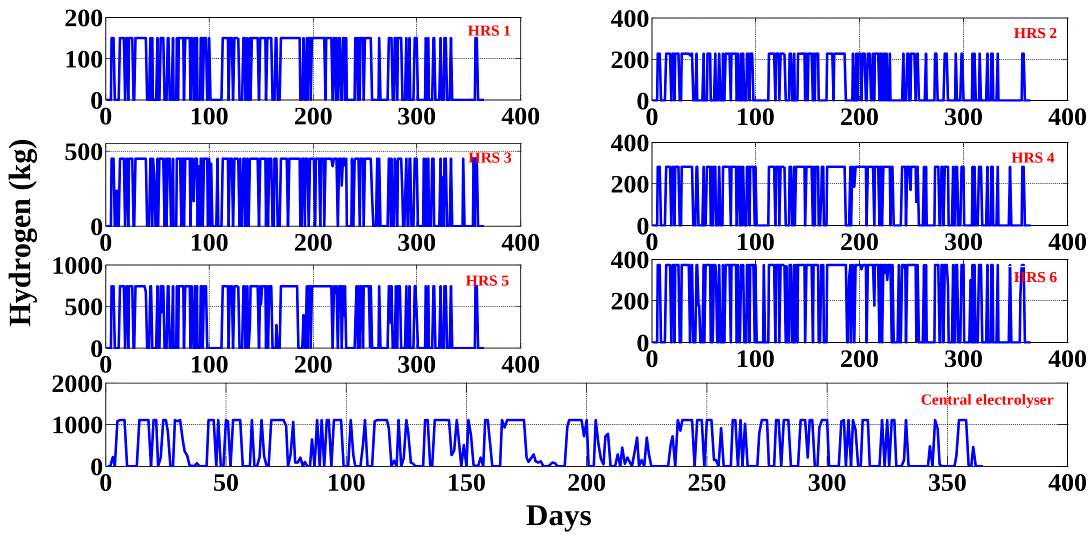


Figure 8.24: HRSs and alkaline central electrolyser hydrogen production throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (LAE Sc. 11) (2015-Cost scenario)

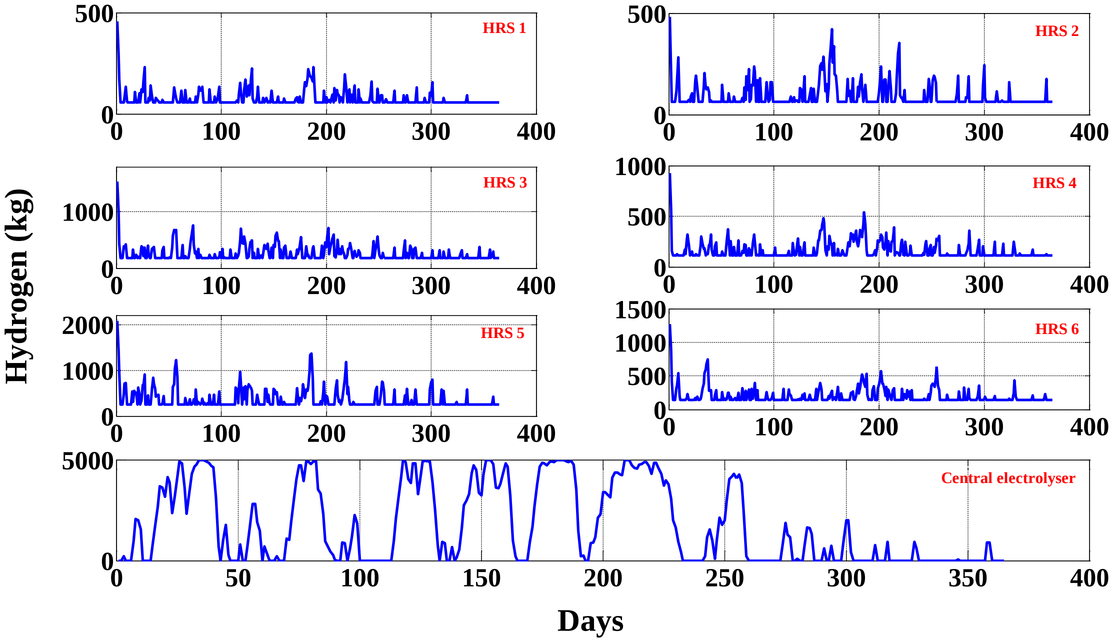


Figure 8.25: Daily variation of Hydrogen level in storage tank throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (LAE Sc. 11) (2015-Cost scenario)

The storage profile of the garage forecourts does not include the imported hydrogen since the storage in this case works just as a means to transfer the hydrogen from the central storage to the consumption area. Figure 8.26 shows the amount of imported hydrogen per garage forecourt during the year.

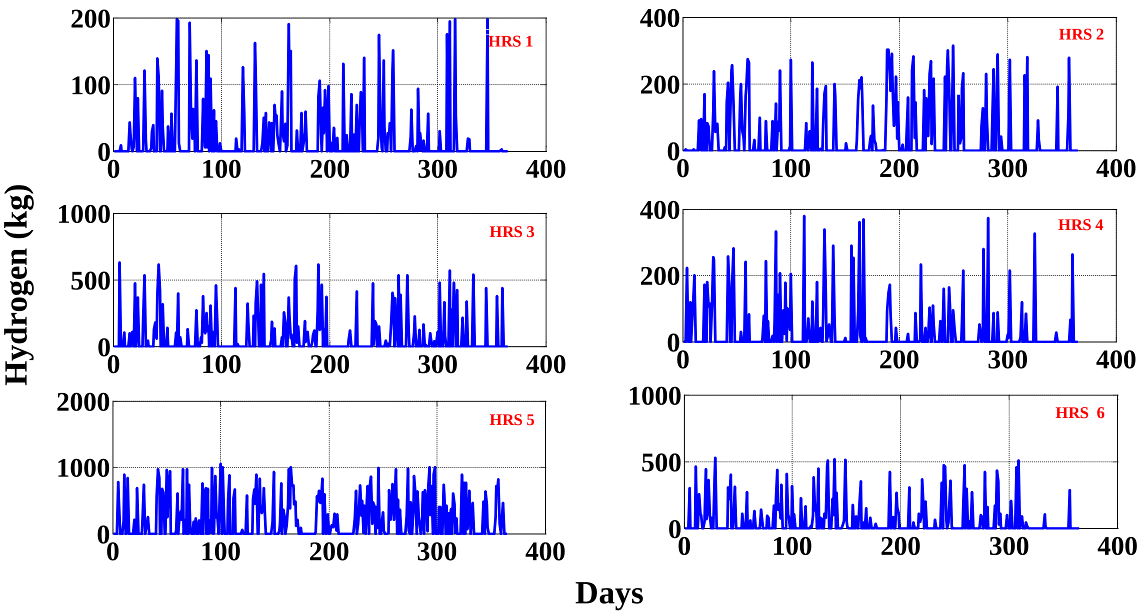


Figure 8.26: Hydrogen imported by HRSs throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (LAE Sc. 11) (2015-Cost scenario)

Table 8.8 below gives a summary using different central electrolyser sizing.

Central electrolyser size (kg/day) \ HRSs		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
LAE Sc. 11	Satisfaction of hydrogen demand (%)	65	66	76	69	82	74
	Average hydrogen price (£/kg)	12.00	12.50	11.60	11.80	12.60	11.80
	Total energy consumed after adding central electrolyser (%)	68					
	Satisfaction of total hydrogen for HRSs (%)	75					
	Average central electrolyser hydrogen price (£/kg)	15.70					
LAE Sc. 12	Satisfaction of hydrogen demand (%)	71	76	81	78	85	81
	Average hydrogen price (£/kg)	13.60	15.00	13.40	13.70	14.70	13.80
	Total energy consumed after adding central electrolyser (%)	73					
	Satisfaction of total hydrogen for HRSs (%)	81					
	Average central electrolyser hydrogen price (£/kg)	20.20					
LAE Sc. 13	Satisfaction of hydrogen demand (%)	81	83	85	84	88	85
	Average hydrogen price (£/kg)	17.00	19.00	16.00	17.00	18.00	16.70
	Total energy consumed after adding central electrolyser (%)	77					
	Satisfaction of total hydrogen for HRSs (%)	86					
	Average central electrolyser hydrogen price (£/kg)	26.00					
LAE Sc. 14	Satisfaction of hydrogen demand (%)	86	87	88	88	91	88
	Average hydrogen price (£/kg)	22.70	25.00	20.00	21.50	24.00	21.30
	Total energy consumed after adding central electrolyser (%)	80					
	Satisfaction of total hydrogen for HRSs (%)	89					
	Average central electrolyser hydrogen price (£/kg)	37.00					

Table 8.8: Assessments of the system under different sizes of central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (2015-Cost scenario).

The average price of the hydrogen from central electrolyser is less than in the previous scenario, but the average hydrogen price at the garage forecourts is nearly the same. Since the capital costs of the garage forecourt components are the same in both central electrolyser scenarios (central electrolyser operation mode) and the variable cost is relatively low, the cost difference between these scenarios should depend on the amount, and the price, of the imported hydrogen. The imported hydrogen as a percentage of the total hydrogen delivered per garage forecourt could determine the stability of the hydrogen price in both scenarios. Table 8.9 shows the share of the imported hydrogen as a proportion of total hydrogen delivered to the consumption area in both scenarios under different sizing.

Scenarios		**HRSs**	**HRS 1**	**HRS 2**	**HRS 3**	**HRS 4**	**HRS 5**	**HRS 6**
Central electrolyser operates under different settlement price to the HRSs refuelled forecourts have been refuelled	**Imported hydrogen (%)**	**LAE Sc. 6**	19	23	15	13	25	21
		LAE Sc. 7	25	33	21	21	30	28
		LAE Sc. 8	31	38	25	25	34	32
		LAE Sc. 9	34	41	26	28	36	34
Central electrolyser and HRSs operates under the same settlement price forecourts	**Imported hydrogen (%)**	**LAE Sc. 11**	22	33	23	18	40	24
		LAE Sc. 12	29	44	30	29	43	32
		LAE Sc. 13	39	51	35	37	48	38
		LAE Sc. 14	43	52	35	39	49	39

Table 8.9: Imported Hydrogen by each HRS under different alkaline central electrolyser sizes and for two different modes of operation

The amount of imported hydrogen was greater in the second scenario, which will lead to an increase in the overall price. Therefore, the lesser amount of imported hydrogen at an expensive price in the first scenario is equivalent to a greater amount of imported hydrogen at a relatively cheap price. The operational mode of the central electrolyser does not have a strong influence on the system targets since all the consumed energy, satisfaction of hydrogen demand and the average price of the hydrogen are similar.

8.2.3.4 Alkaline central electrolyser sizing based on the consumption side

System sizing will rely on the maximum hydrogen production for all garage forecourts. In addition, the storage is equal to five days of production. The compression system is nearly equal to one day's worth of production. Based on these assumptions, the capacity of the central electrolyser is 121,240 kWh or 2220 kg/day (LAE Sc. 10) (at a conversion efficiency of 54.6 kWh/kg), with a hydrogen storage tank size of 11,000 kg and a compression system equal to the production size (2220 kg/day). The two-operation modes of the central electrolyser will be investigated as in the previous scenarios.

a) Central alkaline electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 10)

All system regulations and steps are the same as in the scenario described in Section 1.2.3.3. The electricity sale price to the garage forecourts and to the central electrolyser is given in Figure 8.27.

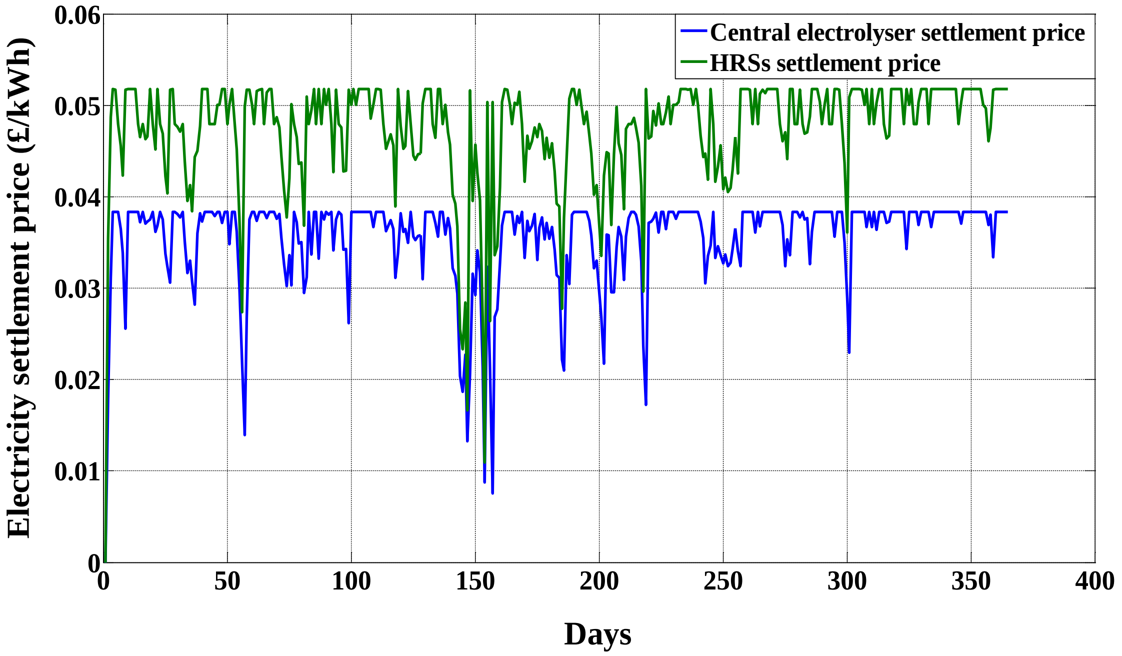


Figure 8.27: Electricity settlement price for the garage forecourts and central electrolyser when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 10) (2015-Cost scenario).

The central electrolyser price is cheaper than the garage forecourt price because of the incentive discount from electricity producer, which is a 20% reduction over the cheapest release price across all HRSs. Hydrogen production and the variation of stored hydrogen during the year for the central electrolyser is presented in Figure 8.28 and Figure 8.29. Table 8.10 shows an economic summary of the system.

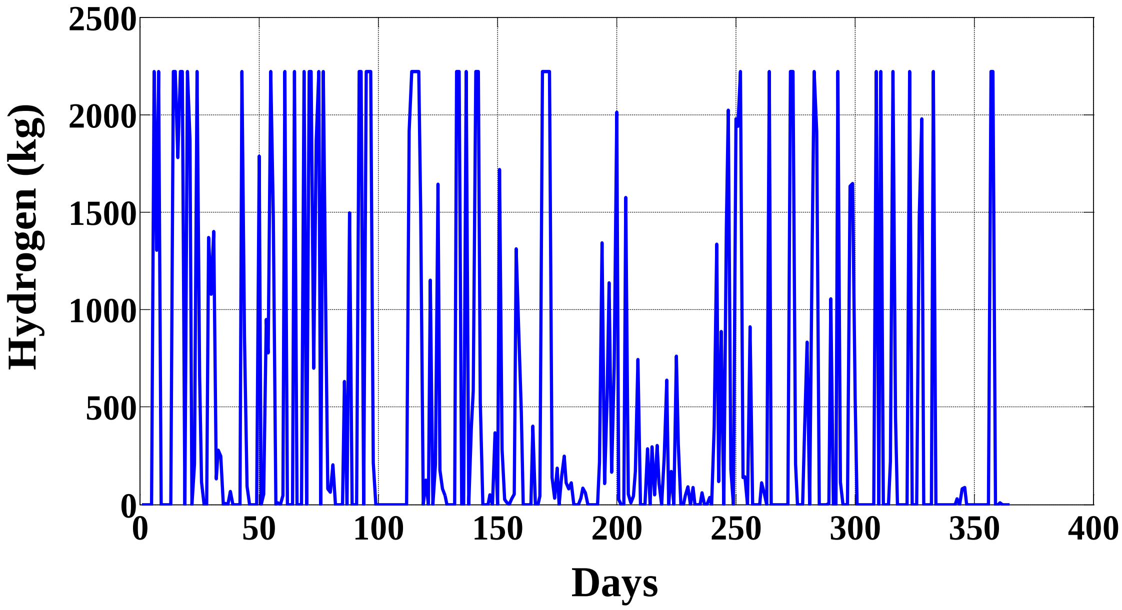


Figure 8.28: Alkaline central electrolyser hydrogen production throughout the year when central electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 10) (2015-Cost scenario).

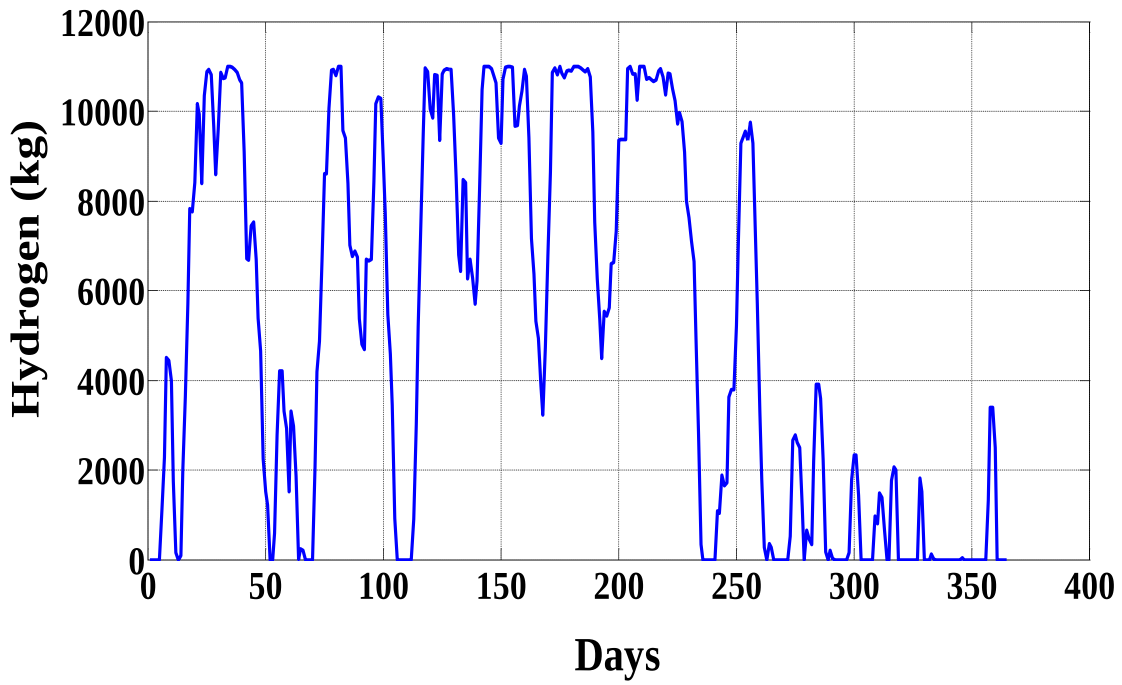


Figure 8.29: Daily variation of Hydrogen level in storage tank throughout the year when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 10) (2015-Cost scenario).

Details / **HRSs**	**Satisfaction of hydrogen demand** (%)	**Average hydrogen price** (£/kg)	**Total surplus energy consumed after adding central electrolyser** (%)	**Satisfaction of total hydrogen demand** (%)	**Average price of hydrogen from**
HRS 1	80	15.00	75	83	28.40
HRS 2	80	16.40			
HRS 3	85	14.00			
HRS 4	83	14.10			
HRS 5	84	15.30			
HRS 6	83	15.50			

Table 8.10: Economic assessment of the system when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 10) (2015-Cost scenario).

b) The central alkaline electrolyser operates under the same electricity settlement price as the HRSs (LAE Sc. 15)

This scenario is similar to the scenario presented in Section 1.2.3.3, but with different sized components (LAE Sc. 15). The central electrolyser in this section is treated the same as if it were one of the garage forecourts, and therefore follows the same steps in the pricing mechanism. The daily electricity price for the central electrolyser throughout the year is shown given in Figure 8.30:

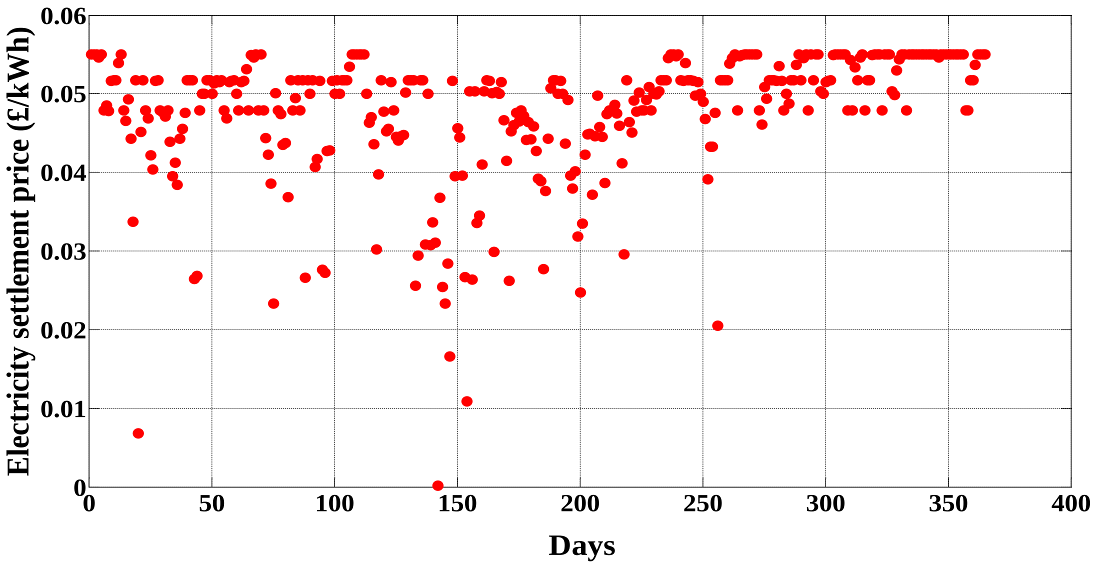


Figure 8.30: Daily electricity settlement price for HRSs and central electrolyser throughout the year when central electrolyser operates under the same electricity settlement price as the HRSs (LAE Sc. 15) (2015-Cost scenario)

The hydrogen production and the variation for hydrogen at the garage forecourts and central electrolyser are shown in Figure 8.31 and Figure 8.32:

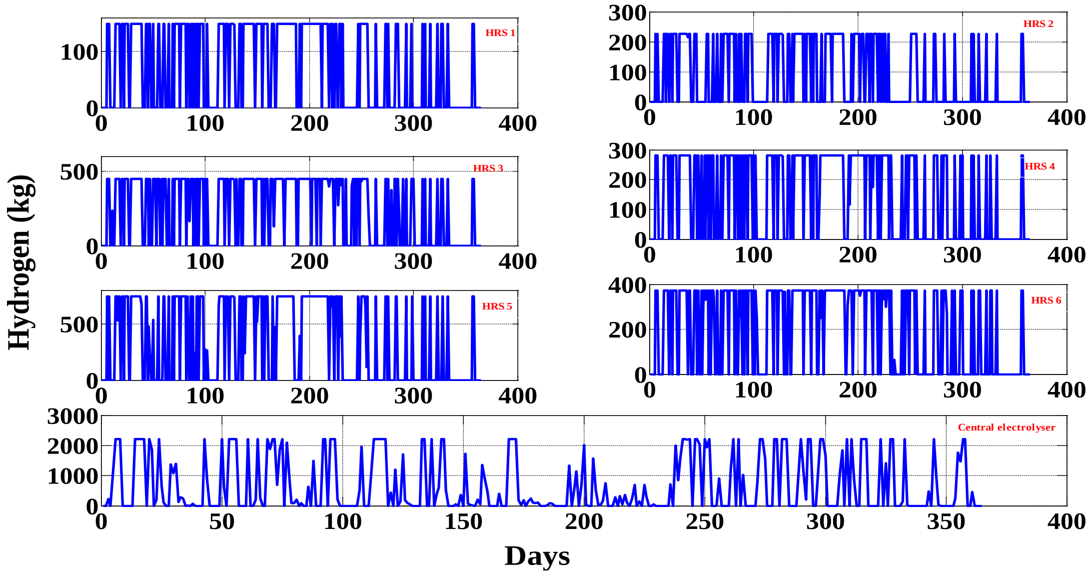


Figure 8.31: HRSs and alkaline central electrolyser hydrogen production throughout the year when the central electrolyser operates under the same settlement electricity price as the HRSs (LAE Sc. 15) (2015-Cost scenario)

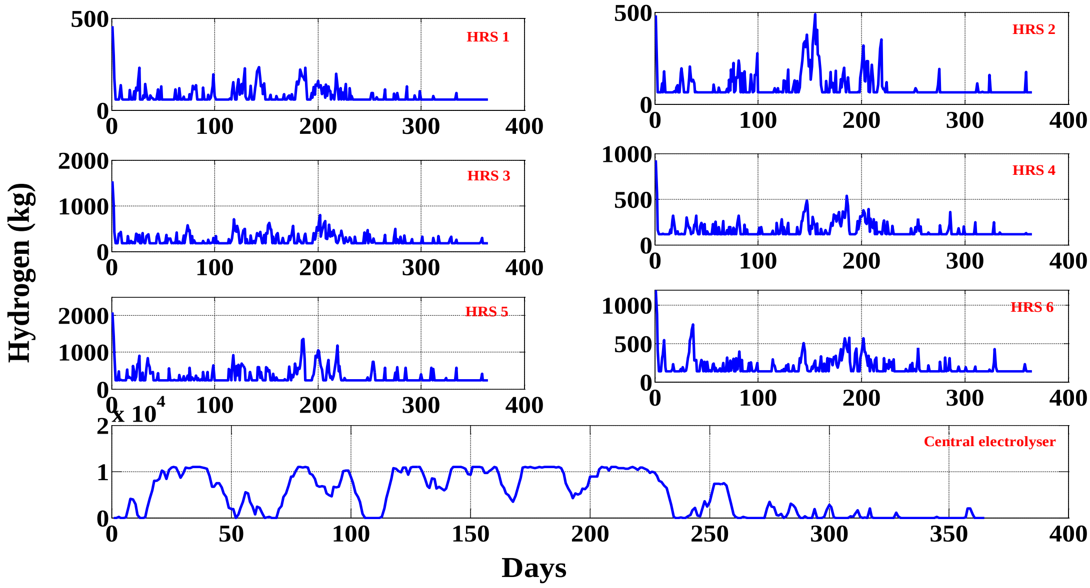


Figure 8.32: Daily variation of Hydrogen level in storage tank throughout the year when the central electrolyser operates under the same settlement electricity price as the HRSs (LAE Sc. 15) (2015-Cost scenario)

Table 8.11 shows a summary of the system and the assessment of having achieved the main goals including grid balancing, hydrogen demand being met and an acceptable selling price for the hydrogen.

Details / HRSs	Satisfaction of hydrogen demand (%)	Average hydrogen price (£/kg)	Total surplus energy consumed after adding central electrolyser (%)	Satisfaction of total hydrogen demand (%)	Average price of hydrogen from central electrolyser (£/kg)
HRS 1	77	15.00	75	83	22.10
HRS 2	79	16.00			
HRS 3	83	14.20			
HRS 4	81	15.00			
HRS 5	86	16.00			
HRS 6	82	14.40			

Table 8.11: Economic assessment of the system when the central electrolyser operates under the same settlement electricity price as the HRSs (LAE Sc. 15) (2015-Cost scenario)

As in other scenarios, the average price of hydrogen production via the central electrolyser is lower than when the central electrolyser operates under a different electricity settlement price to the HRSs. However, the average prices of hydrogen production at the garage forecourts are nearly same. As can be seen in Figure 8.33, the imported hydrogen per garage forecourt in the first scenario when the central electrolyser and HRSs have a different settlement price (an expensive hydrogen price) is lower than the imported hydrogen when the central electrolyser participates in the electricity pricing mechanism as if it were just another HRS. Despite a higher wholesale price (where the central electrolyser sell to the HRSs), the retail price (where the HRSs sell to FCEV drivers) is unchanged.

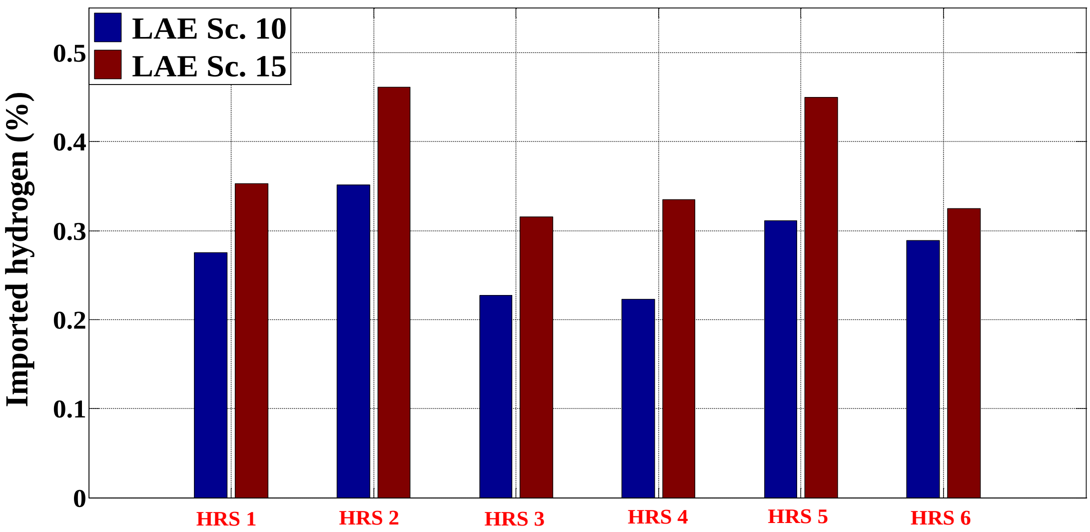


Figure 8.33: Percentage of imported hydrogen in each scenario (LAE Sc. 10 and LAE Sc. 15) as a proportion of the total delivered hydrogen

The sizing based on the electrolyser consumption side does not make a clear difference in contrast with the sizing based on the hydrogen production side. Generally, adding a central electrolyser could be one of the ways by which to consume more surplus energy and tackle any shortage in hydrogen supply, albeit with a relatively high hydrogen price. Further reduction in the investment cost, which is anticipated in the coming years, could reduce the production cost of the hydrogen further. As a result, 2030 price estimates for the system components, as extracted from various references, will be applied. The system cost (electrolyser, storage, compression system, dispenser and fixed costs) will be reduced. In addition, the electrolyser efficiency will improve, as based on the assumptions in Table 7.1.

8.3 2030-Cost scenario with alkaline electrolysers

The alkaline electrolyser will be used in this scenario, and all scenarios will be repeated and compared with the 2015-cost scenarios. Figure 8.34 shows all 2030-cost scenarios.

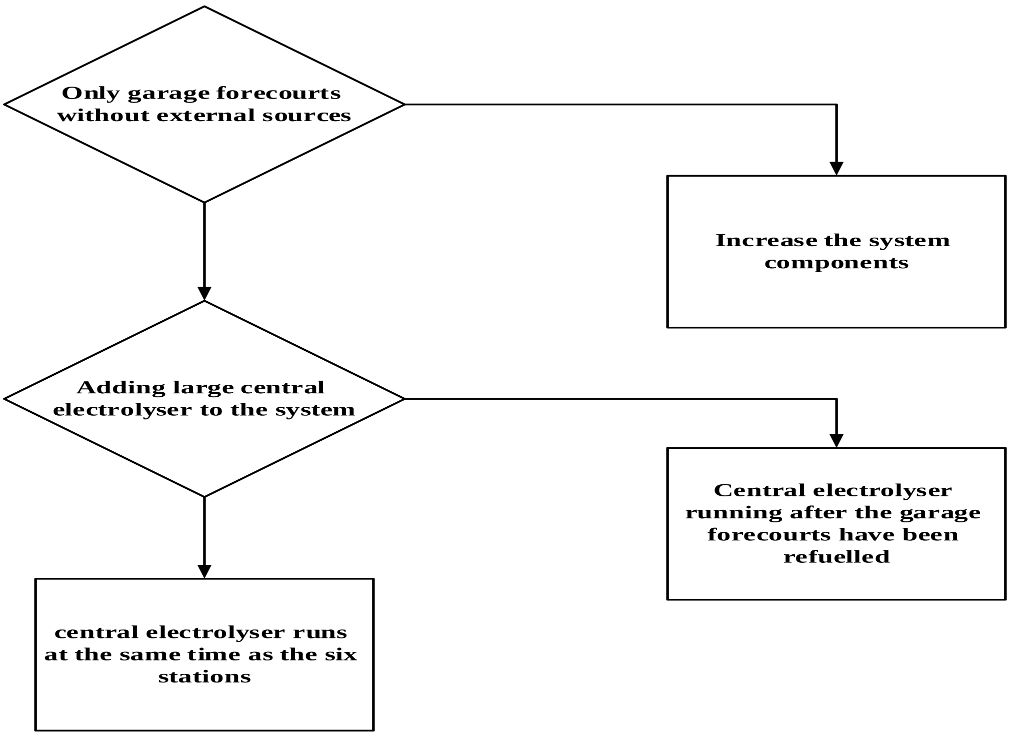


Figure 8.34: All scenarios options under 2030-Cost scenarios

The summary of all alkaline electrolyser scenarios when 2030-Cost scenario is applied are summarised in Table 8.12 below.

Details \ Scenario No.		LAE Sc. 16	LAE Sc. 17	LAE Sc. 18	LAE Sc. 19	LAE Sc. 20	LAE Sc. 21	LAE Sc. 22	LAE Sc. 23	LAE Sc. 24	LAE Sc. 25	LAE Sc. 26	LAE Sc. 27	LAE Sc. 28	LAE Sc. 29	LAE Sc. 30
HRSs electrolyser size (Kg/day)	HRS 1	162	324	486	486	486	162	162	162	162	162	162	162	162	162	162
	HRS 2	246	492	738	738	738	246	246	246	246	246	246	246	246	246	246
	HRS 3	490	980	1470	1470	1470	490	490	490	490	490	490	490	490	490	490
	HRS 4	308	616	924	924	924	308	308	308	308	308	308	308	308	308	308
	HRS 5	812	1624	2436	2436	2436	812	812	812	812	812	812	812	812	812	812
	HRS 6	406	812	1218	1218	1218	406	406	406	406	406	406	406	406	406	406
HRS Storage Size (kg)	HRS 1	560	560	840	1120	1680	560	560	560	560	560	560	560	560	560	560
	HRS 2	630	630	945	1260	1890	630	630	630	630	630	630	630	630	630	630
	HRS 3	1890	1890	2835	3780	5670	1890	1890	1890	1890	1890	1890	1890	1890	1890	1890
	HRS 4	1190	1190	1785	2380	3570	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190
	HRS 5	2464	2464	3696	4928	7392	2464	2464	2464	2464	2464	2464	2464	2464	2464	2464
	HRS 6	1540	1540	2310	3080	4620	1540	1540	1540	1540	1540	1540	1540	1540	1540	1540
HRS Compressor size (Kg/day)	HRS 1	162	324	486	486	486	162	162	162	162	162	162	162	162	162	162
	HRS 2	246	492	738	738	738	246	246	246	246	246	246	246	246	246	246
	HRS 3	490	980	1470	1470	1470	490	490	490	490	490	490	490	490	490	490
	HRS 4	308	616	924	924	924	308	308	308	308	308	308	308	308	308	308
	HRS 5	812	1624	2436	2436	2436	812	812	812	812	812	812	812	812	812	812
	HRS 6	406	812	1218	1218	1218	406	406	406	406	406	406	406	406	406	406
Central Electrolyser size (Kg/day)		×	×	×	×	×	1098	1923	3021	4853	2220	1098	1923	3021	4853	2220
Central Electrolyser. Storage size (kg)		×	×	×	×	×	5000	9000	15000	24000	11000	5000	9000	15000	24000	11000
Central Electrolyser. Compressor Size (kg/day)		×	×	×	×	×	1098	1923	3021	4853	2220	1098	1923	3021	4853	2220
Electrolyser efficiency (kWh/kg)		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Year of the components cost		2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030

Table 8.12: The summary of the alkaline electrolyser scenarios under 2030-Cost scenarios

Where: **LAE Sc. 16:** Only Onsite alkaline electrolyser without central electrolyser (default sizes) (alkaline electrolyser under 2030-Cost scenario).

LAE Sc. 17: Double-sized (twice the size of the default) electrolyser and same as default storage size (alkaline electrolyser under 2030-Cost scenario).

LAE Sc. 18: Triple-sized (three times the size of the default) electrolyser and 1.5 times default storage size (alkaline electrolyser under 2030-Cost scenario).

LAE Sc. 19: Triple-sized (three times the size of the default) electrolyser and double default storage size (alkaline electrolyser under 2030-Cost scenario).

LAE Sc. 20: Triple-sized (three times the size of the default) electrolyser and triple default storage size (alkaline electrolyser under 2030-Cost scenario).

LAE Sc. 21: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day alkaline central electrolyser with 5,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario).

LAE Sc. 22: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day alkaline central electrolyser with 24,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario).

LAE Sc. 23: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario).

LAE Sc. 24: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario).

LAE Sc. 25: Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day alkaline central electrolyser with 11,000 kg storage size (sized based hydrogen on consumption side) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario).

LAE Sc. 26: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day alkaline central electrolyser with 5,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario).

LAE Sc. 27: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day alkaline central electrolyser with 24,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario).

LAE Sc. 28: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario).

LAE Sc. 29: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario).

LAE Sc. 30: Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day alkaline central electrolyser with 11,000 kg storage size (sized based on hydrogen consumption side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario).

8.3.1 Only garage forecourts without central electrolyser (LAE Sc. 16)

The system sizing is identical to that in the 2015-Cost scenario. The cost and system efficiency will be changed as reported in Table 7.1. The surplus energy will be absorbed via garage forecourts, whilst the main targets will have to be tested. The efficiency will be improved from 54.6 kWh/kg to 50 kWh/kg, which will lead to a reduction in energy requirements, increase the amount of hydrogen produced, and then reduce the hydrogen production cost. After applying the electricity pricing mechanism as per the equivalent 2015-Cost scenario, the 2030 electricity prices can be seen as per Figure 8.35.

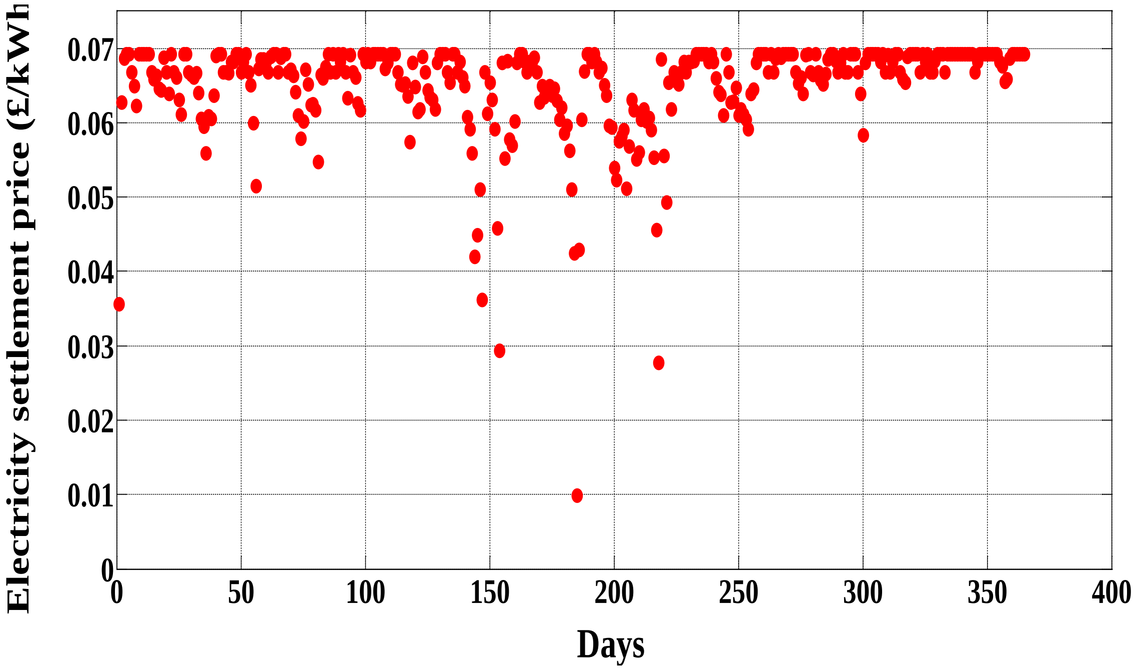


Figure 8.35: Daily electricity price throughout the year (LAE Sc. 16) (2030-Cost scenario)

The average electricity price in this case is higher than the same case in 2015, as can be seen in Figure 8.36:

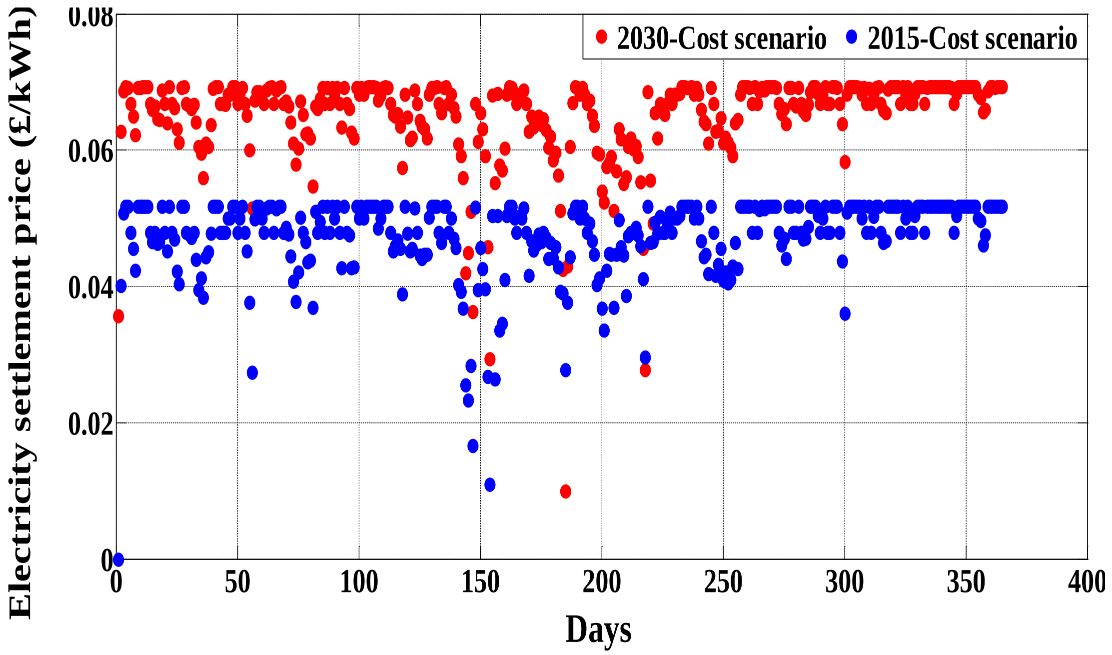


Figure 8.36: Comparison between electricity prices for this case in both the 2015- and 2030-Cost scenarios (LAE Sc. 1 and LAE Sc. 16)

The electricity price is affected by two main factors: the amount of hydrogen produced and the investment cost. The investment cost is constant during the year. In terms of the hydrogen production, because HRSs can set a higher bid price while still meeting economic targets, due to higher efficiency and capital cost reduction. This process is based on Equation (8.2). The assessment of this system will include the grid balancing based on the amount of absorbed energy, the hydrogen demand being met, and the average price of hydrogen.

The energy consumed represents nearly 53.77% of the total surplus energy available, which means that 46.23% of the surplus energy will be wasted. In terms of hydrogen production, the total amount of hydrogen produced by all garage forecourts is 510,678 kg /year, which is equal to 65% of the total hydrogen demand. This value (65%) is higher than the identical case in last scenario (LAE Sc. 1), which was only 60%, because of the efficiency improvements.

Hydrogen production, as contrasted with hydrogen consumption, for each garage forecourt is illustrated in Figure 8.37 and reported in Table 8.13 whereas the economic assessment of this scenario is shown in Table 8.14.

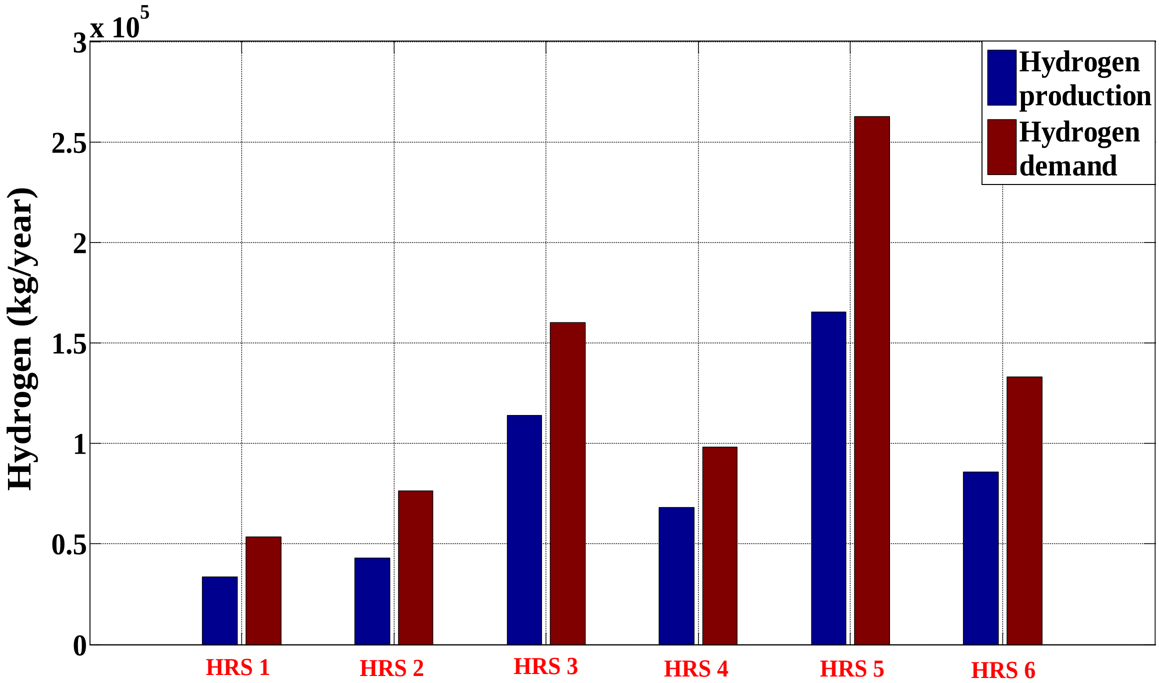


Figure 8.37: Hydrogen production versus hydrogen consumption for each garage forecourt (LAE Sc. 16)

HRS no.	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Hydrogen production (kg/year)	33,779	42,977	114,077	68,313	165,566	85,966
hydrogen consumption (kg/year)	53,645	76,519	160,157	98,244	262,535	133,005
Hydrogen demand satisfaction (%)	63%	56%	71%	70%	63%	65%

Table 8.13: Comparison between hydrogen production and hydrogen consumption at HRSs throughout the year ((LAE Sc. 16)

Cost / HRSs	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electrolyser electricity cost (£/year)	Hydrogen production (kg/year)	Average price (£/kg)
HRS 1	107,450	1,156	5,830	105,298	33,779	6.50
HRS 2	136,279	1,471	7,123	132,709	42,977	6.50
HRS 3	334,089	3,904	20,045	360,085	114,077	6.30
HRS 4	212,380	2,338	11,889	214,761	68,313	6.50
HRS 5	477,629	5,666	27,995	516,873	165,566	6.20
HRS 6	275,007	2,942	15,042	269,288	85,966	6.50

Table 8.14: Capex, Opex and average hydrogen production cost of only garage forecourt without central electrolyser (LAE Sc. 16) under 2030-Cost scenarios

The average hydrogen price is dropped from nearly £9.80 /kg in 2015-Cost scenario to nearly £6.40 /kg in 2030-Cost scenario yet there is an increase of energy price. The significant drop in hydrogen price is driven by a reduced investment cost, as investment cost typically is the dominant factor in off-peak operation mode. The hydrogen cost details are given in Figure 8.38:

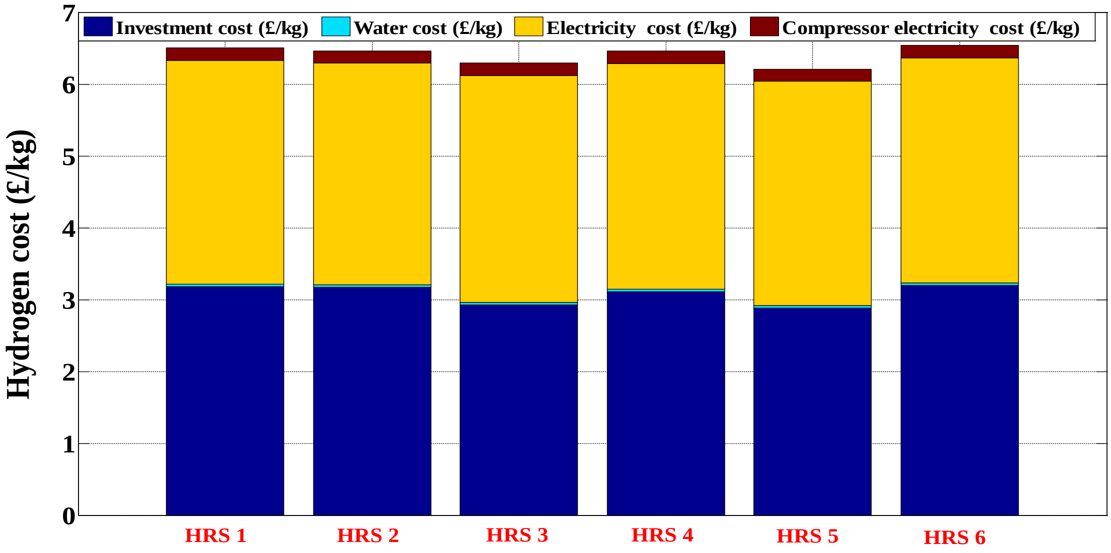


Figure 8.38: Hydrogen cost breakdown per kilogram at each HRS (LAE Sc. 16)

As shown in Figure 8.38, the investment cost represents nearly 49% of the total cost in HRS 1 compared with 82% in the 2015-Cost scenario, whereas the feedstock has increased to 47% in contrast with just 14% in the LAE Sc. 1.

Taking into account price instability and the potential depletion of oil, and the cost reduction of hydrogen, then hydrogen can be considered a strong candidate to replace conventional fuels in the coming years (LAE Sc. 16).

To sum up, this scenario does not meet the main aims of the project because 46.23% of the surplus energy will be lost and only 65% of the total hydrogen demand is met. However, the average hydrogen price is reduced by nearly 35%. Moving to the second option to overcome the shortcoming of this scenario, which is to increase system size, the same steps as in last case will be followed regarding size, but with different system costs and efficiencies.

8.3.2 Increased size of HRS components

As in the equivalent cases for the 2015-Cost scenario, the electrolyser and compression system will be doubled in size.

Regarding hydrogen storage, at double the size of other components, the storage facility will remain identical since the storage profile of hydrogen in tank allows for the possibility of being able to accommodate the extra hydrogen produced.

However, for triple-sized electrolyser, which will be tested subsequently, three different sizes of storage tank will be tested, namely those of 1.5, 2 and 3 times the default size.

a) Double-sized default electrolyser test **(*LAE Sc. 17)***

As mentioned earlier, only the electrolysers and the compression system of the garage forecourts will be doubled in size, whilst the same storage size will be maintained.

Figure 8.39 below shows the electricity price throughout the year after applying the electricity pricing mechanism as in previous scenarios.

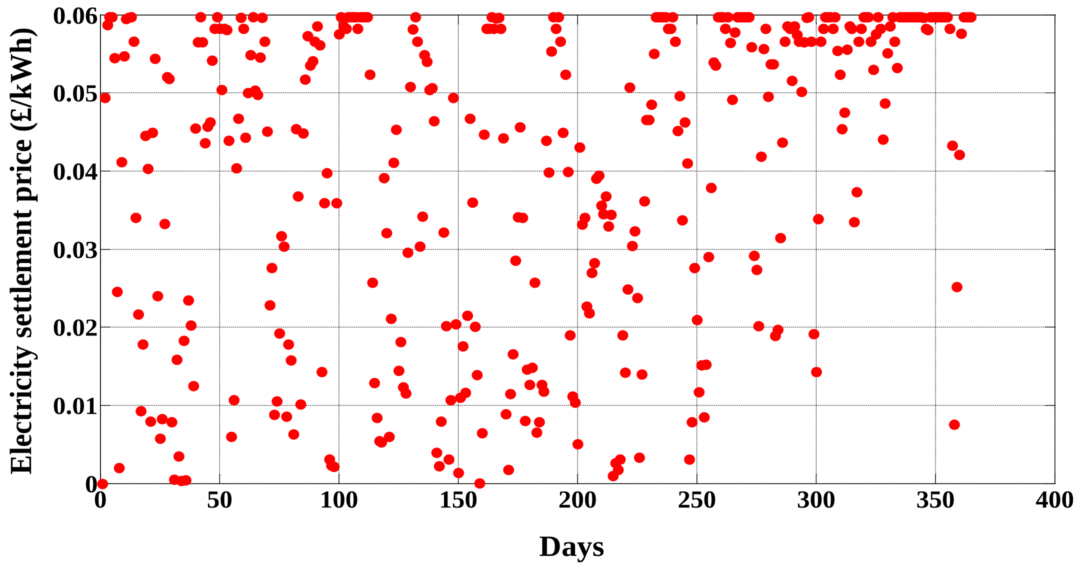


Figure 8.39: Daily electricity settlement price over a year of Double-sized default electrolyser test (LAE Sc. 17)

The electricity price in this case is slightly higher than the same case in the LAE Sc. 2. The improved system efficiency will lead to a reduction in electricity consumption and increase the energy price because HRSs can set a higher bid price while still meeting economic targets, due to higher efficiency and capital cost reduction. The difference between hydrogen production and demand is similar to the same case in 2015, as shown in Figure 8.40 and as reported in Table 8.15.

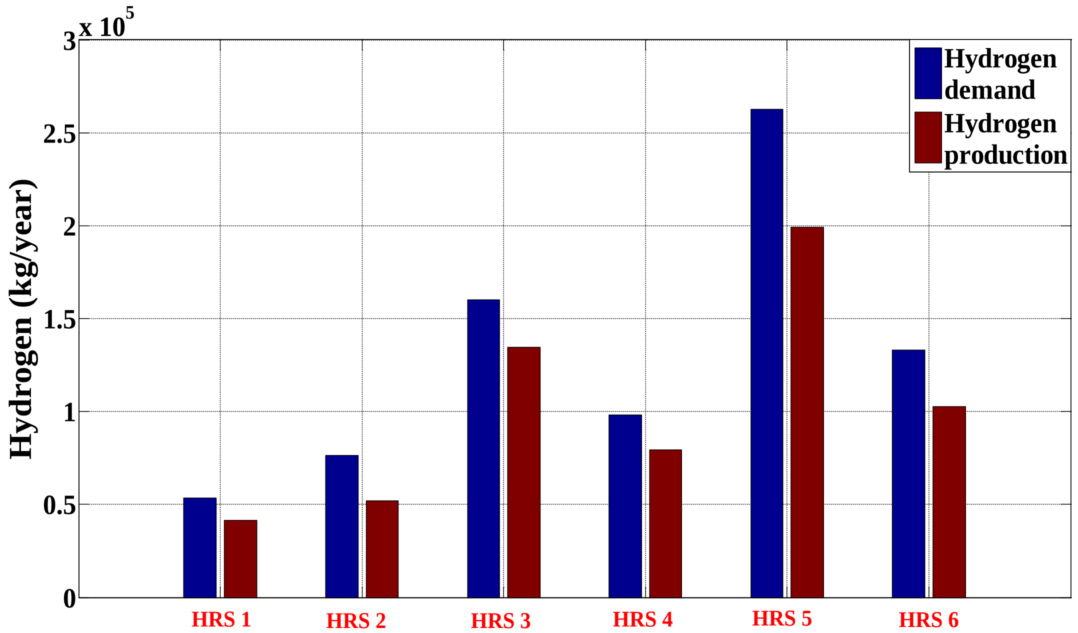


Figure 8.40: Hydrogen production versus hydrogen consumption

HRS no.	**HRS 1**	**HRS 2**	**HRS 3**	**HRS 4**	**HRS 5**	**HRS 6**
Hydrogen production (kg/year)	41,459	51,945	134,752	79,556	199,148	102,718
Hydrogen consumption (kg/year)	53,645	76,519	160,157	98,244	262,535	133,005
Hydrogen demand satisfaction (%)	77%	68%	84%	81%	76%	77%

Table 8.15: Comparison between hydrogen production and hydrogen consumption at HRSs throughout the year

This scenario can meet around 78% of the total demand, and 70% of the total surplus energy can be absorbed. The economic assessment and average hydrogen cost, based on the new investment cost and the hydrogen production, are given in Table 8.16.

Cost / **HRSs**	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average price** (£/kg)
HRS 1	197,176	1,419	4,835	68,462	41,459	6.60
HRS 2	242,207	1,778	6,052	80,072	51,945	6.40
HRS 3	632,365	4,611	15,746	236,103	134,752	6.60
HRS 4	400,143	2,722	9,130	134,812	79,556	6.90
HRS 5	880,049	6,815	23,434	339,900	199,148	6.30
HRS 6	518,574	3,515	12,393	164,097	102,718	6.80

Table 8.16: Capex, Opex and average hydrogen production cost under Double-sized default electrolyser test (LAE Sc. 17)

The average hydrogen prices drop from nearly £9.50 to 6.50 /kg. This reduction is a result of lower investment cost, as can be seen in Figure 8.41.

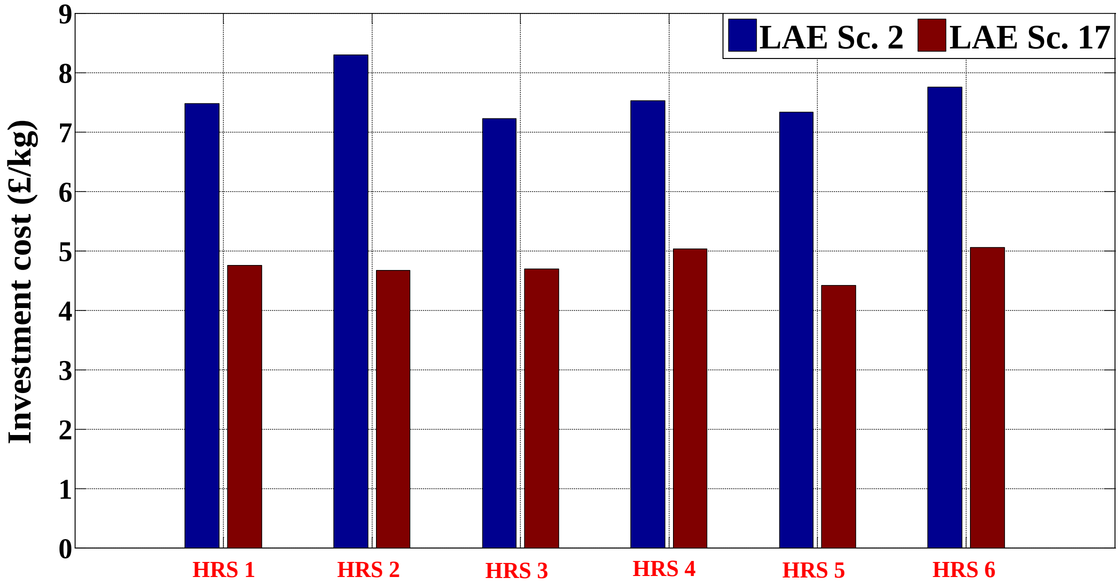


Figure 8.41: Investment cost as a proportion of the total hydrogen cost for the 2015- and 2030- Cost scenarios (LAE Sc. 2 and LAE Sc. 17)

In terms of the impact on electricity price, the difference between the two cost scenarios is not entirely clear. Electricity represents nearly 25% of the total cost in the LAE Sc. 17, compared to 14% in the LAE Sc. 2. The result is this that scenario is better than the equivalent case in the 2015-Cost scenario in terms of the amount of hydrogen production and the average price of hydrogen. The main reasons for this are the efficiency improvements and the consequent investment cost reduction. Regarding the research aims, this scenario could not meet the total hydrogen demand, and nearly 30% of the surplus energy remains to be exploited or curtailed.

b) Triple-sized default electrolyser test

The same steps for the triple-sized electrolyser were applied as in Section 1.2.2. Three different sizes of storage will be used with the triple-sized electrolyser and compression system. These sizes are LAE Sc. 18, LAE Sc. and LAE Sc.. Testing different sizes of storage will optimise the cost in relation to storage size because this is one of the targets parts of the investment cost. As can be seen in Figure 8.42, the first store fills to its maximum capacity many times during the year, which would frequently restrict the triple-sized electrolyser to running at less than maximum capacity. Therefore, the store has to be increased to accommodate the much higher production rate. Given the increase in investment cost increasing the storage size by a factor of two could be a better option.

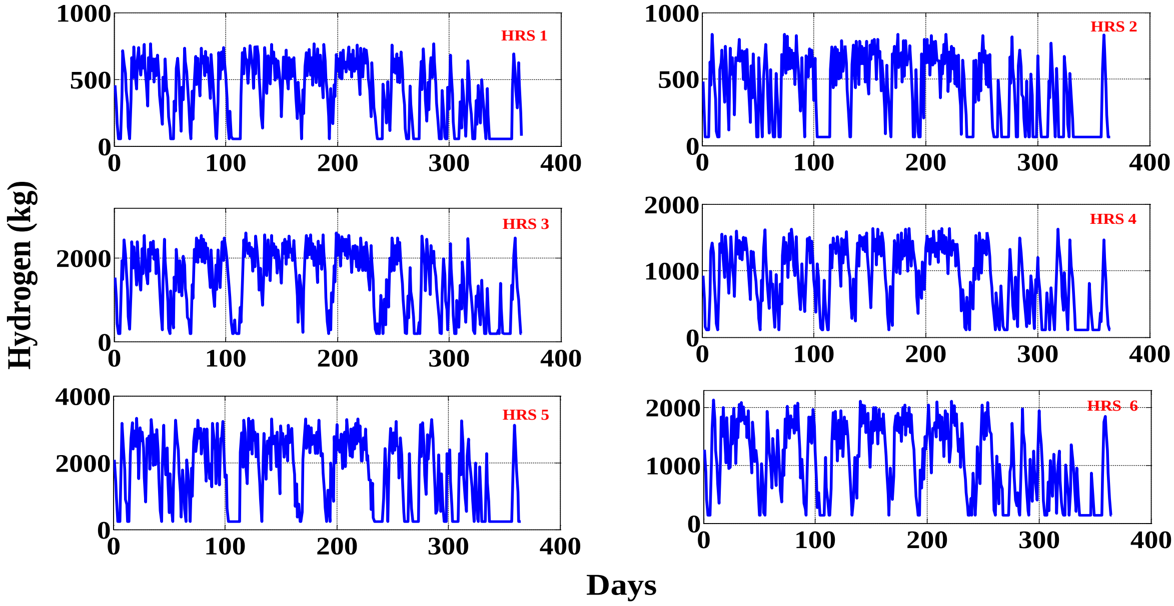


Figure 8.42: Storage variation throughout the year (1.5 times higher than nominal storage size (LAE Sc. 18)

Optimising the storage size could be useful for some HRSs, but might well have a negative impact on others. For instance, moving from a LAE Sc. 18 to a LAE Sc. 19 would help HRSs 1 and 2 to enhance their opportunity to meet hydrogen demand from 83% to 86%, and from 75% to 81%, respectively, with nearly a £1 increase in average hydrogen cost. However, HRS's 4 satisfaction of the demand remains identical when the size is doubled, with a nearly £2 increase in average hydrogen price.

The electricity settlement price is strongly dependent on the HRSs investment cost and the amount of hydrogen required, since the determination of the most economic electricity price every day will be dependent on these components.

This price should be cover the daily running cost of the system, which include bank instalments and operational costs. The average electricity prices of these scenarios are 24p, 24.6p, 23.3p /kWh for the LAE Sc. 18, LAE Sc. 19 and LAE Sc. 20, respectively. Figure 8.43 shows the daily electricity price throughout the year for these three size scenarios. A summary of this case is shown in Table 8.17.

