Design, Modelling and Valuation of Innovative Dispatch Strategies for Energy Storage Systems

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To my Mother

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Abstract

Energy storage has in recent years attracted considerable interest, mainly owing to its potential to support large-scale integration of renewable energy sources (RES). At the same time however, energy storage technologies are called to take over multiple roles across the entire electricity sector, introducing modern applications for both private actors and system operators. In this context, the current thesis focuses on the valuation of emerging energy storage applications, while also proceeding to the design and modelling of novel dispatch strategies, along with the development of financial instruments and support measures for the market uptake of energy storage technologies. In doing so, emphasis is given on mature, bulk energy storage technologies, able to support energy management applications. These include pumped hydro storage, compressed air energy storage and battery technologies. Energy storage applications/dispatch strategies examined are divided into three main categories that focus on private actors, autonomous electricity grids and utility-scale systems.

For private energy storage actors, active, profit-seeking participation in energy markets is examined through the evaluation of high-risk arbitrage strategies. Furthermore, the interplay of energy storage and demand side management (DSM) is studied for private actors exposed to increased electricity prices and energy insecurity, designating also the potential for combined strategies of arbitrage and DSM. To reduce the investment risks associated with participation in energy markets, a novel aspect of collaboration between energy storage and RES is accordingly investigated for energy storage investors, proposing the use of storage for the delivery of guaranteed RES power during peak demand periods and stimulating the development of state support instruments such as feed-in tariffs.

Next, attention is given on the introduction of energy storage systems in autonomous island grids. Such autonomous systems comprise ideal test-benches for energy storage and smart-grids, owed to the technical challenges they present on the one hand (e.g. low levels of energy diversity and limitations in terms of grid balancing capacity) and the high electricity production cost determining the local energy sector on the other (due to the need for oil imports). To this end, combined operation of RES with energy storage could, under the assumption of appreciable RES potential, prove cost-effective in comparison with the current solution of expensive, oil-based thermal power generation. Moreover, by considering the limited balancing capacity of such autonomous grids, which dictates the oversizing of the storage components in order to achieve increased energy autonomy, the trade-off between DSM and energy storage is next studied, becoming increasingly important as the quality of RES potential decays.

With regards to utility-scale energy storage applications, the potential of bulk energy storage to support base-load RES contribution is investigated, proving in this way that the intermittent characteristics of RES power generation could be eliminated. This implies increased energy security at the level of national grids while also challenging the prospect of grid parity for such energy schemes. Furthermore, the market-regulating capacity of utility-scale energy storage is reflected through the examination of different market-efficiency criteria, providing system operators with a valuable asset for the improved operation of electricity markets. Finally, the role of utility-scale energy storage in the optimum management of national electricity trade is investigated, designating the underlying problem of embodied carbon dioxide emissions' exchange over cross-border transmission and paving the way for the consideration of energy storage aspects in electricity grid planning.

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The usual disclaimer applies.

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List of Abbreviations

AL	Albania
APX	Automated Power Exchange
ARV	Arbitrage Value
AT	Austria
BA	Bosnia Herzegovina
BAU	Business as Usual
BE	Belgium
BG	Bulgaria
BOS	Balance of System
BY	Belarus
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CF	Capacity factor
CH	Switzerland
CHP	Combined Heat & Power
CO_2	Carbon Dioxide
CV	Calorific Value
CZ	Czech Republic
DE	Germany
DG	Distributed Generation
DK	Denmark
DSM	Demand Side Management
DoD	Depth of Discharge
EE	Estonia
EEX	European Energy Exchange
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electric Reliability Council of Texas
ES	Spain
FC-HS	Fuel cells and Hydrogen Storage
FI	Finland
FiT	Feed-in-tariff
FR	France
GIS	Geographic Information System
GR	Greece
HGTSO	Hellenic Gas Transmission System Operator
HHI	Herfindahl–Hirschman Index
HR	Heat Rate
HR	Croatia
HU	Hungary
HVDC	High Voltage Direct Current
IE	Ireland
IT	Italy
JRC	Joint Research Centre
L/A	Lead-Acid
LC	Life-cycle
Li-ion	Lithium-ion
LNG	Liquefied Natural Gas
LT	Lithuania
LU	Luxembourg
LV	Latvia
M&O	Maintenance and Operation

MD	Moldova
ME	Montenegro
MK	Macedonia
MO	Morocco
Na-S	Sodium-Sulphur
ND	Net Difference between production cost and arbitrage value
NG	Natural Gas
Ni-Cd	Nickel-Cadmium
NL	Netherlands
NO	Norway
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
PHS	Pumped Hydro Storage
PJM	Pennsylvania-New-Jersey-Maryland Market
PL	Poland
PPC	Public Power Corporation
PT	Portugal
PTC	Production Tax Credit
PV	Photovoltaic
RES	Renewable Energy Sources
RO	Romania
RS	Serbia
RU	Russia
SC	Super Capacitor
SE	Sweden
SI	Slovenia
SK	Slovakia
SMES	Superconducting Magnetic Energy Storage
SWI	Shannon-Wiener Index
TR	Turkey
TSO	Transmission System Operator
UA	Ukraine
UK	United Kingdom

Nomenclature

Nomenclature - Section 3.1

ARV	Arbitrage value (€/MWh)
c_{CAES}	Electricity production cost of CAES
c_{cav}	Specific cost of air cavern (€/kWh)
c_{comp}	Specific cost of compressors (€/kW)
c_f	Natural gas price for CAES (€/kWh)
c_{gt}	Specific cost of gas turbines (€/kW)
c_{PHS}	Electricity production cost of PHS
c_{pump}	Specific cost of pumps (€/kW)
c_{res}	Specific cost of water reservoir (€/m^3)
c_{spot}	Hourly spot price (€/MWh)
$c_{spot\text{-}buy}$	Hourly spot price during buying hours (€/MWh)
$c_{spot\text{-}sell}$	Hourly spot price during selling hours (€/MWh)
c_t	Specific cost of hydro-turbines (€/kW)
E_{buy}	Energy bought from the grid (MWh)
E_{sell}	Energy sold to the grid (MWh)
E_{ss}	Useful energy storage capacity of the storage system (MWh)
FC_{CAES}	Annual fuel consumption cost for CAES (€)
g	Gravitational acceleration (m/s^2)
h_{buy}	Buying hours (h)
H_{PHS}	Net available head of PHS (m)
HR_{CAES}	Heat rate of CAES (kWh_{NG}/kWh_e)
h_{sell}	Selling hours (h)
IC_{CAES}	Initial cost of CAES (€)
IC_{PHS}	Initial cost of PHS (€)
m_{CAES}	Annual maintenance coefficient for CAES (% of the initial cost)
m_{PHS}	Annual maintenance coefficient for PHS (% of the initial cost)
n_{CAES}	Service period of CAES (years)
ND	Net difference (€/MWh)
N_{in}	Input power of the storage system (MW)
N_{out}	Output power of the storage system (MW)
n_{PHS}	Service period of PHS (years)
V_{res}	Volume of the upper water reservoir for PHS (m^3)

Greek Letters - Section 3.1

Δt_{ch}	Charging period duration (h)
Δt_{dis}	Discharging period duration (h)
Δt_{year}	Annual time duration (h)
η_{in}	Charging efficiency of the storage system (%)
η_{out}	Discharging efficiency of the storage system (%)
η_{rt}	Round-trip efficiency of the storage system (%)
ρ_w	Water density (kg/m^3)

Nomenclature - Section 3.2

c_2	Benefit from taxes paid by energy storage (€/kWh$_e$)
c_3	Benefit from the avoided fuel imports (€/kWh$_e$)
c_4	Benefit from the avoided CO_2 emissions (€/kWh$_e$)
CA_{ss}	Initial capital depreciation (€/year)
c_e	Specific cost of energy storage capacity (€/kWh)
c_{ex}	Net benefit from avoiding negative externalities (€/kWh$_e$)
c_f	Input fuel price per unit energy output of CAES (€/kWh$_e$)
$c_{f\text{-}peak}$	Fuel component of the thermal peak power station operation cost (€/kWh$_e$)
c_g	Grid energy input price (€/kWh$_e$)
c_{in}	Energy input price (€/kWh$_e$)
$c_{op\text{-}peak}$	Operational cost of the thermal peak power station (€/kWh$_e$)
c_p	Specific power cost of the energy storage (€/kW)
$c_{r\text{-}peak}$	Residual component of the thermal peak power station operational cost (€/kWh$_e$)
C_{ss}	Total future cost of the investment (€)
c_{ss}	Electricity production cost of the system (€/kWh$_e$)
c_{tot}	Total social benefit (€/kWh$_e$)
$c_{tot\text{-}net}$	Total net social benefit (€/kWh$_e$)
$c_{TPS\text{-}peak}$	Total electricity production cost of the thermal peak power station (€/kWh$_e$)
c_w	Wind energy input price (€/kWh$_e$)
d_o	Hours of guaranteed energy production per day (hours)
DoD_L	Maximum depth of discharge (%)
$d_{o\text{-}max}$	Hours of guaranteed energy production per day ensuring maximum profit (hours)
$d_{o\text{-}ss}$	Hours of energy autonomy corresponding to total energy storage capacity (hours)
e	Electricity price escalation rate (%)
EC_{in}	Cost of annual energy input for charging the energy storage (€/year)
e_f	Mean annual escalation rate of the input fuel price (%)
E_{load}	Annual energy production of the energy storage delivered to the local grid (kWh$_e$)
$E_{load\text{-}1}$	Annual wind farm-derived energy production of the energy storage (kWh$_e$)
$E_{load\text{-}2}$	Annual grid-derived energy production of the energy storage (kWh$_e$)
E_{ss}	Energy storage capacity (kWh)
FC_{ss}	Annual fixed maintenance and operation cost (€/year)
g_{ss}	Maintenance and operation inflation rate (%)
HR	Heat rate of CAES (kWh$_{fuel}$/kWh$_e$)
H_u	Calorific value of fuel (MJ$_{fuel}$/kg$_{fuel}$)
i	Return on investment index (%)
IC_n	Initial investment cost future value for the energy storage (€)
IC_{ss}	Initial investment cost for the energy storage (€)
k_g	Contribution of the grid to system charging on an annual basis (%)
k_w	Contribution of wind energy to system charging on an annual basis (%)
m	Fixed maintenance and operation cost coefficient (%)
M_f	Annual fuel savings (kg)
n_k	Amortization period (years)
N_{load}	Power output delivered to consumption (kW$_e$)
N_{ss}	Nominal power output of the energy storage (kW$_e$)
n_{subs}	Period of fixed annual subsidy for the power premium (years)
p_1	Initial cost subsidy support to energy storage (€/kWh$_e$)
p_2	Guaranteed power premium to energy storage (€/kWh$_e$)
p_{CO2}	Price of CO_2 allowances (€/kg$_{CO2}$)
p_e	Feed-in tariff (€/kWh$_e$)
$p_{e\text{-}b/e}$	Break-even feed-in tariff (€/kWh$_e$)
p_{fuel}	Price of fuel imports for the thermal peak power station (€/kg$_{fuel}$)
$p_{N/m}$	Annual power premium for peak power stations (€/kW·year)
R_{ss}	Annual revenues from the energy storage operation (€)
VC_{ss}	Variable maintenance and operation cost (€/year)
w	Mean annual escalation rate of the input energy price (%)

Greek Letters - Section 3.2

γ	Initial cost state subsidy (%)
δ_{CO2}	Annual avoided CO_2 emissions (kg_{CO2}/year)
$\delta p_{N/m}$	Difference of the annual power premium (€/kW·year)
ε_{CO2}	Net CO_2 emission factor of the thermal peak power plant ($kgCO_2/kWh_e$)
η_d	Efficiency of the conventional power station (%)
η_p	Power output efficiency including transmission losses (%)
η_{ss}	Energy conversion efficiency (%)
ξ	Service period prolongation factor for the thermal peak power plant (%)
π	Size coefficient of energy storage capacity
Φ_{ss}	Annual taxes paid by the energy storage actor (€/year)
φ_{ss}	Tax coefficient (%)

Nomenclature - Sections 4.1, 4.2

C_{pA}	Specific heat capacity of air (J/kg/K)
C_{pR}	Specific heat capacity of gases (J/kg/K)
DOD_L	Air cavern/tank maximum depth of discharge
H_u	Calorific value of natural gas (MJ/kg)
m_a	Mass of air for stoichiometric combustion (kg/kg_{NG})
$\dot{m}_A$	CAES cycle mass air flow (kg/s)
M_A	Air mass level inside the air cavern/tank (kg)
$\dot{m}_{A-dual,\max}$	Dual-mode cycle mass air flow (kg/s)
$\dot{m}_f$	CAES cycle mass fuel flow (kg/s)
$\dot{m}_g$	CAES cycle mass gas flow (kg/s)
$\dot{m}_{g-dual}$	Dual-mode cycle gas air flow (kg/s)
$N_{c\text{-}CAES}$	CAES compression power (MW)
$N_{cr\text{-}CAES}$	CAES compressor power (MW)
$N_{cr\text{-}dual}$	Dual-mode compressor power (MW)
N_d	Load demand (MW)
N_{def}	Initial load demand deficit (MW)
N_{def}'	Secondary load demand deficit (MW)
$N_{gt\text{-}CAES}$	CAES gas-turbine power (MW)
$N_{gt\text{-}dual}$	Dual-mode gas-turbine power (MW)
$N_{gt\text{-}f}$	Final power of the gas turbine (MW)
N_m	Motor power (MW)
N_W	Wind power output (MW)
$N_{W\text{-}curt}$	Wind power curtailments (MW)
N_{WP}	Wind power installed capacity (MW)
P_A	Air pressure level inside the air cavern/tank (Pascal)
P_{amb}	Ambient air pressure (Pascal)
P_{t1}	Total pressure at the compressor inlet (Pascal)
P_{t2}	Total pressure at the compressor outlet (Pascal)
r_c	CAES compressor pressure ratio
r_c'	Dual-mode compressor pressure ratio
R_g	Air constant (J/kg/K)
r_t	Gas turbine pressure ratio
T_{amb}	Ambient air temperature (K)
T_{cav}	Temperature inside the air cavern/tank (K)
T_{cc}	Maximum operational temperature of the combustion chamber (K)
T_{gt}	Temperature of gases at the gas turbine inlet (K)
T_{t1}	Ambient temperature at the inlet of the compressor (K)
$V_A(t)$	Air volume level inside the air cavern/tank (m^3)
V_{max}	Maximum volume of the air cavern/tank (m^3)
V_{min}	Minimum volume of the air cavern/tank (m^3)
V_{ss}	Available volume of the air cavern/tank (m^3)

Greek Letters - Sections 4.1, 4.2

δm	Air mass losses (kg/s)
δP	Pressure losses (Pascal)
δT	Temperature variation inside the air cavern/tank (K)
η_{gen}	Electrical generator efficiency (%)
η_{isc}	Compressor isentropic efficiency (%)
η_{isT}	Gas turbine isentropic efficiency (%)
η_{M}	Motor efficiency (%)
η_{mc}	Compressor mechanical efficiency (%)
η_{mc}	Gas turbine mechanical efficiency (%)
λ_a	Air ratio
ρ_A	Air density (kg/m^3)

Nomenclature - Sections 5.1, 5.3

CF	Wind power capacity factor (%)
CF_{imp}	Capacity factor of cross-border transmission with regards to imports (%)
D_e	National dependence on direct electricity imports (%)
D_f	National dependence on primary fuel imports (%)
df	Import share of imported fuel (%)
DI	National electricity dependence (%)
DoD	Depth of discharge (%)
e_f	Share of fuel in the national fuel mix (%)
E_{PHS}	Useful energy storage capacity of the storage system (MWh)
E_w	Wind energy output (MWh)
g	Gravitational acceleration (m/s^2)
H	Net available head of PHS (m)
h	Hours of storage energy autonomy (hours)
HHI	Herfindahl–Hirschman index
h_{month}	Hours of the month (h)
N'_w	New wind power installed capacity (MW)
N_{PHS}	Power output of the PHS
N_w	Existing wind power installed capacity (MW)
SWI	Shannon-Wiener index
V	Volume of the upper water reservoir for PHS (m^3)

Greek Letters - Sections 5.1, 5.3

ΔCO_2	Emission savings (ktCO_2)
Δt	Time duration (h)
η_{out}	Discharge efficiency of PHS (%)
η_{rt}	Round-trip efficiency of PHS (%)
ρ	Water density (kg/m^3)

1. Introduction

1.1 Large-Scale Integration of Renewables and Energy Storage

Triggered by the need to satisfy large-scale integration of renewable energy sources (RES) in the forthcoming years, research in the development of suitable technological solutions, policy measures and support tools has been intensive during the recent period (Purvins et al., 2011). In fact, it is since the first boom of wind power in California that the global RES capacity has been determined by vast growth rates, gradually paving the way for the establishment mainly of wind and solar power generation. Nowadays, although contribution of RES in several countries may be considered significant, exceeding 10% of the local electricity demand, more ambitious targets challenge the role of RES technologies in the near future. For these to be accomplished, certain downsides of large-scale RES integration need to be addressed first.

Large-scale integration of RES means that a significant portion of electricity generation is based on variable or even stochastic energy supply sources (Früh, 2013), the performance of which is hard to predict. Besides that, it also introduces additional effects in power quality and power system dynamics, with the corresponding impacts becoming more severe for weaker, small-scale autonomous electricity networks, where balancing capacity among different power sources and electricity grids is restricted. Nevertheless, a certain threshold of RES integration exists for every electricity system, including central mainland grids; when violated it can cause both technical and market related side-effects (Connolly et al., 2010; Liu et al., 2011a).

Market related side-effects include increased volatility of spot prices and investment risk, as well as failure to comply with the expectation for considerable spot price reduction (e.g. owed to the need to employ considerable back-up power to support increased penetration of RES). To deal with such effects, electricity market environments need to be investigated in detail, or as Woo et al. (2011, p.3943) put it, to meet the challenge of price variance caused by considerable infusion of wind energy, "*principal actors will need to expend increased effort in risk management and become increasingly familiar, in particular, with the financial instruments that have proved their worth in the financial sector*".

Meanwhile, negative impacts of large-scale RES integration can be addressed by promoting the following technological solutions:

- *Upgrade of electricity grids* can provide better balancing between the variable RES power generation and the inelastic energy demand through elimination of transmission bottlenecks and increased cross-border electricity trade.
- *Spatial planning strategies* facilitating dispersed RES generation is an alternative that is based on the complementarity of RES potential and its quality across large geographical areas.
- *Demand side management (DSM) techniques* along with improved *forecasting methods* can encourage the consumer side to respond to the variability of RES power generation.
- *Large-scale energy storage applications* can store excessive amounts of RES production and recover them through feeding the grid when energy deficits appear.

Although all four solutions are required to provide substantial support to future RES targets and gradually establish the concept of smart grids, my thesis puts in the centre energy storage and specifically bulk energy storage. Both mature (e.g. pumped hydro storage (PHS) and battery storage) and novel technologies (e.g. hydrogen-based storage, advanced batteries, etc.) (Kaldellis and Zafirakis, 2007a; Kaldellis, 2008) are constantly being developed, offering solutions for various applications that are not limited to RES support. Instead they capture different aspects at every stage of the electricity supply chain (i.e. generation-transmission-distribution-consumption). Despite the potential of energy storage systems to provide multiple services, persistently high investment costs and the absence of a concrete valuation framework (Sioshansi et al., 2009; 2011) have hindered market growth so far. As also supported by Sioshansi et al. (2009), the value stemming from privately-owned energy storage provides reduced incentive for investment, except for certain, special cases, where energy storage can compete effectively with established energy solutions (e.g. in isolated energy systems, where the expensive oil-based electricity generation can justify introduction of energy storage to support RES-based energy autonomy). At the same time, identification of social welfare benefits potentially produced by private-owned energy storage has not yet been realized, while benefits accruing from the use of energy storage at the utility scale / system level have not yet been adequately exploited.

In this context, the investigation of emerging energy storage applications as well as the design and development of novel energy storage strategies at the level of private investors and utility scale systems are central in this thesis. The economic evaluation of such applications and strategies and the development of support tools and instruments necessary to accelerate the growth of the energy storage market are also explored. In this way, the development of a concrete support framework and novel business models provide for a broad range of applications that energy storage can support. This is considered critical, since, as validated by my research results, for energy storage, and especially privately-owned systems, a portfolio of services rather than reliance on a single source of revenue will be required to support their financial case. At this point it should be noted, that by no means can such an argument undervalue the importance of supporting RES for energy storage. On the contrary, its purpose is to pronounce the need for energy storage to expand further than the scope of increased RES penetration. Reflections upon this argument are also drawn from the literature review undertaken in the following section, according to which it is designated that although a large body of literature links energy storage directly with RES, there are several studies looking into emerging energy storage strategies associated with the integration of such systems in electricity markets.

1.2 The Focus on Energy Storage Research

Although real life applications of large-scale energy storage dedicated to increased RES penetration are not yet broadly expanded, a significant body of literature already exists. Review of similar studies along with studies emphasizing the role of energy storage alone aims to designate trends, prospects and considerations regarding the potential of energy storage technologies. Within this body of literature, there are two main approaches; the first considers energy storage at the installation level, or from the private investor point of view, and the second evaluates the performance of energy storage at system level, meaning the national grid or a given electricity system such as an isolated grid. The following review begins with the macro-level (i.e., from the system point of view) and continues with the micro-level (i.e., at the level of installation or from the investor point of view).

1.2.1 System Point of View

There are several studies linking large-scale integration of RES with the adoption of energy storage at the market level. Such studies usually examine energy storage from the system point of view. The main question in this body of literature is how to maximize RES penetration with the support of energy storage. More precisely, by acknowledging system characteristics such as fuel mix, interconnection capacity, transmission bottlenecks, dispatchable and non-dispatchable units, technical minima of thermal power plants, quality of RES potential, energy storage characteristics and other information required for advanced simulations, an optimum/feasible level of RES integration is obtained. The focus in the support of large-scale RES integration concerns bulk scale energy storage systems rather than the entire range of contemporary energy storage technologies.

In this context, Tuohy and O'Malley (2011) examined the ability of the Irish national grid to absorb substantial wind energy in 2020, introducing significant PHS capacity that may provide optimum energy management of excess wind energy production. According to their results, PHS may prove to be cost-effective only in the case that wind energy contribution exceeds 50% by 2020, otherwise employment of peak load thermal power plants is preferable. Carton and Olabi (2010) studied the electricity grid of Ireland with high wind energy production, examining the fuel cell and hydrogen storage (FC-HS) solution as the support option for wind energy. They emphasize that although hydrogen may comprise a feasible solution in the near future, several challenges concerning technological developments and social acceptability need to be overcome.

Moreover, Sivakumar et al. (2014) pointed out the necessity for the more efficient exploitation of the existing PHS potential in India through the introduction of variable speed equipment, in an effort to tackle high electricity production prices of conventional peak demand plants and better facilitate increased RES penetration expected in the Indian region in the following years.

Even more interestingly, Anagnostopoulos and Papantonis (2012) proposed the retrofitting of existing grid-operated Greek hydropower stations to PHS plants, putting forward a combined operational mode that can serve both conventional and PHS operational requirements, maximizing in this way the economic performance of the plant while also satisfying increased RES contribution.

Furthermore, De Boer et al. (2014) studied the application of different bulk scale energy storage solutions including power-to-gas, PHS and compressed air energy storage (CAES) with regards to their system electricity cost reducing effect under different levels of wind power generation, owed to the reduction of startup and shutdown costs of thermal units together with the reduction of fuel-based operational costs. According to their results, electricity cost benefits accruing from the application of large-scale energy storage are highest for PHS, followed by CAES and then power-to-gas, indicating however that the impact of energy storage on emissions is less obvious, with certain operation scenarios for energy storage leading to higher system emissions.

Next, Johnson et al. (2014) studied the assessment of optimum energy storage levels under different, hypothetical transmission-constrained wind penetration scenarios for United States regions considering grid-scale battery storage co-located with the wind resource. To this end, the authors designated optimum sizing directions for the storage component realizing that under the given storage costs, 100% recovery of wind energy curtailments would lead to cost-inefficient solutions.

Solomon et al. (2014) examined the role of grid storage for the case of California, estimating that even 85% RES penetration would be possible for the local electricity system under a total storage capacity of 186GWh, corresponding to almost 22% of the daily load demand of the region, also designating the importance of balanced RES curtailments.

Furthermore, Ekman and Jensen (2010) acknowledging the already large participation of wind power in the Danish electrical fuel mix, examined the prospects of grid scale energy storage. According to their analysis, investment in energy storage can be risky because of exposure to spot market fluctuations. However, larger scale integration of wind power in the Danish system implies further regulatory interventions, which in turn opens a new window for energy storage.

In the same context, Dursun et al. (2011) studied the integrated solution of wind-PHS for the wider area of Marmara in Turkey. The authors after identifying six different sites for the installation of PHS systems simulated the electrical network of Marmaras for different levels of wind energy participation and estimated that a cost-effective solution could be established. The share of wind energy in their simulations exceeded 40% on an average annual basis.

Moreover, Salgi and Lund (2008) considered the transmission congestion challenges encountered in the future between Denmark and neighbour countries, which will limit export of excess wind energy by Denmark. The authors tested the solution of CAES for the entire Danish electrical network and found that wind energy share of approximately 55% is achievable. Furthermore, Hedegaard and Meibom (2012) studied different energy storage technologies to support the scenario of 57% wind energy contribution in the Western Denmark region. More specifically, based on the attributes of each technology examined, the authors identified different opportunities in terms of time scale, with PHS, CAES, batteries and hydrogen being suitable for both intra-hour and intra-day/day-ahead balancing services. Certain battery types were excluded from several-day balancing, while finally, CAES, PHS and FC-HS were the only technologies considered for the option of seasonal storage.

Subsequently, Krajacic et al. (2011) examined the scenario of 100% RES contribution for Portugal in 2020, through the investigation of different energy storage solutions. They found that a combination of three different energy storage solutions, i.e. PHS, FC-HS and batteries, could lead to achieving 100% RES contribution, based on the primary energy production, mainly coming from wind energy and hydropower. Additionally, Grunewald et al. (2011) studied opportunities of large-scale energy storage integration in the UK to ensure a low carbon future, through the examination of CAES, FC-HS and flow batteries. Their simulation results indicated that large-scale storage could become commercially viable if a long-term evaluation assessment of technological options is taken into account. Otherwise, gas turbines provide the most appropriate solution to deal with short-term increase of intermittency from the gradual increase of wind energy. At the same time, the authors point out that for energy storage to be established further work is required on the wider social and grid benefits.

Finally, Bueno and Carta (2005) examined the introduction of an integrated wind-PHS system for the island of El Hierro, in the Canarian Archipelago, with simulation results indicating that penetration of wind energy could reach up to 68% under financially viable terms.

1.2.2 Investor Point of View

In addition to the system point of view, energy storage has been examined from the investor side, seeking for profit maximization. In this context, the main body of literature focuses on arbitrage strategies, examining the performance of storage technologies such as CAES and PHS in spot markets, putting at the same time considerable effort in developing the most efficient unit-commitment algorithms for such systems. Among these studies, several focus on the technical and financial feasibility of such systems to recover wind energy or other RES surplus. In most studies the authors indicate the need for the valuation of additional services that could be provided by energy storage to improve economic performance of such configurations.

In this context, Varkani et al. (2011) proposed a self-scheduling strategy for the integrated operation of wind-PHS plants in power markets. More precisely the authors used stochastic programming techniques (neural networks) and considered the participation of the integrated energy solution in both energy and ancillary markets, i.e. the day-ahead energy market and the ancillary service markets of spinning and regulation reserve. They found that the valuation of ancillary services, provided by the PHS system, could considerably improve economic performance of the configuration under study. Furthermore, Duque et al. (2011) studied the optimal operation of a PHS system, designed to compensate imbalances of a wind power producer, through incorporating uncertainty in the prediction of wind energy production into an optimization model aiming to maximize the daily revenue of the PHS plant. Joint operation of the two systems (i.e. the wind park and the PHS system) is found to be more profitable than the respective independent systems.

In addition, Kanakasabapathy and Swarup (2010) developed a bidding strategy for PHS plants based on forecasted hourly market clearing price and a multistage looping algorithm to maximize profit, considering both the spinning and non-spinning reserve bids. Moreover, Kazempour et al. (2009a), developed a self-scheduling algorithm based on mixed integer programming to maximize PHS revenue. To this end, the authors let the system participate in all three energy, spinning reserve and capacity markets, assessing at the same time the risk constraints that should be considered when considering performance of a similar system within the uncertain environment of electricity markets. Next, Hessami and Bowly (2011) investigated the financial feasibility and optimization of different energy storage systems connected to a 186MW wind park in the area of Victoria, Australia. For this purpose the authors used spot market data for three years. They applied dynamic programming techniques to simulate operation of the candidate energy storage technologies and found that CAES produced higher revenue when compared to PHS. Korpaas et al. (2003) used dynamic programming for the scheduling and operation of energy storage combined with wind power, concluding that energy storage may under certain conditions offer a cost-effective alternative to grid expansion, unless less mature technologies such as FC-HS are considered.

Bradbury et al. (2014) tested 14 different storage technologies and seven US electricity markets in order to value arbitrage for energy storage. Their results showed that the profit-maximizing size (i.e. hours of energy storage) of energy storage is primarily determined by its technological characteristics and not market price volatility. Most systems examined had an optimal size of 1-4 h of energy storage, though for pumped hydro and compressed air systems this size is 7-8 h, with the authors putting also forward the need for capital cost reductions or energy storage revenue enhancement through participation in the capacity and ancillary services markets.

In the same context, Shcherbakova et al. (2014) estimated the value of battery energy storage in the South Korea's electricity market, reaching the conclusion that under present market conditions, energy arbitrage in Korea is not profitable enough to attract private entry. Instead, successful integration of storage would require both higher price volatility and lower capital costs of storage technologies. In addition and similar to previous studies, the authors emphasize that storage also has welfare (i.e. non-financial) benefits for consumers and electric utility companies which can raise its implied value.

Next, Cho and Kleit (2015) examined the participation of battery energy storage in both the energy and the ancillary services' markets of ERCOT. According to their results, even with this additional revenue opportunity, the battery does not generate sufficient revenues to pay its cost. To this end, the authors also stressed the importance of several charging and discharging cycles during a day period in contrast with a regular dispatch strategy of a single cycle on a daily basis.

Following, Arghandeh et al. (2014) tested the economically optimal operation of community, distribution network, energy storage systems in competitive energy markets, highlighting the issue of forecasting accuracy concerning electricity prices, as well as the fact that distributed energy storage offer several benefits to electric power system operation, including load support during outages, improved reliability, service availability, renewable energy dispatchability and peak shaving.

Moreover, Fertig and Apt (2011) studied performance of a wind-CAES configuration in Texas and found that the optimal, profit-maximizing CAES capacity is unrealistically expensive and could not compete with natural gas combined cycle plants, even if CAES entered the capacity market. The authors also found that unless extreme price spikes are encountered, CAES cannot prove to be a viable solution, even if social benefits (such as improved air quality) are accounted for. Within the same context, Loisel et al. (2011) examined the economic performance of a wind-CAES system in the French energy market. It was found that the financial viability of the system could only be ensured with a 200% increase in French spot market spreads.

Lund et al. (2009) studied the optimum operation of CAES systems in electricity spot markets with the use of dynamic programming. By also implementing forecasting principles, CAES was found to achieve 80-90% of the respective optimal operation revenues (corresponding to perfect spot price prognosis). Similarly, Connolly et al. (2011a) investigated different, practical arbitrage strategies, this time for PHS configurations participating in 13 different electricity spot markets. Their results indicate that even with a low investment cost, low interest rate and suitable electricity market characteristics, PHS still comprises a high-risk investment. What is again emphasized is the fact that profitability of such systems under arbitrage operation is difficult to predict, while at the same time, additional revenues from ancillary services, capacity payments or participation in the balancing markets should be put forward.

To this end, Drury et al. (2011) examined the value of CAES systems within energy and reserve markets, indicating that arbitrage-only revenues are unlikely to support CAES investment in most USA markets. However, support could be sufficient if reserve services were taken into consideration. More precisely, by using historical price data the authors simulated two different dispatch methods; dispatch for net revenue maximization through energy arbitrage only and by providing both energy arbitrage and contingency reserves. Sioshansi et al. (2011), used historical data of the Pennsylvania-New-Jersey-Maryland (PJM) market for eight consecutive years in order to compare PHS and CAES, pointing out that energy storage should be viewed under the angle of societal benefits. In this context, the authors argued that energy arbitrage will even in this case remain the most critical component among the various revenues streams that can be considered in energy storage deployment. Moreover, Anagnostopoulos and Papantonis (2007) and Kapsali and Kaldellis (2010) studied the joint financial performance of PHS and wind parks operating in Greek islands and found that viability can be optimised for the specific systems under the application of certain dispatch strategies. More precisely, by replacing gas turbine or diesel plants in providing guaranteed energy on a daily basis to shave peak demand during noon and evening. Electricity production cost in small islands often exceeds 1€/kWh, with the smallest islands exhibiting the highest electricity production cost.

Dufo-Lopez et al. (2009) examined different battery types to support Spanish wind farms and found that depending on battery type, peak time electricity price should range between 220€/MWh and 660€/MWh, in order for wind-battery systems to be as cost-effective as wind-only systems. Furthermore, Walawalkar et al. (2007) studied the economics of two different types of energy storage i.e., sodium-sulphur (Na-S) batteries for energy arbitrage and flywheels for voltage regulation, with historical price data for the New York market. By identifying appropriate charging and discharging time periods, net revenues for different capacity configurations were examined. The authors pointed out the importance of ancillary services such as frequency regulation, spinning and non-spinning and 30 minutes operating reserves for energy storage to become profitable within a market environment.

Kazempour et al. (2009b) examined established vs emerging energy storage technologies using Spanish market data on energy transactions, spinning reserve market and regulation market clearing prices. He concluded that for emerging technologies such as Na-S batteries to compete with established systems such as PHS, incentives like decreased tax rates and dedicated gratuitous finance tools would be necessary. Next, He et al. (2011) developed a business model to aggregate the value of electricity storage services, based on the assumption that energy storage can be treated as a common asset between regulated and deregulated actors through auctioning. More precisely, the core of the business model lies in organizing a series of auctions to allocate the available power and energy capacities of the storage unit to different actors. Within the same context, Leou (2012) developed an economic cost-benefit analysis model to compare three different kinds of services provided by an energy storage system (a flow battery in specific) i.e., energy arbitrage, reduction of transmission access cost and deferral of facility investment with the respective system costs. For this purpose the author used a genetic algorithm with linear programming to determine the optimal capacity and operation of the energy storage system. Nazari et al. (2010) pointed out that with optimum unit commitment, deployment of PHS units could result in significant cost savings deriving from the avoidance of fuel consumption, start-up costs and emission costs of conventional thermal generators called to satisfy peak demand. Pruggler et al. (2011) explored a different aspect of energy storage participation in electricity markets. Their study showed that if certain combined strategies of storage and DSM are applied by a dominant deregulated power supplier, arbitrage spread could increase causing storage revenues to grow. The authors concluded that concerning speculation, appropriate market surveillance needs to be guaranteed in markets where DSM and energy storage are still in their early stage.

Finally, Sioshansi et al. (2009) examined the value of energy storage in PJM through energy arbitrage, assigning to it welfare effects such as the decrease in price volatility, which could benefit final consumers. The authors concluded by reflecting on different points of view for energy storage, depending on the system operator, i.e. this could either be a private producer, a transmission owner or a utility, with each of them having different interests and expectations from energy storage. In this context, the authors highlighted the fact that the gradual deployment of energy storage could in turn signal narrowing of the price spread for arbitrage. This would lead to even riskier investments for new private energy storage actors and thus large-scale deployment would only be of interest to transmission owners and regulated entities.

1.2.3 Conclusions and Research Aims

The literature review has flagged up some common findings and issues raised by most researchers:

- Large-scale RES integration can be satisfied only by a limited number of energy storage technologies, including PHS, CAES and certain advanced batteries that are not yet commercially competitive. Furthermore, although FC-HS may prove critical for the dominance of RES technologies over fossil fuels in the future, the technology is not yet mature enough to provide the support required.
- Many system-focused studies conclude that although energy storage can support large-scale RES integration, cost-effectiveness is far from certain.
- There is increased concern expressed with regards to the actual value of arbitrage for energy storage systems and the high risk to which similar investments would be exposed, identifying also the need for market surveillance to avoid speculation by deregulated actors.
- There is a pronounced need to value energy storage ancillary services, i.e. spinning reserve, participation in the capacity market, etc., including social welfare attributes and grid benefits in order to develop greater opportunities for such systems to operate in an electricity market environment.
- Future market uptake of energy storage has to be incentivised with tax allowances and preferential financing schemes.

Acknowledging the potential of energy storage systems to provide support to RES on the one hand and the role that energy storage is called to play in modern electricity markets on the other, the aim of this thesis is twofold: to evaluate emerging energy storage applications and to develop novel operation strategies and instruments that will accelerate the market uptake of energy storage technologies. In this context, the thesis is organized as follows: following the introductory section and literature review of Chapter 1, in Chapter 2 a brief presentation of contemporary energy storage technologies and applications will be undertaken in order to map the characteristics of the available energy storage systems. The thesis is accordingly organized on the basis of a study by study structure, divided in three distinct chapters. In Chapter 3, emerging energy storage strategies for private actors are investigated, while in Chapters 4 and 5 the focus is given on novel energy storage strategies at the system level, looking into autonomous electricity grids and utility-scale energy storage systems. Finally, a synopsis of results together with policy recommendations and future research are given in the last Chapter 6.

2. Energy Storage Technologies and Applications

2.1 Contemporary Energy Storage Applications

Common energy storage applications are summarized in Figure 2.1, which if combined with the technology mapping of Figure 2.2, leads to a rough designation of the most appropriate energy storage technologies for each application considered. Energy storage applications (Zafirakis, 2010) are further analyzed in the following paragraphs, based on their classification in three main categories, each corresponding to a different stage of the electricity supply chain, i.e. electricity generation, transmission and distribution and end consumption.