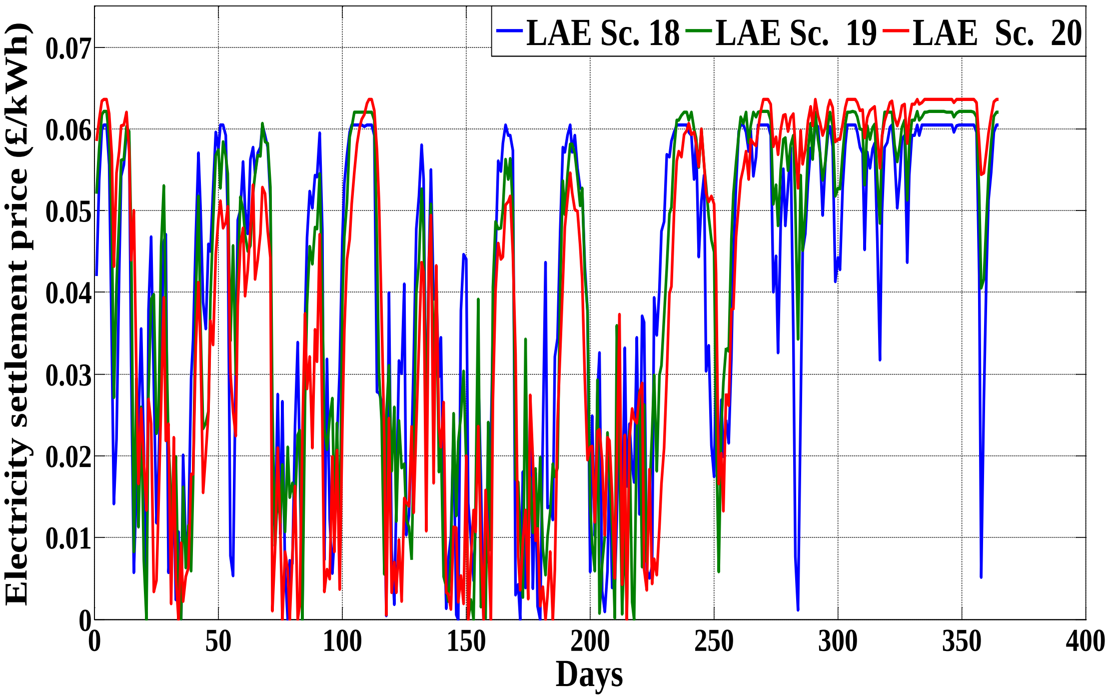


Figure 8.43: Daily settlement prices for different size scenarios (triple-sized electrolyser under 2030-Cost scenario)

Scenario \ HRS		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Triple-sized default electrolyser and 1.5 times default storage size (LAE Sc. 18)	Hydrogen demand satisfaction (%)	83	75	90	89	80	86
	Average hydrogen price (£/kg)	8.40	8.00	8.50	8.60	8.10	8.60
	Total hydrogen demand satisfaction (%)	83					
	Total surplus energy consumed (%)	76					
Triple-sized default electrolyser and double-sized default storage size (LAE Sc. 19)	Hydrogen demand satisfaction (%)	86	81	92	89	86	88
	Average hydrogen price (£/kg)	9.70	9.00	10.00	10.40	9.20	10.00
	Total hydrogen demand satisfaction (%)	87					
	Total surplus energy consumed (%)	79					
Triple-sized default electrolyser and Triple-sized default storage (LAE Sc. 20)	Hydrogen demand satisfaction (%)	90	85	93	92	88	92
	Average hydrogen price (£/kg)	12.20	11.00	12.80	13.40	11.40	12.80
	Total hydrogen demand satisfaction (%)	89					
	Total surplus energy consumed (%)	81					

Table 8.17: Techno- economic assessments of the system under different size of electrolyser and different storage sizes

The next investigation was that of adding a central electrolyser to the system, as in the 2015-Cost scenario's two operational modes of the central electrolyser: The central unit will run in under the same electricity settlement price and when he electricity settlement price of the HRSs and the central electrolyser are different.

8.3.3 Adding a large alkaline central electrolyser to the system

The central electrolyser can be sized based on the production side (surplus energy) or consumption side (garage forecourts' hydrogen demand).

For the production side, the size of the central electrolyser should be enough to consume the surplus energy in participate with the HRSs. However, in this case, the size will need to be quite large and there is no guarantee that all the absorbed energy will be sold to the HRS during shortage of hydrogen supply at the forecourt.

In terms of the consumption side, the size will be based on the total daily production of the six garage forecourts. If the target is to size the central electrolyser based on the surplus energy side, different sizes have to be tested and an assessment of the main target computed in every case.

8.3.3.1 Alkaline central electrolyser sizing based on the production side

Two modes of central electrolyser operation will be tested in this section: the central electrolyser will buy electricity at the same settlement price as HRSs and when the electricity settlement price of the HRSs and the central electrolyser are different

a) ***Central alkaline electrolyser operates under a different electricity settlement price to the HRSs***

As mentioned earlier, if the central electrolyser's settlement price is set after the HRSs, some incentive has to be offered to encourage the central unit to accept such an offer.

In this research, the electricity price for the central electrolyser is set at 20% less than the HRS settlement price (even if not all the HRSs can accept the settlement price on that day). 20% is considered as acceptable profit margin within numerous economic projects (Ebaid, Hammad and Alghamdi, 2015; Investopedia, 2015).

Four different sizes of system components will be tested in the model and, at each size, the main aims will be verified.

These sizes are 1,098 kg/day (LAE Sc. 21) (38% of the surplus energy remaining), 1,923 kg/day (LAE Sc. 22) (60% of the surplus energy remaining), 3,022 kg/day (LAE Sc. 23) (80% of the surplus energy remaining), and 4,853 kg/day (LAE Sc. 24) (95% of the surplus energy remaining).

The electricity pricing mechanism for the system is the same as that in the 2015-Cost scenario. Figure 8.44 shows the electricity settlement price to the garage forecourts and to the central electrolyser for the f LAE Sc. 21.

The price of electricity is higher than same size in the 2015-Cost scenario due to it consuming less energy because of its greater efficiency and the resulting reduction in capital cost.

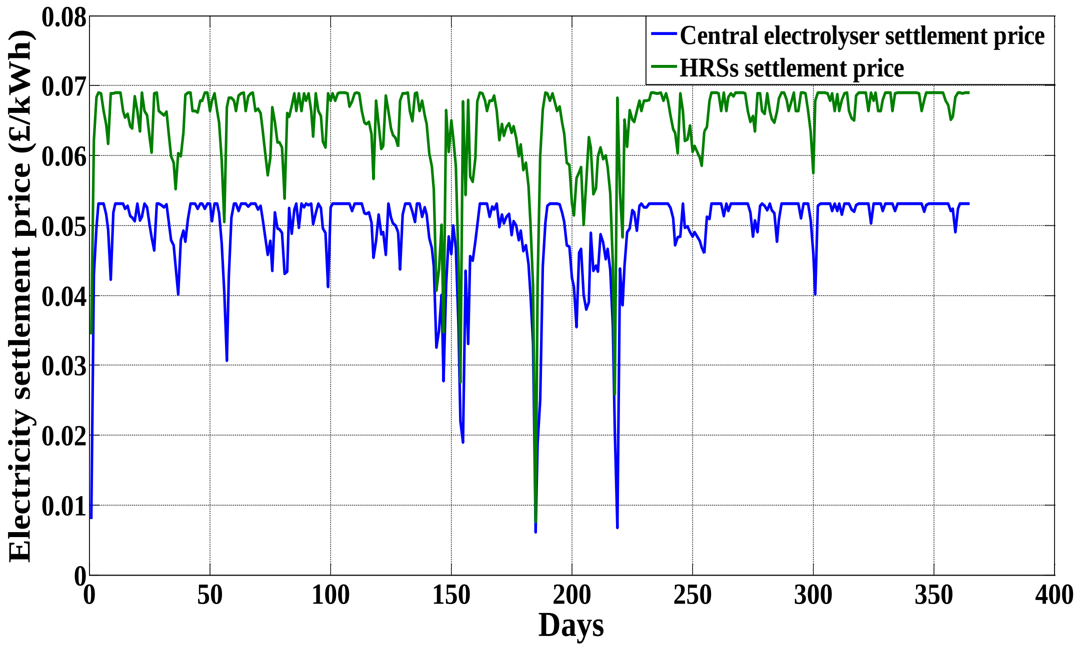


Figure 8.44: electricity settlement price to the central electrolyser and garage forecourts when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 21) (2030-Cost scenario)

The production and the variation in levels of stored hydrogen for all scenarios (LAE Sc. 21, LAE Sc. 22, LAE Sc. 23 and LAE Sc. 24) are presented in Figure 8.45 and Figure 8.46:

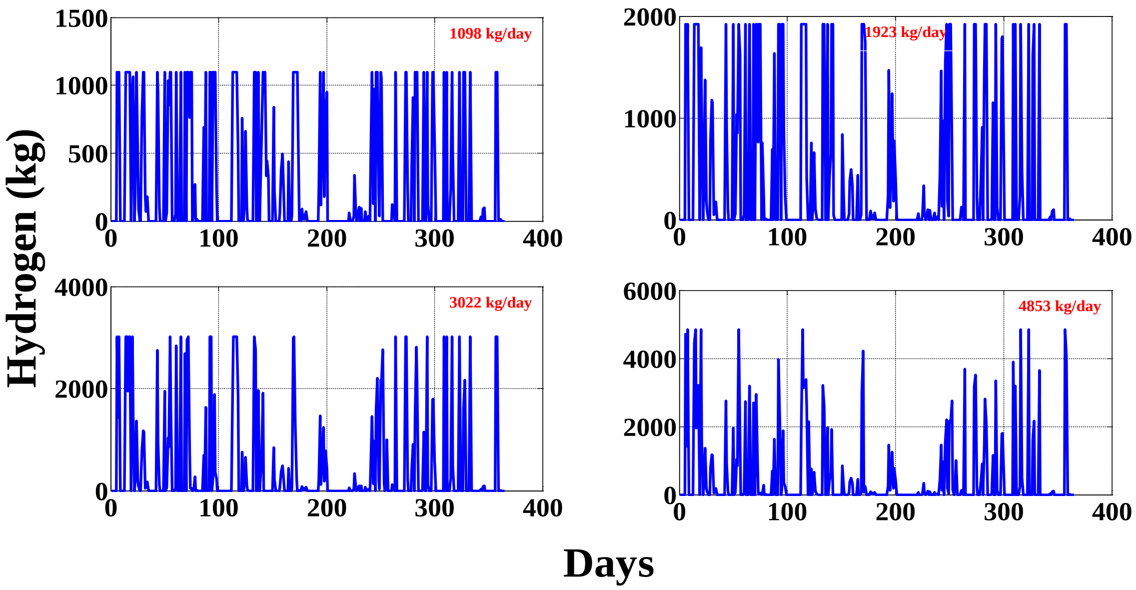


Figure 8.45: Hydrogen production of central electrolyser under different electrolyser sizes when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

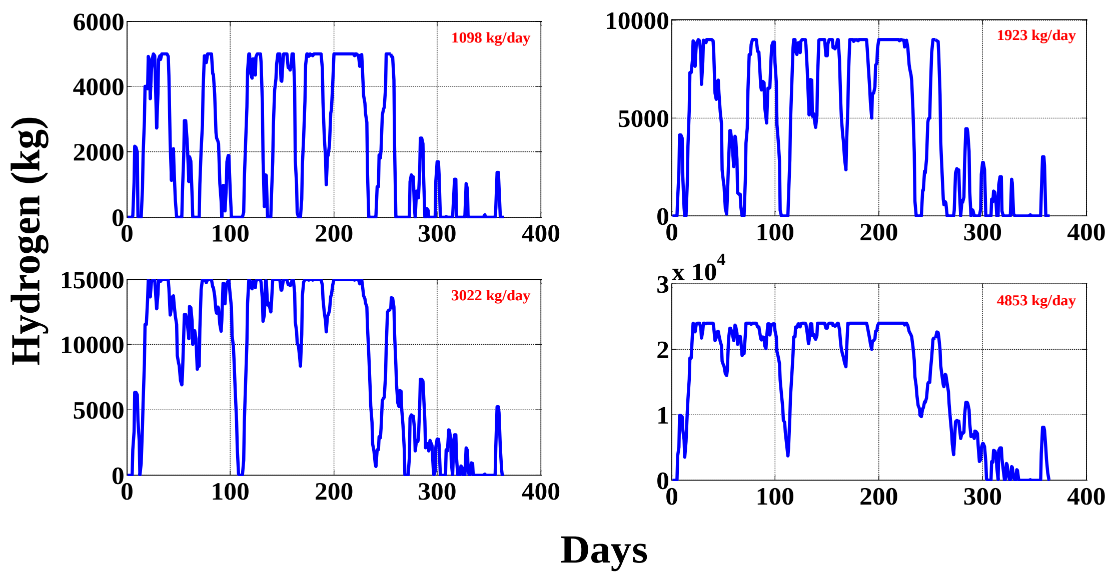


Figure 8.46: Daily variation of Hydrogen level in storage tank throughout the year when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

Table 8.18 summarises the economics in this case. Moving from one size to another could support grid balancing and satisfy hydrogen demand better. However, the average price is dramatically increased, which is one of the main issues with this proposal. Sizing the system based on the production side could solve certain issues like meeting demand and achieving grid balancing, but with different prices for the hydrogen. Hydrogen prices need to be investigated as compared with fossil fuel prices in 2030 to decide whether these prices are competitive.

System size	HRS	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
LAE Sc. 21	Satisfaction of hydrogen demand (%)	74	72	81	77	80	78
	Average hydrogen price (£/kg)	7.50	7.90	7.10	7.10	7.60	7.60
	Total energy consumed after adding central electrolyser (%)	65					
	Satisfaction of total demand (%)	78					
	Average central electrolyser hydrogen price (£/kg)	12.60					
LAE Sc. 22	Satisfaction of hydrogen demand (%)	80	81	86	84	85	84
	Average hydrogen price (£/kg)	8.40	9.10	7.80	8.00	8.50	8.50
	Total energy consumed after adding central electrolyser (%)	69					
	Satisfaction of total demand (%)	84					
	Average central electrolyser hydrogen price (£/kg)	14.80					
LAE Sc. 23	Satisfaction of hydrogen demand (%)	87	87	89	88	89	88
	Average hydrogen price (£/kg)	10.0	10.90	8.80	9.10	10.00	9.80
	Total energy consumed after adding central electrolyser (%)	73					
	Satisfaction of total demand (%)	88					
	Average central electrolyser hydrogen price (£/kg)	18.70					
LAE Sc. 24	Satisfaction of hydrogen demand (%)	91	90	92	92	92	91
	Average hydrogen price (£/kg)	12.30	13.60	10.60	11.20	12.20	12.00
	Total energy consumed after adding central electrolyser (%)	75					
	Satisfaction of total demand (%)	91					
	Average central electrolyser hydrogen price (£/kg)	25.30					

Table 8.18: Economic assessment of the system using different sizes (production side sizing) when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

b) The central alkaline electrolyser operates under the same electricity settlement price as the HRSs

In this scenario, the central electrolyser will effectively act in exactly the same manner as those at the garage forecourts. Every day the central electrolyser, as per the other garage forecourts, will release its price based on the required hydrogen and the investment cost. The electricity side will start with an expensive price until it achieves the goal of selling 90% of its surplus energy. The four sizes of the system will be applied in this scenario, as per the previous case. The electricity settlement price for the electrolysers, including the central electrolyser LAE Sc. 26 (1098 kg/day), is shown in Figure 8.47:

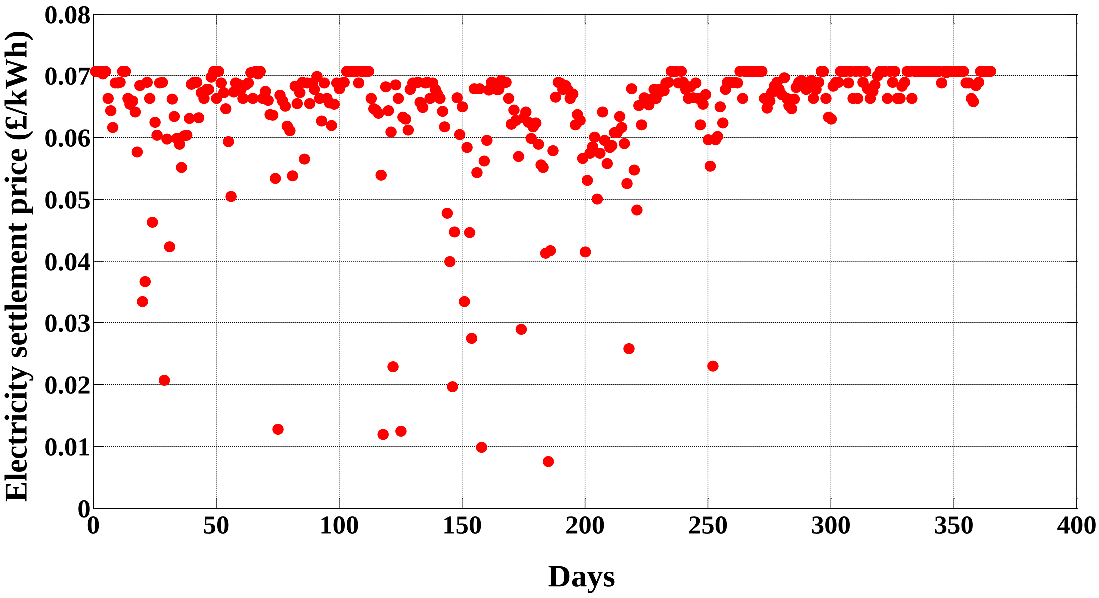


Figure 8.47: Electricity settlement prices for both HRSs and central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (LAE Sc. 26) (2030-Cost scenario)

The electricity price in this case is higher than the equivalent case in the LAE Sc. 11. The electricity price is calculated using Equation (8.2 and, because of the investment in cost reduction, the electricity settlement price will go up. From a technical point of view, the electricity producer is looking to sell energy at as high a price as possible, so the price is inversely proportional to the quantity available. Figure 8.48 shows the electricity price of this case (the central electrolyser runs under the same settlement electricity price as the HRSs) for both the 2015- and 2030-Cost scenarios. Hydrogen production and variation in stored hydrogen stored for LAE Sc. 26 are shown in Figure 8.49 and Figure 8.50.

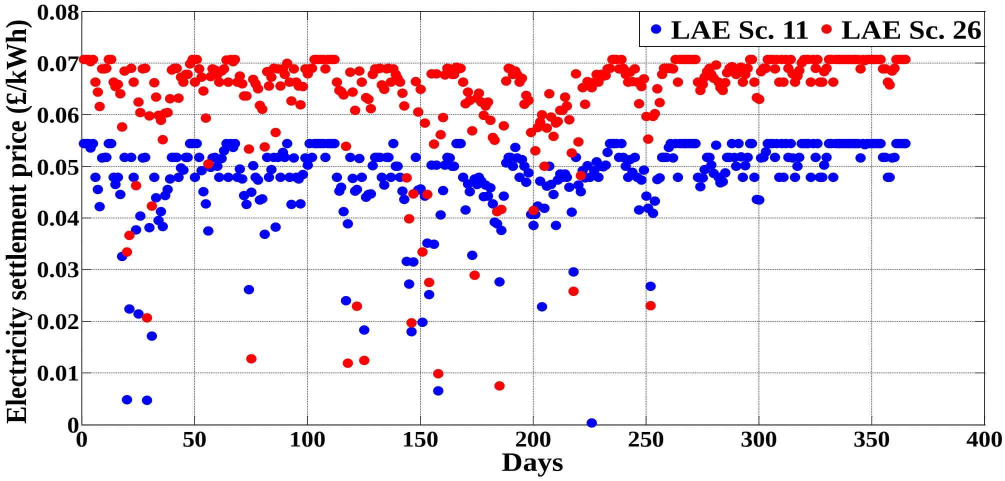


Figure 8.48: Comparison between the electricity price for LAE Sc. 11 and LAE Sc. 26 when central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs

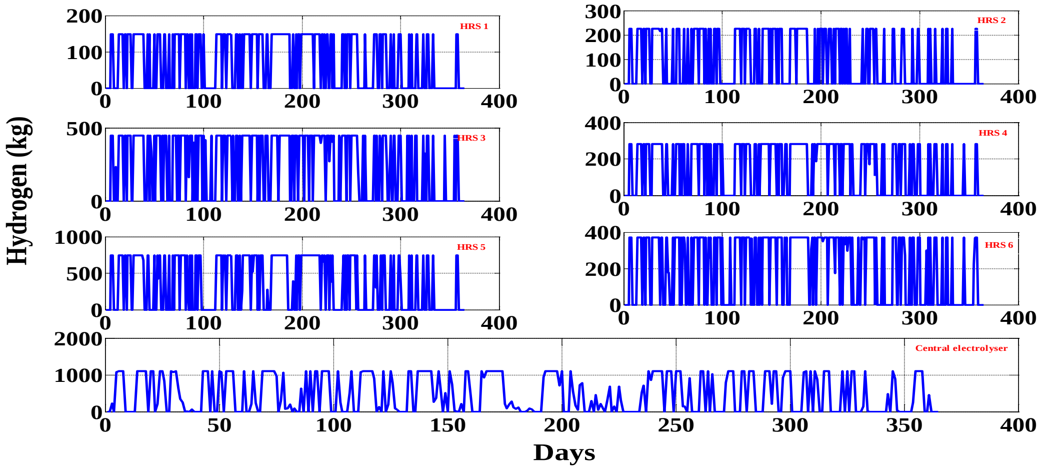


Figure 8.49: Daily hydrogen production throughout the year of the HRSs and Central electrolyser (LAE Sc. 26) when the central electrolyser and HRSs operates under the same settlement prices (2030-Cost scenario).

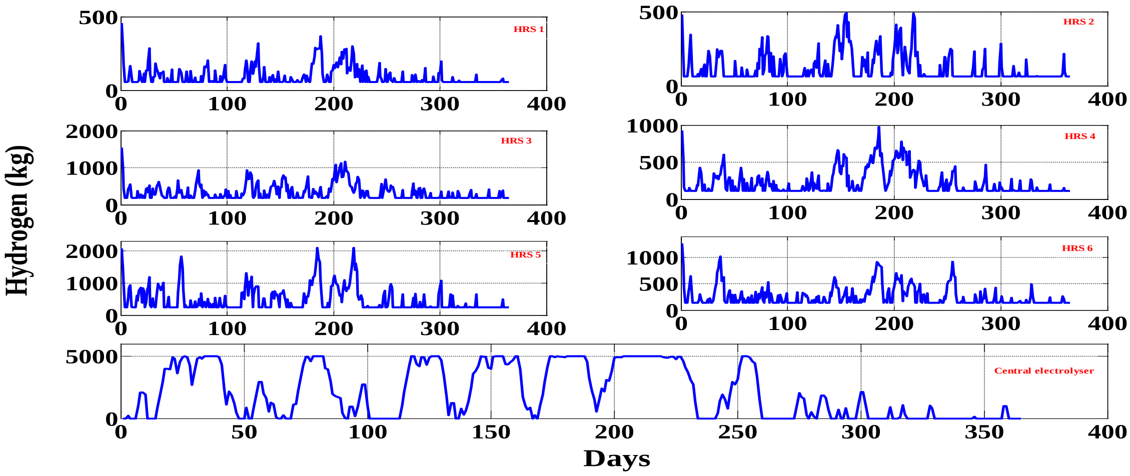


Figure 8.50: Daily variation of Hydrogen level in storage tank throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (2030-Cost scenario)

The economic assessments and the ability of the system to meet the main objectives of the research are presented in Table 8.19.

Central electrolyser size (kg/day)	HRS	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
LAE Sc. 26	Satisfaction of hydrogen demand (%)	69	70	78	73	84	77
	Average hydrogen price (£/kg)	7.40	7.80	7.20	7.30	7.80	7.20
	Total energy consumed after adding central electrolyser (%)	70					
	Satisfaction of total hydrogen demand (%)	78					
	Average central electrolyser hydrogen price (£/kg)	10.30					
LAE Sc. 27	Satisfaction of hydrogen demand (%)	77	80	85	82	87	83
	Average hydrogen price (£/kg)	8.20	90.00	80.00	8.20	8.70	8.10
	Total energy consumed after adding central electrolyser (%)	76					
	Satisfaction of total hydrogen demand (%)	84					
	Average central electrolyser hydrogen price (£/kg)	12.00					
LAE Sc. 28	Satisfaction of hydrogen demand (%)	85	86	88	87	91	87
	Average hydrogen price (£/kg)	9.80	10.70	9.00	9.20	10.20	9.20
	Total energy consumed after adding central electrolyser (%)	79					
	Satisfaction of total hydrogen demand (%)	88					
	Average central electrolyser hydrogen price (£/kg)	15.20					
LAE Sc. 29	Satisfaction of hydrogen demand (%)	90	90	91	91	92	91
	Average hydrogen price (£/kg)	12.00	13.70	10.60	11.30	12.60	11.00
	Total energy consumed after adding central electrolyser (%)	82					
	Satisfaction of total hydrogen demand (%)	91					
	Average central electrolyser hydrogen price (£/kg)	21.00					

Table 8.19: Economic assessments of the system under different sizes of central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (2030-Cost scenario).

Even the average price of the central electrolyser is less than in the previous scenario, so the average hydrogen prices at the garage forecourts are very close to each other. Since the capital costs of the garage forecourt components are the same in both scenarios (central electrolyser operation modes) and the variable cost is relatively low, the cost difference between these scenarios should essentially depend on the amount of, and the price, of any imported hydrogen. The imported hydrogen as a percentage of the total hydrogen delivered per garage forecourt could explain the stability of the price of hydrogen in both scenarios. Table 8.20 shows the share of the imported hydrogen as a proportion of the total hydrogen delivered to the consumption area in both scenarios under different sizes.

Scenarios		HRSs	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Central electrolyser operates under a different electricity settlement price to the HRSs	**Imported hydrogen (%)**	**LAE Sc. 21**	15	22	12	10	21	17
		LAE Sc. 22	22	31	17	17	25	23
		LAE Sc. 23	28	35	20	21	29	27
		LAE Sc. 24	31	38	22	25	31	29
Central electrolyser operates under the same electricity settlement price as the HRSs	**Imported hydrogen (%)**	**LAE Sc. 26**	18	29	18	14	34	18
		LAE Sc. 27	26	40	25	26	37	27
		LAE Sc. 28	35	45	28	29	42	30
		LAE Sc. 29	37	48	29	32	42	31

Table 8.20: Imported hydrogen via HRSs under different alkaline central electrolyser sizes and for two different modes of operation

The amount of hydrogen imported from the central electrolyser was greater in the second scenario, which will lead to an increase in the overall of hydrogen price. Therefore, a lower amount of hydrogen imported at an expensive price in first scenario would be equivalent to a greater amount of hydrogen imported at a relatively cheap price. The operation mode of the central electrolyser does not have a particularly significant effect on the system targets since all the consumed energy, hydrogen demand satisfaction and the average price of the hydrogen are similar.

8.3.3.2 Alkaline central electrolyser sizing based on hydrogen consumption

The central electrolyser size in this case will be equal to the total production at the garage forecourts (LAE Sc. 25 and LAE Sc. 30. The compression system is equal to nearly one-day's worth of production. Shortages of surplus energy can frequently be seen throughout the year. A period of five days without production is quite common during the year, so the storage size is based on this value, which is equivalent to nearly five days of production. Based on these assumptions, the capacity of the central electrolyser is 2,220 kg/day, with a hydrogen storage size of 11,000 kg, and finally the compression system is equal to the daily production size (2,220 kg/day). The two operational modes of the central electrolyser will be investigated as per previous scenarios.

a) Central alkaline electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 25)

All system regulations and steps are same as in Section 1.2.3.4 in the 2015-Cost scenario. The electricity settlement prices to the garage forecourts and central electrolyser are given in Figure 8.51:

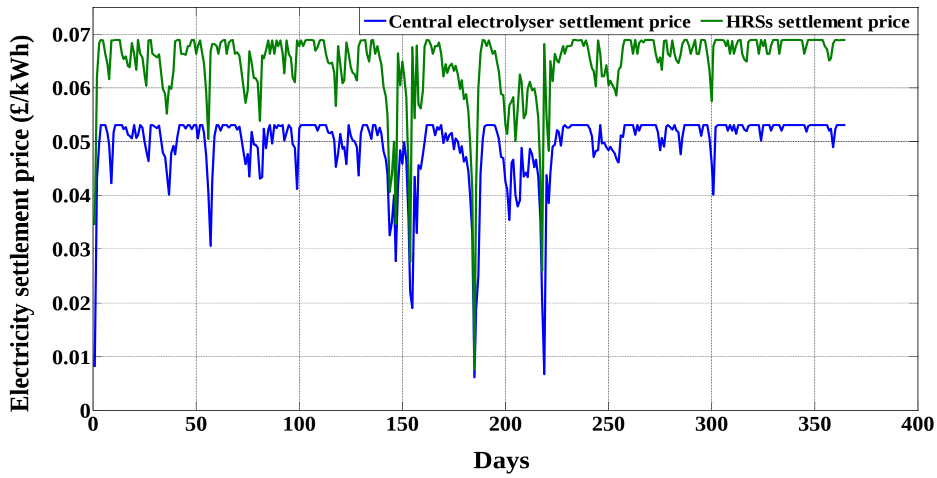


Figure 8.51: Electricity settlement price to the garage forecourts and central electrolyser (Sizing based on the consumption side and 2030-Cost scenario)

As can be seen, the electricity settlement price to the central electrolyser is cheaper than the electricity settlement price at the garage forecourts because of the incentive payment from the electricity producer, which is equivalent to a 20% reduction below the settlement price for the HRSs. Hydrogen production, and the variation of stored hydrogen at the central electrolyser throughout the year, are presented in Figure 8.52 and Figure 8.53. Table 8.21 shows an economic summary of the system.

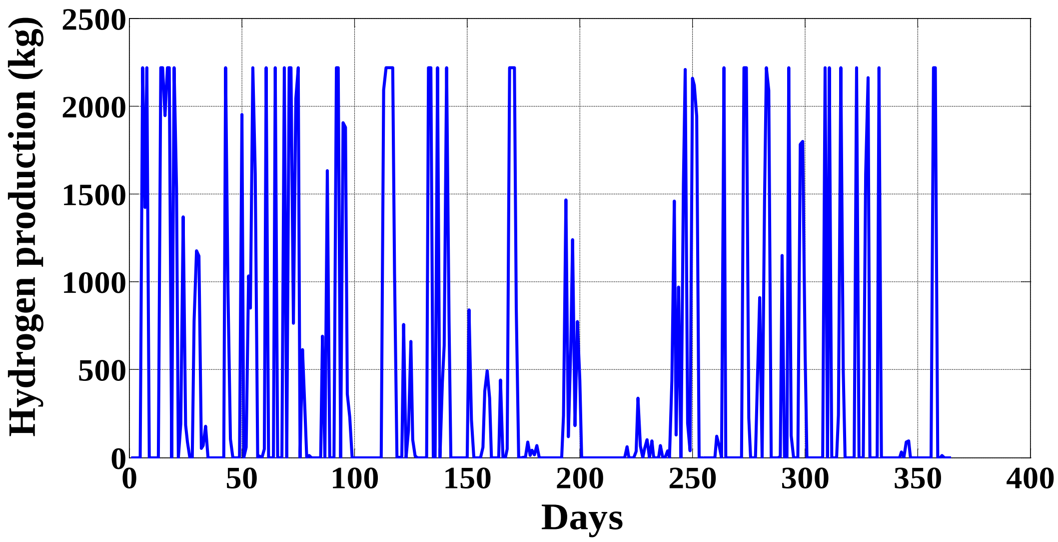


Figure 8.52: Alkaline central electrolyser hydrogen production throughout the year when central electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 25) (2030-Cost scenario).

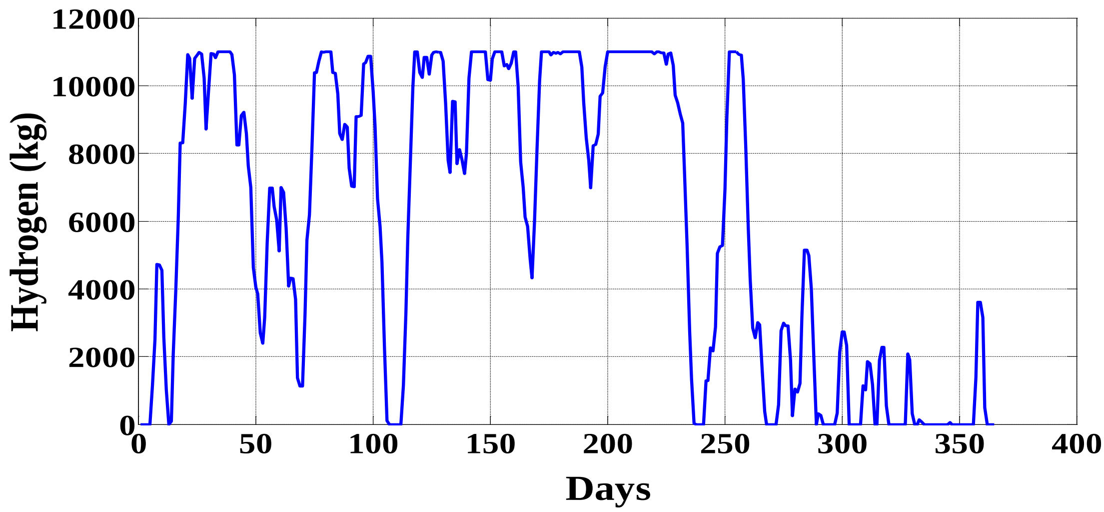


Figure 8.53: Daily variation of Hydrogen level in storage tank throughout the year when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (LAE Sc. 25) (2030-Cost scenario).

Details / HRSs	**Satisfaction of hydrogen demand** (%)	**Average hydrogen price** (£/kg)	**Total surplus energy consumed after adding central electrolyser** (%)	**Satisfaction of total hydrogen demand** (%)	**Average price of hydrogen from central electrolyser** (£/kg)
HRS 1	84	9.00	71	86	16.00
HRS 2	83	9.70			
HRS 3	87	8.10			
HRS 4	86	8.30			
HRS 5	86	9.00			
HRS 6	85	8.90			

Table 8.21: Economic assessment of the system when alkaline central electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario).

The average prices of hydrogen for the central electrolyser and at garage forecourts are lower in this case in comparison with same case in the LAE Sc. 10, due to efficiency improvements and the reduction in investment cost.

Electrolysis efficiency improvements lead to a reduction in energy consumption whilst at the same time increased the level of satisfication of hydrogen demand is increased.

b) The central alkaline electrolyser operates under the same electricity settlement price as the HRSs (LAE Sc. 30)

This scenario is similar to the same scenario described in Section 1.2.3.4 but with different sized components.

LAE Sc. 30 is a Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day alkaline central electrolyser with 11,000 kg storage size (sized based on hydrogen consumption side) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario).

The central electrolyser is this section plays in the electricity price mechanism as if it were just another HRS. The daily electricity settlement prices over a year are given in Figure 8.54.

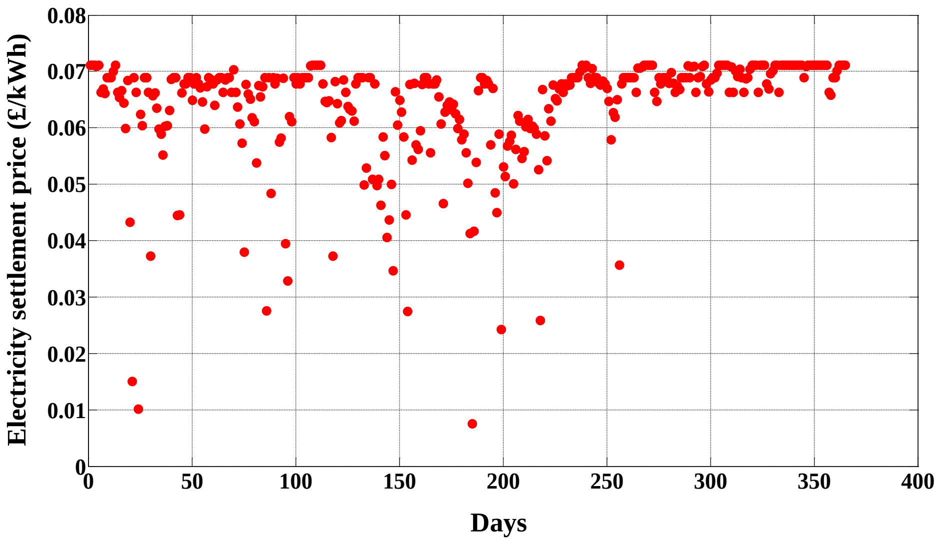


Figure 8.54: Daily electricity settlement price for HRSs and central electrolyser throughout the year when central electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario)

The electricity price in this scenario is higher than for the same case in the LAE Sc. 15. The efficiency improvements in the electrolysis reduces energy consumption, which allow the electricity producer to obtain a better price for the sale of surplus energy. The hydrogen production and the variation in hydrogen stored at the garage forecourts and central electrolyser are shown in Figure 8.55 and Figure 8.56, respectively:

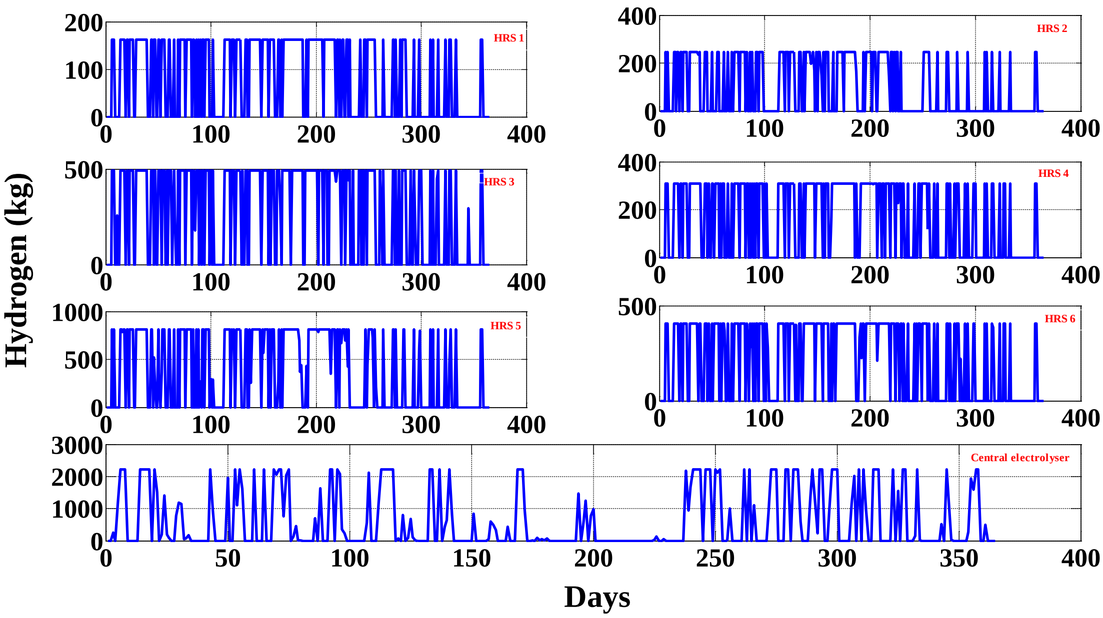


Figure 8.55: Hydrogen production of the alkaline central electrolyser and HRSs throughout the year when central electrolyser operates under the same electricity settlement price as the HRSs (LAE Sc. 30) (2030-Cost scenario)

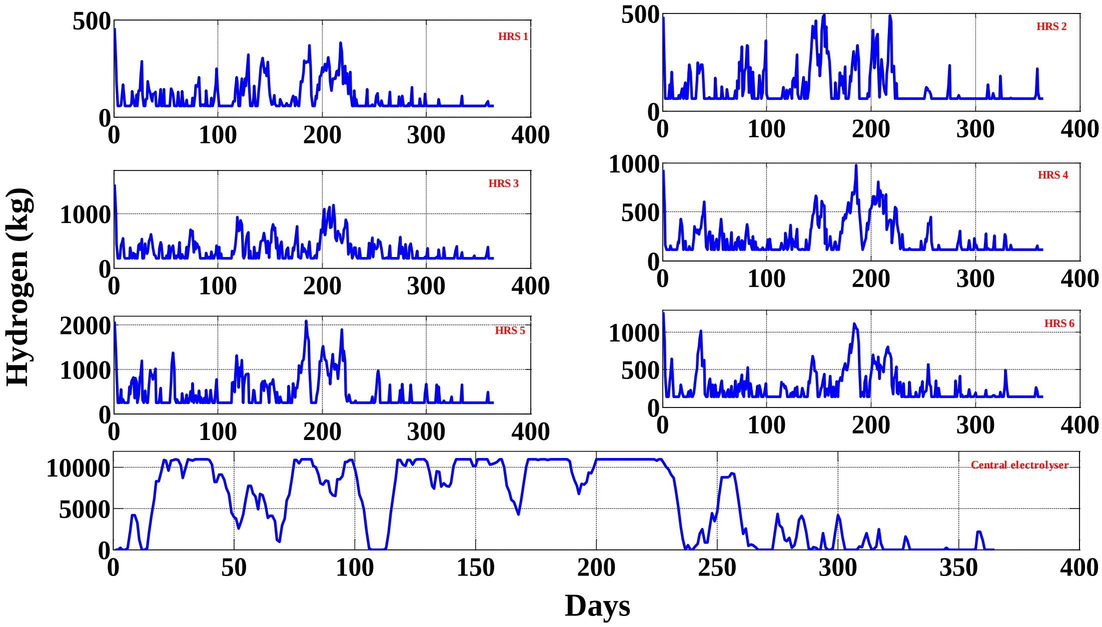


Figure 8.56: Daily variation of Hydrogen level in storage tank throughout the year when alkaline central electrolyser operates under the same s electricity settlement price as the HRSs(LAE Sc. 30) (2030-Cost scenario)

Table 8.22 below shows the summary for the system and the response in achieving the main goals including grid balancing, hydrogen demand being met and an acceptable sale price for the hydrogen.

Details / HRSs	**Satisfaction of hydrogen demand** (%)	**Average hydrogen price** (£/kg)	**Total surplus energy consumed after adding central electrolyser** (%)	**Satisfaction of total hydrogen demand** (%)	**Average price of hydrogen from central electrolyser** (£/kg)
HRS 1	81	8.70	77	86	13.00
HRS 2	83	9.50			
HRS 3	86	8.30			
HRS 4	84	8.60			
HRS 5	88	9.20			
HRS 6	85	8.50			

Table 8.22: Economic assessment of the system when central electrolyser operates under the same electricity settlement price as the HRSs (LAE Sc. 30) (2030-Cost scenario)

As in other scenarios, the average price of hydrogen produced by the central electrolyser is lower than if the central electrolyser runs under different electricity settlement price. However, the average price of hydrogen production at the garage forecourts remains similar. As can be seen in Figure 8.57, the amount of hydrogen imported to each garage forecourt from the central electrolyser in first scenario (an expensive hydrogen price) is less than that imported in second scenario, which reflects the essentially unchanged price between the two scenarios.

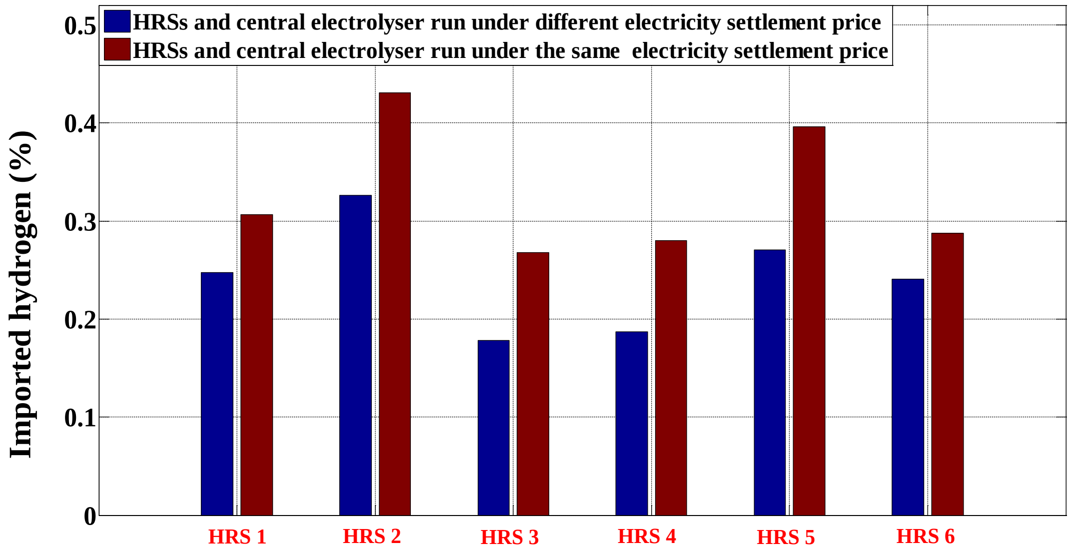


Figure 8.57: Percentage of imported hydrogen for the two scenarios (LAE Sc. 25 and LAE Sc. 30) as compared with the total amount of hydrogen delivered

As in the 2015-Cost scenario (LAE Sc. 5 and LAE Sc. 10), the sizing based on the consumption side does not result in any clear a change of techno-economic characterises in contrast with the sizing based on the production side. Generally, adding a central electrolyser could be one of the principal means of consuming any surplus energy and tackling any shortage of hydrogen demand at the forecourt, albeit with a relatively high hydrogen price. Increased reduction in investment cost, which will probably happen in the coming years, could reduce the production cost of hydrogen to bring it down to a more competitive.

8.4 2015-Cost scenario with PEM electrolysers

PEM, as based on the opinions of experts, will become the principal means of electrolysis in the coming years because it is operational features, which overcome the drawbacks of alkaline electrolysis (Carmo et al., 2013). This means more investigation will be undertaken for PEME in contrast to alkaline electrolysis, which can be interpreted in terms of forecasting of efficiency of PEME to be higher than for alkaline electrolysis, as presented in Table 7.2 .As in alkaline electrolysis, two cost scenarios will be tested, those of the 2015- and 2030-Cost scenarios. Figure 8.58 shows a summary of the various PEME scenarios.

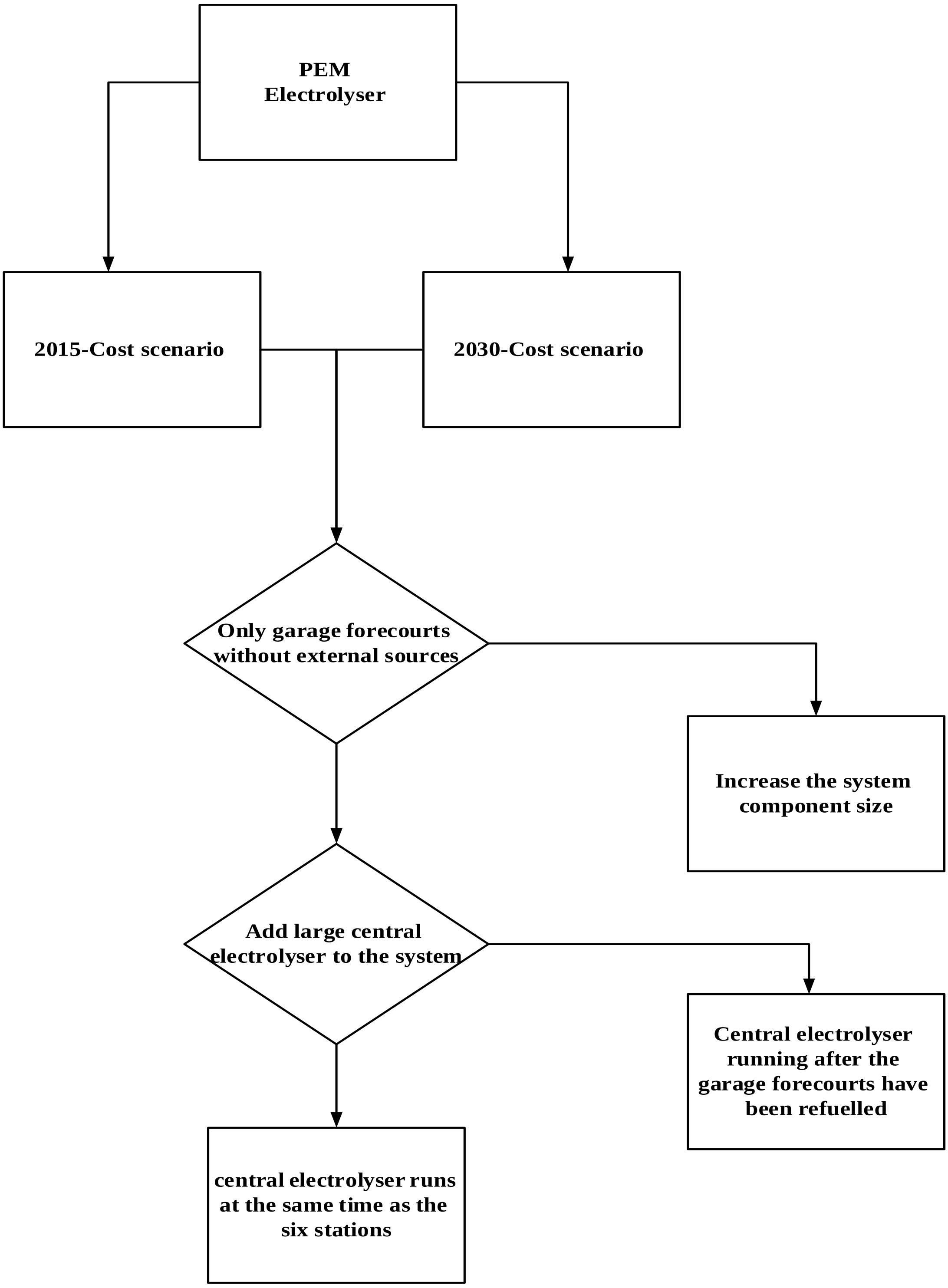


Figure 8.58: summary of the operation scenarios for PEM electrolyser under 2015 and 2030-Cost scenario

Table 8.23 below shows the summary of the PEME under 2015-Cost scenarios.

Details \ Scenario No.		PEME Sc. 1	PEME Sc. 2	PEME Sc. 3	PEME Sc. 4	PEME Sc. 5	PEME Sc. 6	PEME Sc. 7	PEME Sc. 8	PEME Sc. 9	PEME Sc. 10	PEME Sc. 11	PEME Sc. 12	PEME Sc. 13	PEME Sc. 14	PEME Sc. 15
HRSs Electrolyser size (Kg/day)	HRS 1	149	297	446	446	446	149	149	149	149	149	149	149	149	149	149
	HRS 2	226	451	677	677	677	226	226	226	226	226	226	226	226	226	226
	HRS 3	449	897	1346	1346	1346	449	449	449	449	449	449	449	449	449	449
	HRS 4	282	564	846	846	846	282	282	282	282	282	282	282	282	282	282
	HRS 5	744	1487	2231	2231	2231	744	744	744	744	744	744	744	744	744	744
	HRS 6	372	744	1115	1115	1115	372	372	372	372	372	372	372	372	372	372
HRS Storage size (kg)	HRS 1	560	560	840	1120	1680	560	560	560	560	560	560	560	560	560	560
	HRS 2	630	630	945	1260	1890	630	630	630	630	630	630	630	630	630	630
	HRS 3	1890	1890	2835	3780	5670	1890	1890	1890	1890	1890	1890	1890	1890	1890	1890
	HRS 4	1190	1190	1785	2380	3570	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190
	HRS 5	2464	2464	3696	4928	7392	2464	2464	2464	2464	2464	2464	2464	2464	2464	2464
	HRS 6	1540	1540	2310	3080	4620	1540	1540	1540	1540	1540	1540	1540	1540	1540	1540
HRS Compressor size (Kg/day)	HRS 1	149	297	446	446	446	149	149	149	149	149	149	149	149	149	149
	HRS 2	226	451	677	677	677	226	226	226	226	226	226	226	226	226	226
	HRS 3	449	897	1346	1346	1346	449	449	449	449	449	449	449	449	449	449
	HRS 4	282	564	846	846	846	282	282	282	282	282	282	282	282	282	282
	HRS 5	744	1487	2231	2231	2231	744	744	744	744	744	744	744	744	744	744
	HRS 6	372	744	1115	1115	1115	372	372	372	372	372	372	372	372	372	372
Central Electrolyser size (Kg/day)		×	×	×	×	×	1098	1923	3021	4853	2220	1098	1923	3021	4853	2220
Central Electrolyser. Storage size (kg)		×	×	×	×	×	5000	9000	15000	24000	11000	5000	9000	15000	24000	11000
Central Electrolyser. compressor size (kg/day)		×	×	×	×	×	1098	1923	3021	4853	2220	1098	1923	3021	4853	2220
Electrolyser efficiency (kWh/kg)		54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6
Year of the components		2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015

Table 8.23: The summary of the PEME scenarios under 2015-Cost scenarios

Where: **PEME Sc. 1:** Only Onsite PEME electrolyser without central electrolyser (default sizes) (PEME electrolyser under 2015-Cost scenario).

PEME Sc. 2: Double default electrolyser size and default storage size (PEME electrolyser under 2015-Cost scenario).

PEME Sc. 3: Triple-sized (three times default) electrolyser size and 1.5 times default storage size (PEME electrolyser under 2015-Cost scenario).

PEME Sc. 4: Triple-sized (three times default) electrolyser and double default storage size (PEME electrolyser under 2015-Cost scenario).

PEME Sc. 5: Triple-sized (three times default) electrolyser size and triple default storage size (PEME electrolyser under 2015-Cost scenario).

PEME Sc. 6: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day PEME central electrolyser with 5,000 kg storage size (sized based on hydrogen production side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

PEME Sc. 7: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day PEME central electrolyser with 24,000 kg storage size (sized based on hydrogen production side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

PEME Sc. 8: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

PEME Sc. 9: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

PEME Sc. 10: Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day PEME central electrolyser with 11,000 kg storage size (sized based on electricity consumption side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

PEME Sc. 11: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day PEME central electrolyser with 5,000 kg storage size (sized based on hydrogen production side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

PEME Sc. 12: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day PEME central electrolyser with 24,000 kg storage size (sized based on hydrogen production side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

PEME Sc. 13: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

PEME Sc. 14: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on hydrogen production side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

PEME Sc. 15: Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day PEME central electrolyser with 11,000 kg storage size (sized based on electricity consumption side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

8.4.1 Only garage forecourts without central electrolyser (PEME Sc. 1)

In this case, the six garage forecourts are responsible for meeting the energy and hydrogen consumption without any external tools to support grid balancing or to meet any shortages in hydrogen availability. Only the system cost will be different compared to the alkaline electrolysis scenario. In the 2015-Cost scenario, the efficiency of PEM electrolysis will be the same (54.6 kWh/kg).The same electricity pricing mechanism will be applied Figure 8.59 shows the electricity settlement price to the garage forecourts on a daily bias throughout the year. The electricity settlement price is slightly lower than for the same case with the alkaline electrolyser. This is because of the increased cost of the PEME, which thus requires cheaper electricity to meet the economic requirements (bank instalments and variable cost).

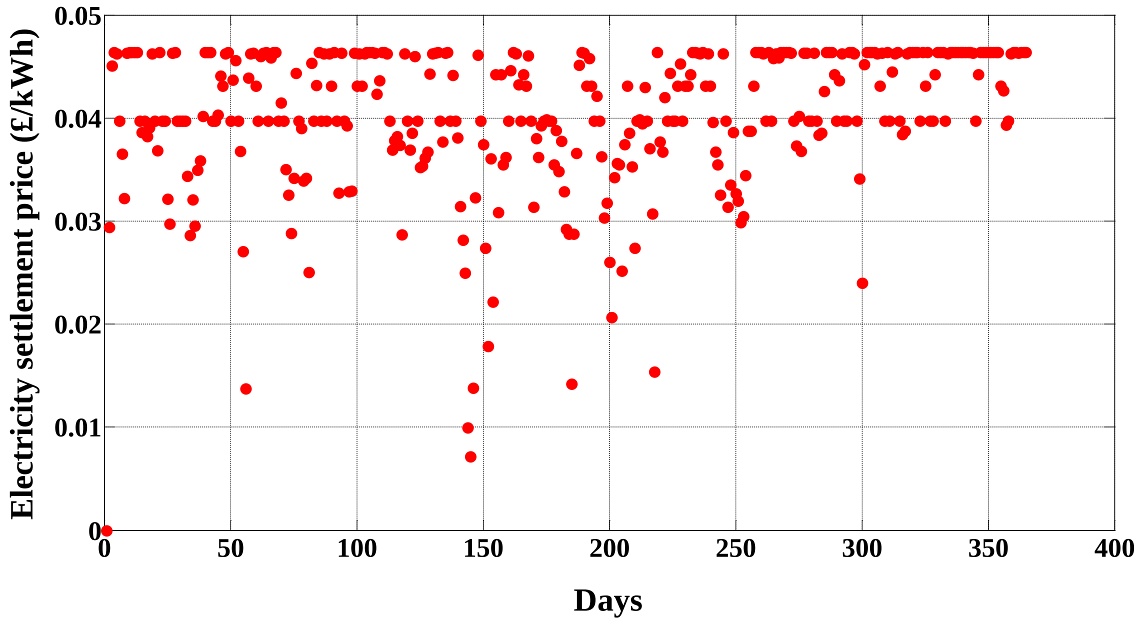


Figure 8.59: Electricity settlement price throughout the year when Only garage forecourts without central electrolyser scenario is applied (PEME Sc. 1)

Three main issues require investigation: grid balancing, hydrogen demand satisfaction, and the average price of hydrogen at the point of sale. For grid balancing, the system should consume the majority of surplus energy to keep the grid stable. Only 54% of the total surplus energy is absorbed via garage forecourts, which will meet nearly 60% of the total hydrogen demand. These values are very similar to the equivalent case for alkaline electrolysers. The only difference is in the economic assessments, as the investment cost is increased because of the cost of the PEME. Table 8.24 shows the economic calculations for this system.

Cost / HRS	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average price** (£/kg)
HRS 1	291,506	1,069	3,836	62,225	31,231	11.50
HRS 2	378,889	1,313	4,046	73,890	38,359	12.00
HRS 3	915,743	3,642	13,638	218,560	106,419	10.80
HRS 4	579,373	2,207	8,261	131,206	64,487	11.20
HRS 5	133,267,6	5,099	17,376	294,895	149,007	11.10
HRS 6	753,276	2,703	10,183	158,992	78,991	11.70

Table 8.24: Hydrogen cost calculation under 2015-Cost scenario (Only garage forecourts without central electrolyser (PEME Sc. 1))

In this scenario, hydrogen production at HRS 2 and 5 is smaller and this causes the highest increase in the average hydrogen price for all HRSs since, as the investment cost increases, the income will decrease. The electricity price has very little impact on the total cost compared with the investment cost. For example, the production at HRS 1 was 31,082 kg/year with a total electricity price of £75,631/year with the 2015-Cost scenario for alkaline electrolysis. The production reached 31,231 kg/year with a total electricity cost of £62,225 /year using the PEM scenario. The electricity price represents 24% of the total cost for alkaline electrolysis, and 17% for PEM electrolysis, but the average price of hydrogen is increased from £10.00 to £11.50 /kg, as driven by the investment cost. The operational advantages of the PEME are not discussed in detail in this investigation. Figure 8.60 shows a comparison of average hydrogen price from PEM and alkaline electrolysers in this scenario.

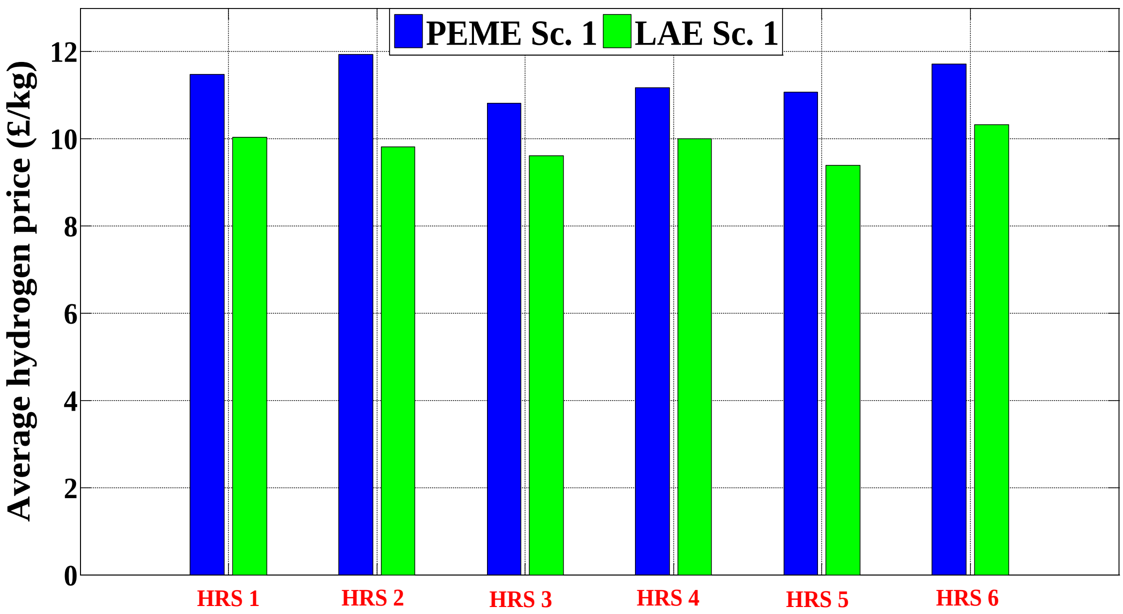


Figure 8.60: Average hydrogen price for alkaline (LAE Sc. 1) and PEM (PEME Sc. 1) electrolysers (Only garage forecourts without central electrolyser)

8.4.2 Increased size of HRS components

Two system sizes will be tested: double-sized and triple-sized systems. As in the alkaline electrolyser scenario, for the double-sized system only the default sizes of the electrolyser and compression system will be doubled whilst the default storage size will be maintained. For the triple-sized system, in addition to tripling the default sizes of the electrolyser and compression system, different storage tank volumes will be tested.

a) Double-sized default electrolyser test (PEME Sc. 2)

Double-sized PEM electrolyser and compressor systems will be used, taking into account the new cost of these components.

This scenario will follow the same instructions as the equivalent case for the alkaline electrolysers (LAE Sc. 2).

Figure 8.61 shows the electricity price after applying the electricity mechanism as per the alkaline electrolyser scenario.

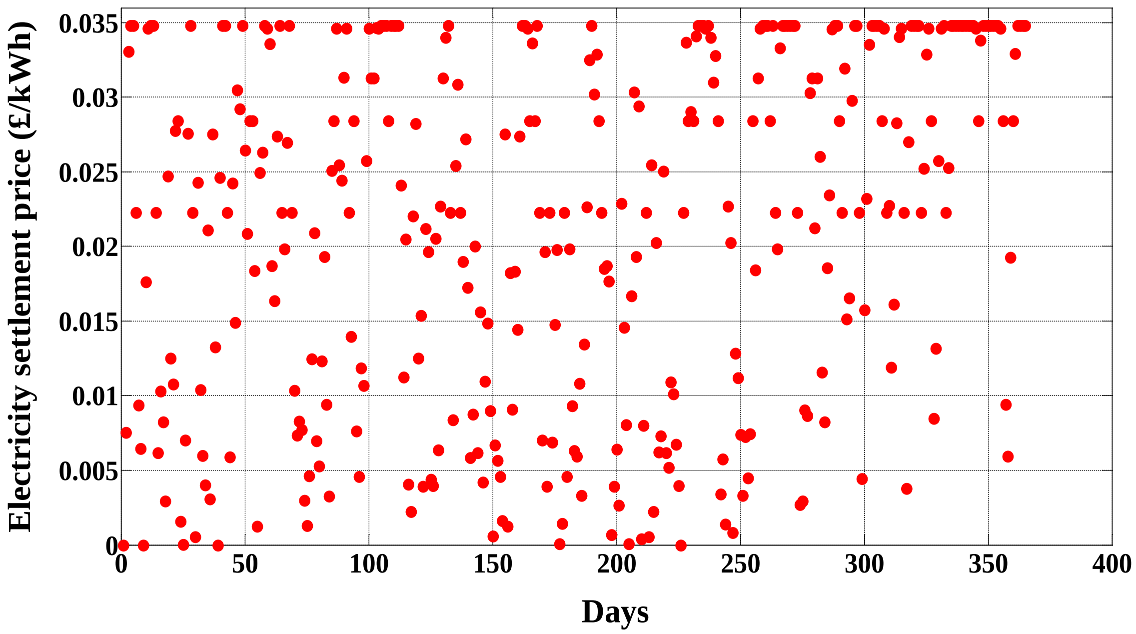


Figure 8.61: Electricity price to the garage forecourts (doubled-sized , 2015-Cost scenario (PEME Sc. 2))

Also, in this scenario, the electricity price is less than that of the equivalent scenario for alkaline electrolysis, which a result of an increased electrolyser capital cost.

This system can consume 65% of the total surplus energy and satisfy around 72% of hydrogen demand. The hydrogen production for the garage forecourts in this scenario is less than in the alkaline electrolyser scenario, as can be seen in Figure 8.62.

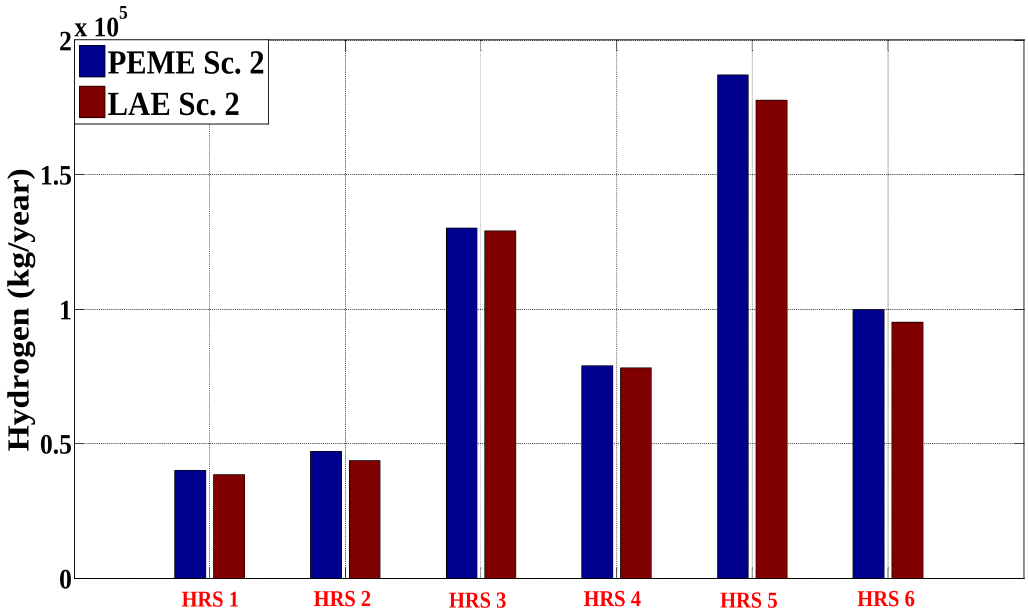


Figure 8.62: Hydrogen production of PEM (PEME Sc. 2) and alkaline (LAE Sc. 2) electrolysers throughout the year

The cost for a PEME in this scenario is higher than that of an alkaline electrolyser, so hydrogen production needs to be greater to meet the economic targets. The electricity pricing mechanism restricts hydrogen production. To illustrate this further, day 7 will be investigated. For both PEM and alkaline scenario, the electricity pricing mechanism is shown in Figure 8.63:

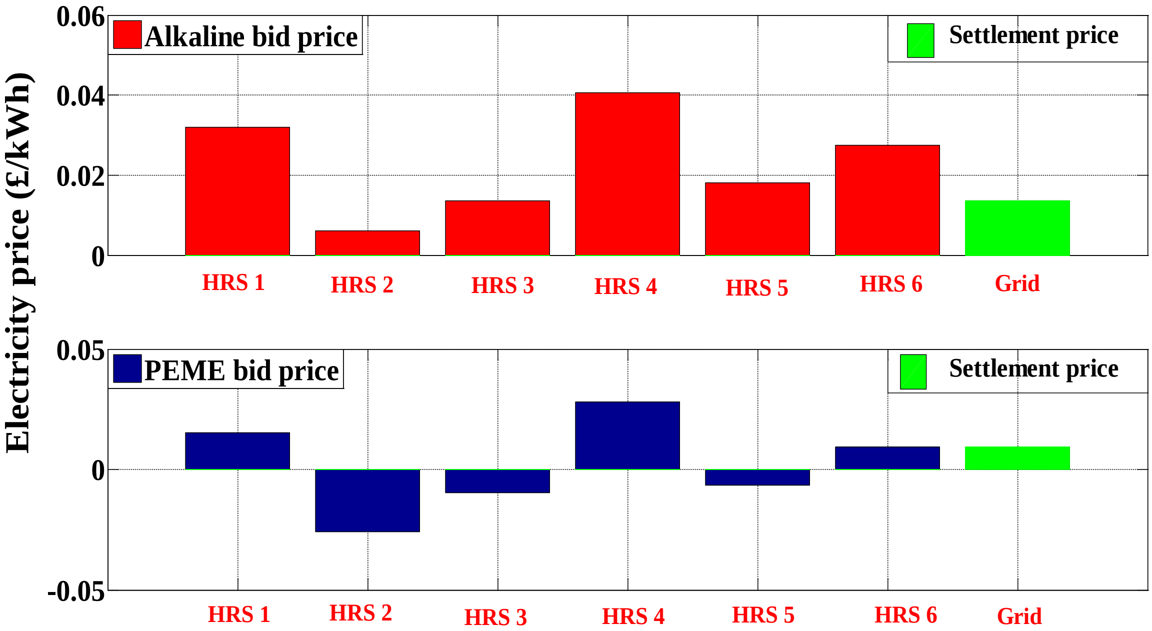


Figure 8.63: Electricity mechanism on day 7 for alkaline and PEM scenarios

As can be seen for the alkaline scenario, the energy target is achieved at garage forecourt 3, which means the settlement price is set to that of HRS 3.

Only HRS 2 is not refuelled on that day. The total energy consumed by the garage forecourts was 192,417 kWh, which is nearly equal to the total surplus energy that day.

However, for the PEM scenario, because of the high investment cost, which requires a lower settlement price to cover the investment cost, some bid prices are set at negative values.

The utility company wants to sell 90% of surplus energy, but to do so would require paying HRSs to take energy (i.e. there would be a negative settlement price).

Instead, the utility company is likely to sell 100% of surplus energy at very low price, but positive settlement price, and waste the remaining surplus energy (i.e. curtail wind output by taking turbines offline).

In some markets, this involve paying wind from operator, in which case, a negative settlement price may be preferable, hence HRSs could get paid to consumer else.

The economic assessments of the system that operates without applying a negative settlement price are given in Table 8.25:

Cost / HRS	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average price** (£/kg)
HRS 1	421,638	1,319	2,896	31,095	38,540	11.90
HRS 2	576,330	1,493	2,456	29,666	43,627	14.00
HRS 3	1,308,382	4,417	9,865	115,777	129,068	11.10
HRS 4	826,175	2,673	5,967	66,343	78,115	11.50
HRS 5	1,983,336	6,082	12,082	144,997	177,737	12.00
HRS 6	1,078,606	3,261	7,215	73,519	95,291	12.20

Table 8.25: Techno-economic assessments of each agree forecourts (doubled-sized, 2015-Cost scenario (PEME Sc. 2))

b) Triple-sized test Triple-sized default electrolyser test

As in the alkaline scenario, three different sizes of storage will be used with the triple-sized electrolyser and compression system.

These sizes are PEME Sc. 3 (Triple-sized default electrolyser and 1.5 default storage size), PEME Sc. 4 (Triple-sized default electrolyser and double default storage size) and PEME Sc. 5 (Triple-sized default electrolyser and triple default storage size).

The electricity settlement price will change with each different storage size because the investment cost will increase. Figure 8.64 shows the settlement price for this system using different storage sizes.

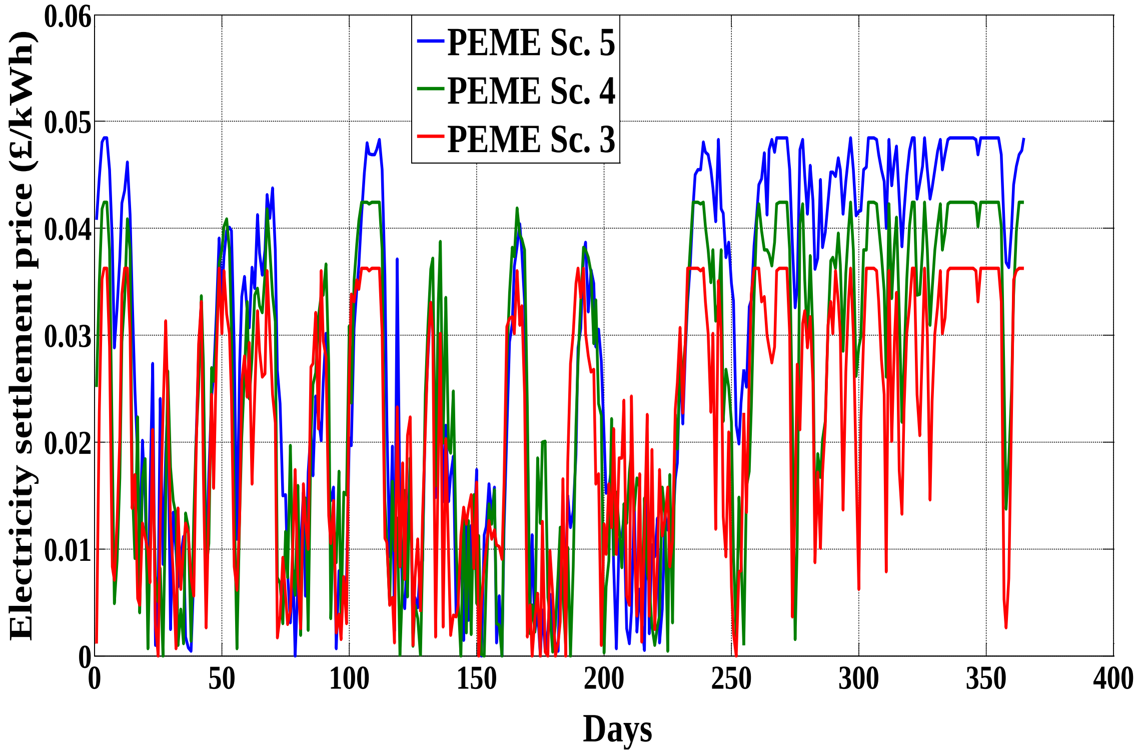


Figure 8.64: Daily settlement prices for different storage size (Triple-sized electrolyser under 2015-Cost scenario)

Table 8.26 below shows the economic summary using these different storage sizes and triple sized of electrolyser.

Scenario	HRS	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Triple-sized default electrolyser and 1.5 times default storage size (PEME Sc. 3)	Hydrogen demand satisfaction (%)	80	60	87	85	75	81
	Average hydrogen price (£/kg)	15.50	19.50	15.10	15.70	16.10	160
	Total hydrogen demand satisfaction (%)	78					
	Total surplus energy consumed (%)	71					
Triple-sized default electrolyser and double-sized default storage size (PEME Sc. 4)	Hydrogen demand satisfaction (%)	83	68	90	89	80	86
	Average hydrogen price (£/kg)	17.00	19.10	16.50	17.10	17.00	17.10
	Total hydrogen demand satisfaction (%)	83					
	Total surplus energy consumed (%)	75					
Triple-sized default electrolyser and Triple-sized default storage (PEME Sc. 5)	Hydrogen demand satisfaction (%)	86	76	91	92	84	87
	Average hydrogen price (£/kg)	19.90	20.50	20.10	20.50	19.30	20.70
	Total hydrogen demand satisfaction (%)	86					
	Total surplus energy consumed (%)	78					

Table 8.26: Techno- economic assessments of the system under different size of electrolyser and different storage sizes

As in the double-size scenario, the amount of hydrogen production from the PEME is less than the alkaline scenario because the electricity settlement required to meet the HRSs economic requirements is low and on some days is less than zero. So, the amount of hydrogen produced will be reduced since it will be zero at these times (i.e. when the bid prices are negative). The system size could help solve some nominal problems because more surplus energy was consumed and the hydrogen demand is closer to being met under this scenario. However, the average price of hydrogen is quite expensive by comparison with the alkaline scenarios. Going up to triple the default size could be a possible option from the perspective of grid balancing and satisfying hydrogen demand, but from the perspective of average hydrogen price this is not acceptable because the price will be expensive.

8.4.3 Adding a large central electrolyser to the system

The central electrolyser will be added to the system to absorb the remainder of the surplus power and to supply the hydrogen during shortages at the garage forecourts. There are two possible modes of operation of the central electrolyser that will be investigated. The first is if the central electrolyser participates in the electricity pricing mechanism as if it were just another HRS. Therefore, only one settlement price will be set for all the HRSs and the central electrolyser and the central electrolyser will buy electricity at the same settlement price as HRSs. In the second scenario, the electricity settlement price of the HRSs and the central electrolyser are different. In other words, the utility company has to check the bid price of HRSs first and choose the settlement price of all HRSs. After that, another settlement price will be given to the central electrolyser, which will be less than the HRSs settlement price, in this case, 20% less. The reduction in central electrolyser settlement price has been made as an incentive and to the delay in releasing the central settlement price (after the HRSs' settlement price).

8.4.3.1 PEM central electrolyser Sizing based on the production side

In terms of the central electrolyser, different production sizes will be teased in this section. These scenarios are PEME Sc. 6 (1098 kg/day) (39% of the residual surplus energy), PEME Sc. 7 (1923 kg/day) (60% of the residual surplus energy), PEME Sc. 8 (3022 kg/day) (81% of the residual surplus energy) and finally PEME Sc. 9 (4853 kg/day) (95%

of the residual surplus energy). Different storage sizes will be applied based on the electrolyser size. Generally, five days of production will be considered as storage in each case. This size is chosen based on the sequential days of shortage without surplus energy. The compression system is equal to one day's production.

a) Central PEM electrolyser operates under a different electricity settlement price to the HRSs

As mentioned earlier, the electricity settlement price of the HRSs and the central electrolyser are different. In other words, the utility company has to check the bid price of HRSs first and choose the settlement price of all HRSs. After that, another settlement price will be given to the central electrolyser. The settlement price of PEME Sc. 6 is shown in Figure 8.65. The electricity settlement prices for all size scenarios are less than those for the equivalent cases in the alkaline scenario (LAE Sc. 6) because of the increase in investment cost. The hydrogen production and the variation in hydrogen stored for all sizes in the PEME scenarios are presented in Figure 8.66 and Figure 8.67.

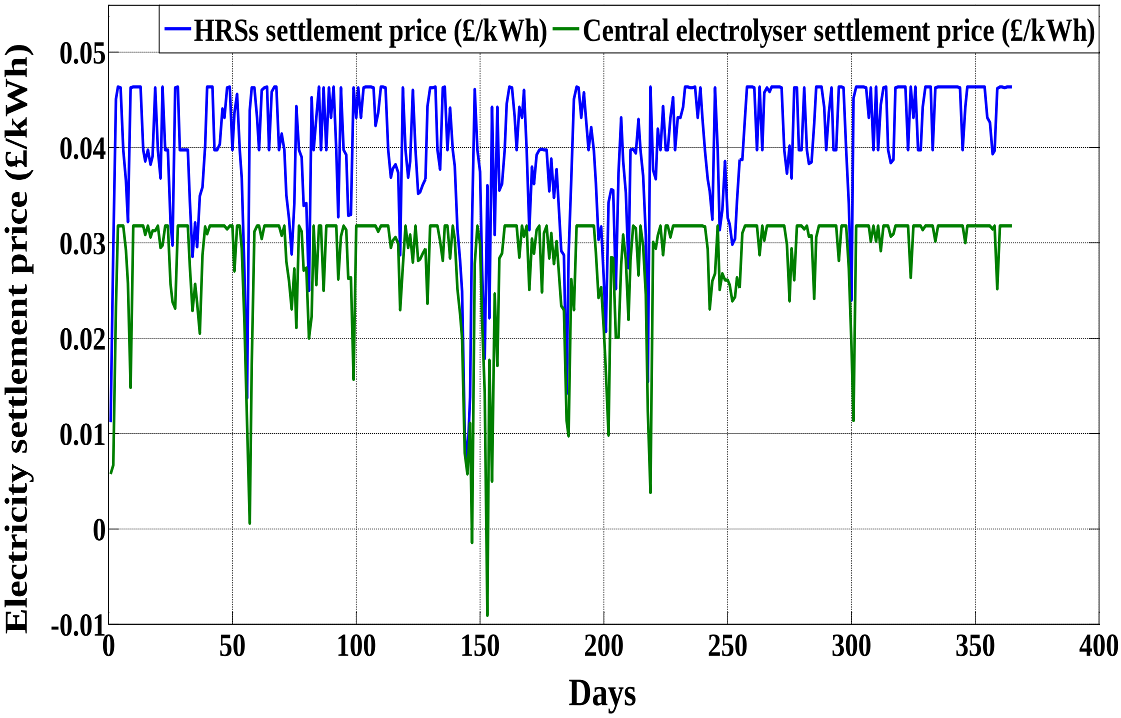


Figure 8.65: Electricity settlement prices to the central electrolyser and garage forecourts when PEM central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 6)(2015-Cost scenario)

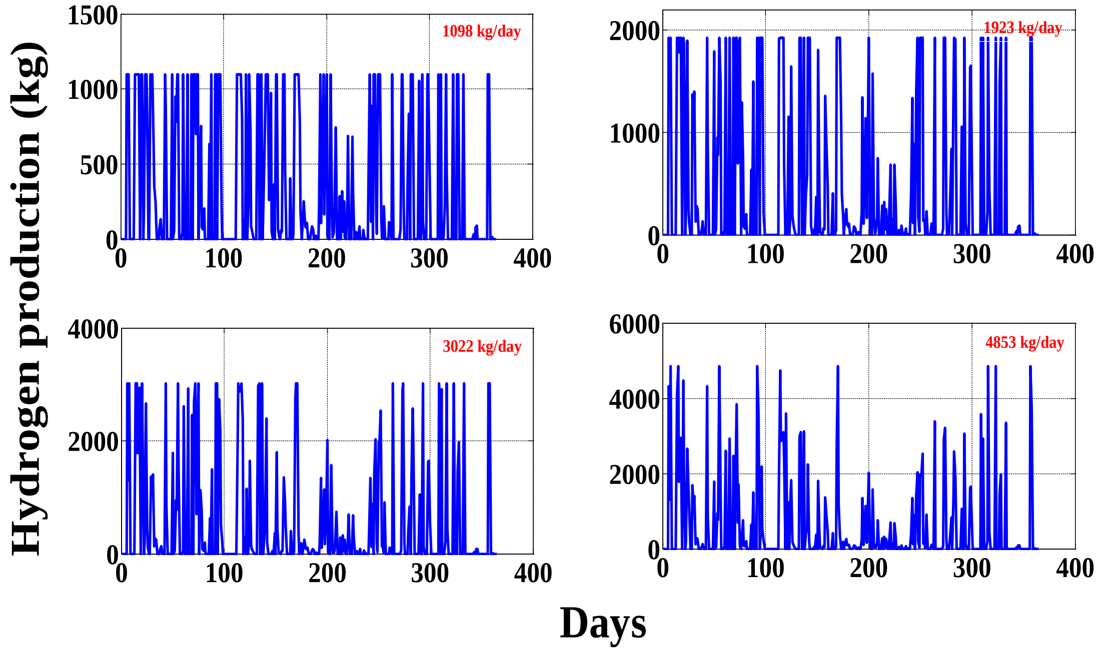


Figure 8.66: Hydrogen production of central electrolyser under different electrolyser sizes when PEM central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

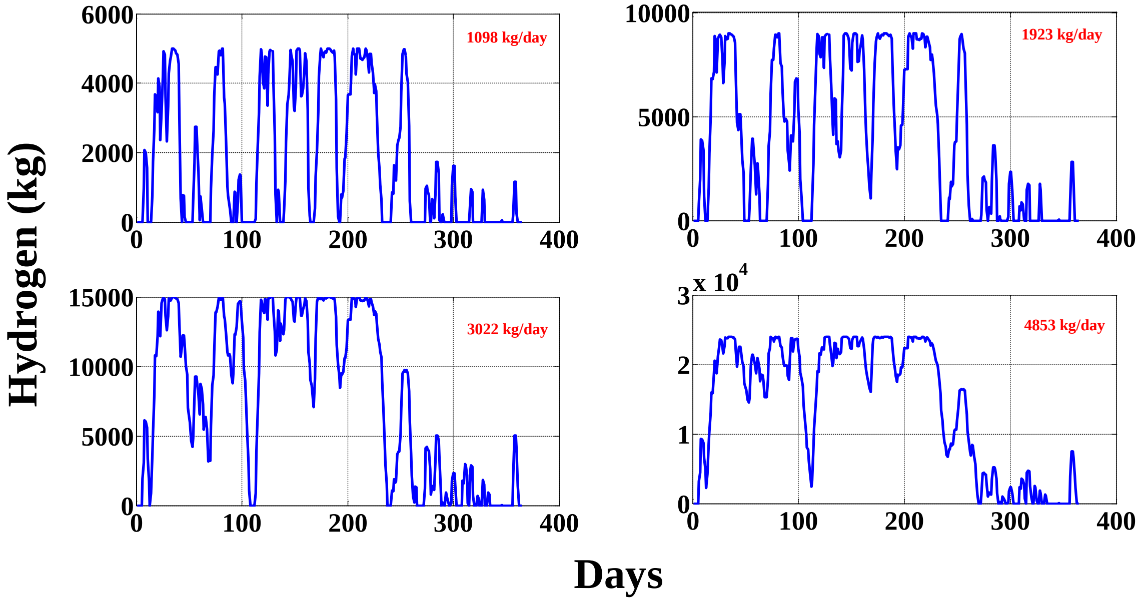


Figure 8.67: Daily variation of Hydrogen level in storage tank throughout the year using different sizes of electrolyser when PEM central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

The hydrogen production and the variation of stored hydrogen are very similar to those of the alkaline central electrolyser. The only difference is in the average hydrogen price, which is expensive in this scenario compared to the alkaline scenario. The summary of this scenario under different system sizes is given in Table 8.27.

Central electrolyser size (kg/day) \ HRS		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
PEME Sc. 6	Satisfaction of hydrogen demand (%)	71	67	78	75	77	74
	Average hydrogen price (£/kg)	14.00	15.20	13.00	12.90	14.70	14.40
	Total energy consumed after adding central electrolyser (%)	68					
	Satisfaction of total hydrogen for HRSs (%)	75					
	Average central electrolyser hydrogen price (£/kg)	25.00					
PEME Sc. 7	Satisfaction of hydrogen demand (%)	78	77	84	82	82	81
	Average hydrogen price (£/kg)	16.40	18.60	15.00	15.10	17.20	17.00
	Total energy consumed after adding central electrolyser (%)	73					
	Satisfaction of total hydrogen for HRSs (%)	81					
	Average central electrolyser hydrogen price (£/kg)	31.00					
PEME Sc. 8	Satisfaction of hydrogen demand (%)	84	82	87	86	87	86
	Average hydrogen price (£/kg)	20.40	23.20	18.00	18.20	21.40	20.60
	Total energy consumed after adding central electrolyser (%)	78					
	Satisfaction of total hydrogen for HRSs (%)	86					
	Average central electrolyser hydrogen price (£/kg)	40.70					
PEME Sc. 9	Satisfaction of hydrogen demand (%)	88	87	90	89	90	89
	Average hydrogen price (£/kg)	22.30	24.60	19.30	20.00	22.70	22.40
	Total energy consumed after adding central electrolyser (%)	80					
	Satisfaction of total hydrogen for HRSs (%)	89					
	Average central electrolyser hydrogen price (£/kg)	57.60					

Table 8.27: Assessments of the system under different central electrolyser sizes when PEM central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

b) The central PEM electrolyser operates under the same electricity settlement price as the HRSs

The central electrolyser participates in the electricity pricing mechanism as if it were just another HRS. Therefore, only one settlement price will be set for all the HRSs and the central electrolyser and the central electrolyser will buy electricity at the same settlement price as HRSs. The electricity settlement price to the HRSs and to the 1098 kg/day PEM central electrolyser (PEME Sc. 11) throughout the year is shown in Figure 8.68:

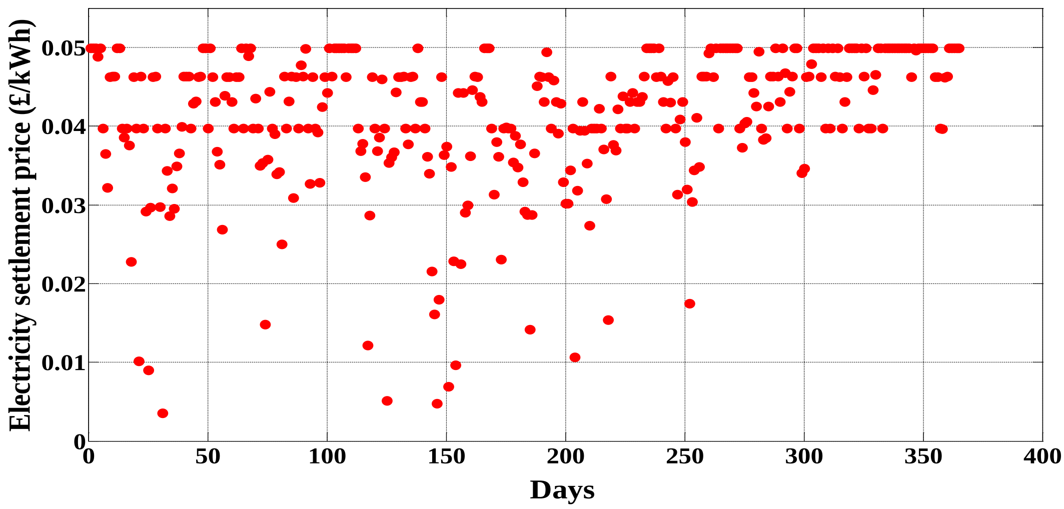


Figure 8.68: Electricity settlement prices to the HRSs and to the central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (PEME Sc. 11) (2015-Cost scenario)

The daily hydrogen production and the variation in stored hydrogen for all HRSs including the PEM central electrolyser of the first size are presented in Figure 8.69 and Figure 8.70.

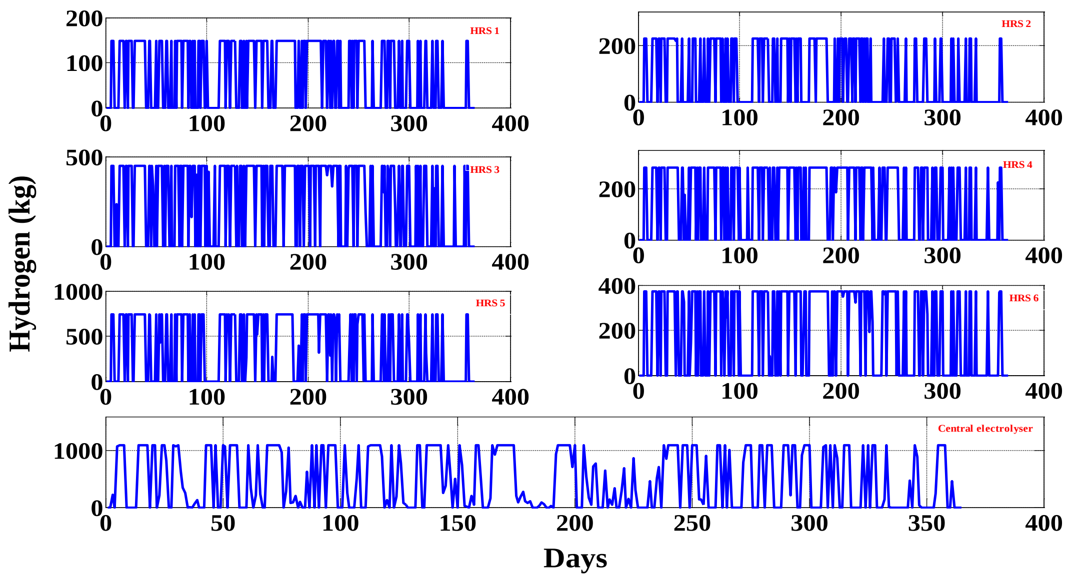


Figure 8.69: HRSs and PEM central electrolyser hydrogen production throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (PEME Sc. 11) (2015-Cost scenario)

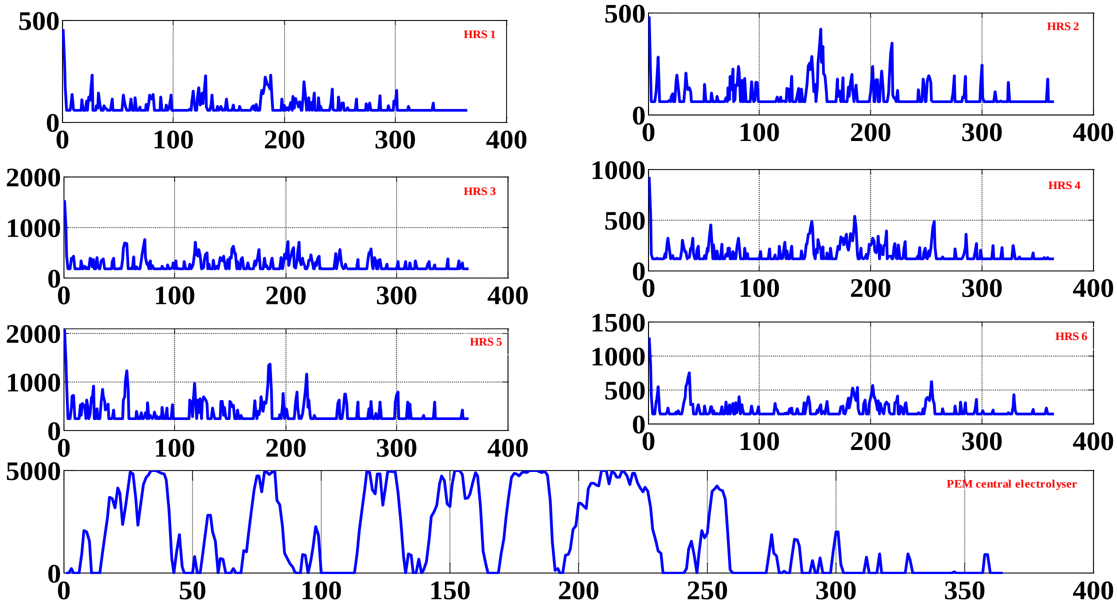


Figure 8.70: Daily variation of Hydrogen level in storage tank throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (PEME Sc. 11) (2015-Cost scenario)

The storage profile for the garage forecourts does not include any imported hydrogen because the storage in this case works merely as a means of transferring hydrogen from the central storage to the HRSs. Figure 8.71 shows the hydrogen imported per garage forecourt for the PEME Sc. 11 over the year.

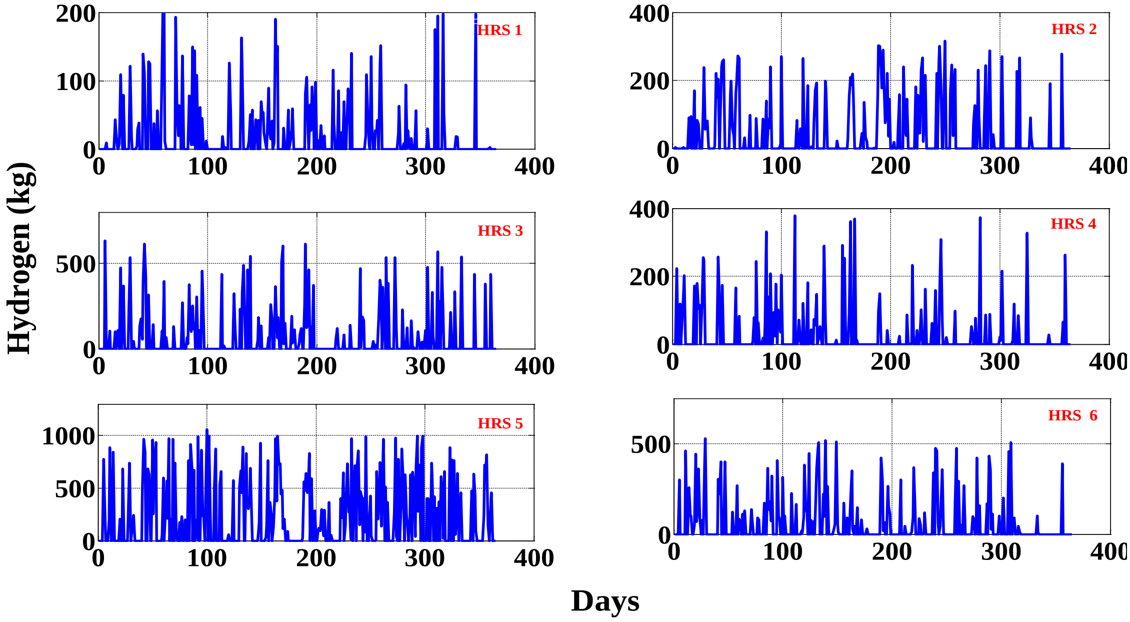


Figure 8.71: Hydrogen imported by HRSs throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (PEME Sc. 11) (2015-Cost scenario).

Table 8.28 gives a summary of this scenario under different system sizes.

Central electrolyser size (kg/day) \ HRS		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
PEME Sc. 11	Satisfaction of hydrogen demand (%)	65	66	76	70	82	73
	Average hydrogen price (£/kg)	14.00	15.00	13.30	13.30	15.00	13.90
	Total energy consumed after adding central electrolyser (%)	68					
	Satisfaction of total hydrogen for HRSs	75					
	Average central electrolyser hydrogen price (£/kg)	18.40					
PEME Sc. 12	Satisfaction of hydrogen demand (%)	72	76	81	78	85	81
	Average hydrogen price (£/kg)	16.10	18.60	15.60	15.80	17.60	16.20
	Total energy consumed after adding central electrolyser (%)	73					
	Satisfaction of total hydrogen for HRSs (%)	81					
	Average central electrolyser hydrogen price (£/kg)	23.80					
PEME Sc. 13	Satisfaction of hydrogen demand (%)	82	83	85	84	88	85
	Average hydrogen price (£/kg)	20.30	23.40	18.70	19.0	21.80	19.90
	Total energy consumed after adding central electrolyser (%)	77					
	Satisfaction of total hydrogen for HRSs	86					
	Average central electrolyser hydrogen price (£/kg)	30.70					
PEME Sc. 14	Satisfaction of hydrogen demand (%)	86	87	89	88	91	88
	Average hydrogen price (£/kg)	27.40	30.90	23.50	24.50	28.80	25.50
	Total energy consumed after adding central electrolyser (%)	80					
	Satisfaction of total hydrogen for HRSs (%)	89					
	Average central electrolyser hydrogen price (£/kg)	44.00					

Table 8.28: Assessments of the system under different sizes of central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (2015-Cost scenario).

Even though the average price of hydrogen from the central electrolyser is less than that of the previous PEME scenario, the average hydrogen price of the garage forecourts is higher or nearly the same. Since the capital cost of the garage forecourt components is the same in both scenarios (central electrolyser operation mode) and the variable cost is relatively low. The cost difference between these scenarios should essentially depend on the amount, and the price, of hydrogen imported from the central electrolyser to HRSs. The imported hydrogen, as a percentage of the total hydrogen delivered per garage forecourt, could be used as a means of interpreting the stability of the price of hydrogen in both scenarios. Table 8.29 shows the share of imported hydrogen as a proportion of the total hydrogen delivered to the HRSs in both scenarios under different sizes.

Scenarios		HRSs	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Central electrolyser operates under a different electricity settlement price to the HRSs	**Imported hydrogen (%)**	**PEME Sc. 6**	18	25	15	12	26	20
		PEME Sc. 7	25	35	21	20	31	27
		PEME Sc. 8	31	39	24	24	35	31
		PEME Sc. 9	34	42	26	27	37	33
Central electrolyser operates under the same s electricity settlement price as the HRSs	**Imported hydrogen (%)**	**PEME Sc. 11**	22	34	22	17	41	25
		PEME Sc. 12	30	46	30	28	44	32
		PEME Sc. 13	40	54	35	35	49	39
		PEME Sc. 14	44	54	35	37	49	40

Table 8.29: Hydrogen imported by each garage forecourt under different PEM central electrolyser sizes and for two different modes of operation

8.4.3.2 PEM central electrolyser sizing based on the power consumption side

System sizing will rely on the maximum hydrogen production for all garage forecourts, with the storage equal to five days of production. The compression system is equal to almost one day's worth of production. Based on these assumptions, the capacity of the central electrolysers is 121,212 kWh or 2,220 kg/day (54.6 kWh/kg), the hydrogen storage size is 11,000 kg, and finally the compression system is equal to the production size (2,220 kg/day). Two operational modes for the central electrolyser will be investigated as in previous scenarios.

a) Central PEM electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 10)

All system regulations and steps are same as same as in the alkaline system scenario. The electricity settlement price to the garage forecourts and the central electrolyser is given in Figure 8.72:

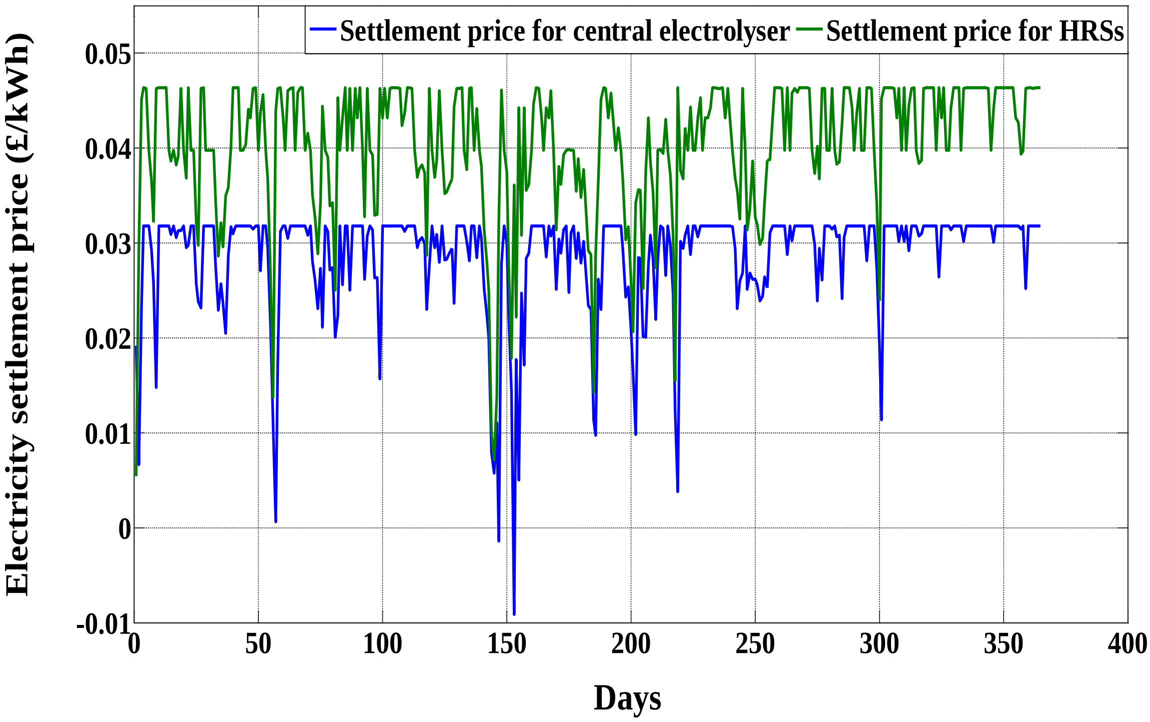


Figure 8.72: Electricity settlement price for the garage forecourts and central electrolyser when central electrolyser operates under a different electricity settlement price to the HRSs (2015-Cot scenario)

The electricity settlement price for the system is less than that of equivalent alkaline electrolysis scenario (LAE Sc. 10). The capital cost of the PEM and the investment cost requires cheaper electricity to meet the economic requirements of the system. Hydrogen production and the variation in stored hydrogen for the central electrolyser over the year are presented in Figure 8.73 and Figure 8.74, respectively.

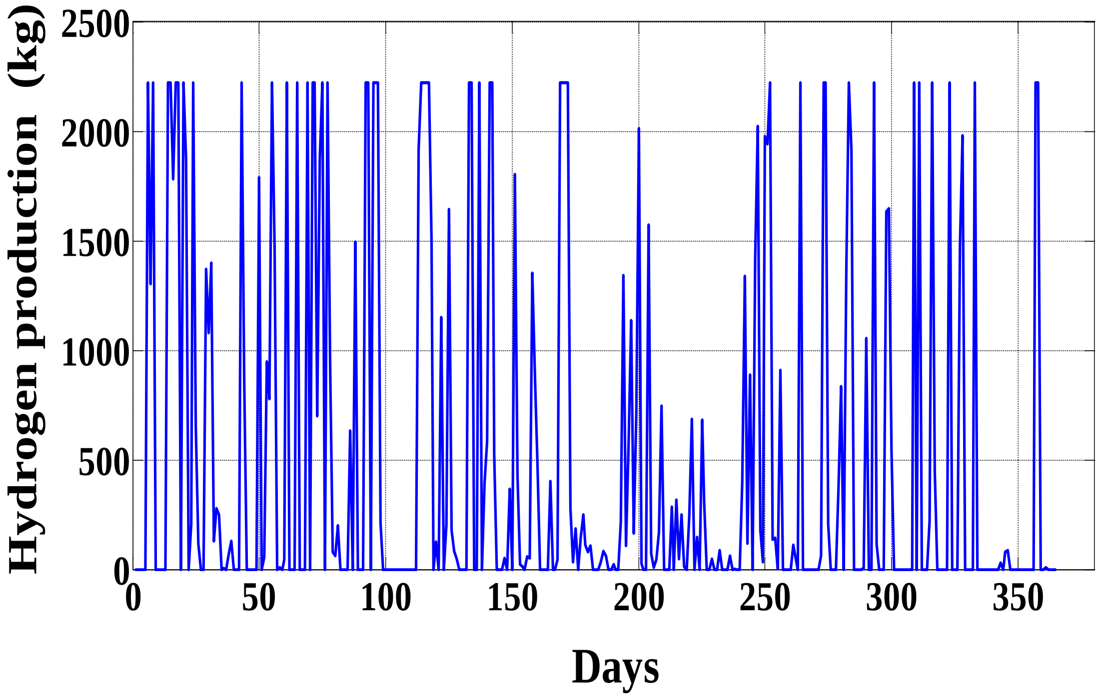


Figure 8.73: PEM central electrolyser hydrogen production throughout the year when central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 10) (2015-Cost scenario).

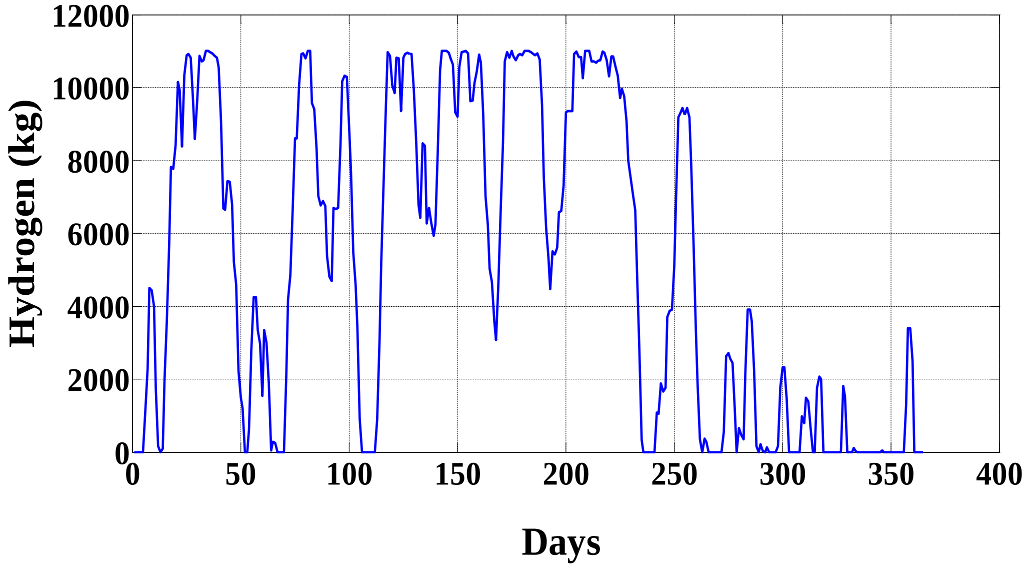


Figure 8.74: Daily variation of Hydrogen level in storage tank throughout the year when PEM central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 10) (2015-Cost scenario).

Table 8.30 below shows the economic summary for the system.

Details / HRSs	**Satisfaction of hydrogen demand** (%)	**Average hydrogen price** (£/kg)	**Total surplus energy consumed after adding central electrolyser** (%)	**Satisfaction of total hydrogen demand** (%)	**Average price of hydrogen from central electrolyser** (£/kg)
HRS 1	80	17.60	75	83	40.00
HRS 2	80	20.10			
HRS 3	85	16.00			
HRS 4	83	16.00			
HRS 5	84	18.40			
HRS 6	83	18.00			

Table 8.30: Economic assessment of the system when central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 10) (2015-Cost scenario).

b) The central PEM electrolyser operates under the same electricity settlement price as the HRSs (PEME Sc. 15)

The PEM central electrolyser in this scenario competes in the pricing mechanism as if it were one of the garage forecourts and follows the same steps in releasing its bid price. The daily settlement prices for the year are shown in Figure 8.75.

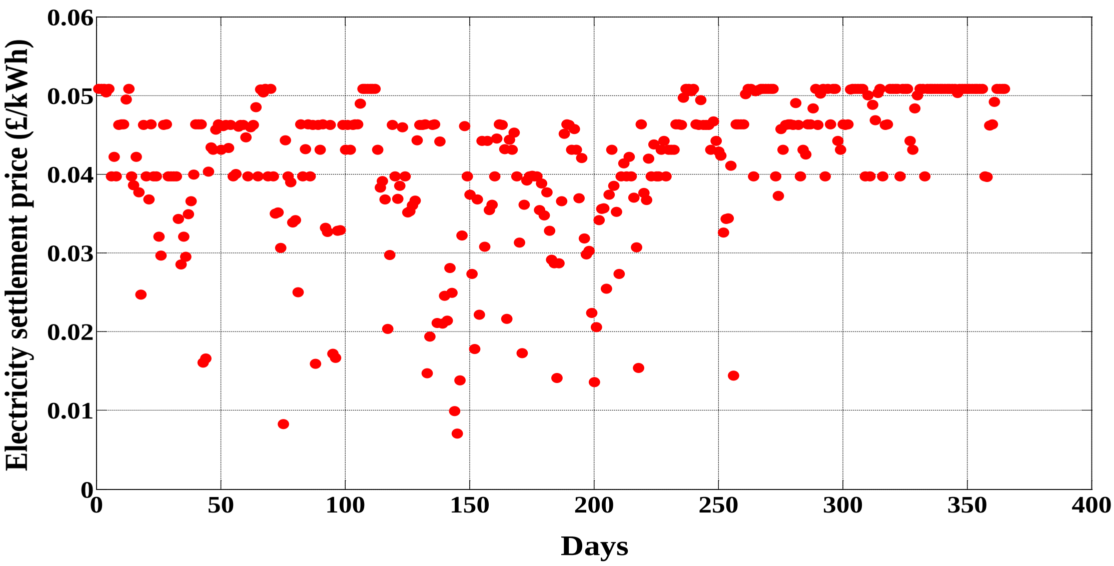


Figure 8.75: Daily electricity settlement price for HRSs and central electrolyser throughout the year when central electrolyser operates under the same electricity settlement price as the HRSs (PEME Sc. 15) (2015-Cost scenario)

The electricity price profile is similar to the equivalent case for the alkaline electrolyser scenario but with a bit lower values because of the increase in the investment cost, since the increased investment cost requires cheaper electricity to meet the economic requirements. The hydrogen production and the variation of stored hydrogen for the garage forecourts and central electrolyser are shown in Figure 8.76 and Figure 8.77, respectively:

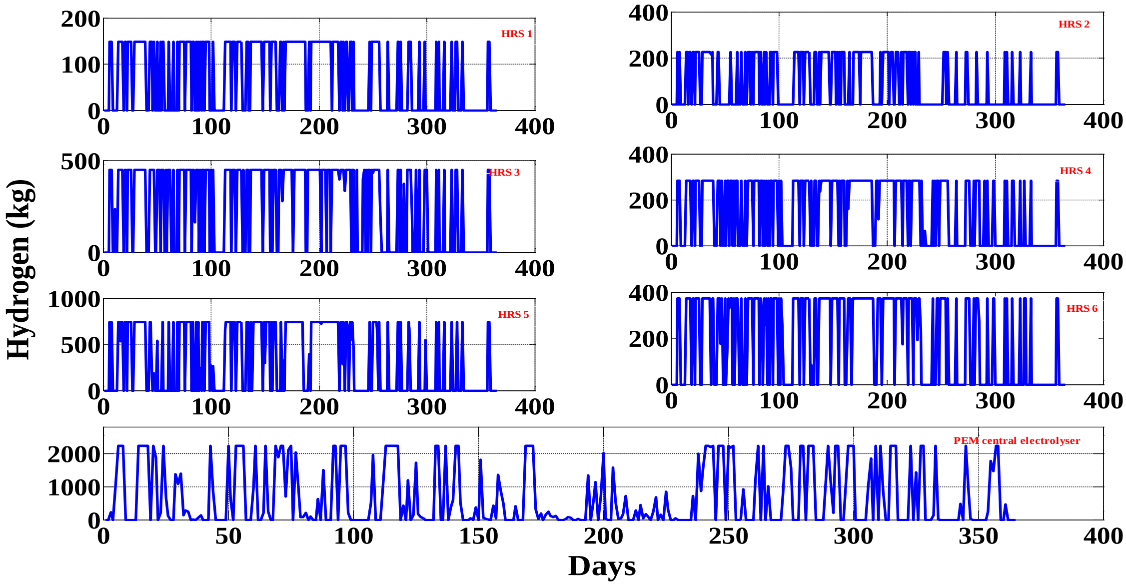


Figure 8.76: Hydrogen production of the PEM central electrolyser and HRSs throughout the year when PEM central electrolyser operates under the same electricity settlement price as the HRSs (PEME Sc. 15) (2015-Cost scenario)

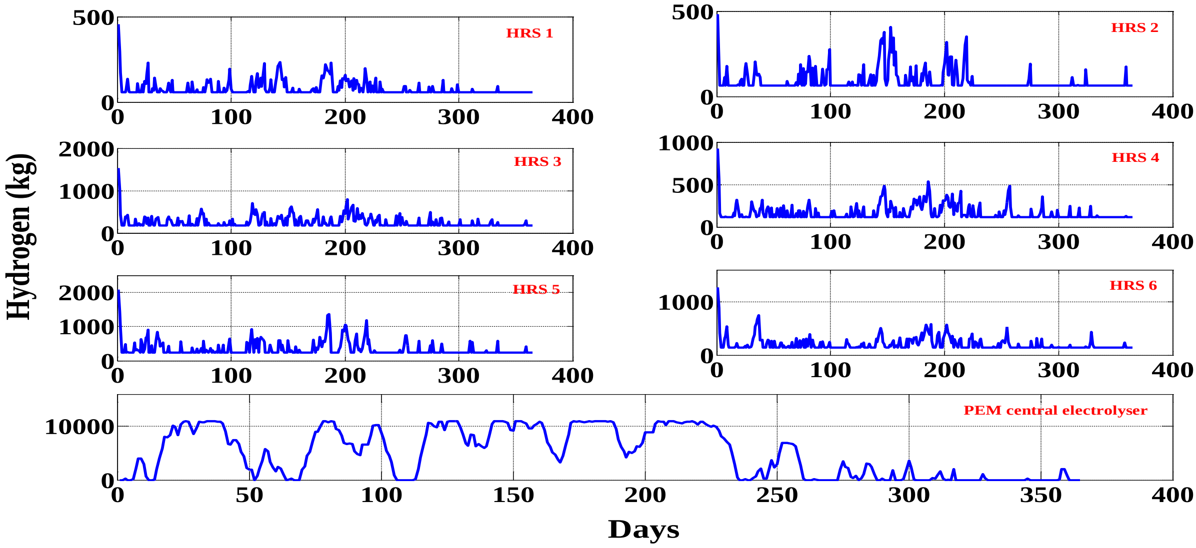


Figure 8.77: Daily variation of Hydrogen level in storage tank throughout the year when PEM central electrolyser operates under the same electricity settlement price as the HRSs (PEME Sc. 15) (2015-Cost scenario)

Table 8.31 below shows a summary for the system and an assessment as to whether the main goals been achieved including grid balancing, the satisfaction of hydrogen demand and an acceptable price of hydrogen.

Details / HRSs	Satisfaction of hydrogen demand (%)	Average hydrogen price (£/kg)	Total surplus energy consumed after adding central electrolyser (%)	Satisfaction of total hydrogen demand (%)	Average price of hydrogen from central electrolyser (£/kg)
HRS 1	76	17.50	75	83	26.00
HRS 2	79	20.00			
HRS 3	83	16.40			
HRS 4	81	16.70			
HRS 5	86	19.00			
HRS 6	82	17.20			

Table 8.31: Economic assessment of the system when PEM central electrolyser operates under the same electricity settlement price as the (PEME Sc. 15) HRSs

As in other scenarios, the average price of hydrogen sold to the HRSs by the central electrolyser is less than if the central electrolyser operates under a different electricity settlement price to the HRSs. However, the average price of hydrogen sold at the garage forecourts is similar. Figure 8.78 shows the hydrogen imported per garage forecourt for both scenarios (PEME Sc. 10 and PEME Sc. 15). The amount of hydrogen imported to HRSs in the first scenario (with the higher price of hydrogen from the central electrolyser) is less than that imported in the second scenario. Despite a higher wholesale price (where the central electrolyser sell to the HRSs), the retail price (where the HRSs sell to FCEV drivers) is unchanged.

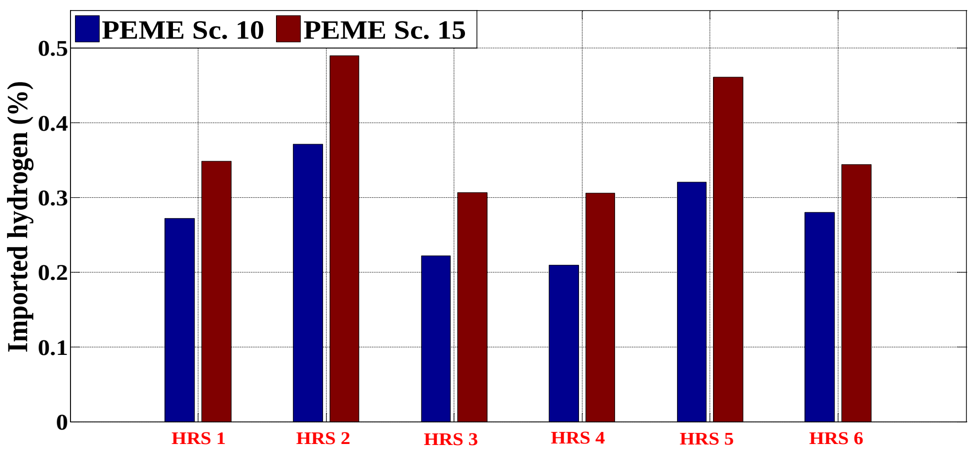


Figure 8.78: Percentage of imported hydrogen for the two scenarios (PEME Sc. 10 and PEME Sc. 15) as compared with the total hydrogen delivered

8.5 2030-Cost scenario with PEM electrolysers

The system will be tested using the cost estimates for components in 2030. All scenarios will be repeated using the new component costs and efficiency levels of the electrolysis. The PEME scenarios under 2030-Cost are summarised in Table 8.32.

Details \ Scenario No.		PEME Sc. 16	PEME Sc. 17	PEME Sc. 18	PEME Sc. 19	PEME Sc. 20	PEME Sc. 21	LAE Sc. 22	PEME Sc. 23	PEME Sc. 24	PEME Sc. 25	PEME Sc. 26	PEME Sc. 27	PEME Sc. 28	PEME Sc. 29	PEME Sc. 30
HRSs Electrolyser size (Kg/day)	HRS 1	173	346	519	519	519	173	173	173	173	173	173	173	173	173	173
	HRS 2	262	524	786	786	786	262	262	262	262	262	262	262	262	262	262
	HRS 3	521	1042	1563	1563	1563	521	521	521	521	521	521	521	521	521	521
	HRS 4	328	656	984	984	984	328	328	328	328	328	328	328	328	328	328
	HRS 5	864	1728	2592	2592	2592	864	864	864	864	864	864	864	864	864	864
	HRS 6	432	864	1296	1296	1296	432	432	432	432	432	432	432	432	432	432
HRS Storage size (kg)	HRS 1	560	560	840	1120	1680	560	560	560	560	560	560	560	560	560	560
	HRS 2	630	630	945	1260	1890	630	630	630	630	630	630	630	630	630	630
	HRS 3	1890	1890	2835	3780	5670	1890	1890	1890	1890	1890	1890	1890	1890	1890	1890
	HRS 4	1190	1190	1785	2380	3570	1190	1190	1190	1190	1190	1190	1190	1190	1190	1190
	HRS 5	2464	2464	3696	4928	7392	2464	2464	2464	2464	2464	2464	2464	2464	2464	2464
	HRS 6	1540	1540	2310	3080	4620	1540	1540	1540	1540	1540	1540	1540	1540	1540	1540
HRS Compressor size (Kg/day)	HRS 1	173	346	486	486	486	173	173	173	173	173	173	173	173	173	173
	HRS 2	262	524	738	738	738	262	262	262	262	262	262	262	262	262	262
	HRS 3	521	1042	1470	1470	1470	521	521	521	521	521	521	521	521	521	521
	HRS 4	328	656	924	924	924	328	328	328	328	328	328	328	328	328	328
	HRS 5	864	1728	2436	2436	2436	864	864	864	864	864	864	864	864	864	864
	HRS 6	432	864	1218	1218	1218	432	432	432	432	432	432	432	432	432	432
Central Electrolyser size (Kg/day)		×	×	×	×	×	1098	1923	3021	4853	2220	1098	1923	3021	4853	2220
Central Electrolyser Storage size (kg)		×	×	×	×	×	5000	9000	15000	24000	11000	5000	9000	15000	24000	11000
Central Electrolyser. compressor size (kg/day)		×	×	×	×	×	1098	1923	3021	4853	2220	1098	1923	3021	4853	2220
Electrolyser efficiency (kWh/kg)		47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Year of the components		2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030

Table 8.32: The summary of the PEM electrolyser scenarios under 2030-Cost scenarios

Where: **PEME Sc. 16:** Only Onsite PEME electrolyser without central electrolyser (default sizes) (PEME electrolyser under 2030-Cost scenario)

PEME Sc. 17: Double-sized default electrolyser size and same default storage size (PEME electrolyser under 2030-Cost scenario)

PEME Sc. 18: Triple-sized default electrolyser and 1.5 default storage size (PEME electrolyser under 2030-Cost scenario)

PEME Sc. 19: Triple-sized default electrolyser and double default storage size (PEME electrolyser under 2030-Cost scenario)

PEME Sc. 20: Triple-sized default electrolyser and triple default storage size (PEME electrolyser under 2030-Cost scenario)

PEME Sc. 21: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day PEME central electrolyser with 5,000 kg storage size (sized based on production side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

PEME Sc. 22: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day PEME central electrolyser with 24,000 kg storage size (sized based on production side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

PEME Sc. 23: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on production side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

PEME Sc. 24: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on production side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

PEME Sc. 25: Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day PEME central electrolyser with 11,000 kg storage size (sized based on consumption side) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

PEME Sc. 26: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day PEME central electrolyser with 5,000 kg storage size (sized based on production side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario)

PEME Sc. 27: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day PEME central electrolyser with 24,000 kg storage size (sized based on production side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario)

PEME Sc. 28: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on production side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario)

PEME Sc. 29: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on production side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario)

PEME Sc. 30: Combination of HRSs (default electrolyser and storage sizes) and 2,220 kg/day PEME central electrolyser with 11,000 kg storage size (sized based on consumption side) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2030-Cost scenario).

8.5.1 Only garage forecourts without central electrolyser (PEME Sc. 16)

The system sizing is still the same as for the same case in the 2015-Cost scenario (PEME Sc. 1). The cost and system efficiency will change as in Table 7.2 for the 2030-Cost scenario. The surplus energy will be absorbed only at the garage forecourts without any central electrolyser. The efficiency will improve from 54.6 kWh/kg in the PEME Sc. 1 to 47 kWh/kg in the PEME Sc. 16 due to the previously mentioned intensive research focus on PEM electrolysis. This will lead to reductions in energy consumption, increased amounts of hydrogen produced and thus reductions in the hydrogen production cost after applying the same electricity pricing mechanism as in the equivalent the 2015-Cost scenario. Figure 8.79 shows the electricity price to the system.

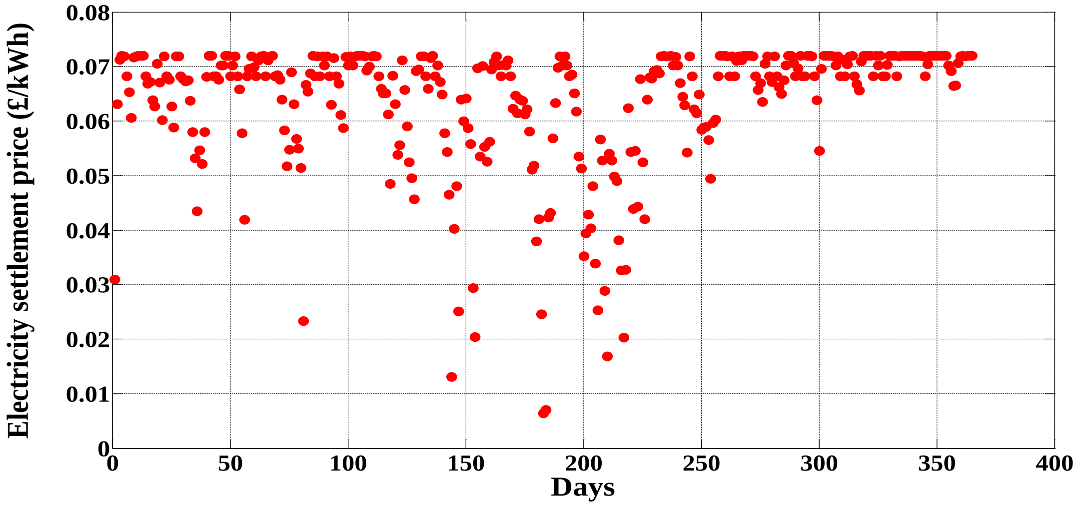


Figure 8.79: Daily electricity settlement price throughout the year under Only garage forecourts without central electrolyser scenario (2030-Cost scenario)

The electricity settlement price in the PEME Sc. 16 is higher than for the PEME Sc. 1. The efficiency improvement should lead to a reduction in the energy consumption and thus the electricity settlement price that the utility company can charge will be higher. Moving to the main gaols of the work, this scenario can consume 53% of the total surplus energy and meet nearly 69% of the total hydrogen demand. With nearly the same amount of energy, this scenario can meet a greater proportion of hydrogen demand than the PEME Sc. 1 (which was 60% of hydrogen demand) because of the efficiency improvement. Hydrogen production, as compared to hydrogen demand, for each garage forecourt is shown in Figure 8.80 and reported in Table 8.33.

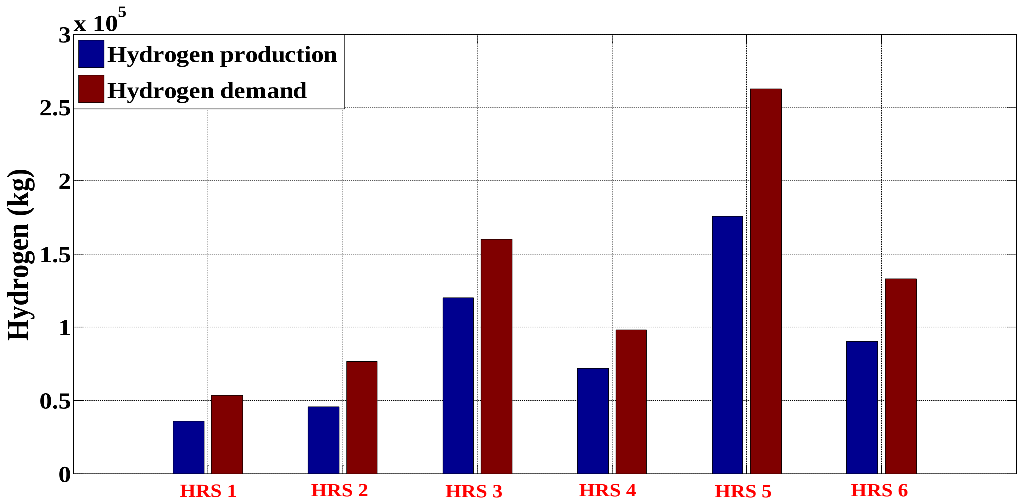


Figure 8.80: Hydrogen production versus hydrogen consumption for each garage forecourt under Only garage forecourts without central electrolyser scenario (PEME Sc. 16) (2030-Cost scenario)

HRS no.	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Hydrogen production (kg/year)	35,685	45,435	119,985	71,730	175,589	90,087
Hydrogen demand (kg/year)	53,645	76,519	160,157	98,244	262,535	133,005
Satisfaction of hydrogen demand (%)	67%	59%	75%	73%	67%	68%

Table 8.33: Comparison between hydrogen production and hydrogen demand in all HRSs throughout the year under Only garage forecourts without central electrolyser scenario (PEME Sc. 16)

Table 8.34 summarises the economic situation for this scenario.