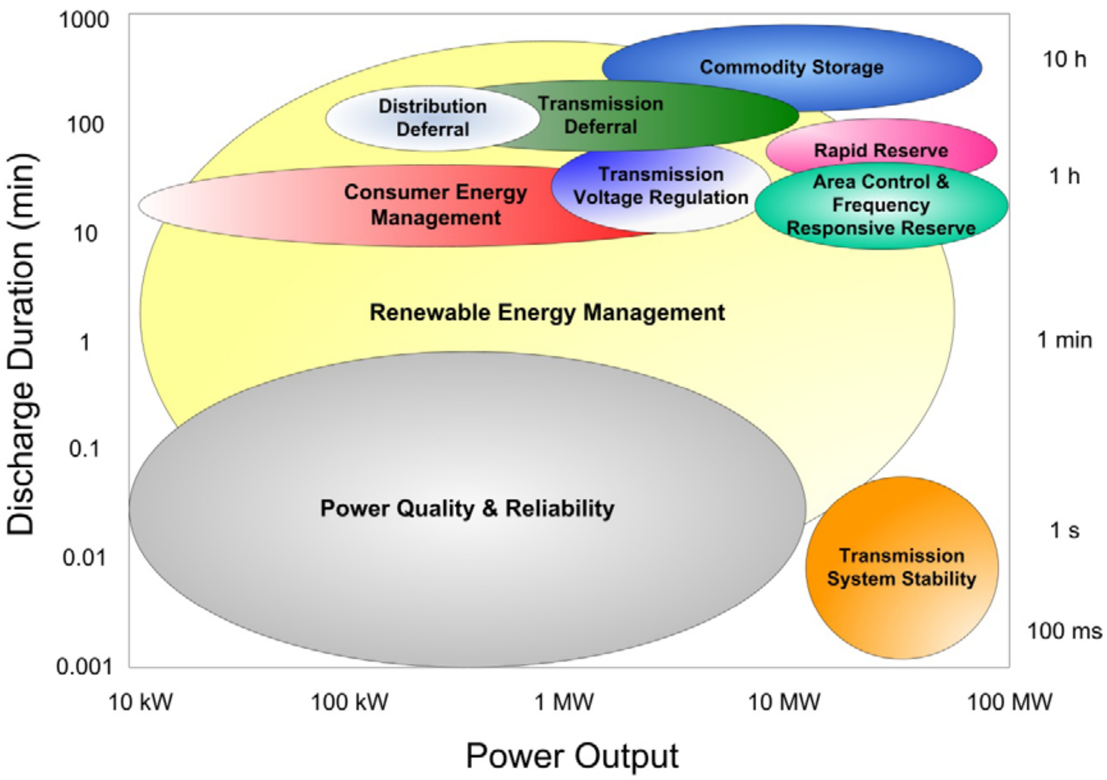


Figure 2.1: Mapping of energy storage applications

2.1.1 Category of Generation

Rapid or spinning reserve or contingency reserve

In order for utilities to compensate for the possible failure of a generator, thermal power stations are used as back-up power. This is achieved either by the operation of existing thermal power stations below their rated power or the use of new, flexible back-up systems (combustion turbines), dedicated to cover energy deficits. This results in increased fuel consumption and fast wear for the already operating power units, since they are called to operate at off-design conditions, and also implies rather low load factors for back-up combustion turbines. To this end, energy storage can replace conventional back-up power and cover any energy deficit.

Area control and frequency responsive reserve

Although large-scale networks have the ability to address the imbalance between generation and load demand, the same is not valid for small-scale, islanded network areas. In the absence of energy trade with neighbouring network areas, energy storage is a critical energy management asset. On the other hand, vulnerability of such isolated networks to load fluctuations entails significant frequency variation that can affect electrical appliances at the consumer end and utility equipment at the generation side. With the introduction of energy storage, counterbalancing of load fluctuations and regulation of frequency are possible.

Commodity storage or load levelling or arbitrage

Commodity storage or load levelling or arbitrage is one of the most important applications for energy storage. Satisfaction of peak demand has always been a challenge for utilities. Similar to spinning reserve, extra energy required to cover peak load is usually provided by the operation of additional combustion generators, that have very low utilization rates and therefore increased costs of operation. During off-peak times, when the generation relies on inflexible base-load thermal power stations or the large-scale RES integration, significant energy surplus can appear. Recovering this energy surplus to cover peak loads with the use of appropriate energy storage systems is an alternative that can prove cost-effective, depending on the price spread between peak and off-peak periods.

Renewable energy

Collaboration with RES is the most important challenge that energy storage is faced with. This is owed to the fact that large scale RES integration at the grid level comes with certain shortcomings, synopsized in the following:

- Variability: RES output can vary considerably as the underlying resource fluctuates. That means that to balance generation with electricity load requires more flexibility from the grid operation point of view.
- Uncertainty: RES generation cannot be predicted with perfect accuracy which suggests that system operators could need additional reserves and/or an improved ability to dispatch generation.
- Location specificity: RES generation is more economical where highest quality resources are available. This implies that more transmission and more advanced planning could be needed.
- Non-synchronous generation: Voltage and frequency stability from variable RES generators is not yet standard practice, since in most cases additional equipment is necessary which comes at added capital costs.
- Low capacity factors (CFs): Owed to the availability of the underlying resource, the run-time of RES plants is limited. That means that existing conventional generators could be needed to meet demand, although expected to run less than originally anticipated, affecting in this way cost recovery.

To this end, use of energy storage can provide multiple gains to RES power plants, allowing for the delivery of guaranteed energy power output that eliminates the inherent characteristic of variable or even stochastic RES power generation. Applications extend in this context from primary frequency control to energy management addressing uncertainty at the longer term, each time involving different types of energy storage systems and portfolios.

Different energy storage strategies that can be adopted in this context, either seek profit (e.g. replacement of peak plants) or energy autonomy maximization (e.g. energy supply of isolated grids that rely on oil-based generation). RES potential quality along with demand patterns and complementarity between the different RES and demand are critical factors that determine the overall performance of similar configurations.

2.1.2 Category of Transmission and Distribution

Transmission system stability

When system generators fail to synchronize with the rest of the system, the system becomes unstable. That means that there is a difference between the phase angle of the generator and the demand. If the change is too big for the system to handle, it may even lead to system collapse. Since load disturbances are the primary cause of transmission instabilities, load smoothing via energy storage can eliminate instability and ensure synchronous network operation.

Transmission voltage regulation

To obtain uniform voltage across the entire transmission line, injection of reactive power is necessary. Hence, to deal with voltage difference, capacitors are used that provide the required reactive power. Injection of reactive power is also possible with the use of energy storage at all operation stages (charging, discharging and standby), on top of other, main grid services provided.

Transmission facility deferral

Utilities being faced with the constant increase of electricity demand are obliged to provide sufficient transmission capacity. This in turn results in low utilization of new lines and transformers if peak demand increases disproportionally to total demand, making transmission upgrade cost-ineffective. As an alternative, grid energy storage can be used to serve peak demand periods. In this context, use of energy storage can smooth the demand profile, allowing a less fluctuating pattern of operation for the transmission lines (reduced peak demand and increased demand during off-peak periods to charge grid energy storage). Owed to the trade-off between energy storage and transmission lines, load factor of the transmission network can increase, leading to greater utilization of the respective investment.

Distribution facility deferral

Similar to transmission investment deferral, installation of new distribution equipment may also be postponed through the use of demand side energy storage. This is aligned with the promotion of distributed generation (DG) patterns and future smart grids that will foster community and even domestic energy storage.

2.1.3 Category of End Consumers

Energy management or peak shaving

Energy management focuses on the reduction of peak loads in order for utility customers to avoid paying high demand charges, which are related to the highest peak recorded on a monthly basis. Peak shaving via the implementation of energy storage is used to prevent the occurrence of a peak that leads to penalty fees. To this end, demand side energy storage is set to charge during off-peak hours (through either onsite energy generation or using the grid) in order to shave the respective peak load through onsite energy supply instead of grid reliance during peak hours. The specific application can support DSM strategies, especially for the industrial sector.

Power quality and reliability

Harmonic distortions, voltage sags, spikes and failures may cause serious problems to vulnerable electronic appliances. In order for end-users to protect these devices, appropriate, small-scale domestic energy storage (e.g. uninterruptible power supply) can be used to replace grid power supply until power quality of the supply network is restored.

2.2 Energy Storage Technologies

One way of classifying energy storage technologies is according to the means and method of energy storage. In this context, the three main categories of energy storage systems (Zafirakis, 2010) correspond to:

- Mechanical energy storage; including PHS, CAES and flywheels.
- Chemical energy storage; including all types of conventional and advanced batteries, flow batteries and FC-HS.
- Electrical energy storage; including super capacitors (SCs) and superconducting magnetic energy storage (SMES).

Depending on their application field, energy storage technologies are divided into two large groups, i.e. the group of energy management and the group of power quality and reliability. In the first group are bulk energy storage technologies, such as PHS and CAES, which are able to support applications requiring considerable energy storage capacity and available energy autonomy. In the second group, technologies that are able to deliver short-term (even in the scale of msec) power injections, such as flywheels, SCs and SMES, are included. Between these two groups, the bridging power category captures the overlapping area that is mainly supported by the various battery technologies. Classifications are better illustrated in Figure 2.2, where the different, contemporary energy storage technologies are plotted against their typical energy storage capacity, available energy autonomy and power output. Large-scale energy storage systems serving energy management applications are found in the upper right side of the figure. Power quality and reliability technologies on the other hand cover the lower left side of the figure, with battery systems spreading across the entire bridging power range that also involves FC-HS.

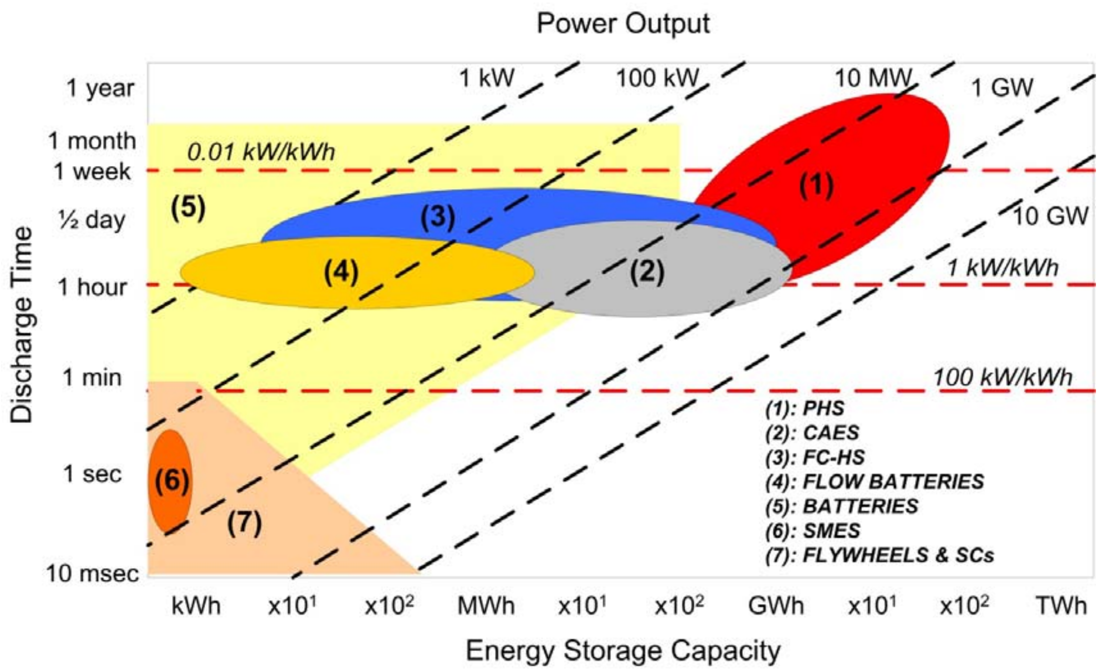


Figure 2.2: Mapping of contemporary energy storage technologies

To this end, it should be noted that the application range of individual energy storage technologies is found to constantly expand, supporting the notion that an energy storage system should take over multiple roles and not be limited to a single application area. Such a trend challenges not only energy storage capacity and available energy autonomy of smaller-scale technologies but also calls for the improvement of bulk-scale energy storage characteristics in areas such as response time and cycling potential. These challenges are gradually being addressed, mainly by the progress met in the field of batteries (Battke et al., 2013), with new technologies offering the opportunity for a single system to practise both energy management and power quality and reliability services.

2.3 Comparison of Energy Storage Technologies

Each energy storage system is determined by certain advantages and disadvantages that make it suitable for a certain range of applications (Figures 2.3 to 2.8). Data for the figures has been drawn from a number of sources including: (Baker, 2008; Beurskens and de Noord, 2003; Boyes, 2000; Butler et al., 2002; Cavallo, 2001; Chen et al., 2009; Dell and Rand, 2001; Denholm and Kulcinski, 2004; Divya and Østergaard, 2009; ESA, 2009; Eyer et al., 2004; Gonzalez et al., 2004; Hadjipaschalis et al., 2009; Hall and Bain, 2008; Hubert et al., 2003; Ibrahim et al., 2008; Kaldellis et al., 2009a; Kondoh et al., 2000; Makansi and Abboud; 2002; Rydh and Sanden, 2005a, 2005b; Sauer, 2006; Schoenung, 2001; Swanbarton, 2004; Thackeray, 2004); thus capturing the entire variation range.

2.3.1 Energy Storage Capacity Vs. Discharge Time

Energy storage capacity can be plotted against the respective discharge time, i.e. the period over which the energy storage system may discharge at its rated power (Figure 2.1); thus the system rated power and power to energy ratio (kW/kWh) are available. Systems found on the right upper side of the chart (where discharge time and energy storage capacity are high) like PHS, CAES and FC-HS, are ideal for applications of commodity storage, arbitrage, rapid reserve and area control-frequency responsive reserve. Systems found on the lower left side of the chart (where the power to energy ratio is high and the discharge time requirements are low), such as flywheels, SCs and SMES, are suitable for power quality-reliability and transmission system stability applications. Batteries cover a wide range of applications, from power quality to the early stages of energy management, with flow batteries being more appropriate for transmission and distribution deferral. More information about the performance of actual systems is available in the regularly updated database of the Electricity Storage Association (ESA, 2009 see also Figure 2.3). In this context, Na-S is the battery technology with the highest discharge time, not influenced by the rated power output. Lead acid (L/A), nickel-cadmium (Ni-Cd) and lithium-ion (Li-ion) batteries have lower discharge time. Additionally, Na-S and L/A demonstrate similar power outputs (up to the scale of 10s to 100s of MW), as opposing to Li-ion that are now reaching the stage of commercialization for applications in the order of 100s of kW. Ni-Cd batteries on the other hand, cover a wide range of power, from few kWs to tens of MWs. Finally, the power output of VRB and Zn-Br is not affected by the discharge time variation, while VRB extends its power range back to the scale of few kWs and in the interstage between customer energy management and power quality applications. Furthermore, SCs are suitable for conditions of high rated power (even in the scale of MW) and minimum discharge time (in the scale of seconds). Finally, flywheels satisfy both high power applications for short duration (high power flywheels) and lengthier time applications at moderate power output (long duration flywheels).

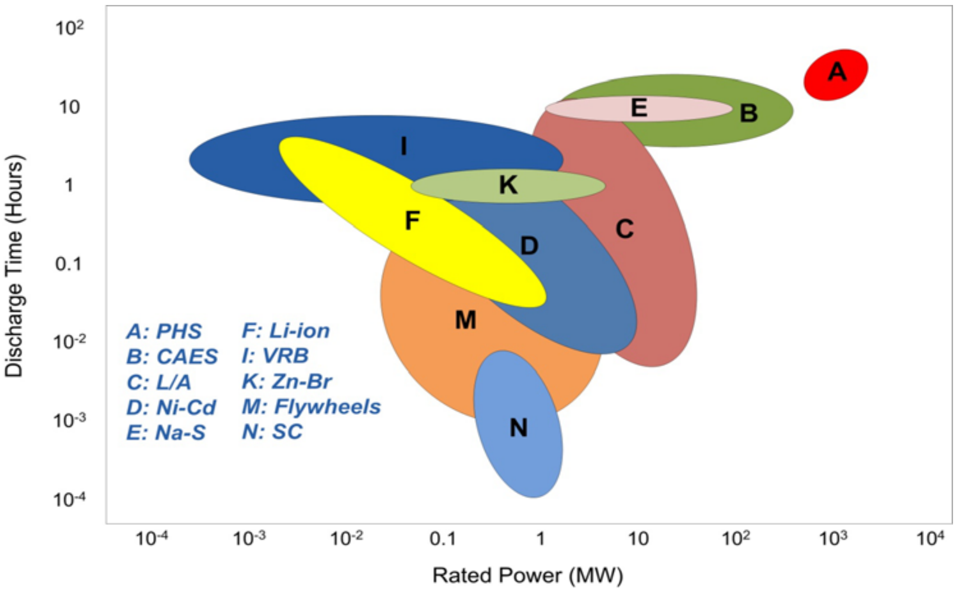


Figure 2.3: Energy storage capacity and power output of contemporary energy storage systems

2.3.2 Self-Discharge Vs. Recommended Storage Duration

As already discussed, self-discharge expresses the losses of a storage system during off-duty periods and determines the recommended maximum storage duration (Figure 2.4). The self-discharge importance is divided in four areas; negligible and low, for both benign and very small self-discharge (up to ~5% per month), moderate, in case of 5%-30% per month, and high, if self-discharge losses exceed 30% per month. The relation between self-discharge importance and recommended storage period is evident. Na-S and metal-air batteries together with bulk energy storage including PHS, CAES and flow batteries experience zero (in the case of Na-S) or minimum losses, while SCs and flywheels are limited by the inherent self-discharge (flywheels may fully discharge over a day period or less). Limitations in storage period excludes these systems from certain applications like spinning reserve, where the periodicity of cycling is very low and long time intervals between two consecutive cycles are expected.

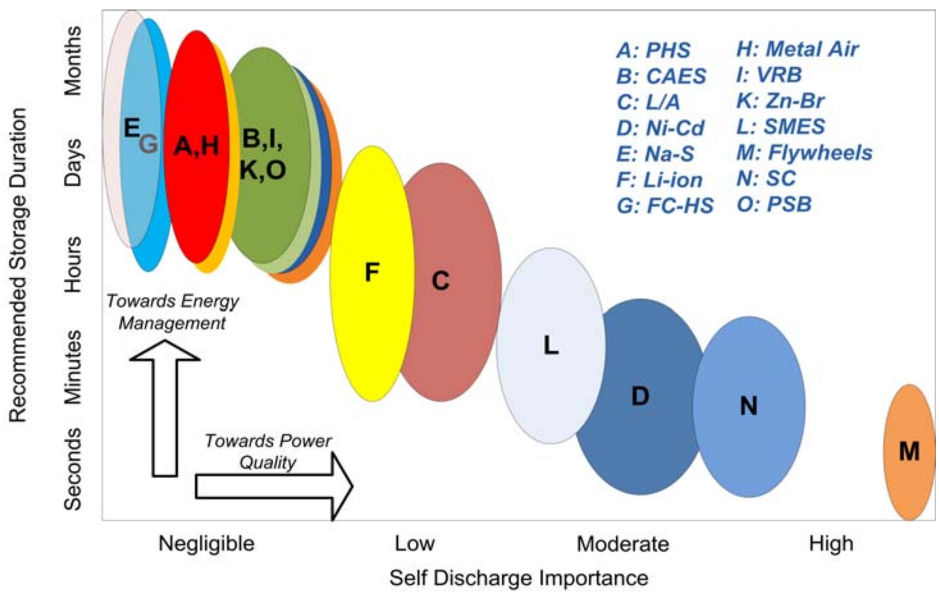


Figure 2.4: Self discharge and recommended storage period of contemporary energy storage systems

Nevertheless, subject to other requirements, these systems can be suitable for power quality applications, where the cycling periodicity is high (annual duty cycle requirements reaching 1,000cycles/year). On the other hand, bulk energy storage systems are essential for energy management applications, such as rapid reserve and arbitrage.

2.3.3 Energy and Power Density

Another aspect of energy storage is covered by the investigation of energy and power density (Figures 2.5a and 2.5b). Most chemical storage media are favoured with high values of both mass and volume energy density, while mechanical and electrical energy storage technologies are determined by lower values (Figure 2.5a). Among these, only flywheels extend to 90Wh/lit, presenting also the highest mass density, owed to the use of composite materials.

Nevertheless, to store substantial energy in a SC requires enormous systems, whereas metal-air and fuel cells have minimum footprint and are easily portable. Electrical and small-scale mechanical systems (i.e. flywheels) present moderate energy densities and high mass and volume power density (Figure 2.5b). Indeed, SCs are determined by high values, followed by the technologies of SMES and flywheels, while chemical systems -namely batteries- are not as efficient in terms of power extraction per unit mass or per unit volume.

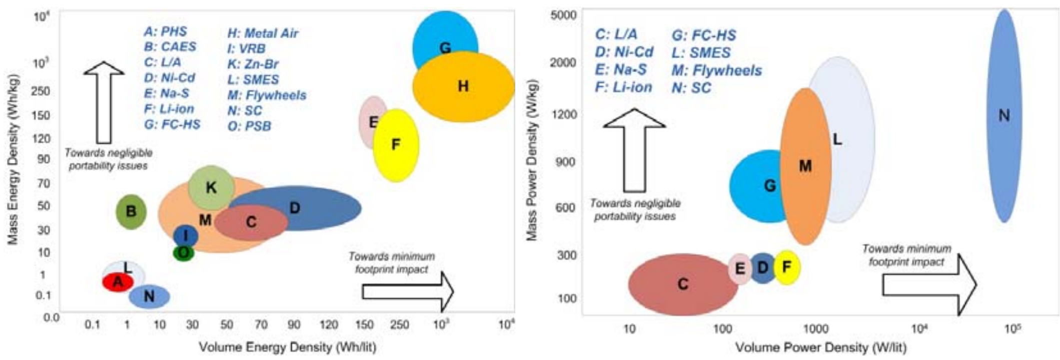


Figure 2.5: Mass and volume energy (a) and power (b) density of contemporary energy storage systems

2.3.4 Service Period and Number of Cycles

The life time and the total number of cycles are critical for the selection of a suitable energy storage system (Figure 2.6). Although chemical energy storage demonstrates high energy and power density, most systems' lifespan is limited to 15 years. Mechanical and electrical storage (apart from flywheels) can exceed 20 years of service period, and bulk energy storage systems can reach 40-60 years.

Furthermore, chemical storage, excluding the PSB technology, is limited by the number of cycles, with most of the systems found on the left side of the 1,000 cycle per year curve (between 150-350 cycles per year on average). Flywheels, SCs and SMES may be fully charged and discharged between 2,500 and 3,500 times during a year on average while metal-air batteries demonstrate the least attractive lifetime characteristics. Finally, lifetime limitations is the main disadvantage of L/A batteries, affecting also the life-cycle (LC) cost of these systems.

At this point it is important to note that the sensitivity of certain energy storage technologies' service period with regards to the operational depth of discharge (DoD) is considerable. This is valid especially for battery storage, where deep discharges are often responsible for the decrease of the system useful life.

What should be noted however, is that modern battery technologies can nowadays support DoD in the order of 80%, opposite to conventional ones such as L/A that are normally operated at DoD in the order of 50%. In any case, operation of battery storage technologies at lower DoD ensures extension of the system useful life and could thus improve values included in Figure 2.6.

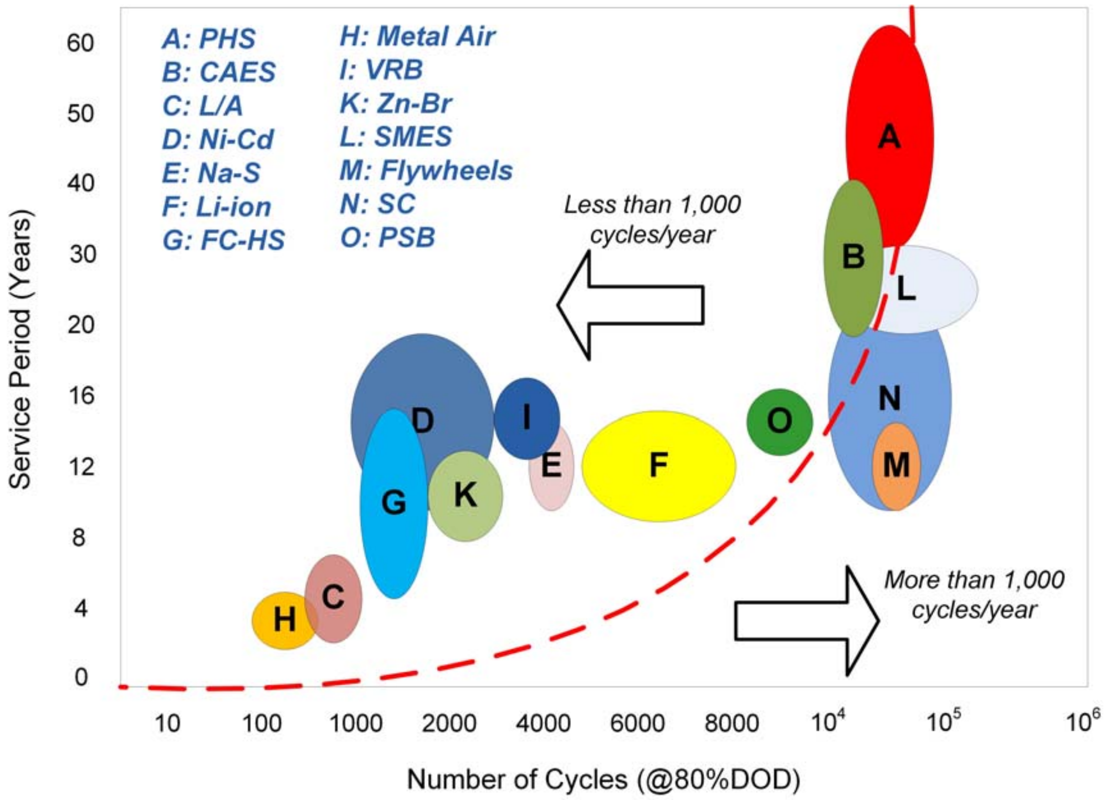


Figure 2.6: Service period and cycling frequency of contemporary energy storage systems

2.3.5 Energy and Power Costs

The capital cost of a system is the sum of the energy cost (per unit of storage capacity) and the power cost (per unit of power output). On top of these, balance of system (BOS) components entail a capital cost, while in order to obtain LC evaluation of the investment it is necessary to know the fixed and variable maintenance and operation (M&O) cost of the energy storage system. The above information is case-specific, therefore relying on generic data leads to highly uncertain results. Besides, economies of scale and market size also influence the configuration of the capital cost. In this context, in Figure 2.7, the energy and power costs of each system are given.

Energy storage systems found in the direction of power cost reduction are suitable for applications where high power over short time period is required. The energy storage systems being most appropriate for energy management applications (long discharge duration and considerable power) are in the direction of energy cost reduction. Bulk energy storage systems including PHS, CAES and FC-HS demonstrate the lowest energy costs, while electrical storage, flywheels and metal-air batteries are kept under 400€/kW.

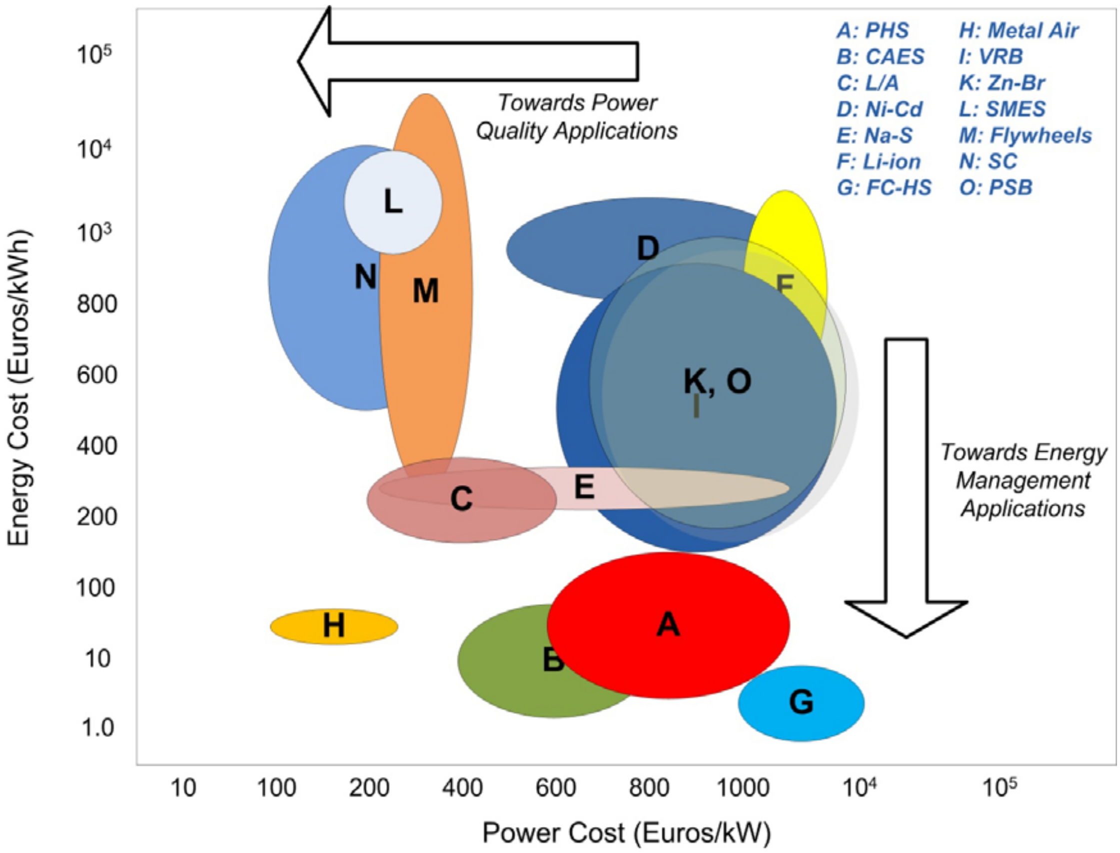


Figure 2.7: Energy and power costs of contemporary energy storage systems[1]

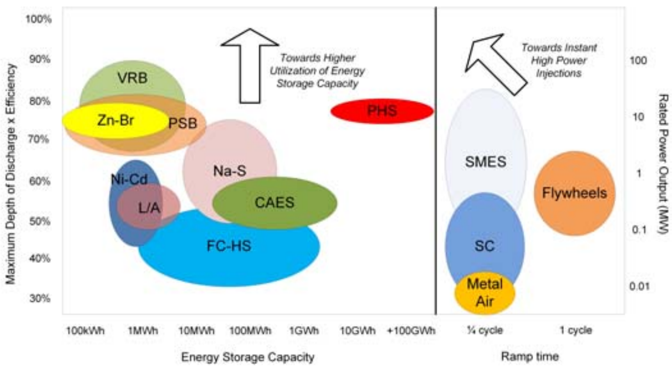
2.3.6 Useful Energy, Power Extraction Response and Cycle Efficiency

By considering the energy efficiency during discharge and the maximum recommended depth of discharge of an energy storage system, its useful energy can be estimated. Using the information available, the product of the two aforementioned parameters is plotted against the energy storage capacity ratings of certain energy storage systems (Figure 2.8a). In this context, systems used for power quality applications, where storage capacity is already limited, are not evaluated. Instead, they are used in the second half of Figure 2.8a, where power rating is compared with the systems' ramp time. Concerning the left half of the figure, although electrolysis is excluded from the output efficiency, FC-HS still presents the lowest utilization of energy storage capacity among all energy storage systems. CAES require air pressure maintenance inside the storage cavern and L/A batteries cannot perform deep discharges and as a result leave almost 40% of their energy capacity unexploited. Flow batteries and PHS allow more than 70% of their capacity to be extracted, with VRB approaching 90% of energy utilization. Moreover, according to the right side figure, SMES provide the highest power output in the shortest time, while flywheels require the entire cycle duration to take up load.

Another important aspect of contemporary energy storage technologies is given in the table of Figure 2.8b, where response times are provided for different energy storage technologies. These can be grouped together in systems supporting immediate response (<sec), including battery storage, flywheels, SCs and SMES, in systems supporting response of a few seconds, including flow batteries, in systems providing response in a time window of tens of seconds-minute, including FC-HS, and in systems that support

[1] It is noted that the values provided do not take into account the effect of cycling and life-cycle operation and thus only refer to installation cost values.

response in the time scale of a few/tens of minutes such as CAES and PHS. Combining these with the requirement for primary (few seconds), secondary (tens of seconds to tens of minutes) and tertiary (longer time scales) frequency response at the grid level, it becomes clear that it is a portfolio of energy storage systems that can sufficiently encounter such needs, starting from immediate response technologies and gradually introducing systems that can support energy delivery for longer time periods.



Energy Storage Technology	Response Time
PHS	min
CAES	
FC-HS	sec-min
VRB	sec
Zn-Br	
PSB	
L/A	<sec
Na-S	
Ni-Cd	
Flywheels	
Metal-Air	
SC	
SMES	

Figure 2.8: Useful energy for energy management storage systems and ramp time for power quality storage systems (a) and response time of storage systems (b)

Furthermore, in Figure 2.9, cycle efficiencies of energy storage systems are provided. Flywheels and electrical storage systems, along with Na-S and Li-ion batteries clearly exceed 80%, while it is the FC-HS and metal-air batteries that drop below 50%.

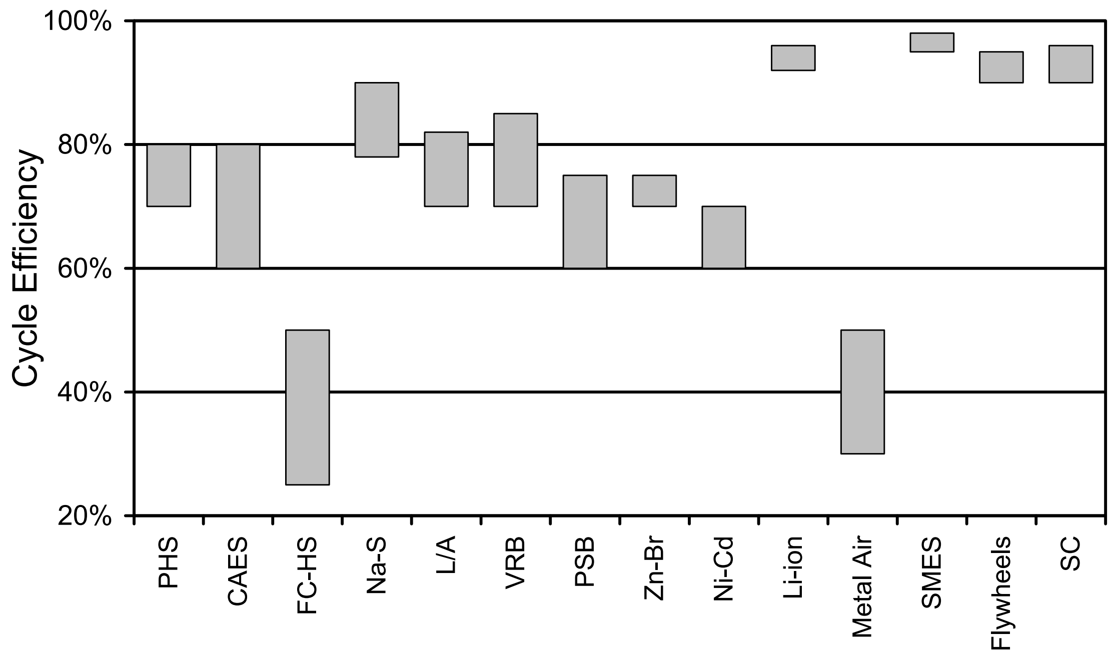


Figure 2.9: Typical cycle efficiency of energy storage systems

2.3.7 Environmental and Safety Concerns

Environmental impacts caused by the implementation and operation of an energy storage system overall are hard to quantify. In terms of magnitude, bulk energy storage entails the most considerable impacts. PHS requires the construction of dams and tunnels, the employment of heavy equipment and the utilization of water resources, while CAES requires cavern formation, installation of the plant and natural gas infrastructure, as well as consumption of fuel that also implies emissions. Lower cycle efficiency (Figure 2.9) suggests, among others, increased environmental footprint that links to increased emissions in the case of thermal power generation being exploited for system charging. Furthermore, certain chemical storage systems entail the production of toxic wastes (e.g. lead and cadmium disposal) and the production of excessive heat in the surroundings (e.g. Na-S batteries). Safety is an issue in the cases of: flywheels' operation, where the containment structure should be compact enough to withstand a possible burst; in the case of SMES, where intense magnetic fields are developed; and finally in the case of FC-HS, where high pressure hydrogen storage implies high level of risk.

2.3.8 Commercial Maturity

According to their commercial maturity, energy storage technologies can be classified into three main categories, i.e. mature systems, systems found in the developing stage (from concepts to demonstration) and systems already developed (from demonstration to commercial use) (Figure 2.10). In the first category of mature systems one may encounter PHS and CAES as well as certain battery types, while in the developing stage more novel technologies such as SMES are included. The rest of the technologies are consequently classified in the category of developed technologies. Nevertheless, research and development is constant in the field and thus new concepts arising do not allow strict classification in any of the three categories. In this context and in order to increase the reliability of research results, in the current thesis emphasis is given on mature storage technologies that can also support energy management applications. PHS, CAES and typical battery storage technologies are investigated to this end in the following chapters of the thesis, looking into applications that capture both the private actor and the system point of view.

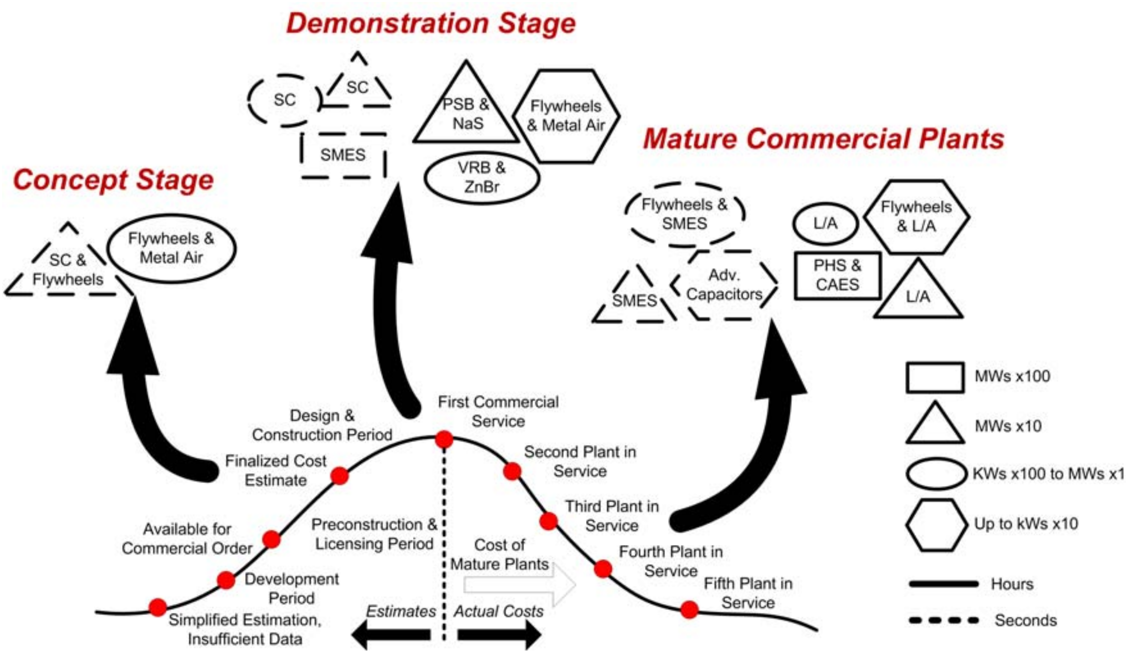


Figure 2.10: Technology readiness level of different energy storage systems

3. Energy Storage for Private Actors

The focus of this Chapter is on the evaluation of emerging energy storage applications as well as on the development of novel energy storage strategies and support instruments for private actors. The thematic studies are about:

1. Arbitrage strategies and their actual value for energy storage across European power markets.
2. The development and evaluation of combined arbitrage and DSM energy storage strategies for the industrial sector.
3. The development of a novel dispatch strategy and support instruments for RES-based energy storage.

More precisely, in the first study, several arbitrage strategies are investigated for PHS and CAES systems, using historical data of electricity spot price for five European power markets (Nord Pool, UK, EEX, Spain and Greece) of different characteristics. The aim of the study is to put a value on arbitrage for energy storage and investigate electricity market characteristics that can foster such applications. The analysis of time and price signal-based arbitrage strategies is undertaken under different storage cycling (various time windows of operation are tested). The results obtained are used to appraise the value of arbitrage and its potential to support similar energy storage investments either on its own, or in combination with other energy storage services.

In the second study, typical battery storage is employed in order to support novel strategies combining arbitrage and DSM (load shifting for peak shaving), using an industrial facility as a case study. The industrial sector is often exposed to increased energy prices while requiring increased security of supply for critical operation processes. Thus, it is believed that the introduction of energy storage at the industrial sector can produce multiple benefits not only for industrial facilities but for the electricity grid as a whole. The proposed strategy has been evaluated for the Greek electricity market.