Cost / HRSs	**Investment cost** (£/year)	**Water cost** (£/year)	**Compressor electricity cost** (£/year)	**Electrolyser Electricity cost** (£/year)	**Hydrogen production** (kg/year)	**Average price** (£/kg)
HRS 1	124,556	1,221	6,279	98,563	35,685	6.50
HRS 2	163,657	1,555	7,524	123,884	45,435	6.60
HRS 3	384,403	4,106	21,558	338,792	119,985	6.30
HRS 4	243,993	2,455	12,776	201,584	71,730	6.40
HRS 5	565,337	6,009	29,834	487,487	175,589	6.20
HRS 6	316,865	3,083	16,141	250,688	90,087	6.50

Table 8.34: Economic assessment summary of Only garage forecourts without central electrolyser scenario (PEME Sc. 16)

The average hydrogen price is reduced from nearly £11.40 /kg in the PEME Sc. 1 to nearly £6.40 /kg in the PEME Sc. 16, even with the increase in energy price. The huge drop in hydrogen price is driven by the reduction of investment cost and the increase of hydrogen production due to the anticipated efficiency improvements. The hydrogen cost details are given in Figure 8.81.

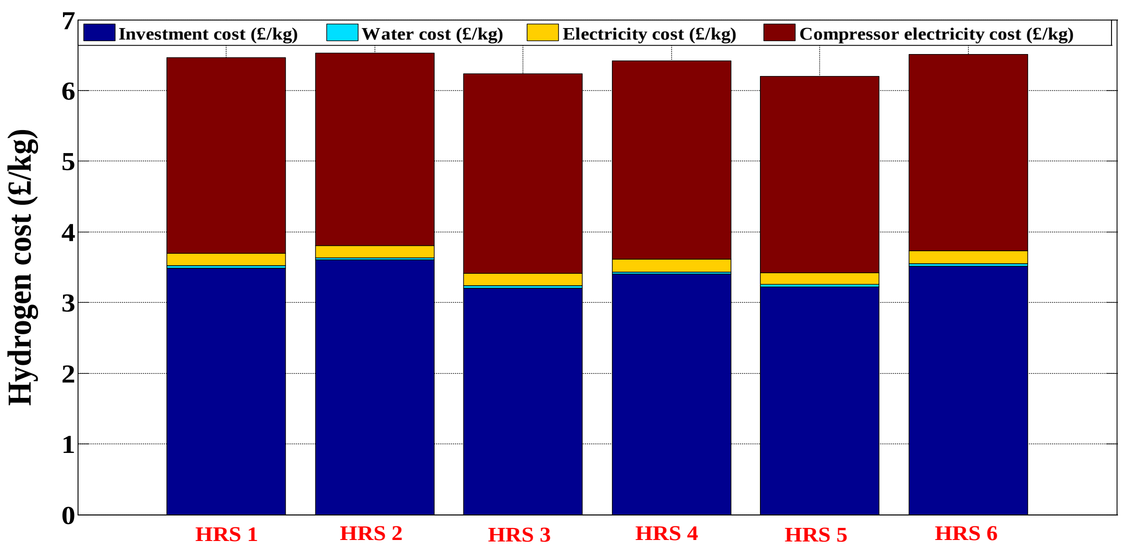


Figure 8.81: Hydrogen cost breakdown per kilogram at each HRS under Only garage forecourts without central electrolyser scenario (PEME Sc. 16)

As it is presented in Figure 8.81 the investment cost represents nearly 53% of the total cost in all HRSs, compared with more than 80% in the PEME Sc. 1, whereas the electrolyser electricity cost increased to 44% in contrast with around just 17% in the 2015-Cost PEME Sc. 1. This scenario does not meet the main aims of the project because 47% of the surplus energy will be curtailed, and only 69% of the total hydrogen demand is met. Only the average price is reduced, by nearly 44%. To overcome the drawbacks of this scenario, one option is to increase the system size.

8.5.2 Increased size of HRS components

The default system size was based on the average hydrogen demand because maximum demand was observed only a few times during the year. However, that scenario does not seem sufficient to achieve the system targets. Increasing the system size could address the shortcomings of the previous scenarios

a) Double-sized default electrolyser test (PEME Sc. 16)

The PEM electrolysers and compression systems will be doubled in size compared to the default size, and consequently the optimal storage needs to be investigated. Figure 8.82 shows the storage profile of PEME Sc. 17. Based on the storage profiles of all the HRSs, the maximum capacity of the storage tank is rarely needed, so the storage in this scenario will be kept the same.

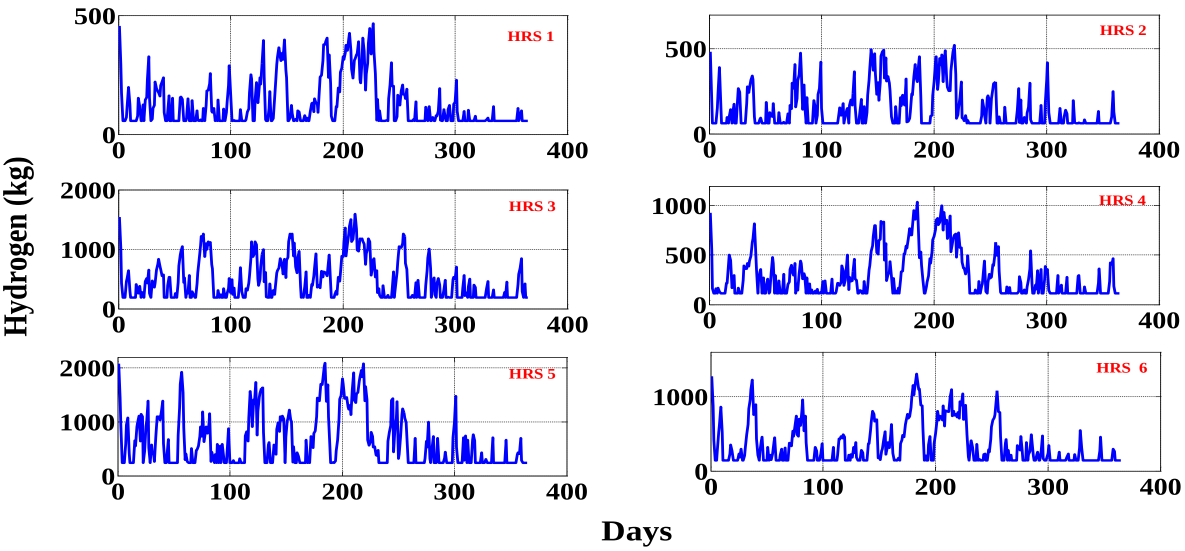


Figure 8.82: Daily variation of Hydrogen level in storage tank throughout the year under double-sized PEME scenario (PEME Sc. 17) (2030-Cost scenario)

Figure 8.83 below shows the electricity settlement price throughout the year after applying the electricity pricing mechanism as in previous scenarios:

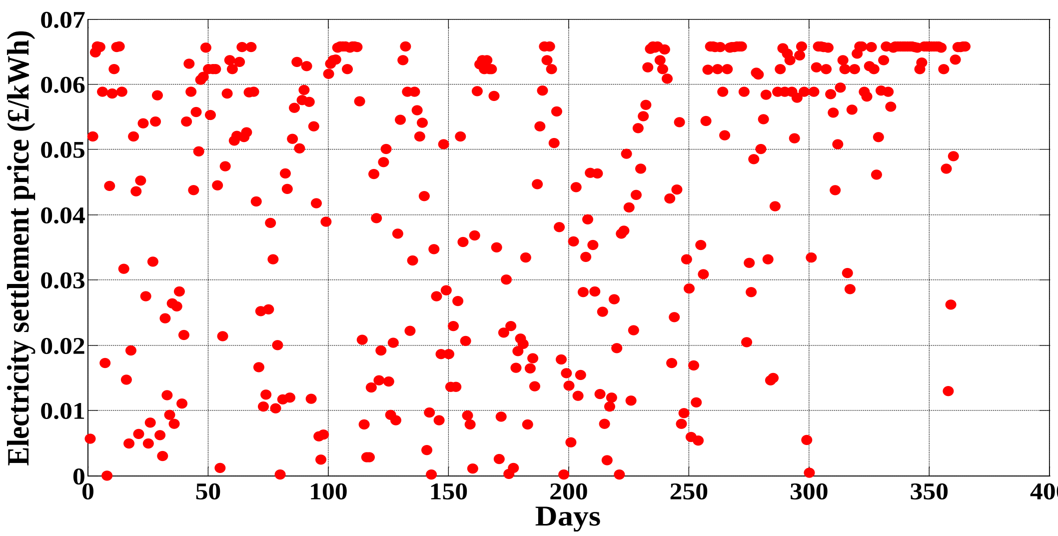


Figure 8.83: Daily electricity settlement prices for a year under double-sized PEME scenario (PEME Sc. 17) (2030-Cost scenario)

The settlement price found in this case is higher than the same case for the PEME Sc. 2 because the efficiency improvements lead to a reduction in energy consumption for the same hydrogen output; there is an inverse relationship between the electricity consumption and the price of electricity. The hydrogen production volume for the garage forecourts in this case is higher than the equivalent case in the PEME Sc. 2, as shown in Figure 8.84:

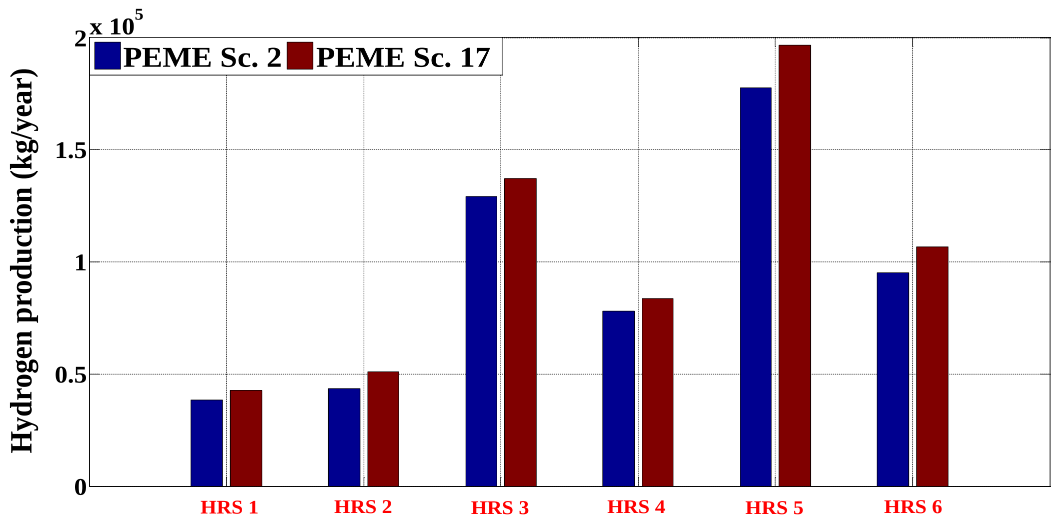


Figure 8.84: Comparison between a total hydrogen production of each HRS throughout the year under 2015 (PEME Sc. 2)and 2030-Cost (PEME Sc. 17) scenarios when double-sized PEME scenario is applied

The cost summary for this system is shown in Table 8.35:

HRS \ Cost	Investment cost (£/year)	Water cost (£/year)	Compressor electricity cost (£/year)	Electrolyser electricity cost (£/year)	Hydrogen production (kg/year)	Average price (£/kg)
HRS 1	184,520	1,463	5,329	71,727	42,739	6.20
HRS 2	254,638	1,744	6,236	77,244	50,969	6.70
HRS 3	565,331	4,693	17,875	244,394	137,128	6.10
HRS 4	357,719	2,864	11,047	147,246	83,693	6.20
HRS 5	865,159	6,730	24,151	331,170	196,670	6.20
HRS 6	466,776	3,652	13,802	177,060	106,727	6.20

Table 8.35: Cost summary for the scenario under double-sized PEME scenario (2030-Cost scenario)

The average hydrogen price in this case is lower than or equal to the default case because of the increase in hydrogen production achieved with lower investment costs in the 2030-Cost scenario. However, as in the last scenario, this scenario consumes 61% of the total surplus energy and meets 79% of the total hydrogen demand.

b) Triple-default-sized electrolyser test

The electrolysers and compressor capacities will be extended to be three times greater than the default size. Different storage sizes will be considered with the same size of electrolysis and compression system. Figure 8.85 shows the storage profile (1,098 kg/day) throughout the year in a triple-sized PEME test.

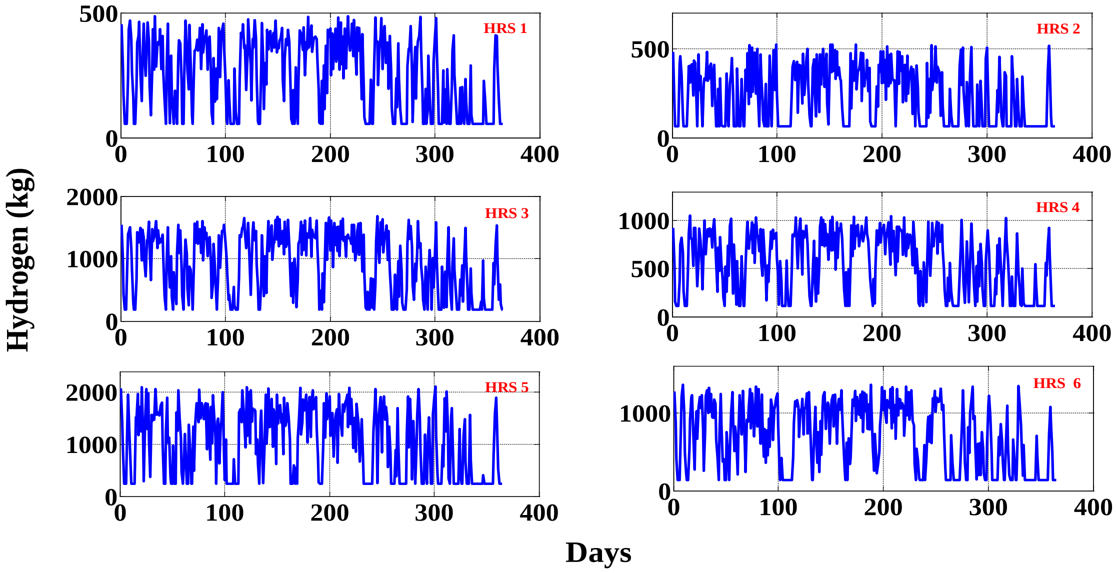


Figure 8.85: Daily variation of Hydrogen level in storage tank throughout the year under triple-sized PEME scenario (2030-Cost scenario)

The maximum storage capacity for each garage forecourt is nearly reached on frequent occasions during the year, so the storage should be extended to avoid imposing any production limitations since the optimal production will be based on the system sizes. Three different sizes will be tested.

These sizes are PEME Sc. 18 (Triple-sized default electrolyser and 1.5 default storage size), PEME Sc. 19 (Triple-sized default electrolyser and double default storage size) and PEME Sc. 20 (Triple-sized default electrolyser and triple default storage size).. The electricity settlement prices for all scenarios are shown in Figure 8.86.

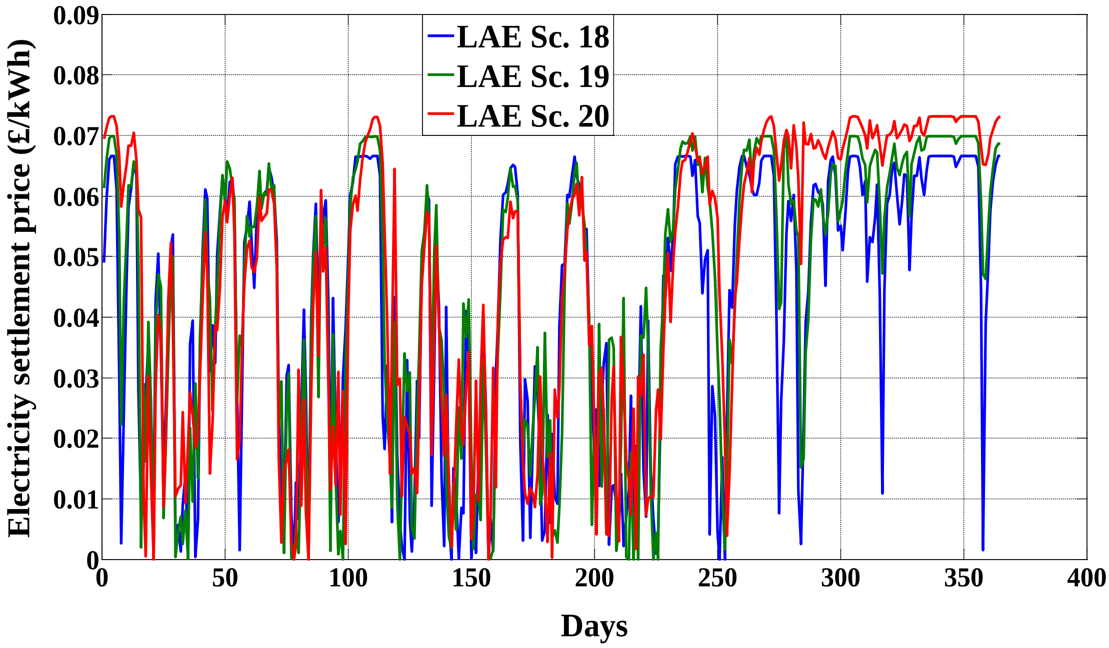


Figure 8.86: Electricity settlement prices under triple-sized PEME scenario with three different storage sizes (2030-Cost scenario)

In all three scenarios, the electricity settlement price is higher than the equivalent PEM 2015-Cost scenario cases. The reason for this is that electrolysis efficiency reduces energy consumption and thus the settlement price will go up.

The system cost summary with different storage sizes is presented in Table 8.36. The average prices for hydrogen under different sizes are very promising, which opens the door to further investigation of hydrogen as an energy storage tool that could efficiently support grid balancing.

Scenario \ HRS		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Triple-sized default electrolyser and 1.5 times default storage size (LAE Sc. 18)	Hydrogen demand satisfaction (%)	84	73	90	91	81	88
	Average hydrogen price (£/kg)	8.00	8.40	7.74	7.90	7.90	7.80
	Total hydrogen demand satisfaction (%)	85					
	Total surplus energy consumed (%)	66					
Triple-sized default electrolyser and double-sized default storage size (LAE Sc. 19)	Hydrogen demand satisfaction (%)	86	81	93	92	87	90
	Average hydrogen price (£/kg)	8.50	8.50	8.40	8.60	8.30	8.40
	Total hydrogen demand satisfaction (%)	89					
	Total surplus energy consumed (%)	69					
Triple-sized default electrolyser and Triple-sized default storage (LAE Sc. 20)	Hydrogen demand satisfaction (%)	90	84	95	94	91	92
	Average hydrogen price (£/kg)	9.50	9.40	9.60	10.00	9.10	9.70
	Total hydrogen demand satisfaction (%)	92					
	Total surplus energy consumed (%)	71					

Table 8.36: Techno- economic assessments of the system under different size of electrolyser and different storage sizes

8.5.3 Adding a large PEM central electrolyser to the system

Adding a central electrolyser to the system can tackle the main issue with the previous scenario in which only HRSs produce hydrogen. The main aims of the central electrolyser are to absorb the remaining surplus energy and meet any shortages in hydrogen supply at the forecourts.

8.5.3.1 PEM central electrolyser sizing based on the production side

The size of the central electrolyser is critical since this directly affects the total hydrogen cost. The central electrolyser size can be chosen based on the production side (surplus energy availability) or the consumption side (hydrogen demand at the garage forecourt side). The testing will include different sizes of central PEM electrolyser. Selecting these sizes relies on the amount of surplus energy that needs to be absorbed. The storage is equal to nearly five days of production.

These scenarios are PEME Sc. 21 (1,098 kg/day, 39% of the residual surplus energy), PEME Sc. 22 (1,923 kg/day, 60% of the residual surplus energy), PEME Sc. 23 (3,022 kg/day, 81% of the residual surplus energy) and finally PEME Sc. 24 (4,853 kg/day, 95% of the residual surplus energy).

a) Central PEM electrolyser operates under a different electricity settlement price to the HRSs

As mentioned earlier, if the central electrolyser's settlement price is set after the HRSs, some incentive has to be offered to encourage the central unit to accept such an offer. In this research, the electricity price for the central electrolyser is set at 20% less than the HRS settlement price (even if not all the HRSs can accept the settlement price on that day). The HRS settlement price and the central electrolyser settlement price for the PEME Sc. 21 is shown in Figure 8.87.

The electricity prices for all size scenarios are less than the equivalent scenarios in the alkaline electrolyser case because of the associated increase in investment cost. For days when the central electrolyser settlement price is zero, such as days 201-229, the central hydrogen production was zero, even though there was available surplus power.

This is due to storage limitations; since on these days, there was no available storage and all HRSs were able satisfy their hydrogen demand without the need to import any from central electrolyser. This situation was observed frequently during the year.

Figure 8.88 and Figure 8.89 show hydrogen production and the storage profile of the central PEM electrolyser and variation in hydrogen storage for all sizes respectively.

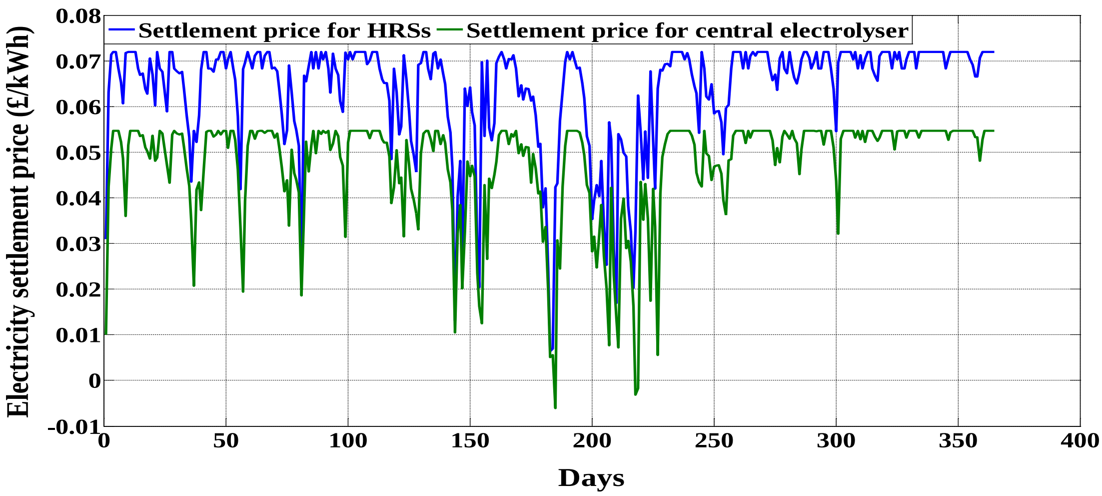


Figure 8.87: electricity settlement price to the central electrolyser and garage forecourts when PEM central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 21)

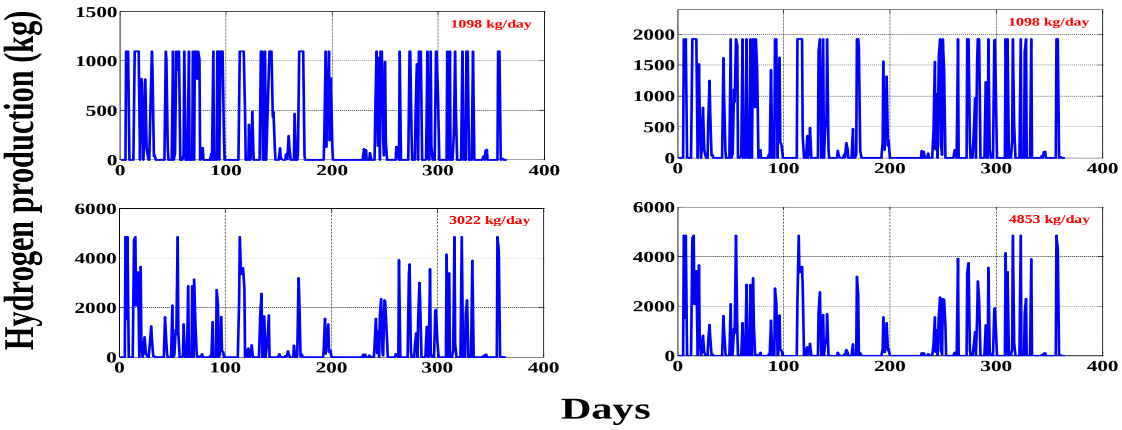


Figure 8.88: Hydrogen production of central electrolyser under different electrolyser sizes when PEM central electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

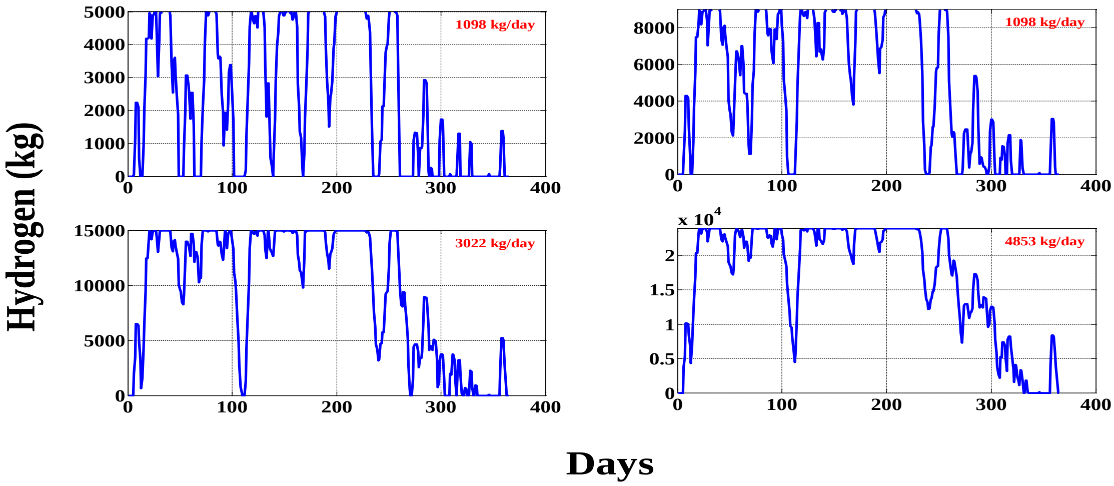


Figure 8.89: Daily variation of Hydrogen level in storage tank throughout the year when PEM central electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

Table 8.37 shows a summary of the system. Moving from one size to another could support grid balancing and satisfy hydrogen demand better. However, the average price is dramatically increased, which is one of the main issues with this proposal.

Central electrolyser size (kg/day) \ HRS		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
PEME Sc. 21	Satisfaction of hydrogen demand (%)	76	75	83	81	82	80
	Average hydrogen price (£/kg)	7.50	8.10	7.00	7.10	7.70	7.70
	Total energy consumed after adding central electrolyser (%)	63					
	Satisfaction of total hydrogen for HRSs (%)	81					
	Average central electrolyser hydrogen price (£/kg)	14.00					
PEME Sc. 22	Satisfaction of hydrogen demand (%)	83	83	87	85	87	85
	Average hydrogen price (£/kg)	8.60	9.50	7.70	80	8.70	8.60
	Total energy consumed after adding central electrolyser (%)	67					
	Satisfaction of total hydrogen for HRSs (%)	86					
	Average central electrolyser hydrogen price (£/kg)	16.90					
PEME Sc. 23	Satisfaction of hydrogen demand (%)	88	88	90	89	91	89
	Average hydrogen price (£/kg)	10.20	11.40	8.80	9.20	10.20	10.10
	Total energy consumed after adding central electrolyser (%)	70					
	Satisfaction of total hydrogen for HRSs (%)	90					
	Average central electrolyser hydrogen price (£/kg)	21.50					
PEME Sc. 24	Satisfaction of hydrogen demand (%)	93	93	93	94	93	92
	Average hydrogen price (£/kg)	12.80	14.60	10.60	11.30	12.50	12.50
	Total energy consumed after adding central electrolyser (%)	72					
	Satisfaction of total hydrogen for HRSs (%)	93					
	Average central electrolyser hydrogen price (£/kg)	28.00					

Table 8.37: Economic assessments of the system when PEM central electrolyser operates under a different electricity settlement price to the HRSs (2030-Cost scenario)

b) The central PEM electrolyser operates under the same electricity settlement price as the HRSs

In this case, the PEM central electrolyser is run in the same manner as the six garage forecourts and follows the same electricity pricing mechanism without any additional incentives. The system will test the all previous central electrolyser sizes and present an associated economic summary. After applying the electricity pricing mechanism, the electricity settlement price for both garage forecourts and central electrolyser is given in Figure 8.90 for the PEME Sc. 21.

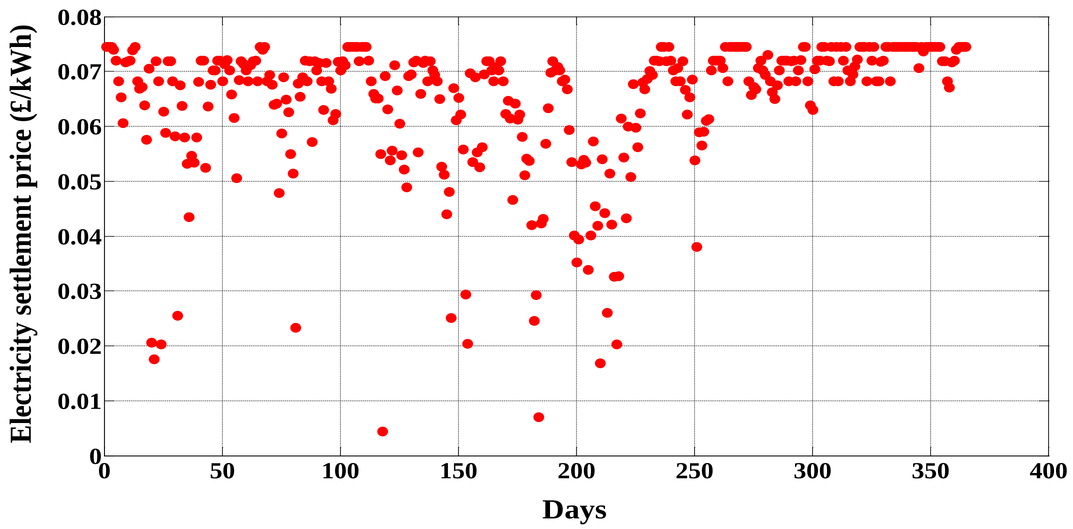


Figure 8.90: Electricity settlement prices for both HRSs and central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (PEME Sc. 26) (2030-Cost scenario)

The price of hydrogen in this case is expensive by comparison with the same case in the PEME Sc. 11. Efficiency improvements reduce the electricity consumption required to produce same amount of hydrogen and thus the settlement price will be higher. Figure 8.91 and Figure 8.92 below show the hydrogen production and the storage profiles of all HRSs, including the central PEM electrolyser, for the PEME Sc. 26. The production and storage profile of the central PEM electrolyser and garage forecourts is somewhat different compared to the same case of the PEME Sc. 11. Efficiency improvements in this scenario lead to greater hydrogen production on some days, which results in energy not being absorbed on others, as can be seen for days 201-229. In this scenario, the production of the central PEM electrolyser is zero for these days. Whereas in the PEME Sc. 11, the central unit does absorb energy on these days.

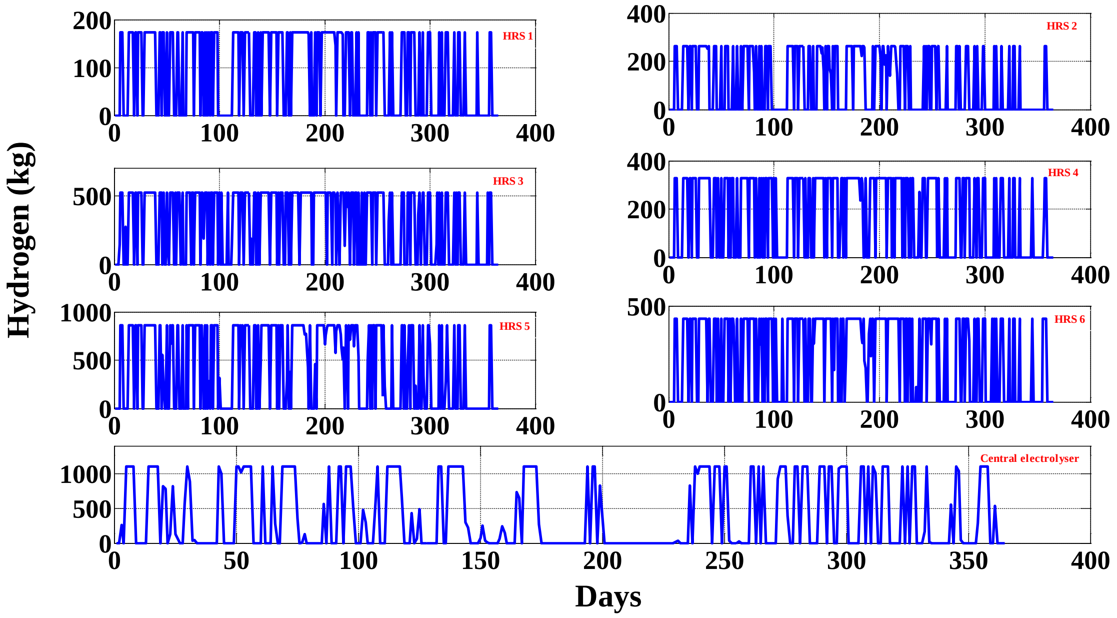


Figure 8.91: HRSs and PEM central electrolyser hydrogen production throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (PEME Sc. 26) (2030-Cost scenario)

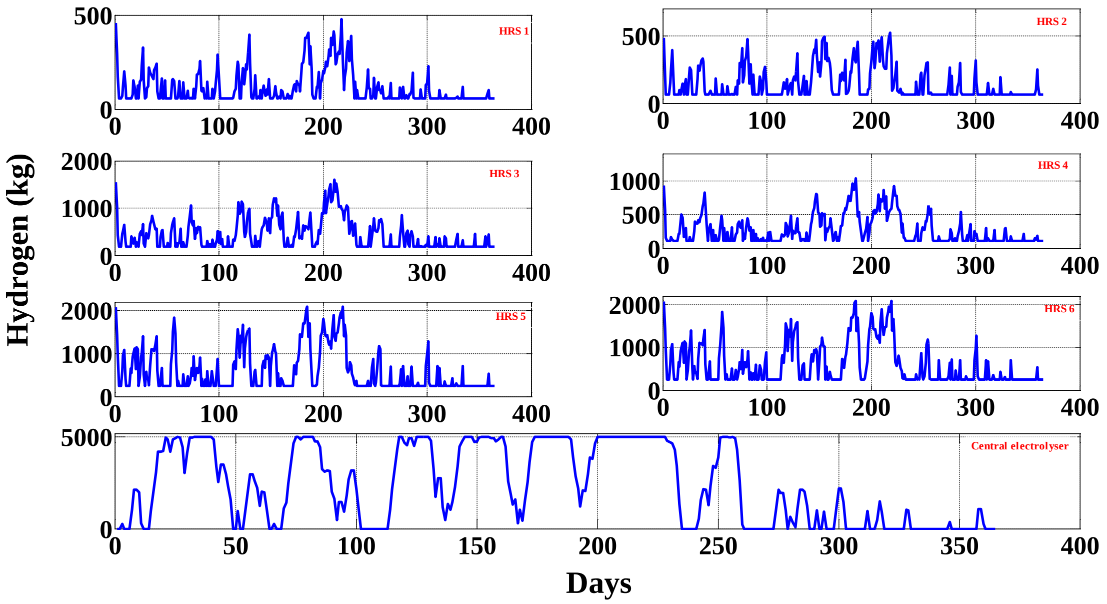


Figure 8.92: Daily variation of Hydrogen level in storage tank throughout the year when the central electrolyser runs under the same settlement electricity price as the HRSs (PEME Sc. 26) (2030-Cost scenario)

Figure 8.93 and Figure 8.94 compare the central hydrogen production and the storage variations (1098 kg/day) when the central PEME bid the same as if it were another HRS in the PEME Sc. 11 and the PEME Sc. 26. The efficiency improvement in the 2030-cost scenario leads to improved efficiency of production at the garage forecourts, which reduces the need for imported hydrogen and thus the central storage might remain full for several days at a time, even if there is surplus energy still available to be absorbed.

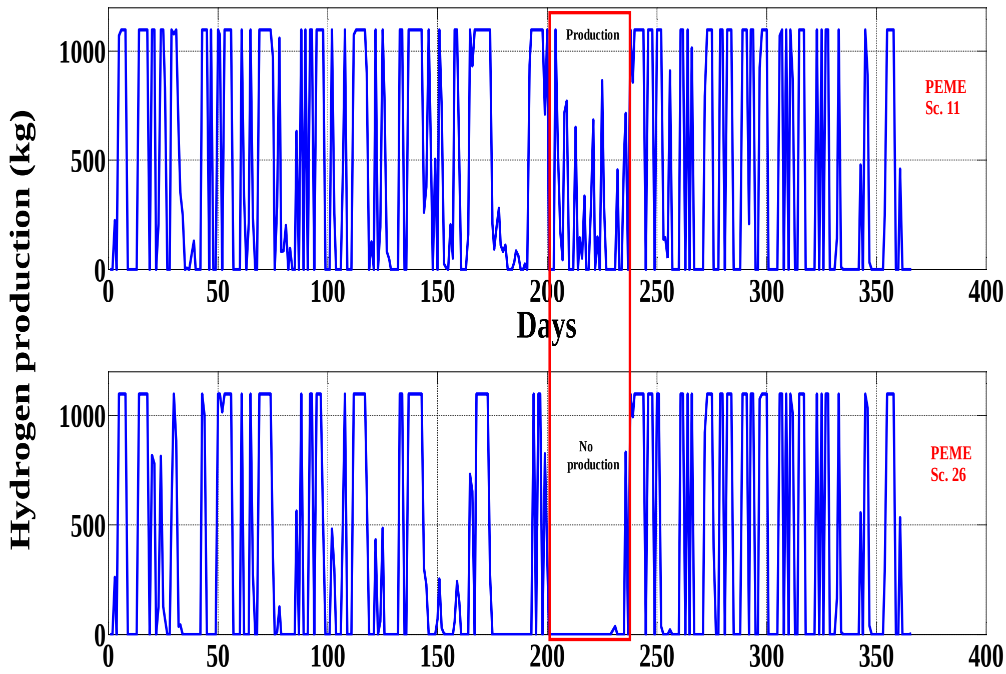


Figure 8.93: Central PEM electrolyser hydrogen production (PEME Sc. 11 and PEME Sc. 26) (2015- and 2030-Cost scenarios)

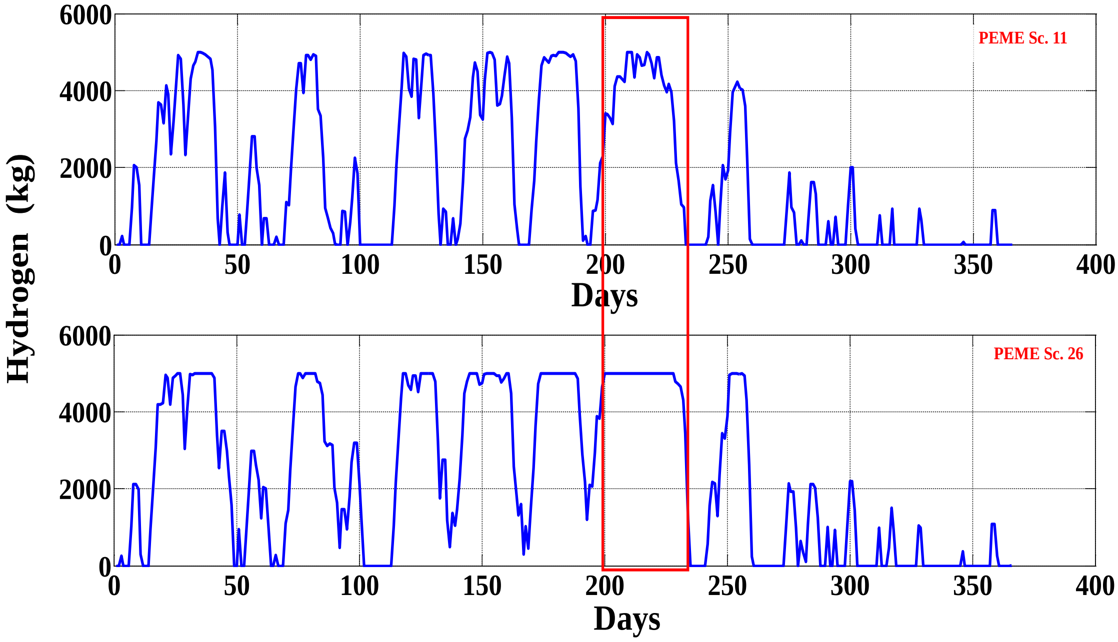


Figure 8.94: Central PEM electrolyser hydrogen storage (PEME Sc. 11 and PEME Sc. 26) (2015- and 2030-Cost scenarios)

Table 8.38 shows the assessments of the system under different sizes of central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs.

Central electrolyser size (kg/day) \ HRS		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
PEME Sc. 26	Satisfaction of hydrogen demand (%)	72	73	82	77	86	80
	Average hydrogen price (£/kg)	7.40	8.00	7.20	7.30	8.00	7.40
	Total energy consumed after adding central electrolyser (%)	63					
	Satisfaction of total hydrogen for HRSs (%)	81					
	Average central electrolyser hydrogen price (£/kg)	11.30					
PEME Sc. 27	Satisfaction of hydrogen demand (%)	80	82	86	84	88	85
	Average hydrogen price (£/kg)	8.30	9.30	8.00	8.20	8.80	8.20
	Total energy consumed after adding central electrolyser (%)	67					
	Satisfaction of total hydrogen for HRSs (%)	86					
	Average central electrolyser hydrogen price (£/kg)	13.30					
PEME Sc. 28	Satisfaction of hydrogen demand (%)	87	88	89	88	91	89
	Average hydrogen price (£/kg)	10.00	11.20	9.00	9.50	10.50	9.30
	Total energy consumed after adding central electrolyser (%)	70					
	Satisfaction of total hydrogen for HRSs (%)	90					
	Average central electrolyser hydrogen price (£/kg)	17.30					
PEME Sc. 29	Satisfaction of hydrogen demand (%)	92	92	92	93	93	93
	Average hydrogen price (£/kg)	12.40	14.40	11.00	11.50	130	11.40
	Total energy consumed after adding central electrolyser (%)	72					
	Satisfaction of total hydrogen for HRSs (%)	93					
	Average central electrolyser hydrogen price (£/kg)	24.70					

Table 8.38: Assessments of the system under different sizes of central electrolyser when the central electrolyser runs under the same settlement electricity price as the HRSs (2030-Cost scenario).

Moving from one size to another could support grid balancing and satisfy hydrogen demand better. However, the average price is dramatically increased, which is one of the main disadvantages of this proposal.

As in all scenarios, the average price of the central PEM electrolyser in this scenario is cheaper than the scenario where the central unit bids after the settlement price for garage forecourts has been set.

The central electrolyser in this scenario could absorb energy at any time without any constraint once its bid price is accepted from energy supplier side. However, this reduction of the central price does not obviously affect the garage forecourt prices, as most of them are still the same or show very little change, by comparison with the central electrolyser bidding after garage forecourts' settlement price has been agreed.

The amount of hydrogen imported to the HRSs from the central electrolyser unit in this instance will be greater than in the previous scenario when the central electrolyser bid prices was set after garage forecourts had been offered a settlement price, which leads to an increase in the price of hydrogen sold to the HRSs.

8.5.3.2 PEM central electrolyser sizing based on the power consumption side

The sizing in this section will depend on the garage forecourt side. Two modes of operation will be investigated, as per other scenarios. All system sizes are the same as in the PEME Sc. 10.

a) Central PEM electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 25)

The central electrolyser will earn a certain amount of profit based on its electricity settlement price being 20% lower than that of the HRSs, which follow the electricity pricing mechanism described previously to determine their daily settlement price of the system.

Figure 8.95 shows the electricity settlement price offered to the garage forecourts and to the central electrolyser.

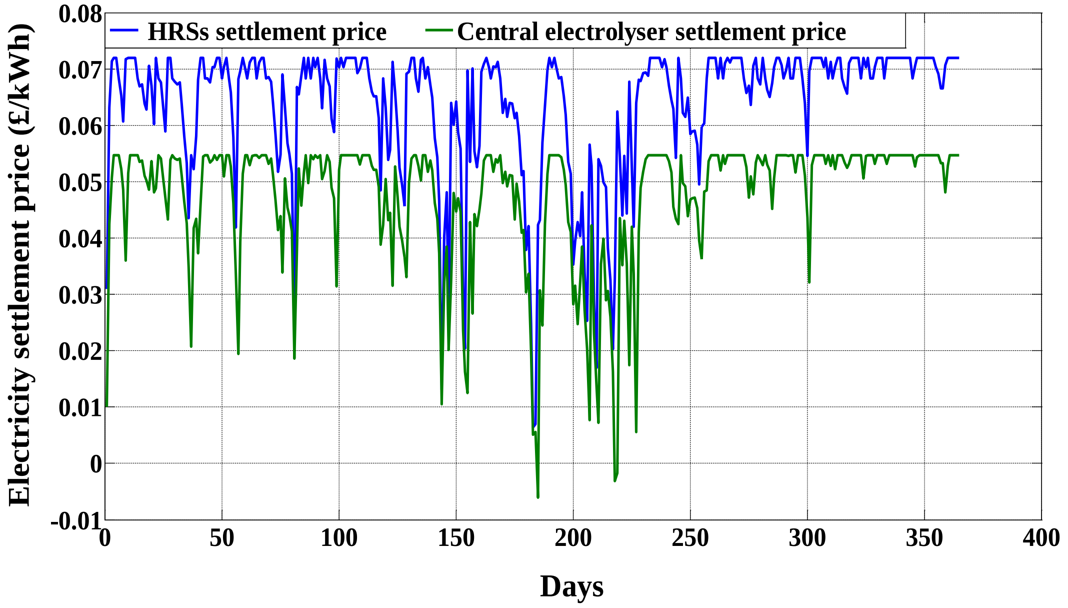


Figure 8.95: Electricity settlement price offered to the HRSs and the central PEM electrolyser when central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 25) (2030-Cost scenario)

Figure 8.96 and Figure 8.97 show the hydrogen production and the storage profile during the year, respectively.

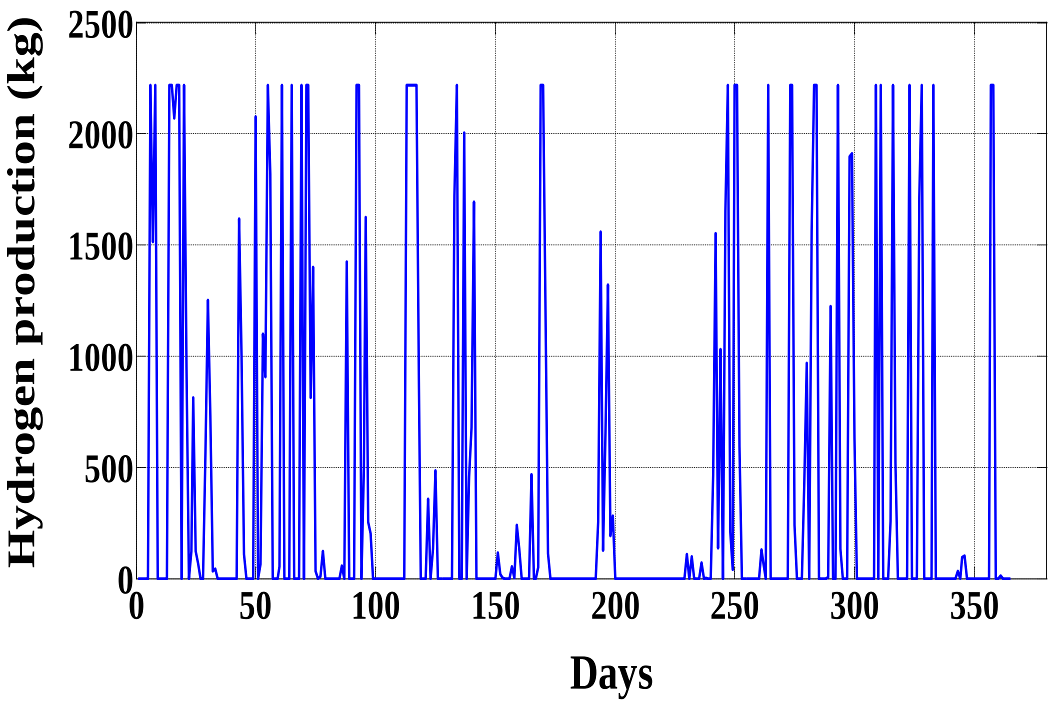


Figure 8.96: PEM central electrolyser hydrogen production throughout the year when central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 25) (2030-Cost scenario).

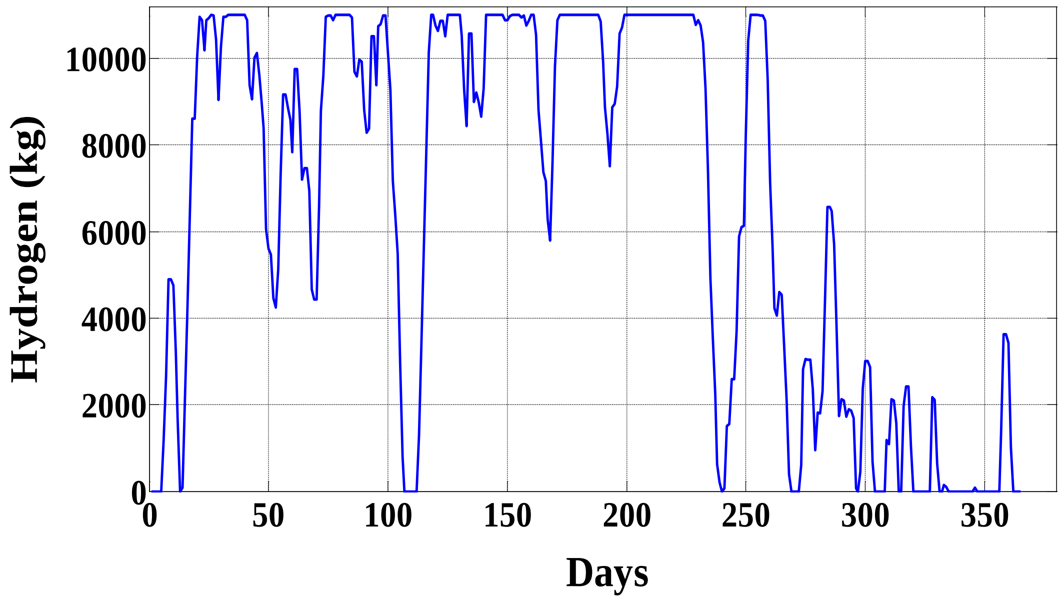


Figure 8.97: Daily variation of Hydrogen level in storage tank throughout the year when PEM central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 25) (2030-Cost scenario).

In all scenarios, the storage profile seems to show a positive outlook since the hydrogen in storage at the end of the year is zero, which means both modes of operation of the central electrolyser could provide a certain benefit to the central unit regardless of the impact on the garage forecourts. The garage forecourts should import hydrogen during shortages to avoid losing customers regardless of price, even though this will affect the total hydrogen cost. Table 8.39 gives the economic summary of this scenario.

Details / HRSs	Satisfaction of hydrogen demand (%)	Average hydrogen price (£/kg)	Total surplus energy consumed after adding central electrolyser (%)	Satisfaction of total hydrogen demand (%)	Average price of hydrogen from central electrolyser (£/kg)
HRS 1	85	9.10	68	87	18.30
HRS 2	85	10.10			
HRS 3	88	8.10			
HRS 4	86	8.30			
HRS 5	88	9.10			
HRS 6	87	9.10			

Table 8.39: Economic assessment of the system central electrolyser operates under a different electricity settlement price to the HRSs (PEME Sc. 25) (2030-Cost scenario).

The average price of hydrogen across all garage forecourts is reduced by half with high levels of hydrogen demand satisfaction and surplus energy absorption.

These specifications pave the way to hydrogen being used for future grid balancing and as a clean fuel to replace traditional fuels, especially since all these calculations do not account for any government intervention.

b) The central electrolyser operates under the same electricity settlement price as the HRSs (PEME Sc. 30)

The central unit will run in the same way as the garage forecourts, so every day it will release an economic electricity bid price and follow the electricity pricing mechanism, as if it were just another HRS.

Figure 8.98 shows the daily electricity settlement price offered to all electrolysers, including the central electrolyser.

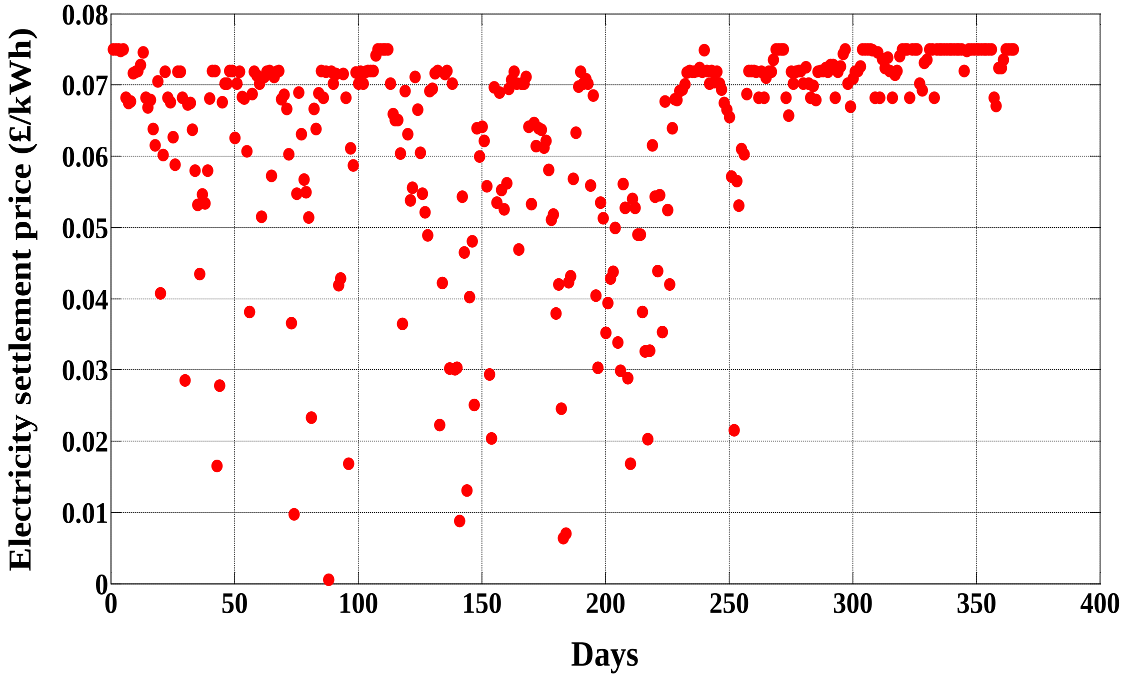


Figure 8.98: Daily electricity settlement price for HRSs and central electrolyser throughout the year when central electrolyser operates under the same electricity settlement price as the HRSs (PEME Sc. 30) (2030-Cost scenario)

Daily hydrogen production and the storage profile throughout the year are shown in Figure 8.99 and Figure 8.100, respectively.

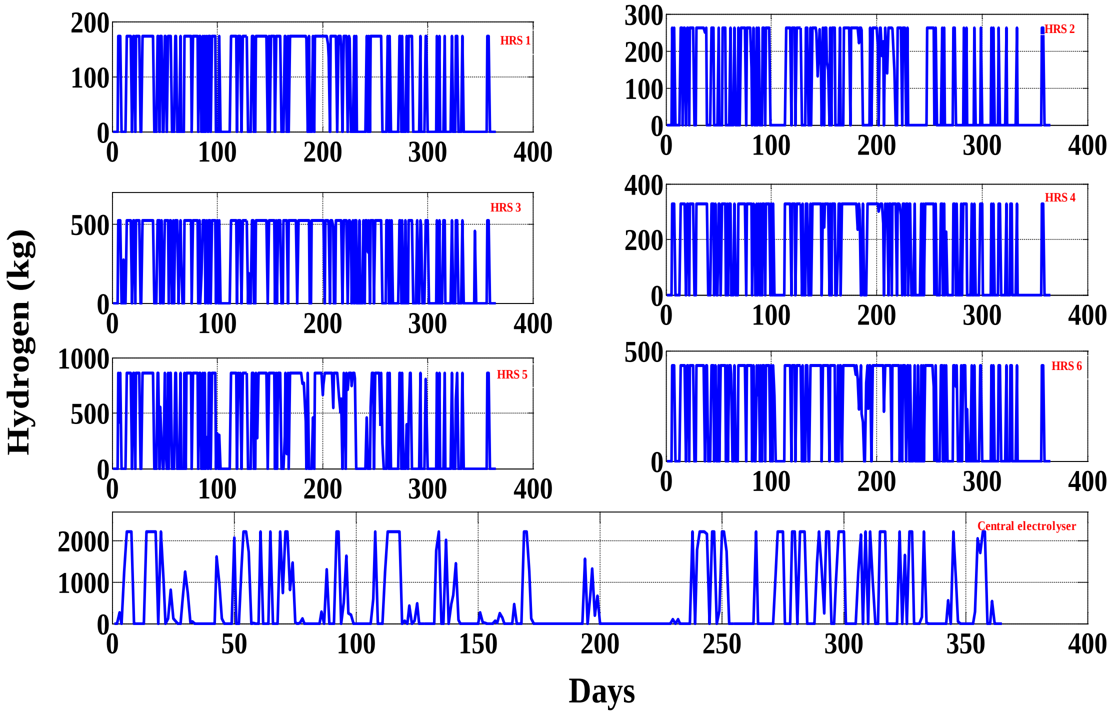


Figure 8.99: Hydrogen production of the PEM central electrolyser and HRSs throughout the year when PEM central electrolyser operates under the same electricity settlement price as the HRSs (PEME Sc. 30) (2030-Cost scenario)

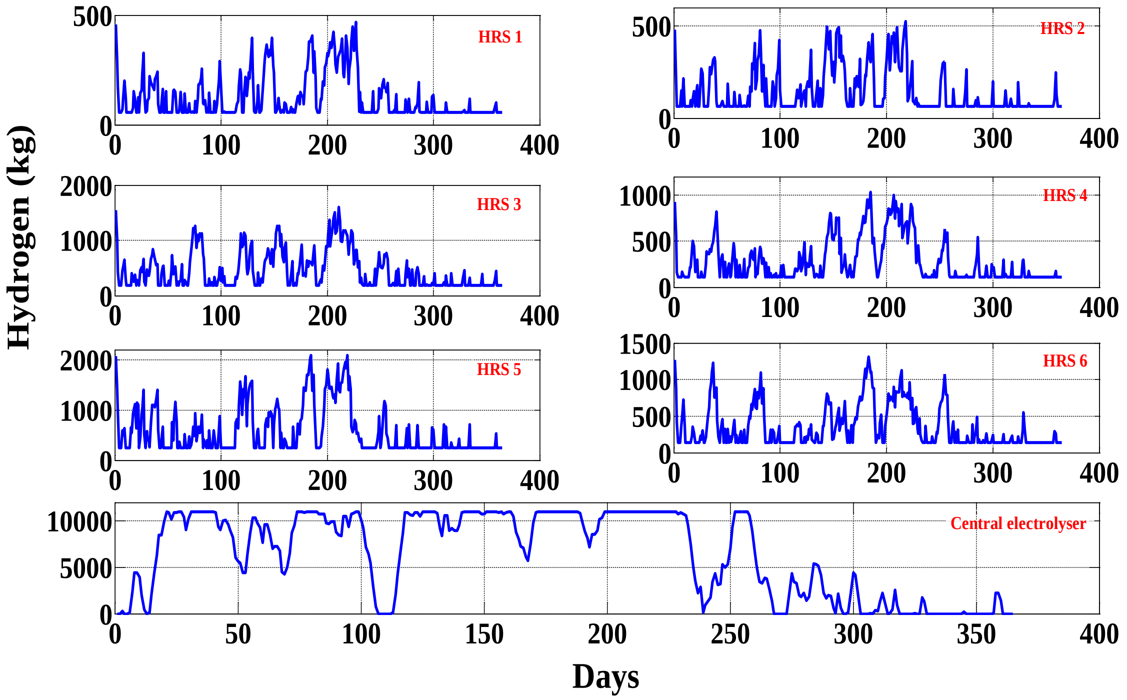


Figure 8.100: Daily variation of Hydrogen level in storage tank throughout the year when PEM central electrolyser operates under the same electricity settlement price as the HRSs (PEME Sc. 30) (2030-Cost scenario)

When the central electrolyser runs at the same time as the garage forecourts, the central hydrogen price is reduced due to the increase in hydrogen production. The price of hydrogen from the garage forecourts remains almost the same due to the change in the amount of imported hydrogen according to the central electrolyser's operational modes, as presented in Table 8.40.

Scenario / HRSs	Central electrolyser operates under different settlement price to the HRSs (PEME Sc. 25)	Central electrolyser and HRSs operates under the same settlement price (PEME Sc. 30)
	Imported hydrogen (%)	**Imported hydrogen (%)**
HRS 1	22	28
HRS 2	30	39
HRS 3	15	23
HRS 4	16	25
HRS 5	24	35
HRS 6	22	25

Table 8.40: Imported hydrogen depending on operational mode of the central PEM electrolyser (PEME Sc. 25 and PEME Sc. 30) (2030-Cost scenario)

Table 8.41 summarises the economic assessment of the system when central electrolyser operates under the same s electricity settlement price as the HRSs.

Details / HRSs	**Satisfaction of hydrogen demand** (%)	**Average hydrogen price** (£/kg)	**Total surplus energy consumed after adding central electrolyser** (%)	**Satisfaction of total hydrogen demand** (%)	**Average price of hydrogen from central electrolyser** (£/kg)
HRS 1	84	8.80	68	87	14.60
HRS 2	85	9.80			
HRS 3	87	8.20			
HRS 4	87	8.60			
HRS 5	89	9.30			
HRS 6	87	8.50			

Table 8.41: Economic assessment of the system when central electrolyser operates under the same s electricity settlement price as the HRSs (PEME Sc. 30) (2030-Cost scenario)

8.6 Summary of the chapter

Onsite hydrogen production has been investigated in this chapter. Two different cost scenarios, those for 2015 and 2030, and two common types of electrolyser, alkaline and PEM, have been examined. Various different scenarios were tested. There are three main goals that have to be achieved, namely those of grid balancing by consuming any surplus energy, meeting hydrogen demand at the forecourt, and maintaining an acceptable and relatively competitive hydrogen price at the point of sale compared to conventional fuel prices. Onsite hydrogen production at the forecourt, without additional external support, cannot meet these main goals. Based on the limitation of the onsite hydrogen production scenario, different supported scenarios such as increasing the system size, and that of adding a central electrolyser to the system, have been examined in detail. Generally, the average hydrogen prices for alkaline and PEM electrolysers under the 2015-Cost scenario are expensive, and cannot meet the economic requirements. However, under the 2030-Cost scenario, the average price of hydrogen could support the replacement of the fossil fuels. There are many reasons to encourage governments to focus on hydrogen storage as a grid-balancing tool. One of the main reasons is the reduction of greenhouse gas emissions, which can be achieved in two ways simultaneously. First, increasing renewable energy penetration will reduce emissions from oil and gas stations and, second, hydrogen fuel can limit the transport-based emissions due to the associated reduction in use of fossil fuels. Penetration of hydrogen into the energy sector requires strong governmental support through either establishing or modifying policies and energy laws to increasingly support renewable energy usage. Government support could effectively bring forward the date at which hydrogen becomes techno-economically viable (i.e. sooner than 2030). If government is happy to leave it until 2030, it need not intervene and can leave it entirely to the market, but if it wants to embrace the opportunity and gain an early advantage, it should take steps to support hydrogen energy systems and accelerate uptake.

Chapter 9: Techno-Economic Analysis of Dispatchable Operation of Central Electrolyser for Demand Side Response and Hydrogen Fuel Production

9.1 Introduction

There are three ways to produce hydrogen via electrolysis. These ways are central production, semi-central production, and distributed hydrogen production (U.S. Department of Energy, 2015). These methods are expected to play an important role in the evolution and long-term application of hydrogen as an energy carrier. The different resources and operations used to produce hydrogen might be suitable for one or more of these scales of hydrogen production. Hydrogen can be produced in small-scale units as and where required, such as vehicle refuelling stations. Onsite hydrogen production at the garage forecourt may be the most suitable way for producing hydrogen in the near-term, in part because the current demand for hydrogen as a fuel is low. Massive central electrolysis facilities (producing 750,000 kg of hydrogen per day) that take advantage of the economy of scale will be required in the long-term to meet the expected increase in demand for hydrogen (Ball and Weeda, 2015; Skov and Mathiesen, 2017). In contrast with decentralised hydrogen production, centralised production will require greater capital investment costs as well as a substantial transport and delivery infrastructure which could include pipelines or trucks. Semi-centralised hydrogen production facilities (5,000–50,000 kg/day), normally located close (25–100 miles) to the point of use, might also play an important role in the long-term use of hydrogen as an energy carrier (U.S. Department of Energy, 2015). Installing semi-central electrolysis close to the point of use has the economic advantage of saving transport and delivery costs. Losses during the transportation and delivery process could be added as a one of the disadvantages of centralised production (Kim, Lee and Moon, 2008). In this chapter, the central electrolyser will be considered alone, without any garage forecourts. The hydrogen production will then be delivered to HRSs via truck. The two types of electrolysis (alkaline and PEM) and two cost-scenarios (2015 and 2030) will be investigated. Figure 9.1 below shows the overall process for this system.

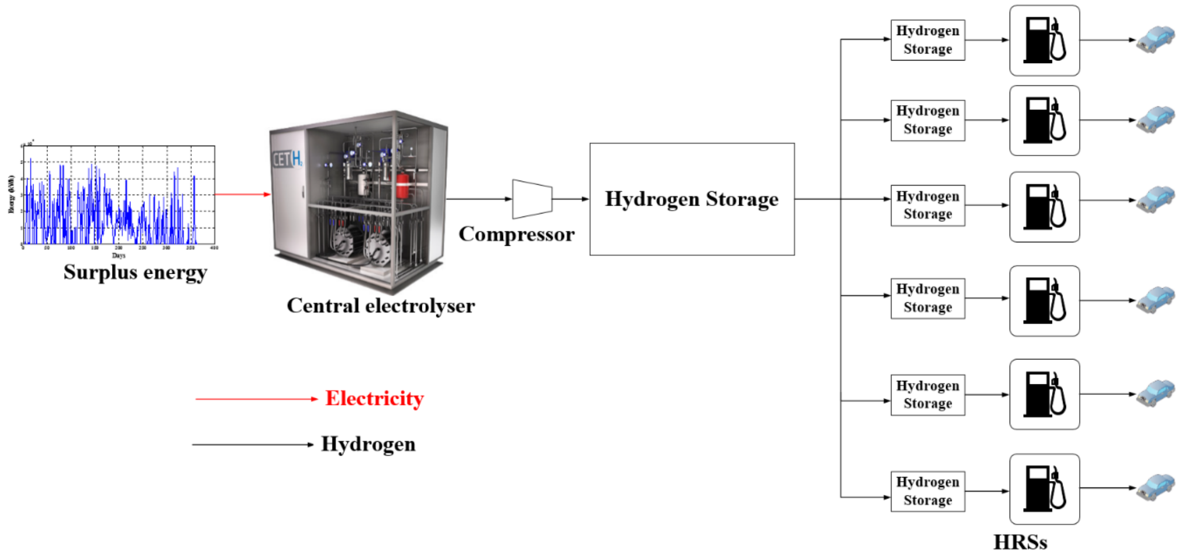


Figure 9.1: Summary of the system process when central electrolyser is applied without forecourt electrolysis

9.2 Cost of the system

The unit (i.e. £/kW, £/kWh, or £/kg) cost is inversely proportional to size due to economies of scale, so the unit cost of centralised electrolyser should be less than for small electrolysers (Steward et al., 2009). However, the central electrolyser in this research is not classed as large by the DOE definition and could be considered as a semi-central, therefore, the same cost assumptions as summarised in Table 7.1 and Table 7.2 will be used in this chapter.

9.3 2015-Cost scenario for Alkaline electrolysis

Two cost scenarios will be investigated for alkaline electrolysis: the 2015-Cost scenario and the 2030-Cost scenario. The system size will be for the same production rate, in kg/day, for both cost scenarios. However, the energy consumption will change because of the expected efficiency improvements by 2030.

9.3.1 Sizing of the central electrolyser and the HRSS

The main goal of the system is to support grid balancing, so the central electrolyser size will be based on the energy availability side. The system will test different sizes of electrolyser; which will affect the percentage of energy absorbed. At the same time, the hydrogen demand should be met with an acceptable sale price. The testing will include four different sizes, as based on the amount of energy consumed. The system efficiency in this scenario is 54.6 kWh/kg for alkaline electrolysers. The sizes are 130,105 kWh (2383 kg/day), which will consume 57% of total surplus energy, 260,210 kWh (4766 kg/day), which will consume 87% of total surplus energy, 300,000 kWh (5,495 kg/day), which will consume 92% of total surplus energy, and 350,000 kWh (6,410 kg/day), which will consume 96% of total surplus energy. Figure 9.2 show the share of these sizes in contrast with the surplus energy.

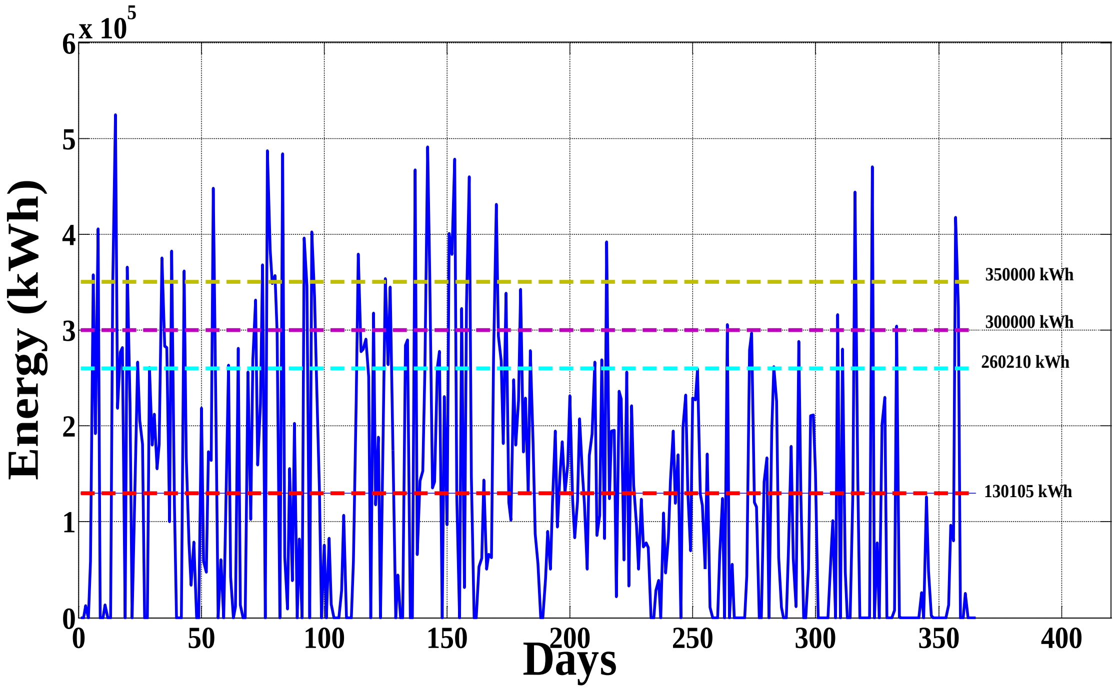


Figure 9.2: Electrolyser size limits compared to the total surplus power available for each day of the year

The storage size will vary depending on the electrolyser size. Five days' production is considered the optimal storage size for each electrolyser size. The compression system has a capacity equal to one day's production.Table 9.1 shows the alkaline central electrolyser and HRSs components for all scenarios. There is no surplus energy available during the first few days of the year; however, the assumption is made that there is some hydrogen in the store from the end of previous year. With the caveat that the simulated year must have at least the same amount in the store at the end of the sampled year. The central storage should have an initial amount in its tank. The storage tank size will therefore be considered 80% full at the beginning of the year. Each garage forecourt has a medium-sized storage tank to hold the imported hydrogen. The details of the garage forecourts are given in Table 9.2:

DetailsDetails / Scenario No.		Cen. LAE Sc. 1	Cen. LAE	Cen. LAE	Cen. LAE
HRSs Electrolyser size (Kg/day)	HRS 1	×	×	×	×
	HRS 2	×	×	×	×
	HRS 3	×	×	×	×
	HRS 4	×	×	×	×
	HRS 5	×	×	×	×
	HRS 6	×	×	×	×
HRS Storage size (kg)	HRS 1	560	560	560	560
	HRS 2	630	630	630	630
	HRS 3	1840	1840	1840	1840
	HRS 4	1190	1190	1190	1190
	HRS 5	2464	2464	2464	2464
	HRS 6	1540	1540	1540	1540
HRS Compressor size (Kg/day)	HRS 1	149	149	149	149
	HRS 2	226	226	226	226
	HRS 3	449	449	449	449
	HRS 4	282	282	282	282
	HRS 5	744	744	744	744
	HRS 6	372	372	372	372
Central Electrolyser size (Kg/day)		2383	4766	5495	6410
Central Electrolyser Storage size (kg)		12000	24000	27500	32000
Central Electrolyser compressor size		2383	4766	5495	6410
Electrolyser efficiency (kWh/kg)		54.6	54.6	54.6	54.6
Year of the components cost		2015	2015	2015	2015

Table 9.1: Alkaline central electrolyser and HRSs components size (2015-Cost scenario)

Where: **Cen. LAE Sc. 1:** 2,383 kg/day alkaline central electrolyser with 12,000 kg hydrogen storage without electrolyser at the HRSs under 2015-Cost scenario.

Cen. LAE Sc. 2: 4,766 kg/day alkaline central electrolyser with 24,000 kg hydrogen storage without electrolyser at the HRSs under 2015-Cost scenario.

Cen. LAE Sc. 3: 5,495 kg/day alkaline central electrolyser with 27,500 kg hydrogen storage without electrolyser at the HRSs under 2015-Cost scenario.

Cen. LAE Sc. 4: 6,410 kg/day alkaline central electrolyser with 32,000 kg hydrogen storage without electrolyser at the HRSs under 2015-Cost scenario.

Components / HRSs	Storage tank (kg)			Number of dispensers
	Max	Initial value	Min	
HRS 1	560	448	65	3
HRS 2	630	504	63	3
HRS 3	1840	1472	182	3
HRS 4	1190	952	112	3
HRS 5	2464	1971	245	3
HRS 6	1540	1232	140	3

Table 9.2: Garage forecourt components size under 2015-Cost scenario

9.3.2 Alkaline central electrolyser and garage forecourts assessments

In this scenario, the central electrolyser has an investment cost, and each garage forecourt also has an investment cost; the same cost calculation process as in Figure 8.6 will be applied to calculate the total cost of the this system, and the same assumptions as in the last two chapters will be applied (financed by a loan with an interest rate of 5% over seven years).

The investment cost of the garage forecourts includes the storage and dispenser costs, while the central electrolyser cost includes the electrolyser, storage, compressor and fixed costs. As in previous scenarios, three aims need to be investigated: grid balancing, hydrogen demand satisfaction and average hydrogen price at the point of sale. Starting with the Cen. LAE Sc. 1, an economically viable energy price, based on the daily hydrogen demand and the daily investment cost for the central electrolyser has to be calculated.

There is no option or chance on the energy producer side to make money based on the trading as in onsite scenario because only one price will be released by central electrolyser and this price will be the daily energy settlement price as it shown in Figure 9.3 below. Therefore, the daily released price for the central unit will be the settlement energy price. The electricity price can be calculated using Equation (9.1).

$$\text{PriceElectric}(£/kWh) = \left(\frac{\text{Hydrogen cost}\left(\frac{£}{\text{kg}}\right) \times demand_{H_2(\text{kg})} - \text{DailyInvestment Cost})(£)}{(hydrogen\ demand\ (\text{kg}) \times 54.6(\text{KWh/kg})} \right) \quad (9.1)$$

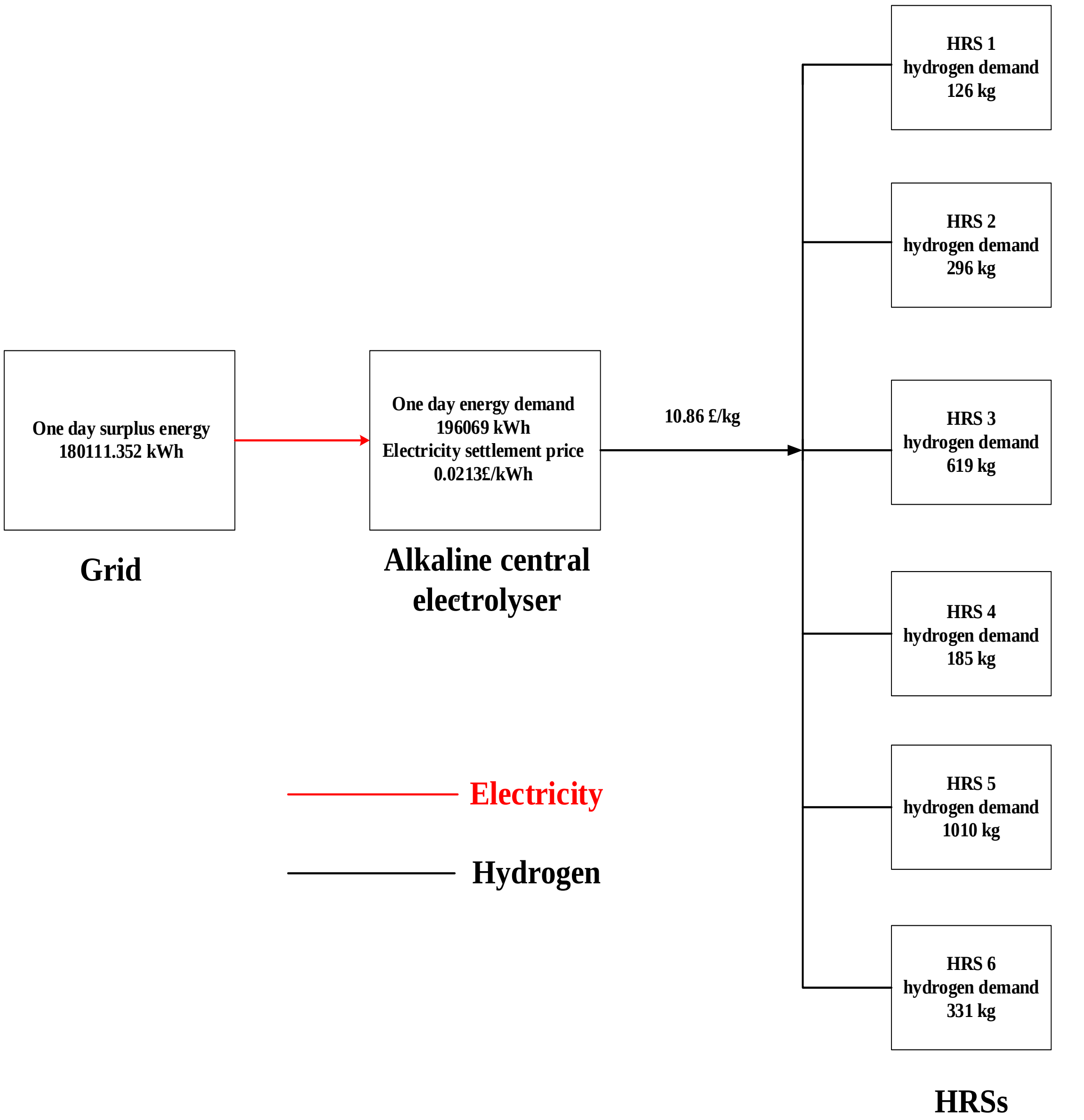


Figure 9.3: Central electrolyser electricity pricing mechanism , hydrogen production , and settlement hydrogen price to the HRSs

The amount of hydrogen required is the production target for the central electrolyser, and is dependent on the storage capacity and electrolyser size.The hydrogen production could be less than the maximum capacity of the central electrolyser based on the amount of surplus power available on any given day.The central electrolyser hydrogen production, the total hydrogen imported by the garage forecourts and central electrolyser storage profile are shown in Figure 9.4.

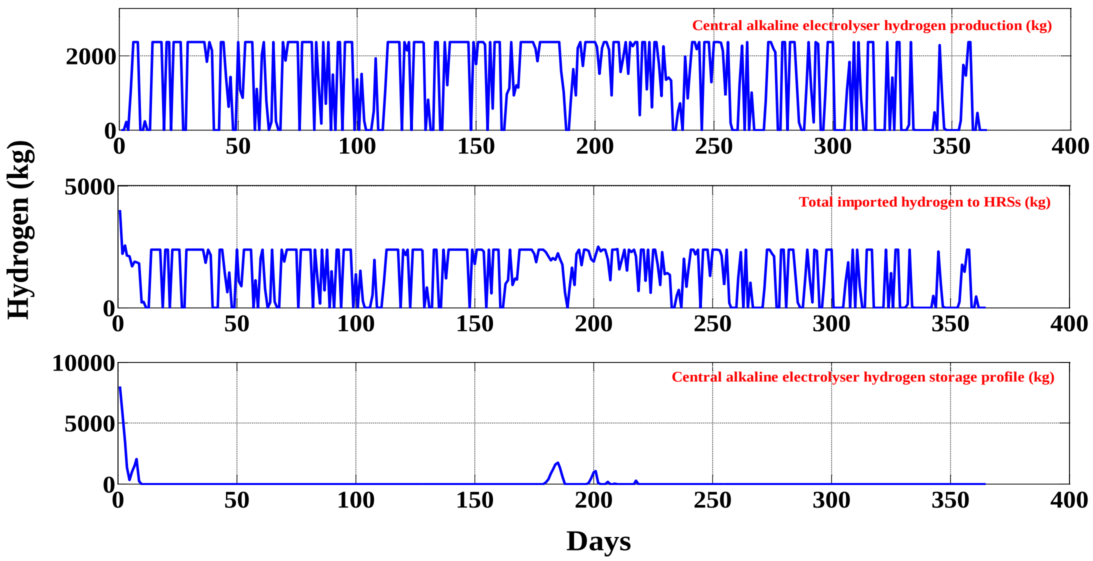


Figure 9.4: Central hydrogen production, garage forecourts imported hydrogen and central storage profile (2383 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 1))

For the first few days of the year, the imported hydrogen comes from storage until the central electrolyser starts production. As can be seen, the central production profile is very similar to the imported hydrogen profile, which means the hydrogen produced passes from storage to the garage forecourt areas without remaining in central storage. This explains why the central storage is empty at the end of the majority of days. Figure 9.5 and Figure 9.6 show the amount of imported hydrogen and the storage profile per garage forecourt, respectively.

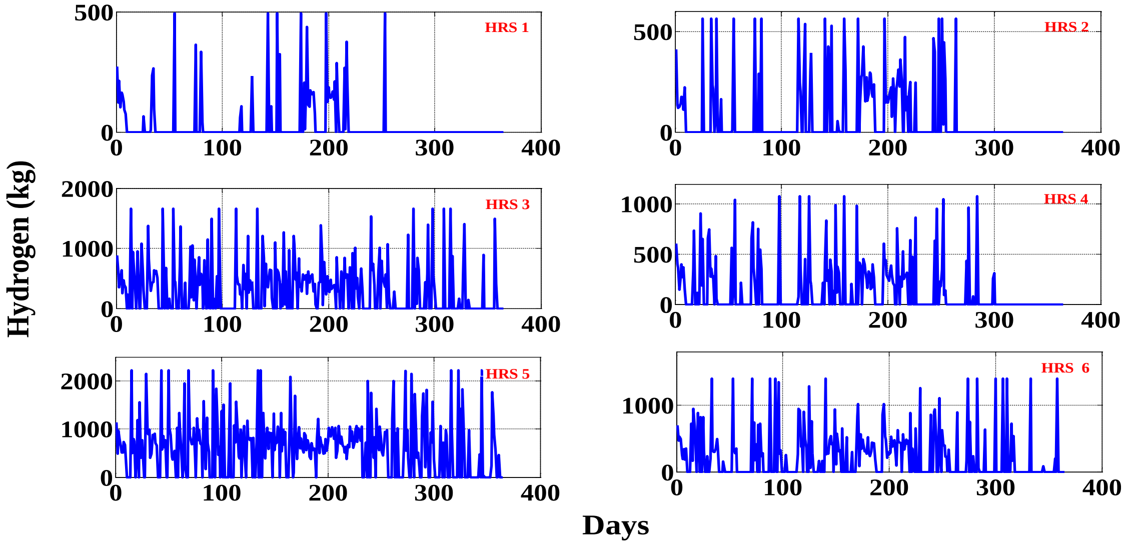


Figure 9.5: Imported hydrogen at each garage forecourt throughout the year (2383 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 1))

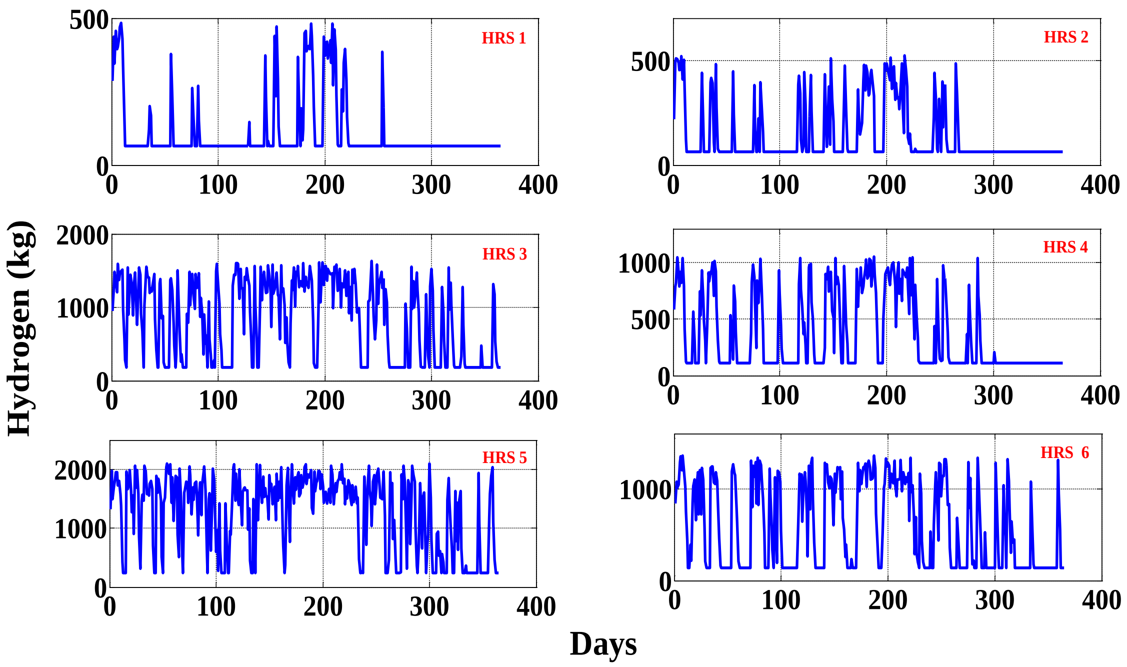


Figure 9.6: Daily variation of hydrogen level in storage tank throughout the year (2383 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 1))

Hydrogen is supplied to each garage forecourt in order of hierarchy from the one with the highest demand to the lowest. Hence, the storage at HRS 5, which has the highest demand reach full capacity many times more than other HRSs. The average settlement price will be based on the total cost and total hydrogen demand, including the amount in storage at the beginning of the year as per Equation (9.2).

$$Average\ hydrogen\ price\ (£/kg) = \left(\frac{Total\ cost\ (£\ /year)}{Hydrogen\ imported\ (kg/year)}\right) \tag{9.2}$$

The total cost includes the investment cost, fixed cost and variable cost. In terms of garage forecourt price, the investment cost (storage and dispenser) should be added to the average central cost. Delivery and transportation can be undertaken in different ways and different states of hydrogen such as gas or liquid. Because of the economics of hydrogen production, a tube trailer could be the best option for delivery. Delivery from the central electrolyser to the HRSs is ignored because the distance between the assumed central location (which is close to the renewable power generators) to the HRSs is not far (this fluctuates between 0.5 to 1 mile). Another compression system must be added to the HRSs to meet the required pressure at sale point because most tube trailers' pressure is

250 bar, while 700 bar has been chosen by the manufactures for the first market-ready and 350 bar for lift trucks and buses (U.S. Department of Energy, 2015). The central electrolyser's hydrogen production, the total hydrogen imported by the garage forecourts and the central electrolyser storage profile of Cen. LAE Sc. 2 are shown in Figure 9.7. Figure 9.8 shows the imported hydrogen at each HRS and Figure 9.9 show the hydrogen storage profile per garage forecourt.

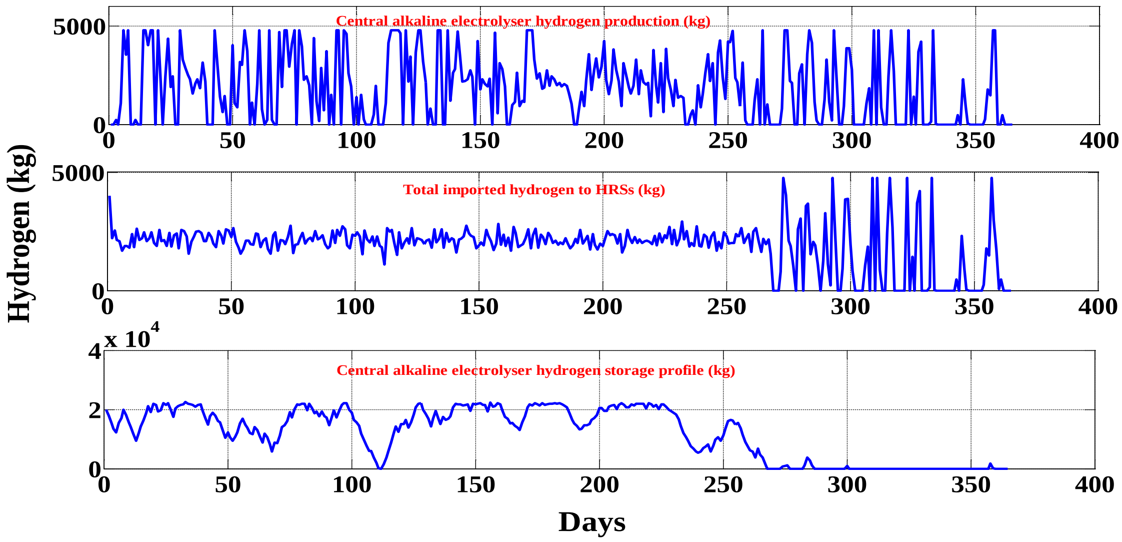


Figure 9.7: Central hydrogen production, hydrogen imported at HRSs and central storage profile (4,766 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 2))

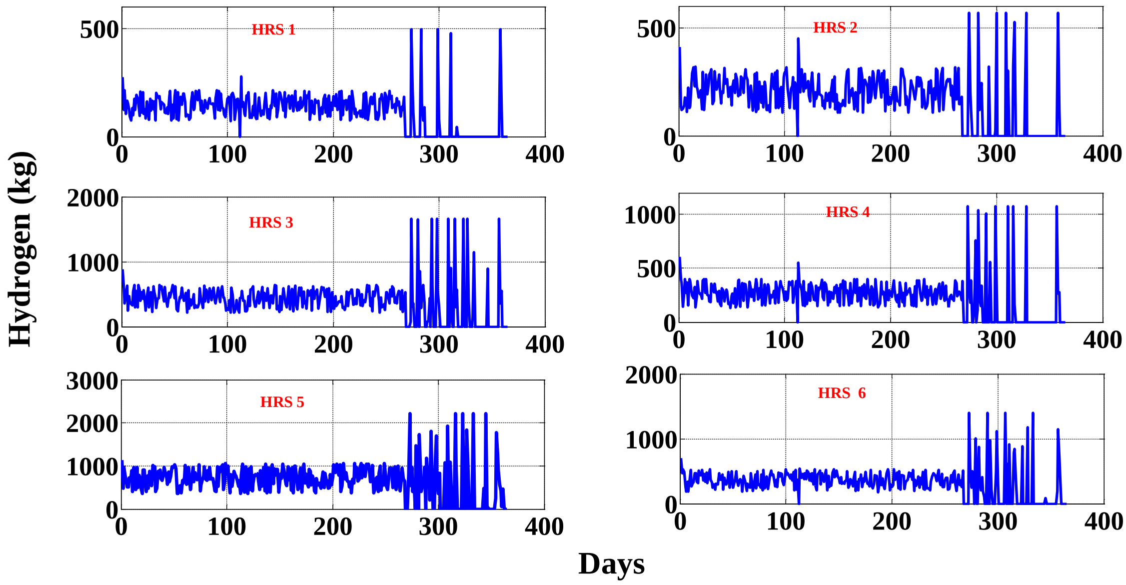


Figure 9.8: Imported hydrogen at each garage forecourt throughout the year (4,766 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 2))

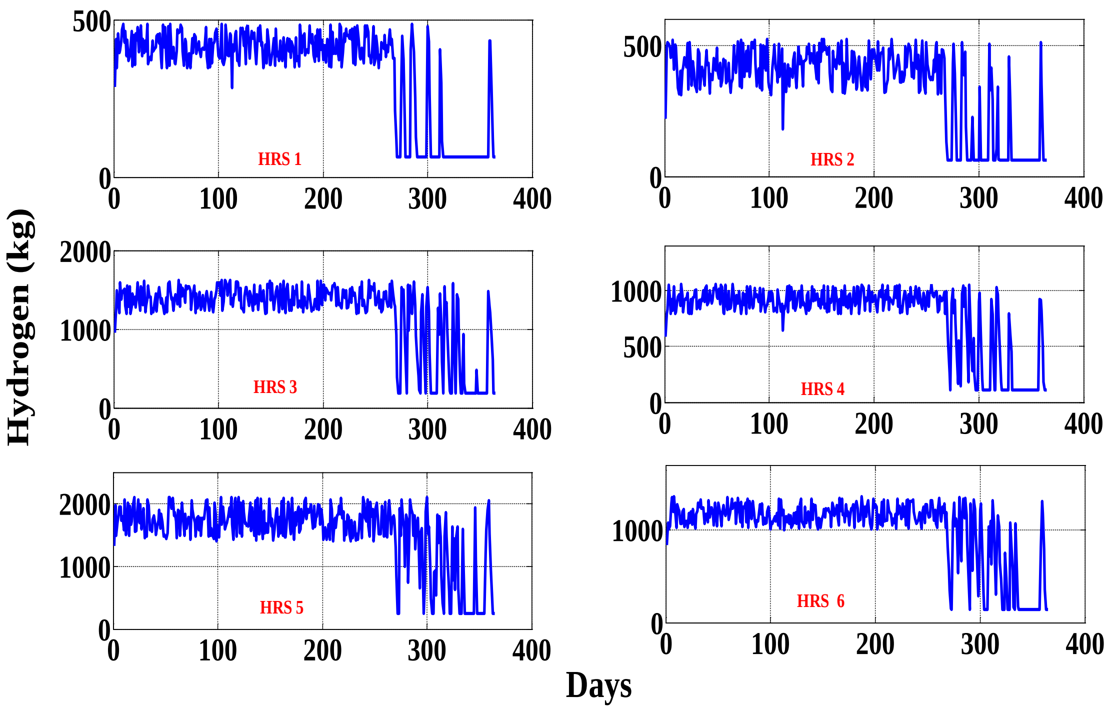


Figure 9.9: Daily variation of hydrogen level in storage tank throughout the year

(4,766 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 2))

Increase the size of central electrolyser and the storage gives the opportunity for all the HRSs to import amount of hydrogen compared to the first size. However, the central electrolyser cost will increase, as driven by the new investment cost.

For this size, the average price for all the HRSs except HRS 1 either increases or remains unchanged because of the increase in price of the imported hydrogen. HRS 1's price is reduced because the amount of hydrogen imported reached 79% of the total, compared to 21% with the first, smaller size.

Figure 9.10 shows the central electrolyser's hydrogen production, the total hydrogen imported at the garage forecourts and the second size of central electrolyser's storage profile (Cen. LAE Sc. 3). Figure 9.11 shows the imported hydrogen at each HRS and Figure 9.12 show the storage profile per garage forecourt.

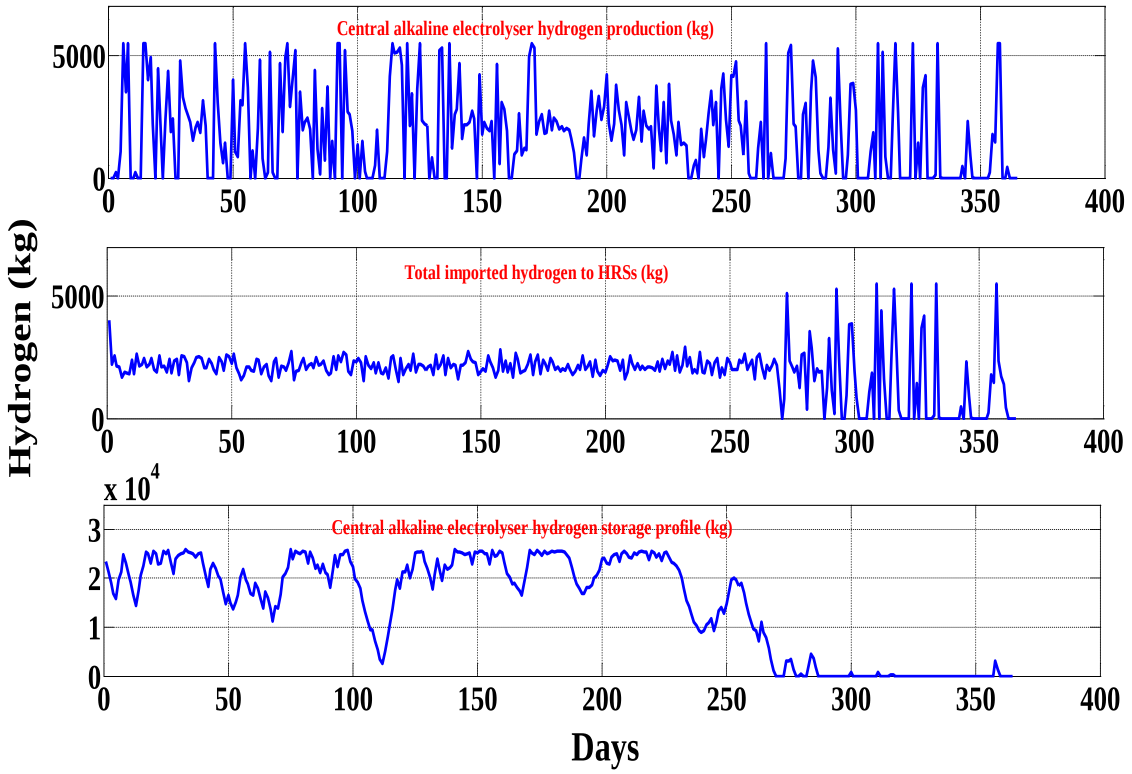


Figure 9.10: Central hydrogen production, hydrogen imported at HRSs and central storage profile (5,495 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 3))

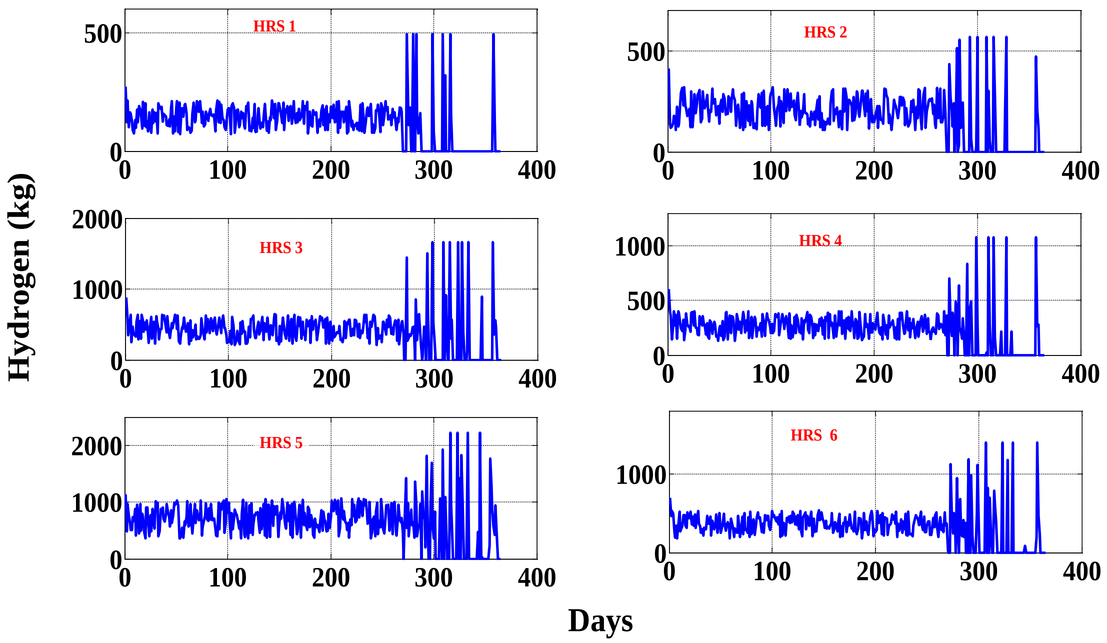


Figure 9.11: Imported hydrogen at each garage forecourt throughout the year (5,495 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 3))

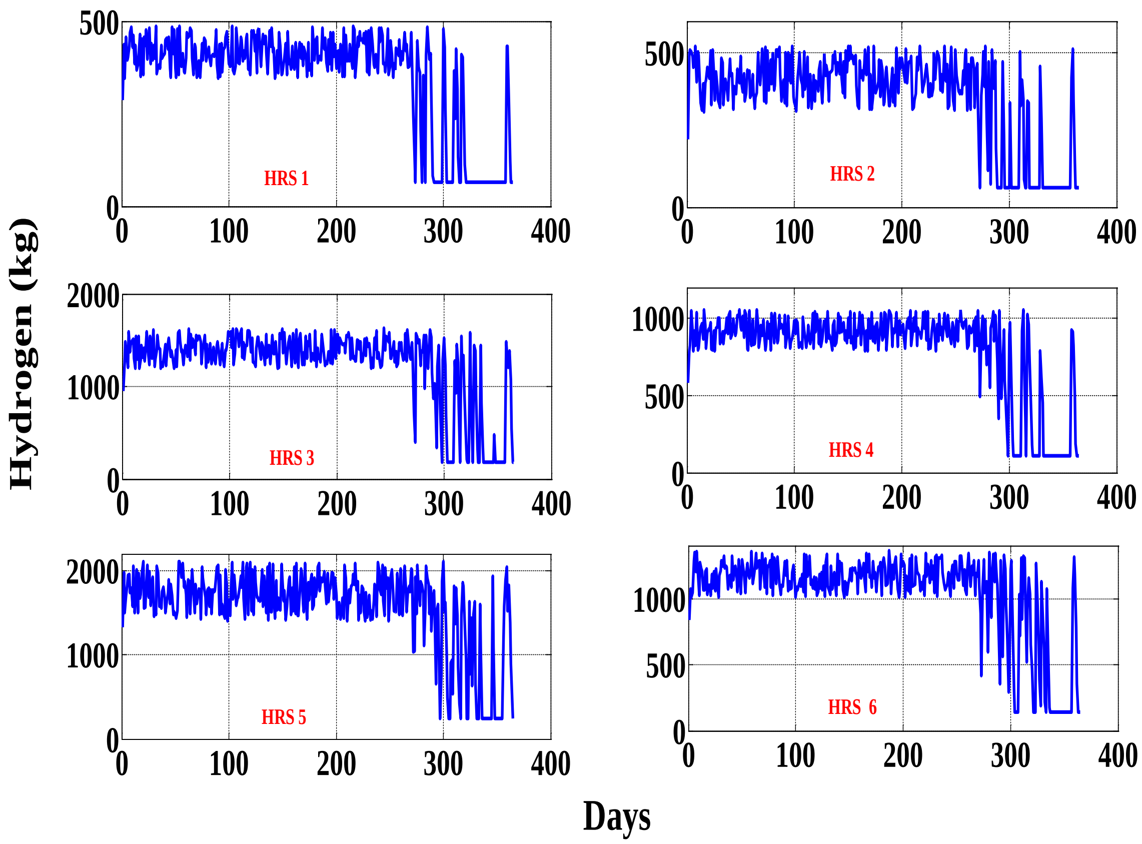


Figure 9.12: Daily variation of hydrogen level in storage tank throughout the year (5,495 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 3))

Figure 9.13 shows the central electrolyser hydrogen production, the total hydrogen imported by the garage forecourts and the storage profile of the third size of central electrolyser (Cen. LAE Sc. 4).

The increase in size of the central electrolyser will solve certain issues such as grid balancing and hydrogen demand being met, but the price of hydrogen will still be expensive.

Figure 9.14 shows the imported hydrogen at each HRS whereas Figure 9.15 shows daily variation of hydrogen level in storage tank throughout the year.

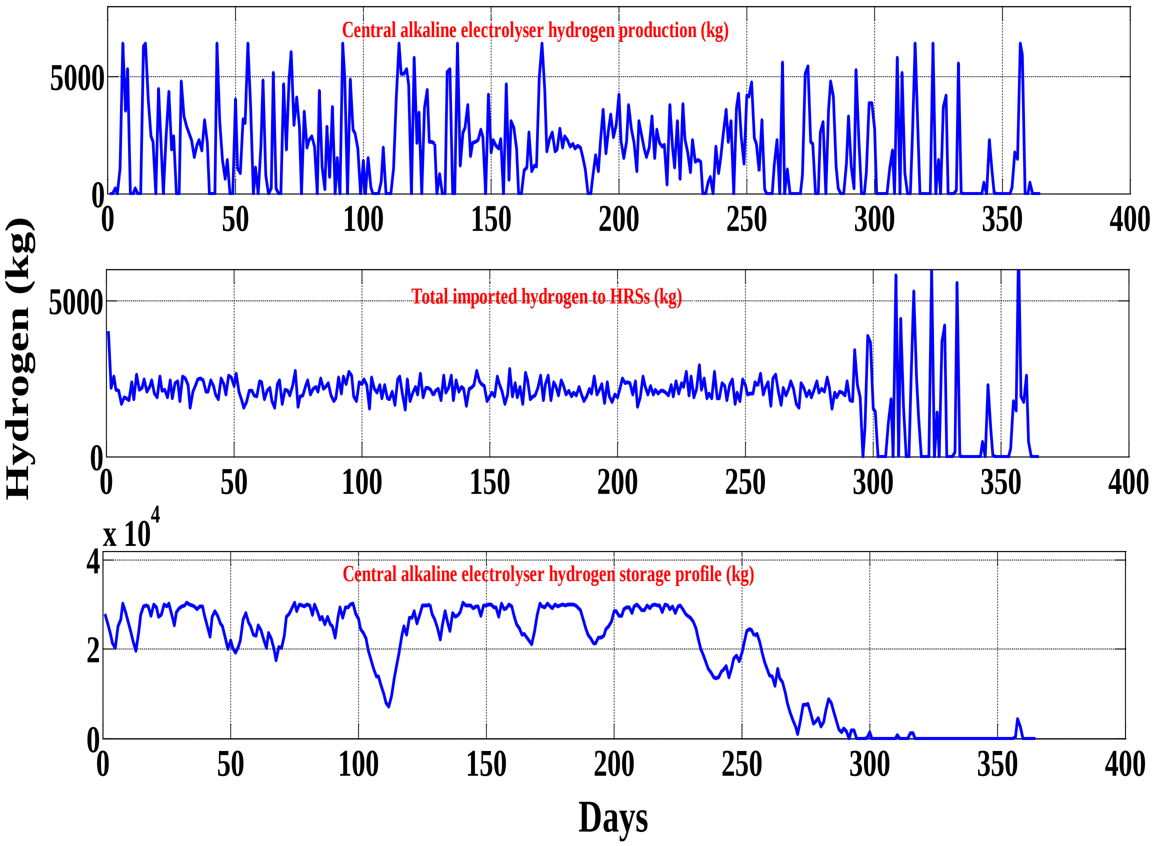


Figure 9.13: Central hydrogen production, hydrogen imported at HRSs and central storage profile (6,410 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 4))

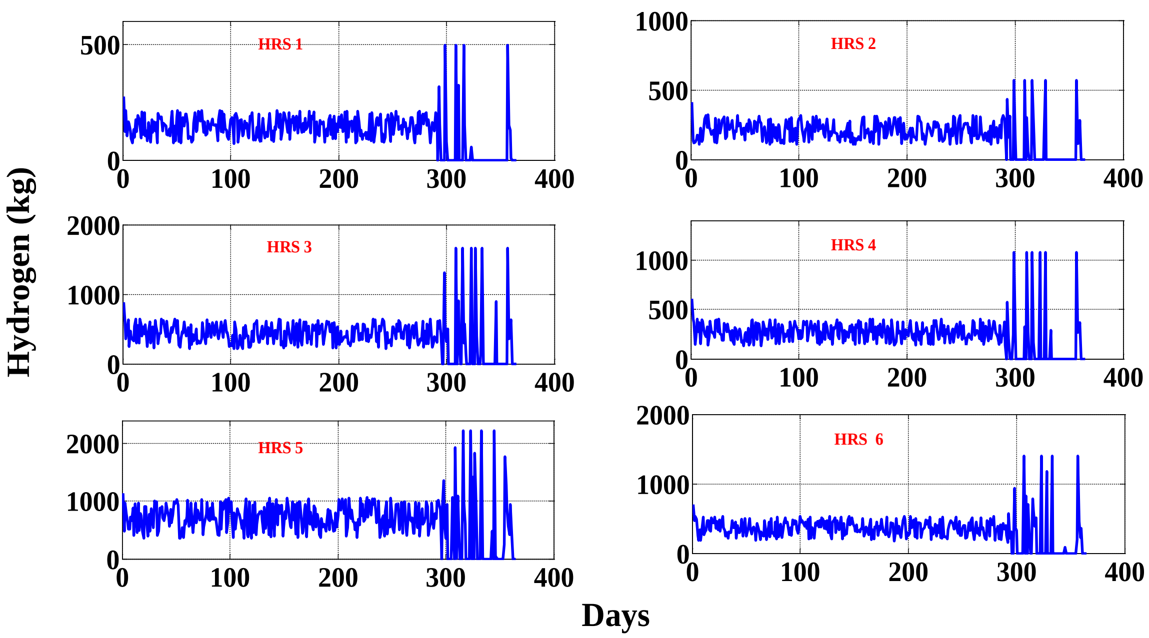


Figure 9.14: Imported hydrogen at each garage forecourt throughout the year (6,410 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 4))

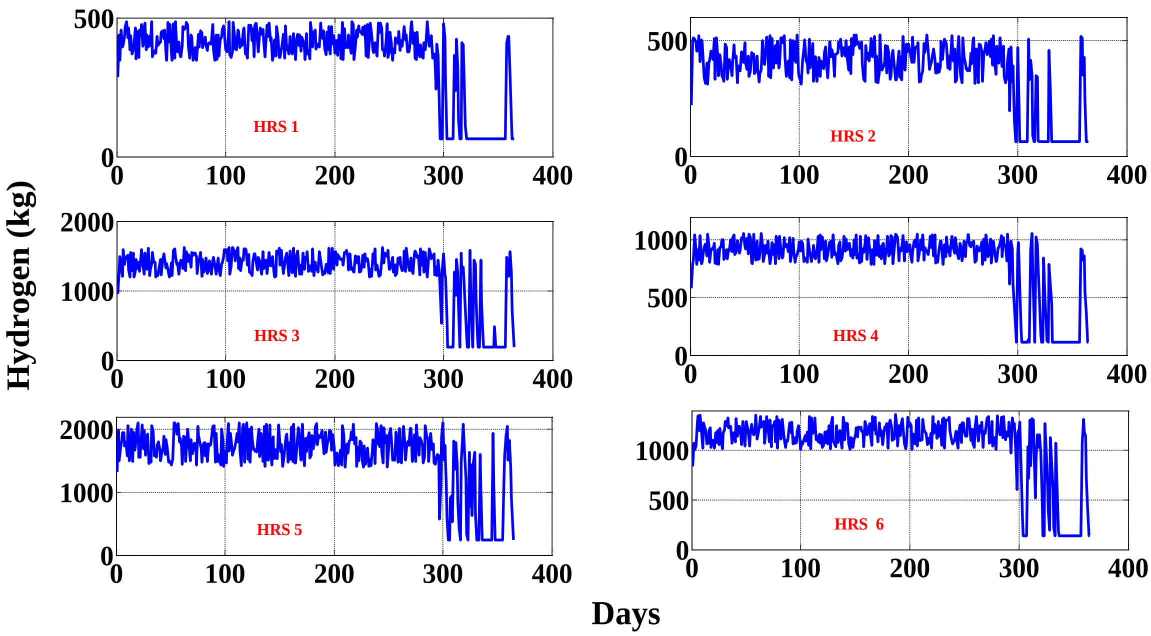


Figure 9.15: Daily variation of hydrogen level in storage tank throughout the year (6410 kg/day alkaline central electrolyser under 2015-Cost scenario (Cen. LAE Sc. 4))

Table 9.3 shows the economic summary of the system with different electrolyser sizes. From the second to the fourth sizes, the energy consumed and hydrogen demand being met are similar, even with the different electrolysers and storage sizes. However, the average hydrogen price of the central and garage forecourts is increased because of the new investment costs. The similarity in energy consumption between the last three sizes is due to the amount, and value, of the surplus energy. For the second size (260,210 kWh or 4766 kg/day), maximum production capacity was used 44 times during the year, which means that most days the electrolyser is running at less than its maximum production rate, while maximum hydrogen porduction was seen 21 and 11 times during the year for the second and third sizes, respectively. So, increasing the size does not seem to be the best option to meet the main goals. A central alkaline electrolyser under the 2015-Cost scenario can partly enhance renewable energy penetration by absorbing the surplus power and also providing clean fuel for vehicles. The central production method is relatively simple compared with the onsite production, especially for short distance delivery. The electricty mechnism is easer than for decentrlised production. This system could also be safer because the production is away from the consumption area. Despite the advantages of central production, the system price is nevertheless quite expensive. The 2030-Cost scenario will be tested to asses effectivness of deploying central hydrogen production by electrolysis in the coming years.

Scenario \ HRS		HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Cen. LAE Sc. 1	Satisfaction of Hydrogen demand (%)	21	32	75	48	87	64
	Average hydrogen price (£/kg)	23.30	16.80	13.70	16.40	12.50	14.40
	Total surplus energy consumed (%)	57					
	Satisfaction of total hydrogen demand for HRSs (%)	66					
	Average central electrolyser hydrogen price (£/kg)	9.60					
Cen. LAE Sc. 2	Satisfaction of Hydrogen demand (%)	79	82	90	88	93	91
	Average hydrogen price (£/kg)	17.60	16.80	17.40	17.70	16.70	17.40
	Total surplus energy consumed (%)	77					
	Satisfaction of total hydrogen demand for HRSs (%)	89					
	Average central electrolyser hydrogen price (£/kg)	14.00					
Cen. LAE Sc. 3	Satisfaction of Hydrogen demand (%)	83	84	92	89	94	91
	Average hydrogen price (£/kg)	19.20	18.40	19.00	19.40	18.40	19.10
	Total surplus energy consumed (%)	78					
	Satisfaction of total hydrogen demand for HRSs (%)	91					
	Average central electrolyser hydrogen price (£/kg)	15.80					
Cen. LAE Sc. 4	Satisfaction of Hydrogen demand (%)	86	87	92	91	94	92
	Average hydrogen price (£/kg)	21.40	20.70	21.30	21.60	20.70	21.40
	Total surplus energy consumed (%)	78					
	Satisfaction of total hydrogen demand for HRSs (%)	92					
	Average central electrolyser hydrogen price (£/kg)	18.00					

Table 9.3: Economic assessment of this scenario under different system component sizes (under 2015-Cost scenario)

9.4 2030-Cost scenario for alkaline electrolysis

This cost scenario is summarised in Table 7.1. The 2030-Cost scenario also includes electrolysis efficiency improvements.

9.4.1 Sizing of the central electrolyser and the HRSS

The system size will be the same as described in Section 9.3.1. Only the system cost and efficiency will change. Table 9.4 below shows the alkaline central electrolyser and HRSs components size and scenarios.

Details	Scenario No.	Cen. LAE Sc. 5	Cen. LAE Sc. 6	Cen. LAE Sc. 7	Cen. LAE Sc. 8
HRSs Electrolyser size (Kg/day)	HRS 1	×	×	×	×
	HRS 2	×	×	×	×
	HRS 3	×	×	×	×
	HRS 4	×	×	×	×
	HRS 5	×	×	×	×
	HRS 6	×	×	×	×
HRS Storage size (kg)	HRS 1	560	560	560	560
	HRS 2	630	630	630	630
	HRS 3	1840	1840	1840	1840
	HRS 4	1190	1190	1190	1190
	HRS 5	2464	2464	2464	2464
	HRS 6	1540	1540	1540	1540
HRS Compressor size (Kg/day)	HRS 1	149	149	149	149
	HRS 2	226	226	226	226
	HRS 3	449	449	449	449
	HRS 4	282	282	282	282
	HRS 5	744	744	744	744
	HRS 6	372	372	372	372
Central Electrolyser size		2383	4766	5495	6410
Central Electrolyser Storage size (kg)		12000	24000	27500	32000
Central Electrolyser compressor size (kg/day)		2383	4766	5495	6410
Electrolyser efficiency (kWh/kg)		50	50	50	50
Year of the components cost		2030	2030	2030	2030

Table 9.4: Alkaline central electrolyser and HRSs size details under 2030-Cost scenario

Where: **Cen. LAE Sc. 5:** 2,383 kg/day alkaline central electrolyser with 12,000 kg hydrogen storage without electrolyser at the HRSs under 2030-Cost scenario.

Cen. LAE Sc. 6: 4,766 kg/day alkaline central electrolyser with 24,000 kg hydrogen storage without electrolyser at the HRSs under 2030-Cost scenario.

Cen. LAE Sc. 7: 5,495 kg/day alkaline central electrolyser with 27,500 kg hydrogen storage without electrolyser at the HRSs under 2030-Cost scenario.

Cen. LAE Sc. 8: 6,410 kg/day alkaline central electrolyser with 32,000 kg hydrogen storage without electrolyser at the HRSs under 2030-Cost scenario.

9.4.2 Alkaline central electrolyser and garage forecourts assessments

This scenario will be capable of producing hydrogen at a cheaper price than the 2015-Cost scenario. However, the other goals should be investigated. The hydrogen price here should also compare with the forecasted price of fossil fuels to evaluate the possibility of competition. Table 9.5 summarises the economic assessments of this scenario with different system sizes. The hydrogen prices are reduced in this scenario, as enabled by the reduction in the investment cost, and a slightly higher electricity price (the electricity price fluctuates between £0.030-0.0372/kWh depending on the size of the central electrolyser). Even with lower energy consumption, the satisfaction of hydrogen demand is higher than in the 2015-Cost scenario. Figure 9.16 compares the average hydrogen prices with the central electrolyser prices for the two different cost scenarios.

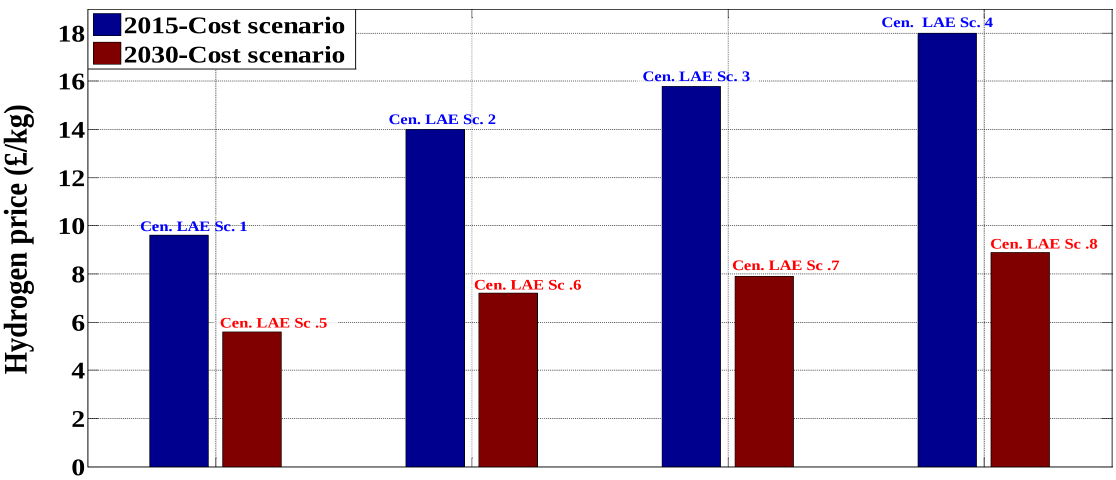


Figure 9.16: Central alkaline electrolyser hydrogen price for different cost scenarios and under different system sizes

Scenario	HRS	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Cen. LAE Sc.	Satisfaction of Hydrogen demand (%)	23	32	76	50	87	66
	Average hydrogen price (£/kg)	10.60	8.40	7.20	8.20	6.70	7.40
	Total surplus energy consumed (%)	53					
	Satisfaction of total hydrogen demand for HRSs (%)	67					
	Average central electrolyser hydrogen price (£/kg)	5.60					
Cen. LAE Sc.	Satisfaction of Hydrogen demand (%)	85	86	92	88	93	92
	Average hydrogen price (£/kg)	8.60	8.20	8.50	8.60	8.20	8.50
	Total surplus energy consumed (%)	72					
	Satisfaction of total hydrogen demand for HRSs (%)	91					
	Average central electrolyser hydrogen price (£/kg)	7.20					
Cen. LAE Sc. 7	Satisfaction of Hydrogen demand (%)	88	88	93	91	95	93
	Average hydrogen price (£/kg)	9.20	9.00	9.20	9.30	8.90	9.20
	Total surplus energy consumed (%)	73					
	Satisfaction of total hydrogen demand for HRSs (%)	93					
	Average central electrolyser hydrogen price (£/kg)	7.90					
Cen. LAE Sc. 8	Satisfaction of Hydrogen demand (%)	91	91	94	94	95	94
	Average hydrogen price (£/kg)	10.10	9.90	10.10	10.20	9.90	10.10
	Total surplus energy consumed (%)	74					
	Satisfaction of total hydrogen demand for HRSs (%)	94					
	Average central electrolyser hydrogen price (£/kg)	8.90					

Table 9.5: Economic assessment of this scenario under different system component sizes (under 2030-Cost scenario)

9.5 2015-Cost scenario for PEM electrolysis

Two cost scenarios will be investigated using PEM electrolysis: the 2015-Cost scenario and the 2030-Cost scenario. The system size will be the same in terms of production in kg/day for both scenarios.

9.5.1 Sizing of the central electrolyser and the HRSS

The main goal of the system is to support grid balancing, so the central electrolyser size should be based on the energy availability. The system will test different electrolyser sizes. At the same time, the hydrogen demand should be met at an acceptable sale price. The system sizes will be the same as for the alkaline 2015-Cost scenario (see Section 9.3.1). Table 9.6 below summarises the PEME and HRSs components size.

Details	Scenario No.	Cen. PEME Sc. 1	Cen. PEME Sc. 2	Cen. PEME Sc. 3	Cen. PEME Sc. 4
HRSs Electrolyser size (Kg/day)	HRS 1	×	×	×	×
	HRS 2	×	×	×	×
	HRS 3	×	×	×	×
	HRS 4	×	×	×	×
	HRS 5	×	×	×	×
	HRS 6	×	×	×	×
HRS Storage size (kg)	HRS 1	560	560	560	560
	HRS 2	630	630	630	630
	HRS 3	1840	1840	1840	1840
	HRS 4	1190	1190	1190	1190
	HRS 5	2464	2464	2464	2464
	HRS 6	1540	1540	1540	1540
HRS Compressor size (Kg/day)	HRS 1	149	149	149	149
	HRS 2	226	226	226	226
	HRS 3	449	449	449	449
	HRS 4	282	282	282	282
	HRS 5	744	744	744	744
	HRS 6	372	372	372	372
Central Electrolyser size (Kg/day)		2383	4766	5495	6410
Central Electrolyser Storage size (kg)		12000	24000	27500	32000
Central Electrolyser compressor size (kg/day)		2383	4766	5495	6410
Electrolyser efficiency (kWh/kg)		54.6	54.6	54.6	54.6
Year of the components cost		2015	2015	2015	2015

Table 9.6: PEM central electrolyser and HRSs size details under 2015-Cost scenario

Where: **Cen. PEME Sc. 1:** 2,383 kg/day PEM central electrolyser with 12,000 kg hydrogen storage without electrolyser at the HRSs under 2015-Cost scenario.

Cen. PEME Sc. 2: 4,766 kg/day PEM central electrolyser with 24,000 kg hydrogen storage without electrolyser at the HRSs under 2015-Cost scenario.

Cen. PEME Sc. 3: 5,495 kg/day PEM central electrolyser with 27,500 kg hydrogen storage without electrolyser at the HRSs under 2015-Cost scenario.

Cen. PEME Sc. 4: 6,410 kg/day PEM central electrolyser with 32,000 kg hydrogen storage without electrolyser at the HRSs under 2015-Cost scenario.

9.5.2 PEM central electrolyser and garage forecourts assessments

Figure 9.17 shows the hydrogen production for the first size of central electrolyser (Cen. PEME Sc. 1), the total hydrogen imported by the garage forecourts and the central electrolyser's storage profile.

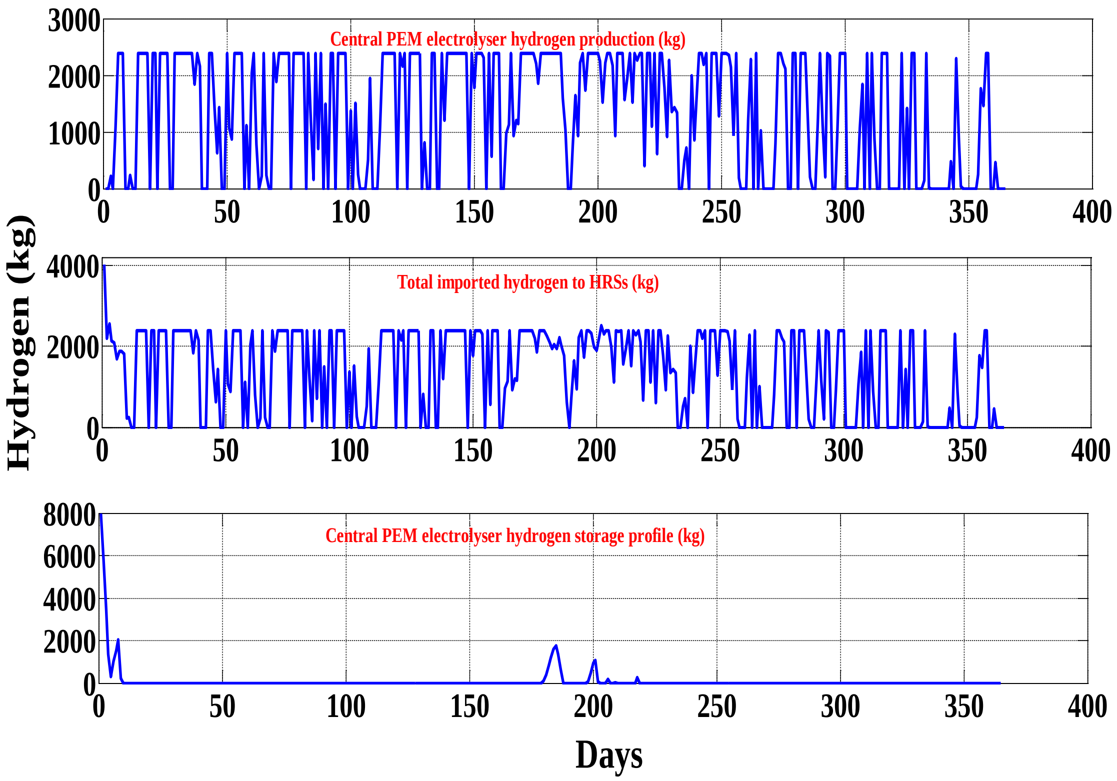


Figure 9.17: Central hydrogen production, hydrogen imported at HRSs and central storage profile (2383 kg/day PEM central electrolyser (Cen. PEME Sc. 1)) under 2015-Cost scenario

The energy-selling price for the first size (Cen. PEME Sc. 1) is £0.0206/kWh. The amount of imported hydrogen is quite similar to the central electrolyser's hydrogen production. In other words, at the end of most days the storage is empty because all hydrogen produced has been transferred to the garage forecourts where it is stored until sold. Figure 9.18 shows the imported hydrogen at each HRS and Figure 9.19 shows the daily variation of hydrogen level in storage tank throughout the year for the first size of central electrolyser (Cen. PEME Sc. 1).