Finally, in the third study of Chapter 3, a LC socioeconomic cost-benefit model is developed to assess "socially just" FiTs and support the operation of combined wind-based energy storage systems. The developed strategy proposes operation of RES-based energy storage configurations for guaranteed energy delivery (by the storage system) during hours of peak demand, replacing in this way high-cost thermal-based power generation units such as gas turbines. Both PHS and CAES were investigated for different economic scenarios.

At this point, it must be noted that the approach followed with regards to modelling, simulation and valuation of the strategies investigated is defined as deterministic/retrospective, meaning that use of past (historical) prices patterns is considered in order to evaluate the performance of the configuration each time examined.

3.1 Evaluation of Arbitrage Strategies for Energy Storage

3.1.1 Introduction

The debate on what roles can energy storage support in the power sector and contemporary electricity markets has been prominent for more than a decade (Makansi and Abboud, 2002). At the same time, despite the fact that such systems can provide a bundle of services (Makansi and Abboud, 2002; Naish et al., 2008), investment remains limited due the absence of a concrete service valuation framework and the persistently high capital costs of most energy storage systems. Nevertheless, research on energy storage and its role in supporting increased integration of RES has been intensive (Beaudin et al., 2010; Kaldellis and Zafirakis, 2007a; Kaldellis et al., 2009a; Nyamdash et al., 2010; Zafirakis, 2010). In this context, innovative operation strategies that consider collaboration with RES challenge state support for energy storage through the production of social welfare effects (Sioshansi, 2011; Zafirakis et al., 2013). Arguing that energy storage can take over multiple roles, our notion is that a portfolio of value-adding services (Drury et al., 2011; Kazempour et al., 2009a; Varkani et al., 2011) can produce further revenue streams; thus facilitate investments in the sector more effectively.

One such source of revenue is arbitrage. Arbitrage practised by energy storage systems takes advantage of spot market price spreads (between off-peak and peak demand hours) which, if substantial, can produce economic benefits. Similar research has been conducted in the past (Connolly et al., 2011a; Kazempour et al., 2009a; Sioshansi et al., 2009; Walawalkar et al., 2007), reaching the general conclusion that arbitrage is not in itself adequate to support energy storage investments and thus welfare gains of energy storage services need to be identified in order to elicit state support (Schill and Kemfert, 2011; Sioshansi, 2010; Sioshansi et al., 2009). Nevertheless, in most of these studies, comparison between the system operational cost and the arbitrage value is used as a measure of economic performance, disregarding capital costs and the system CF. To this end, a serious limitation of this body of literature relates to the fact that a fixed system size, corresponding to a price-taker unit, is usually investigated within the context of a single electricity market, while in most cases only one type of energy storage technology is considered.

To capture market and technology effects, examination of the arbitrage value across different European electricity markets is undertaken for PHS and CAES, taking also into account variation of the system size. For this purpose, historical, hourly spot price data for the period 2007-2011 is used, for the electricity markets of Nord Pool, EEX, UK, Spain and Greece. The selection of the specific markets aims to reflect differences in the value of arbitrage in association with market characteristics such as fuel mix and market competition. In terms of arbitrage strategies, both time and price based signals are applied on a daily and weekly time step. To this end, the arbitrage value and its net difference with the system electricity production cost is estimated. Moreover, in the case of price signals, variable system sizes are also studied and optimum size results concerning both the value of arbitrage and its net difference with the system production cost are provided.

Following this introduction, the selected electricity markets are described in Section 3.1.2, while in Section 3.1.3 we analyse the applied methodology and arbitrage strategies. Section 3.1.4 presents the application results and discusses the association of the arbitrage value with market characteristics, energy storage technology and trading strategy used. The study concludes with Section 3.1.5, where the main findings are critically presented.

3.1.2 European Electricity Markets

In order to capture different market characteristics both regionally integrated and isolated electricity markets of different competition level, fuel mix characteristics (see also Figure 3.1) and cross-border transmission capacity are examined. More precisely, the markets of Nord Pool, Spain, UK (APX), EEX (European Energy Exchange) and Greece were selected as representative examples.

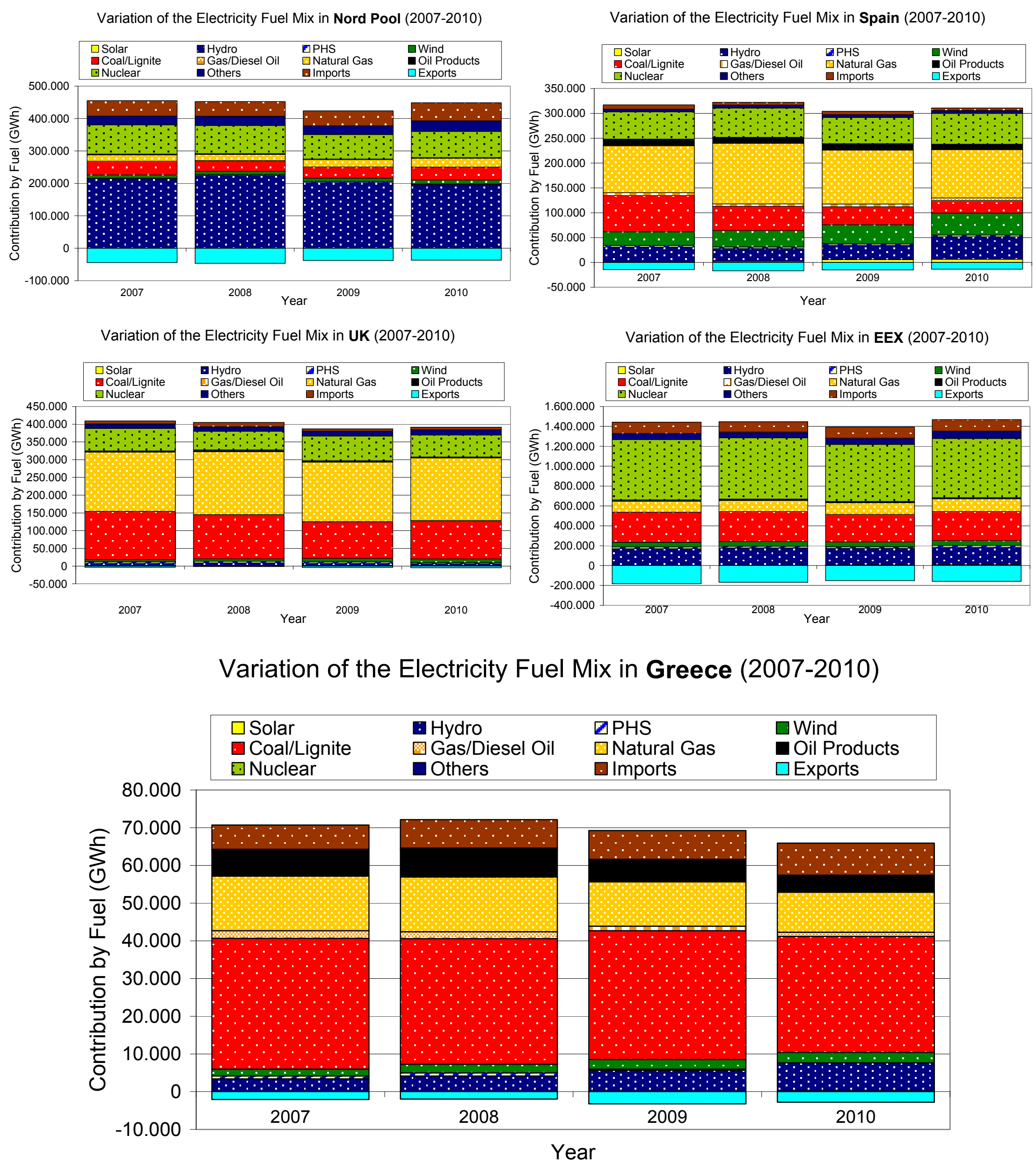


Figure 3.1: 4-year electricity supply fuel mix for the examined electricity markets

<u>The market of Nord Pool</u>

Nord Pool is the first and largest market for power trading in the world (Nord Pool, 2013). It comprises of the former Nordic markets (i.e. the Danish, the Finish, the Swedish and the Norwegian) that were deregulated in the early 1990s to engage into an integrated new market along with Estonia and Lithuania deregulated in the late 2000s. The participation of different countries in that case ensures a liquid market environment that can handle extreme price events effectively (Hellström et al., 2012) and provides a relatively diverse fuel mix. Nevertheless, electricity generation in Nord Pool is mainly based on hydropower and nuclear, with sufficient power exchange potential playing an important role (Figure 3.1). Nord Pool facilitates large-scale wind energy integration in Denmark (Green and Vasilakos, 2012; Mauritzen, 2013) and is highly competitive; thus, in the context of this study, Nord Pool is used as an integrated, mature and highly energy secure market, with sufficient regulating and balancing ability deriving from its hydro and power exchanging potential.

The Spanish market

In 1998, Spain and Portugal formed the integrated, pool-structured Iberian market, known as Mibel (OMEL, 2013). Integration between the two markets has intensified over the years (Amorim et al., 2013; Garrués-Irurzun and López-García, 2009), resulting in minimum price difference explained by greater convergence of the two countries' fuel mix and the effectiveness of the cross-border trading mechanism. However, Spain does not enjoy equal interaction with neighbouring European regions, with its cross-border transmission capacity to France limited to less than 2.8GW. Moreover, the Spanish market suggests an ideal example of high RES contribution (Cossent et al., 20121) with almost 1/3 of its total electricity generation coming from hydro, wind and solar energy. To facilitate this large-scale RES integration (mainly wind), natural-gas power plants are employed to provide the required flexibility, similar to the UK. Thus, Spain is a market of high RES contribution that depends on fuel imports and enjoys a close synergy with Portugal but limited communication with the rest of Europe.

The UK market (APX)

APX Power UK was established in 2000 as Britain's first independent power exchange (UK APX, 2013). In 2011, coupling with Netherlands -through the BritNed electrical cable- brought increased liquidity to the local market from the very liquid Power NL spot market and beyond from Germany, Belgium, France and Norway that also affected electricity prices. In the meantime, the UK is increasingly dependent on primary energy imports (Skea et al., 2012) while presenting –until 2010- little activity in electricity trade (see also Figure 3.1). As a result, APX can be seen as a less integrated, highly competitive and import-dependent market which is in a transitional stage of decarbonising its fuel mix (Anderson et al., 2008) and enhancing its electricity trade.

The European Energy Exchange (EEX) market

The EEX (EEX, 2013) was founded in 2002 from the merger of the two German power exchanges in Frankfurt and Leipzig. Later, in 2008, EEX entered a close cooperation with Powernext, during which both partners integrated their power spot and derivatives markets. EEX now holds 50% of the shares in the joint venture EPEX SPOT which operates the spot market for Germany, France, Austria and Switzerland. As a result, EEX comprises a diverse electricity market that is dependent on fuel imports in order to support nuclear power and natural-gas based generation. At the same time, it is a market that despite its considerable power exchange potential, suffers relatively frequently from extreme price events.

The Greek market

Greece although liberalizing its market in 2001 (HITSO, 2013), comprises a deregulated market only by euphemism and should thus be studied as a monopoly. The local Public Power Corporation (PPC) holds almost 85-90% (Eurostat, 2013) of the market generating capacity. In this regard, the country is mainly based on the exploitation of local lignite reserves that contribute approximately 50% of the electricity generation fuel mix, followed by natural gas imports that were recently decreased slightly due to economic recession impacts. Moreover, Greece has strong cross-border transmission capacity, including transmission lines to the Balkan region, Italy and Turkey, used mainly for importing energy. Thus, Greece offers an example of a monopolistic market that is largely based on the exploitation of low cost lignite reserves and uses its cross-border transmission capacity to mainly import electricity.

3.1.3 Methodology

For the purpose of this paper, hourly electricity spot price data from 2007 to 2011 is used for the five markets of Nord Pool, Spain, APX, EEX and Greece. Using this dataset, different daily and weekly arbitrage strategies are applied in order to determine the annual arbitrage value of PHS and CAES per unit of energy produced. Moreover, the system mean annual production cost is estimated, considering the capital costs as well as the frequency of system operation (or CF). Finally, in the case of price signals, where variable system dimensions for price-taker storage plants are examined, the results are optimised using as criteria the maximum arbitrage value and the minimum difference between the system production cost and the arbitrage value. In the following sections, a short description of the two energy storage technologies examined and an analysis of the applied arbitrage strategies and methodology are provided.

PHS and CAES

PHS is the most mature bulk energy storage technology (Deane et al., 2010), with almost 130GWs of installed capacity worldwide. In a PHS system, off-peak energy or energy in excess is used to pump water to an elevated (upper) reservoir. During peak demand or times of energy deficit, water is released from the upper reservoir to operate hydro-turbines. Cycle efficiency of modern PHS is in the order of 70-80% (Bjarne, 2012), while such systems can take up load in a few tens of seconds and feature a high rate of extracted energy. In general, PHS systems are suitable for applications of energy management, spinning reserve and frequency control. Similarly, in a CAES system, off-peak or excess power is used (Lund et al., 2009; Zafirakis and Chalvatzis, 2014) to compress air into an underground cavern or a tank (at pressures that can even reach 80bars). During periods of peak demand or energy deficit, the required amount of air is released from the cavern, heated with natural gas and fed to a gas turbine where expansion takes place as in the Brayton/Joule cycle. Note that in a CAES system the entire gas turbine output is available for consumption (since the compressor and the gas turbine are not coupled), which also implies considerably lower heat rates (or fuel consumption), in comparison to conventional open-cycle gas turbine plants (in the order of 1.25kWh of fuel per kWh of electricity output). Moreover, CAES systems have a satisfying response time and can take up load in a few minutes, while because of their ability to store energy as pressurised air -under pressures reaching even 80bars- the respective energy density is normally higher than that of PHS featuring typical manometric heads.

Arbitrage strategies

As seen earlier, arbitrage strategies based on either time or price signals and two different time steps are applied, i.e. daily and weekly. In the case of time signals, both longer and short-term price data is used, with the employed set of strategies considered straightforward for applied practice. Contrariwise, price signal based strategies depend strictly on short-term price signals (currently the static or moving average price of the previous 24h or 168h) and require a greater level of commitment that assumes accurate prediction of next hours' spot price. During application of all strategies, apart from the annual arbitrage value, the system's operation frequency (cycling) is recorded through the estimation of the respective CF.

- *Historical arbitrage* (time signals): In this strategy historical spot price data (currently the 4-year period of 2007-10) is used to determine buying and selling time points during the day/week and apply them for the following year, i.e. 2011. For this purpose, the historical hourly average values of spot price on a daily and weekly basis are estimated. From the obtained results the hour of minimum price is used as a buying signal and the hour of maximum price as a selling signal, assuming that exploitation of historical data could increase the strength of the signals. Note that in the case of the weekly time scale, to increase system frequency of operation and thus reduce systems costs, charging of the system is allowed on a daily basis (using the same signal as in the daily time scale), combined with discharging during the maximum price hour of the week alone.
- *Mirror arbitrage* (time signals): The exact same day or week of the previous year is used in this strategy to determine time signals and apply them to the current year's day/week, forcing coincidence of the weekdays and weekends rather than calendar dates[2]. Therefore the years between 2007 and 2011 are examined in pairs. Similar to the previous strategy, the selected time points correspond to the minimum /maximum hour of the week or day. The assumption is that the stronger the seasonality in electricity prices the greater the signal reliability will be.
- *Back to back arbitrage* (time signals): In the current strategy, the previous day or week of the same year is used to determine signals for the next day/week. As a result, moving time signals are considered, that are expected to capture both seasonality and consistency of price patterns during the same year.
- *Static and moving average arbitrage* (price signals): Finally, the common trading strategies of static and moving average are used, deriving from the discipline of finance. In that case, price signals of the previous 24h or 168h are used to make a buying or selling decision for the next hour, assuming perfect prognosis of the respective spot price. Note that according to price signals, the system is set to operate whenever there is incentive to do so, restricted only by its input/output power and storage capacity. To this end, the system size examined is variable, and optimization is undertaken under the criteria of maximum arbitrage value and its minimum difference with the system production cost.

<u>Comparison between arbitrage value and system production cost</u>

In the first case of time signal strategies, the size of system components is interdependent, owing to the fact that system operation is predefined in accordance with the period of time that the system is set to charge and discharge (considering a full cycle). Thus, if given a certain input power N_{in} for the system investigated, the system energy storage capacity E_{ss} and the system power output N_{out} depend on the time period of charging Δt_{ch} and discharging Δt_{dis}, as well as on the system input and output efficiency (η_{in} and η_{out}), with all parameters' values kept constant throughout the analysis. More precisely, energy is stored in the system when a time signal for buying is given and is delivered back to the electricity grid when a time signal for selling follows. However, in order to store an amount of energy equal to E_{ss}, the amount of energy bought E_{buy} should be somewhat higher, taking also into account the input side energy efficiency (see also equation 3.1), neglecting at this stage the depth of discharge factor.

[2] The holiday effect is not taken into account in the application of the examined arbitrage strategies.

$$E_{buy} = \frac{E_{ss}}{\eta_{in}} = \frac{N_{in} \cdot \Delta t_{ch}}{\eta_{in}} \tag{3.1}$$

At the same time, the respective energy being sold (E_{sell}) is reduced due to the system output efficiency, i.e. $E_{sell}=E_{ss}\cdot\eta_{out}$, taking also into account that the system is fully discharged, i.e. a full cycle of charging and discharging is always executed by the system on either a daily or a weekly basis. Finally, based on the available energy stores E_{ss} and time period of discharging Δt_{dis}, the system nominal output power N_{out} can be estimated by equation 3.2. Eventually, the energy sold to the grid, E_{sell}, is equal to the product of energy bought, E_{buy}, multiplied by the round-trip efficiency of the energy storage system, i.e. $\eta_{rt} = \eta_{in}\cdot\eta_{out}$.

$$E_{sell} = E_{ss} \cdot \eta_{out} = N_{out} \cdot \Delta t_{dis} = E_{buy} \cdot \eta_{in} \cdot \eta_{out} = E_{buy} \cdot \eta_{rt} \tag{3.2}$$

Price signal strategies differ from time signal strategies in that they suggest examination of system components the size of which is variable and independent from one another (see also Table 3.1). This is owed to the fact that the system may buy and sell electricity during the entire day or week, subject to price signals and the limitations introduced by the size of system components (i.e. input and output power, as well as storage capacity). On top of that, both input and output system components are set to operate at their nominal point of operation.

Considering the above, for each type of strategy applied, the arbitrage value *ARV* derives from the comparison between revenues (from selling energy to the grid) and expenses (from buying energy from the grid) on an annual basis, with c_{spot} being the spot electricity price of each hour examined and h^{sell} and h^{buy} corresponding to the hours of selling and buying energy respectively (time step is hourly, i.e. $h^{sell} = h^{buy} = 1$). At this point it should be noted that hours of buying and selling energy are not predetermined and derive from the application of a price criterion concerning the value of c_{spot}, i.e. when c_{spot} is above a given price signal then the system is set to sell energy at the price met, i.e. $c_{spot\text{-}sell}$ subject to the available energy stores and its output power. Inversely, when c_{spot} is found below a given price signal then the system is set to buy energy at the price met, i.e. $c_{spot\text{-}buy}$ subject to its state of charge and its input power capacity. Finally, when the price of c_{spot} is found to be equal to the given price signal (or alternatively within a price zone that does not encourage neither buying nor selling decisions) the system is set to remain idle.

Next, to express the annual value of arbitrage per unit of produced energy, the annual energy yield is estimated, with *CF* being the system production side annual CF (year duration of Δt_{year}).

$$ARV = \left(N_{out} \cdot \sum_{t=1}^{t\max} c_{spot-sell}(t) \cdot h^{sell}(t) - \frac{N_{in}}{\eta_{rt}} \cdot \sum_{t=1}^{t\max} c_{spot-buy}(t) \cdot h^{buy}(t) \right) \cdot \left(N_{out} \cdot CF \cdot \Delta t_{year} \right)^{-1} \tag{3.3}$$

In this context, although in the case of time signal strategies estimation of the *ARV* is straightforward (since the size of components is dependent on one another), in the case of price signal strategies, where the size of system components is variable, an optimization problem is introduced, i.e. how to maximize the *ARV*. Accordingly, the net difference between the system LC electricity production cost ($c_{ss}=c_{PHS}$ or $c_{ss}=c_{CAES}$) and the *ARV* is estimated, with the former including both installation and M&O costs that in the case of CAES also takes into account the necessary fuel consumption. The net difference (*ND=ARV*-c_{ss}) provides an additional optimization criterion for price signal based strategies which in that case requires determination of the respective minimum. To estimate this however, the system LC electricity production cost (€/MWh) over the entire system service period n_{ss} (either n_{PHS} or n_{CAES}) needs to be determined first, assuming in this context -for the case of price signal strategies- that the system will operate under constant *CF* throughout its service period.

To determine the LC electricity production cost of PHS systems, the initial capital cost IC_{PHS} is combined with the system M&O cost for a service period of n_{PHS} years, that is expressed with the help of the respective annual coefficient m_{PHS} (being a percentage of the initial installation cost). The initial cost is further broken down to the components of water reservoir cost, hydro-turbines' cost and pumping station cost. In this context, c_t (€/kW) is the specific purchase cost for hydro-turbines, c_{pump} (€/kW) is the respective cost for pumping stations and c_{res} (€/m^3) corresponds to the specific cost of building a reservoir of certain volume V_{res}. The latter depends on the available head of the installation H_{PHS} (currently considered at 100m), the water density ρ_w, the gravitational acceleration g and the energy storage capacity E_{PHS}. Finally, the nominal power of the pumping and the hydropower station are symbolized as N_{pump} and N_t respectively.

Table 3.1: PHS and CAES characteristics (Baker, 2008; Chen et al., 2009; ESA, 2009; Hadjipaschalis et al., 2009; Hall and Bain, 2008; Ibrahim et al., 2008)

Energy Storage Parameters				**Price Signals Range**	
PHS Parameters	**Value**	**CAES Parameters**	**Value**	**Parameter**	**Range**
c_{pump} (€/kW)	500	c_{comp} (€/kW)	400	N_{in} (MW)	20-300
c_t (€/kW)	500	c_{gt} (€/kW)	400	N_{out} (MW)	20-300
c_{res}[3] (€/m^3)	15	c_{cav} (€/kWh)	20	E_{ss} (MWh)	100-3000
m_{PHS}	5%	m_{CAES}	5%		
n_{PHS} (years)	30	n_{CAES} (years)	30		
H_{PHS} (m)[4]	100	HR_{CAES}[5] (kWh_{NG}/kWh_e)	1.25		
η_{rt}[6]	77%	c_f (€/MWh_{NG})	30		
		η_{rt}[7]	125%		

$$c_{PHS} = \left(IC_{PHS} + m_{PHS} \cdot IC_{PHS} \cdot n_{PHS}\right) \cdot \left(\sum_{i=1}^{n_{PHS}} N_t \cdot CF \cdot \Delta t_{year}\right)^{-1} \tag{3.4}$$

$$IC_{PHS} = c_{res} \cdot V_{res} + c_t \cdot N_t + c_{pump} \cdot N_{pump} \tag{3.5}$$

$$V_{res} = E_{PHS} \cdot \left(H_{PHS} \cdot \rho_w \cdot g\right)^{-1} \tag{3.6}$$

[3] Cost values provided for storage capacity, consider also the system maximum depth of discharge.
[4] H_{PHS} refers to the net available head, i.e. considering also energy losses in the penstock.
[5] HR_{CAES} refers to the heat rate of the CAES cycle requiring almost 1.25kWh of natural gas per kWh_e.
[6] The round-trip efficiency of PHS refers to the overall efficiency of pumping and hydro-turbines.
[7] In a CAES plant, the electrical output is higher than the respective input (used to operate the compressor) due to the fact that fuel is also used to operate the gas turbine.

Similarly, the initial cost of CAES includes the components of cavern / tank cost, compressor cost and gas turbine cost, which may also derive from the respective specific cost coefficients c_{cav} (€/kWh), c_{comp} (€/kW) and c_{gt} (€/kW) and the size of the respective system components (i.e. E_{cav}, N_{comp} and N_{gt} respectively). Furthermore, the LC M&O costs for a period of n_{CAES} years are estimated with the maintenance coefficient m_{CAES}; fuel costs FC_{CAES} are given by combining the system heat rate HR_{CAES} with the fuel (natural gas) price c_f and the system energy yield for the entire system service period n_{CAES}.

$$c_{CAES} = \left(IC_{CAES} + m_{CAES} \cdot IC_{CAES} \cdot n_{CAES} + FC_{CAES} \cdot n_{CAES}\right) \cdot \left(\sum_{i=1}^{n_{CAES}} N_{gt} \cdot CF \cdot \Delta t_{year}\right)^{-1} \tag{3.7}$$

$$IC_{CAES} = c_{cav} \cdot E_{cav} + c_{gt} \cdot N_{gt} + c_{comp} \cdot N_{comp} \tag{3.8}$$

$$FC_{CAES} = HR_{CAES} \cdot c_f \cdot N_{gt} \cdot CF \tag{3.9}$$

3.1.4 Application Results

First, the results of time signal strategies are presented, considering all five markets and the entire period of study, i.e. from 2007 to 2011. Accordingly, exhaustive system operation simulations are performed to capture the size variation of energy storage components. Price signal strategies are examined throughout the entire period of study and all five markets. The results presented in the following sections are representative with an aim to evaluate the impact of different parameters on the value of arbitrage. Most importantly, the optimum energy storage system size and configuration is determined for each different electricity market and energy storage technology examined.

Application of time signal strategies

Historical time signal strategy

The application of the historical time signal strategy is based on the extraction of 4-year hourly average price curves on a daily and weekly basis for the five electricity markets examined. The results obtained by the analysis of the 4-year time series (see Figure 3.2 for daily average values, including 2011) are presented in Figure 3.3 and Table 3.2, with the corresponding curves and hours of minimum and maximum spot price.

Greece and Spain follow an identical pattern. This is defined by two price peaks during the noon and night time, with the second one appearing to be comparatively higher. For northern areas, the second day peak appears earlier, during late afternoon hours, and is apart from the case of the UK found to be lower than the noon peak price. Moreover, Greece's monopolistic market yields higher spot prices overall, while the mature and integrated market of Nord Pool presents the smallest price spread. The greatest spread is noted in the UK market (values given in £/MWh), reflecting the expensive operation of peak power plants in comparison to base load, but also in comparison to the rest of electricity markets investigated.

In addition, the significant contribution of RES in Spain is reflected in the lower spot price. In EEX the morning to mid-day market operation commands the second highest electricity prices. The observations of the weekly price curves are similar, with the minimum and maximum hour price concentrating during weekends and mid-week respectively with the exception of Spain (see also Table 3.2).

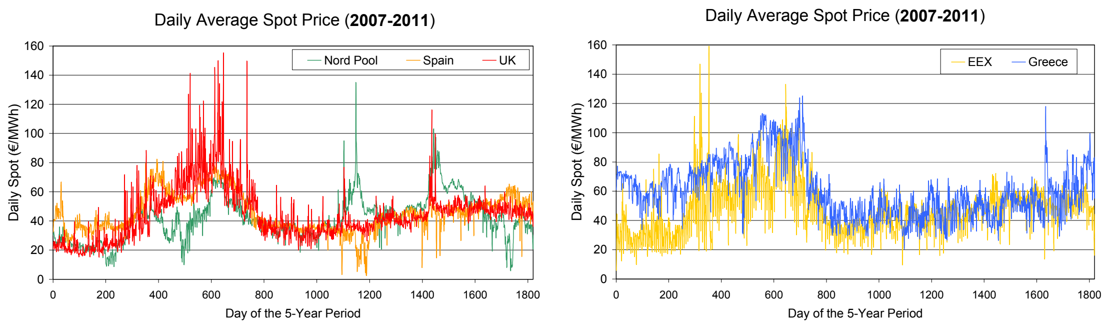


Figure 3.2: Time series of historical hourly spot prices presented as daily averages for the electricity markets of (a) Nord Pool, EEX and UK, and (b) Greece and Spain

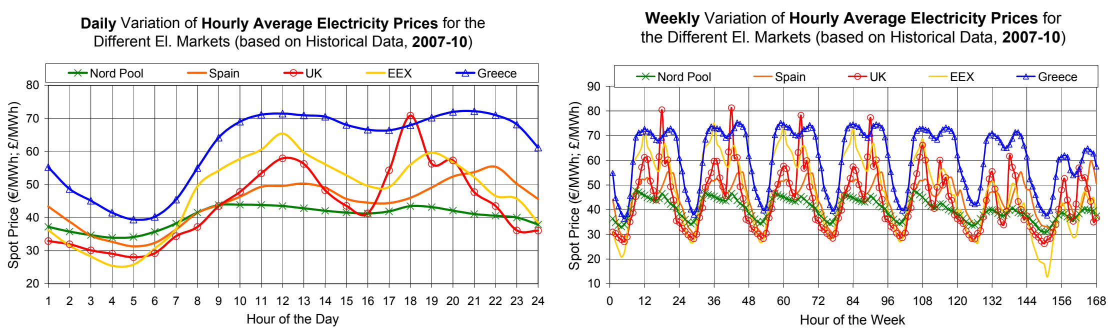


Figure 3.3: 4-year daily and weekly average hourly electricity price pattern (2007-2010)

Table 3.2: Spot price time series analysis (2007-2010) (EEX, 2013; HITSO, 2013; Nord Pool, 2013; OMEL, 2013; UK APX, 2013)

Market	Week Max	Price €/MWh	Daily Max	Price €/MWh	Week Min	Price €/MWh	Daily Min	Price €/MWh
Nord Pool	Monday-9:00	47.66	10:00	43.92	Sunday-6:00	31.03	4:00	33.94
Spain	Sunday-22:00	59.77	22:00	55.38	Friday-1:00	28.92	5:00	31.32
UK	Tuesday-18:00	81.26	18:00	70.85	Sunday-6:00	26.25	5:00	28.04
EEX	Tuesday-12:00	75.11	12:00	65.44	Sunday-7:00	12.75	4:00	25.46
Greece	Tuesday-20:00	75.31	21:00	72.17	Friday-1:00	36.33	5:00	39.44

The *ARV* (arbitrage value) versus the system production cost for all markets is investigated for 2011 and the system operation is configured to permit additional energy purchase for 1 or 2 hours before and after the determined minimum price time point (Figure 3.4). Greece presents the highest *ARV* while Nord Pool presents the lowest that also becomes negative for PHS. More frequent system operation achieved by extending the system charging period has a slight negative impact on the *ARV* but reduces considerably the system production cost, with analogous results expected if also extending the selling time slot. Moreover, the weekly time scale produces higher *ARV* in all cases apart from Greece, although it also increases the system production cost to above 700€/MWh. Generally, except for the case of Nord Pool, the value of arbitrage compensates for the energy losses introduced by energy storage, producing net revenues ranging from 5-40€/MWh. Furthermore, if adopting the daily time scale (which implies smaller storage capacity needs in comparison to a weekly time scale), the minimum system cost drops to almost 150€/MWh which yields a net difference of 110-125€/MWh. Overall, CAES outperforms PHS in terms of both *ARV* and *ND*, considering however that the obtained *ND* results are subject to the volatile price of natural gas used to operate the system (see also Table 3.1).

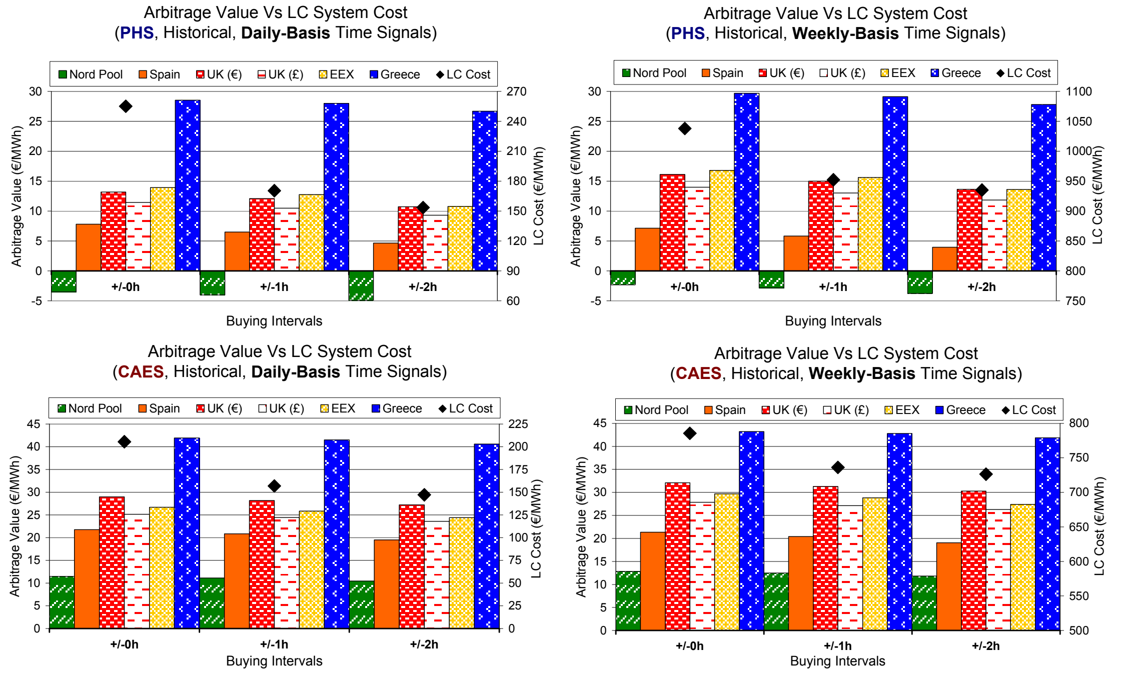


Figure 3.4: *ARV* vs system LC production cost based on the application of historical time signals for PHS (a, b) and CAES (c, d) on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year*)

Mirror time signal strategy

The *ARV* deriving from the application of mirror arbitrage strategies is compared to the system production cost (Figure 3.5).

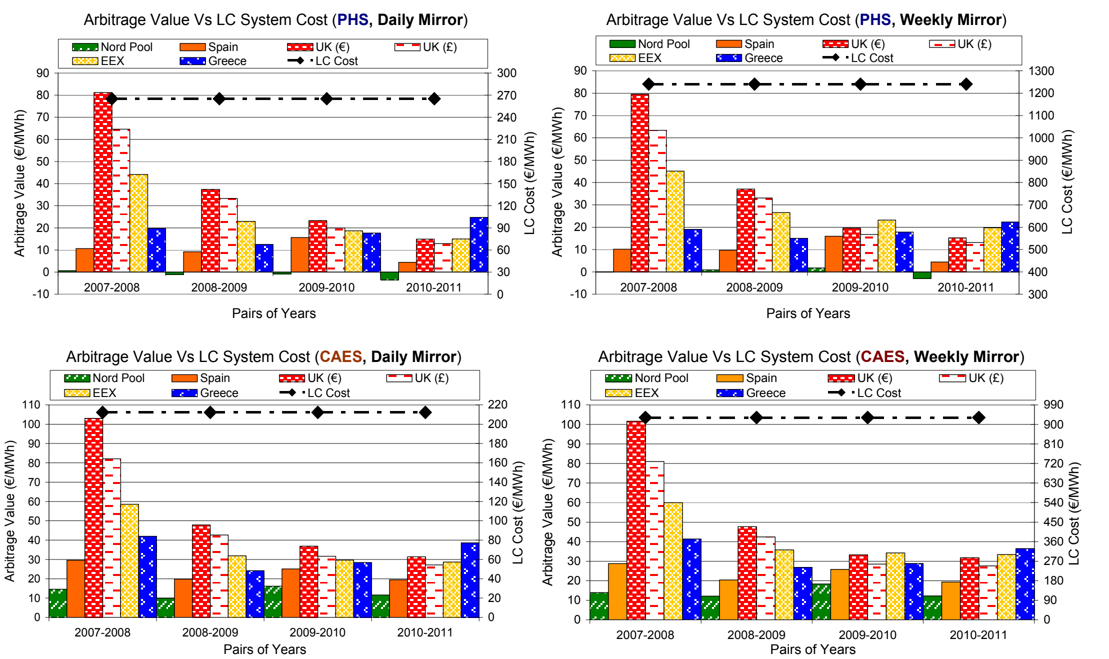


Figure 3.5: *ARV* vs system LC production cost based on the application of "mirror" time signals for PHS (a, b) and CAES (c, d) systems on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year time*)

In that case, the *ARV* presents considerable variation in the course of time for the markets of UK and EEX, owed mainly to the difference of the annual spot price (see Figure 3.2, where increase of prices during 2008 led to greater price spreads) and the greater consistency between mirror day and week time signals. On the contrary, fluctuation in the *ARV* in Greece and Spain is of narrow range, while Nord Pool presents negative values, apart from 2007-2008. Concerning 2010-2011, results obtained are similar to the ones deriving from historical signals. In addition, CAES is again producing higher *ARV* that in the case of the UK (2007-2008) even exceeds 80€/MWh. Overall, the examination of consecutive years reveals stable and unstable markets in terms of *ARV*, which can be associated with the respective fuel mix. Specifically, markets that are strongly dependent on fuel imports (such as UK and EEX) present considerable variation in electricity prices. This could lead to increased *ARV* for certain periods as a result of high fuel prices increase. Overall, minimum *ARV* of ~10€/MWh should be expected for all cases, with daily system cycling suggesting production costs of 250€/MWh and 200€/MWh for PHS and CAES respectively.

Back to back time signal strategy

Intense variation of the *ARV* for the markets of UK and EEX is demonstrated when following back to back signal strategies (Figure 3.6).

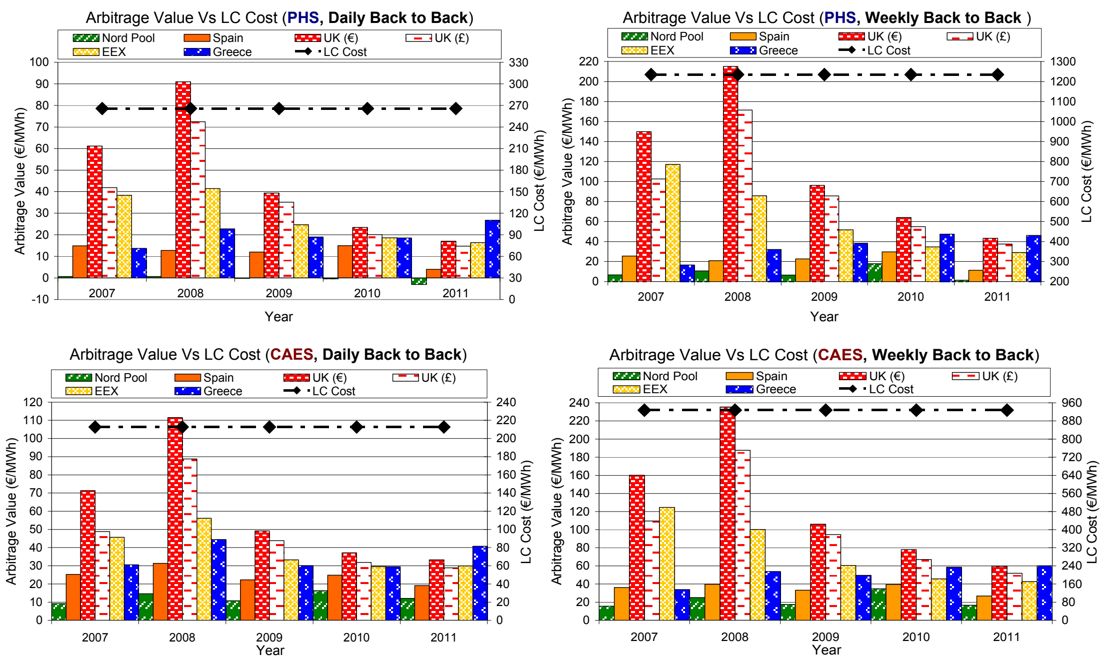


Figure 3.6: *ARV* vs system LC production cost based on the application of "back to back" time signals for PHS (a, b) and CAES (c, d) systems on a daily and weekly basis (*The ARV for the UK market is given in €/MWh and £/MWh, using the average annual exchange rate of each examined year*)

In this case, there is significant difference between the weekly and the daily time scale. Daily arbitrage values are similar to those of mirror signals with weekly ones being considerably higher. In fact, the weekly back to back strategy increases the *ARV* in all markets examined, producing a positive value even for Nord Pool. It is noteworthy that in certain markets and years, the *ARV* exceeds 80€/MWh, reaching even 180€/MWh for the UK in 2008. In this context, among the examined time signal strategies, the weekly back to back is the most effective in terms of *ARV*. As already described, in such a strategy the system is set to charge on a daily basis, adopting as a buying signal the hour of minimum price of the previous day, and discharge on a weekly basis, using as selling signal the hour of maximum price of the previous week. Operation of the system based on this strategy alone would not cover system costs that reach 900€/MWh and 1200€/MWh for PHS and CAES respectively. Instead, such a strategy enables the system to provide additional services, since the system output operates for only one hour per week. In conclusion, energy storage systems can exploit time signal based arbitrage under the condition that this comprises a complementary (secondary) source of revenue, maximized in the case of the weekly back to back strategy.