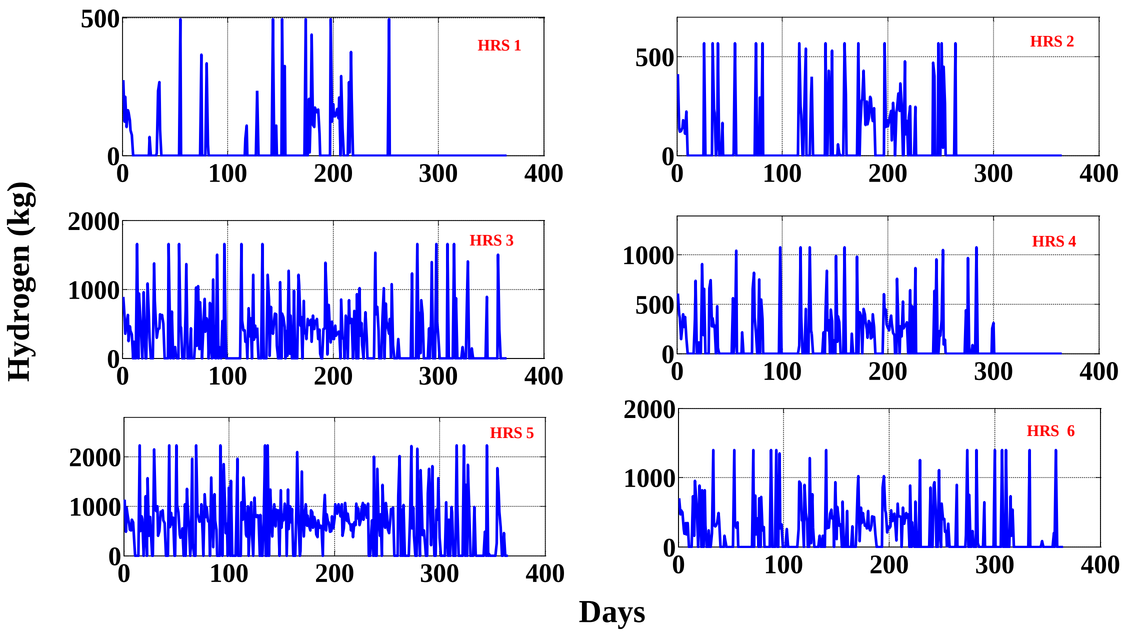


Figure 9.18: Imported hydrogen at each garage forecourt throughout the year profile (2383 kg/day PEM central electrolyser (Cen. PEME Sc. 1)) under 2015-Cost scenario

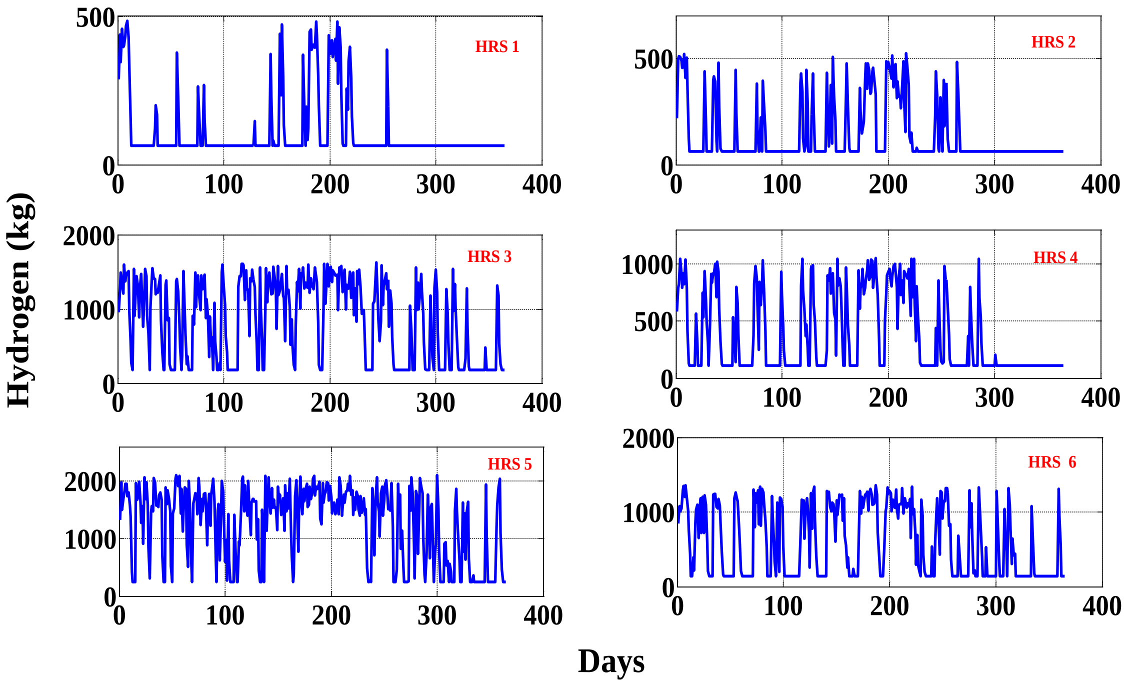


Figure 9.19: Daily variation of hydrogen level in storage tank throughout the year profile (2383 kg/day PEM central electrolyser (Cen. PEME Sc. 1)) under 2015-Cost scenario

Table 9.7 summarises the economic assessment of this scenario for different sizes

Scenario	HRS	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Cen. PEME Sc. 1	Satisfaction of Hydrogen demand (%)	21	32	75	48	87	64
	Average hydrogen price (£/kg)	25.00	18.20	15.20	17.90	14.00	16.00
	Total surplus energy consumed (%)	57					
	Satisfaction of total hydrogen demand for HRSs (%)	66					
	Average central electrolyser hydrogen price (£/kg)	11.20					
Cen. PEME Sc. 2	Satisfaction of Hydrogen demand (%)	79	82	90	88	93	91
	Average hydrogen price (£/kg)	20.00	19.10	19.70	20.00	19.00	19.70
	Total surplus energy consumed (%)	77					
	Satisfaction of total hydrogen demand for HRSs (%)	89					
	Average central electrolyser hydrogen price (£/kg)	16.40					
Cen. PEME Sc. 3	Hydrogen demand satisfaction (%)	83	84	92	89	94	91
	Average hydrogen price (£/kg)	22.00	21.10	21.80	22.10	21.10	21.80
	Total surplus energy consumed (%)	78					
	Total hydrogen demand satisfaction (%)	91					
	Average central electrolyser hydrogen price (£/kg)	18.50					
Cen. PEME Sc. 4	Satisfaction of Hydrogen demand (%)	86	87	92	91	94	92
	Average hydrogen price (£/kg)	24.60	24.00	24.60	24.90	24.00	24.60
	Total surplus energy consumed (%)	78					
	Satisfaction of total hydrogen demand for HRSs (%)	92					
	Average central electrolyser hydrogen price (£/kg)	21.40					

Table 9.7: Economic assessment of this scenario under different system component sizes (for 2015-Cost scenario)

Of PEME with the 2015-Cost scenario, which does not result in any changes in terms of the energy absorbed and hydrogen demand met. However, the hydrogen price at the central electrolyser and garage forecourts is increased because of the cost of the PEM electrolyser. The 2030-Cost scenario could lead to greater absorption of energy, and thus greater satisfaction of hydrogen demand is achieved because of the reduction in system cost and the projected efficiency improvements in electrolysis. The energy price range was £0.0081-0.0087/kWh.

9.6 2030-Cost scenario for PEM electrolysis

The system will follow the same steps as for the 2015-Cost scenario with new cost system data and new efficiencies for the electrolysis and compression systems as it is shown in Table 9.8 below.

Details	Scenario No.	Cen. PEME Sc. 5	Cen. PEME Sc. 6	Cen. PEME Sc. 7	Cen. PEME Sc. 8
HRSs Electrolyser size (Kg/day)	HRS 1	×	×	×	×
	HRS 2	×	×	×	×
	HRS 3	×	×	×	×
	HRS 4	×	×	×	×
	HRS 5	×	×	×	×
	HRS 6	×	×	×	×
HRS Storage size (kg)	HRS 1	560	560	560	560
	HRS 2	630	630	630	630
	HRS 3	1840	1840	1840	1840
	HRS 4	1190	1190	1190	1190
	HRS 5	2464	2464	2464	2464
	HRS 6	1540	1540	1540	1540
HRS Compressor size (Kg/day)	HRS 1	149	149	149	149
	HRS 2	226	226	226	226
	HRS 3	449	449	449	449
	HRS 4	282	282	282	282
	HRS 5	744	744	744	744
	HRS 6	372	372	372	372
Central Electrolyser size (Kg/day)		2383	4766	5495	6410
Central Electrolyser Storage size (kg)		12000	24000	27500	32000
Central Electrolyser compressor size (kg/day)		2383	4766	5495	6410
Electrolyser efficiency (kWh/kg)		47	47	47	47
Year of the components cost		2030	2030	2030	2030

Table 9.8: PEM central electrolyser and HRSs size details under 2030-Cost scenario

Where: **Cen. PEME Sc. 5:** 2,383 kg/day PEM central electrolyser with 12,000 kg hydrogen storage without electrolyser at the HRSs under 2030-Cost scenario.

Cen. PEME Sc. 6: 4,766 kg/day PEM central electrolyser with 24,000 kg hydrogen storage without electrolyser at the HRSs under 2030-Cost scenario.

Cen. PEME Sc. 7: 5,495 kg/day PEM central electrolyser with 27,500 kg hydrogen storage without electrolyser at the HRSs under 2030-Cost scenario.

Cen. PEME Sc. 8: 6,410 kg/day PEM central electrolyser with 32,000 kg hydrogen storage without electrolyser at the HRSs under 2030-Cost scenario.

Regarding size, the system sizes listed in Table 9.8 will be tested. The new cost details are given in Table 7.2. Figure 9.20 shows the central electrolyser's hydrogen production, hydrogen imported at the garage forecourts and the storage profile of the first size of PEM central electrolyser (Cen. PEME Sc. 5) throughout the year.

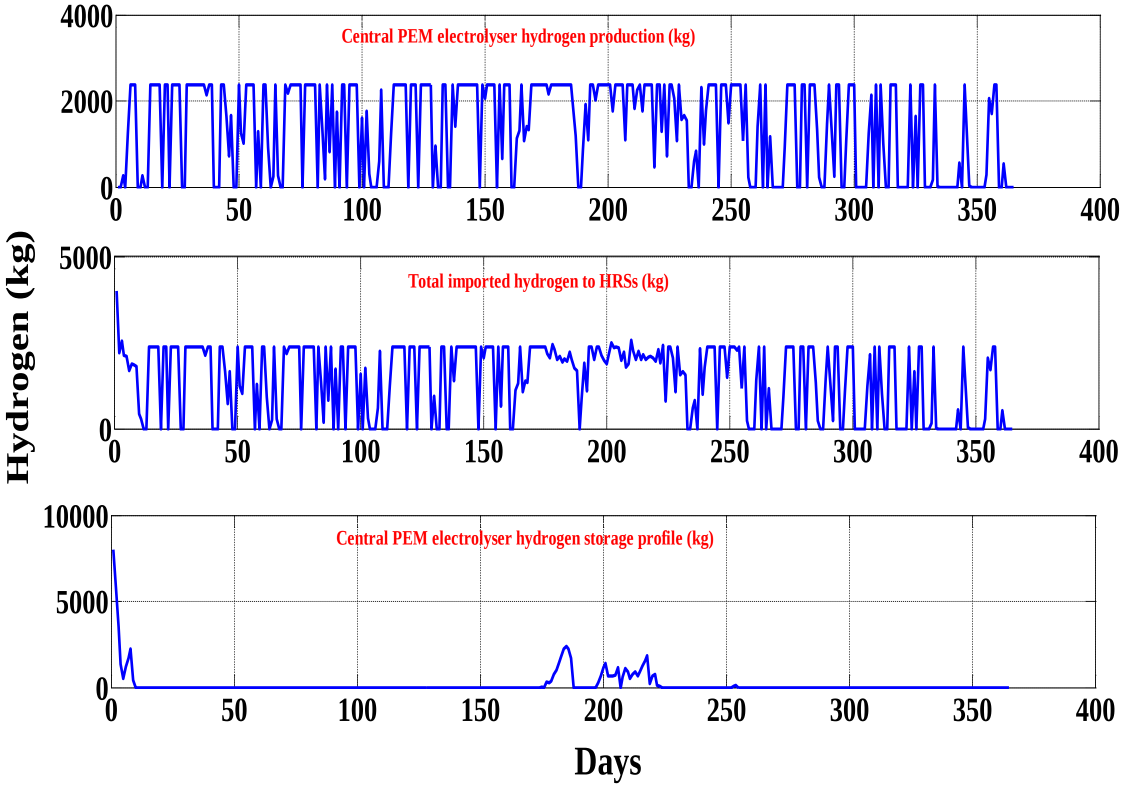


Figure 9.20: Central hydrogen production, hydrogen imported at HRSs and central storage profile (2,383 kg/day PEM central electrolyser (Cen. PEME Sc. 5)) under 2030-Cost scenario

Figure 9.21 shows the imported hydrogen at each HRS and Figure 9.22 show the storage profile per garage forecourt.

The calculation are similar to those of the equivalent scenario using an alkaline 2030-Cost profile, with slightly more hydrogen demand being met since the efficiency of the electrolysis is improved.

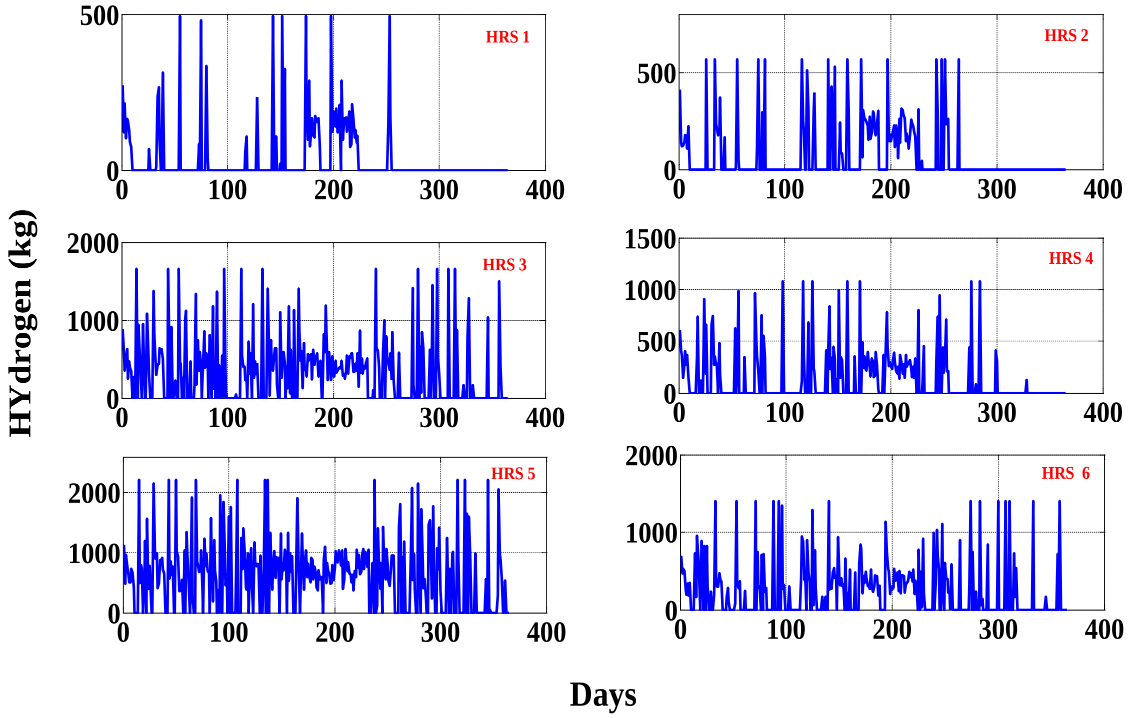


Figure 9.21: Imported hydrogen at each garage forecourt throughout the year (2,383 kg/day PEM central electrolyser (Cen. PEME Sc. 5)) under 2030-Cost scenario

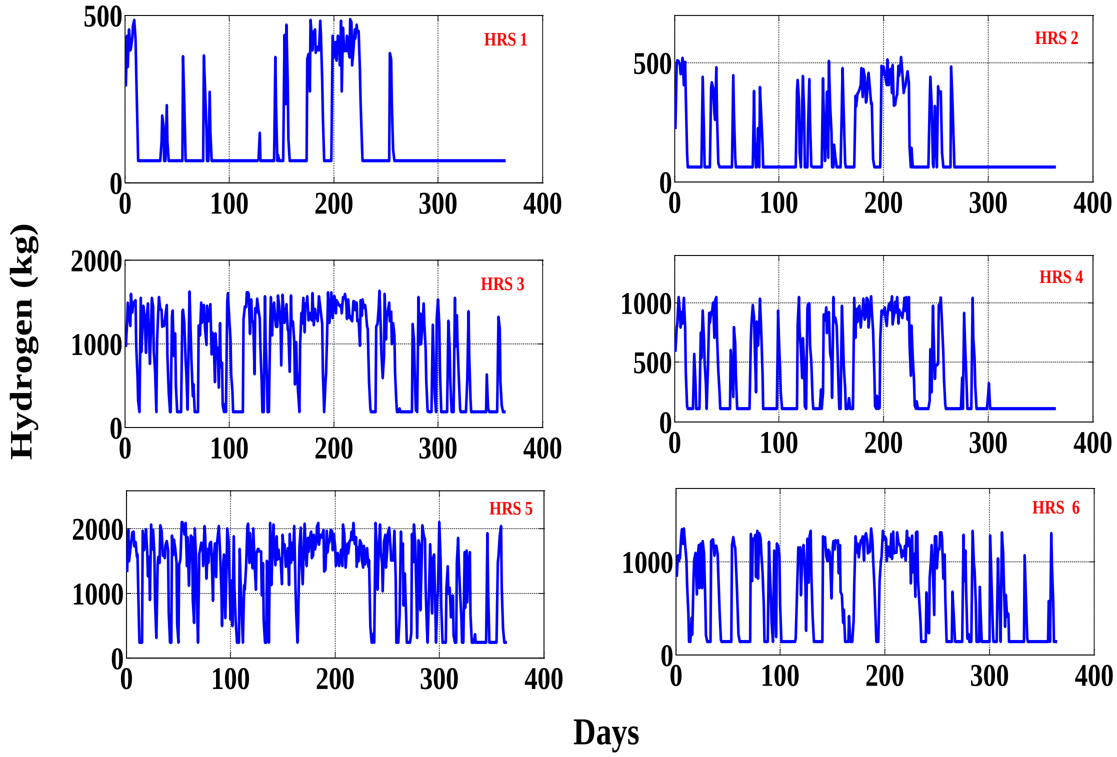


Figure 9.22: Daily variation of hydrogen level in storage tank throughout the (2,383 kg/day PEM central electrolyser (Cen. PEME Sc. 5)) under 2030-Cost scenario

Figure 9.23, Figure 9.24 and Figure 9.25 show summaries for the second size of electrolyser (Cen. PEME Sc. 6).

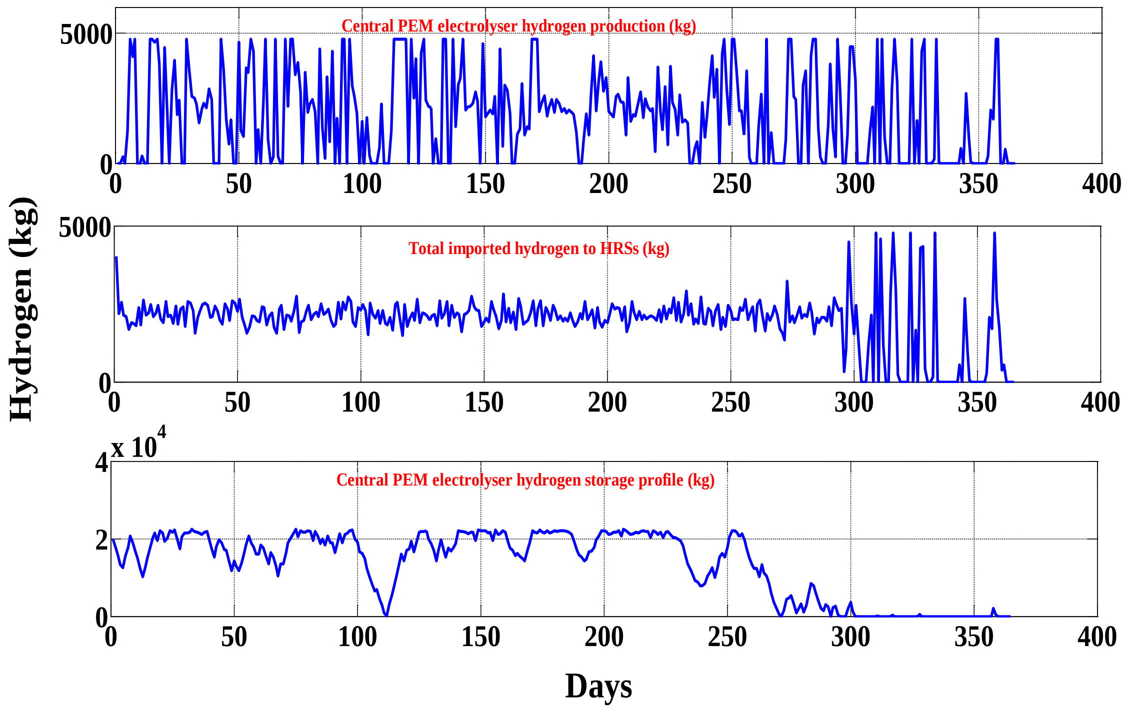


Figure 9.23: Central hydrogen production, hydrogen imported at HRSs and central storage profile (4,766 kg/day PEM central electrolyser (Cen. PEME Sc. 6)) under 2030-Cost scenario

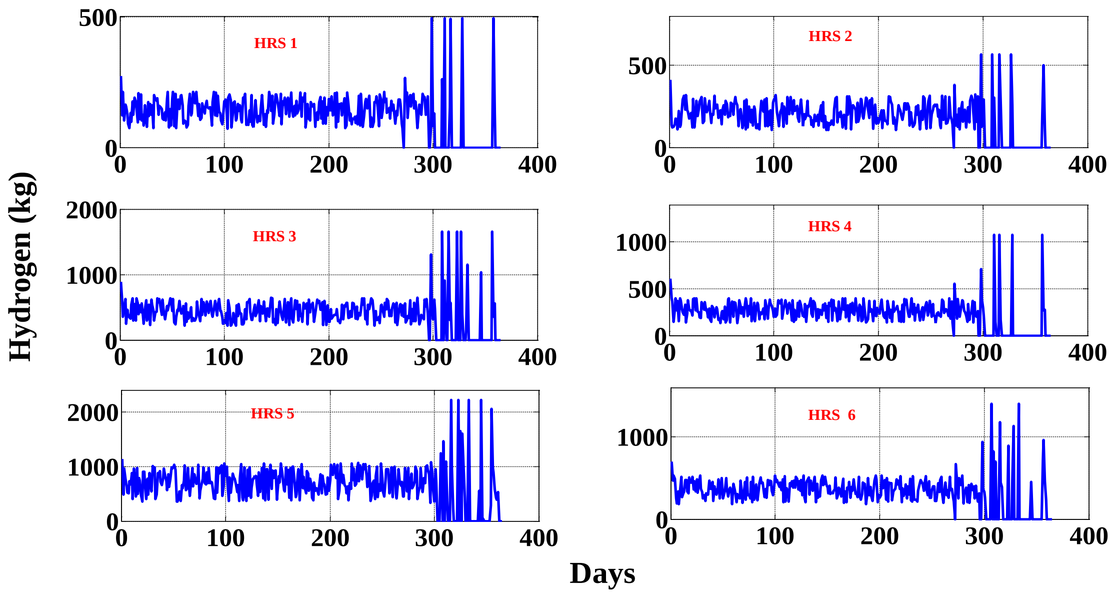


Figure 9.24: Imported hydrogen at each garage forecourt throughout the year (4,766 kg/day PEM central electrolyser (Cen. PEME Sc. 6)) under 2030-Cost scenario

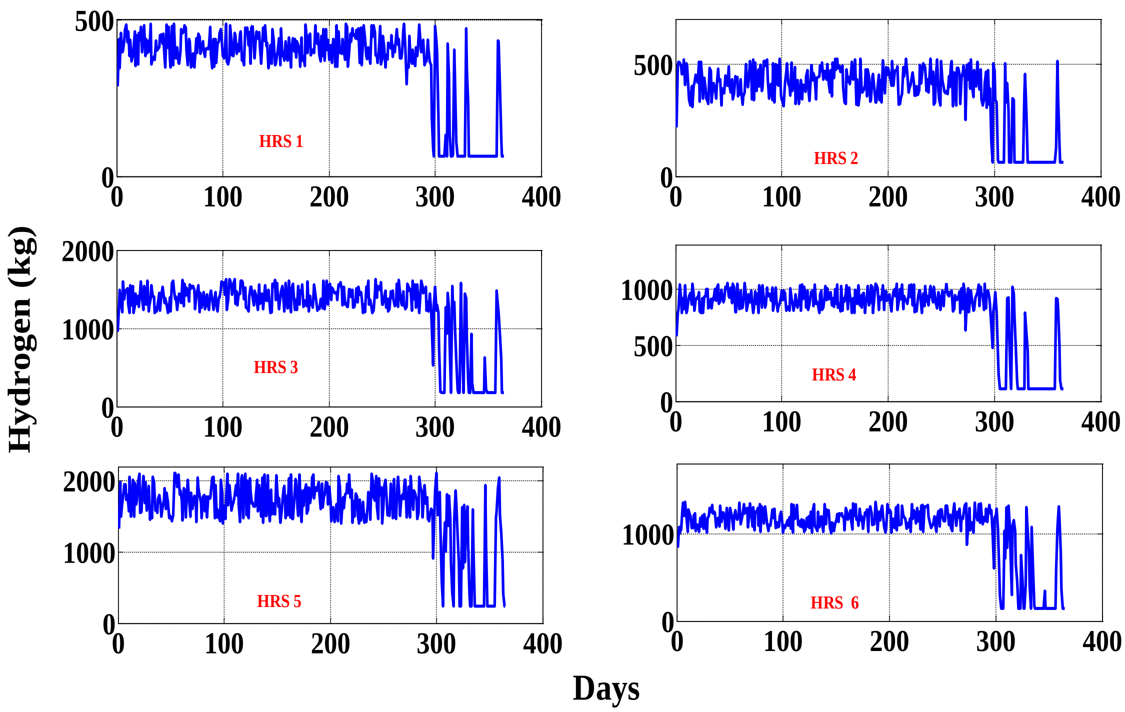


Figure 9.25: Daily variation of hydrogen level in storage tank throughout the year (4,766 kg/day PEM central electrolyser (Cen. PEME Sc. 6)) under 2030-Cost scenario

Based on the storage profile of the central electrolyser, hydrogen imported and storage variation per garage forecourt, this scenario represents a certain improvement over the last scenario because the amount of imported hydrogen is greater and more hydrogen can be stored in the central tank, which means all garage forecourts can have their daily requirements for hydrogen on the majority of days.

However, the price of the hydrogen will be higher due to the increased investment for the new system size.

Figure 9.26 shows the hydrogen production of the central electrolyser, the total hydrogen imported at each garage forecourt and the hydrogen storage variation at the central electrolyser under third system size (Cen. PEME Sc. 7) throughout the year.

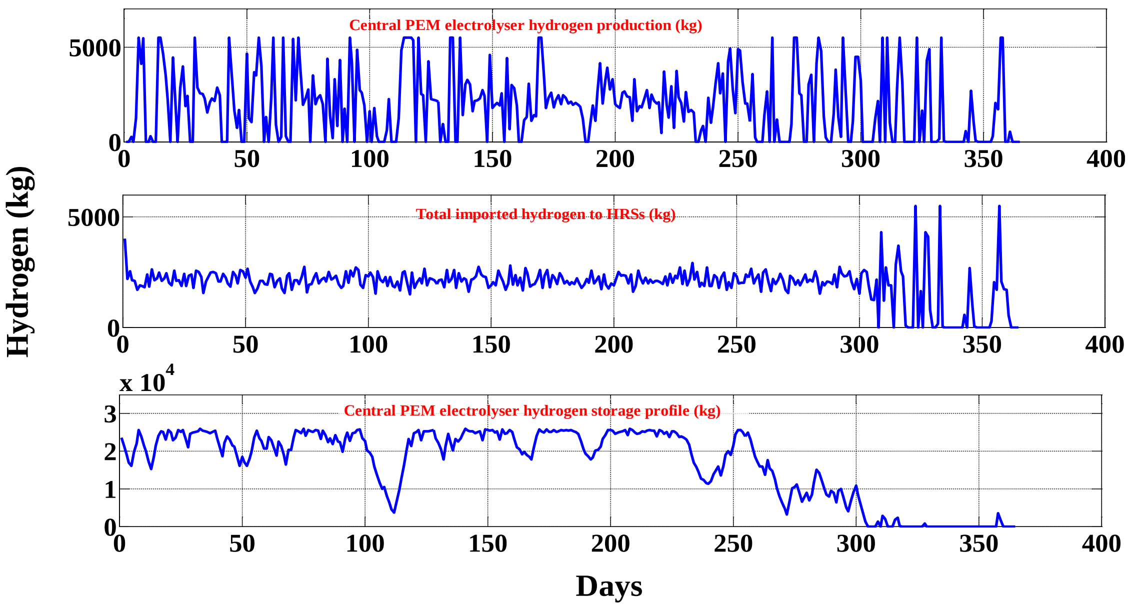


Figure 9.26: Central hydrogen production, hydrogen imported at HRSs and central storage profile (5,495 kg/day PEM central electrolyser (Cen. PEME Sc. 7)) under 2030-Cost scenario

The amount of hydrogen imported is less than that produced for the period between day 1 and day 304 with the rest staying in storage, after this period the central storage became empty and the amount of hydrogen imported to HRSs is very similar to the production of hydrogen at the central electrolyser. Figure 9.27 shows the imported hydrogen at each HRS and Figure 9.28 shows the daily variation of hydrogen level in storage tank throughout the year for the central size of electrolyser (Cen. PEME Sc. 7).

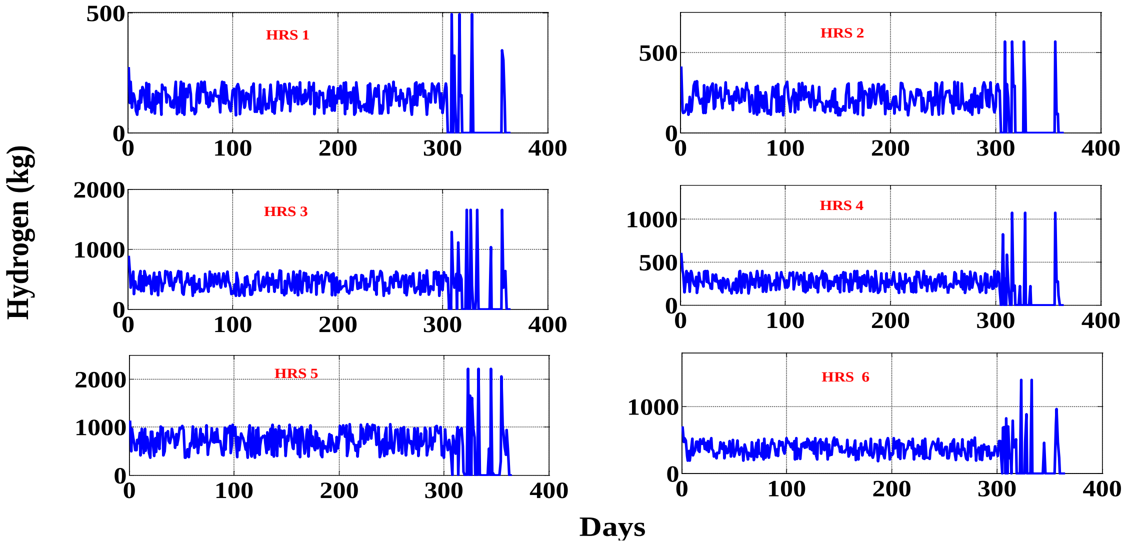


Figure 9.27: Imported hydrogen at each garage forecourt throughout the year (5495 kg/day PEM central electrolyser (Cen. PEME Sc. 7)) under 2030-Cost scenario

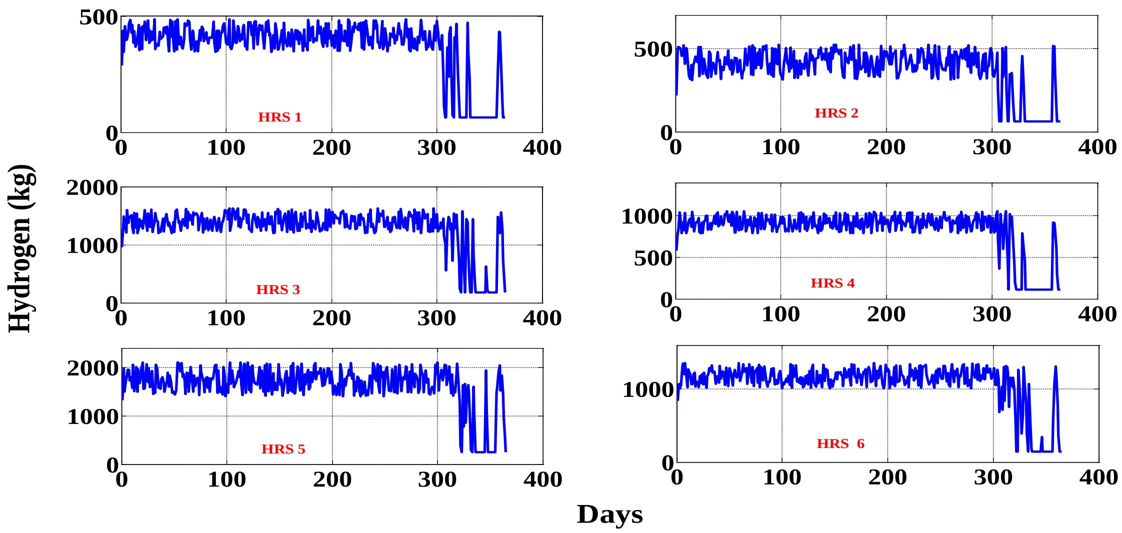


Figure 9.28: Daily variation of hydrogen level in storage tank throughout the year (5495 kg/day PEM central electrolyser (Cen. PEME Sc. 7)) under 2030-Cost scenario

This system size does not result in any significant change in terms of energy consumption when compared with the previous size (Cen. PEME Sc. 6); 68% of the energy is consumed at the previous size, whereas 69% is absorbed with this size. The reason can be understood from the maximum production times for each size: the previous size's maximum production occurred 48 times over the year while the maximum production with this size occurred only 32 times during the year. Figure 9.29, Figure 9.30 and Figure 9.31 summaries this scenario with the longest size of electrolyser (Cen. PEME Sc. 8).

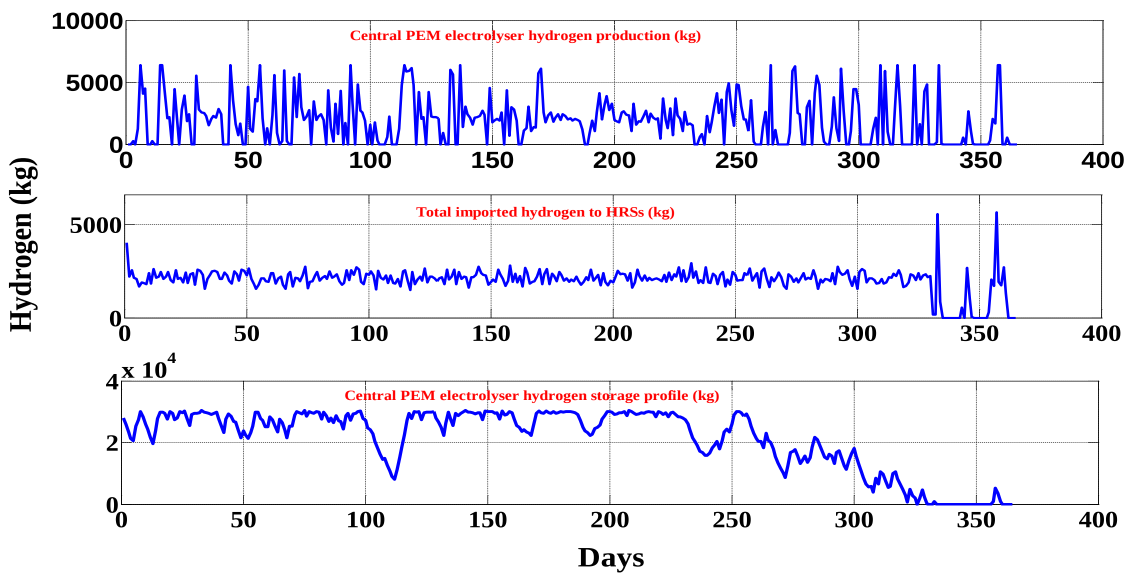


Figure 9.29: Central hydrogen production, hydrogen imported at HRSs and central storage profile (6410 kg/day PEM central electrolyser (Cen. PEME Sc. 8)) under 2030-Cost scenario

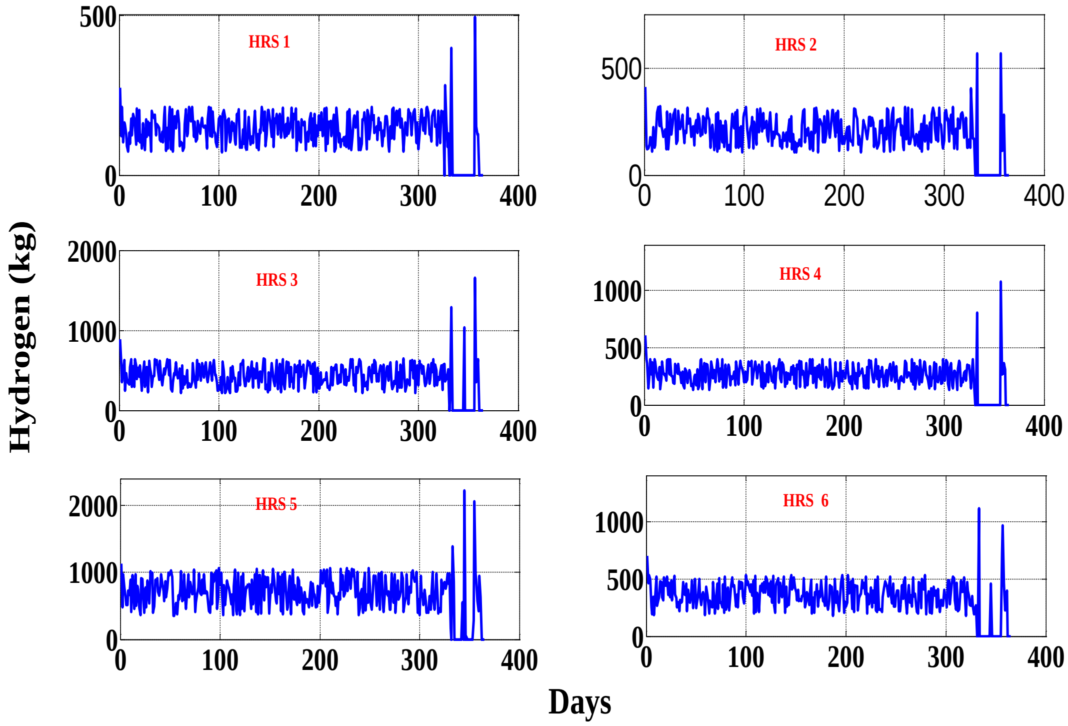


Figure 9.30: Imported hydrogen at each garage forecourt throughout the year (6410 kg/day PEM central electrolyser (Cen. PEME Sc. 8)) under 2030-Cost scenario

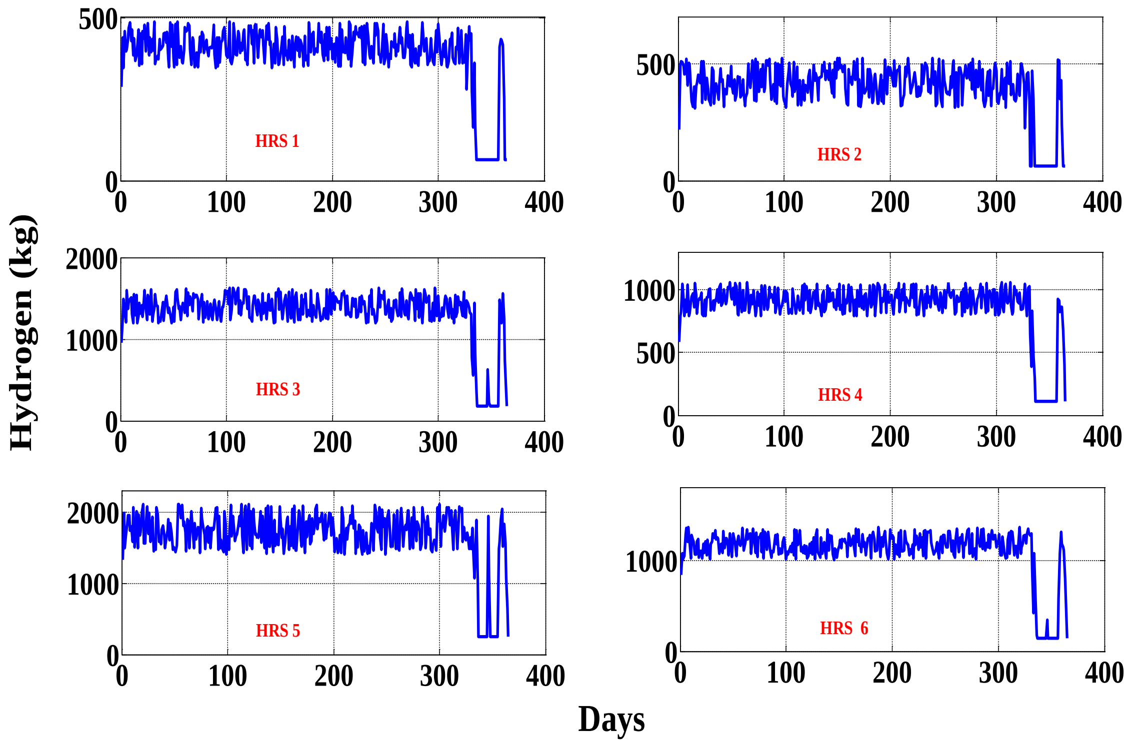


Figure 9.31: Daily variation of hydrogen level in storage tank throughout the year (6410 kg/day PEM central electrolyser (Cen. PEME Sc. 8)) under 2030-Cost scenario

Table 9.9 below shows a summary of 2030-Cost scenario under different system sizes.

Scenario	HRS	HRS 1	HRS 2	HRS 3	HRS 4	HRS 5	HRS 6
Cen. PEME Sc. 5	Satisfaction of Hydrogen demand (%)	25	34	77	51	88	67
	Average hydrogen price (£/kg)	10.20	8.30	7.20	8.10	6.70	7.40
	Total surplus energy consumed (%)	51					
	Satisfaction of total hydrogen demand for HRSs (%)	68					
	Average central electrolyser hydrogen price (£/kg)	5.70					
Cen. PEME Sc. 6	Satisfaction of Hydrogen demand (%)	87	87	92	89	94	92
	Average hydrogen price (£/kg)	8.80	8.50	8.70	8.90	8.50	8.80
	Total surplus energy consumed (%)	68					
	Satisfaction of total hydrogen demand for HRSs (%)	92					
	Average central electrolyser hydrogen price (£/kg)	7.50					
Cen. PEME Sc. 7	Hydrogen demand satisfaction (%)	89	89	94	91	95	93
	Average hydrogen price (£/kg)	9.50	9.30	9.50	9.60	9.30	9.50
	Total energy consumed (%)	69					
	Total hydrogen demand satisfaction (%)	93					
	Average central electrolyser hydrogen price (£/kg)	8.30					
Cen. PEME Sc. 8	Hydrogen demand satisfaction (%)	94	93	95	95	96	94
	Average hydrogen price (£/kg)	10.50	10.20	10.50	10.60	10.30	10.50
	Total energy consumed (%)	70					
	Total hydrogen demand satisfaction (%)	95					
	Average central electrolyser hydrogen price (£/kg)	9.30					

Table 9.9: Economic assessment of this scenario under different system component sizes under 2030-Cost scenario

This scenario will absorb only 1% more at the surplus energy than the previous size, even with its considerable increase in investment costs (nearly 15% higher for this size). The energy price of this scenario under different electrolyser sizes fluctuates between £0.0351/kWh and £0.0353 /kWh.

9.7 Potential economic benefits of previous scenarios through CO_2 reduction

Regardless of the environmental benefit that can be achieved when renewable energy sources are integrated into the energy system and hydrogen is used as a replacement for fossil fuel, the economic benefits are the main engine of any project. So, the economic benefits that can be gained due to deployment of renewable sources will be assessed. Economic benefits can be determined in different ways based on the intention of the government. In other words, if the target is to reduce the CO_2 emissions, some fossil fuel production must be cut and replaced by renewable energy sources and hydrogen.

There are also 'external cost' arising from the use of fossil fuels, which include the cost of dealing with negative environmental and health effects. The use of CO_2 taxes is a way of internalising external cost.

The economic benefits of this scenario can be obtained by the introduction of the CO_2-based taxes. Another option to gain economic benefits is to keep the oil production at the same levels when the renewable energy integration starts, and rather than being used for local consumption, it can be used to increase oil export levels, which in turn will lead to an increase in income, but with the same levels of CO_2 emission. Two potential benefits will be tested under all previous scenarios in Chapter 8.

9.7.1 CO_2 emission reduction and associated benefits (reduction in fossil use due to renewable energy integration into the grid)

In this case, there are two components that need to be calculated, namely those of the energy injected to the grid and used to meet demand, and the surplus energy that is exploited to produce hydrogen. However, the calculation in this case will be based on the fossil fuel reduction when the hydrogen is used as a substitute. Figure 9.32 below explains the CO_2 reduction process.

The cost of any CO_2 produced differs between countries. In the UK, this cost will increase to £116.05 $/tCO_2e$ by 2030. Total energy consumed can be straightforwardly calculated since the total energy production via renewable energy and the surplus energy are known (UK Government, 2016).

$$Total\ consumed\ energy = total\ RE\ energy\ production - total\ surplus\ energy \qquad (9.3)$$

$$Total\ consumed\ energy = 143481 - 47488 = 95993\ MWh$$

Based on the general electricity company of Libya, the Libyan emission factor is 0.8843 $tCO_2\ /MWh$ in 2012. So, the total CO_2 emissions from energy sources that will be replaced by the renewable energy can be calculated as in Equation (9.4).

$$Total\ CO_2\ emissions = total\ consumed\ energy \times CO_2\ emission\ factor \qquad (9.4)$$

$$Total\ CO_2\ \ emissions\ =\ 95993 \times 0.8843 = 84887\ tCO_2e$$

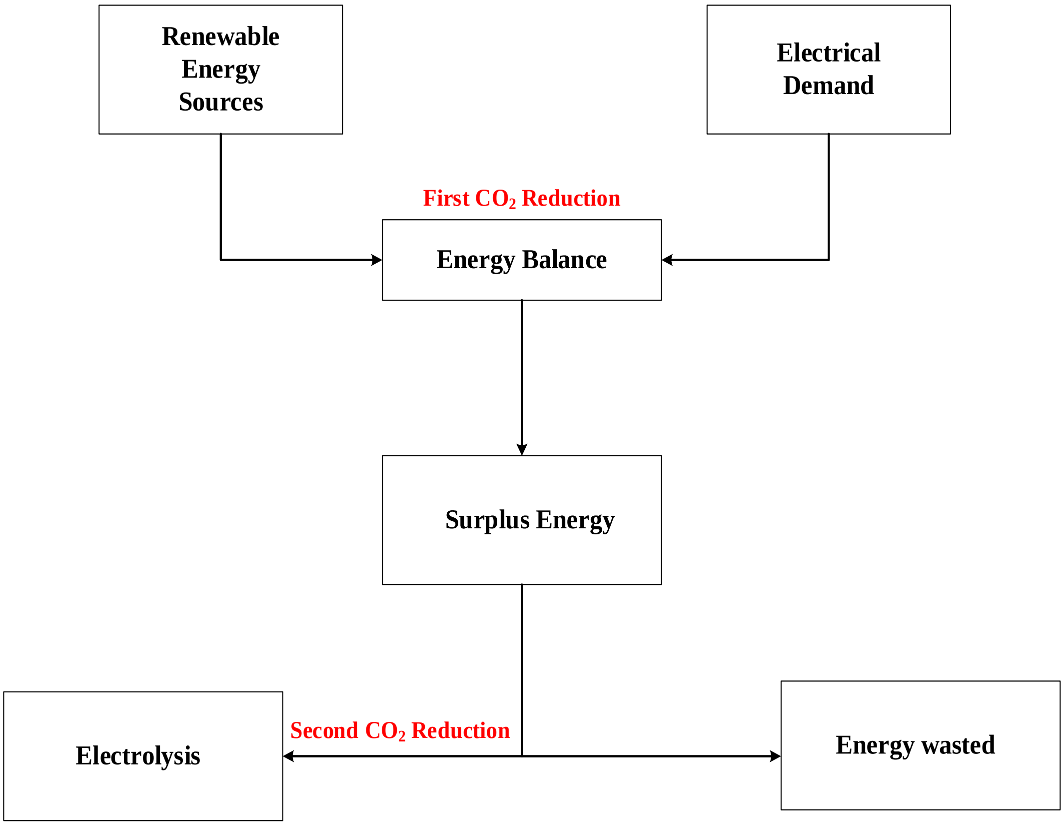


Figure 9.32: Summary of CO_2 reduction process

The social cost of carbon (SCC) in Libya seems to be ambiguous and difficult to estimate and thus an assumption will be applied for 2015 and future (2030) prices based on the prices in (Litterman, 2013). In this paper, the 2015 SCC is small at nearly \$10/ $tCO2$ (£7.76/ $t\mathrm{CO}_2$), whilst a future price of between \$$100 - 200$/ $t\mathrm{CO}_2$ will be assumed to be \$150 / $t\mathrm{CO}_2$ (£116.42/ $t\mathrm{CO}_2$), as based on 2017 exchange rates.

Based on these prices, the monetary savings that can be achieved due to the energy used in the electricity sector can be computed as follows:

$$Current\ total\ money\ saving\ =\ Total\ \mathrm{CO}_2\ emissions \times SCC_{current} \qquad (9.5)$$
$$Current\ total\ money\ saving\ =\ 84887 \times 7.76 = 658{,}723\ £$$

$$Future\ total\ money\ saving\ =\ Total\ \mathrm{CO}_2\ emissions \times SCC_{future} \qquad (9.6)$$

$$Future\ total\ money\ saving\ = 84887 \times 116.42 = 9{,}882{,}545\ £$$

The future monetary saving is promising, and could well encourage many companies and states to reduce their emissions, in contrast with the low savings that are currently possible.

The cost reduction due to the use of hydrogen as a fuel instead of fossil fuels will be calculated in all scenarios under the 2015- and 2030-Cost scenarios for alkaline and PEM electrolysers.

Because of difficulties in determining CO_2 emissions in the case of Libya, the latest available information from the UK will be applied (UK Government, 2016). Based on this information, burning 1 ton of fossil fuel (mainly diesel) will produce around 3,108.5 $kgCO_{2_e}$.

Meeting hydrogen demand in each scenario represents an equivalent fossil fuel reduction, and thus the cost can be calculated for the 2015 and future costs of *SCC*. The calculation steps are presented in Figure 9.33 .

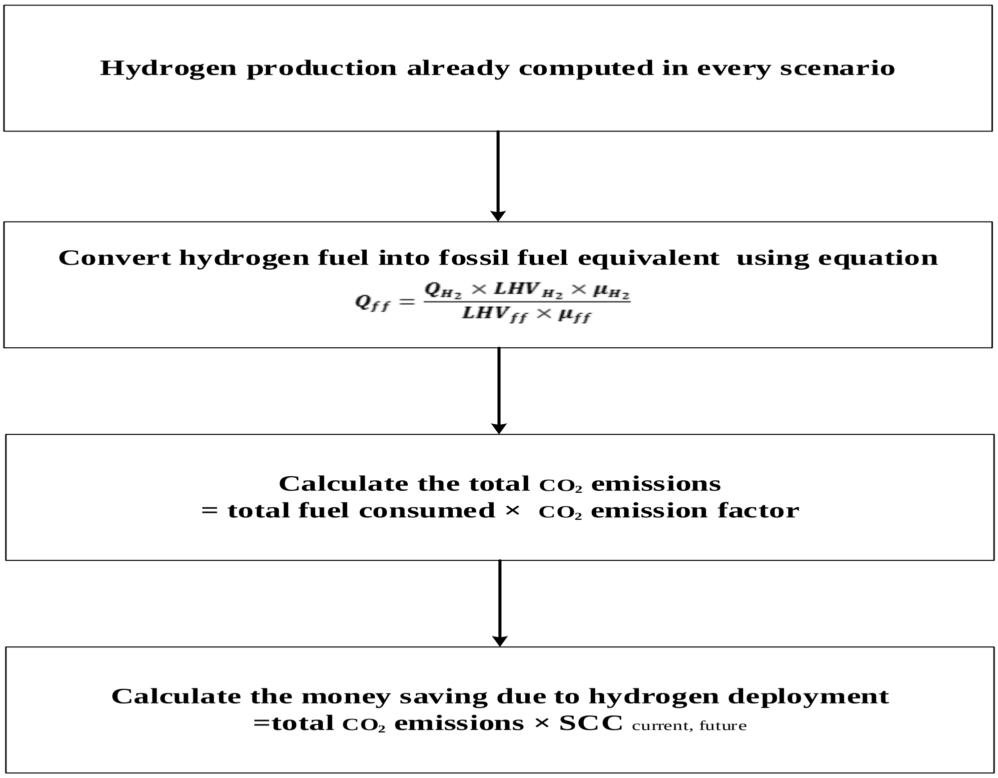


Figure 9.33: Process of saving money due to hydrogen energy penetration

The total savings for the system under the 2015- and 2030-Cost scenarios can be calculated by Equation (9.7)

$$Total\ monetary\ savings\ = total\ \text{money saved from}\ energy +\ total\ \text{money saved from}\ fuel \qquad (9.7)$$

A summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for alkaline operation under the 2015-Cost scenario is presented in Table 9.10. In this scenario, due to the lower cost of *SCC*, the total savings resulting from fuel and energy reduction does not represent any real incentive to encourage governments to reduce emissions, at least from an economic perspective. However, in the future scenario, the *SCC* will be considerably higher in order to enhance renewable energy penetration.

Table 9.11 shows the summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for alkaline operation and under the 2030-Cost scenario. A summary of the total monetary savings for alkaline electrolyser operation under the 2015- and 2030-Cost scenarios due to replacing conventional sources of electricity and fuel by renewable energy sources are presented in Table 9.12 and Table 9.13, respectively.

PEME scenarios are very similar to alkaline electrolyser scenarios, showing very little difference in CO_2 emission reductions or monetary savings due to the overall system efficiency. Table 9.14 and Table 9.15 show the Summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for PEM under the 2015 and 2030-cost scenarios, respectively, whereas Table 9.16 and Table 9.17 represent the total monetary savings due to fossil source reductions, in terms of both energy and fuel.

There is no clear difference between the savings derived from alkaline or PEM electrolysers. The electrolyser efficiency could, relatively speaking, affect monetary savings. In 2030, PEM electrolysis savings are expected to be higher than those from alkaline electrolysers due to the anticipated efficiency improvements in the former technology. This efficiency improvement should lead to increased hydrogen production and less fossil fuel consumption, and thus greater monetary savings. Generally, the improvement characteristics have a direct impact on average hydrogen prices.

Alkaline electrolyser, 2015-Cost scenario						
Scenarios \ Cost			Total hydrogen production (ton/year)	Total fossil fuel reduction (ton/year)	Total CO2 reduction (tCO_{2_e}/year)	Total saving (£/year)
LAE Sc. 1			469	3,243	10,081	78,226
Increase the system size	LAE Sc. 2		583	4,032	12,533	97,258
	Triple default electrolyser size	LAE Sc. 3	627	4,339	13,487	10,4662
		LAE Sc. 4	659	4,556	14,162	109,895
		LAE Sc. 5	682	4,719	14,668	113,820
Central electrolyser operates under a different electricity settlement price to HRSs		LAE Sc. 6	588	4,068	12,644	98,121
		LAE Sc. 7	635	4,393	13,656	105,971
		LAE Sc. 8	674	4,664	14,499	112,512
		LAE Sc. 9	698	4,827	15,005	116,437
Central electrolyser operates under the same electricity settlement price as the HRSs		LAE Sc. 11	588	4,068	12,644	98,121
		LAE Sc. 12	635	4,393	13,656	105,971
		LAE Sc. 13	674	4,664	14,499	112,512
		LAE Sc. 14	698	4,827	15,005	116,437

Table 9.10: Summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for alkaline electrolyser and under the 2015-Cost scenario

Alkaline electrolyser- 2030-Cost scenario						
Scenarios \ Cost			Total hydrogen production (ton/year)	Total fossil fuel reduction (ton/year)	Total CO2 reduction (tCO_{2_e}/year)	Total saving (£/year)
LAE Sc. 16			511	3,532	10,980	1,278,292
Increase the system size	LAE Sc. 17		610	4,216	13,107	1,525,917
	Triple default electrolyser size	LAE Sc. 18	651	4,502	13,993	1,629,065
		LAE Sc. 19	682	4,719	14,668	1,707,649
		LAE Sc. 20	698	4,827	15,005	1,746,882
Central electrolyser operates under a different electricity settlement price to HRSs		LAE Sc. 21	612	4,230	13,150	1,530,923
		LAE Sc. 22	659	4,556	14,162	1,648,740
		LAE Sc. 23	690	4,773	14,836	1,727,207
		LAE Sc. 24	714	4,935	15,342	1,786,116
Central electrolyser operates under the same electricity settlement price as the HRSs		LAE Sc. 26	612	4,230	13,150	1,530,923
		LAE Sc. 27	659	4,556	14,162	1,648,740
		LAE Sc. 28	690	4,773	14,836	1,727,207
		LAE Sc. 29	714	4,935	15,342	1,786,116

Table 9.11: Summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for alkaline electrolyser and under the 2030-Cost scenario

Alkaline electrolyser, 2015-Cost scenario					
Scenarios / Cost			Money saved (£/year) (energy reduction)	Money saved (£/year) (fuel reduction)	Total saving (£/year)
LAE Sc. 1			658,723	78,226	736,949
Increase the system size	LAE Sc. 2		658,723	97,258	755,981
	Triple default electrolyser size	LAE Sc. 3	658,723	104,662	763,385
		LAE Sc. 4	658,723	109,895	768,618
		LAE Sc. 5	658,723	113,820	772,543
Central electrolyser operates under a different electricity settlement price to HRSs		LAE Sc. 6	658,723	98,121	756,844
		LAE Sc. 7	658,723	105,971	764,694
		LAE Sc. 8	658,723	112,512	771,235
		LAE Sc. 9	658,723	116,437	775,160
central electrolyser operates under the same electricity settlement price as the HRSs		LAE Sc. 11	658,723	98,121	756,844
		LAE Sc. 12	658,723	105,971	764,694
		LAE Sc. 13	658,723	112,512	771,235
		LAE Sc. 14	658,723	116,437	775,160

Table 9.12: Summary of total cost reduction due to renewable energy and hydrogen fuel penetration of alkaline electrolyser under the 2015-Cost scenario

Alkaline electrolyser, 2030-Cost scenario					
Scenario / Cost			Money saved (£/year) (energy reduction)	Money saved (£/year) (fuel reduction)	Total saving (£/year)
LAE Sc. 16			9,882,545	1,278,292	11,160,837
Increase the system size	LAE Sc. 17		9,882,545	1,525,917	11,408,462
	Triple default electrolyser size	LAE Sc. 18	9,882,545	1,629,065	11,511,610
		LAE Sc. 19	9,882,545	1,707,649	11,590,194
		LAE Sc. 20	9,882,545	1,746,882	11,629,427
Central electrolyser operates under a different electricity settlement price to HRSs		LAE Sc. 21	9,882,545	1,530,923	11,413,468
		LAE Sc. 22	9,882,545	1,648,740	11,531,285
		LAE Sc. 23	9,882,545	1,727,207	11,6097,52
		LAE Sc. 24	9,882,545	1,786,116	11,668,661
central electrolyser operates under the same electricity settlement price as the HRSs		LAE Sc. 26	9,882,545	1,530,923	11,413,468
		LAE Sc. 27	9,882,545	1,648,740	11,531,285
		LAE Sc. 28	9,882,545	1,727,207	11,609,752
		LAE Sc. 29	9,882,545	1,786,116	11,668,661

Table 9.13: Summary of total cost reduction due to renewable energy and hydrogen fuel penetration of alkaline electrolyser under the 2030-Cost scenario

PEM electrolyser, 2015-Cost scenario							
Scenario \ Cost			**Total hydrogen production** (ton/year)	**Total fossil fuel reduction** (ton/year)	**Total CO2 reduction** (tCO_{2_e}/year)	**Total saving** (£/year)
PEME Sc. 1			468	3,241	10,073	78,168
Increase the system size	**PEME Sc. 2**		562	3,890	12,092	93,833
	Triple default electrolyser size	**PEME Sc. 3**	612	4,230	13,150	102,046
		PEME Sc. 4	651	4,502	13,993	108,587
		PEME Sc. 5	674	4,664	14,499	112,512
Central electrolyser operates under a different electricity settlement price to HRSs		**PEME Sc. 6**	588	4,068	12,644	98,121
		PEME Sc. 7	635	4,393	13,656	105,971
		PEME Sc. 8	674	4,664	14,499	112,512
		PEME Sc. 9	698	4,827	15,005	116,437
central electrolyser operates under the same electricity settlement price as the HRSs		**PEME Sc. 11**	588	4,068	12,644	98,121
		PEME Sc. 12	635	4,393	13,656	105,971
		PEME Sc. 13	674	4,664	14,499	112,512
		PEME Sc. 14	698	4,827	15,005	116,437

Table 9.14: Summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for PEME under the 2015-Cost scenario

PEM electrolyser- 2030-Cost scenario						
Scenario \ Cost			**Total hydrogen production** (ton/year)	**Total fossil fuel reduction** (ton/year)	**Total CO2 reduction** (tCO_{2_e}/year)	**Total saving** (£/year)
PEME Sc. 16			539	3,725	11,579	1,347,990
Increase the system size	**PEME Sc. 17**		617	4,274	13,286	1,546,780
	Triple default electrolyser size	**PEME Sc. 18**	666	4,610	14,330	1,668,342
		PEME Sc. 19	698	4,827	15,005	1,746,852
		PEME Sc. 20	721	4,990	15,511	1,805,737
Central electrolyser operates under a different electricity settlement price to HRSs		**PEME Sc. 21**	635	4,393	13,656	1,589,832
		PEME Sc. 22	674	4,664	14,499	1,687,974
		PEME Sc. 23	706	4,881	15,173	1,766,482
		PEME Sc. 24	729	5,044	15,679	1,825,364
central electrolyser operates under the same electricity settlement price as the HRSs		**PEME Sc. 26**	635	4,393	13,656	1,589,832
		PEME Sc. 27	674	4,664	14,499	1,687,974
		PEME Sc. 28	706	4,881	15,173	1,766,482
		PEME Sc. 29	729	5,044	15,679	1,825,364

Table 9.15: Summary of CO_2 reduction and monetary savings due to hydrogen fuel penetration for PEM electrolyser under the 2030-Cost scenario

PEM electrolyser, 2015-Cost scenario						
Scenario \ Cost			Money saved (£/year) (energy reduction)	Money saved (£/year) (fuel reduction)	Total saving (£/year)
PEME Sc. 1			658,723	78,168	736,949
Increase the system size	**PEME Sc. 2**		658,723	93,833	755,981
	Triple default electrolyser size	**PEME Sc. 3**	658,723	102,046	763,385
		PEME Sc. 4	658,723	108,587	768,618
		PEME Sc. 5	658,723	112,512	772,543
Central electrolyser operates under a different electricity settlement price to HRSs		**PEME Sc. 6**	658,723	98,121	756,844
		PEME Sc. 7	658,723	105,971	764,694
		PEME Sc. 8	658,723	112,512	771,235
		PEME Sc. 9	658,723	116,437	775,160
central electrolyser operates under the same electricity settlement price as the HRSs		**PEME Sc. 11**	658,723	98,121	756,844
		PEME Sc. 12	658,723	105,971	764,694
		PEME Sc. 13	658,723	112,512	771,235
		PEME Sc. 14	658,723	116,437	7751,60

Table 9.16: Summary of total cost reduction due to renewable energy and hydrogen fuel penetration of PEM electrolyser under the 2015-Cost scenario

PEM electrolyser- 2030-Cost scenario					
Scenario \ Cost			Money saved (£/year) (energy reduction)	Money saved (£/year) (fuel reduction)	Total saving (£/year)
PEME Sc. 16			9,882,545	1,347,990	11,230,535
Increase the system size	**PEME Sc. 17**		9,882,545	1,546,780	11,429,325
	Triple default electrolyser size	**PEME Sc. 18**	9,882,545	1,668,342	11,550,887
		PEME Sc. 19	9,882,545	1,746,852	11,629,397
		PEME Sc. 20	9,882,545	1,805,737	11,688,282
Central electrolyser operates under a different electricity settlement price to HRSs		**PEME Sc. 21**	9,882,545	1,589,832	11,472,377
		PEME Sc. 22	9,882,545	1,687,974	11,570,519
		PEME Sc. 23	9,882,545	1,766,482	11,649,027
		PEME Sc. 24	9,882,545	1,825,364	11,707,909
central electrolyser operates under the same electricity settlement price as the HRSs		**PEME Sc. 26**	9,882,545	1,589,832	11,472,377
		PEME Sc. 27	9,882,545	1,687,974	11,570,519
		PEME Sc. 28	9,882,545	1,766,482	11,649,027
		PEME Sc. 29	9,882,545	1,825,364	11,707,909

Table 9.17: Summary of total cost reduction due to renewable energy and hydrogen fuel penetration of PEM electrolyser under the 2030-Cost scenario

9.7.2 Exporting crude oil instead of stopping production

The total energy consumed via the electricity sector and the production of hydrogen fuel is equal to the energy which could be exported as a fuel. Two cost scenarios, under operation of two common types of electrolyser, will be investigated. The current fuel prices are 69.69 LD/barrel (£34.85/barrel) of oil and for barrel of oil equivalent (boe) natural gas the price was 21.17 LD (£11.61) in 2015 (Agha and Zaed, 2013; bloomberg, 2017). In Libya, the power sector is fuelled by a variety of oil and natural gas resources. Based on the renewable GECOL reports in 2012, the total fuel consumption by the electricity sector was 10,197 thousand tonne of oil equivalent (toe), of this, 65% is supplied by natural gas, 23% from light fuel oil and 12% from heavy fuel oil (Agha and Zaed, 2013; GECOL, 2012). 65% of the fuel saved in the power sector could be exported as natural gas and 35% as oil. The emissions during the natural gas and oil extraction process should be calculated and subtracted from the revenue generated by sales of fuel. The general formula to calculate the profit due to renewable energy penetration plus the sale of fuel is given below.

$$Revenue = F.S + \mathrm{E.r}_{CO2} + \mathrm{F.r}_{CO2} - \mathrm{E.c}_{CO2} \qquad (9.8)$$

Where $F.S$ is fuel sales, $\mathrm{E.r}_{\mathrm{CO_2}}$ is the monetary saving due to the reduction of CO_2 emissions in electricity generation. $\mathrm{F.r}_{\mathrm{CO_2}}$ is the monetary saving due to the reduction of CO_2 from fuel use and $\mathrm{E.c}_{CO2}$ are CO_2 emissions due to oil and natural gas extraction. The world average of CO_2 emission intensity for oil and gas extraction is $130\ kg\ \mathrm{CO_2}/toe$ (Gavenas, Rosendahl and Skjerpen, 2015). Equation (9.9) shows the fuel sale calculation.

$$F.S = \mathrm{NG\_export} \times \mathrm{NG\_price} + \mathrm{Oil\_export} \times \mathrm{Oil\_price} \qquad (9.9)$$

$\mathrm{E.r}_{\mathrm{CO_2}}$ and $\mathrm{F.r}_{\mathrm{CO_2}}$ are calculated in the last scenario where oil production reduced in response to renewable energy generation, whereas $E.c_{CO2}$ can be calculated from Equation (9.10):

$$E.c_{CO2} = CO_2\mathrm{\_emissions} \times \mathrm{SCC} \qquad (9.10)$$

This scenario is clearly better than the previous scenario from an economic perspective because more money will be earned from selling the oil and natural gas. The effect of carbon tax credit is very low due to *SCC* having low values.

Table 9.18 and Table 9.20 shows the 2015-cost scenarios under alkaline and PEM operation, respectively, whereas Table 9.19 and Table 9.21 show the future scenario for both electrolysers.

Future oil prices are assumed to be higher than current prices, based on various recent studies and reports (Lee and Huh, 2017; eia, 2017; eia, 2016). It is anticipated to fluctuate between $\$111$ and $\$131\ /\mathrm{Bbl}$ (assumed to be $\$121/\mathrm{Bbl} \approx £93.65/\mathrm{Bbl}$, whereas the future price for natural gas is projected to be low, at between $\$5$ and $\$6\ /\mathrm{million\ Btu} \approx £4.266\ /\mathrm{million\ Btu}$ (eia, 2017; eia, 2016).

In terms of the central electrolyser only, the satisfaction of hydrogen demand and energy consumption are similar to the onsite electrolyser scenarios, so the CO_2 reduction calculation will be similar to those of the previous calculations.

Alkaline electrolyser, 2015-Cost scenario							
Scenario \ Cost			**Total saving money** ($E.r_{CO_2} + F.r_{CO_2}$) (£/year)	**Fuel sale** ($F.S$) (£/year)	**CO_2 emission cost** ($E.c_{CO_2}$) (£/year)	**Revenue** (£/year)
LAE Sc. 1			736,949	1,164,043	8,329	1,892,663
Increase the system size	**LAE Sc. 2**		755,981	1,164,045	8,330	1,911,696
	Triple default electrolyser size	**LAE Sc. 3**	763,385	1,164,045	8,330	1,919,100
		LAE Sc. 4	768,618	1,164,045	8,330	1,924,333
		LAE Sc. 5	772,543	1,164,046	8,330	1,928,259
Central electrolyser operates under a different electricity settlement price to HRSs		**LAE Sc. 6**	756,844	1,164,045	8,330	1,912,559
		LAE Sc. 7	764,694	1,164,045	8,330	1,920,409
		LAE Sc. 8	771,235	1,164,046	8,330	1,926,951
		LAE Sc. 9	775,160	1,164,046	8,330	1,930,876
central electrolyser operates under the same electricity settlement price as the HRSs		**LAE Sc. 11**	756,844	1,164,045	8,330	1,912,559
		LAE Sc. 12	764,694	1,164,045	8,330	1,920,409
		LAE Sc. 13	771,235	1,164,046	8,330	1,926,951
		LAE Sc. 14	775,160	1,164,046	8,330	1,930,876

Table 9.18: Summary of oil sale scenario for alkaline electrolyser under the 2015-Cost scenario

Alkaline electrolyser, 2030-Cost scenario							
Scenario		**Cost**	**Total saving money** ($E.r_{CO_2} + F.r_{CO_2}$) (£/year)	**Fuel sale** ($F.S$) (£/year)	**CO_2 emission cost** ($E.c_{CO_2}$) (£/year)	**Revenue** (£/year)
LAE Sc. 16			11,160,837	2,507,941	124,554	13,544,224
Increase the system size	**LAE Sc. 17**		11,408,462	2,508,070	124,569	13,791,963
Increase the system size	**Triple default electrolyser size**	**LAE Sc. 18**	11,511,610	2,508,123	124,569	13,895,164
		LAE Sc. 19	11,590,194	2,508,164	124,569	13,973,789
		LAE Sc. 20	11,629,427	2,508,185	124,569	14,013,043
Central electrolyser operates under a different electricity settlement price to HRSs		**LAE Sc. 21**	11,413,468	2,508,073	124,569	13,796,972
		LAE Sc. 22	11,531,285	2,508,134	124,569	13,914,850
		LAE Sc. 23	11,609,752	2,508,174	124,569	13,99,3357
		LAE Sc. 24	11,668,661	2,508,206	124,569	14,052,298
central electrolyser operates under the same electricity settlement price as the HRSs		**LAE Sc. 26**	11,413,468	2,508,073	124,569	13,796,972
		LAE Sc. 27	11,531,285	2,508,134	124,569	13,914,850
		LAE Sc. 28	11,609,752	2,508,174	124,569	13,993,357
		LAE Sc. 29	11,668,661	2,508,206	124,569	14,052,298

Table 9.19: Summary of oil sale scenario for alkaline electrolyser under the 2030-Cost scenario

PEM electrolyser- 2015-Cost scenario						
Scenario		**Cost**	**Total saving money** ($E.r_{CO_2} + F.r_{CO_2}$) (£/year)	**Fuel sale** ($F.S$) (£/year)	**CO_2 emission cost** ($E.c_{CO_2}$) (£/year)	**Revenue** (£/year)
PEME Sc. 1			736,891	1,164,347	8,329	1,892,909
Increase the system size	**PEME Sc. 2**		752,556	1,164,410	8,330	1,908,636
Increase the system size	**Triple default electrolyser size**	**PEME Sc. 3**	760,769	1,164,443	8,330	1,916,882
		PEME Sc. 4	767,310	1,164,468	8,330	1,923,448
		PEME Sc. 5	771,235	1,164,484	8,330	1,927,389
Central electrolyser operates under a different electricity settlement price to HRSs		**PEME Sc. 6**	756,844	1,164,427	8,330	1,912,941
		PEME Sc. 7	764,694	1,164,458	8,330	1,920,822
		PEME Sc. 8	771,235	1,164,484	8,330	1,927,389
		PEME Sc. 9	775,160	1,164,500	8,330	1,931,330
central electrolyser operates under the same electricity settlement price as the HRSs		**PEME Sc. 11**	756,844	1,164,427	8,330	1,912,941
		PEME Sc. 12	764,694	1,164,458	8,330	1,920,822
		PEME Sc. 13	771,235	1,164,484	8,330	1,927,389
		PEME Sc. 14	775,160	1,164,500	8,330	1,931,330

Table 9.20: Summary of oil sale scenario for PEM electrolyser under the 2015-Cost scenario

PEM electrolyser- 2030-Cost scenario						
Scenario / **Cost**			**Total saving money** $(E.r_{CO_2} + F.r_{CO_2})$ (£/year)	**Fuel sale** $(F.S)$ (£/year)	**CO_2 emission cost** $(E.c_{CO_2})$ (£/year)	**Revenue** (£/year)
PEME Sc. 16			11,230,535	2,507,935	124,554	13,613,916
Increase the system size	**PEME Sc. 17**		11,429,325	2,508,031	124,554	13,812,802
	Triple default electrolyser size	**PEME Sc. 18**	11,550,887	2,508,091	124,569	13,934,409
		PEME Sc. 19	11,629,397	2,508,130	124,569	14,012,958
		PEME Sc. 20	11,688,282	2,508,158	124,569	14,071,871
Central electrolyser operates under a different electricity settlement price to HRSs		**PEME Sc. 21**	11,472,377	2,508,053	124,554	13,855,876
		PEME Sc. 22	11,570,519	2,508,101	124,569	13,954,051
		PEME Sc. 23	11,649,027	2,508,140	124,569	14,032,598
		PEME Sc. 24	11,707,909	2,508,168	124,569	14,091,508
central electrolyser operates under the same electricity settlement price as the HRSs		**PEME Sc. 26**	11,472,377	2,508,053	124,554	13,855,876
		PEME Sc. 27	11,570,519	2,508,101	124,569	13,954,051
		PEME Sc. 28	11,649,027	2,508,140	124,569	14,032,598
		PEME Sc. 29	11,707,909	2,508,168	124,569	14,091,508

Table 9.21: Summary of oil sale scenario for PEM electrolyser under the 2030-Cost scenario

The difference between the two possible options in terms of oil and natural gas production when some of the electricity and fuel will be supplied via renewable energy is huge when 2015 prices are applied, even with a clear drop in oil prices. However, by 2030, and due to the increase of SCC, the difference becomes less than the 2015-Cost scenario, although the expectation is for oil prices to be high. It can be said that the main factor driving the move away from fossil fuel, at least when energy comes from renewable resources, is government policy and regulation. For example, increasing the social carbon cost could encourage companies to reduce their fossil fuel usage.

9.8 Summary of the chapter

The first part of this chapter tested the central hydrogen production as a grid-balancing tool, which required hydrogen to be delivered to the HRSs. Generally, this technique is less complex and safer than onsite hydrogen production, especially if the consumption areas are not far from the production site. However, the techno-economic assessments are the criteria under assessment for this project. As presented, different sizes of central electrolyser components, as based on the absorbed amount of surplus energy, have been tested. After that, a general comparison between the central electrolyser and all scenarios of onsite hydrogen production was undertaken. These calculations were further considered for alkaline and PEM electrolysers under two cost scenarios, 2015 and 2030. Increasing the size of the central electrolyser allows for the two main issues, those of energy consumption and satisfaction of hydrogen demand, to be solved, but the average hydrogen price becomes expensive. The 2030-Cost scenario could support central hydrogen production due to allowing for an acceptable price of hydrogen. The last part of this chapter focused on the economic benefits that can be realised from the integration of renewable resources. Two possible options for the economic calculations have been investigated, under two cost scenarios, and for both alkaline and PEM electrolysers. For the first option, due to renewable energy integration into the grid, the same reduction in fossil fuel use will be achieved. The economic benefit will be gained from the CO_2 reduction from the electricity and transportation sectors. The second option is to continue producing and exporting fossil fuels when renewable resources have been fully integrated into the Libyan power system. The assessment showed that the second option is better than the first, especially for the current cost scenario. By 2030, the first option will be competitive with the second option due to the anticipated increase in the social carbon cost, investment cost reduction and system efficiency improvement.

Chapter 10: Comparison of Decentralised and Centralised Hydrogen Production Results

10.1 Introduction

This chapter presents a general comparison and analysis of the scenarios presented in Chapters 8 and 9 to give the reader the chance to understand the differences between these scenarios and also to show their advantages and disadvantages.

Chapter 8 investigated different scenarios of onsite hydrogen production under two different cost scenarios using both alkaline and PEM electrolysis. In Chapter 9, central production was investigated in detail and the potential economic benefits of CO_2 reduction for the scenarios presented in both Chapters 8 and 9 has been calculated.

In this chapter, the onsite and central hydrogen production will be compared and analysed. The main aims of the research in each chapter will be investigated to determine the best options for hydrogen production in the instance of Libya. Only alkaline electrolysis scenarios will be tested because the PEM scenarios are expected to be essentially similar, with only a slight change in hydrogen cost and satisfaction of demand.

10.2 Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 1) versus 2,383 kg/day (Cen. LAE Sc. 1) and 6,410 kg/day (Cen. LAE Sc. 4) central alkaline electrolysers without electrolyser at HRSs (2015-Cost scenario)

In this section, different scenarios for onsite hydrogen production (onsite electrolysis only, with increased system size and finally adding a central unit to the onsite electrolysers) will be compared with central production under the 2015-Cost assumptions for alkaline-type electrolysis. Figure 10.1 shows a comparison of hydrogen demand satisfaction between the LAE Sc. 1 and the Cen. LAE Sc. 1 whereas Figure 10.2 shows a comparison of hydrogen demand satisfaction between the LAE Sc. 1 and the Cen. LAE Sc. 4 for each HRS.

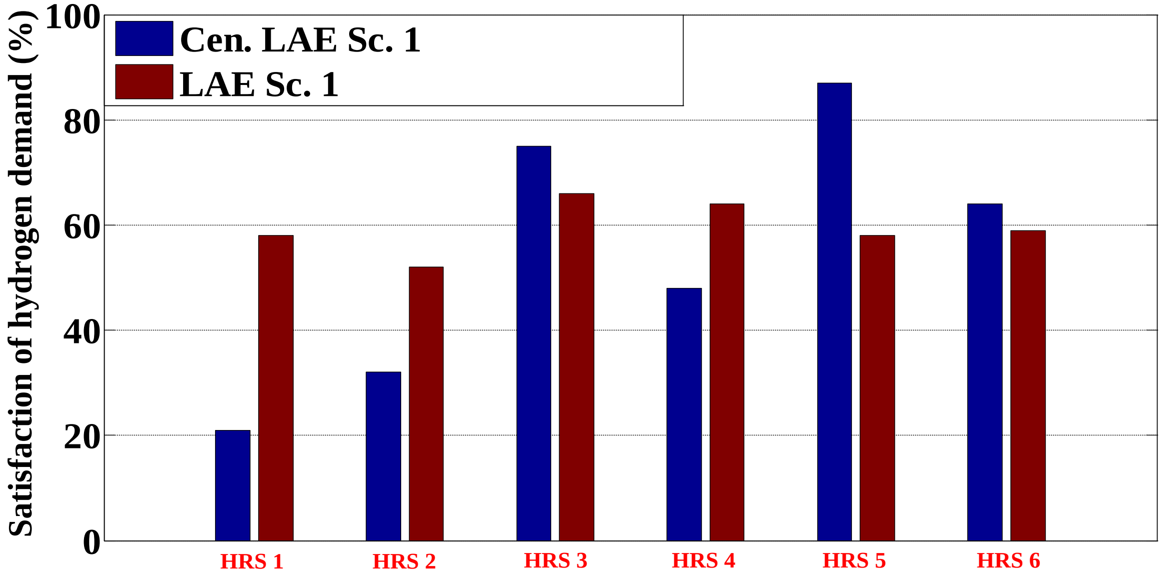


Figure 10.1: Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 1) and 2383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 1)

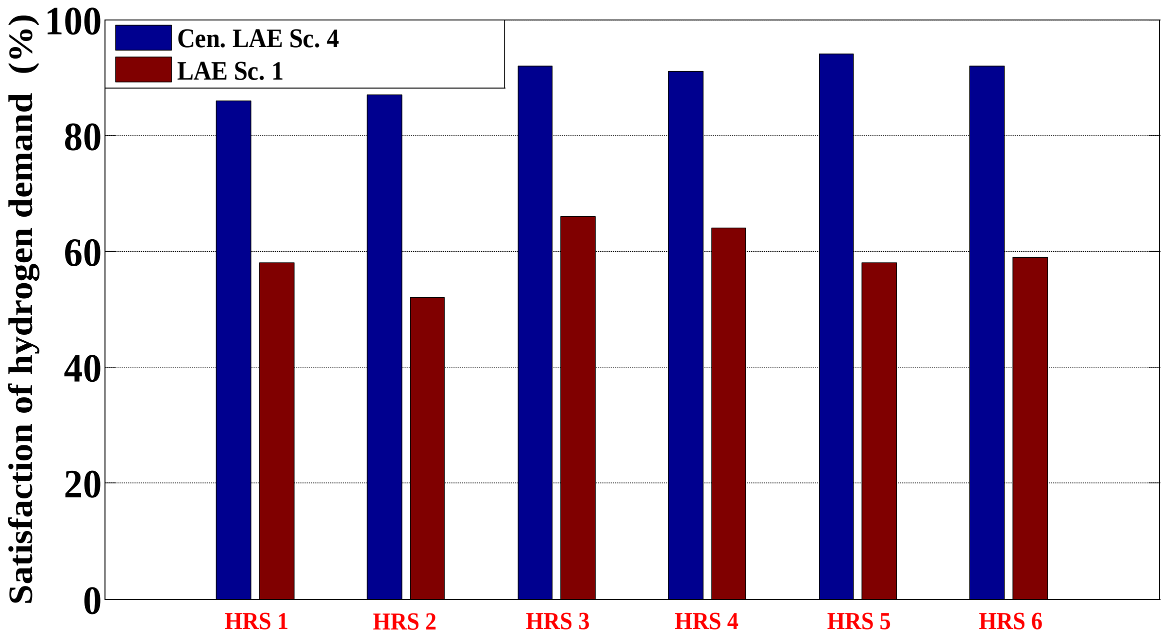


Figure 10.2: Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 1) and 6410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 4)

In the first figure, the level of satisfication of hydrogen demand varies between HRSs, with some HRSs finding that a central unit is better than an onsite, whilst the opposite is seen in others. The interpretation of this is that, for HRSs with high demand (3 and 5), Cen. LAE Sc.

4 and Cen. LAE Sc. 1 is better than LAE Sc. 1. The reason for this is because there is no electricity pricing mechanism for the central production, and demand is met in order of hierarchy from the highest demand to the lowest.

For other HRSs, the first scenario is better because the electricity pricing mechanism gives them the chance to consume hydrogen if its big price has been accepted by the utility company.

From Figure 10.2, it is clear that all HRSs can meet more than 80% of their demand when a Cen. LAE Sc. 4 is used. However, other factors need to be investigated, mainly the average hydrogen price.

Figure 10.3 shows the energy consumed via the LAE Sc. 1, with both a Cen. LAE Sc. 4 and Cen. LAE Sc. It is clear that the energy consumption is increased when the electrolyser size increases. The highest consumption of energy implies a greater chance of achieving grid balancing.

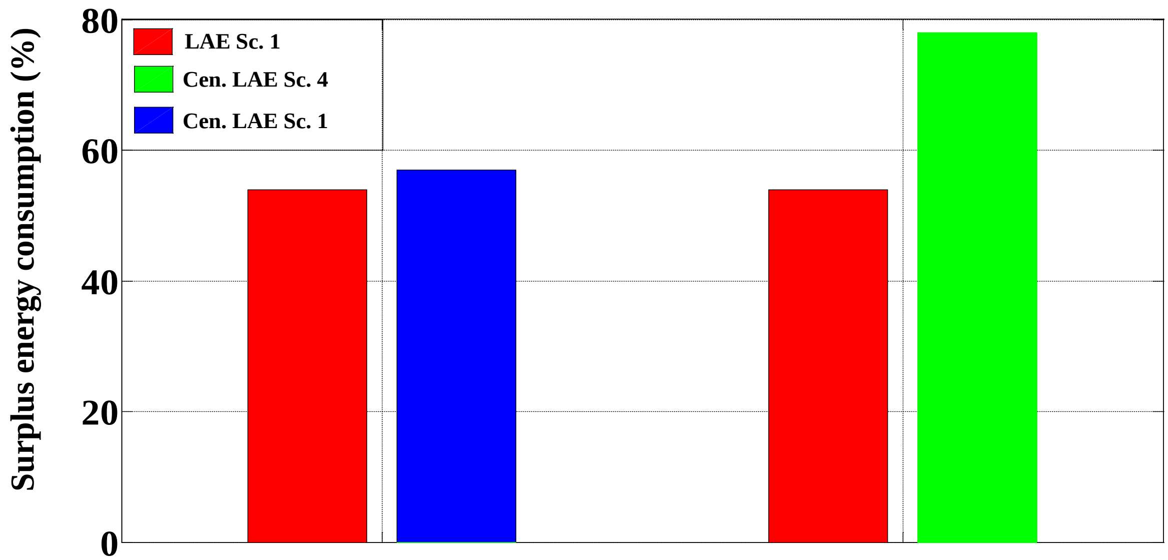


Figure 10.3: Energy consumption of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 1) , 2,383 kg/day(Cen. LAE Sc. 1) and ,6410 kg/day (Cen. LAE Sc. 4) alkaline central electrolysers without electrolyser at the HRSs

Figure 10.4 shows a comparison of average hydrogen price between Cen. LAE Sc. 1 production and LAE Sc. 1 hydrogen production for each HRS.

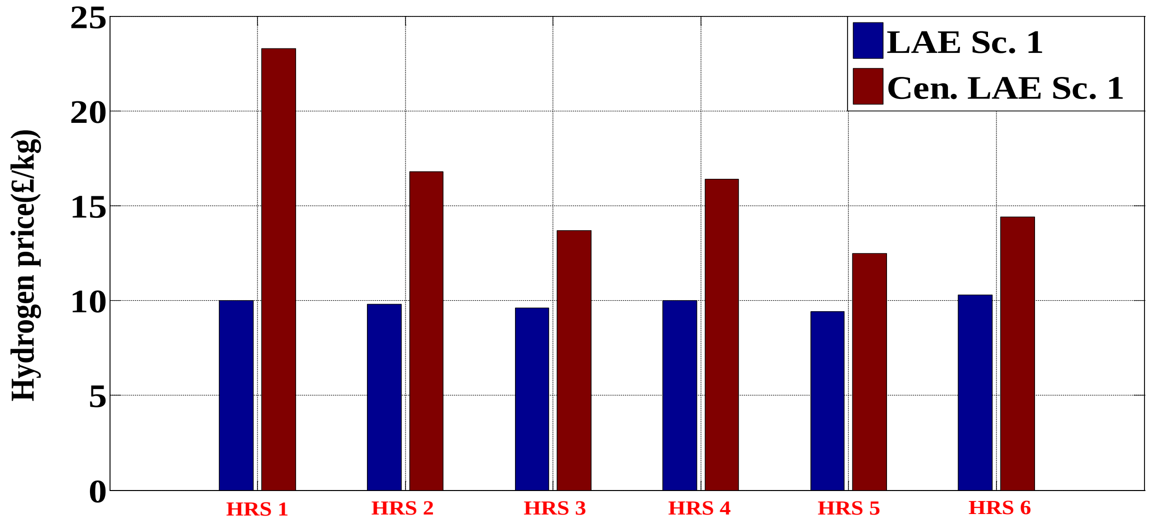


Figure 10.4: Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 1) and 2,383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 1)

Figure 10.5 shows the average hydrogen price per HRS under LAE Sc. 1 and Cen. LAE Sc. 4.

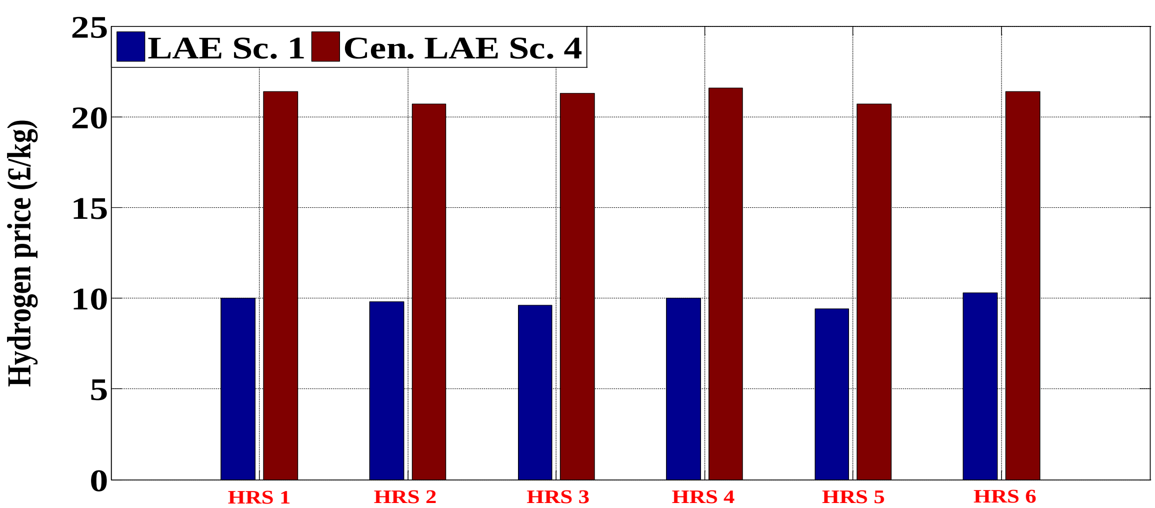


Figure 10.5: Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 1) and 6,410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 4)

As expected, there is a proportional relationship between energy consumption, satisfaction of hydrogen demand and average hydrogen price. For all HRSs, the average hydrogen price for the Cen. LAE Sc. 4 and Cen. LAE Sc (central production) is higher than for LAE Sc. 1.

For the central production, the average hydrogen price is highly variable with a Cen. LAE Sc. 1 compared to a Cen. LAE Sc. 4 due to the variation in hydrogen demand satisfaction levels between HRSs. However, for the Cen. LAE Sc. 4 (large central unit), the hydrogen demand satisfaction of HRSs are closer to each other, which leads to the correlation in hydrogen price between HRSs.

10.3 Double-sized electrolyser (LAE Sc. 2) and Triple-sized electrolyser (LAE Sc. 5) versus 2,383 kg/day (Cen. LAE Sc. 1) and 6,410 kg/day (Cen. LAE Sc. 4) alkaline central electrolysers without electrolyser at the HRSs (2015-Cost scenario)

An increase in system size can tackle the limitations of LAE Sc. 1 hydrogen production. There are two scenarios for increased system sizes (LAE Sc. 2 and LAE Sc. 5), which will be compared with small and large central central electrolyser (LAE Sc. 2 and LAE Sc. 5) sizes. The investigation will include hydrogen demand satisfaction levels, energy consumption and hydrogen price for each HRS. Figure 10.6 presents the levels to which hydrogen demand is satisfied at each HRS when the LAE Sc. 2(Double-sized default electrolyser size) and Cen. LAE Sc. 1 (2,383 kg/day alkaline central electrolysers without electrolyser at the HRSs) are compered.

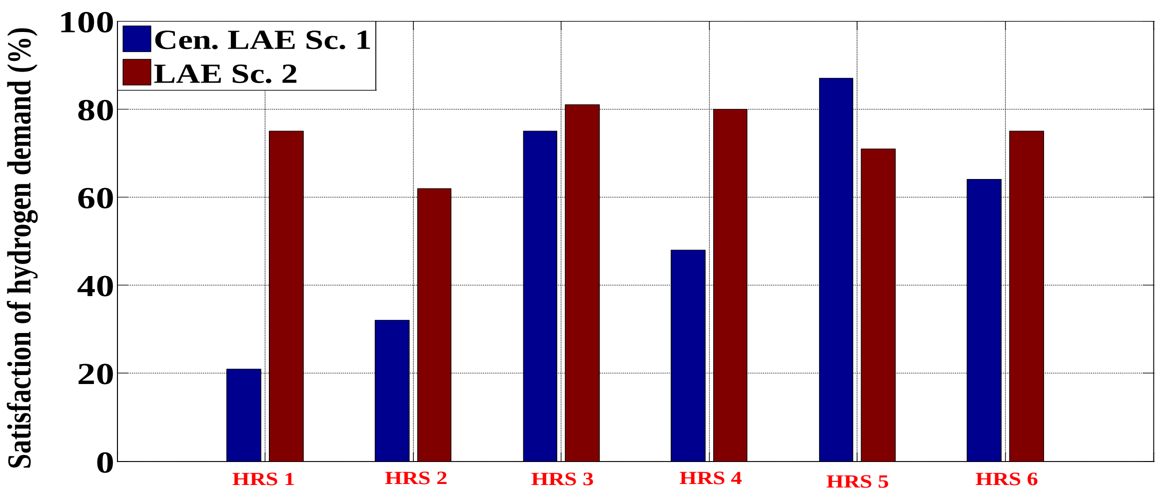


Figure 10.6: Comparison of Double-sized default electrolyser size (LAE Sc. 2) and 2383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 1)

For all HRSs except HRS 5 (the HRS with highest demand), the LAE Sc. 2 (double-sized electrolyser scenario) allowed each to meet a greater hydrogen demand than the Cen. LAE Sc. 1. The electricity pricing mechanism gives all HRSs the ability to be supplied regardless of the central production, which does not have a clear means of selling hydrogen and depends on the hierarchy technique of selling first to the HRS with the highest demand down to the lowest last. Figure 10.7 shows the comparison between a LAE Sc. 5 and Cen. LAE Sc. 4 in terms of hydrogen demand satisfaction.

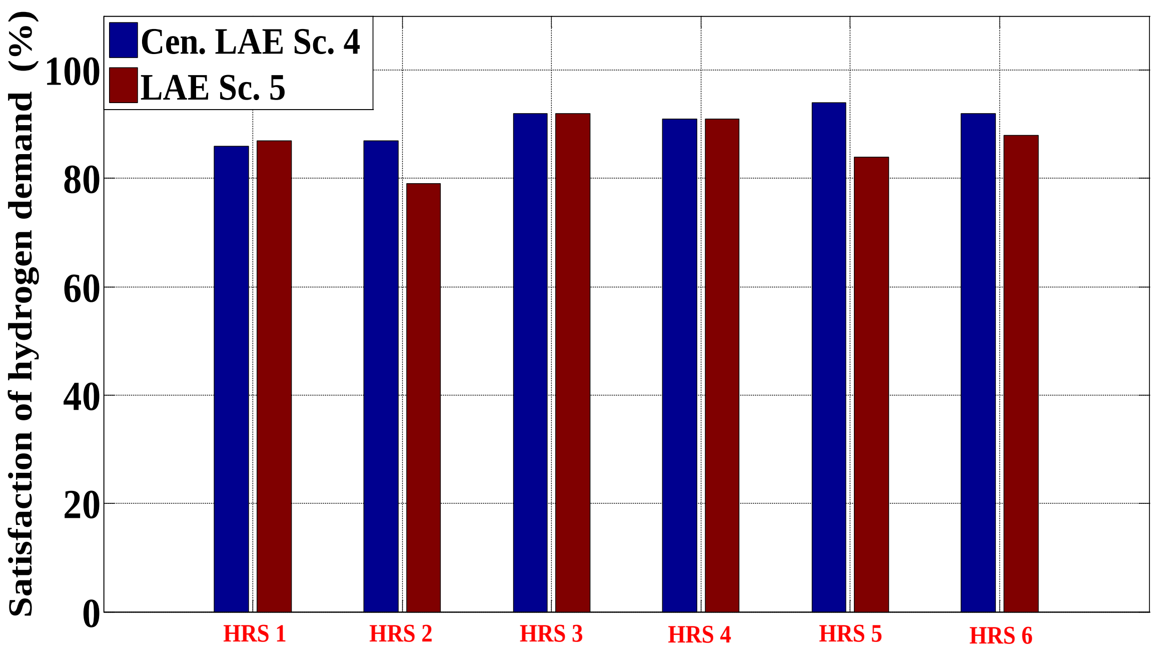


Figure 10.7: Comparison of Triple-default electrolyser size (LAE Sc. 5) and 6,410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 4)

In this scenario, the ability of the Cen. LAE Sc. 4 to meet hydrogen demand is slightly higher than, or equal to, the LAE Sc. 5 for all HRSs. A Cen. LAE Sc. 4 could produce hydrogen in large amounts during the day, allowing all HRSs to be supplied, which is the same case as would happen with the LAE Sc. 5 (triple-sized electrolyser scenario).

The main criterion in deciding which of these scenarios would be the best is that of average hydrogen price. Figure 10.8 shows the energy consumption for each scenario.

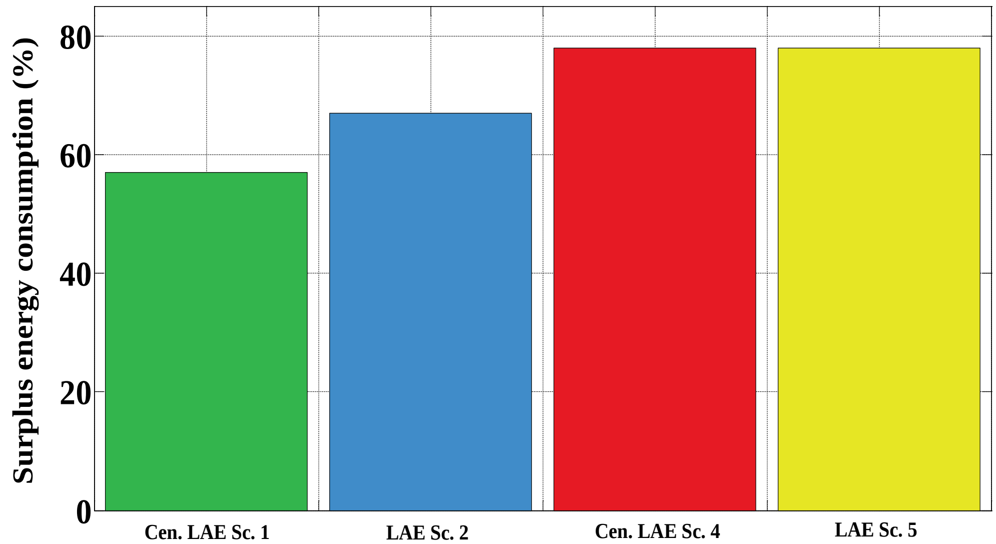


Figure 10.8: Energy consumption of Double-sized default electrolyser size (LAE Sc. 2) ,Triple-sized default electrolyser (LAE Sc. 5) , 2,383 kg/day (Cen. LAE Sc. 1) and 6,410 kg/day (Cen. LAE Sc. 4) alkaline central electrolysers without electrolyser at the HRSs

The Cen. LAE Sc. 4 and LAE Sc. 5 consume nearly the same amount of energy, which can be interpreted in terms of the similarity in the proportion of hydrogen demand being meet. The lowest was the Cen. LAE Sc. 1, followed by the LAE Sc. 2.

The average hydrogen prices of the various scenarios are presented in Figure 10.9 and Figure 10.10, respectively. The hydrogen price for central electrolyser (Cen. LAE Sc. 1 and Cen. LAE Sc. 4) is quite expensive compared to the two increased-size scenarios.

For the LAE Sc. 2 (double-sized) and Cen. LAE Sc. 1 (small sized central electrolyser scenarios), the difference between the hydrogen prices reflects the level of satisfaction of hydrogen demand, since the LAE Sc. 2 can meet a greater proportion of the demand for hydrogen, which will lead to a reduced cost.

However, for the LAE Sc. 5 (triple-sized) and Cen. LAE Sc. 4 (large central electrolyser), both these scenarios can meet same amount of hydrogen demand with a relatively cheap hydrogen price for the LAE Sc. 5 due to the higher investment cost of the central electrolyser components.

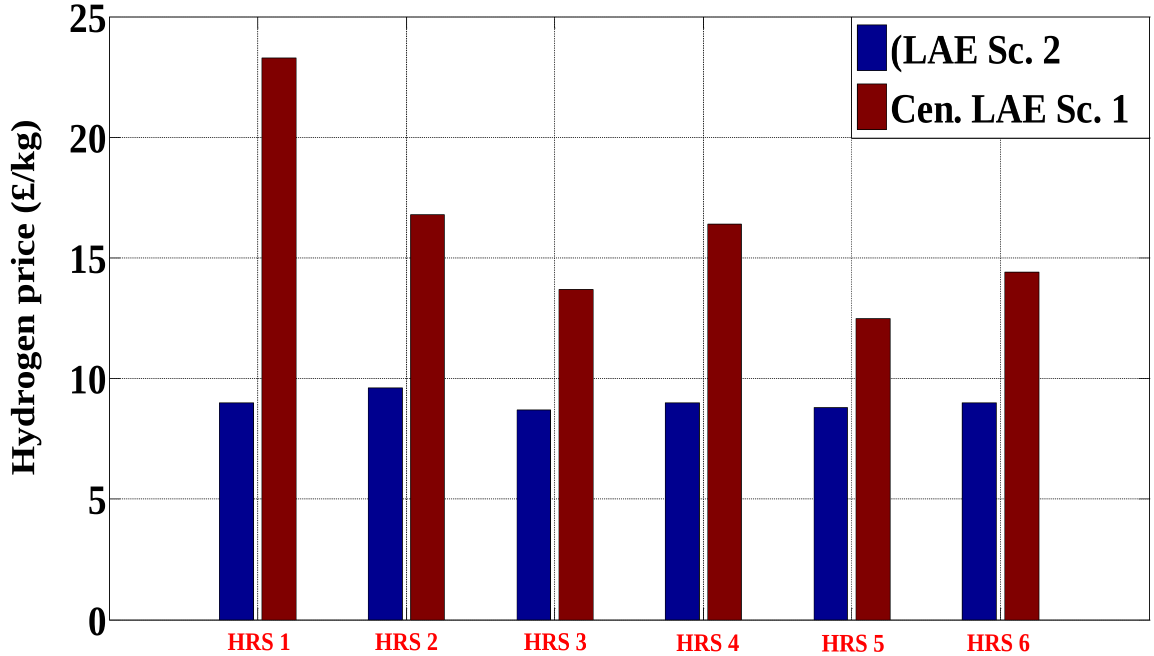


Figure 10.9: Comparison of Double-sized default electrolyser size (LAE Sc. 2) and 2383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 1)

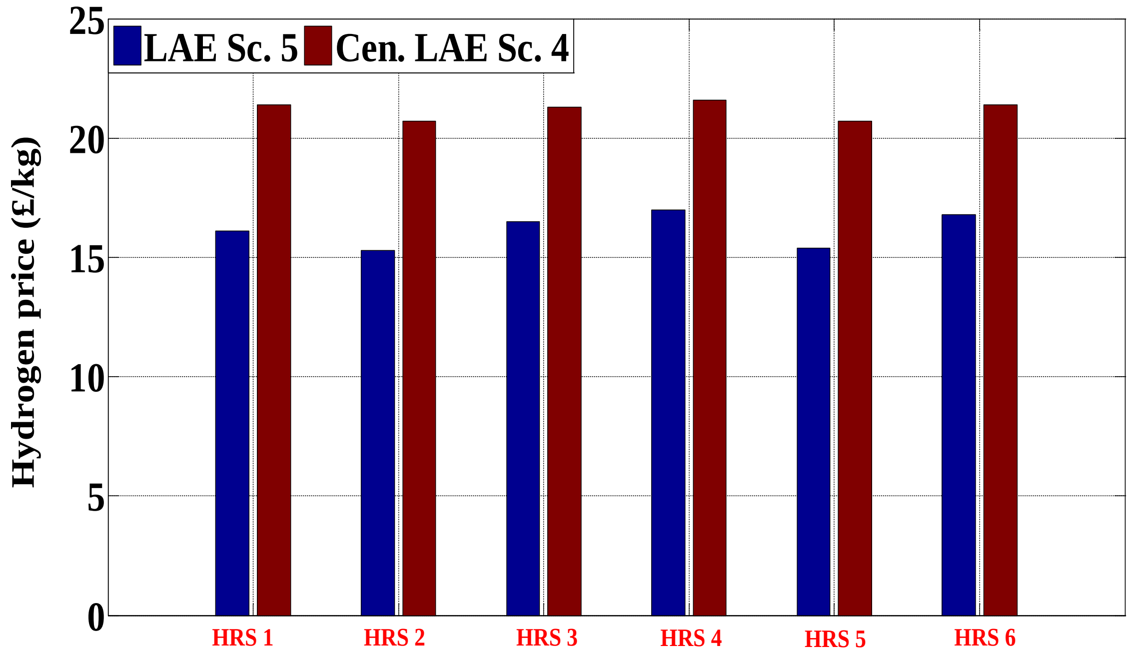


Figure 10.10: Comparison of Double-sized default electrolyser size (LAE Sc. 5) and 2383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 4)

10.4 Combination of HRSs and 1,098 kg/day (LAE Sc. 6), 4,853 kg/day (LAE Sc. 9) alkaline central electrolysers versus 2,383 kg/day (Cen. LAE Sc. 1), 6,410 kg/day (Cen. LAE Sc. 4) alkaline central electrolysers without electrolyser at the HRSs (2015-Cost scenario)

In this section, the LAE Sc. 6 and LAE Sc. 9 (onsite electrolysers with central electrolysis scenario) will be compared with Cen. LAE Sc. 4 and Cen. LAE Sc. 1(central electrolysers only). Like the other scenarios in Sections 10.3, three main issues have to be addressed, which are those of surplus energy consumption, hydrogen demand being met and the average hydrogen price for each HRS. There are two sizes of central electrolyser(1,098 kg/day and 2383 kg/day), which are connected to the onsite HRS electrolyser scenarios to consume the remaining of surplus energy and to meet the shortage production at HRSs and also two sizes of central electrolyser (Cen. LAE Sc. 4 and Cen. LAE Sc. 1). Figure 10.11 shows the comparison between the LAE Sc. 6 and the Cen. LAE Sc. 1.

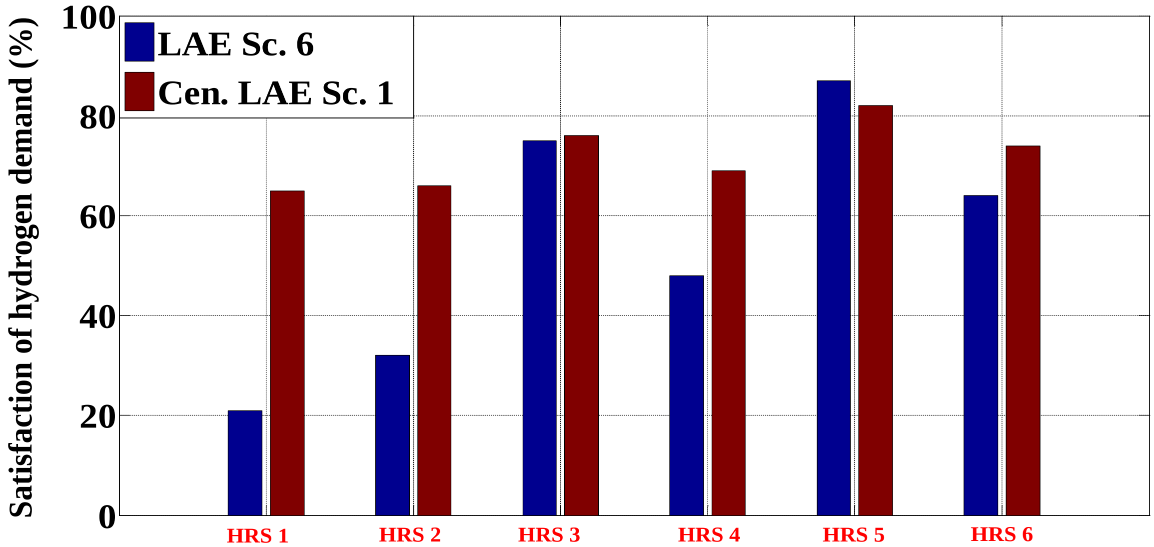


Figure 10.11: Comparison of Combination of HRSs and 1098 kg/day alkaline central electrolysers (LAE Sc. 6) and 2383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 1)

As can be seen, the onsite with central electrolyser scenario is preferable for all HRSs expect HRS 3 and 5. HRSs 3 and 5 have the highest demand of all HRSs throughout the year, so the Cen. LAE Sc. 1 gives them priority due to the hierarchy of supply, whereas the LAE Sc. 6

follows the electricity pricing mechanism, which gives all HRSs the chance to be supplied first, depending on how they set their bid price. Figure 10.12 shows the same scenario but with a Cen. LAE Sc. 4 and LAE Sc. 9.

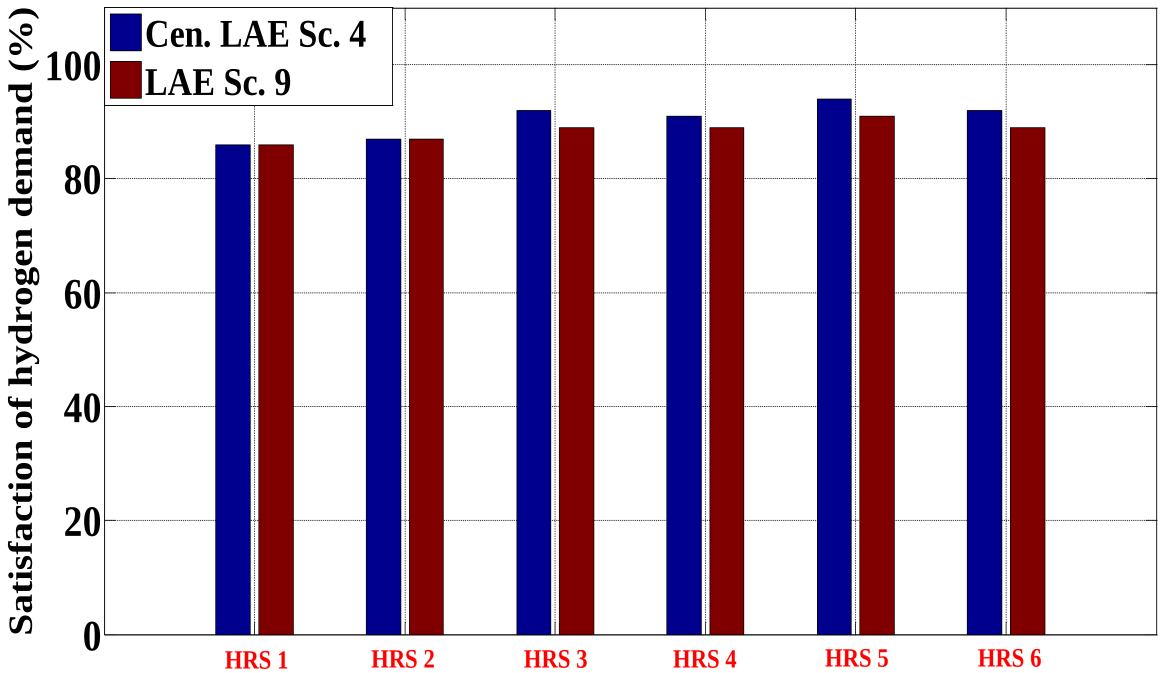


Figure 10.12: Comparison of Combination of HRSs and 4853 kg/day alkaline central electrolysers (LAE Sc. 9) and 6410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 4)

The level of hydrogen demand satisfaction for both production configurations in Figure 1.12 are very close to each other, with the greatest benefit, by a small margin, being evident for the case with Cen. LAE Sc. 4.

Another advantage with the Cen. LAE Sc. 4 is that the complexity of this system is less than that of LAE Sc. 9, since the system will deal with only one electrolyser rather than sever (i.e. a central electrolysis unit plus six at the HRSs).

The LAE Sc. 9 requires two electricity pricing mechanism if the central bid price is set after the HRS settlement price has been set, which will lead to a complex electricity trading mechanism. The energy consumed in each scenario is shown in Figure 10.13.

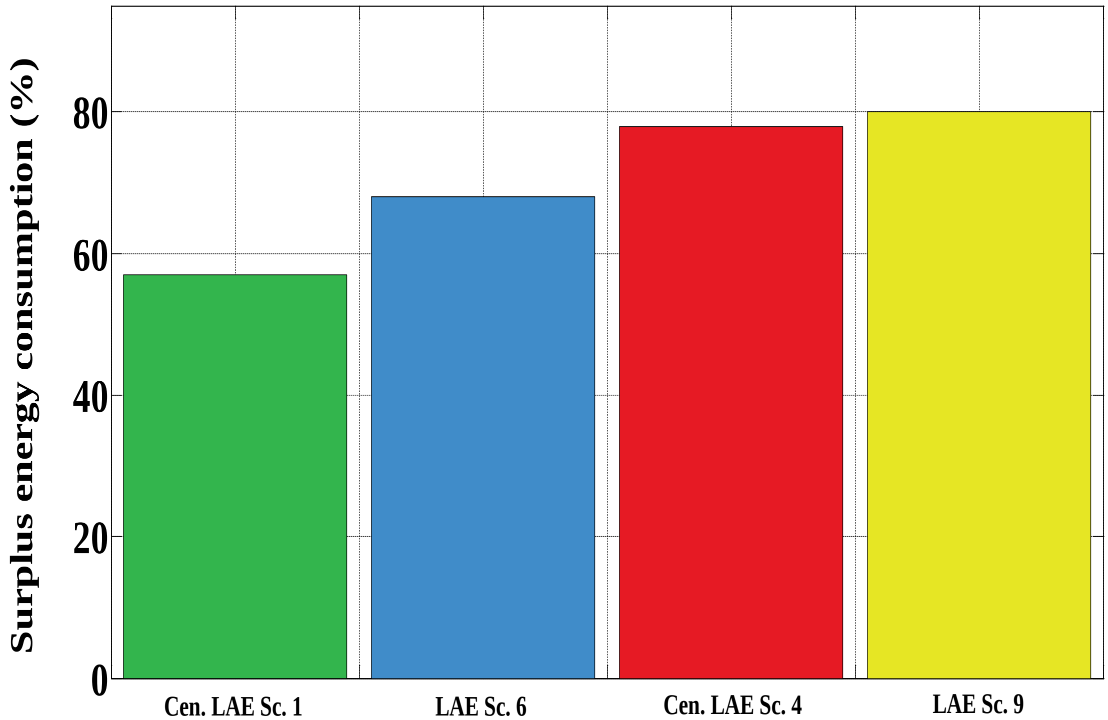


Figure 10.13: Total energy consumed in each hydrogen production scenario (alkaline, 2015-Cost scenario)

The of LAE Sc. 9 consumes nearly 80% of the total surplus energy, which can be considered a good scenario for grid balancing. However, hydrogen price and demand satisfaction are important factors in the assessment of this scenario.

As can be seen in Figure 10.12 the Cen. LAE Sc. 4 can meet a greater hydrogen demand with less energy consumption. Figure 10.14 shows the average hydrogen price when the Cen. LAE Sc. 1 and LAE Sc. 6 are compared.

The LAE Sc. 6 is cheaper than the Cen. LAE Sc. 1, as it can meet a greater proportion of the demand for hydrogen.

The highest cost is that of the Cen. LAE Sc. 1, which arises due to the higher cost of the system (electrolyser, storage and compression system). Figure 10.15 shows average hydrogen price with LAE Sc. 9 and Cen. LAE Sc. 4.

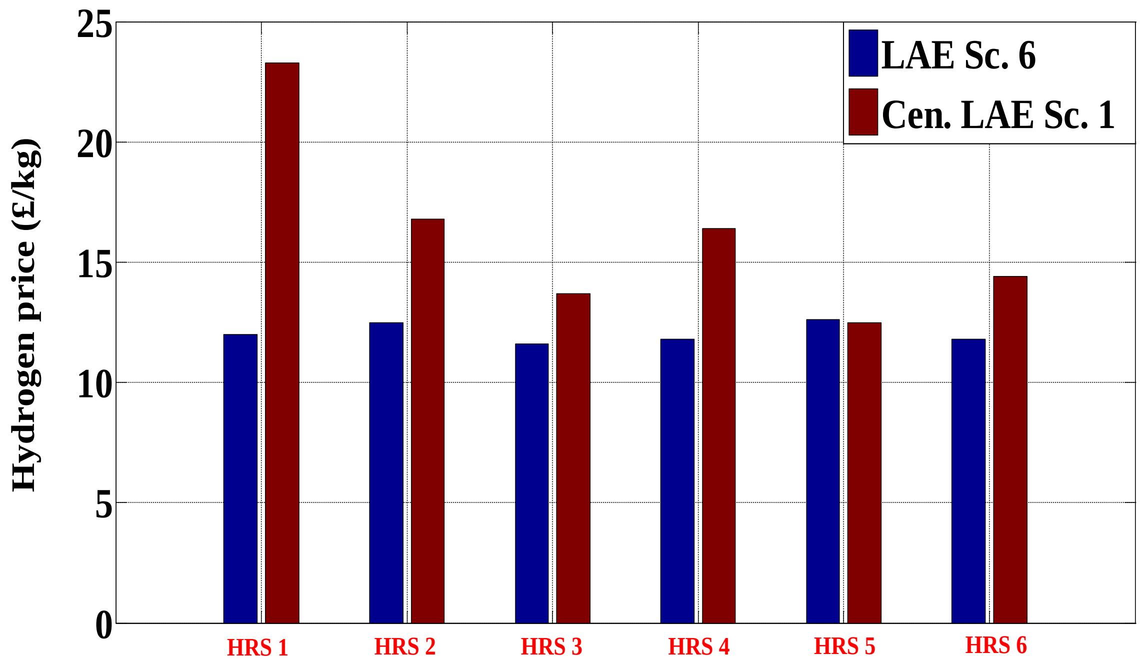


Figure 10.14: Comparison of Combination of HRSs and 1,098 kg/day alkaline central electrolysers (LAE Sc. 6) and 2,383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 1)

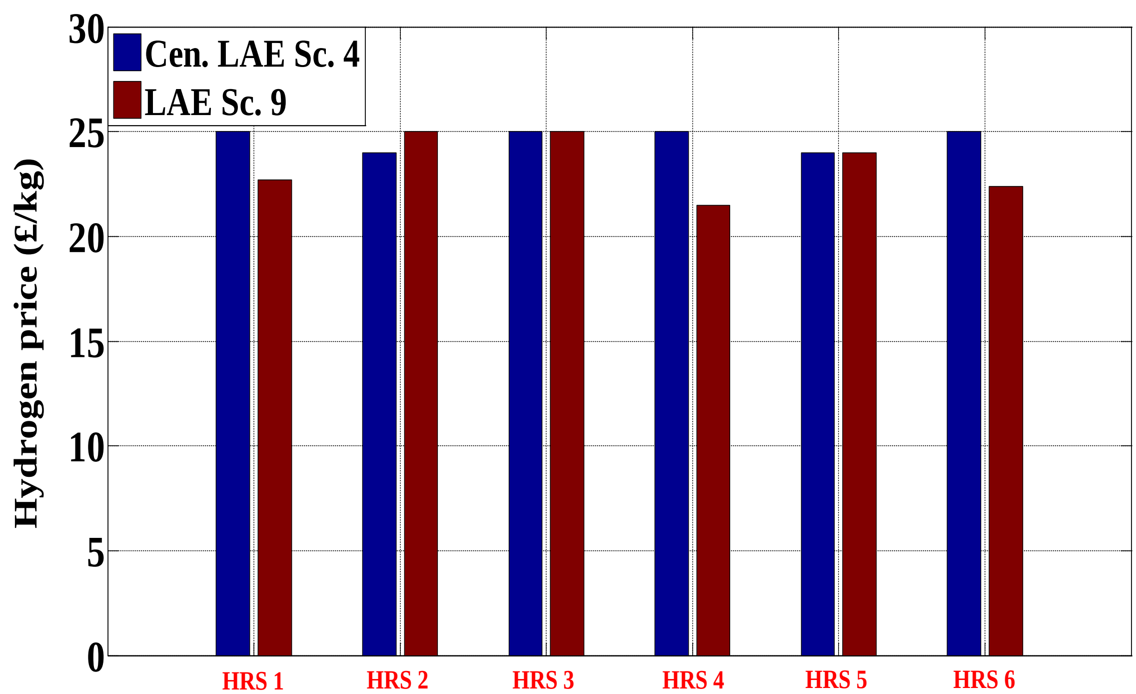


Figure 10.15: Comparison of Combination of HRSs and 4,853 kg/day alkaline central electrolysers (LAE Sc. 9) and 6,410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 4)

The average hydrogen price for the Cen. LAE Sc. 4 and LAE Sc. 9 are almost identical but with a slight increase when Cen. LAE Sc. 4 (large central production) is used. This is due to the more expensive system components. The decision as to which of the two is the best needs the consideration of numerous factors, such as safety issues and system complexity, in addition to the main aims of the project. All these comparisons will be repeated with alkaline electrolysis under the 2030-Cost assumptions. 2030-Cost assumptions will affect two parameters: system components and electrolysis efficiency, which will lead to improved system efficiency and reduced average hydrogen price.

10.5 Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 16) versus 2,383 kg/day (Cen. LAE Sc. 5) and 6,410 kg/day (Cen. LAE Sc. 8) central alkaline electrolysers without electrolyser at HRSs (2030-Cost scenario)

The same steps as in Section 10.2 will be followed and then compared. Figure 10.16 and Figure 10.17 reveal the hydrogen demand being met by onsite hydrogen production only versus small and large central production, respectively.

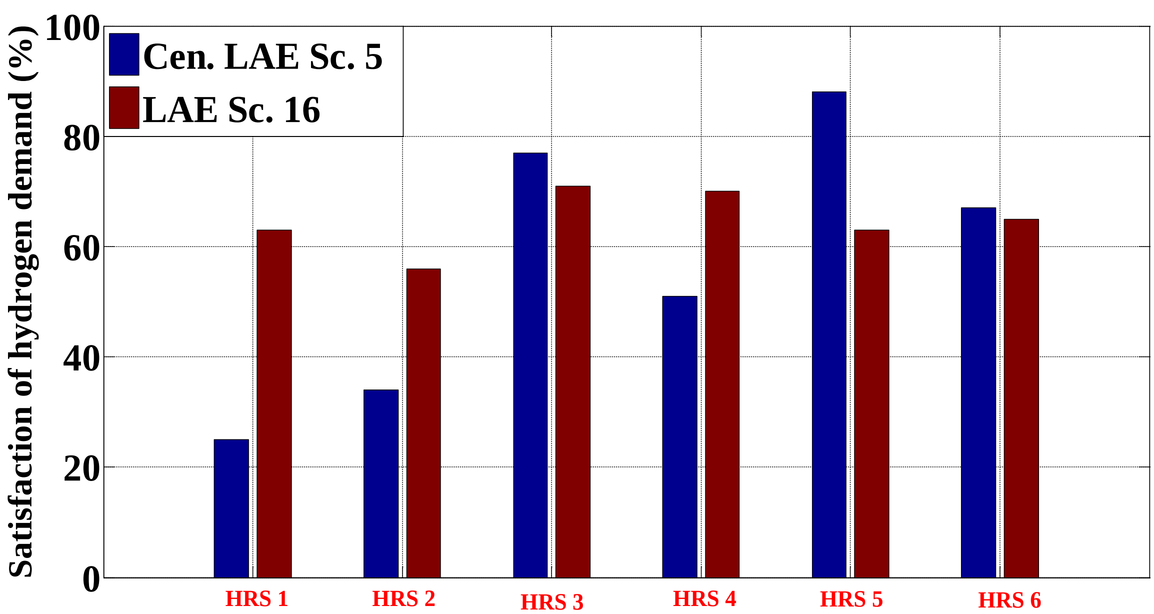


Figure 10.16: Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 16) and 2,383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 5)

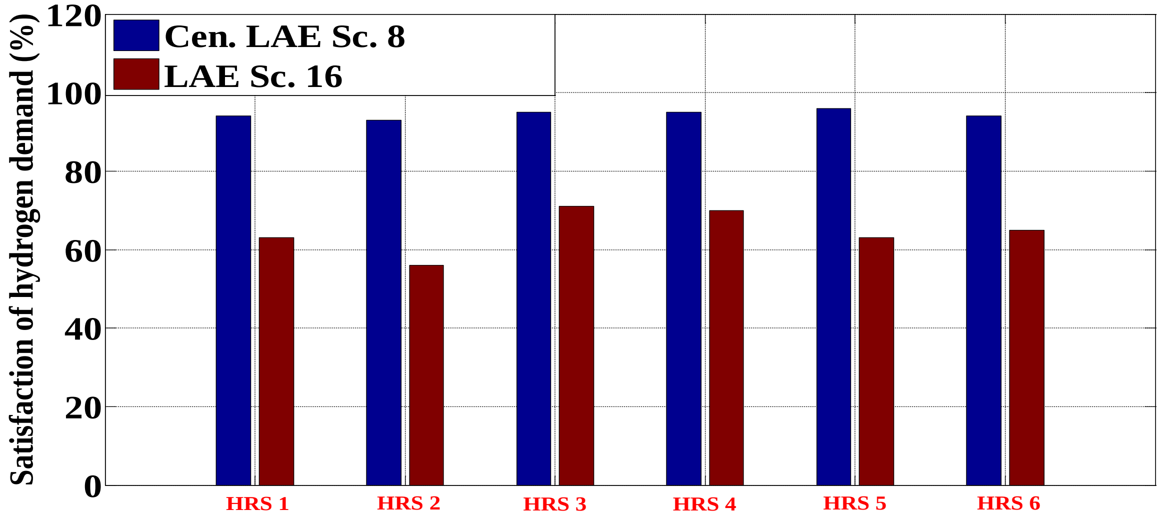


Figure 10.17: Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 16) and 6,410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 8)

Both scenarios achieve some increase in meeting hydrogen demand, but with the features of the 2015-Cost assumptions. The LAE Sc. 16 is better compared to the Cen. LAE Sc. 5, with an increase inability to meet hydrogen demand in both scenarios. In the Cen. LAE Sc. 8 versus that of LAE Sc. 16, a greater proportion of hydrogen demand can be met via the large central electrolyser scenario (Cen. LAE Sc. 8), which can reach nearly 90% of hydrogen demand, where as it is only 55-70% for the LAE Sc. 16. Figure 10.18 shows the total energy consumed in each scenario.