<u>Application of price signal strategies</u>

The impact of applying different strategies

The price signal strategies employed use static and moving-average approaches (Figures 3.7-3.12).

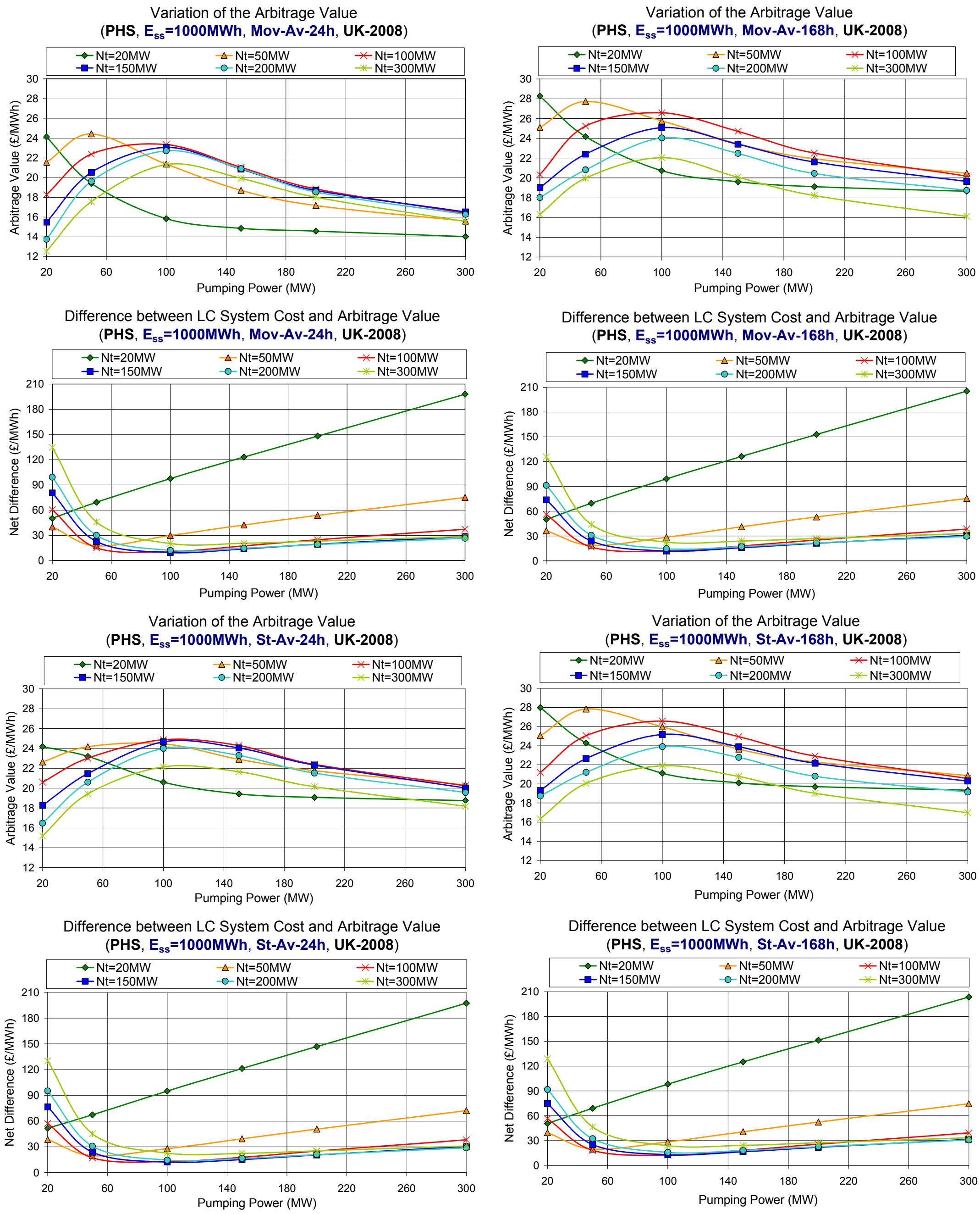


Figure 3.7: Variation of the *ARV* and *ND* between the system production cost and the *ARV* from the application of different price signal based strategies (PHS, UK-2008)

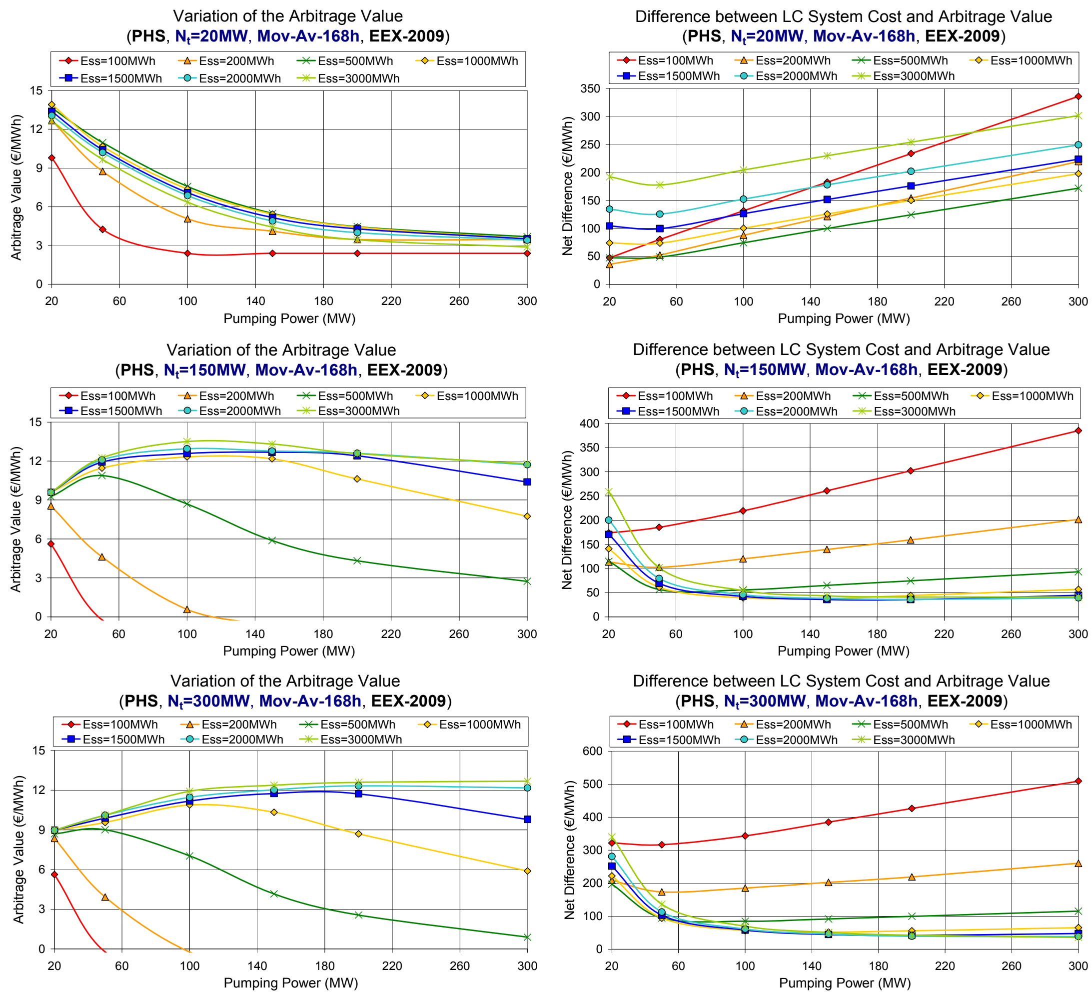


Figure 3.8: Variation of the *ARV* and *ND* between the system production cost and the *ARV* for low, medium and high capacity system output (PHS, EEX-2009)

System size in these cases is variable (see also Table 3.1), between 20MW-300MW for the input and output system power capacity and 100MWh-3GWh for energy storage capacity. Similar to other studies, upper values of input and output power capacity are constrained by the fact that the energy storage plant is assumed to be a price-taker, i.e. too small to influence electricity price during its operation, while assuming perfect next hour spot price prognosis.

The impact of using different time-scales and strategies is studied for PHS, in the UK (2008), under a fixed, medium-large-scale energy storage capacity of 1GWh (Figure 3.7). At the same time, variation of the *ARV* and *ND* is provided for different values of input and output power capacity (pumping station and hydro-turbine respectively). The use of different strategies and time-scales does not cause important *ARV* variation. Moreover, there is an area of output power capacity between N_t=50MW and N_t=150MW that gives the highest *ARV* for almost the entire range of input power capacity (i.e. the pumping power) and the given energy storage capacity of 1GWh. Furthermore, for the range of 100-140MW the higher the value of the output power capacity N_t, the higher the value of pumping power that gives the maximum *ARV*. Instead, *ND* tends to become higher for 20MW and 50MW as the pumping power increases beyond that same range of 100-140MW, with all other curves concentrated in the area of 20€/MWh to 50€/MWh. As a result, although the *ARV* is restricted below 30€/MWh, *ND* is minimized, even reaching 20€/MWh. More frequent operation imposed to the system by the application of price signals is critical for the reduction of the system production cost, which also minimizes *ND*, despite the fact that *ARV* is lower (for this system size) than the one produced by time signal strategies for that particular market and year studied.

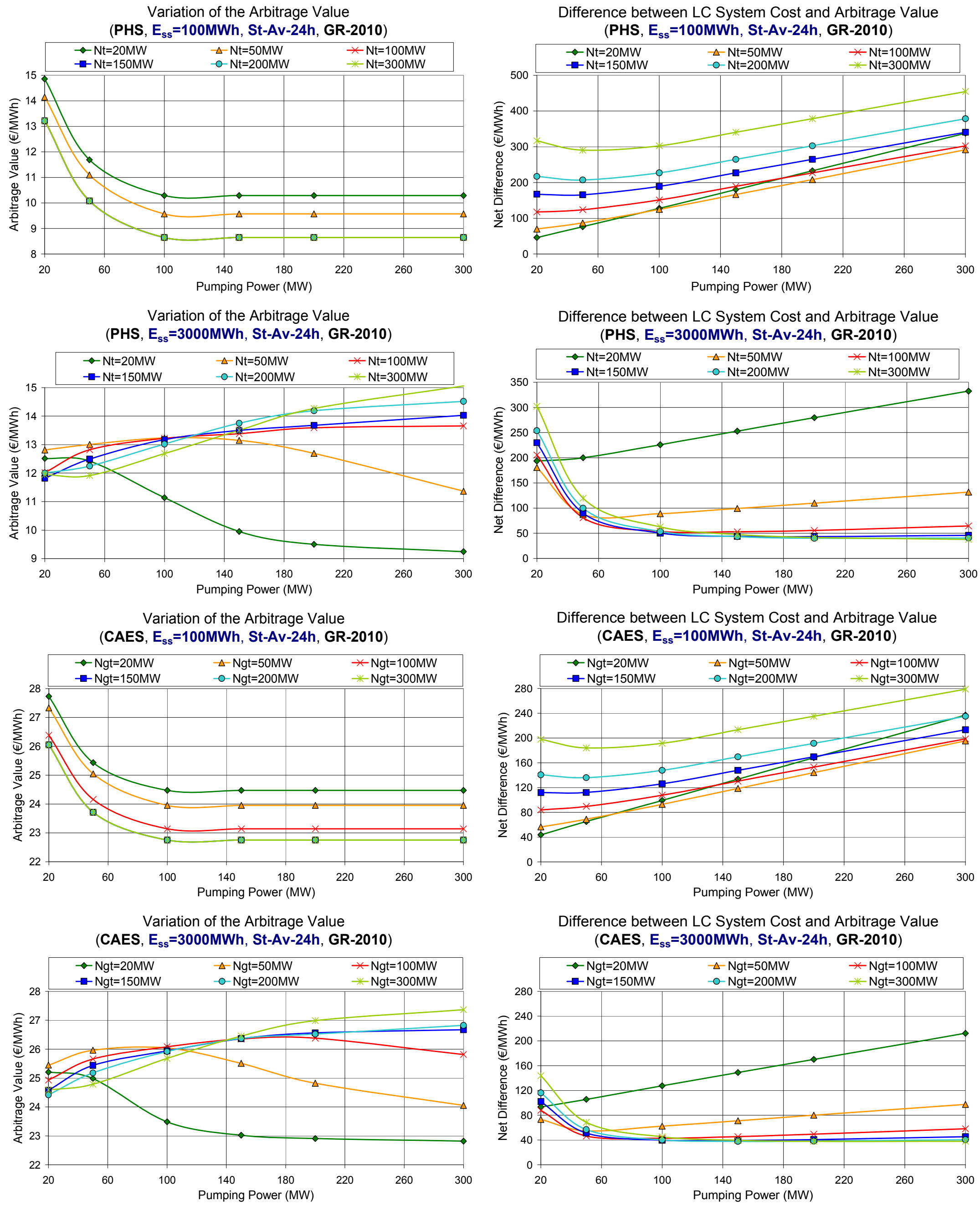


Figure 3.9: Variation of the *ARV* and *ND* between the system production cost and the *ARV* for small and large-scale storage capacity (PHS-CAES, Greece-2010)

The impact of system size

Subsequently, the impact of energy storage capacity is studied for small, medium and large-scale output power (i.e. N_t=20MW, N_t=150MW and N_t=300MW) in the EEX market (2009) using the weekly moving average strategy (Figure 3.8). To this end, the conclusion previously drawn concerning maximization of the *ARV* for output power capacity in the area of N_t=150MW is confirmed. More precisely, higher energy storage capacities yield higher *ARV*, except for N_t=20MW. In that case the small-scale hydro-turbine of 20MW is unable to exploit the large energy storage capacity that encourages operation of pumping until it is completely charged (full). Furthermore, use of small-scale hydro turbines (N_t=20MW), although giving higher *ARV* for energy storage capacity below 500MWh, implies also higher *ND* for energy storage capacity above 500MWh and pumping power exceeding 50-60MW.

The impact of energy storage technology

Comparison between PHS and CAES was performed for the Greek market (2010) where small and large-scale energy storage capacities were tested (Figure 3.9). As previously mentioned in the application of time signal strategies, CAES delivers higher *ARV*, which is confirmed for both the lower and the higher energy storage capacity studied, i.e. 100MWh and 3GWh. Net difference values of CAES and PHS on the contrary tend to become equal for the larger-size systems.

The temporal impact and the interannual arbitrage value

Furthermore, to account for the *ARV* and *ND* variation in the course of time, which could be thought representative of the risk taken by a potential investor, the UK market and weekly static average are used as example (Figure 3.10). Variation of the *ARV* and *ND* is represented by the vertical lines, with the average value for the 5-year period studied (2007-11) for both the maximum *ARV* and the minimum *ND* also provided. According to the figure, the maximum arbitrage value for the UK presents considerable variation in the course of time. Concerning the 5-year average values, increase of the selected energy storage capacity has a slight increasing effect on the *ARV*. Instead, in the case of the *ND*, a minimum appears in the area of 1000-1500MWh.

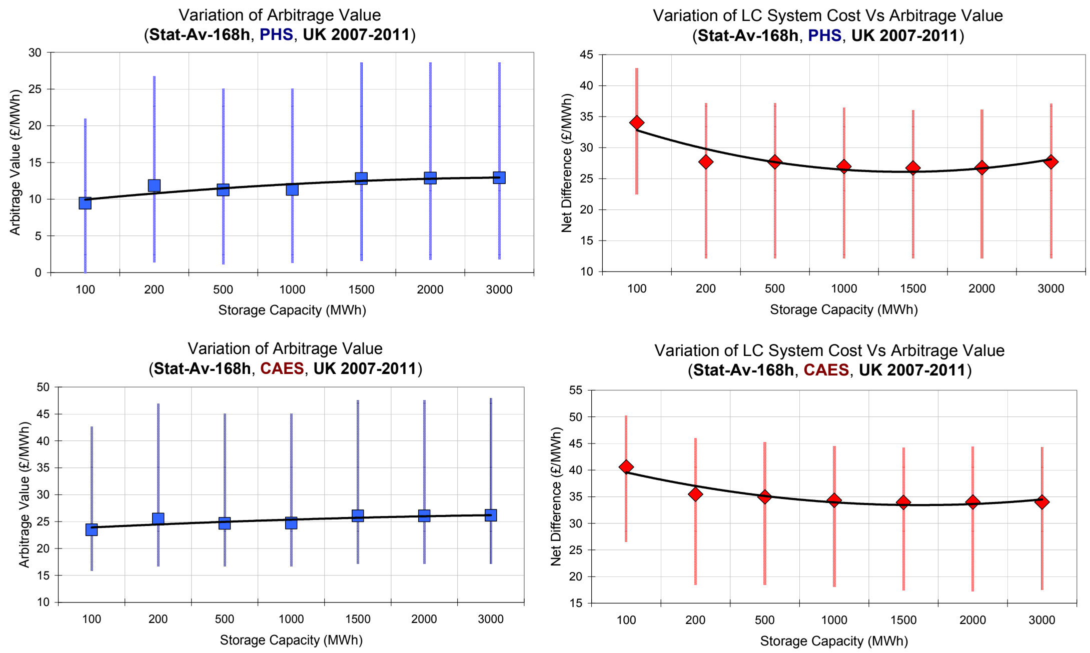


Figure 3.10: Variation of the maximum *ARV* and the minimum *ND* between system production cost and *ARV* (PHS-CAES, UK-2007-11)

Accordingly, the 5-year average values for the maximum *ARV* and the minimum *ND* are gathered in Figure 3.11, for daily static average and all electricity markets examined. The advantage of CAES over PHS concerning the *ARV* is clear for all markets, with Greece, EEX and UK producing the greatest value. On the contrary, *ND* results are in most cases comparable, with CAES proving more suitable for Greece, Nord Pool and for smaller energy storage capacity systems (in the order of 100MWh) and PHS presenting lower *ND* values for higher energy storage capacities. Moreover, although price signal based *ARV* fails to meet the value produced by time signal strategies, it implies high frequency operation which reduces the system production cost considerably. As a result, *ND* is minimized and even drops to 30€/MWh (e.g. Greece).

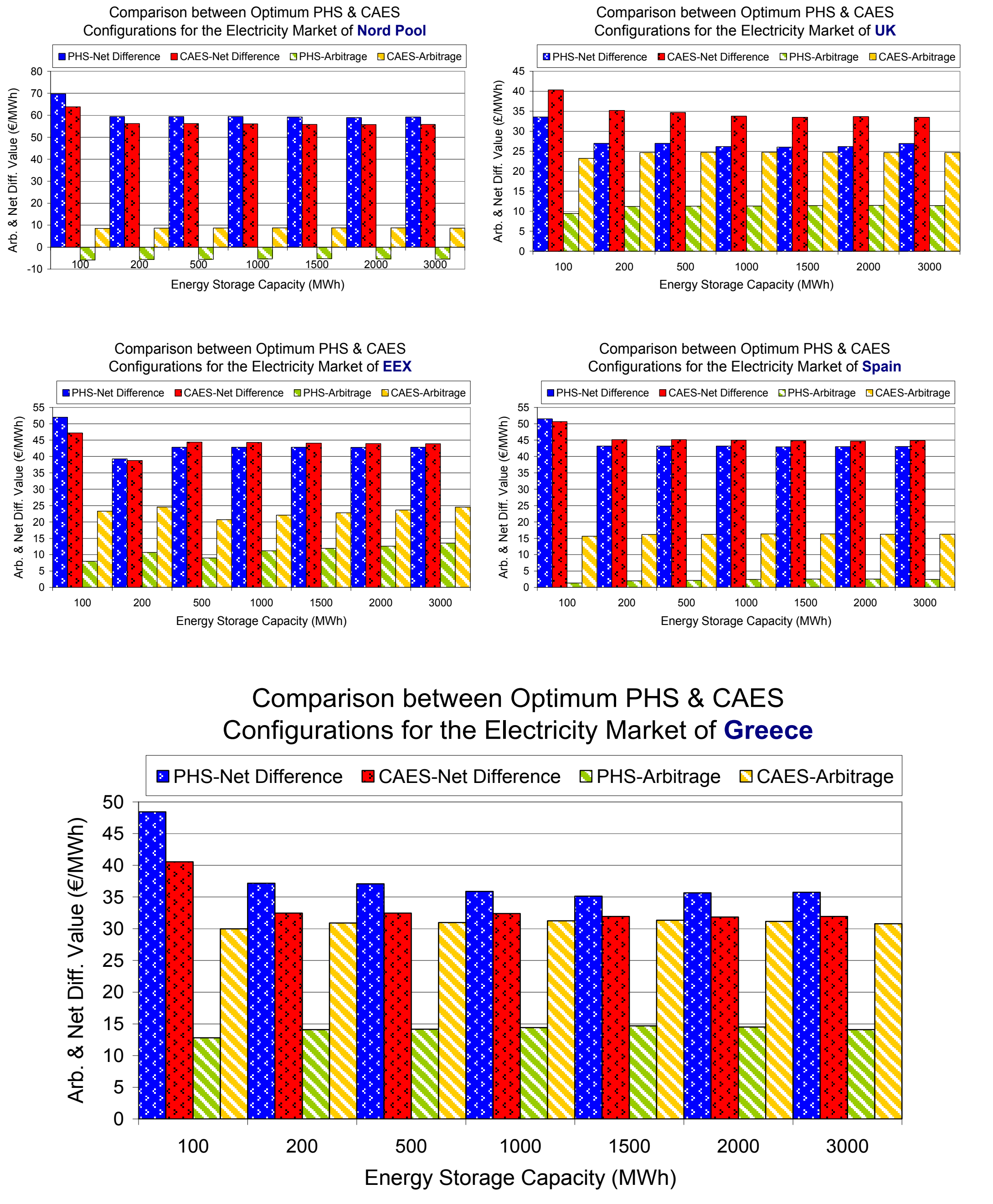


Figure 3.11: 5-year maximum average *ARV* and 5-year minimum average difference of system production cost and *ARV* for PHS and CAES configurations (all markets examined)

Determination of optimum system dimensions

Finally, in Figure 3.12, the respective optimum system dimensions are given. Daily static-average and all markets are examined, taking into account the average 5-year period values previously seen. More precisely, in the included charts, by selecting the value of energy storage capacity, the type of the energy storage system and an optimization criterion between maximum *ARV* and minimum *ND*, the recommended size for both input and output system size can be obtained. To this end, as energy storage capacity increases, Greece and Nord Pool require the greatest input power capacity, followed by UK and Spain. At the same time, EEX encourages operation of smaller-scale systems that do not exceed 100MW, similar to the case of the output power capacity, where CAES is in general encouraging operation of larger scale systems in comparison to PHS. Additionally, in the case of Spain, a maximum appears for both output and input capacity in the area of 1500MWh-2000MWh for both CAES and PHS. Finally, if examining the criterion of minimum *ND*, difference between markets is largely eliminated, with the UK found to require the lower input and higher output power capacity.

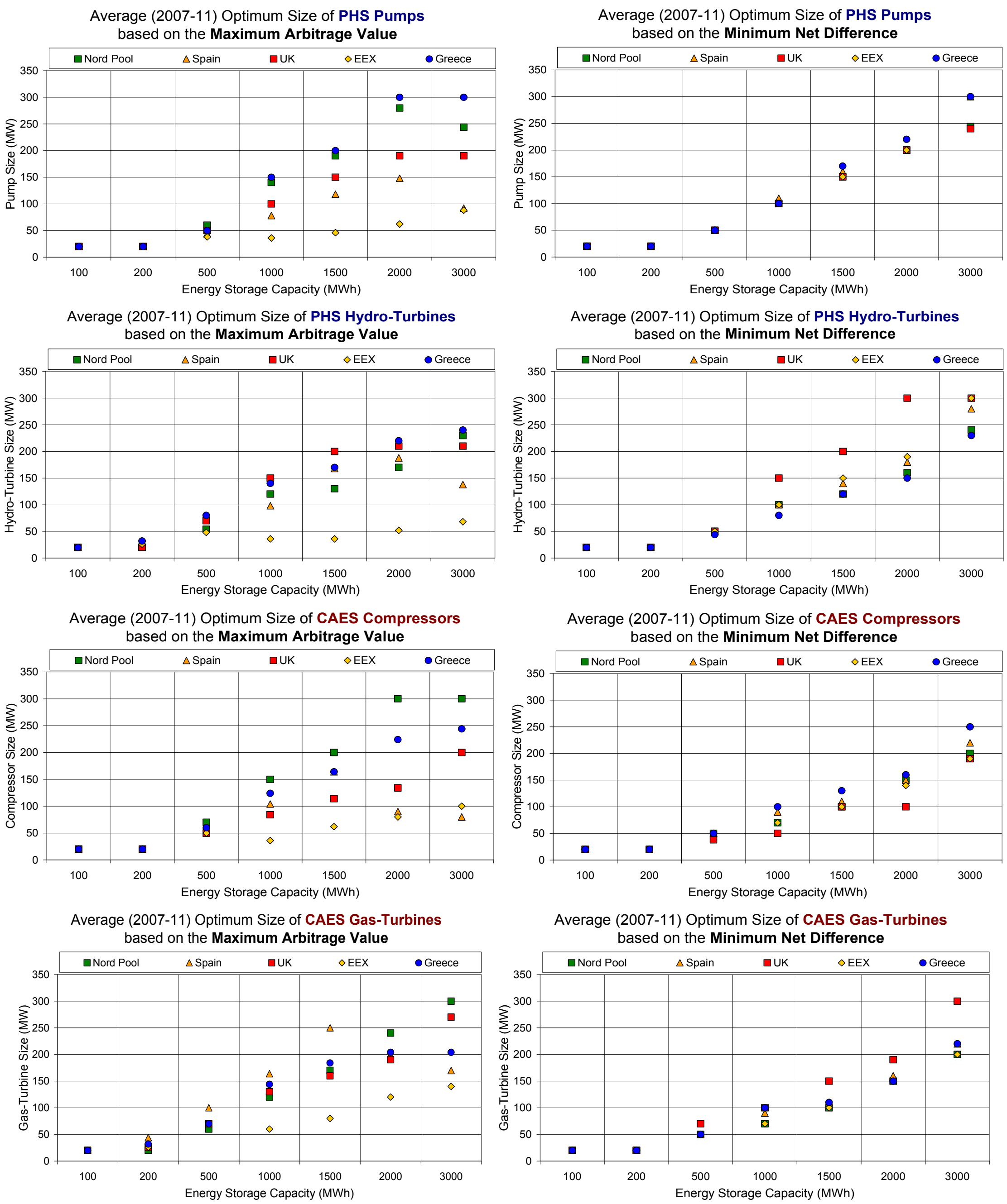


Figure 3.12: Optimum input and output power capacity to achieve maximum *ARV* and minimum *ND* for both PHS and CAES systems (all markets examined)

3.1.5 Discussion and Conclusions

By applying different energy trade strategies for a 5-year period in the markets of Nord Pool, EEX, UK, Spain and Greece, the value of arbitrage for PHS and CAES was estimated. Our results demonstrate that as European markets integrate and become more efficient, the value of arbitrage for energy storage is reduced. On the contrary, heavy reliance of markets on fuel imports (e.g. UK and EEX) create arbitrage opportunities from which a risk-adaptive investor could benefit. Arbitrage is also encouraged in less competitive markets such as the one of Greece, especially when indigenous energy reserves are used to cover base load and energy imports to cover peak load, creating thus a significant price spread. It must be noted at this point that increased competition suggests limited speculation opportunities from which an energy storage actor could benefit, especially if appreciating a significant market share, which could be the case in oligopolistic electricity markets. This is further supported by a concrete regulation framework that allows for increased market surveillance in order to face such phenomena. From a different perspective, energy storage looked at from the operator point of view could comprise an important asset for market regulation, set to operate in order to meet certain market criteria and also secure the market from speculation. To this end, presence of significant hydropower capacity proves, as expected, to be a disincentive for energy storage, such as in the case of Nord Pool. On the other hand, for wind energy, the impact of intermittency and the requirement for greater flexibility is yet to be studied in terms of arbitrage, since no important evidence could be drawn from e.g. the case of Spain, where effective trading with Portugal, facilitates the presence of wind power.

Moreover, time-based signals currently used suggest reduced operation of the storage configuration, which implies increased system production costs (especially in the case of weekly-based operation) but also encourages the adoption of additional services for the storage actor. Allowing for the extension of operation periods on the other hand for both buying and selling time signals would reduce system LC costs but at the same time would lead to the exploitation of less favourable price spreads. With regards to price-based signals, frequency of operation depends on the distribution of spot prices in comparison to the price signal each time adopted. To this end, optimization of such strategies also needs to take into account cost implications of increased cycling for energy storage, considering that the range of price signals adopted may be limited to satisfy both optimum cycling (i.e. ensuring increased CF and minimum maintenance requirements) and the need to exploit a maximum arbitrage value. Acknowledging the above, development of strategies based on the combination of time and price signals could potentially produce greater benefit for storage configurations, based also on the application of certain dispatching rules that will align with the overall dispatch strategy and portfolio of services adopted by the system.

Among the examined strategies, weekly back to back produces the highest arbitrage value; however, additional sources of revenue would be required to support the investment. At the same time, although requiring reliable prognosis of the next hours' spot price, price signal strategies also produce a worthwhile arbitrage value that is found to maximize for different energy storage system size in each of the examined markets. In addition, the comparison between PHS and CAES reveals the advantage of CAES that nevertheless largely depends on the price of natural gas required for system operation. Overall, despite the fact that our findings align with the common conclusion that arbitrage in itself cannot support investments in the energy storage sector, they also provide a set of directions on the optimum size and strategy for PHS and CAES practising arbitrage in electricity markets of different characteristics. In this way, development of innovative strategies that combine optimum arbitrage directions together with additional energy storage services such as RES support can be put forward, exploiting the potential of energy storage to perform different roles in an electricity market environment.

3.2 Novel Strategies for Industry-based Energy Storage

3.2.1 Introduction

Directive 2012/27/EU on energy efficiency requires the promotion of best energy practices in the industrial sector which is responsible for approximately 37% of the EU total electricity consumption and daytime peak loads challenging the capacity of electrical grids (Paulus and Borggrefe, 2011). At the same time, significant progress has been made over the past years in the field of energy storage (González et al., 2012, Kaldellis et al., 2009a, Sauer, 2008, Zafirakis, 2010). Both mature and emerging technologies support numerous applications (Figures 2.1 and 2.2), including integration of RES, transmission deferral, practice of arbitrage trading strategies, etc. At the same time, the dramatic cost drop of decentralized PV power generation encouraged further expansion of energy storage systems during the last years. However, owed to the absence of a concrete support framework (Zafirakis et al., 2013) and the fact that energy storage systems are a priori capital intensive, market diffusion has been slow. Acknowledging the above, the main objective of the current study focuses on the examination of load management (Schroeder, 2011) and arbitrage (Sioshansi et al., 2009) strategies practised by battery storage in industrial facilities. Massive adoption of energy storage in the industrial sector can favour both industrial actors (through e.g. improved energy management and supply security) and the system grid (through e.g. peak shaving). Besides, adoption of such schemes paves the way for large-scale RES penetration (Wang et al., 2012) within the existing infrastructure, by avoiding or deferring costly upgrade or extension of electricity grids.

To this end, by developing an appropriate load management and arbitrage simulation algorithm, the proposed strategies are tested, using as a case study the industrial facilities of a Greek manufacturing company and the characteristics of the Greek electricity market. The results show that despite the fact that the implementation of the proposed strategies leads to substantial reduction of the company's operational costs, the deriving gains cannot support similar investments. With this in mind, both revision of retail electricity price rates and development of novel financial support tools (Zafirakis et al., 2013) are thought to be necessary in order to obtain potential benefits at the national grid level.

3.2.2 Methodology – Proposed Storage Strategies

To introduce energy storage in the industrial sector, application of load shifting / peak shaving and arbitrage strategies have been considered. More precisely, when electricity fixed rates for industrial actors do not offer a stimulating spread (between low and high load demand periods), interaction of the storage system with the local wholesale electricity market is suggested. In this way the system may –under a certain risk– purchase energy at lower rates during low demand periods. This energy used to charge the system can then be recovered to either perform load shifting and peak shaving (to avoid power costs owed to extreme peaks) or deliver (sell) energy back to the grid in order to take advantage of the increased spot electricity prices encountered during peak demand hours. To this end, both load management (i.e. load shifting and peak shaving) and combined load management-arbitrage strategies are investigated. In doing so, the storage system is operated on a daily cycling basis while using price signals within certain time limits concerning buying and selling energy decisions, assuming also perfect prediction (or ex-post approach) of the next hour spot electricity price.

During the analysis, variation of main parameters including the peak limit (i.e. the maximum peak load demand set under the implementation of the proposed strategy), the price signal concerning selling energy decisions and the battery storage capacity, is also investigated, while keeping the buying energy price signal fixed. Finally, for each of the examined combinations, power and energy cost savings are recorded and a comparison between different configurations is provided.

The main inputs of the developed algorithm are given in the following:

Main inputs

- Determination of the peak shaving signal, defining the desired reduction of peak demand in order to avoid increased power costs on a monthly basis.
- Determination of the buying price signal for the battery storage, considering the spot prices' pattern, the industrial prices in force and the conversion losses introduced by the energy storage component.
- Determination of the selling price signal for the battery storage (applying only in the case of arbitrage), considering the spot prices' pattern and the conversion losses introduced by the energy storage component.
- Determination of the energy storage capacity, considering the load demand profile of the industrial facility.
- Determination of buying and peak shaving/selling hours for the energy storage system, considering the load profile of the industrial facility and the energy autonomy of the storage configuration.

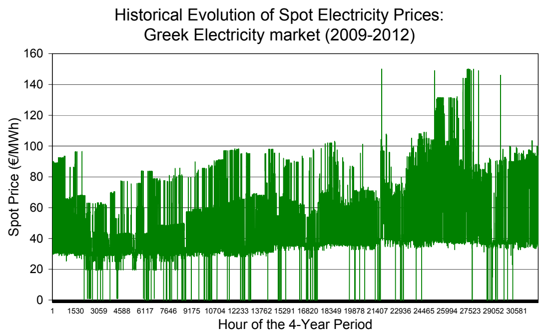
Main steps

- Depending on the hour of the day, the storage system is set either on charging or discharging mode, subject to the limitation of the available energy storage capacity, conversion losses and maximum depth of discharge.
- During charging, the system buys energy from the grid only in the case that the appearing spot price is equal or lower than the buying price signal adopted.
- During discharging, in the case of the peak shaving strategy, the system is called to practise peak shaving only, provided that the appearing demand is higher than the peak limit determined and that energy stores are available, otherwise the system remains idle.
- During discharging, in the case that the system is called to practise either peak shaving or arbitrage, arbitrage is given priority in the case the appearing spot price is found to exceed the selling price signal adopted. Otherwise the system, if this is necessary, performs peak shaving, always under the assumption that the required energy stores are available.
- The simulation is carried out on an hourly basis for an entire year, recording cost savings from peak shaving and arbitrage, repeated for numerous scenarios of energy storage capacity and peak limit application.

3.2.3 Case Study Characteristics

Description of the Greek electricity market

The electricity generation system of Greece is divided in two main sectors, i.e. the mainland and the island sub-systems. As far as the mainland electricity grid (interconnected system) is concerned, centralized power generation is mainly based on indigenous lignite reserves (Kaldellis et al., 2009b). In this regard, national dependence on fossil fuels is confirmed by the employment of approximately 6.1GW of steam turbines using indigenous lignite reserves, 2.3GW of combined cycle power plants using imported natural gas, and a total of 1.3GW of oil and gas based generation (gas turbines and internal combustion engines) mainly used for the service of non-interconnected Aegean island grids. Additionally, the mainland electricity grid is also supported by the operation of large hydropower plants that exceed 3GW and are used as peak shaving units, on top of which there are also two PHS plants of almost 700MW. Besides that, contribution of RES is mostly based on wind energy (~1.8GW) and PV installations (~2.5GW), while a small proportion corresponds to small-hydro, biogas and industrial waste installations. At the same time, the Greek electricity market, although being deregulated since 2002, is largely monopolistic at both the wholesale and the retail level, with the greatest power generator-retailer holding approximately 90% of the local market share. In this regard, the spot price time series for a period of four years (2009-2012) is given in Figure 3.13a, with the respective probability density curve for the year 2012 alone provided in Figure 3.13b.



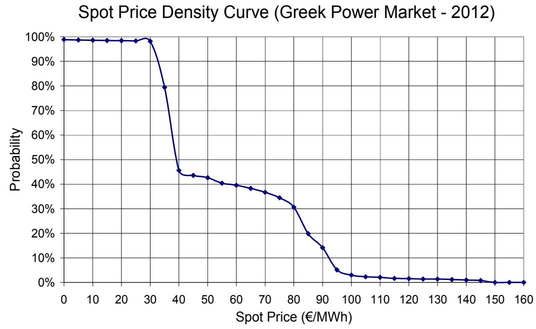


Figure 3.13: Historical electricity spot price variation (a) and probability density curve for year 2012 (b)

Furthermore, price rates for industrial consumers provided by the greater market retailer (i.e. PPC) are given in Table 3.3 (PPC, 2012a). The flat retail price-spread between daytime and night-hours does not encourage installation of energy storage to practise peak shaving with the use of energy stores drawn during night-time (Table 3.3). On the other hand, lower off-peak prices may even drop to the level of 30€/MWh in the spot market, while peak prices exceed 100€/MWh for about 2% of the time (Figure 3.13).

Table 3.3: Electricity price rates of PPC for the industrial sector (2012) (PPC, 2012a)

Time period	**Power cost (€/kW/month)**[8]	**Energy cost (€/kWh)**
7:00 – 23:00 week-days	7.25	0.06388
23:00 – 7:00 week-days & weekends	-	0.05015

To this end, the storage system is set to interact with the local wholesale market in order to draw energy during off-peak hours that will then be used for either load management or arbitrage (delivery of energy back to the local grid during peak hours). However, it seems that the power cost is more interesting, with storage systems potentially levelling out power consumption and reducing power costs significantly.