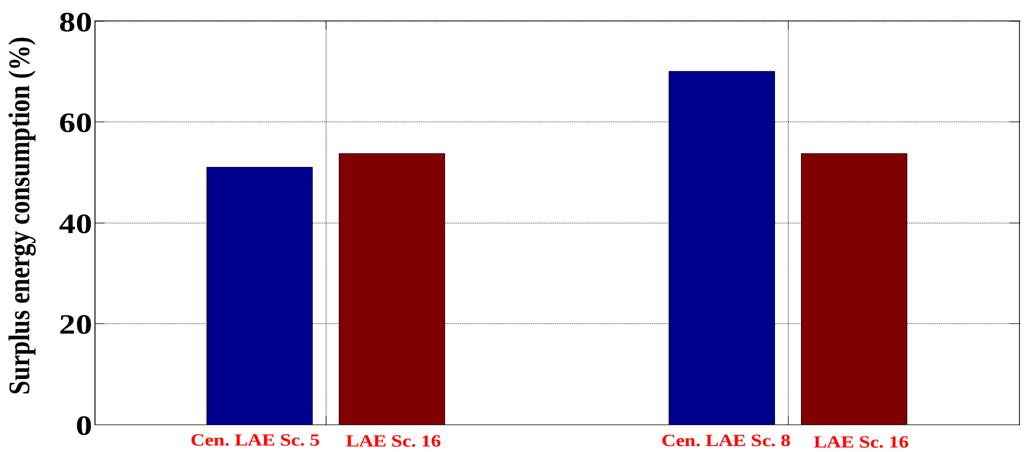


Figure 10.18: Energy consumption of Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 16) , 2,383 kg/day(Cen. LAE Sc. 5) and 6,410 kg/day (Cen. LAE Sc. 8) alkaline central electrolysers without electrolyser at the HRSs

The energy consumption of the LAE Sc. 16 is higher than that of the Cen. LAE Sc. 5 (small central electrolyser), whereas the Cen. LAE Sc. 8 (large central electrolyser) energy consumption is higher than that of the LAE Sc. 16. The average hydrogen prices for the LAE Sc. 16 hydrogen production compared with the Cen. LAE Sc. 5 and Cen. LAE Sc. 8 are shown in Figure 10.19 and Figure 10.20, respectively.

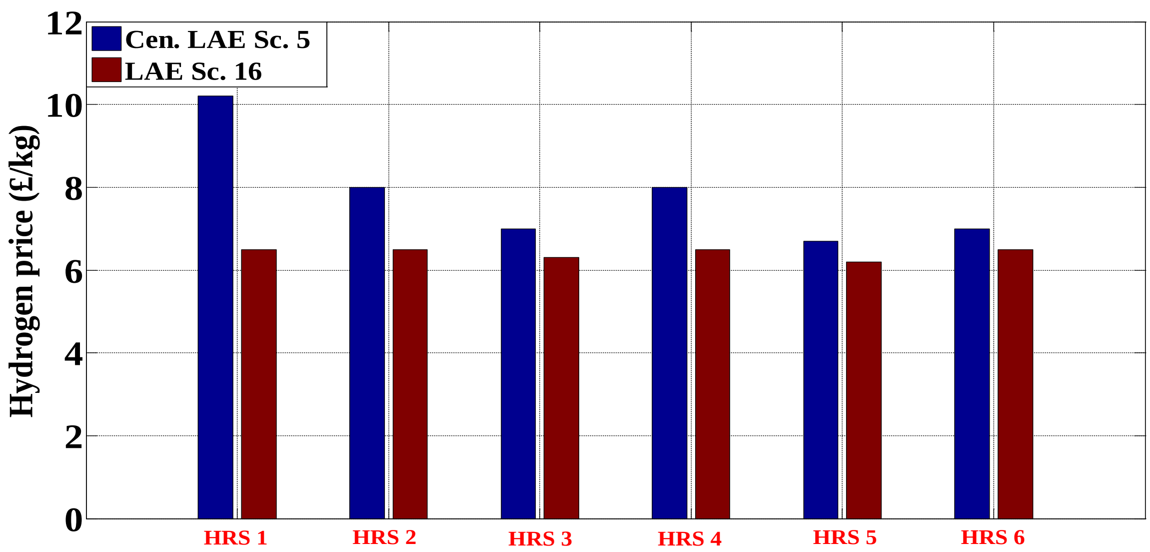


Figure 10.19: Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 16) and 2383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 5)

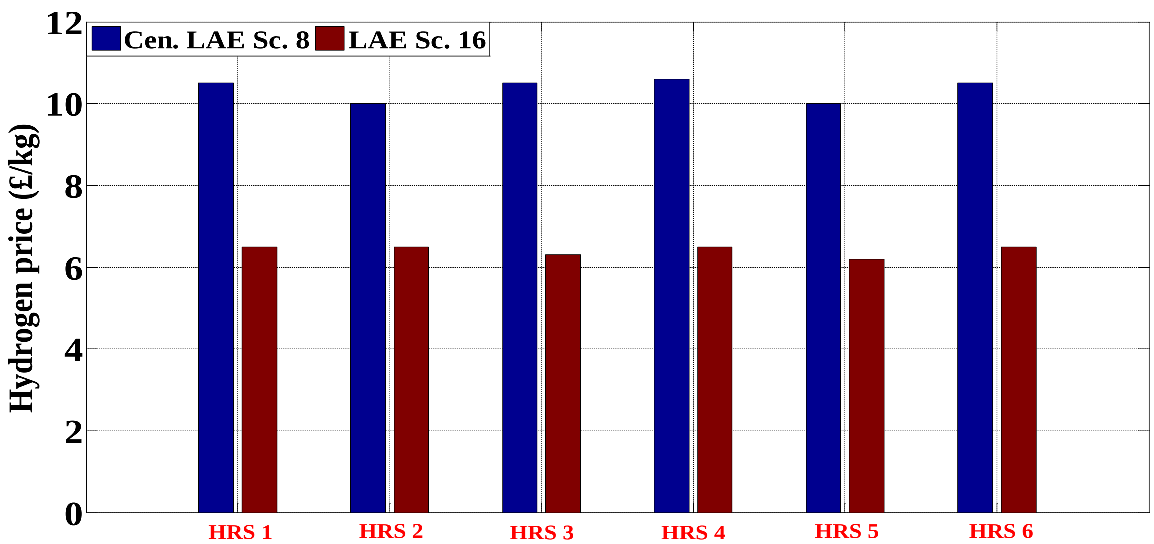


Figure 10.20: Comparison of Only onsite alkaline electrolyser without central electrolyser (LAE Sc. 16) and 6410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 8)

In Figures 1.19 and 1.20, the energy prices are dramatically reduced due to the reduction in the capital cost of the system as well as the improvement in electrolysis efficiency. In Figure 10.20, the LAE Sc. 16 price is cheaper than for the Cen. LAE Sc. 5. Neither scenario can satisfy a large proportion of the demand for hydrogen. For the Cen. LAE Sc. 8 price, the average hydrogen price is higher than or equal to £10/kg with nearly 90% of hydrogen demand being met, whereas the LAE Sc. 16 price is nearly £6.5/kg with only 65% of hydrogen demand being met. Based on the energy consumption and satisfaction of hydrogen demand, the Cen. LAE Sc. 8 is somewhat better than the LAE Sc. 16. However, the price of hydrogen in this scenario is quite expensive compared with that of LAE Sc. 16.

10.6 Double-sized electrolyser (LAE Sc. 17) and Triple-sized electrolyser (LAE Sc. 20) versus 2,383 kg/day (Cen. LAE Sc. 5) and 6,410 kg/day (Cen. LAE Sc. 8) alkaline central electrolysers

As given in section 10.3, the hydrogen demand being met, energy consumption and average hydrogen price will be tested. Figure 9.21 presents the satisfaction of hydrogen demand at garage forecourts for two different electrolyser configuration: Cen. LAE Sc. 5 and the LAE Sc. 17. Figure 10.22 also shows hydrogen demand being met by HRSs using Cen. LAE Sc. 8 and LAE Sc. 20.

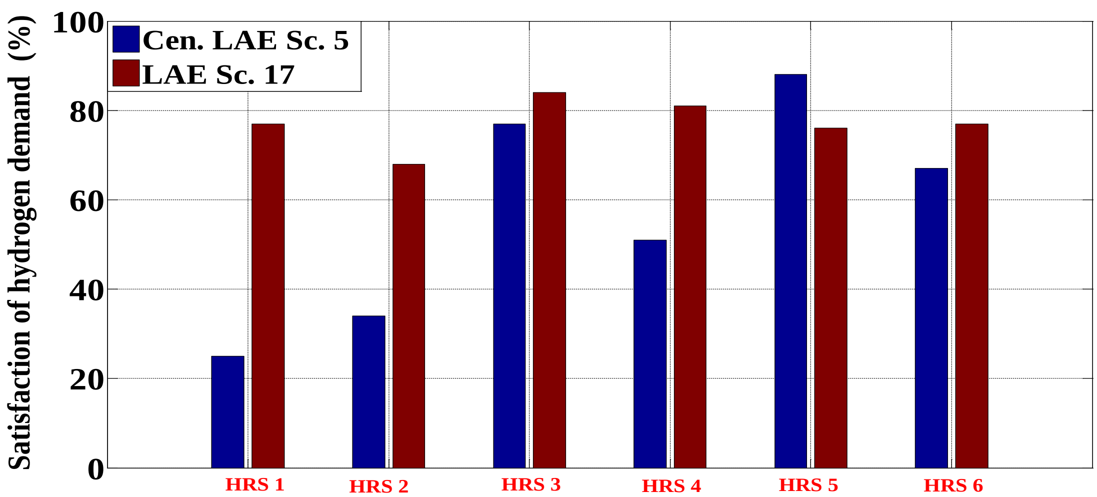


Figure 10.21: Comparison of Double-sized default electrolyser size (LAE Sc. 17) and 2383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 5)

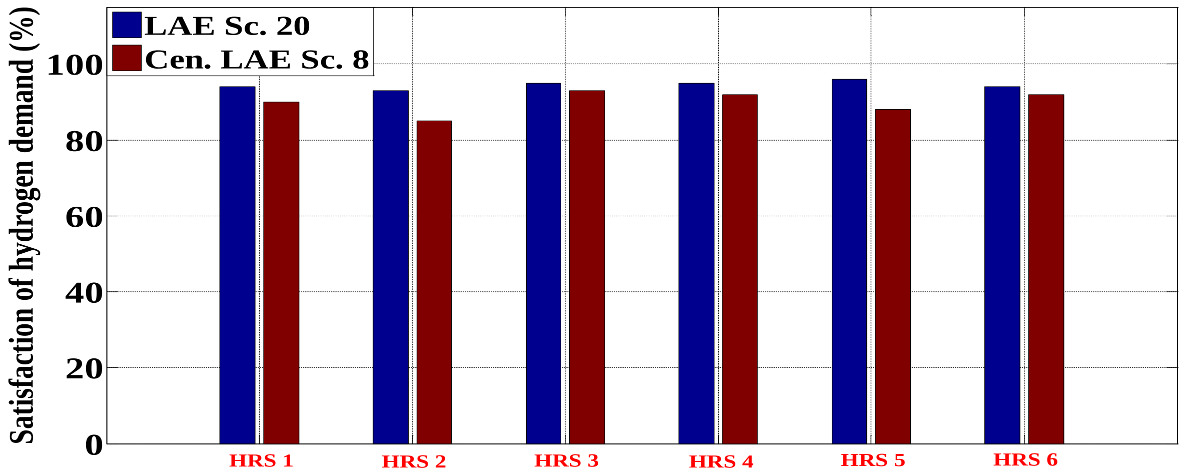


Figure 10.22: Comparison of Triple-sized default electrolyser size (LAE Sc. 20) and 6410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 8)

LAE Sc. 17 can meet a greater demand for hydrogen than the Cen. LAE Sc. 5 for all HRSs except HRS 5 (HRS with highest demand). The electricity pricing mechanism gives all HRSs the chance to be the first supplied regardless the small central production, which gives priority to the highest demand (which, as shown, is HRS 5). Hydrogen production by the Cen. LAE Sc. 8 can meet a high percentage of hydrogen demand than the LAE Sc. 20 due to its large system components, which can produce enough hydrogen for all HRSs each day. The total energy consumed in each scenario is presented in Figure 10.23.

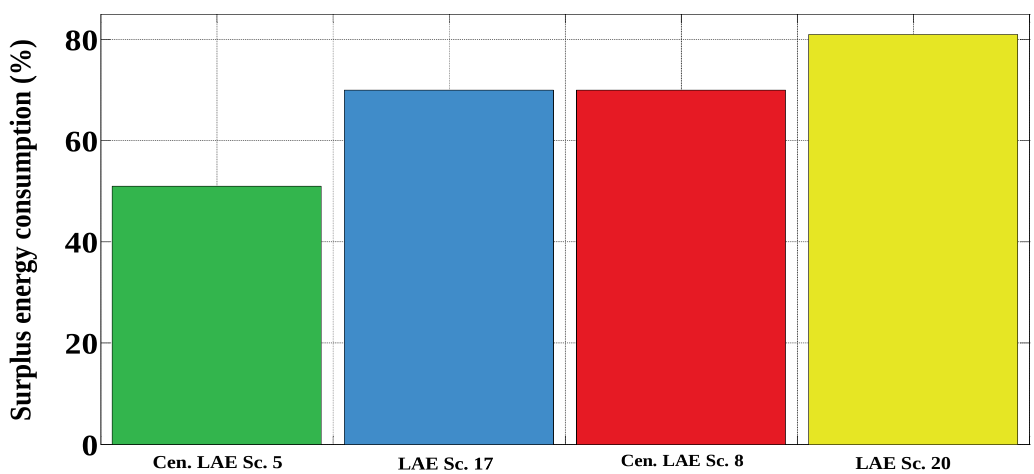


Figure 10.23: Energy consumption of Double-sized electrolyser (LAE Sc. 17) , Triple-sized electrolyser (LAE Sc. 20) , 2,383 kg/day (Cen. LAE Sc. 5) and 6410 kg/day (Cen. LAE Sc. 8) alkaline central electrolysers

Although the hydrogen consumed in the LAE Sc. 20 is higher than the Cen. LAE Sc. 8, the Cen. LAE Sc. 8 can meet a greater proportion of hydrogen demand. The last parameter that can be examined is that of average hydrogen price. Like other parameters, the LAE Sc. 17 will be compared with the Cen. LAE Sc. 5, whereas the Cen. LAE Sc. 8 will be compared with the LAE Sc. 20, as shown in Figure 10.24 and Figure 10.25, respectively.

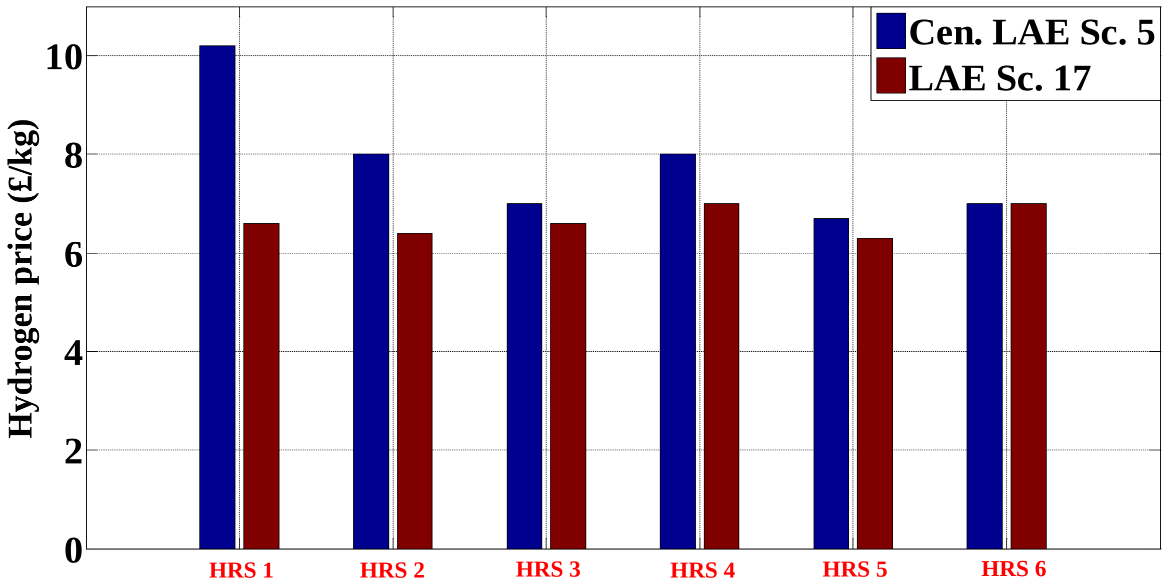


Figure 10.24: Comparison of Double-sized default electrolyser size (LAE Sc. 17) and 2383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 5)

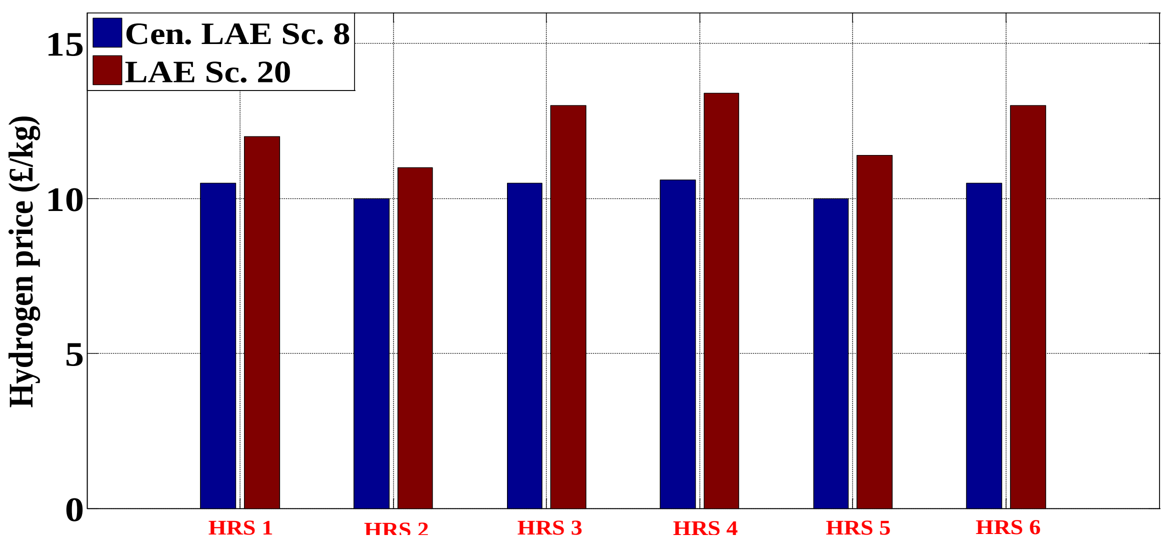


Figure 10.25: Comparison of Triple-sized default electrolyser size (LAE Sc. 20) and 6410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 8)

The LAE Sc. 17 (double-sized default electrolyser) can meet a greater proportion of hydrogen demand at a cheaper price than the Cen. LAE Sc. 5. This might be due to the system capital cost for the LAE Sc. 17 being less than that of the Cen. LAE Sc. 5 since both systems consume the same surplus power under the same circumstances. The LAE Sc. 20 price will be higher than for the Cen. LAE Sc. 8 with a slightly lower satisfaction of hydrogen demand than the Cen. LAE Sc. 8. Centralised hydrogen production (Cen. LAE Sc. 5 and Cen. LAE Sc. 8) can be achieved away from the consumption area, which could be considered as particular safety point. Consumption area reconstruction will be reduced when the production process is not included, but when only the storage and high pressure compression system for the dispenser is required. The main drawbacks of the central unit are the storage and delivery process, especially when the distance between production and consumption area is large.

10.7 Combination of HRSs and 1,098 kg/day (LAE Sc. 21), 4,853 kg/day (LAE Sc. 24) alkaline central electrolysers versus 2,383 kg/day (Cen. LAE Sc. 5), 6,410 kg/day (Cen. LAE Sc. 8) alkaline central electrolysers without electrolyser at the HRSs (2030-Cost scenario)

Adding a central electrolyser to the onsite ones could be one of the possible solutions to tackling the shortages arising from having an onsite electrolyser only. In the long term (2030), central production can replace onsite production if the hydrogen consumption reaches the diffusion target. Various factors that could determine whether any given production type will be the best option in 2030 will be investigated.

Figure 10.26 and Figure 10.27 show the production of LAE Sc. 21 compared to Cen. LAE Sc. 5 and LAE Sc. 24 compared to with Cen. LAE Sc. 8, respectively. When the Cen. LAE Sc. 5 is compared with LAE Sc. 21, all HRSs can satisfy a greater percentage of hydrogen demand than the LAE Sc. 21, with the exception of HRS 5. This could be due to the sizing of the system, since t LAE Sc. 21 is sized to tackle the drawbacks of the LAE Sc. 16 (onsite only scenario). When the Cen. LAE Sc. 8 is applied, the satisfaction of hydrogen demand for the two cases, as shown in Figure 10.27, will be almost identical, with very little benefit to having the Cen. LAE Sc. 8.

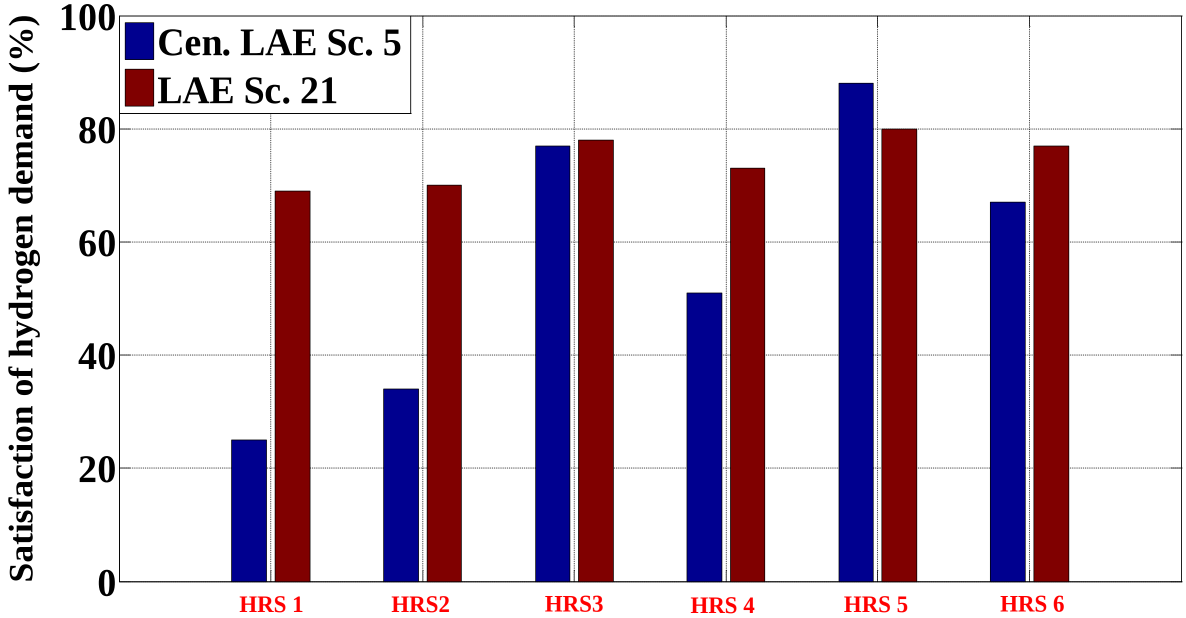


Figure 10.26: Comparison of Combination of HRSs and 1,098 kg/day alkaline central electrolysers (LAE Sc. 21) and 2,383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 5)

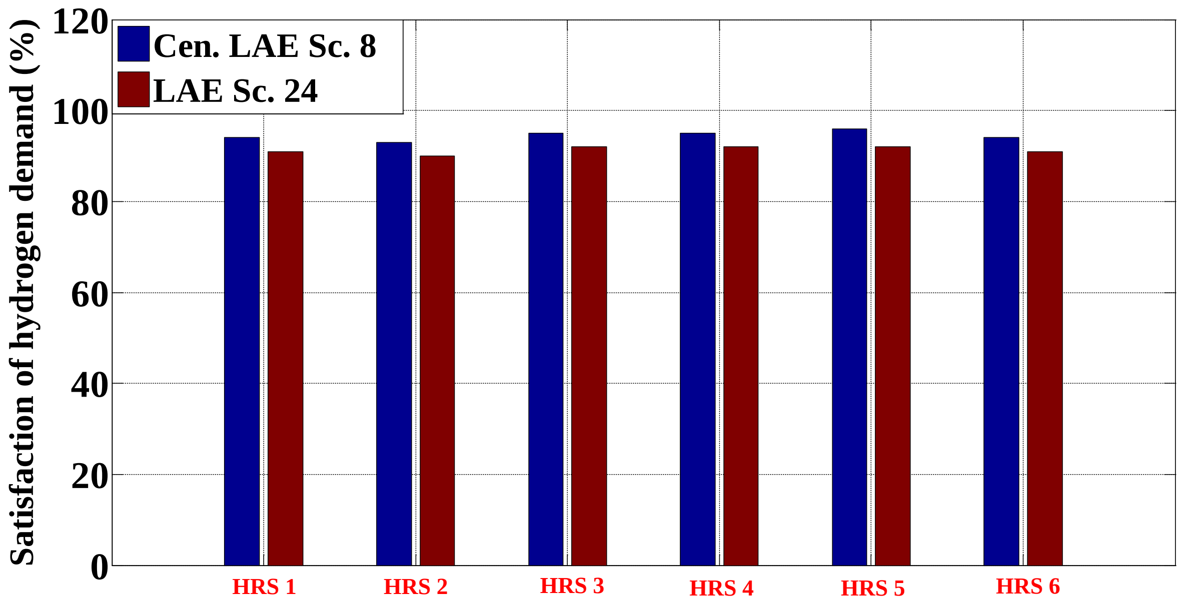


Figure 10.27: Comparison of Combination of HRSs and 4,853 kg/day alkaline central electrolysers (LAE Sc. 24) and 6,410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 8)

A second factor that needs to be investigated is the energy consumption of each scenario, which will support any grid balancing targets. Figure 10.28 shows the energy consumed per sector.

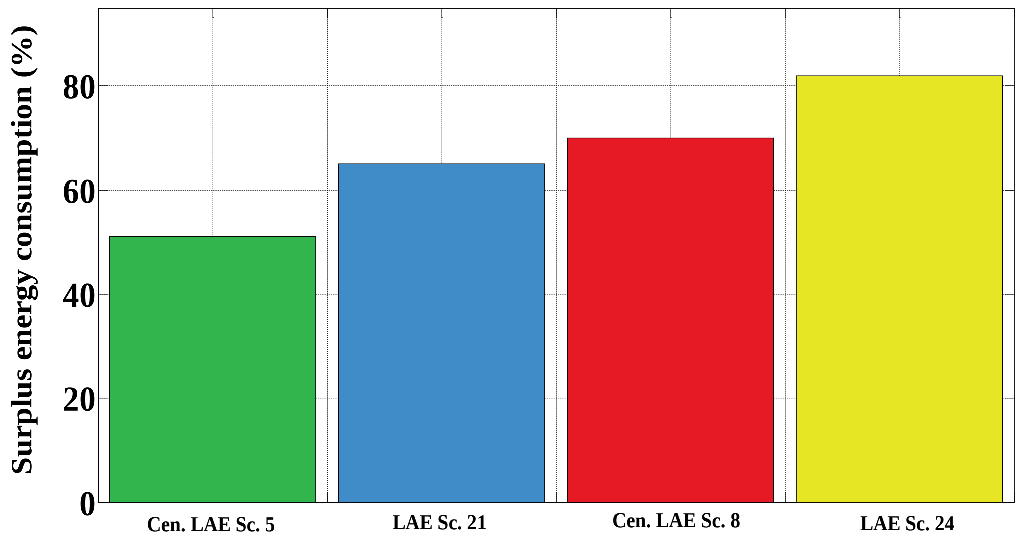


Figure 10.28: Energy consumption of Combination of HRSs and 1,098 kg/day (LAE Sc. 21), 4,853 kg/day (LAE Sc. 24) alkaline central electrolysers , 2383 kg/day (Cen. LAE Sc. 5) and 6,410 kg/day (Cen. LAE Sc. 8) alkaline central electrolysers without electrolyser at the HRSs energy consumption

In terms of energy consumption, the LAE Sc. 24 could be considered the best option since 82% of the total surplus energy will be absorbed compared with 70% when the b Cen. LAE Sc. 8 is applied. A comparison of the average hydrogen prices is presented in Figure 10.29 and Figure 10.30.

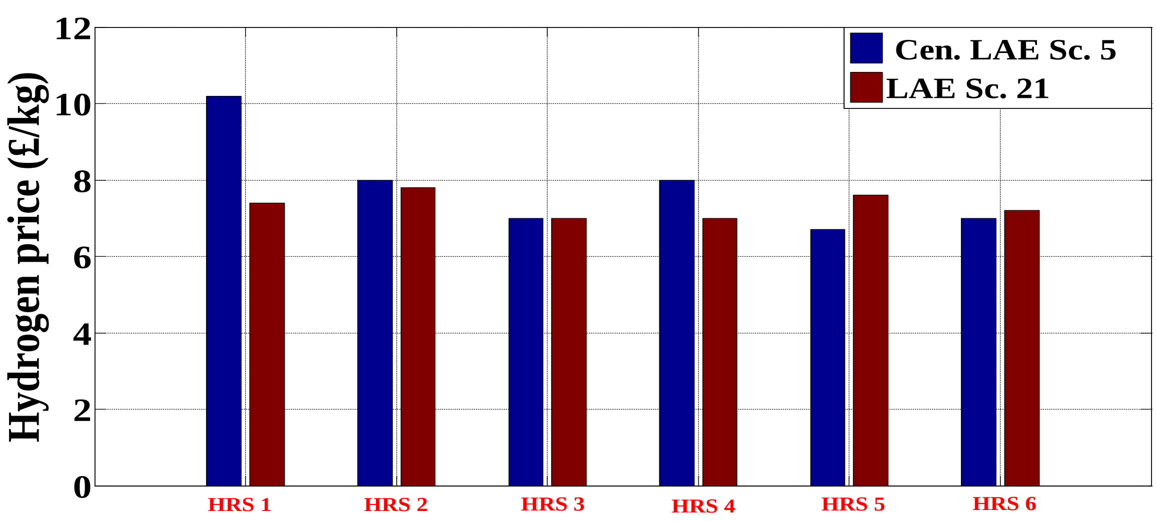


Figure 10.29: Comparison of Combination of HRSs and 1,098 kg/day alkaline central electrolysers (LAE Sc. 21) and 2,383 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 5)

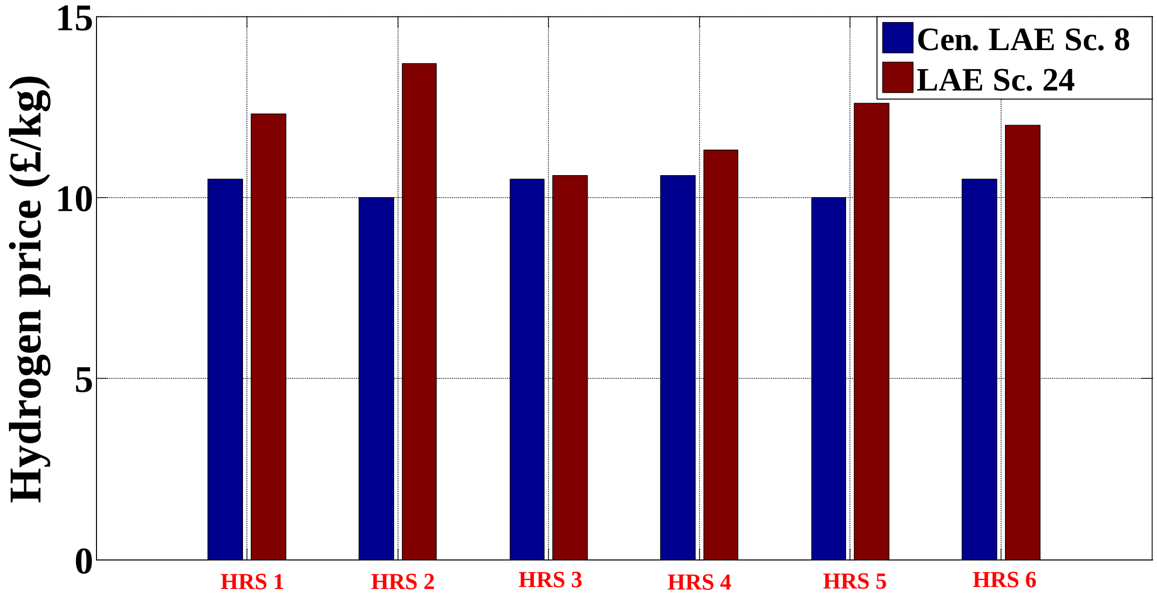


Figure 10.30: Comparison of Combination of HRSs and 4,853 kg/day alkaline central electrolysers (LAE Sc. 24) and 6,410 kg/day alkaline central electrolyser without electrolyser at the HRSs (Cen. LAE Sc. 8)

When the Cen. LAE Sc. 5 is compared with the onsite with LAE Sc. 21, HRSs with low demand find the LAE Sc. 21 is better and cheaper because of the electricity pricing mechanism t, which gives them the chance to produce more hydrogen, as was found for HRSs 1 and 4.

However, the HRSs with high demand prefer the Cen. LAE Sc. 5 scenario since the demand is supplied in order of hierarchy from the highest to the lowest demand, as for HRS 5. For the second scenario in Figure 10.30 , all HRSs find the Cen. LAE Sc. 8 cheaper than the LAE Sc. 24. This is due to the greater amount of hydrogen that can be produced via the Cen. LAE Sc. 8, which will lead to a reduction in the average cost of hydrogen.

The same result is true in PEM electrolysis scenarios, but there are a number of differences, mainly in the average cost of hydrogen, due to the higher cost of PEM by comparison with alkaline electrolysis when the 2015-Cost assumptions are applied. When 2030-cost assumptions are applied, two main components will change: the capital cost will be reduced, and the efficiency of the electrolysis will be improved.

10.8 Comparison of CO_2 reduction benefits

This section will compare the possible benefits in terms of CO2 reduction when renewable energy is integrated into the gird. There are two possible ways to gain benefits through this integration: first, the integration of renewables into the grid will lead to an equivalent reduction in fossil fuel consumption, economic benefits can be gained by reducing carbon emissions through reduced energy and fuel consumption. This scenario will be worthwhile in the future when the social carbon cost might be increased; for instance, the SCC is projected to be £116/ton in 2030. Secondly, if less fossil fuels are consumed internally, the option is to increase exports or reduce the production of crude oil. The former has the advantage of increasing income to the country. Two types of electrolysers (PEM and alkaline) will be considered under the 2015- and 2030-cost assumptions. There are 13 possible operational scenarios here, as presented in Chapter 9.

10.8.1 Alkaline financial benefits due to renewable energy and hydrogen fuel deployment (2015- and 2030-Cost scenarios)

Figure 10.31 shows the comparison between the first and second possible options for gaining benefits from the alkaline scenario under the 2015-Cost assumption for 13 operational cases, where these scenarios are:

LAE Sc. 1: Only Onsite alkaline electrolyser without central electrolyser (default sizes) (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 2: Double default electrolyser size with default storage size (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 3: Triple default electrolyser size and 1.5 times default storage size (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 4: Triple default electrolyser size and double the default storage size (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 5: Triple default electrolyser size and triple the default storage size (alkaline electrolyser under 2015-Cost scenario).

LAE Sc. 6: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day alkaline central electrolyser with 5,000 kg storage size (sized based on hydrogen production) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 7: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day alkaline central electrolyser with 24,000 kg storage size (sized based on hydrogen production) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 8: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 9: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production) when the central alkaline electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario).

LAE Sc. 10: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day alkaline central electrolyser with 5,000 kg storage size (sized based on production) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

LAE Sc. 11: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day alkaline central electrolyser with 24,000 kg storage size (sized based on hydrogen production) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

LAE Sc. 12: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

LAE Sc. 13: Combination of HRSs (default electrolyser and storage sizes) and 4,853 kg/day alkaline central electrolyser with 15,000 kg storage size (sized based on hydrogen production) when the central alkaline electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario).

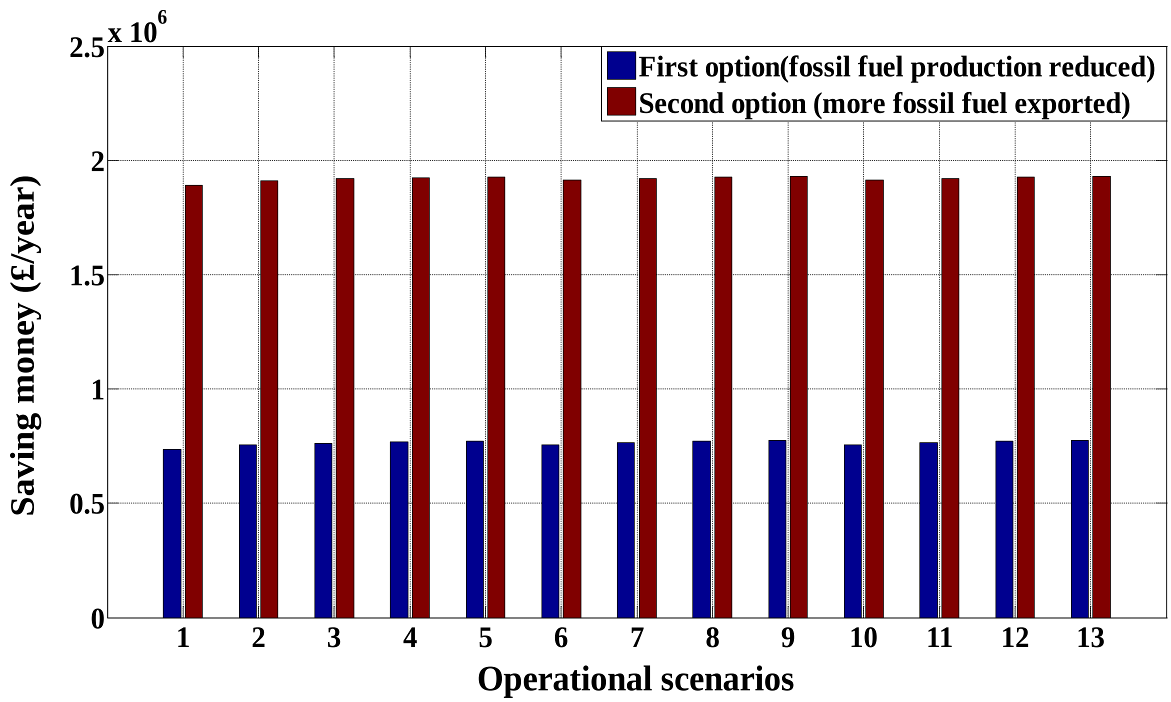


Figure 10.31: Comparison of two options for adjusting the oil market in response to renewable energy penetration in terms of CO2 reduction for alkaline electrolysis under 2015-Cost assumptions

Even with the low current price of oil ($\approx \$50/barrel$) , the export option is considerably better than the reduction option.

This is due to low value of the social carbon cost in 2015 (£7.76/ $tCO2$). The emission cost due to the extraction process of oil and natural gas is added as a cost that can be subtracted from the sale revenue. Figure 10.32 shows the same scenarios when the 2030-Cost assumptions are applied.

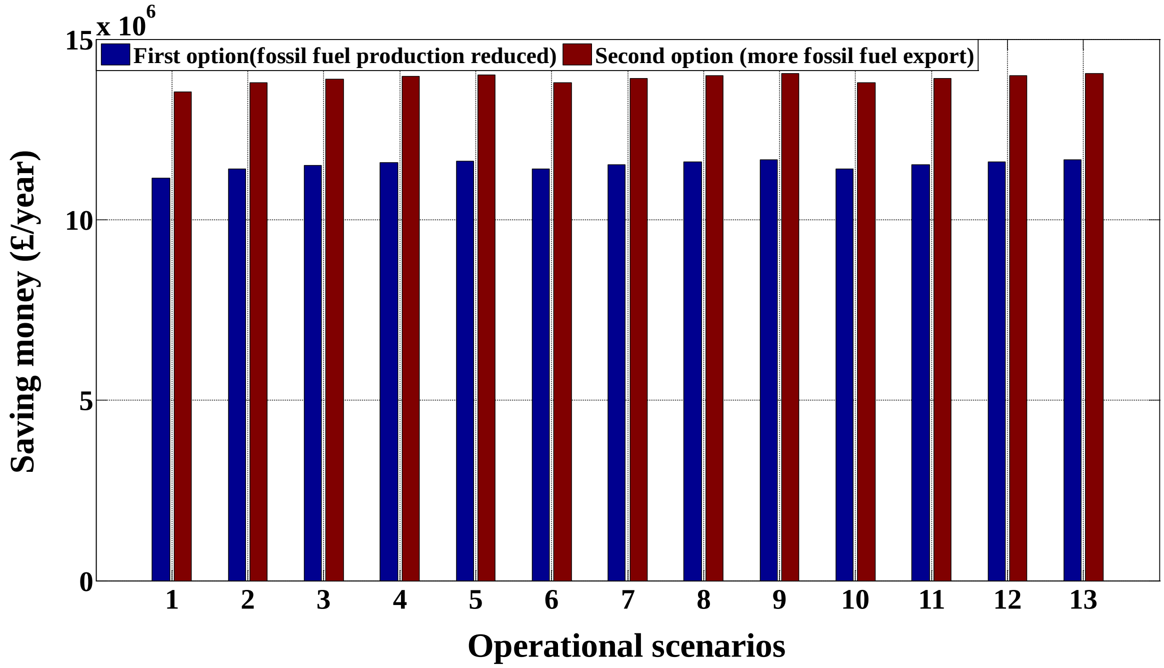


Figure 10.32: Comparison of two options for adjusting the oil market in response to renewable energy penetration in terms of CO2 reduction for alkaline electrolysis under the 2030-cost assumptions

General expectations suggest higher oil prices in the coming years, which are expected to reach$121/$Bbl$ (≈ £93.65/Bbl). The social carbon cost will increase to £116.05 /tCO_2e in 2030, according to UK data (UK Government, 2016). This predicted increase will lead to greater benefits under both scenarios, with higher financial savings in the second scenario (where the production is reduced). If government regulations and policy focus on renewable energy resource support, the first option would be better than the second, in which exports are increased.

10.8.2 PEM financial benefits due to renewable energy and hydrogen fuel deployment (2015- and 2030-Cost assumptions)

The effect of replacing alkaline electrolysers by PEM electrolysers will be apparent in hydrogen fuel production since some fossil fuel will be replaced by hydrogen fuel and the amount of hydrogen production will differ in the PEME case, due to the PEME price and efficiency. Figure 10.33 shows the two possible options by which benefits can be obtained under the 2015-Cost assumptions for the 13 operational scenarios where these scenarios are:

PEME Sc. 1: Only Onsite PEME electrolyser without central electrolyser (default sizes) (PEME electrolyser under 2015-Cost scenario)

PEME Sc. 2: Double default electrolyser size with default size storage (PEME electrolyser under 2015-Cost scenario)

PEME Sc. 3: Triple default electrolyser size with 1.5 times default storage size (PEME electrolyser under 2015-Cost scenario)

PEME Sc. 4: Triple default electrolyser size and double default storage size (PEME electrolyser under 2015-Cost scenario)

PEME Sc. 5: Triple default electrolyser size and triple default storage size (PEME electrolyser under 2015-Cost scenario)

PEME Sc. 6: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day PEME central electrolyser with 5,000 kg storage size (sized based on hydrogen production) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

PEME Sc. 7: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day PEME central electrolyser with 24,000 kg storage size (sized based on hydrogen production) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

PEME Sc. 8: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on hydrogen production) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

PEME Sc. 9: Combination of HRSs (default electrolyser and storage sizes) and 4,000 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on hydrogen production) when the central PEME electrolyser operates under a different electricity settlement price to the HRSs (2015-Cost scenario)

PEME Sc. 10: Combination of HRSs (default electrolyser and storage sizes) and 1,098 kg/day PEME central electrolyser with 5,000 kg storage size (sized based on hydrogen production) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario)

PEME Sc. 11: Combination of HRSs (default electrolyser and storage sizes) and 1,923 kg/day PEME central electrolyser with 24,000 kg storage size (sized based on hydrogen production) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario)

PEME Sc. 12: Combination of HRSs (default electrolyser and storage sizes) and 3,021 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on hydrogen production) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario)

PEME Sc. 13: Combination of HRSs (default electrolyser and storage sizes) and 4,000 kg/day PEME central electrolyser with 15,000 kg storage size (sized based on hydrogen production) when the central PEME electrolyser operates under the same electricity settlement price as the HRSs (2015-Cost scenario)

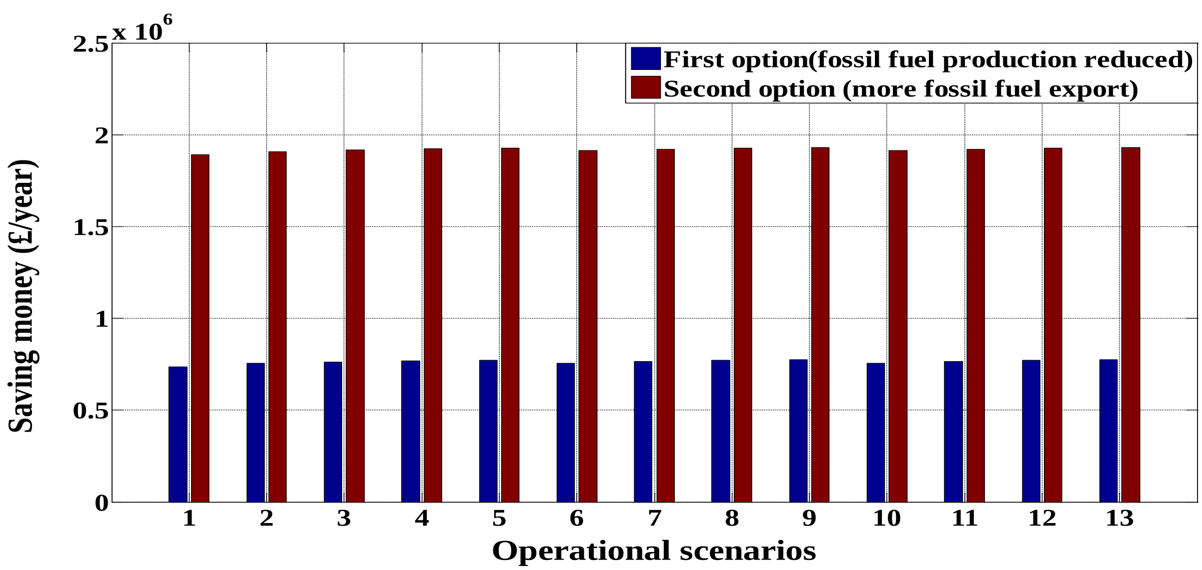


Figure 10.33: Comparison of two options for adjusting the oil market in response to high renewable energy penetration in terms of CO2 reduction for PEM electrolysis under 2015-Cost assumptions

Generally, the financial saving from oil export is less than £ 2×10^6 /year due to the low current price in contrast with less than 800,000 £/year in the alkaline electrolyser scenario. Figure 10.34 shows the comparison when the predicted price of oil and social carbon cost for 2030 are applied.

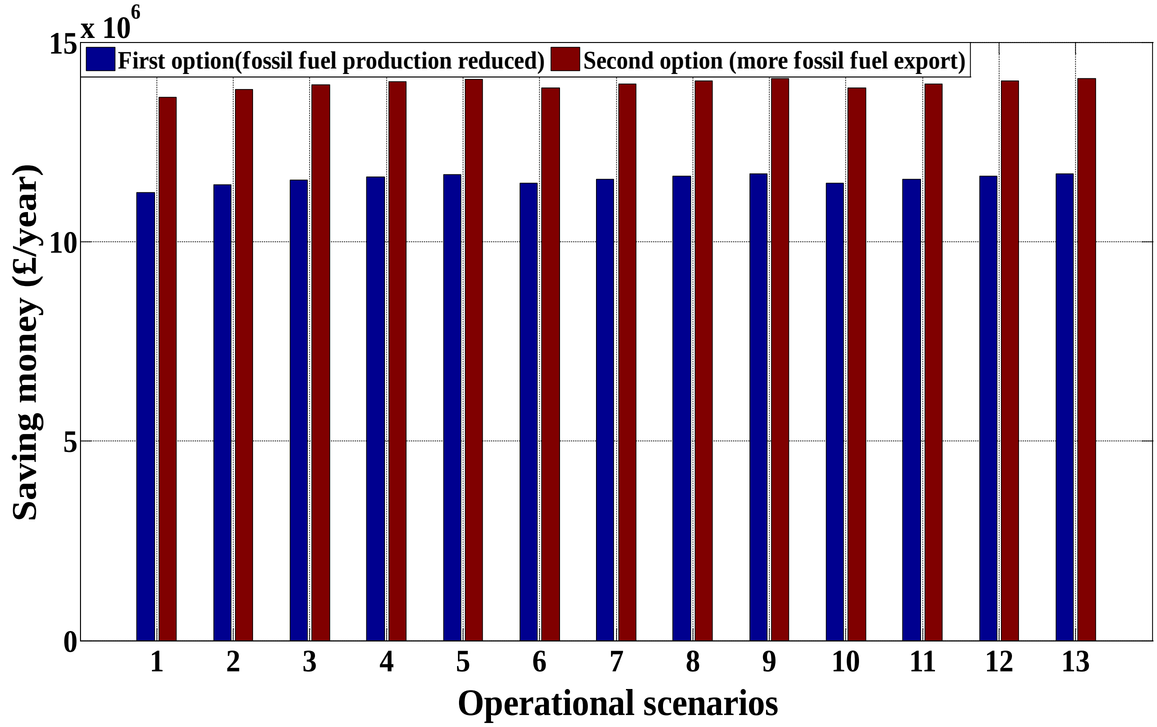


Figure 10.34: Comparison between the two options for adjusting the oil market in response to high renewable energy penetration in terms of CO2 reduction for PEM electrolysis under 2030-Cost assumptions

This case is very similar to the alkaline electrolysers case, where the new social carbon cost will increase the financial gain to the extent that it could be competitive with the second option, even with a dramatic increase in oil prices.

10.9 Summary of the chapter

This chapter presents a comparison between the main results of this research in order to encapsulate the main findings of this research. In terms on the main aims of the project, which are those of grid balancing, meeting hydrogen demand and achieving acceptable hydrogen prices, there is some considerable difficulty in deciding the best system configuration, as the centralised hydrogen production could be better in terms of one of the main goals of the project whereas onsite hydrogen production is better for another. Inclusion of a large central electrolyser could be a good option, since it is capable of meeting a large proportion of hydrogen demand but it has the disadvantage of creating an expensive price for the hydrogen. The same is true of the triple-sized electrolyser scenarios and when there is a large central electrolyser in combination with onsite electrolysers. The average prices of the central electrolyser hydrogen production will be reduced in 2030 due to investment cost reduction and efficiency gains. In the second part of this chapter, the benefits of CO2 reduction have been calculated based on the reduction in fossil fuel use due to renewable energy deployment. Under the 2015-Cost scenario, exporting the fossil fuel thereby saved would be better than reducing the production of an equivalent amount of fossil fuel, because a reasonable oil price is anticipated and social carbon cost is low. Based on future forecasts for social carbon costs, the option to reduce oil production would will be competitive with the export option, even with the anticipated dramatic increase in oil prices in coming years. Government policy and regulations could be used to support both renewable deployment in electricity and hydrogen production and their symbiotic relationship.

Chapter 11: Conclusions and future work

11.1 Reflection on the research

This thesis has concentrated on investigating hydrogen production, storage and use in order to support its wider application and uptake in stabilising electricity grids in the presence of high renewable generation. Each chapter's findings are summarised below.

Chapter 1 gave a short summary about the history of energy crises and the reason for making the decision to move away from conventional fuels. Furthermore, this chapter explained the issues facing current electrical grid infrastructures with the fast growth of their integration with renewable energy sources. The lack, and disadvantages, of existing tools to quickly evaluate hydrogen storage as a potential choice for such issues was also discussed.

Chapter 2 discussed different energy storage methods. The advantages and disadvantages of each method were addressed. Energy storage applications, and a general comparison between them, was also given.

Chapter 3 presented a general overview of hydrogen energy storage, which included hydrogen production methods and the ways and cases by which hydrogen can be stored. The applications of hydrogen as a demand-side management system were explained. This chapter also presented a comparison between conventional fuels and hydrogen fuel based on several physical characteristics such as energy density and carbon content. This is important part as one of the main targets of this research was to test the possibility of hydrogen replacing fossil fuels.

Chapter 4 focused on the electrolytic method of hydrogen production because the research was focused on absorbing surplus renewable power and producing hydrogen for the transport sector. This chapter explained the hydrogen electrolysis process, including the main electrolyser system components, particularly the cell arrangement, and challenges to the establishment of widespread electrolysis industry. Economic details relating to the electrolyser industry were also discussed in detail. This chapter gave the reader a general idea of the current electrolysis industry. The economic details form a crucial part of the research work because the model was focused on a techno-economic assessment of the system.

Chapter 5 summarised the production and consumption of energy in Libya, considering also its future prospects. The fluctuation in oil production due to the security situation in Libya and the decline in oil prices were also discussed as the basis on which to seek new sources of energy and income. The Libyan electricity price and subsidy issues were also addressed. Finally, renewable energy projects in the country were investigated in order to understand the current and potential levels of renewable energy generation. All these steps were aimed at establishing the initial conditions for simulating the integration of renewable energy into the Libyan system, even in cases of partial integration.

Chapter 6 concentrated on the case study of the city of Darnah, giving descriptions of the city's location, the electricity demand for the Green Mountain area, and weather data for the region. Details of hourly wind and solar energy were calculated for Darnah. Renewable power is one of the main focuses of the research because the target is to maintain the balance of a grid with a high penetration of renewable energy. A simple, and new, technique was applied to determine the size of the renewable energy system based on the capacity factor of wind turbines and photovoltaic systems, and the electricity demand. The sizing technique led to saving in the system cost and an accurate match between supply and demand. All these steps were considered a new research area as previous work had only focused on investigating the renewable energy option in Libyan regions in isolation, rather than additionally considering the integration of renewables into the Libyan grid. Finally, historical fuel consumption, oil prices with government subsidies, and then the fuel consumption of Darnah, including simulation of hydrogen consumption, have been addressed.

Chapter 7 investigated the effect of a variable electricity tariff price on the cost of hydrogen. An optimisation system was applied to reduce hydrogen costs based on the electricity price. A linear programming algorithm was used as all equations are linear. The studies were based on two cost scenarios and for two different types of electrolyser. The results of the chapter supported the hypothesis that it is a possible to reduce the cost of the hydrogen if off-peak (low-tariff) electricity is used. These results paved the way to further investigation of off-peak hydrogen production. A simple model was also created to assess the system economically. In contrast to similar studies (which normally ignore certain system costs), this chapter took into account all the electrolysis costs such as fixed costs, water costs and compressor electricity cost as well as the bank loan calculations with compound interest also included in the study.

Chapter 8 investigated a new scenario for the Libyan case study where was used the electrolyser as a grid balancing mechanism with two further constraints, which were that the produced hydrogen should meet 20% of assumed hydrogen demand in Darnah city (which was simulated in Chapter 6) and the hydrogen price should be competitive with that of fossil fuels. A novel electricity pricing mechanism was applied, which allowed the seller (utility company) and the buyer (HRSs) to both gain a profit. In this scenario, on-site hydrogen production at the forecourt was applied and a techno-economic assessment was undertaken. Under on-site hydrogen production scenarios, different cases were tested, such as increasing the size of system components to try to mitigate certain associated problems, such as shortage of hydrogen supply and inability to consume all of the remaining surplus energy. This chapter also introduced the idea of adding a large central electrolyser to the system that could top-up the forecourts with extra hydrogen and absorb some of the remaining power surpluses. All these scenarios are new studies in the context of Libya.

Chapter 9 used a central electrolyser instead of on-site hydrogen production at the forecourt for grid balancing and as a clean fuel. It was able to meet 20% of the anticipated hydrogen demand. As the hydrogen price was also calculated, the total system was investigated both technically and economically. All these steps can be considered a new study in the Libyan context.

Chapter 10 presented an overall comparison between the onsite-only production scenarios and the central hydrogen production. This comparison has been carried out on the basis of the energy absorption, the level of satisfaction of hydrogen demand and the average hydrogen price of each scenario under cost assumptions of both 2015 and 2030. The economic benefit due to renewable energy penetration and the resultant CO_2 reduction has been compared using oil price and social carbon cost assumptions for both 2015 and 2030.

11.2 Contribution to knowledge

In conclusion, the contributions to knowledge, which have been shown within this thesis can be briefly described as follows:

1- Full integration of renewable energy into the Libyan electrical grid has, as far as it is possible to know, been investigated for the first time since previous studies have not looked at grid-connected renewable energy when assessing hydrogen's potential in Libya. The assessment of fuel consumption data in Libya generally, and in Darnah in particular, is also new within the extant literature. This was achieved through collection data from station owners and oil companies in Libya. Literature on these points is very rare in the context of Libya. Simulation of hydrogen demand based on fuel consumption data and the applied equations for this purpose are again new in the context of Libya.

2- A simple and novel method of determining the size of the system components for the (optimal) use of surplus renewable power has been applied. The sizing technique does not need the input a great deal of data to give clear and accurate results. Solar power investigation in Darnah, it seems, is new, since the extant literature focuses only on wind power not the solar power, in the city due to the wind power project that was started there a few years ago.

3- An optimisation system was developed to investigate different electricity price tariffs would affect the total hydrogen cost. This investigation includes sizing the system components (electrolyser, compressor and storage system) based on the hydrogen demand and the amount of surplus energy available. The system cost was extracted from various recent studies on this subject. To make the result as accurate as possible, and to consider how the price might change in the future, two cost scenarios have been applied (the 2015- and 2030-Cost scenarios) as well as two common types of electrolyser (alkaline and PEM). Different electricity tariff structures were applied, each price representing a potential practical case; for example, 12 p/kWh for on-peak times and 5p/kWh for off-peak times. Techno-economic assessments have been undertaken to assess each scenario. Unlike most studies, water costs, compressor electricity costs and fixed costs were included in the system cost.

4- The use of hydrogen as a grid balancing mechanism and as a clean fuel to meet the refuelling demands of a specific number of vehicles has been tested under various different scenarios. Based on the data, electricity price could play an important role in reducing hydrogen fuel cost. As a result, a novel electricity pricing mechanism was developed in this thesis to produce an economic price for both the electricity production and hydrogen consumption sides of this mechanism. This technique allows the electricity generator and electrolyser operator (electricity consumer) to mutually agree the electricity price each day. A techno-economic model has been created to assess every scenario. Two main cases, on-site hydrogen production and central hydrogen production, were tested in various alternative configurations in an attempt to address some of the shortcoming of the two main default scenarios. Generally, the application of hydrogen as a grid balancing mechanism and as a clean fuel are a new investigation in the context of Libya.

5- The economic benefits derived from the deployment of renewable energy, plus the social carbon cost and the oil prices has been investigated and can be considered as new work in the Libyan case.

6- MATLAB code has been developed to simulate all these scenarios. These models developed are flexible in use so that, changing the input data from the Libyan case to another situation and rerunning the simulation will produce an assessment of the new system as based on the input data.

7- The main finding of this study which is discovered through all this works that electrolysis can provide a viable means of grid balancing, through industrial scale DSR in a way that allows a competitive hydrogen price. However, this study shows that this only possible under certain conditions, which require: 1) that government policy and regulation should support renewable energy deployment and hydrogen production; 2) that there is continued reduction in the cost of system components; and 3) that there is major diffusion of vehicles into the market that use hydrogen fuel.

11.3 Limitations of this work

This project has faced many obstacles, which have forced adjustments to be made to the project plan. These issues can be summarized as follows:

1- Data collection: the data collection includes weather data, electricity demand, and fuel consumption demand.

a) Weather data: wind speed and solar irradiance data have been collected from different sources such as NASA, commercial websites and meteorological stations at airports. 10 years' worth of wind speed data could be obtained in 10-minute resolution if the Renewable Energy Authority of Libya (REAOL) chose to release these data. Increasing the time resolution of wind speed data will lead to a more accurate result, especially for capacity factor calculations. In addition, REAOL already have a primary result for the 60 MW wind turbine project in Darnah, but because of the small amount of data on their central website, see (http://reaol.ly), and travel being highly restricted because of the security situation in Libya, obtaining these data was not possible during the research period.

b) Electricity demand data: the only source of electricity production and consumption data is the General Electricity Company of Libya (GECOL). GECOL publishes annual reports, but the published data is not quite sufficient for accurate calculations; for example, hourly consumption data is not available, and this led to changing the plan from an hourly to a daily analysis pattern. However, since electrolysis is more competitive in long-timescale DSR (diurnal and longer) than the numerous DSR technologies that are techno-economically more suitable at shorter timescales (less than diurnal), so this is not a major impediment to this thesis. If this study were extended to include short timescale DSR (as a by-product of the core operation), the higher resolution data might be valuable, but this is research to save for future work. Energy generation data is not included in company's annual reports, which limits the accuracy of the calculation for CO_2 reduction when the renewable energy and hydrogen fuel is used. Finally, the most recently published report relating to Libya was from 2012, which required the use of certain scaling methods that were based on the load growth rate, which might affect the research results; see (https://www.gecol.ly/GECOL_EN/Default.aspx).

c) Fuel consumption data: the fuel consumption data was extracted from daily sales reports from the forecourt owners. In some cases, these reports might not be accurate enough, which could affect the accuracy of the result, so reasonable assumptions had to be made.

d) Data from the Libyan central bank in terms of loan types, exchange rates and interest rates were also rare, and were based on simple available reports; see (https://cbl.gov.ly/en/).

2- Lack of data and literature sources on hydrogen applications as both a grid balancing tool and as a clean fuel, since most studies focus exclusively on one or the other of these roles. Existing work has helped the author to validate and compare results with the literature, which gives an indication of the veracity of the research contribution.

3- Uncertainty about Libyan government policy and intended strategy make the use of Libyan electricity tariffs in the simulation difficult, which is why UK currency and electricity tariffs have been applied. Reference to the exchange rate between the British pound and Libyan dinar has been provided to give the reader the chance to understand Libyan prices by comparison with UK prices. However, due to the flexibility of the model, Libyan prices can easily be applied once sufficiently accurate data has been obtained.

11.4 Future work

Based on the work undertaken in this thesis, the following recommendations are made for further investigation:

1- Hourly patterns could be applied to see the impact of the number of switching operations on the performances of both alkaline and PEM electrolysers. In this case, the maintenance costs should be included.
2- An economic model that can be extended to investigate the system over the project lifetime, not just one of the first seven years. This model will take various important points into consideration, such as the wind energy resource variation because the weather data will differ between years, as will the electricity demand and fuel consumption data. These calculations will give a general technical and economical assessment of the project.
3- Investigate the operational characteristics of the two types of electrolyser, because in this model, the work has focused on system-level technical issues such as energy absorption (grid balancing purposes), fuel satisfaction (hydrogen demand being met) and the average hydrogen price (economic aspects).
4- Applying this model in a practical way and to compare these results with the theoretical results, which is one of possible ways to evaluate this model. Practical tests can be done in Libya, or indeed any other country, due to the flexibility of the model. This would require a very large-scale pilot project. The closest such a trail has come to reality is in various power-to-gas projects (e.g. in Germany)
5- Future forecasting of conventional fuel prices can be undertaken in more details and these compared with future calculated prices for hydrogen to assess its competitiveness in the coming years.
6- Due to renewable energy penetration and use of hydrogen fuel instead of conventional energy sources and traditional fuels, carbon dioxide (CO_2) emissions should be reduced. This reduction can be calculated and taken into consideration when the comparison between this system and the traditional system without renewable energy penetration is made. The economic aspects of this as an external cost, or internalised through taxes, carbon trading, etc., can also be assessed.
7- The work can be extended to include other areas of the country. The only obstacle in this case is the scarcity of reliable data to the input into the model. This step gives the

researcher a means of deciding the best place to install the electrolysers and renewable energy capacity.

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