Description of the industrial facility

The industrial facility used as a case study belongs to the Sunlight S.A. manufacturing company. It ranks among the world's top manufacturers of energy products and systems, specialising in the design, production and distribution of energy storage systems for industrial, consumer and advanced applications, energy power systems, green energy systems and energy services. The company's manufacturing plant is

[8] The power cost takes into account the maximum appearing demand on a monthly basis.

located in the area of Xanthi, Northern Greece, with its detailed mean hourly energy consumption for the year 2012 given in Figure 3.14a. The cumulative probability curve is provided in Figure 3.14b, while further processing of load demand data follows in Figures 3.15a and 3.15b, where the average 24h load demand pattern and the respective six-4h period cumulative probability curves are depicted.

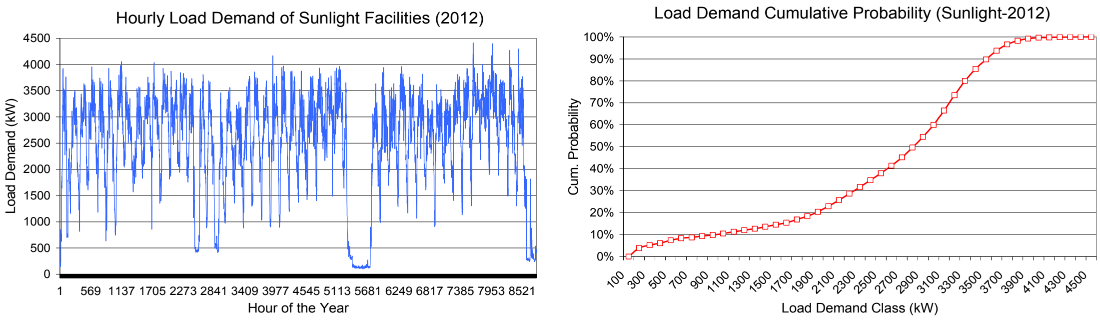


Figure 3.14: Hourly (a) and cumulative probability (b) of load demand for Sunlight (2012)

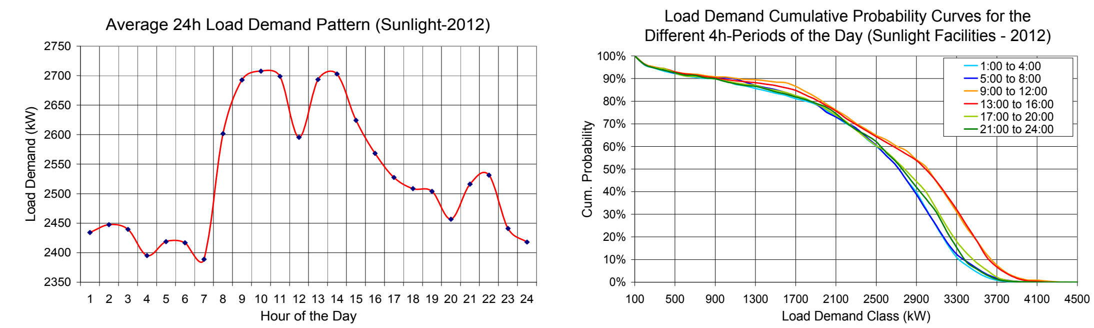


Figure 3.15: 24h average (a) and six-4h cumulative probability curves (b) of load demand for Sunlight (2012)

According to the load demand information, the annual peak demand marginally exceeds 4.4MW, with the respective year-round electricity consumption reaching approximately 22.2GWh and reducing remarkably during August owed to summer closure. Furthermore, peak load demand is usually encountered during morning and mid-day hours (i.e. between 9:00 and 15:00), while the probability for load demand to be higher than 3.9MW drops below 1% (Figures 3.14b and 3.15b).

3.2.4 Application Results

Time periods selected for the storage system to be charged and discharged are set to coincide with the respective low and high price periods of industrial rates (see also Tables 3.3 and 3.4, i.e. 23:00 to 7:00 for system charging and 7:00-23:00 for system discharging). Furthermore, a relatively high round-trip efficiency of 85% has been selected for the battery storage system, while energy storage capacity examined refers to the useful / exploitable one, i.e. for the actual size of the battery storage to be given the maximum permitted depth of discharge should also be taken into account.

In the first week of the year (Figure 3.16), a maximum peak demand of 3.5MW is selected together with useful storage capacity of 3MWh (not examined in the parametrical analysis following), considering also that the buying energy price signal is set at 50€/MWh (i.e. the system is allowed to buy energy when the electricity spot price is less or equal to 50€/MWh). The revised load demand is modified so as to allow energy purchase during night hours (provided that the condition of the maximum buying price is fulfilled) in order to charge the battery system on the one hand, and perform peak shaving (above the 3.5MW limit) during daytime on the other.

Table 3.4: Problem input parameters

Input parameter	**Assigned values**
Daily charging period	23:00 – 7:00
Daily discharging period (peak shaving/arbitrage)	7:00 – 23:00
Useful storage capacity range of variation	500kWh – 2000kWh
Peak-limit range of variation	3200kW – 3900kW
Selling energy price signal range of variation	60€/MWh – 90€/MWh

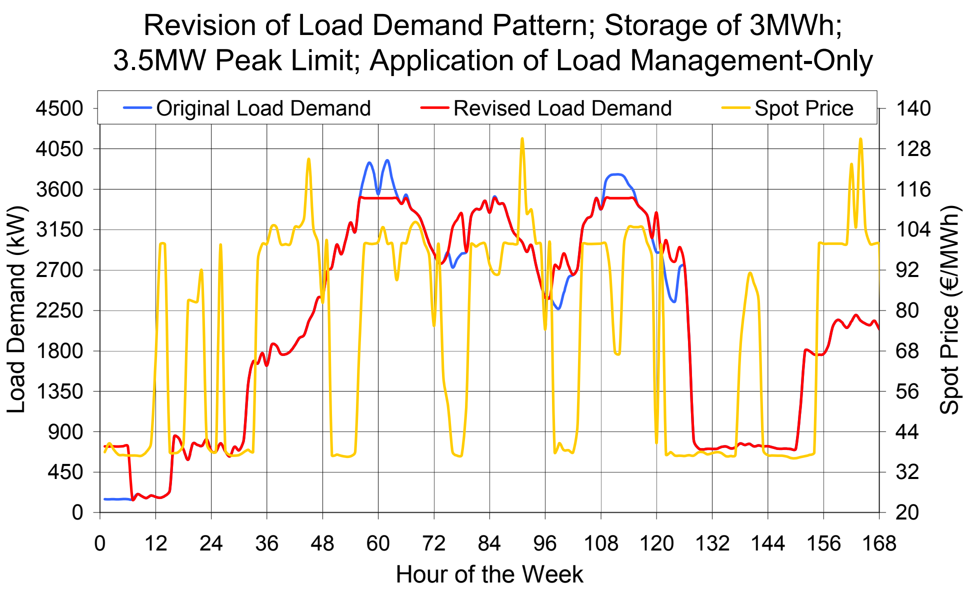


Figure 3.16: Load demand revision for the load shifting and peak shaving strategy

The application of the combined load management and arbitrage strategy gives priority to arbitrage if during the discharging period the appearing spot price is equal to or higher than the minimum price limit. This is illustrated in Figure 3.17, where load management is only partly performed for this first week of the year since the spot price during the charging period may exceed the limit of 100€/MWh and thus activate the prioritized arbitrage strategy.

The power cost savings of the load management strategy (Figure 3.18) show operation cost reduction due to peak shaving and do not take into account the cost of input energy in order to charge the battery storage installation. In this context, increase of battery storage is suggesting increase of power cost savings, reaching even 22500€/year for a 2MWh useful energy storage capacity, while at the same time encouraging for a decrease of the maximum peak limit (since the maximum in each of the curves gradually shifts to lower peak limits as the useful energy storage capacity increases). This can be explained, since increase of the battery storage capacity allows for greater reduction of the peak demand, which in turn increases power cost savings. Thus, as the storage capacity increases, the optimum point shifts to the left of the graph, as greater peak shaving can be performed effectively. On the other hand, significant reduction of the peak shaving application (i.e. right side of the graph) signals as expected reduced power cost savings due to the limited reduction of the peak demand. Furthermore, for the application of greater peak shaving, i.e. reduction of peak demand below 3.2MW, the energy storage capacity should be increased above 2MWh, otherwise it cannot perform the necessary reduction sufficiently, owed to its limited capacity that cannot achieve elimination of the maximum peak demand appearing on a monthly basis. It is reminded at this point that power costs refer to the monthly peak demand; thus if the latter is not eliminated during the entire month, no power cost savings are accomplished.

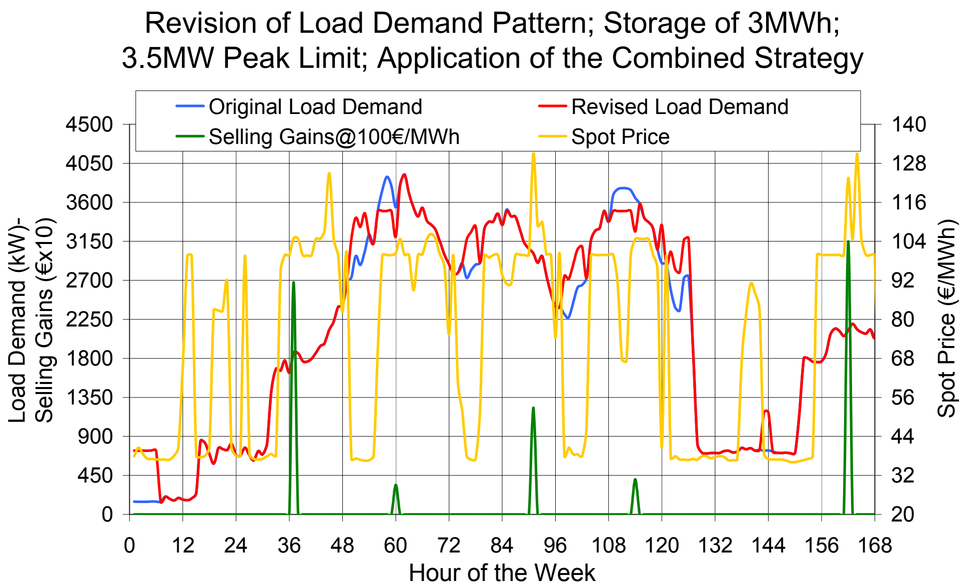


Figure 3.17: Load demand revision for the combined strategy

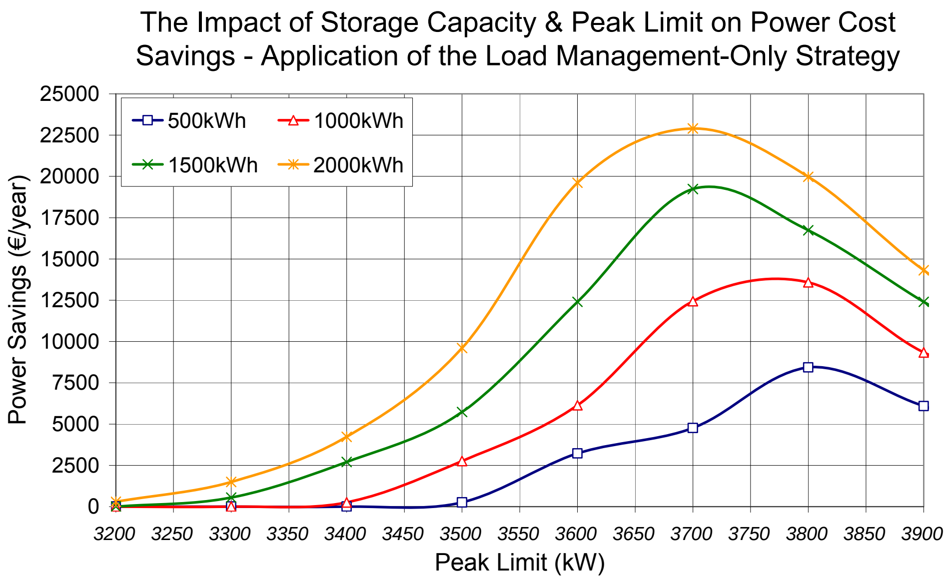


Figure 3.18: Power cost savings in relation to peak limit and storage capacity variation

The respective energy gains are presented in relation to the peak limit and the selling energy price signal variation (Figure 3.19), taking into account both input energy expenses and sold energy revenues through arbitrage; for comparison purposes, the load management-only strategy is also included. Energy costs present an increase for the load management-only strategy (since energy is only purchased and not sold in that case) that tends to be reduced as the peak limit increases. This is owed to the fact that as the peak limit is allowed to increase, less energy is bought from the grid to charge the battery storage, and thus less energy expenses are recorded. At the same time, since less energy is used for peak shaving, more energy is available to practise arbitrage, which suggests increase of energy revenues, especially if appreciating a favourable spot price spread. Furthermore, although energy gains increase up to the price signal of 70€/MWh, they are then being reduced considerably, especially in the case of 90€/MWh where the high price signal decreases selling energy frequency.

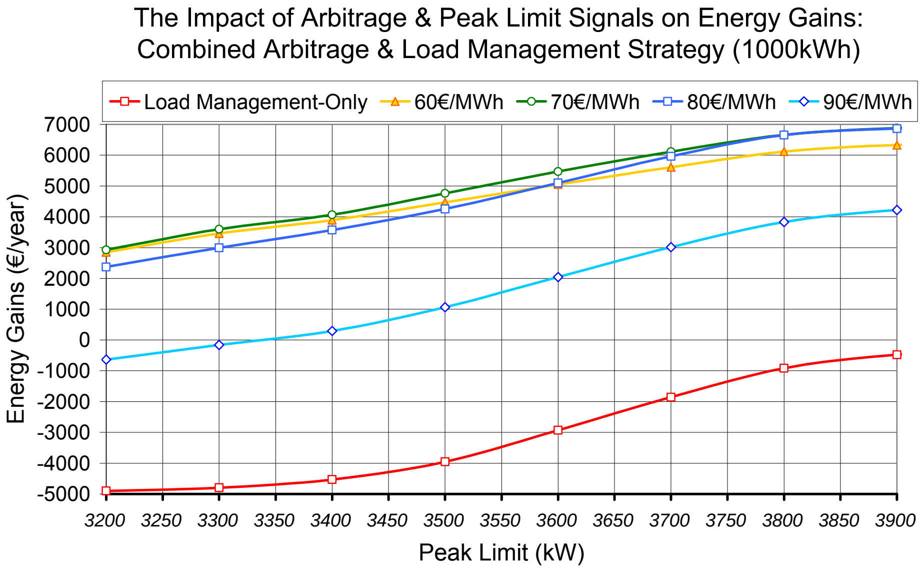


Figure 3.19: Energy cost gains in relation to peak limit and selling energy price signal

Finally, total annual gains are presented in relation to the peak limit, the storage capacity and the selected strategy variation (Figure 3.20). To this end, the load management-only strategy provides higher gains that come with reduced risk, provided that the optimum peak shaving limit is determined. On the other hand, the combined load management and arbitrage strategy yields lower gains in comparison to the respective load management-only maximum, presenting narrow variation across the entire peak limit area.

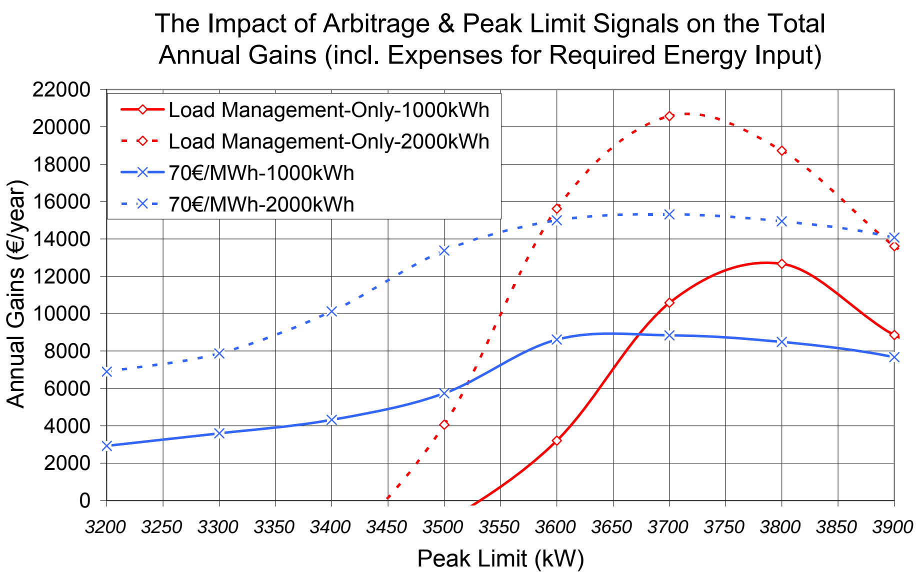


Figure 3.20: Total gains in relation to peak limit, storage capacity and strategy selection variation

3.2.5 Summary

Based on the development of a simulation algorithm, load management-only and combined load management and arbitrage energy storage strategies have been investigated. The industrial facility of a Greek manufacturer was used as a case study, aiming to demonstrate the potential benefits that could derive from the massive application of energy storage in the industrial sector. Industrial electricity price rates along with the status of the Greek wholesale electricity market do not encourage investments in energy storage at the moment (taking into account that mature battery storage energy and power costs are in the order of 200€/kWh and 500€/kW respectively).

On the other hand, the potential for energy management and the achievement of considerable gains at the industrial facility level is reflected in the results of the specific study. Thus, it is believed that with the development and implementation of appropriate policy mechanisms and financial support measures, benefits deriving from the adoption of energy storage solutions in the industrial sector could be harvested at the national grid level. Besides that, investigation of more advanced energy storage strategies at the industry level could also encompass facilitation of on-site RES power generation, further advancing efforts towards optimum energy management in the specific sector.

Additionally, it is also worth analyzing different industrial consumers in detail, because the load patterns differ substantially. There are consumers with significantly wider difference between day and night time or even higher peak values. Therefore, this work can be advanced through the analysis of more load profiles that will result in a classification of different load patterns. The same is valid for the investigation of different battery storage systems, which could lead to the development of an integrated algorithm that can incorporate the appropriate life-time and efficiency variation prediction models, based on the type of battery storage and strategies.

3.3 Novel Strategies for RES-based, Private-owned Energy Storage

3.3.1 Introduction

Despite the progress made during the last thirty years in the field of wind energy (Kaldellis and Zafirakis, 2011), the tantalizing question still remains: Can wind energy move away from the side lines of conventional thermal power generation and shoulder the burden of electricity supply on its own? So far, by playing the role of ancillary power sources, wind energy and other RES have managed to hide inherent limitations from sight. However these drawbacks will become more manifest once RES-based power generation is called to take on a more important role (Mount et al., 2012; Purvins et al., 2011; Trainer, 2010). In this context, large-scale integration of wind power entails that a significant portion of electricity generation is based on a fluctuating energy supply source, which in practice cannot always meet load demand, and more importantly cannot be easily predicted (Landberg et al., 2003).

This in turn requires that support is provided to wind energy production through introduction of back-up power (Wang et al., 2011) that can compensate for calm spells or extremely high wind speed. In addition, as addressed in Georgilakis (2008), large-scale integration of wind energy strongly affects power quality, while in terms of market operation, a large share of wind power can result in increased volatility of spot prices and extreme negative price events, as identified by several researchers (Brandstätt et al., 2011; Cutler et al., 2011; Traber and Kemfert, 2011; Woo et al., 2011). Nevertheless, increased contribution of wind energy is crucial for many countries aiming at improved electricity supply security through reduced reliance on imported power and resources (Chalvatzis and Hooper, 2009).

To this end, there are certain proposed solutions that may alleviate the adverse impacts of large-scale wind energy integration, summarized in the following:

- Energy management strategies can provide better balancing between energy supply and demand, allowing large-scale wind energy integration. Elimination of transmission "bottlenecks", upgrade of electricity grids and improved communication between different grids are among the alternatives that may support export of excess wind energy as well as energy imports to cover energy deficits owed to insufficient wind energy production (Gerber et al., 2012; Green and Vasilakos, 2012).
- Spatial planning strategies that will take into account the importance of dispersed wind energy generation in combination with grid expansion is a promising strategy that relies on the quality distribution of wind potential across a given area (Akhmatov and Knudsen, 2007).
- DSM techniques (Druitt and Früh, 2012; Moura and De Almeida AT, 2010) along with improved wind speed forecasting methods (Foley et al., 2012; Li and Shi, 2010; Liu et al., 2011b; Skittides and Früh, 2014) is another combined tool that could encourage the consumer side to cope with the variability of wind energy production.
- Large-scale energy storage infrastructure (Beaudin et al., 2010; Kaldellis and Zafirakis, 2007a; Madlener and Latz, 2013; Tuohy and O'Malley, 2011) that may allow storage of excess wind energy and grid supply when energy deficits appear.

Although the development of all four solutions should be encouraged to provide substantial support for future wind power and RES targets (Saidur et al., 2010), in this study emphasis is given on the option of energy storage. In this regard, growing interest is recently recorded in the field of electrical energy storage, with many emerging and more mature energy storage technologies (Zafirakis, 2010) providing a set of options for various applications in an electricity network (ESC, 2002), e.g., arbitrage, peak shaving, spinning reserve, voltage and frequency regulation, deferral of new transmission and distribution facilities, etc. At the same time because of the current high capital cost of commercial energy storage technologies (Zafirakis, 2010), market integration has been slow while absence of a valuation framework for ancillary services further discourages investment. In particular, as many authors have recently pointed out (Connolly et al., 2011a; Drury et al., 2011; Loisel et al., 2011), adoption of arbitrage strategies based on spot price spreads is not in itself sufficient to ensure cost-effectiveness, with imperfect prognosis of the spot price (Weron and Misiorek, 2008) implying an extremely high-risk investment. To this end, assignment of a value to social welfare attributes of energy storage technologies comprises a subject of major interest, recently reviewed by many authors (Sioshansi, 2010; Sioshansi et al., 2009), realizing that even if ancillary services were given a value, arbitrage would still comprise a high-risk source of revenues. On top of that, authors like Kazempour et al. (2009a), argue that energy storage technologies should be incentivised with tax credits rates and preferential loans, securing in this way operation of such systems in electricity market environments.

In this context, use of appropriate energy storage technologies to support wind power through the elimination of intermittent energy production could balance wind energy production and assign some indisputable social welfare attributes to the role of energy storage (Sioshansi, 2011). More precisely, by exploiting wind energy surplus that is otherwise valueless (occurring in times of high wind energy production and low demand), two things are accomplished. On the one hand reduction of wind energy curtailments and on the other, shift to times of peak demand is carried out through the use of energy storage systems. In this way, wind energy is used to cover peak demand, otherwise met by expensive thermal power stations.

Thus, by identifying the role of energy storage to support large-scale integration of wind energy, the question is: Under what terms can synergy between wind energy and expensive energy storage be encouraged? To address it appropriately, this study explores the application of suitable financial support mechanisms for the promotion of energy storage technologies recovering wind energy. More precisely, the approach adopted investigates the use of FiTs in conjunction with initial investment subsidies, through the development of a comprehensive socioeconomic cost-benefit model that can be used for the examination of additional incentive mechanisms such as tax break subsidies and power premiums.

At this point, it should be noted that a combination of investment incentives is explored for the first time for electricity storage, with the estimation of suitable FiTs that are not simply based on the investor's profitability. Instead, to account for externalities, FiTs are currently estimated through the valuation of social attributes assigned to energy storage systems from the exploitation of wind energy, and are compared with the system electricity production cost to identify socially profitable investment opportunities in energy storage. In this regard, a case study based on the mainland power system of Greece is examined. The selected case study is considered to be suitable, owed to the fact that the installed wind energy capacity in the country is rapidly expanding (HWEA, 2012a), with current interconnections (RAE, 2011) not considered able to accommodate the wind energy surplus expected in the future (Caralis et al., 2012) and with unidentified potential of neighbouring countries to absorb this energy.

Following the introduction section, this chapter continues with a description of the available electricity storage systems and a justification of the selected technologies. The methodology adopted in the cost-benefit model is then explained in detail in section 3.3.3, while results obtained are discussed extensively through comparative cases and sensitivity analysis in section 3.3.4. Finally, section 3.3.5 provides the concluding remarks.

3.3.2 The Concept of Energy Storage

State of the art in energy storage

As previously mentioned, there are a number of energy storage technologies that cover a broad range of applications (Ibrahim et al., 2008; Kaldellis et al., 2009a). Contemporary energy storage technologies include PHS, CAES, FC-HS, flywheels, SCs, SMES, and various battery systems. Each one of them has certain features that make it suitable for specific applications. Among the most important characteristics determining an energy storage system is its ability to store large amounts of energy (i.e., the energy storage capacity E_{ss} of the system) and its ability to provide considerable power output N_{ss}.

Based on these two main characteristics, mapping of energy storage technologies is provided in Figure 2.1, where one may distinguish two main groups. The first (energy management) group encompasses applications that aim to balance energy generation and load demand via the implementation of energy storage. Applications for this group require the use of bulk energy storage systems with considerable energy storage capacity, storage duration and discharge time. As a result, in the specific group PHS, CAES, FC-HS and certain battery types are included. In the second group of power quality and reliability, the requirement is for low to medium power output for very short time, which makes flywheels, SMES, SCs and certain batteries the most suitable technologies.

Between these two extremes, the intermediate group of bridging power is identified, satisfied mainly by battery storage. To this end, support of large-scale wind energy integration may only be achieved by bulk energy storage systems, encountered in the group of energy management applications. However, the classification of energy storage systems cannot be considered as static. For example, research and development in Li-ion batteries during the recent years gradually allows for the expansion of the technology's application field from portable devices to plug-in electrical vehicles and grid-scale storage, with certain pilot installations in the MW-MWh scale already in operation (ESA, 2012; Leadbetter and Swan, 2012).

Operation principle of energy storage systems

Operation of a typical energy storage system is based on the principle that when energy excess is available (i.e., when energy demand is lower than supply) the system operates in "charging" mode and stores the surplus of electrical energy (coming from either a RES plant or the grid) in a specific storage media (e.g. water at a given elevation, compressed air or hydrogen, chemical solutions, rotating masses, magnetic fields, etc.) through energy conversion. Energy remains stored in the system until electricity supply fails to cover demand or an economic incentive appears for the energy storage system to deliver its energy to the grid. At that point, the required energy is drawn from the storage and is converted back to useful electricity. In this context, energy losses incurred during the system's charging-discharging cycle should be considered, with the overall energy efficiency being a detrimental factor for the performance of such systems. Concerning operation strategies, recovery of excess energy production by energy storage systems is undertaken either diurnally or on the basis of seasonal storage patterns, although the second option usually requires availability of extreme storage capacity. As far as diurnal or short-term operation is concerned, energy storage systems usually take advantage of arbitrage strategies on the basis of price difference between low energy demand periods (when energy excess usually appears) and peak demand times (when prices increase considerably). Nevertheless, as discussed earlier, extremely high investment costs required in most cases for the employment of an energy storage system are not always compensated by this profit margin.

Proposed operation mode

Based on the above, a different mode of operation is proposed to improve cost-effectiveness of such systems, through the recovery of wind energy surplus. More precisely, the concept of interaction between wind farms and energy storage systems considers diurnal (at least) cycling of the latter, on the basis of guaranteed energy provided to the grid during peak demand hours. In this regard, energy surplus, deriving either exclusively or at a minimum permitted contribution share from wind farms (currently selected to be 70%, with the rest potentially deriving from the grid during times of low demand), is used for charging the system. Next, during times of peak demand (i.e., during mid-day and early night-time), stored energy is used to fulfil guaranteed energy requirements. As it may be concluded, an appropriate size for an energy storage system is critical to satisfy the requirement of guaranteed energy output. In this context, interplay between the available wind energy curtailments, the energy storage capacity of the system, the guaranteed power output and the minimum contribution share of wind farms, needs to be studied in detail as in Zafirakis and Kaldellis (2010).

Description of examined energy storage systems

Two different energy storage systems were examined. PHS and CAES were selected, because they are mature technologies that are capable of storing large amounts of energy. In this way, large-scale recovery of wind energy curtailments as well as satisfaction of guaranteed power output can be facilitated. On top of that, both technologies are characterized by a service period that exceeds 20 years and moderate energy losses. On the other hand, FC-HS has been excluded, because such systems are still affected by rather low energy efficiency that impedes a substantial exploitation of wind energy production. Furthermore, conventional batteries are determined by a considerably lower service period (less than 10 years), while advanced flow batteries and Li-ion batteries (Zafirakis, 2010) cannot be yet regarded as a mature option.

PHS systems

PHS should be regarded as the most mature bulk energy storage technology (Deane et al., 2010), with almost 130GW of installed capacity worldwide. In a PHS system, the energy surplus in times of low demand, either deriving from the electrical grid or any given generation unit (such as a wind park), is exploited to pump water to an elevated (upper) storage reservoir with the use of pumps or reversible hydro-turbines. During peak demand, water is released from the upper reservoir and hydro-turbines operate to feed the connected electric generator. As a result, the system is able to cover energy deficits by supplying the energy previously stored. Cycle efficiency of modern PHS is in the order of 70-80% (Anagnostopoulos and Papantonis, 2008; Bjarne, 2012), whereas its main drawback is the high capital cost, directly related to the need for the construction of reservoirs. Such systems are able to take up load in a few seconds' time and feature a high rate of extracted energy. In general, PHS systems are suitable for applications of energy management, spinning reserve and frequency control and thus, are also suitable for the support of large-scale wind energy integration (Bueno and Carta, 2006; Kaldellis et al., 2010; Kapsali and Kaldellis, 2010; Katsaprakakis et al., 2012).

CAES systems

In a CAES system, off-peak or excess power is also taken from the grid or other power generation sources and is used to compress air into an underground cavern or a tank (with pressures that can reach 80bars) (Najjar and Zaamout, 1998). During times of peak demand, the required amount of air is released from the cavern, heated with natural gas and then fed to a gas turbine where expansion takes place as in a typical Brayton/Joule cycle. This is actually the main benefit of a CAES system, i.e., the fact that the stages of compression and generation are separated from one another. Consequently, approximately 2/3s of fuel consumption for the compressor's Brayton/Joule cycle is saved in CAES which uses otherwise wind energy surplus in order to operate the compressors. As a result, in a CAES system, the entire gas turbine power is available for consumption. There are only two operating CAES facilities worldwide: The first ever was built in Huntorf Germany (Crotogino et al., 2001) and is still in operation since 1978. It serves as a minute-reserve and peak shaving power station, facilitating also the increasing wind energy contribution in Germany through its availability as a flexible back-up plant. The second was declared commercial in 1991 and is in Alabama, USA, covering both peak and intermediate load demand with the use of off-peak energy stored during night (PowerSouth, 2010). Moreover, similar to PHS, CAES systems have a rather satisfying response time and can take up load in a few minutes, while due to their ability to store energy at high pressure, the respective energy density is higher than that of PHS. Finally, flexibility of such systems to serve as both base load plants (Greenblatt et al., 2007) and peak following units (Lund et al., 2009) provides considerable opportunities for the improved management of wind energy generation (Salgi and Lund, 2008).

3.3.3 Methodology

To account for social welfare attributes into energy planning decisions, made possible by energy storage systems through the exploitation of wind energy surplus, an integrated socioeconomic cost-benefit model is developed. Its aim is the determination of "socially just" FiTs. To this end, the break-even FiTs, that equate social costs and benefits, are compared with the electricity production cost of the energy storage system, in order to investigate the profit margin for the respective investment. For this purpose, sizing of the energy storage system needs to be undertaken first. This is based on the wind energy expected to be recovered and the limitations that should be taken into account, such as the minimum contribution share of wind energy to system charging and the available size of the energy storage reservoir or cavern. In this section the sizing methodology and estimation of the electricity production cost are presented, followed by an analysis of the cost-benefit model.

Sizing of an energy storage system

Sizing of the system requires defining the energy storage capacity E_{ss} and the nominal power output N_{ss} of the energy storage system. The required energy storage capacity, the typical hours of energy autonomy $d_{o\text{-}ss}$ corresponding to the reservoir/cavern size, the maximum depth of discharge DoD_L and the energy conversion (round-trip) efficiency of the energy storage system η_{ss}[9], should be taken into account (Kaldellis and Zafirakis, 2007a); hence:

$$E_{ss} = d_{o-ss} \cdot \frac{E_{load}}{8760} \cdot \frac{1}{\eta_{ss}} \cdot \frac{1}{DoD_L} \tag{3.10}$$

where E_{load} represents the annual energy production of the energy storage system delivered to the local electricity grid, as defined by the guaranteed power output of the energy storage system on a daily basis, i.e.,

$$E_{load} = 365 \cdot d_o \cdot N_{load} \tag{3.11}$$

with d_o being the hours of guaranteed energy generation per day by the energy storage system, at a standard power output delivered for consumption N_{load} (depending on the pattern and total amount of energy surplus, e.g. wind energy curtailments). That also defines the nominal power of the energy storage system N_{ss} on the basis of power efficiency η_p which considers transmission and distribution losses, i.e.,

$$N_{ss} = \frac{N_{load}}{\eta_p} \tag{3.12}$$

At the same time, the hours of energy generation per day d_o may also be connected with the required (or available) energy storage capacity in the form of energy autonomy hours d_{o-ss}, through the following equation:

$$d_{o-ss} = \pi \cdot d_o \tag{3.13}$$

where π is a multiplier that takes into account the required size of the reservoir/cavern so as to compensate periods of insufficient wind energy surplus. In the best-case scenario, π would allow satisfaction of the next day guaranteed energy requirement without the need of "oversizing" (i.e., π=1), meaning that the system would fully recharge on a daily basis. For this to be achieved sufficient wind energy surplus should be available every day, otherwise storage capacity needs to be increased (i.e., π>1) in order to cover the equivalent of continuous periods of zero or insufficient wind energy surplus.

Electricity production cost of an energy storage system

The estimation of the system electricity production cost first requires determination of the respective initial capital that needs to be invested. The initial investment cost IC_{ss} may be expressed as a function of the energy storage capacity and the nominal power output of the system, using two cost coefficients (Kaldellis and Zafirakis, 2007a). The first c_e (€/kWh) relates to the storage capacity and type of the system (e.g. the water reservoirs of PHS and the air cavern of CAES), and the second c_p (€/kW) refers to the nominal power and type of energy storage system (e.g. pumps and hydro turbines for PHS and compressors and gas turbines for CAES). To this end, the future value IC_n of the initial investment cost (after n years of operation) is given from the following relation, where γ is the potential subsidy offered by the state to RES-based investments

[9] Energy efficiency does not consider idling losses, which are currently assumed to be negligible, owed to both the energy storage technologies examined (i.e. inconsiderable pressure and water evaporation losses for CAES and PHS respectively) and the diurnal cycling adopted in the current model.

(which could also apply to energy storage systems using wind energy) and i is the return on investment index. In this regard, the range of values of the above parameters (i.e., DoD_L, η_{ss}, η_p, c_e, c_p), for both PHS and CAES systems, is presented in Table 3.5 and is based on the available information in the international literature (ESA, 2009; Ibrahim et al., 2008; Kaldellis et al., 2009a; Nurai, 2003; Schoenung and Hassenzahl, 2003; Zafirakis, 2010).

$$IC_n = IC_{ss} \cdot (1-\gamma) \cdot (1+i)^n = \left(c_e \cdot E_{ss} + c_p \cdot N_{ss}\right) \cdot (1-\gamma) \cdot (1+i)^n \Rightarrow$$
$$\Rightarrow IC_n = \left(c_e \cdot d_{o-ss} \cdot \frac{E_{load}}{8760} \cdot \frac{1}{\eta_{ss}} \cdot \frac{1}{DoD_L} + c_p \cdot \frac{N_{load}}{\eta_p} \right) \cdot (1-\gamma) \cdot (1+i)^n \tag{3.14}$$

Estimating the electricity production cost of an energy storage system requires also the cost of input energy for charging the energy storage system EC_{in} as well as the respective M&O cost. As previously mentioned, since the operator of the energy storage system provides guaranteed energy to the local grid, in case of insufficient wind energy production any storage deficit will be covered through the use of low cost, off-peak energy deriving from the local grid, provided that the minimum threshold set for the annual contribution of wind energy is not missed. Since the amount of energy needed to charge the storage system is expressed as E_{load}/η_{ss}, the corresponding input energy cost for a period of n years can be expressed as:

$$EC_{in} = \frac{E_{load}}{\eta_{ss}} \cdot c_{in} \cdot \sum_{j=1}^{n} \left(\frac{(1+w)}{(1+i)} \right)^{j} \cdot (1+i)^{n} \tag{3.15}$$

where E_{load} can be broken down to the sum of $E_{load-1}=k_w \cdot E_{load}$ and $E_{load-2}=k_g \cdot E_{load}$. Note that k_w and k_g correspond to the contribution -to the charging of the system on an annual basis- of the wind farms and the local grid respectively, with k_g set to not exceed a maximum of 30%. In this regard, the specific input energy cost coefficient c_{in} results as the weighed cost of the wind energy curtailment c_w and the low-price grid energy (night hours) c_g costs respectively, with c_w being usually lower than the respective wind energy FiT and with w being the mean annual escalation rate of the input energy price.

Accordingly, the M&O cost can be split into the fixed FC_{ss} and variable VC_{ss} components. The first component concerns scheduled maintenance needs, while the second regards replacement of system-components, or of the entire system, if the respective service period is lower than the economic life of the investment. The second component is neglected, since no critical part replacement should be considered within the lifetime of the investment for the two examined energy storage systems. At the same time, by expressing the annual fixed M&O cost as a fraction m (see Table 3.5) of the initial capital invested and by assuming an annual inflation of the M&O cost equal to g_{ss}, the fixed M&O cost FC_{ss} is given as (Kaldellis and Zafirakis, 2007a):

$$FC_{ss} = IC_{ss} \cdot m \cdot \sum_{j=1}^{n} \left(\frac{(1+g_{ss})}{(1+i)} \right)^{j} \cdot (1+i)^{n} + c_f \cdot E_{load} \cdot \sum_{j=1}^{n} \left(\frac{(1+e_f)}{(1+i)} \right)^{j} \cdot (1+i)^{n} \tag{3.16}$$

with the second term of the RHS of the equation applying only for CAES, so as to capture the cost of fuel consumption. In this context, the c_f coefficient derives from combining the specific energy cost of the fuel used (e.g. €/kWh_{fuel}) with the heat rate

HR (kWh_{fuel}/kWh_e) of the CAES unit, while the term e_f expresses the mean annual escalation rate of the fuel input price.

Table 3.5: Values of input parameters[10]

	Peak Power Plant					
Parameter	**Natural Gas OCGT**		**Oil-Diesel Plants**		**Hydro Plants**	
	PHS	CAES	PHS	CAES	PHS	CAES
c_e (€/kWh)[11]	20 / 100	5 / 40	20 / 100	5 / 40	20 / 100	5 / 40
c_p (€/kW)	550/ 1100	350/ 550	550/ 1100	350/ 550	550/ 1100	350/ 550
c_w (c€/kWh$_e$)[12]	4 / 6	4 / 6	4 / 6	4 / 6	4 / 6	4 / 6
c_g (c€/kWh$_e$)[13]	3 / 4	3 / 4	3 / 4	3 / 4	3 / 4	3 / 4
m (%)[1]	2 / 3	2.5 / 3.5	2 / 3	2.5 / 3.5	2 / 3	2.5 / 3.5
c_f (€/MWh$_e$)	-	24 / 54	-	24 / 54	-	24 / 54
$d_{o\text{-}ss}$ (hours)	$5 \cdot d_o$	$5 \cdot d_o$	$5 \cdot d_o$	$5 \cdot d_o$	$5 \cdot d_o$	$5 \cdot d_o$
N_{load} (MW$_e$)	300 / 50	300 / 50	300 / 50	300 / 50	300 / 50	300 / 50
DoD_L (%)	85	65	85	65	85	65
η_p (%)	90	90	90	90	90	90
η_{ss} (%)	70	85	70	85	70	85
n_{max} (years)	25	25	25	25	25	25
n_k (years)[14]	25	25	25	25	25	25
i (%)[15]	8	8	8	8	8	8
e (%)	5	5	5	5	5	5
w (%)	4	4	4	4	4	4
g_{ss} (%)	2	2	2	2	2	2
e_f (%)	5	5	5	5	5	5
HR (kWh_{fuel}/kWh_e)	-	1.2	-	1.2	-	1.2
ξ (%)	5	5	5	5	5	5
$\delta\varphi_{ss}$ (%)	15	15	15	15	15	15
η_d (%)	40	40	35	35	-	-
H_u (MJ_{fuel}/kg_{fuel})	50	50	46	46	-	-
p_2 (€/MWh$_e$)	0	0	0	0	0	0
$c_{r\text{-}peak}$ (€/MWh$_e$)	50	50	50	50	25	25
p_{fuel} (€/t_{fuel})	600	600	715	715	-	-
$c_{TPS\text{-}dep}$ (€/MWh$_e$)	20	20	20	20	50	50
$c_{TPS\text{-}peak}$ (€/MWh$_e$)	178	178	230	230	75	75
ε_{CO2} (kg_{CO2}/MWh_e)	550	285	650	385	0	-265
p_{CO2} (€/t_{CO2})	15	15	15	15	15	15
c_{ex} (€/MWh$_e$)[16]	9.4	4.7	15.8	11.4	-0.16	-4.6

[10] Use of slash separates values for the low and the high cost scenario respectively.
[11] Values of ESS cost parameters refer to 2010 (see also Kaldellis and Zafirakis (2007a) and Zafirakis (2010)).
[12] Value of c_w is adjusted so as to be kept under the existing wind energy FiT in the order of 100€/MWh for Greece and above the off-peak electricity price c_g.
[13] Value-range of c_g is related to the data presented in Figure 3.22.
[14] The amortization period selected refers to the entire initial cost IC_{ss}.
[15] Values correspond to the current Greek market status and present technologies, which could yield higher peak prices than that of the past.
[16] Values of c_{ex} are estimated on the basis of results obtained from Georgakelos (2012) concerning the electricity system of Greece.

The future total cost C_{ss} ascribed to the storage system installation and operation after n years (neglecting the VC_{ss} component) may be estimated using equation 3.17, including also the input fuel term only in the case of CAES.

$$C_{ss} = IC_{ss}\left\{(1-\gamma)+m\cdot\sum_{\mathrm{j=1}}^{\mathrm{n}}\left(\frac{(1+g_{ss})}{(1+i)}\right)^{\mathrm{j}}\right\}\cdot(1+i)^n + E_{load}\cdot\left\{\frac{c_{in}}{\eta_{ss}}\cdot\sum_{\mathrm{j=1}}^{\mathrm{n}}\left(\frac{(1+w)}{(1+i)}\right)^{\mathrm{j}} + c_f\cdot\sum_{\mathrm{j=1}}^{\mathrm{n}}\left(\frac{(1+e_f)}{(1+i)}\right)^{\mathrm{j}}\right\}\cdot(1+i)^n \quad (3.17)$$

Finally, for the estimation of the energy production cost of the energy storage system (€/kWh$_e$, in present values), the total cost of the system should be divided with the corresponding total energy production, i.e.,

$$c_{ss} = \frac{C_{ss}}{E_{load}\cdot\sum_{\mathrm{j=1}}^{\mathrm{n}}\left(\frac{(1+e)}{(1+i)}\right)^{\mathrm{j}}\cdot(1+i)^n} \quad (3.18)$$

with e being the electricity price escalation rate.

Presentation of the cost-benefit model

The development of the cost-benefit model considers costs and benefits from the point of view of society as a whole. As a result, costs correspond to social support potentially provided to an energy storage system project, while benefits concern either avoided social costs or direct social benefits deriving from the operation of the energy storage system using wind energy surplus. The break-even point where costs and benefits become equal is used to define the value of appropriate support mechanisms (i.e., FiTs).

Determination of social support (costs) to energy storage systems

RES-based investments, including wind energy projects, are environmentally friendly energy options that may contribute to the economy of a country. In this context, RES projects receive state support in several countries (De Vries et al., 2003), on the basis of financing schemes (Tsoutsos et al., 2008). These support schemes could also apply to energy storage systems under the condition that these systems facilitate further RES penetration. Two main support mechanisms that can be considered for the cost-benefit model, include the initial cost subsidy –already mentioned- and the FiT mechanism. In addition to that, peak power units (including thermal power stations) are often compensated by a guaranteed power premium which can apply to energy storage systems, while RES-based installations can receive tax credits (such as the production tax credit (PTC)) that could be used in the case of wind-based energy storage systems.

- Initial cost subsidy

Energy storage projects can be subsidized with a portion γ of the initial capital investment IC_{ss} (see also equation 3.14). As a result, the private investor takes advantage of a significant financial contribution, which corresponds to the first part p_1 of social support (per unit of electricity delivered annually by the energy storage system, i.e., E_{load}) that can be provided to energy storage systems, expressed via the following equation, where n_{max} describes the service period of the installation, considered equal to 25 years.

$$p_1 = \frac{\gamma}{n_{\max}}\cdot\frac{IC_{ss}}{E_{load}} \quad (3.19)$$

- The FiT mechanism

The most popular RES support mechanism is FiTs, used in several countries (Butler and Neuhoff, 2008; Perez and Ramos-Real, 2009). More precisely, the FiT corresponds to a price p_e for each kWh_e or MWh_e of renewable energy production delivered to the grid (€/MWh_e) and is usually determined on the basis of technological maturity and local RES potential. Similar FiTs can apply to energy storage systems that use wind energy as input.

- Guaranteed power premium

Contribution of a peak power unit can be compensated in terms of power delivered to the grid. Existing schemes such as the capacity assurance mechanism in Greece (HTSO, 2010; 2012) suggest that a fixed annual subsidy $p_{N/m}$ (€/MW.year) is offered for the first years of operation n_{subs} (e.g. 5 years), provided that power supply is guaranteed. A similar power premium can be offered to energy storage systems, considering however that unless this premium is higher than the one provided to thermal peak power units, the net social support is zero. As a result, the net power premium p_2 (€/MWh_e) should be considered, taking into account the difference (if any) between the two power premiums $\delta p_{N/m}$ (i.e., power premium of the energy storage system minus the power premium of the thermal peak power station).

$$p_2 = \delta p_{N/m} \cdot \frac{N_{load}}{E_{load}} \cdot \frac{n_{subs}}{n_{\max}} \tag{3.20}$$

- The PTC mechanism

The PTC mechanism comprises a per kWh tax credit (i.e., cents/kWh) of electricity produced by certain qualified energy sources, including wind energy, which was originally enacted in 1992 under the USA Energy Policy Act, boosting USA wind energy investments in the years following (Lu et al., 2011). The tax credit is provided for the first ten years of operation while any unused credits may be carried forward for up to 20 years following the year they were generated, or carried back one year if the taxpayer files an amended return (USDOE, 2009).

Determination of social benefits from the operation of energy storage systems

Operation of an energy storage system that uses wind energy surplus entails social benefits that may be categorized to direct and indirect. The former include taxes paid by the energy storage system, and the latter are the avoided costs from the operation of conventional thermal peak power stations; fuel imports; purchasing of carbon dioxide (CO_2) allowances; and finally negative externalities attributed to thermal power generation. Besides that, (although not currently examined) an energy storage system can provide ancillary services such as spinning reserve, frequency control, new transmission lines' deferral and others, producing in this way additional benefits that are however difficult to value in the absence of a concrete market framework.

- Peak power station replacement by the energy storage system

Replacement of already operating peak power units (using natural gas or oil) is the first source of social benefit (or avoided cost) from the operation of bulk energy storage systems. Such units often entail high electricity production costs, owed to the fact that they use fossil fuels and operate at both low load factors and relatively low efficiency. More precisely, resulting benefits (or avoided costs) c_1 mainly occur due to the avoided operating cost of the replaced peak power station $c_{op\text{-}peak}$ (mainly fuel and maintenance costs) and a small (≈5%) percentage ξ of the constant cost reduction (Kaldellis, 2011) (e.g. service period prolongation of the peak power station), with $c_{TPS\text{-}peak}$ being the total electricity generation cost of the replaced peak power station, including also depreciation costs $c_{TPS\text{-}dep}$.

$$c_1 = c_{op-peak} + \xi \cdot \left(c_{TPS-peak} - c_{op-peak}\right) = c_{op-peak} + \xi \cdot c_{TPS-dep} \tag{3.21}$$

The $c_{op\text{-}peak}$ term can be broken down to the $c_{f\text{-}peak}$ component, corresponding to the fuel cost, and the $c_{r\text{-}peak}$ component, corresponding to the rest of the operational costs of the peak power station. At the same time, quantity of fuel M_f avoided depends on the efficiency η_d of the thermal peak power station examined, as well as on the calorific value H_u (kWh_{fuel}/kg_{fuel}) of the fuel consumed, allowing estimation of $c_{f\text{-}peak}$ using the following equation:

$$c_{f-peak} = \frac{M_f \cdot p_{fuel}}{E_{load}} = \frac{p_{fuel}}{\eta_d \cdot H_u} \tag{3.22}$$

with p_{fuel} being the average fuel price (e.g. €/kg_{fuel}) during the year under study.

- Taxation of the energy storage system

A second, direct source of social benefit concerns annual taxes Φ_{ss} paid by the energy storage system on the basis of net cash flows. Actually, $\Phi_{ss(j)}$ describes the tax paid during the year j, mainly due to revenues of the previous year $R_{ss(j-1)}$, accruing from the remuneration of energy production and guaranteed power provided by the energy storage system.

$$R_{ss} = E_{load} \cdot (p_e + p_2) \tag{3.23}$$

In this context, $\Phi_{ss(j)}$ depends on a regulation-defined tax-coefficient φ_{ss}, the net cash flow of the j-1 year, the investment depreciation and the financial obligations of the enterprise. More precisely,

$$\Phi_{ss(j)} = \phi_{ss(j)} \cdot \left[R_{ss(j-1)} - EC_{in(j-1)} - FC_{ss(j-1)} - CA_{ss(j-1)}\right] \tag{3.24}$$

where CA_{ss} describes the initial capital depreciation and may be expressed using a simple constant annual investment depreciation model that can also consider different depreciation periods n_k for the g different components (e.g. different type of equipment used) of the initial capital cost IC_{ss} as:

$$CA_{ss} = (1-\gamma) \cdot \sum_{x=1}^{g} \left(\frac{IC_{ss(x)}}{n_{k(x)}} \right) \tag{3.25}$$

Taxes paid by the peak power plant to be replaced, i.e., $\Phi_{peak(j)}$, should also be considered in order to obtain the net benefit deriving from the taxation of the energy storage system, i.e., $\Phi_{ss\text{-}net(j)}$. To this end, because of the high levels of uncertainty attached to the determination of $\Phi_{peak(j)}$ in the absence of actual data, the variable of net taxation coefficient $\delta\varphi_{ss}$ is introduced (see also equation 3.26) to approach the problem of taxation and thus address uncertainty through sensitivity analysis. Besides, it should be mentioned that the net taxation coefficient can be adjusted to allow examination of additional support mechanisms (such as the PTC seen earlier) through the introduction of an equivalent reduction of $\delta\varphi_{ss}$.

$$\Phi_{ss-net(j)} = \Phi_{ss(j)} - \Phi_{peak(j)} = \delta\phi_{ss(j)} \cdot \left[R_{ss(j-1)} - EC_{in(j-1)} - FC_{ss(j-1)} - CA_{ss(j-1)}\right] \quad (3.26)$$

According to the presented analysis the total amount paid by the energy storage system c_2 (€/kWh$_e$ or €/MWh$_e$) on the basis of the annual tax is estimated as:

$$c_2 = \frac{\Phi_{ss-net}}{E_{load}} \quad (3.27)$$

- Avoided CO_2 allowances

Furthermore, among the main benefits deriving from an energy storage system operation is the avoidance of CO_2 related costs (Weber and Neuhoff, 2010). The annual equivalent CO_2 emissions δ_{CO2}, avoided due to the recovery of wind energy curtailments by the energy storage system, may be estimated by using the respective net CO_2 emission coefficient of the replaced thermal peak power station ε_{CO2} (kgCO_2/kWh$_e$), considering also any emissions deriving from the energy storage system operation (valid for CAES).

$$\delta_{CO2} = E_{load} \cdot \varepsilon_{CO2} \quad (3.28)$$

Hence, the CO_2 cost c_3 avoided per unit of energy delivered by the energy storage system is given via the equivalent specific allowance value p_{CO2} (€/kg$_{CO2}$) using the following equation:

$$c_3 = \frac{\delta_{CO2} \cdot p_{CO2}}{E_{load}} \quad (3.29)$$

- Avoided negative externalities

Finally, the net social benefit from avoiding electricity generation negative externalities is accounted for by introducing the corresponding net external cost c_{ex} (€/MWh$_e$) (i.e., the negative externalities attributed to the use of conventional power generation minus the negative externalities attributed to wind energy -and natural gas in the case of CAES- which are used by the energy storage system, as well as the negative externalities attributed to the energy storage systems themselves (Denholm and Kulcinski, 2004)). For this purpose, results obtained by the application of the ExternE[17] methodology (EC, 2005; Georgakelos, 2012) are used, treating PHS systems as hydropower plants and CAES as natural gas-fired power stations that are however responsible for considerably lower emissions and thus lower negative externalities (deriving from the ratio of heat rates of CAES and typical natural gas-fired peak power plants).

- Total social benefits

The total social benefits for each MWh$_e$ of electricity produced by the wind energy-based energy storage system c_{tot} can be described by the following equation:

$$c_{tot} = (c_1 + c_3 + c_{ex}) \cdot k_w + c_2 \quad (3.30)$$

[17] External Costs of Energy methodology, computing the monetary values of damages caused by harmful by-products of electricity generation on human health, through the estimation of dose-response functions that include both fatal and non-fatal effects, damages on the local ecosystems and materials, and finally damages from global warming provoked by GHG emissions on a LC basis

considering that avoided costs are directly related to the contribution of wind energy k_w and assuming -for simplicity reasons- that the off-peak, grid-derived energy used to charge the energy storage system in case of insufficient wind energy surplus, has similar operational characteristics with the peak-time energy production to be replaced by the energy storage system.

Determination of break-even FiTs
After the analysis of costs and benefits, break-even FiTs $p_{e\text{-}b/e}$, i.e., FiTs ensuring that social costs and benefits are equal (or that the FiT provided is equal to the net social benefits $c_{tot\text{-}net}$), are estimated as:

$$p_{e-b/e} : p_e = c_{tot-net} = c_{tot} - p_1 - p_2 \tag{3.31}$$

which is a function of the d_o parameter. Finally, by comparing the price of the break-even FiT $p_{e\text{-}b/e}$ with the electricity production cost of the energy storage system installation c_{ss}, the profitability (i.e., $p_{e\text{-}b/e} > c_{ss}$) -or the loss (i.e., $p_{e\text{-}b/e} < c_{ss}$)- of the energy storage system can be determined.

3.3.4 Application Results

The cost-benefit model is then applied for representative case studies, considering different peak power plants to be replaced in the final paragraph of this section. In this context, two distinct energy scenarios are examined; the first investigating exploitation of wind energy only, i.e., k_w=100%, and the second allowing the energy storage system to draw a maximum of k_g=30% from the grid on an annual basis. Furthermore, the main cost parameters are examined for low and high investment cost scenarios (see also Table 3.5). The guaranteed power output of N_{load} over a daily period of d_o hours, ranges between 1 and 8 hours/day (i.e., at least one full cycle per day), while based on previous studies (Zafirakis and Kaldellis, 2010), a moderate total energy storage capacity is taken into account, configured on the basis of π=5.

The reference country is Greece, where large-scale hydropower stations are the first power plants considered for peak shaving followed by natural gas-fired open-cycle gas turbines (OCGTs) (see also Figure 3.21), with peak demand satisfaction occasionally supported by oil-fired gas turbines (see also Table 3.6) or even energy imports. Base load in Greece is met by lignite-fired steam turbine plants and intermediate load is mainly met by natural gas-fired combined cycle gas turbines (CCGT) plants (see Table 3.6 and Figure 3.21).

At the same time, RES contribution is mainly based on the operation of 2.6GW of PV power and 1.9GW of wind power (including installations in the non-interconnected island region of Greece), with plans for wind power capacity of 7.5-10GW until 2020 (GMEECC, 2011; HWEA, 2012b). Assuming the implementation of these plans in combination with the existing limited international grid interconnections (Caralis et al., 2012; RAE, 2011) and the questionable potential of interconnected neighbouring countries to absorb the expected wind energy surplus (Caralis et al., 2012), the need for investigating the solution of bulk energy storage for the recovery of excess wind energy is strong.

Table 3.6: Thermal power and hydropower plants of the Greek mainland grid (PPC, 2012b)

Lignite-fired plants (base-load)	**Capacity (MW)**	**Hydro plants (peak/interm.)**	**Capacity (MW)**
Agios Dimitrios I, II	2x300	Agras	2x25
Agios Dimitrios III, IV	2x310	Asomata	2x54
Agios Dimitrios V	375	Edesseos	19
Aminteo I, II	2x300	Thisavros	3x128
Kardia I, III	2x300	Kastraki	4x80
Kardia III, IV	2x306	Kremasta	4x109.3
Liptol I	10	Ladonas	2x35
Liptol II	33	Aoos	2x105
Megalopoli I, II	2x125	Plastiras	3x43.3
Megalopoli III	300	Platanovrisi	2x58
Megalopoli IV	300	Polifito	3x125
Meliti	330	Pournari I	3x100
Ptolemaida I	70	Pournari II, 1-2	2x16
Ptolemaida II, III	2x125	Pournari II, 3	1,6
Ptolemaida IV	300	Stratos	2x75
		Sfikia	3x105
Oil-fired diesel plants (interm./peak)	**Capacity (MW)**	**CCGT plants (interm.)**	**Capacity (MW)**
Aliveri III, IV	2x150	Komotini	484.6
Lavrio I	130	Lavrio III	176.5
Lavrio II	300	Lavrio IV	560
		Lavrio V	385.3
		Energiaki Thess.	390+421.6
		Iron Thermoil. II	435
OCGT plants (peak/interm.)	**Capacity (MW)**	**CHP plants (interm./peak)**	**Capacity (MW)**
Agios Georgios VIII	160	ELPE (oil)	50
Agios Georgios IX	200	Motoroil (oil)	66.1
Iron Thermoilektriki	147.8	Alouminion (NG)	334

Besides that, peak demand hours may also derive from Figure 3.21, with two distinct peak time periods appearing during noon time (more intense during the summer period) and late evening-early night (more intense during the winter period), supporting the hour-range of guaranteed power output selected for the energy storage systems (i.e., from 1 to 8 hours of operation).

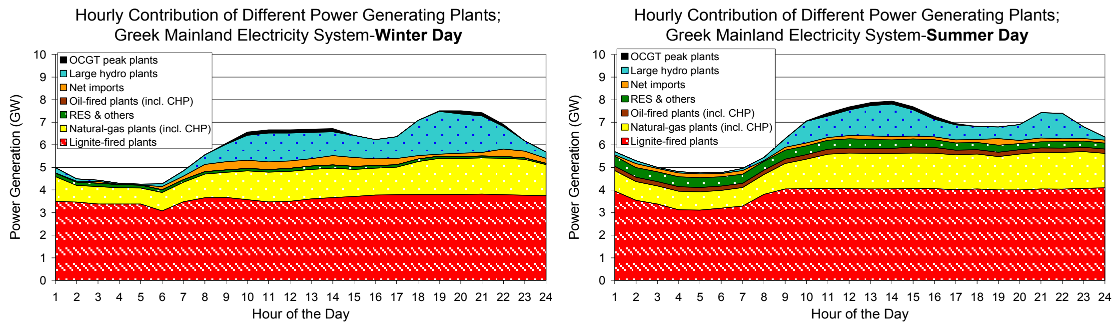


Figure 3.21: Typical daily fuel mix variation profiles for the Greek mainland electricity system in case of OCGT peak power plants participation

Furthermore, in Figure 3.22 the hourly variation of the market clearing price for the Greek mainland system is given for a 5-year period (from 2007 to 2011). The respective duration curves indicate the strong variation met in peak demand prices that even reach 150€/MWh when expensive peak power plants or expensive energy imports are called to cover peak load demand. Moreover, off-peak prices corresponding to late night-early morning hours (i.e., hours during which charging of the energy storage systems may be supported by the mainland grid) is mainly concentrated in the area of 30-40€/MWh, illustrating the price spread potentially considered for the application of arbitrage strategies by energy storage systems.

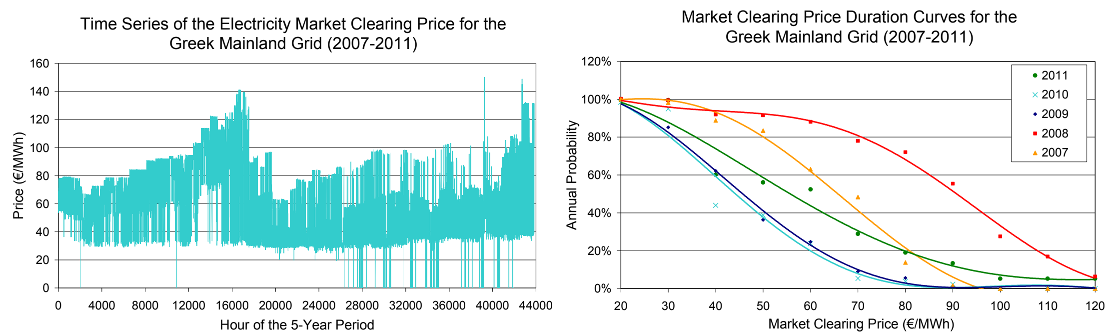


Figure 3.22: Hourly variation (a) and probability density curves (b) of the Greek mainland electricity system market clearing price for five consecutive years (2007-2011)

To this end, this study focuses on the comparison of the proposed wind-based energy storage schemes with natural gas-fired OCGT peak power plants.

Study of direct cost parameters

Considering the above, emphasis is first given on the comparison of the proposed schemes with natural gas-fired OCGT peak power plants (for cost parameters associated with the energy storage systems see also Table 3.5). In this context, the first set of results concerning PHS and CAES in comparison with natural gas-fired OCGT plants are demonstrated in Figures 3.23-3.36 and 3.27-3.30 respectively, where break-even FiTs are compared with the corresponding electricity production cost of the system, in relation to the variation of both state subsidy and energy storage capacity (as expressed in hours of guaranteed energy per day). At this point, it must be mentioned that to compare the break-even FiTs and the electricity production cost of configurations, it is assumed that the operational pattern of the configuration remains the same during the entire life-span of the installation. To this end, when the curves of break-even FiT and electricity production cost intersect, a break-even point occurs, determining the minimum (critical) storage capacity that allows the system to be cost-effective. Overall results are then gathered in Figure 3.31 in order to compare performance of the two proposed configurations in terms of marginal profit.

PHS results

The low cost scenario results for PHS are presented in Figure 3.23. When 100% wind energy is exploited by the PHS configuration, the critical storage capacity required for the system to become cost-effective corresponds to d_o marginally higher or marginally lower than 1 hour. When wind energy exploitation is reduced to 70%, the break-even point increases to almost 2 hours, as a result of the reduction that is mainly noted in the break-even FiT curves, dropping from a maximum of 193€/MWh for k_w=100% to 131€/MWh for k_w=70% (for d_o=8hours). The reduction of wind energy contribution is leading to reduction of the break-even FiT, because social benefits attributed to the substitution of thermal power generation are decreased in relation to the 100% wind energy scenario.

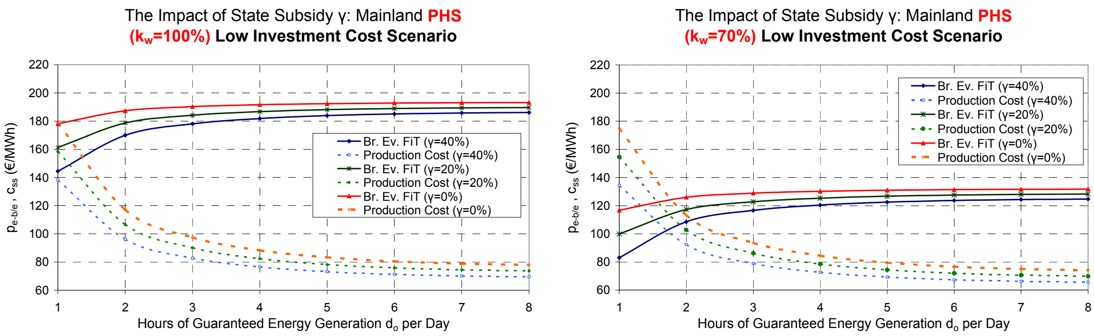


Figure 3.23: Comparison between break-even FiTs and system electricity production cost (PHS, low cost scenario)

At the same time, the impact of state subsidy is illustrated in both the break-even FiT and electricity production cost curves. Increase of state subsidy γ is reducing the electricity production cost (from 178€/MWh$_e$ to 138€/MWh$_e$ in the case of k_w=100% and d_o=1hour) and decreasing the break-even FiT (from 178€/MWh$_e$ to 144€/MWh$_e$), resulting in no actual variation in the critical storage capacity that ensures cost-effectiveness of the system. Furthermore, both sets of curves follow an asymptotical pattern, with the vast reduction encountered for the lower values of d_o in both the electricity production cost and the break-even FiT, followed by convergence to 70-78€/MWh$_e$ and 186-193€/MWh$_e$ (in the case of k_w=100%) and to 65-74€/MWh$_e$ and 124-131€/MWh$_e$ (in the case of k_w=70%). As a result, since the price difference between wind energy and grid energy is minimum (1c€/kWh$_e$) (see also Table 3.5), the marginal profit (i.e., $p_{e\text{-}b/e}$-c_{SS}) is maximized when k_w=100%, as no actual reduction is noted in the electricity production cost of the system in relation to the k_w=70% case.

For the high cost scenario increased cost requires larger storage capacity (in the order of 3.5-4 hours) to achieve cost-effectiveness (Figure 3.24). In this context, for k_w=70%, PHS is cost-ineffective if break-even FiTs are applied due to both the reduction of the break-even FiT (deriving from the reduction of social benefits from the decrease of k_w) and the direct increase of the electricity production cost in comparison to the low cost scenario. The high cost scenario presents an "optimum" point defined by the minimum electricity production cost and the maximum break-even FiT for d_o=6.1hours, suggesting a marginally cost-effective configuration producing a profit in the order of 13€/MWh$_e$ for k_w=100% and γ=40%. Besides, a point of maximum profit is also obtained in the case of the low cost scenario (again for k_w=100% and γ=40%, in the order of 117€/MWh$_e$) that however extends the value of $d_{o\text{-}max}$ to 9.6hours, which is too long for peak demand duration and refers to intermediate load.

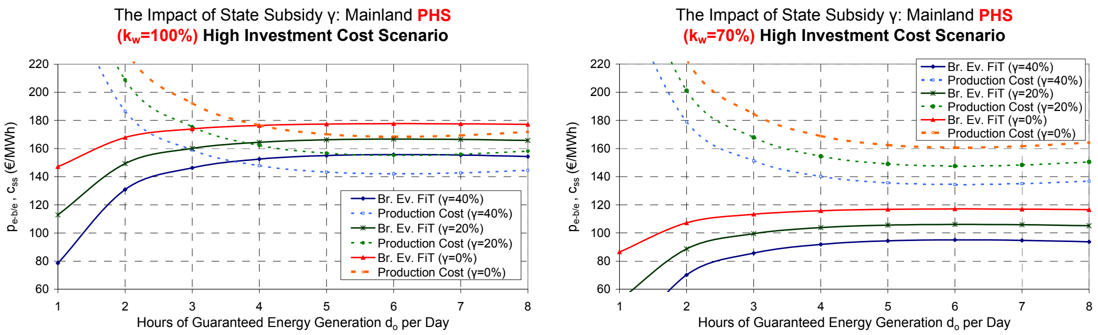


Figure 3.24: Comparison between break-even FiTs and system electricity production cost (PHS, high cost scenario)

To assist in the interpretation of optimum points analysis of the electricity production cost in relation to the hours of guaranteed energy generation is provided in Figure 3.25, for k_w=100% and γ=40%.

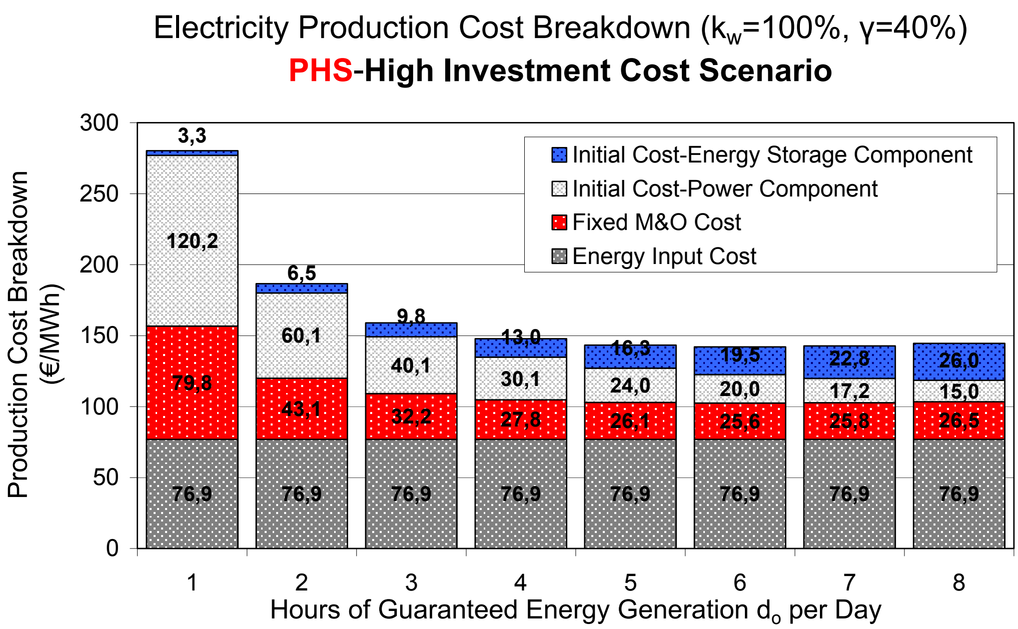


Figure 3.25: Electricity production cost analysis (PHS, high cost scenario)

Although the initial cost power component presents a reduction with the increase of the system storage capacity (since N_{load} is kept constant and increase of d_o increases the energy delivered to the grid), the respective energy storage component gradually increases, reaching a point when it outweighs the power component reduction; thus resulting in an optimum minimum point. At the same time, the break-even FiT curve presents a maximum, because the tax is maximized, as a result of minimum expenses. The contribution of energy input cost is substantial exceeding 50% as d_o stands above 3 hours. Finally, the investigation of the PHS solution is completed with the application of a sensitivity analysis to determine the upper limits of system costs that do not jeopardize system cost-effectiveness (Figure 3.26). The main system cost parameters are stretched at a relative increase of 300% (in comparison with the reference low cost scenario value, see Table 3.5), in order to obtain each one's impact on the marginal profit of the system (i.e., $p_{e\text{-}b/e}$-c_{ss}).

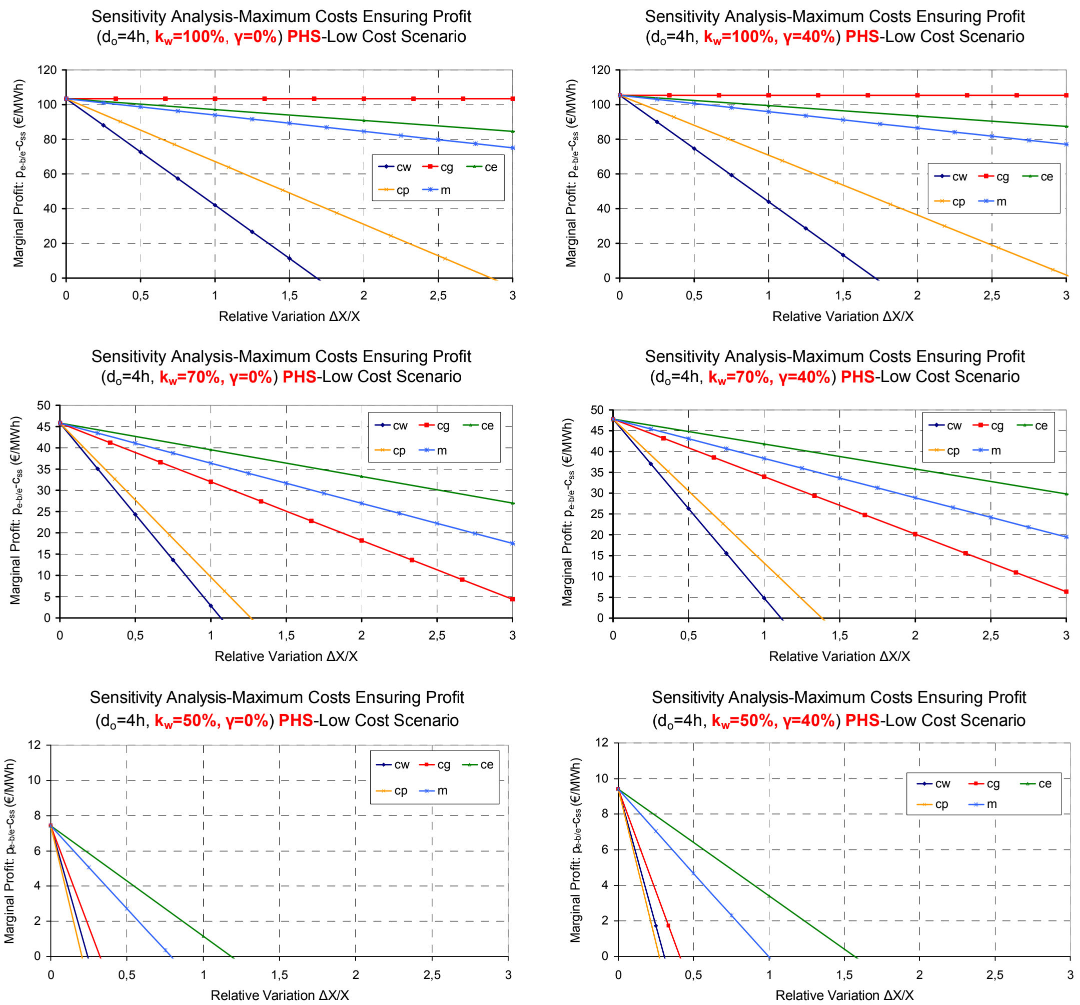


Figure 3.26: The impact of increasing PHS costs on system profitability

In this regard, both zero and 40% state subsidies are examined, while wind energy contribution is allowed to drop to 50%. For k_w=100%, c_g has no impact. As k_w is reduced, influence of c_g becomes substantial and of proportionate importance to that caused by the two most critical factors, the c_w and c_p. It is only when k_w=50% that c_w becomes less critical than c_p. Moreover, when k_w<100%, c_e and m cause the least impact and return zero profit for k_w=50%. Finally, increasing γ from 0% to 40% has negligible impact, requiring slightly higher relative increase of cost parameters to eliminate the marginal system profit.

CAES results

Concerning CAES, for the low cost scenario (Figure 3.27), critical storage capacity (or hours of guaranteed energy generation) is lower than 1 hour when k_w=100%, while for k_w=70%, it exceeds d_o=1.5hours, similar to the case of PHS. Furthermore, electricity production cost and break-even FiT curves maintain an asymptotical pattern that produces values of ~75-80€/MWh$_e$ and ~180€/MWh$_e$ (k_w=100%), and ~72-77€/MWh$_e$ and ~122€/MWh$_e$ (k_w=70%) for d_o=8hours respectively. At the same time, results of the high cost scenario (Figure 3.28) indicate the increase of the critical storage capacity, that reaches 4 hours in the case of k_w=100%, as well as the cost-ineffectiveness of the CAES system when k_w=70%. Besides that, break-even FiTs are reduced, which is combined with a vast increase of the electricity production cost that reaches 162€/MWh$_e$ for d_o=8hours and k_w=100%.

Similar to the case of PHS systems, optimum points designated for CAES configurations correspond to $d_{o\text{-}max}$=6.5hours for the high cost scenario (k_w=100% and γ=40%, with a marginal profit of 8.1€/MWh$_e$) and $d_{o\text{-}max}$=14.8hours (not applicable for peak load demand) for the low cost scenario (k_w=100% and γ=40%, with a marginal profit of 105.7€/MWh$_e$), while for comparison purposes, analysis of the CAES system for the high cost scenario and k_w=100%, γ=40%, is given in Figure 3.29.

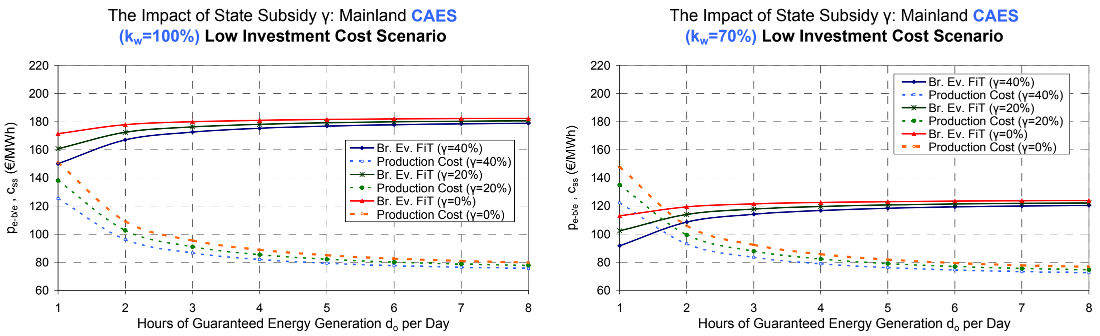


Figure 3.27: Comparison between break-even FiTs and system electricity production cost (CAES, low cost scenario)

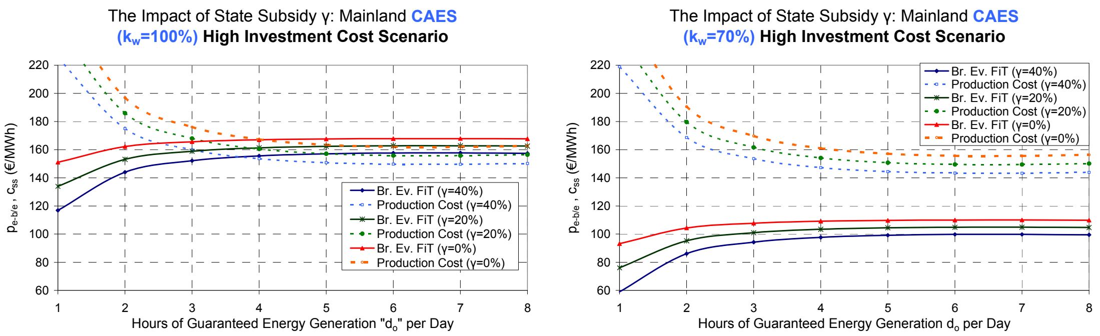


Figure 3.28: Comparison between break-even FiTs and system electricity production cost (CAES, high cost scenario)

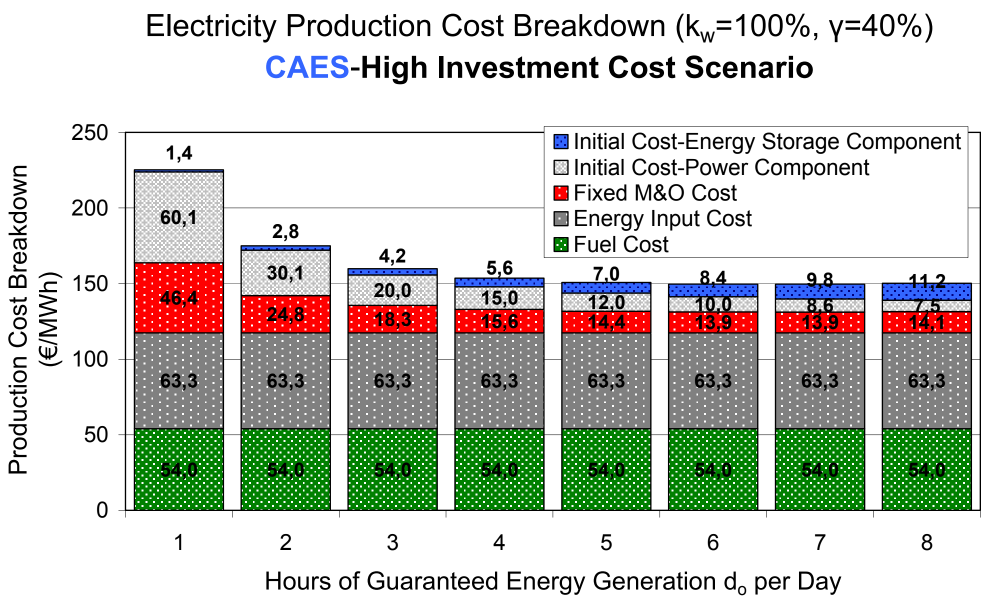


Figure 3.29: Electricity production cost analysis (CAES, high cost scenario)

Lower initial cost components for CAES are outweighed by the fuel factor, contributing almost 35% to the overall electricity production cost for d_o>3hours, while as in PHS, the contribution of the energy input cost is rather considerable, exceeding 40% for the higher values of d_o. At this point it must be noted that currently, the maximum peak demand duration considered is equal to 8 hours, which if exceeded implies that thermal units to be replaced by the proposed wind-based energy storage solutions do not correspond to peak power plants and are thus determined by different operational characteristics (i.e. fuel used, operational cost, emissions, etc.).

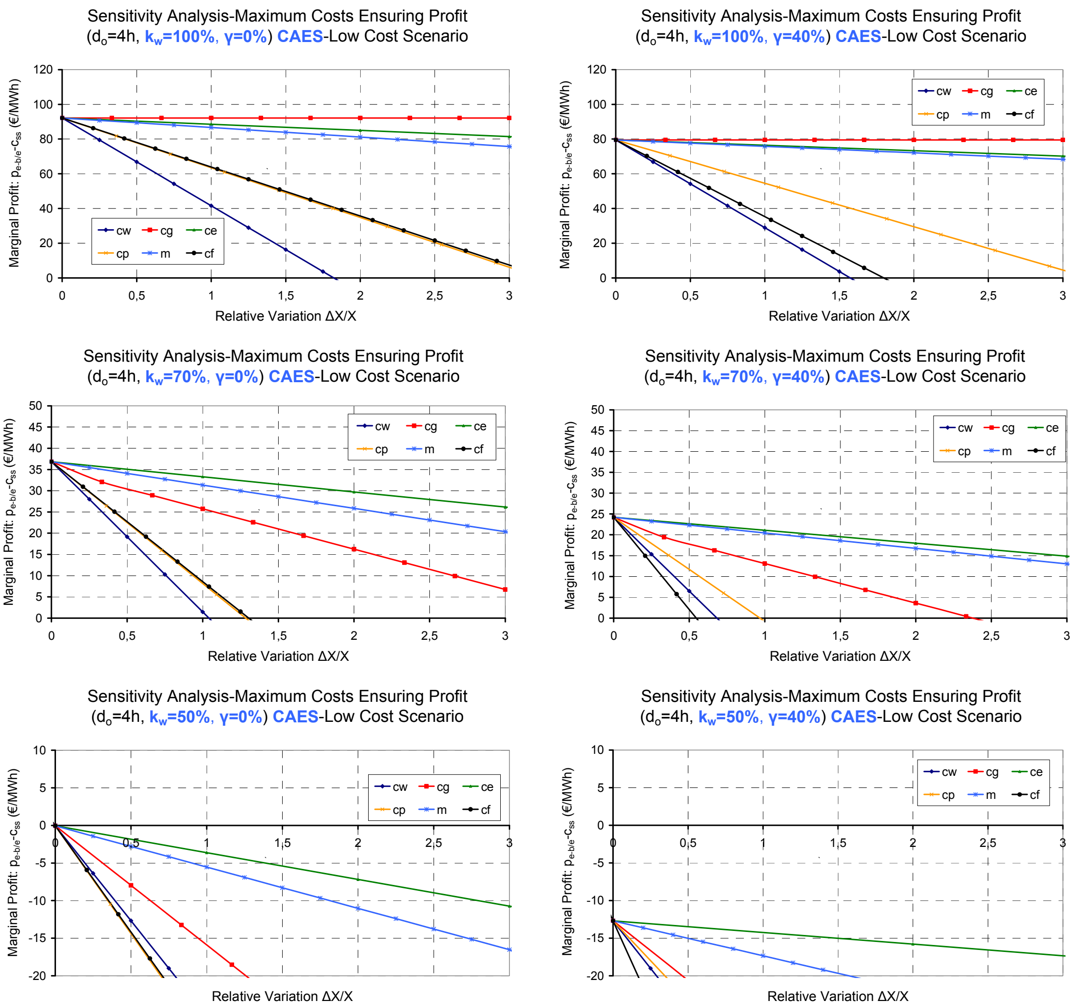


Figure 3.30: The impact of increasing CAES costs on system profitability

Furthermore, the results of sensitivity analysis for the CAES cost parameters are given in Figure 3.30. Similar to PHS, c_w has an important role, surpassed only in the case of k_w=50% and γ=0% by both c_f and c_p, as well as in the cases of γ=40%-k_w=70% and γ=40%-k_w=50%, this time only by the c_f parameter. Concerning the latter, increase of state subsidy and reduction of wind energy contribution gradually increase its influence, similar to c_g. Besides that, c_e and m maintain the behaviour exhibited in the PHS analysis, while when k_w=50%, CAES becomes cost-ineffective, i.e., even if the original low cost scenario values apply.

Comparison of PHS and CAES

Finally, in Figure 3.31, the different low-cost PHS and CAES configurations are compared, in terms of marginal profit. Although CAES presents a comparative advantage up to d_o=2hours (owed to the lower electricity production cost-see also

Figures 3.23 and 3.27), the situation is inversed for d_o>2hours, with PHS presenting a marginal profit that is for d_o>4hours kept within the range of 12-14€/MWh$_e$ higher than the respective of CAES. Furthermore, wind energy is responsible for a reduction of the marginal profit by up to 55€/MWh$_e$ when k_w drops to 70%. The impact of state subsidy makes no difference in the resulting marginal profit.

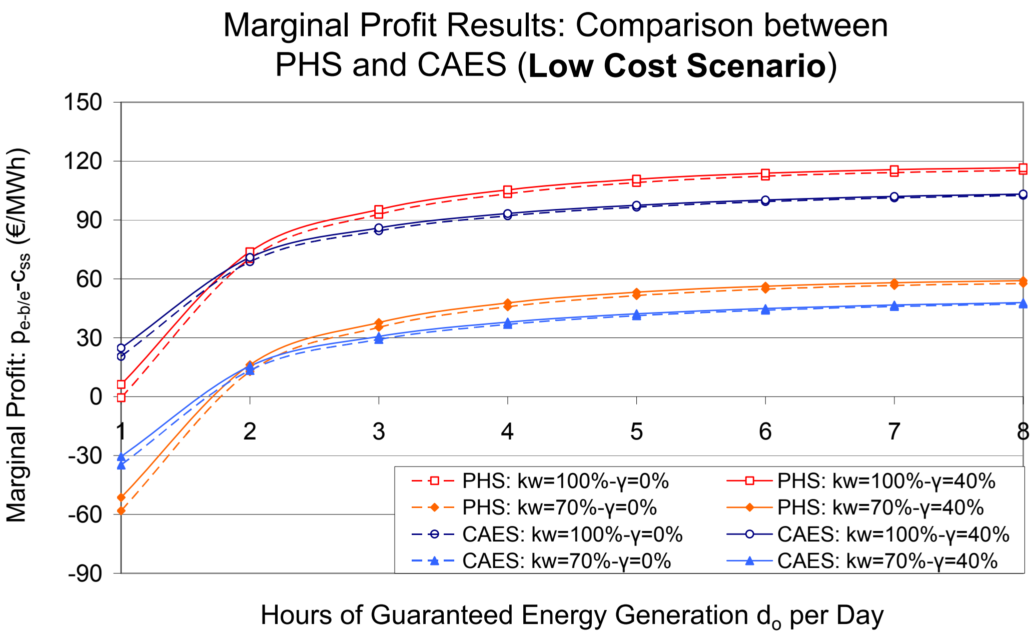


Figure 3.31: Comparison of the resulting marginal profit for different PHS and CAES configurations

Study of indirect cost parameters

In this section a sensitivity analysis is performed for representative configurations of d_o=4hours, for the low and the high cost scenario. The purpose for that is to determine the influence of other, non-system cost parameters. Results of the sensitivity analysis are given in Figures 3.32 and 3.33 for the low and the high cost scenarios respectively. For the low cost scenario, even in the case that non-system cost parameters are assigned with minimum values, the configuration examined is expected to remain cost-effective for k_w=100%. Considerable reduction of fuel price p_{fuel} (by 50% for PHS and by 40% for CAES) leads to negative values of the marginal profit for k_w=70% (Figure 3.32). Furthermore, the fuel price p_{fuel} (determining also the $c_{f\text{-}peak}$ term of the thermal peak power station), followed by the $c_{r\text{-}peak}$ component, are the most important parameters for the marginal profit.

At the same time, the parameter of net taxation $\delta\varphi_{ss}$ (used to address uncertainty in the determination of net taxes paid by the energy storage system) has a small impact on the marginal profit, while for p_{CO2} and c_{ex} the resulting impact is almost negligible, especially in the case of CAES, due to the impact of the fuel factor. The impact differences among the non-system cost parameters is pronounced in the high cost scenario (Figure 3.33), with a mild increase / reduction of almost all cost parameters leading to cost-effective or cost-ineffective configurations respectively for k_w=100% (since the marginal profit for both PHS and CAES in that case is almost 0€/MWh$_e$). At the same time, the net taxation parameter plays no role, because the reference scenario assumes zero marginal profit for both CAES and PHS and thus no taxes paid. Finally, an increase of more than 50% for the fuel price parameter would be required to allow cost-effective configurations to emerge for both PHS and CAES in the case of k_w=70%.

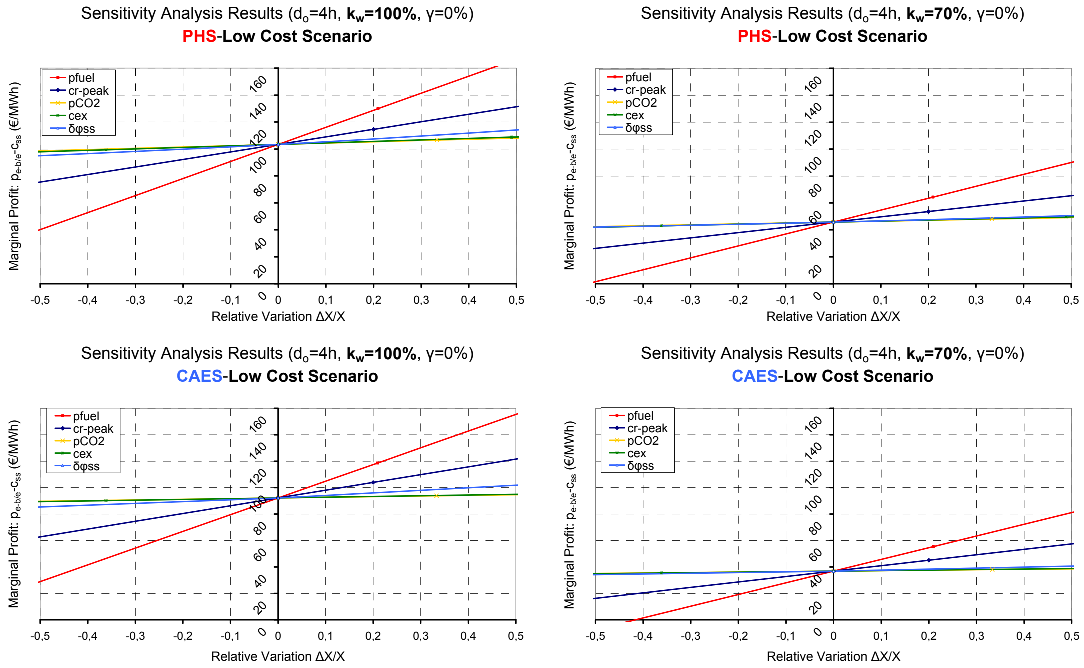


Figure 3.32: Low cost scenario sensitivity analysis results

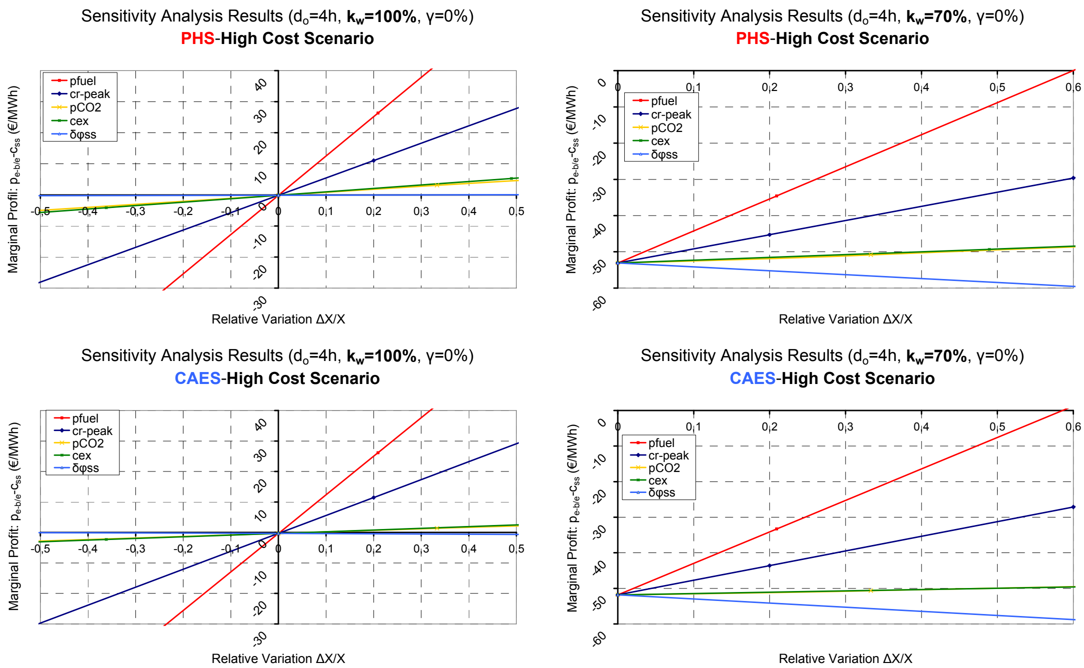


Figure 3.33: High cost scenario sensitivity analysis results

Application of fixed FiTs

When applying fixed FiTs for the entire range of d_o values, the marginal profit results of different cost-effective configurations are presented in Figures 3.34 and 3.35, for γ=0%. Although cost-ineffective configurations are included in the specific figures, the respective results do not appear, since the marginal profit-axis includes only positive values for better illustration of the results. Fixed FiTs range from 100€/MWh$_e$ to 200€/MWh$_e$, taking into account that peak electricity prices encountered in the Greek mainland system can reach 150€/MWh$_e$ and that use of energy storage systems comprises a novel electricity solution. The marginal profit results for the low cost scenario and for both k_w=70% and k_w=100% are provided for all fixed FiTs, including also the marginal profit deriving from the application of break-even FiTs (Figure 3.34).

In all cases examined -except for the case of fixed FiT equal to 100€/MWh$_e$- PHS and CAES systems become cost-effective even for d_o<2hours. Besides that, marginal profit deriving from the application of break-even FiTs is found to be considerably lower than the one corresponding to both the 200€/MWh$_e$ and the 150€/MWh$_e$ FiT in the case of k_w=70%. Moreover if break-even FiTs apply, PHS configurations tend to be more cost-effective than the respective CAES systems as d_o increases. This is justified because the difference between break-even FiTs and the electricity production cost in the case of PHS is higher than that of CAES (see also Figure 3.31), while at the same time the electricity production cost of CAES is lower than that of PHS (see also Figures 3.23 and 3.27) which leads to better results when fixed FiTs are applied.

Next, in Figure 3.35, fixed FiTs are applied for the high cost scenario. A positive marginal profit cannot be achieved in any of the 100€/MWh$_e$ and 150€/MWh$_e$ cases (the respective curves are found below zero and thus do not appear in the graphs), while in the case of k_w=70%, break-even FiTs also do not produce a marginal profit.

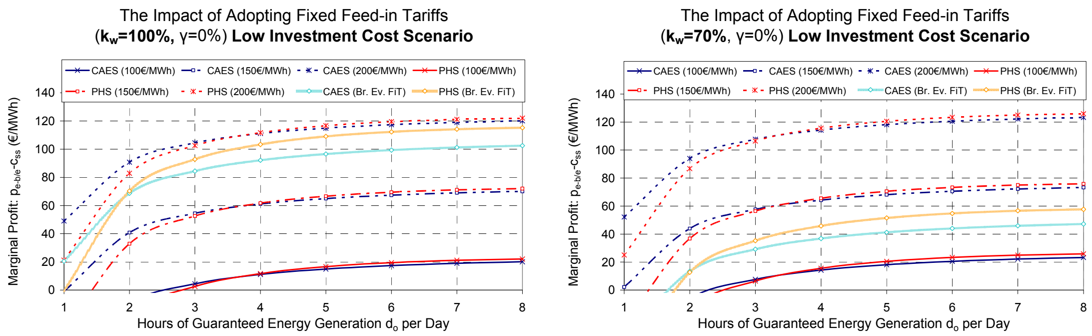


Figure 3.34: The impact of applying fixed FiTs for the low cost scenario

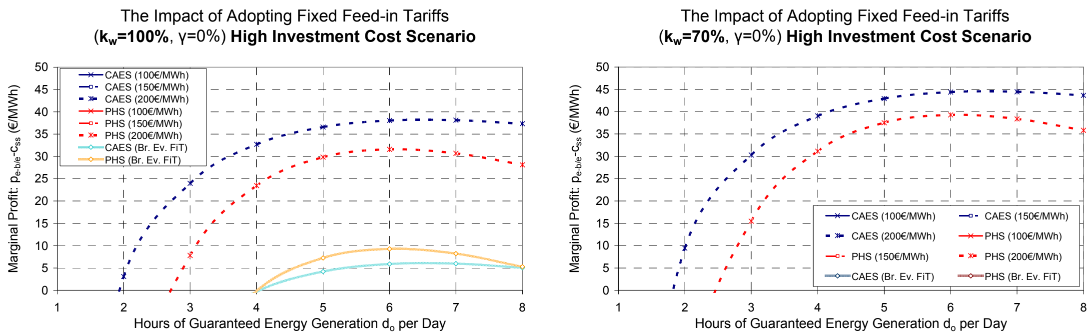


Figure 3.35: The impact of applying fixed FiTs for the high cost scenario

At the same time, marginal profit is reduced reaching a maximum (optimum) of 38€/MWh$_e$ (CAES) and 31€/MWh$_e$ (PHS) for k_w=100%, and 39€/MWh$_e$ (CAES) and 44€/MWh$_e$ (PHS) for k_w=70%. CAES is found to perform better under the application of fixed FiTs, while PHS responds better to break-even FiTs (Figure 3.34).

<u>Examination of different peak power plants</u>

Finally, the impact of replacing different types of peak power plants is examined, based on the values provided in Table 3.5. In this context, apart from the already investigated natural gas-fired peak plants, diesel oil-fired and hydropower peak plants are investigated in terms of marginal profit for both PHS and CAES (Figure 3.36) in order to generalize results and evaluate the applicability of the proposed solutions under different circumstances. Because of the higher price of oil as well as the higher negative externalities and CO_2 emissions assigned to this type of power generation, the resulting marginal profit is considerably higher than that corresponding to the replacement of natural gas-fired plants, exceeding 185€/MWh$_e$ and 170€/MWh$_e$ for PHS and CAES respectively, i.e., almost 60€/MWh$_e$ higher than marginal profit of the reference natural-gas scenario.

On the other hand, since hydropower is fuel-free and presents lower negative externalities (especially when compared with wind-CAES schemes), the business as usual (BAU) scenario adopting the values of Table 3.5 yields negative values of marginal profit due to extremely low break-even FiTs. In fact, for the proposed solutions to become marginally cost-effective, the extreme scenario of 140€/MWh$_e$ for the hydropower station total electricity production cost (i.e., the equivalent of $c_{TPS\text{-}peak}$) should apply. For comparison purposes the results of the high cost scenario are included in Figure 3.36. If an oil-fired peak power plant was to be replaced by either wind-based PHS or wind-based CAES, its marginal profit would exceed 75€/MWh$_e$, even in the high cost scenario.

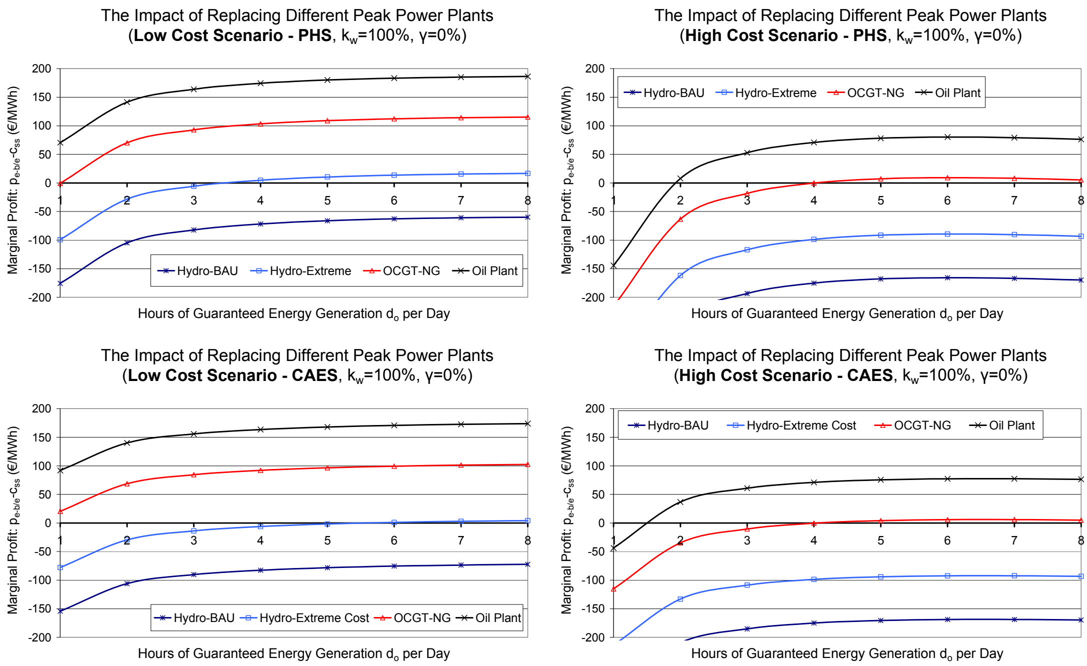


Figure 3.36: The impact of replacing different peak power plants on system profitability

3.3.5 Summary

It is acknowledged that support is required for large-scale wind energy integration and that profitability of energy storage systems operating in an electricity market is limited. Therefore, the use of wind energy surplus to operate energy storage systems that can cover peak demand loads has been investigated. In this context, social welfare attributes assigned to energy storage systems exploiting wind energy were quantified, to estimate appropriate FiTs for two different energy storage technologies, i.e., PHS and CAES. After the determination of break-even FiTs using an integrated cost-benefit model, system profitability margins were investigated for various cost scenarios, using Greece as a reference country. Break-even FiTs ensure system profitability for the low cost scenario in all examined cases. Furthermore, two different scenarios were examined with regards to the input energy used for the charging of the storage system, i.e., 100% use of wind energy and 70% use of wind energy. In this context, although the use of 100% wind energy implies relatively higher electricity production cost, break-even FiTs increase is far more important, leading to higher marginal profit for both PHS and CAES cost-effective configurations. At the same time, a sensitivity analysis for the main energy storage system cost parameters determines the maximum values of cost parameters permitting profits for both PHS and CAES. The cost of wind energy input and fuel (for the CAES only) has a major impact on the marginal profit of the proposed schemes. Additionally, the operating cost of the conventional peak power station to be replaced by the energy storage system was found to be of critical importance. Moreover, the application of fixed FiTs showed that the cost-effectiveness of certain PHS and CAES configurations was ensured by FiTs that were lower than the respective break-even point. At the same time, because of the lower electricity production cost of CAES, the advantage of PHS in the case of the low cost scenario break-even FiTs disappeared when either fixed FiTs were applied instead of break-even FiTs, or higher cost scenarios were examined.

Finally, the impact of replacing different types of peak power plants was also examined. To this end, higher costs and more severe environmental impacts induced by the operation of oil-fired peak power plants resulted in considerably higher values of marginal profit –in comparison to the natural gas peak power plants- ensuring cost-effective energy storage systems configurations in the case of the high cost scenario as well. On the contrary, unless the electricity production cost of the hydropower station examined is higher than 140€/MWh_e, wind-energy storage solutions are not cost-effective with break-even FiTs.

Overall, the results reflect the importance of applying FiTs for energy storage systems exploiting wind energy surplus, which combined with initial cost subsidies can provide profitability and considerably reduce the initial investment cost of such capital intensive projects. Thus, compensation of wind farm curtailments is achieved and profit opportunities for several energy storage configurations arise, since deferral of valueless wind energy to cover peak demand loads through storage guarantees substitution of power units that are usually determined by high cost of electricity production. This of course becomes increasingly important with the increase of wind power shares, since the latter requires increased grid system flexibility, which if not offered by dispatchable thermal units can be equally well provided by means of energy storage appreciating favourable response times and ramp rates.

3.4 Conclusions

The main conclusions of Chapter 3 are synopsized in the following:

Concerning arbitrage, it was concluded that as European markets integrate and become more efficient, the value of arbitrage for energy storage is reduced. On the other hand, results obtained indicate that heavy reliance of markets on fuel imports (e.g. UK and EEX), or low levels of market competition, seem to create substantial arbitrage opportunities from which a risk-adaptive investor could benefit. In any case however, although application results for all energy trade strategies investigated validate the common conclusion that arbitrage in itself cannot support investments in the energy storage sector, results obtained also provide a set of directions on the optimum size and strategy for PHS and CAES practising arbitrage in electricity markets of different characteristics, determining also the level at which arbitrage can contribute if a portfolio of services is adopted by a private energy storage actor.

Next, looking at energy storage from the end-consumer point of view, it is argued that combination of DSM with distributed energy storage can provide increased flexibility which can protect the demand side from its exposure to increased electricity prices. To this end, DSM could combine with arbitrage, giving the opportunity for increasing the value of distributed energy storage assets by allowing them to actively participate in the energy market. Such schemes could be applied in the industrial sector and accordingly extend to capture other sectors, such as the residential and the transportation ones (e.g. plug-in electric vehicles), and could also pave the way for the introduction of distributed energy storage to other markets, such as the reserve one, as well as for the provision of ancillary services to utility grids. Similar to the case of arbitrage however, the interplay between energy storage DSM and arbitrage cannot support investments in the energy storage sector, at least under the current installation costs of such configurations.

What became evident to this end is that to increase profitability for energy storage, such strategies should extend to involve distributed RES power generation as well. In fact, it was proved that by combining RES power generation with energy storage under the application of a strategy supporting delivery of guaranteed energy and replacing thermal peak plants can lead to the production of considerable social welfare benefits. Such benefits could be harvested by private actors through state-supported financial instruments, like FiTs for energy storage in the support of RES power generation. Acknowledging the above, optimum energy storage strategies can be built on a case by case basis, encouraging the adoption of a portfolio of services that can involve, apart from RES support, also arbitrage, DSM, etc, assigning in this way energy storage assets with multiple roles and thus increased value.

4. Energy Storage Strategies at the Autonomous Grid Level

The focus of Chapter 4 is on the evaluation of emerging energy storage applications at the level of autonomous grids. Such applications are stimulated by the fact that electricity supply in autonomous electricity grids (e.g. non-interconnected island grids) is usually based on oil-fired power generation. As a result, introduction of RES-based energy storage systems could prove cost-effective, depending on the local grid and the RES potential characteristics. The two studies included in the current chapter concern the following:

1. Energy storage in the support of increased RES penetration.
2. The interplay between DSM and energy storage in the support of increased RES penetration.

More precisely, in the first of two studies, CAES technology is used together with wind power, to ensure green energy autonomy, under economically effective terms for a non-interconnected island region of medium scale. The proposed solution is compared with conventional, thermal-based systems in terms of economic and environmental performance. The proposed solution also reflects on the debate on the introduction of natural gas in island regions.

In the second study, battery storage is employed to support novel strategies of DSM (peak shaving and load shifting), using as case study a small-scale island region. The proposed configuration couples battery storage with wind power and is examined under different DSM scenarios and the assumption of perfect wind power generation and demand prognosis. The aim of the study is the maximum downsizing of the energy storage system, reflecting in this way the importance of the interplay between DSM and energy storage under the concept of smart grids. This in turn implies the cost reduction of the storage component, which highlights that the application of similar schemes should not be limited only to isolated areas determined by extreme electricity production costs.

Similar to the case of Chapter 3, the approach followed with regards to modelling, simulation and valuation of the strategies investigated is defined as deterministic/retrospective, meaning that use of past (historical) price patterns is considered in order to evaluate the performance of the configuration each time examined.

4.1 Energy Storage to Increase RES Integration in Autonomous Grids

4.1.1 Introduction

There has been an increased interest in promoting DG during the last two decades (Ackermann et al., 2001). RES are called to play a critical role in the transition attempted from centralized power generation to DG patterns. At the same time, there are several regions worldwide that are not connected to a central electricity grid (e.g. non-interconnected island regions) and thus rely on stand-alone energy production systems, such as autonomous, oil-fired power stations (Kaldellis and Zafirakis, 2007b). In many of these regions, RES potential is of medium to high quality and encourages installation of wind and solar energy systems. Nevertheless, although such technologies are nowadays considered established, they still require back-up power to satisfy energy demand at all times, owed to their stochastic nature. In this context, there are various energy storage technologies (González et al., 2012; Hall and Bain, 2008; Kaldellis et al., 2009a), either mature or emerging, that can interact with the primary RES energy source and achieve high levels of energy autonomy, largely reducing or even eliminating the contribution of thermal power generation.

Among the various energy storage technologies, CAES systems (Kim et al., 2011; Lund et al., 2009; Rezvani et al., 2012), can be used in energy management applications. Their operation is based on the exploitation of surplus (e.g. wind energy curtailments) or off-peak, low-price energy (Crotogino et al., 2001). Using this energy, air is compressed inside either an underground air cavern or a high pressure tank. When an incentive to sell energy (i.e. during peak hours) or an energy deficit (i.e. when demand is high and RES energy production is not sufficient) appears, high pressure air is drawn from the cavern/tank and is mixed with natural gas to produce high enthalpy gases, then used to operate a gas-turbine for power generation. It is noteworthy that during this cycle CAES achieves operation under a considerably lower heat rate (Crotogino et al., 2001) if compared with the respective conventional gas turbine cycle; thus ensures proportional fuel savings.

Acknowledging the benefits arising from CAES operation and the fact that CAES can serve small-medium size applications (Proczka et al., 2013), this study investigates an integrated Wind-CAES scheme used to support electrification in remote communities. At this point, it is worth mentioning that plans concerning gradual introduction of natural gas in island areas (Marrero and Ramos-Real, 2010; Ramos-Real et al., 2007), as a substitute for oil, could facilitate the operation of CAES configurations and lead to cleaner and more efficient energy production patterns. To ensure 100% energy autonomy without oversizing system components, a novel Wind-CAES system is proposed, allowing switching from the CAES to the Brayton cycle when stored energy is not adequate to satisfy demand (Zafirakis and Kaldellis, 2009; 2010). A new algorithm for the sizing of such configurations is developed, while for demonstration purposes the case study of a typical, medium-scale island of the Aegean Sea is used in combination with three representative wind regimes. Accordingly, the recommended solution is evaluated in terms of economic performance and CO_2 emissions' reduction. Following the introduction section, description of a typical CAES system is given in section 4.1.2, with the proposed dual-mode, wind-based energy solution analyzed in section 4.1.3 and the model governing equations presented in section 4.1.4. Description of the examined case study along with application results are then provided in sections 4.1.5 and 4.1.6, while the main conclusions of this research work are discussed in section 4.1.7.

4.1.2 Description of the CAES Solution

In a typical CAES configuration, off-peak power is used to compress air into an underground cavern (pressure reaching 80bars (Crotogino et al., 2001)). During times of peak demand, the required amount of air is released from the cavern, heated with natural gas and then supplied in the form of gases to a gas-turbine, where expansion takes place as in the typical Brayton/Joule cycle. The main benefit of a CAES system is that the stages of compression and generation are separated from one another. Consequently, approximately 2/3 of fuel consumption that drives the compressor in a Brayton/Joule cycle is not used in the CAES cycle.

As a result, in a CAES system, the entire power of the gas-turbine is available for consumption. During a complete cycle, 1kWh of output electricity requires approximately 0.75kWh of input electricity for the compressor and 4,500kJ of fuel during combustion (Denholm and Kulcinski, 2004). This fuel raises controversy over the unconditional acceptance of such systems, presenting a negative (even if limited) impact in terms of energy autonomy and emissions when compared with other energy storage solutions. Although alternative approaches suggest the use of biofuel (Denholm, 2006), or fuel-free systems such "Advanced Adiabatic CAES" (Bullough et al., 2004; Jubeh and Najjar, 2012), the specific concepts are still in the development stage; thus they are not currently considered mature enough to substantially support increased contribution of wind energy production in remote communities.

The requirement of CAES for favourable sites and geological formations that can facilitate underground storage is also a disadvantage for the specific technology. The storage media most commonly used include rock and salt caverns, porous media reservoirs or even buried pipes for small subsurface CAES units (Dayan et al., 2004). The use of high pressure tanks could equally well serve for the storage of compressed air, especially in small-medium size applications. Furthermore, since storage losses identified in CAES are not significant, the storage period is rather long.

Moreover, the system presents faster ramp rates (2 to 3 times faster than conventional units) and lower fuel consumption and CO_2 emissions (compared to both simple and combined cycle units). Finally, flexibility of CAES systems to serve as both base load plants (Greenblatt et al., 2007) and peak following units (Lund et al., 2009) strongly supports collaboration with wind farms (Cavallo, 2007; Salgi and Lund, 2008), requiring both sufficient energy storage capacity and adequate system flexibility in order to better adjust to inelastic demand.

4.1.3 Description of the Dual-Mode CAES System

Any type of power generation system that relies on wind for energy generation requires oversizing to achieve a high level of demand satisfaction. This is owed to the stochastic nature of wind energy. In order to avoid expensive oversized Wind-CAES configurations, an alternative solution is proposed. More precisely, to counterbalance the need for extreme wind power and energy storage capacity, a dual-mode CAES plant is adopted. It has the ability to switch its operation from the CAES mode to the traditional gas-turbine cycle with the addition of a second compression system and the help of a clutch that allows connection between the gas-turbine and the compressor.

In this way, the system can appreciate increased levels of energy autonomy, although of course relying on natural gas, without having to oversize wind capacity and storage volume. The same configuration also makes sense in the case of smaller-scale systems, not necessarily destined to support 100% energy autonomy of such an island system.

Instead, they can be used as a private-owned power producing units, following the dispatch strategy developed in section 3.3 of the thesis. In such a case, the dual-mode CAES system operator could cover guaranteed output requirements on the basis of wind energy and natural gas, relying also on the ability to switch to the classical Brayton cycle, opposite to the scenario of thematic section 3.3 where the system, in the absence of sufficient wind energy surplus, draws conventional power directly from the grid. This normally implies exposure to higher costs since even if off-peak, oil-based grid power is used to charge the system, the use of primary natural gas fuel to operate the gas turbine would normally be more cost-effective, especially if also considering storage losses introduced in the first case.

The proposed system (see also Figure 4.1) comprises of the following components:

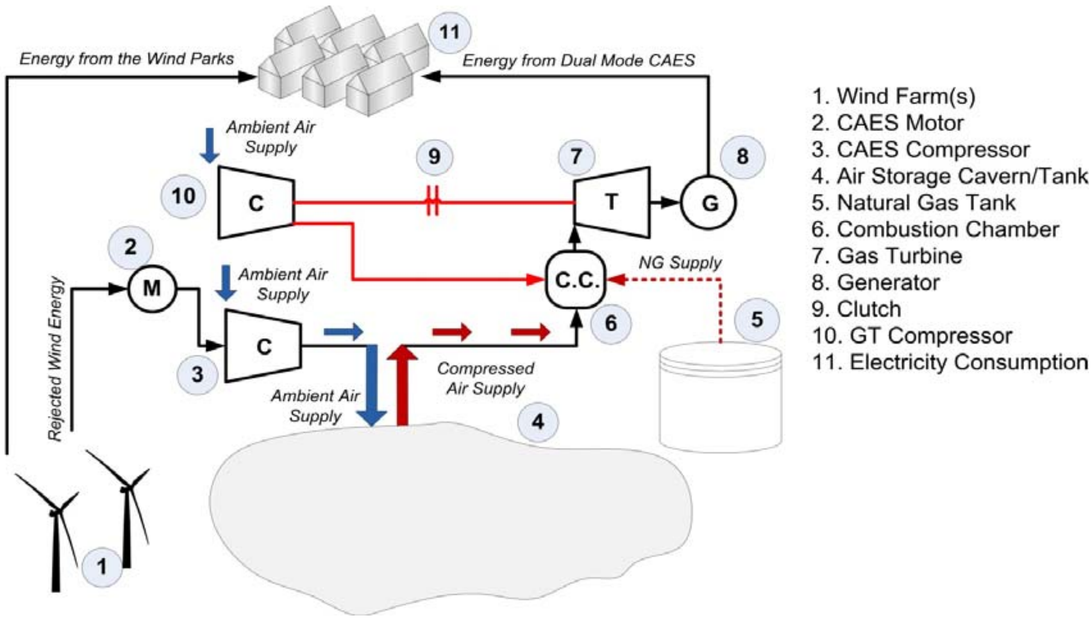


Figure 4.1: The proposed dual-mode Wind-CAES system

- A wind farm that includes a number of wind turbines with total capacity "N_{WP}".
- A CAES motor of rated power "N_m", used to exploit any wind energy surplus and feed the compressor under an efficiency of "η_m".
- A multi-stage compressor, used in the CAES cycle to compress ambient air into the air cavern/tank, under a given pressure ratio "r_c". Similar to the case of the motor, the compressor power "$N_{cr\text{-}CAES}$" is determined in relation to the maximum wind energy surplus appearing, i.e. "N_W-N_d", taking also into account any energy losses induced by the motor. "N_W" represents the mean hourly wind farm power output and "N_d" the mean hourly load demand.
- A second compression system, operated in the case of the dual-mode cycle execution, i.e. when energy deficit appears and the combined Wind-CAES system is not able to cover it. Its rated power is "$N_{cr\text{-}dual}$" and its pressure ratio is "r_c'".
- A storage cavern or tank of maximum volume storage "V_{ss}" and maximum depth of discharge "DOD_L", determined by the ratio of $[(r_c\text{-}r_t)\cdot r_c^{-1}]$, where "$r_t$" is the pressure ratio of the gas-turbine. The approach currently adopted concerns constant storage volume and sliding pressure, with the latter allowed to reduce up to the minimum permitted level determined by the expansion ratio of the gas turbine. To this end, the pressurized air outlet is controlled by the introduction of constant pressure valves that allow supply of pressurized air under constant pressure that is set to align with the expansion ratio of the gas turbine. Given the gradual reduction of the

pressurized air mass inside the storage cavern/tank, the pressure reduces proportionally, not allowed to violate the maximum "DOD_L" condition.

- A combustion chamber, where the required amount of compressed air and natural gas are mixed for the production of gases that will operate the gas-turbine under a maximum permitted temperature of "T_{cc}".
- A natural gas tank, used for fuel storage and the fuel's calorific value (CV) "H_u".
- A gas-turbine of power output "N_{gt-f}", determined after considering the maximum appearing deficit in the case of both the CAES "N_{def}" and the dual-mode "N_{def}'" cycle, that is connected to an electrical generator responsible for the delivery of electrical energy to the demand side.

The main variables taken into account are the wind farm capacity and storage volume, while detailed wind speed and ambient temperature-pressure data alongside hourly electricity load are required. At the same time, the technical characteristics of the main system components are also required (Table 4.1). Finally, to simulate operation of similar systems, a sizing algorithm was developed in C# (Figures 4.2 and 4.3).

The operation scenarios of the proposed configuration are the following (Figure 4.2):

- When wind energy production is sufficient to meet demand, wind energy is fed directly to the local consumption. Any potential energy surplus is used to compress air inside the cavern/tank, provided that the latter is not full. If the latter is full, then a second-level wind energy surplus appears, which if possible, can be exploited to operate secondary loads, electric vehicles, desalination plants, etc. During this stage, and given also the maximum appearing wind energy surplus exploited for compression, the nominal compression power required is estimated. This of course could suggest oversizing of the compression side in many cases, which could be avoided if treating compression power as an additional problem variable.

- When wind energy production is not sufficient to meet demand, the required amount of compressed air and fuel are used in order to operate the gas-turbine. In that case, the CAES cycle is operated, exploiting wind energy stores together with natural gas, under a reduced heat rate, provided of course that the maximum depth of discharge condition is not violated. Given also the maximum appearing energy deficit or residual load to be covered, the nominal gas turbine power is determined for the case of the CAES cycle, while, simultaneously, the fuel consumption required to operate the gas turbine is also recorded.

- When the combined operation of wind energy and CAES is not able to meet demand, the energy deficit is covered by the dual-mode system operation of CAES, i.e. the gas-turbine is clutched to the dual-mode compressor, under a different heat rate in comparison to the CAES cycle. In that case, fuel consumption of natural gas increases, while the size of the gas turbine is challenged by the need to also operate the compression side. To this end, the gas turbine power required to operate the typical Brayton cycle is also determined and is then compared with the respective size required for the CAES operation in order to define the final power required for the gas turbine side. At the same time, the fuel consumption under the operation of the dual-mode cycle is also recorded.

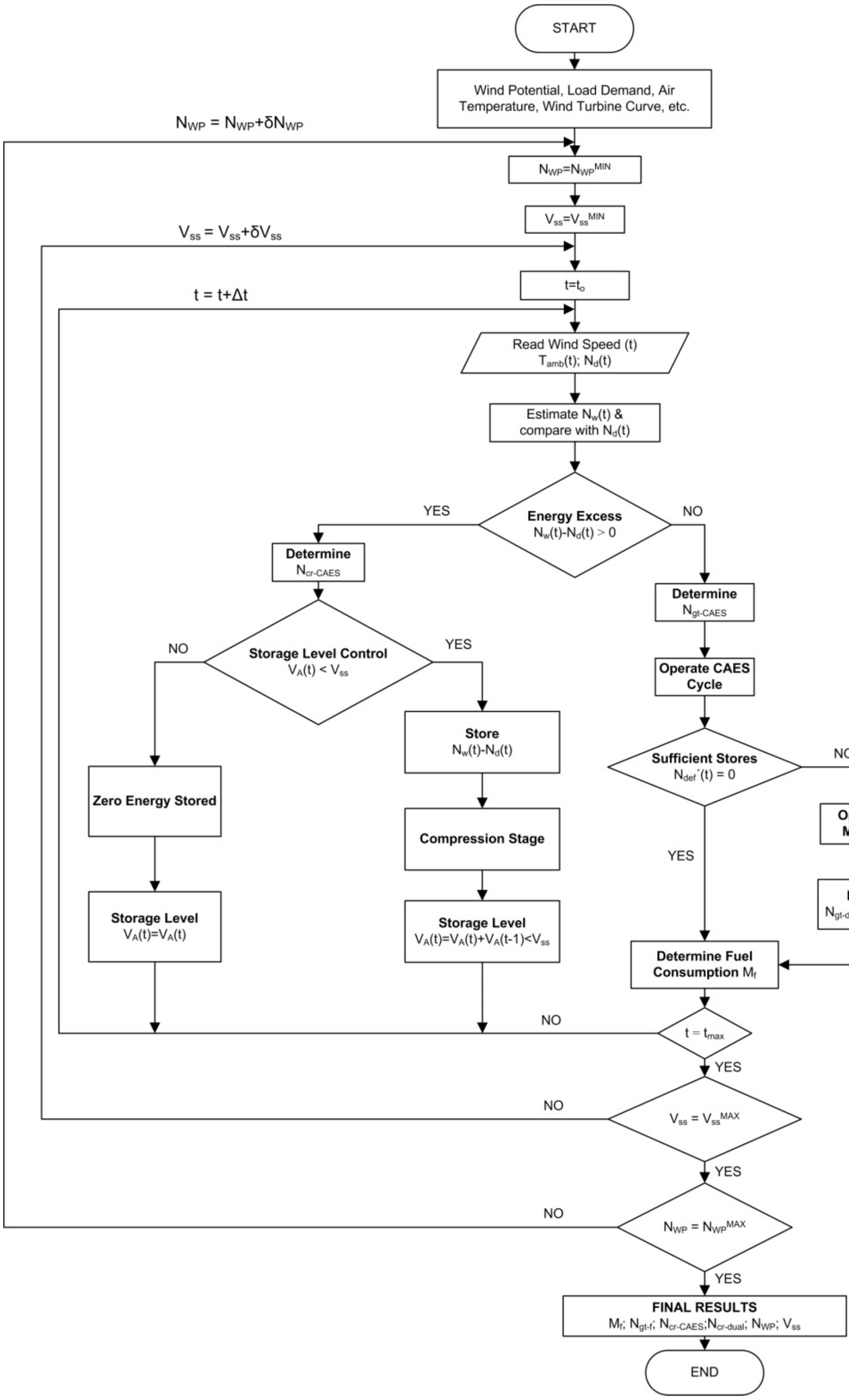


Figure 4.2: The Wind-CAES-DM-2 algorithm

In this context, for a fixed wind farm capacity and storage volume, the annual hours of load rejection are recorded and to minimize load rejection the storage capacity is gradually increased within a predefined range. Furthermore, when energy autonomy is not achieved, the wind park capacity is increased, until 100% energy autonomy is made possible relying only on the Wind-CAES solution. The obtained results include the complementary energy (fuel consumption) required by the dual-mode CAES cycle in case that 100% energy autonomy is not achieved by the original Wind-CAES system, emphasizing the fuel savings achieved by the system operation.

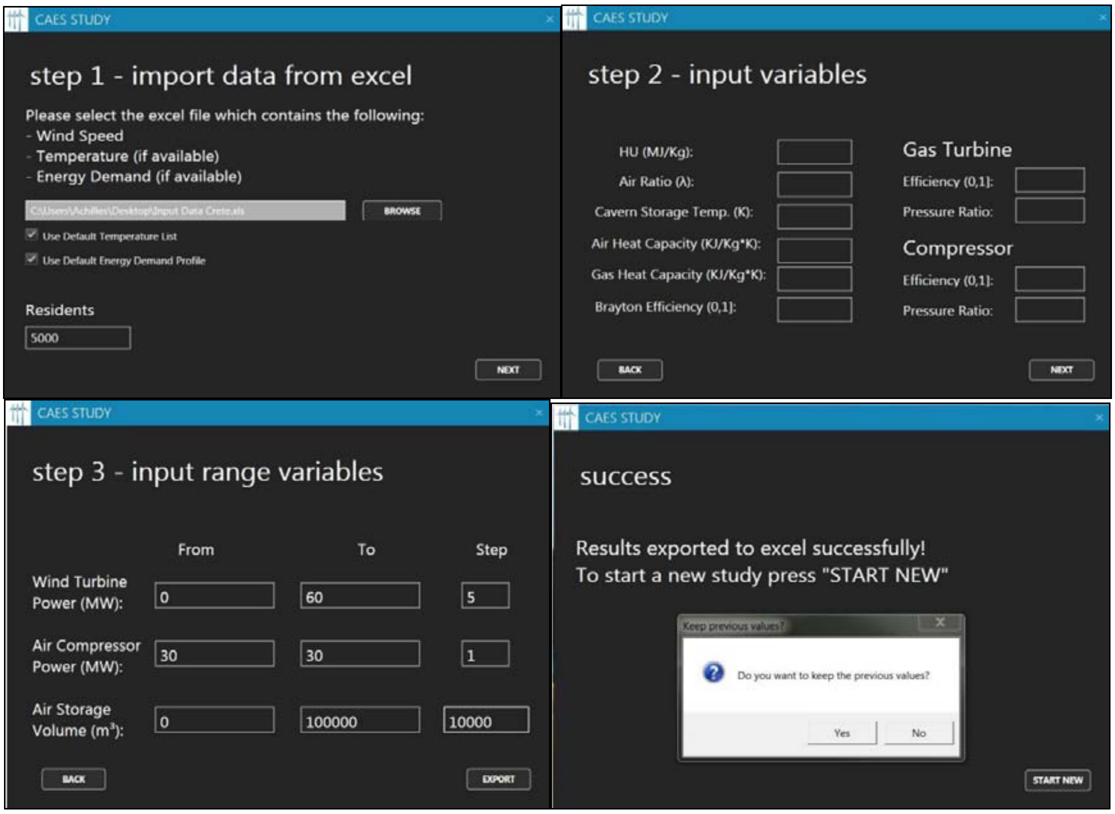


Figure 4.3: Screen-shots of the Wind-CAES-DM-2 algorithm

Table 4.1: Energy-related problem inputs (Cavallo, 2007; Jubeh and Najjar 2012; Kim et al., 2011; Lund and Salgi, 2009; Lund et al., 2009; Zafirakis and Kaldellis, 2010)

Parameter	**Symbol / Unit**	**Assigned Value**
Compressor isentropic efficiency	η_{isc}	0.85
Gas turbine isentropic efficiency	η_{isT}	0.88
Compressor mechanical efficiency	η_{mc}	0.98
Gas turbine mechanical efficiency	η_{mc}	0.98
Motor efficiency	η_{M}	0.98
Electrical generator efficiency	η_{gen}	0.98
Storage temperature	T_{cav} (K)	300
CAES compressor pressure ratio	r_c	75
Dual-mode compressor pressure ratio	$r_c{'}$	32
Gas turbine pressure ratio	r_t	30
Specific heat capacity of air	C_{pA} (J/kg/K)	1004.5
Specific heat capacity of gases	C_{pR} (J/kg/K)	1105
Air ratio	λ_a	4
Mass of air for stoichiometric combustion	m_a (kg/kg_{NG})	15
Combustion chamber max operational temperature	T_{cc} (K)	1200
Air constant	R_g (J/kg/K)	287
Calorific value of natural gas	H_u (MJ/kg)	47

4.1.4 Model Governing Equations

The CAES and the Brayton/Joule cycle modes are studied in terms of thermodynamics and the CAES operation is divided in its main stages, i.e. compression, storage and combustion-expansion.

Compression stage-CAES cycle

During the CAES cycle, the mean hourly power each time available for the compression of air "$N_{c\text{-}CAES}$" derives from the hourly wind energy curtailment "$N_{W\text{-}curt}$" (in case of wind energy surplus, i.e. N_W-N_d>0= $N_{W\text{-}curt}$) and the employed motor efficiency "η_M" (equation 4.1).

$$N_{c-CAES} = N_{W-curt} \cdot \eta_M \tag{4.1}$$

The mass flow rate of air "$\dot{m}_A$" pressurized inside the storage cavern is given by equation 4.2, where "η_{isc}" and "η_{mc}" are the compressor's respective isentropic and mechanical efficiency. "T_{t1}" is the temperature of air (currently treated as an ideal gas) entering the compressor (usually equal to the ambient air temperature; "T_{t1}=T_{amb}"), "r_c" is the compressor pressure ratio; "C_{pA}" is the specific heat capacity of air; and "γ" is the adiabatic coefficient.

$$\dot{m}_A = \frac{N_{c-CAES} \cdot \eta_{isc} \cdot \eta_{mc}}{C_{pA} \cdot T_{t1} \cdot \left(r_c^{\frac{\gamma-1}{\gamma}} - 1 \right)} \tag{4.2}$$

The nominal power of the CAES cycle compressor "$N_{cr\text{-}CAES}$" is determined on the basis of the maximum wind energy curtailment appearing, in order to absorb the entire amount of energy excess coming from the wind farm, after considering the motor efficiency.

$$N_{cr-CAES} = \max\{N_{W-curt} \cdot \eta_M\} \tag{4.3}$$

Compression stage-Brayton cycle

At the same time, after the CAES cycle is executed, the algorithm examines the appearance of any new deficit, i.e. N_{def}'=N_d-N_W-$N_{gt\text{-}CAES}$>0, where "$N_{gt\text{-}CAES}$" is the output of the gas turbine during the CAES cycle operation. In that case, based on the maximum air mass flow rate "$\dot{m}_{A-dual,\max}$", required to provide the necessary gas flow "$\dot{m}_{g-dual}$" in order to cover the remaining new energy deficit, the nominal power of the dual-mode compressor "$N_{cr\text{-}dual}$" is determined:

$$N_{cr-dual} = \dot{m}_{A-dual,\max} \cdot C_{pA} \cdot T_{t1} \cdot \left(r_c'^{\frac{\gamma-1}{\gamma}} - 1 \right) \cdot \left(\eta_{isc} \cdot \eta_{mc} \right)^{-1} \tag{4.4}$$

considering however a different pressure ratio "r_c'" than the one used in the CAES cycle, normally being slightly higher than the respective pressure ratio of the employed gas turbine, i.e. "r_t".

Energy storage stage

In the case of the CAES cycle, the ambient air, after being compressed, is stored inside the storage cavern/tank. The cavern/tank storage level is described by equation 4.5, where "$M_A(t)$" represents the mass of stored air at a given time "t" and "$M_A(t-1)$" is the storage level during the previous hour (an hourly time step is to be considered). The air mass entering the cavern is "$\dot{m}_A \cdot \delta t$" and "δm" stands for air mass losses (currently neglected).

$$M_A(t) = M_A(t-1) + \dot{m}_A \cdot \delta t - \delta m \tag{4.5}$$

Furthermore, the respective pressure, at which the air is delivered in the cavern/tank is determined by the pressure ratio of the compressor "r_c" and the potential pressure losses "δP" from the compressor outlet up to the storage cavern/tank inlet (currently neglected),

$$P_A = P_{t2} - \delta P = r_c \cdot P_{t1} - \delta P \approx r_c \cdot P_{amb} - \delta P \tag{4.6}$$

with "P_{t2}" being the total pressure at the exit of the compressor and "P_{t1}" being the pressure in the entry of the compressor, usually taken slightly less than the ambient air pressure "P_{amb}".

Similarly, the air temperature inside the cavern may vary at a given variation level "$\pm\delta T \approx 0\text{-}2^oC$" (positive during winter and negative during summer). This depends on the heat transfer characteristics of the cavern/tank walls, although it is assumed as constant (i.e. T_{cav}=300K).

$$T_{cav} = T_{amb} \pm \delta T \tag{4.7}$$

Finally, the storage level may vary in terms of storage volume "$V_A(t)$" between a minimum permitted value of discharge "V_{min}", determined by the corresponding maximum depth of discharge (i.e. $(r_c\text{-}r_t)\cdot r_c^{-1}$), and a maximum "$V_{max}$" defined by the selected volume of the cavern/tank "V_{ss}" (see equation 4.8).

$$V_{\min} \le V_A(t) = \frac{M_A(t)}{\rho_A(t)} \le V_{\max} = V_{ss} \tag{4.8}$$

where "ρ_A" is the density of air inside the cavern, determined by the corresponding values of air pressure "P_A" and air temperature "T_{cav}", as well as by the air constant "R_g", equal to 287J/kg·K (see equation 4.9).

$$\rho_A = \frac{P_A}{R_g \cdot T_{cav}} \tag{4.9}$$

<u>*Combustion-expansion stage*</u>

According to the equation of energy balance for the combustion chamber the temperature of gases entering the gas turbine "T_{gt}" (see equation 4.10) is not allowed to exceed the maximum temperature of operation "T_{cc}" ascribed to the gas turbine specifications.

$$T_{gt} = \frac{C_{p\,A}}{C_{p\,R}} \cdot \frac{\lambda_a \cdot m_a}{(\lambda_a \cdot m_a + 1)} \cdot T_{cav} + \frac{H_u}{(\lambda_a \cdot m_a + 1) \cdot C_{p\,R}} \le T_{cc} \tag{4.10}$$

"C_{pR}" is the specific heat capacity of gases; "T_{cav}" is the air temperature inside the cavern or tank; "H_u" is the calorific value of natural gas; "λ_α" is the air ratio; and "m_α" is the mass of air used for stoichiometric combustion of 1kg of natural gas.

Finally, during the CAES cycle, the power delivered to the local grid "$N_{ex\text{-}CAES}$" can be estimated by equation 4.11 based on the power generation provided by the gas turbine "$N_{gt\text{-}CAES}$" and the efficiency of the electrical generator "η_{gen}" used to produce electrical energy.

$$N_{ex-CAES} = N_{gt-CAES} \cdot \eta_{gen} = (\lambda_a \cdot m_a + 1) \cdot \dot{m}_f \cdot C_{pR} \cdot T_{gt} \cdot \left(1 - r_t^{\frac{\gamma-1}{\gamma}}\right)^{-1} \cdot \eta_{isT} \cdot \eta_{mT} \cdot \eta_{gen} \tag{4.11}$$

or

$$N_{ex-CAES} = N_{gt-CAES} \cdot \eta_{gen} = \dot{m}_g \cdot C_{pR} \cdot T_{gt} \cdot \left(1 - r_t^{\frac{\gamma-1}{\gamma}}\right)^{-1} \cdot \eta_{isT} \cdot \eta_{mT} \cdot \eta_{gen} \tag{4.12}$$

To this end, "$\dot{m}_f$" and "$\dot{m}_g$" are the mass flow rates of fuel and gas, and "η_{mT}" and "η_{isT}" are the mechanical and isentropic efficiencies of the gas turbine in operation. The mass flow rate of natural gas "$\dot{m}_f$" is directly related to the corresponding mass flow rate of air "$\dot{m}_A$" and gas "$\dot{m}_g$", see also equation 4.13.

$$\dot{m}_f = \frac{\dot{m}_A}{\lambda_a \cdot m_\alpha} = \dot{m}_g - \dot{m}_A \tag{4.13}$$

At the same time, based on the deficit appearing after the execution of the CAES cycle, i.e. "N_{def}'", the dual-mode system is called to operate on the basis of gas flow rate "$\dot{m}_g'$". This is estimated by using the following relation (4.14), taking into account the requirement to operate the dual-mode compressor:

$$\dot{m}_g' = N_{def}' \cdot \left(\begin{array}{l} C_{pR} \cdot T_{gt} \cdot \left(1 - \dfrac{1}{r_t^{\frac{\gamma-1}{\gamma}}}\right) \cdot \eta_{isT} \cdot \eta_{mT} \cdot \eta_{gen} - \left(\dfrac{1}{\lambda_a \cdot m_a} + 1\right)^{-1} \cdot \\ C_{pA} \cdot Tt_1 \cdot \left(r_c'^{\frac{\gamma-1}{\gamma}} - 1\right) \cdot \left(\eta_{isc}' \cdot \eta_{mc}'\right)^{-1} \end{array} \right)^{-1} \tag{4.14}$$

which leads to the estimation of the necessary gas turbine rated power "$N_{gt\text{-}dual}$":

$$N_{gt-dual} = \dot{m}_g' \cdot C_{pR} \cdot T_{gt} \cdot \left(1 - r_t^{\frac{\gamma-1}{\gamma}}\right)^{-1} \cdot \eta_{isT} \cdot \eta_{mT} \tag{4.15}$$

as well as to the estimation of the respective fuel consumption "$\dot{m}_f'$"

$$\dot{m}_f' = \frac{\dot{m}_{A-dual}}{\lambda_a \cdot m_\alpha} = \dot{m}_g' - \dot{m}_{A-dual} \tag{4.16}$$

In this regard, the nominal power of the gas turbine, destined to serve both the typical CAES and the dual mode cycle, is eventually decided by considering the maximum appearing value between "$N_{gt\text{-}dual}$" and "$N_{gt\text{-}CAES}$", considering also that parallel operation of the two compressors is not taken into account:

$$N_{gt-f} = \max\{N_{\text{gt-CAES, max}}; N_{\text{gt-dual, max}}\} \quad (4.17)$$

4.1.5 Area of Interest-Case Study Characteristics

For the application of the proposed system, the area of the Aegean Sea was selected as a case study. The specific region is located between the Greek mainland and Turkey and comprises of hundreds of scattered islands that are, in their majority, not interconnected to the main electricity grid. Therefore electricity demand on these islands is served by local autonomous, oil-based power stations as opposing to the mainland grid that relies mostly on local lignite reserves (Kaldellis et al., 2009b). Furthermore, many of these islands are favoured by high quality wind potential (Vogiatzis et al., 2004) that stimulates application of wind-energy storage schemes. In fact, part of the existing literature studies wind-PHS schemes (Kapsali and Kaldellis, 2010; Kapsali et al., 2012; Katsaprakakis et al., 2008), with suitability and cost-effectiveness of these systems depending on certain morphological characteristics i.e. water reservoirs of sufficient capacity at considerable elevations. These requirements can be by-passed by the use of compact CAES schemes, utilizing air storage tanks.

The proposed system is further stimulated by the recent plans of the Hellenic Gas Transmission System Operator (HGTSO) for the introduction of natural gas to non-interconnected islands of the Aegean Sea. More precisely, according to the latest roadmap concerning the long-term national energy planning (GMEECC, 2012), a sea LNG supply network could be supported in the entire Aegean through shipments executed by one or two LNG carriers, using as a supply centre the island of Revithoussa (where an LNG terminal already exists for the supply of Algerian NG to the Greek mainland; 5.2-5.3 billion cubic meters annually).

Besides that, Greece has to increase wind energy contribution substantially to achieve a target of 40% of the national gross electricity consumption covered by RES by 2020 (Kalampalikas and Pilavachi, 2010), as well as additional environmental goals (Kaldellis et al., 2011). To achieve that, the high-quality wind potential of the Aegean Sea should be extensively exploited. As previously mentioned, non-interconnected islands of the Aegean Sea rely on oil imports that entail high electricity production costs, heavy environmental degradation (Kaldellis and Zafirakis, 2007b; Spyropoulos et al., 2005) and increased energy security vulnerabilities (Chalvatzis and Hooper, 2009). As a result, the option of combined wind power and natural gas comes with multiple benefits, facilitating at the same time application of Wind-CAES schemes.

The proposed system is applied to three areas with different wind potential which could be argued that addresses both spatial and temporal uncertainties with regards to the variation of wind patterns in the broader area of interest. These correspond to representative Aegean Sea islands wind regimes of low, medium and high wind potential. In this context, annual wind energy measurements of the three representative wind regimes (at hub height) are given in Figure 4.4 (PPC, 1986) along with typical temperature data of the area.

Furthermore, the annual mean wind speed of the three different wind regimes is 8.2m/sec, 6.2m/sec and 4.7m/sec respectively. Additionally, the hourly demand profile of a medium scale island (of approximately 8,000-10,000 local habitants) for an entire year is given in Figure 4.5, with the peak demand reaching 6MW and the respective minimum demand dropping to 1MW, while the annual energy demand exceeds 30GWh. Finally, a typical wind turbine power curve is used to estimate wind energy production on the basis of wind potential measurements (Figure 4.6), while in the same figure one also includes annual duration curves of the respective hourly wind CFs for all three wind regimes, combined with the corresponding of the non-dimensional load demand (load demand to annual peak demand).

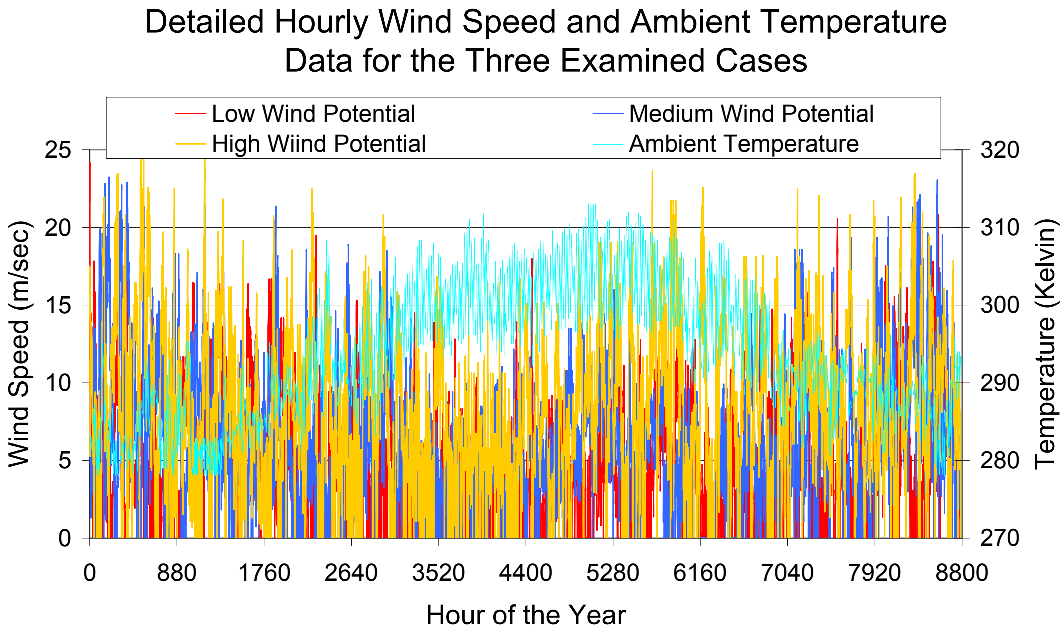


Figure 4.4: Annual wind potential and mean temperature of case studies examined

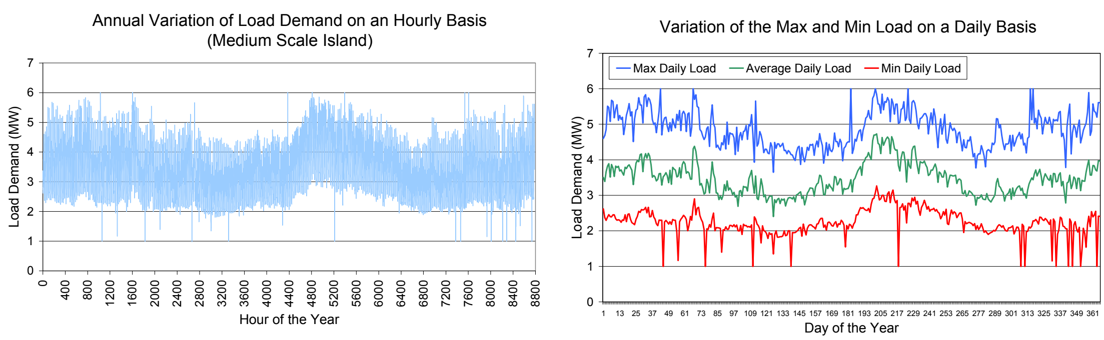


Figure 4.5: Annual load demand variation on an hourly basis (a) and daily max, min and average load (b) for a representative medium-scale island area

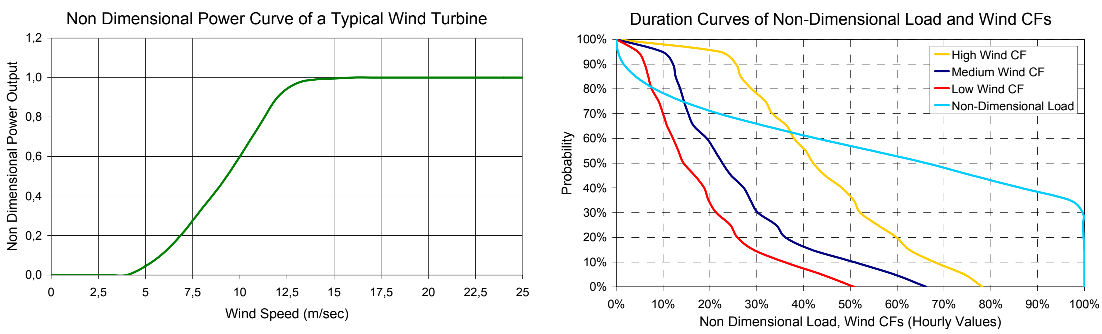


Figure 4.6: Typical wind turbine power curve (a) and duration curves of load demand and wind CFs (b)

4.1.6 Application Results

<u>*Energy-related results*</u>

The proposed methodology returns results about the detailed energy balance analysis on an hourly basis for the entire year (Figures 4.7-4.9). The variation of both main parameters, i.e. wind power capacity and storage volume, is examined within the predefined ranges of 4-60MW and 10,000m^3-100,000m^3 respectively. Energy autonomy is measured by the number of hours of load rejection per year. The fewer the hours of load rejection, the higher the energy autonomy. Increase of wind power capacity gradually improves energy autonomy, while the simultaneous increase of the storage volume allows for greater exploitation of the resulting wind energy surplus; thus leading to the reduction of load rejections per year. Energy autonomous configurations (i.e. configurations that guarantee zero load rejections for the entire year period) are explored in all cases.

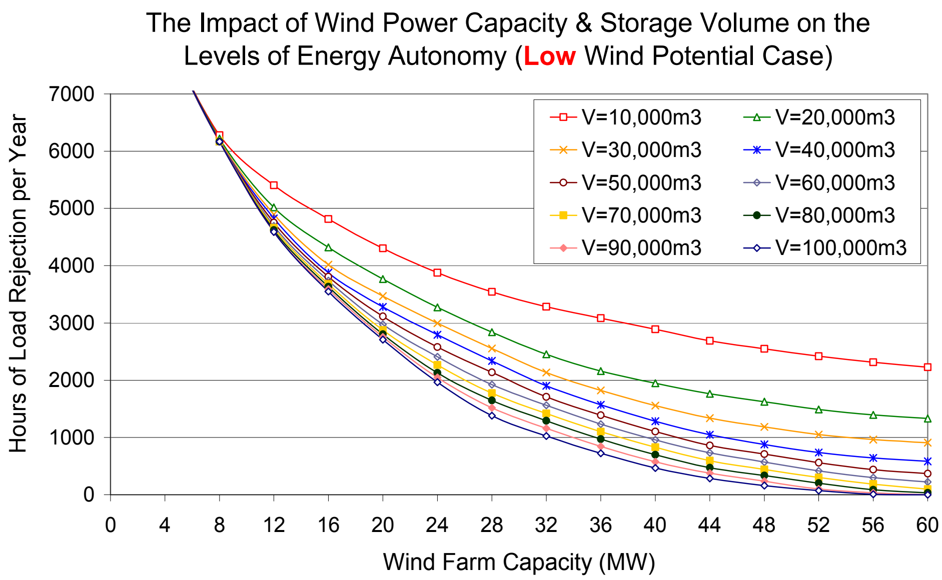


Figure 4.7: Energy autonomy results (low wind case)

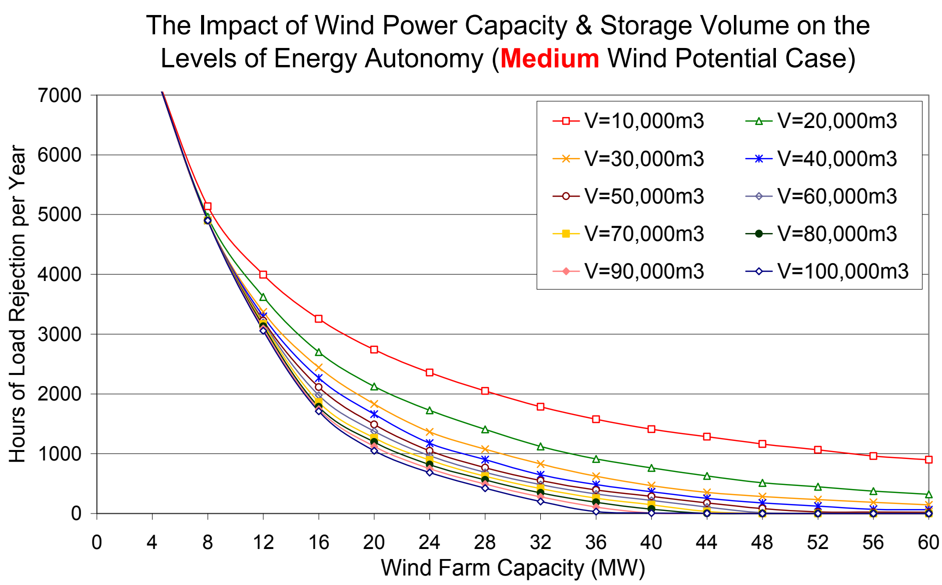


Figure 4.8: Energy autonomy results (medium wind case)

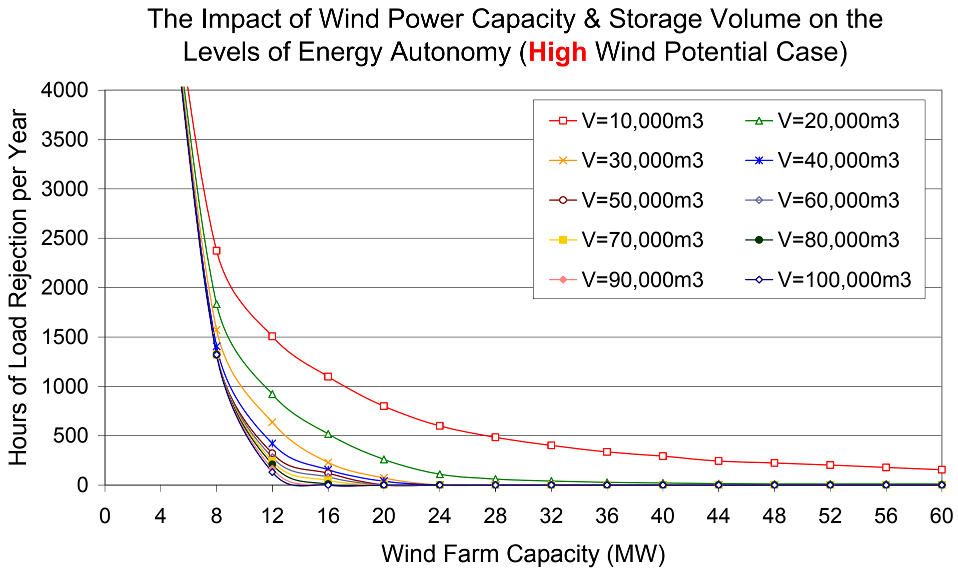


Figure 4.9: Energy autonomy results (high wind case)

To this end, in the case of low wind potential (Figure 4.7), a wind farm capacity that exceeds 50MW and a storage volume in the order of 100,000m^3 are required; in the case of medium wind potential (Figure 4.8), energy autonomous configurations require wind power capacity that is higher than 40MW, with the respective minimum storage capacity approaching 50,000m^3 for the highest wind power capacity, i.e. 60MW (half the one corresponding to the low wind potential case).Finally, for the high wind potential case (Figure 4.9), wind farm capacity of even 12-14MW is able to provide 100% energy autonomy, assuming employment of the highest storage capacity. Furthermore, if the case of using storage capacity in the order of 10,000m^3 is excluded, all other storage capacity values examined can guarantee energy autonomy throughout the year, provided however that a minimum wind power capacity is used.

In addition to the above, the algorithm produces the energy balance of each examined installation on an hourly basis (Figure 4.10) providing in this way detailed information on the operational status of the installation.

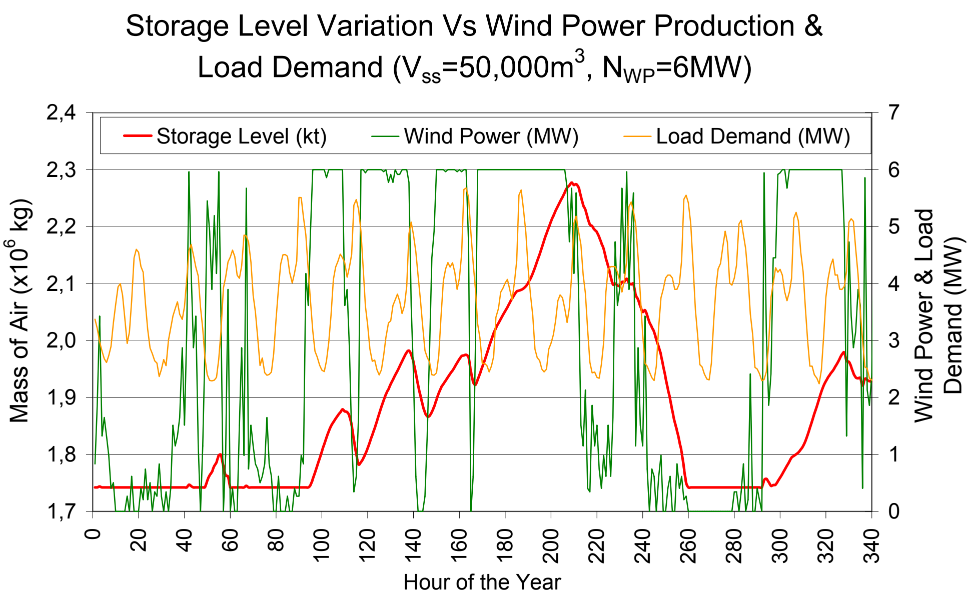


Figure 4.10: Variation of storage cavern air mass levels (medium wind potential)

At this point it must be mentioned that no idling losses relating to cavern/tank pressure drop are taken into account, since on the one hand CAES systems are in principle determined by very low levels of self-discharge (10^{-6} of energy stores per day of idle state), dependent of course on the air-tightness of the storage cavern/tank, and on the other diurnal cycling of the proposed system suggests minimum idling time.

<u>*Fuel consumption results*</u>

Next, the algorithm calculates the annual fuel consumption attributed to the operation of the CAES cycle only (Figures 4.11-4.13). There is a vast increase of CAES fuel consumption for the smaller wind power capacity considered, while maximum fuel consumption is recorded near the 100% energy autonomy. From that point onward, fuel consumption is reduced due to the increased participation of wind energy. This is more clearly demonstrated in the case of high wind potential (Figure 4.13), where a maximum CAES fuel consumption between 12-20MW is more noticeable for storage volumes exceeding 10,000m^3.

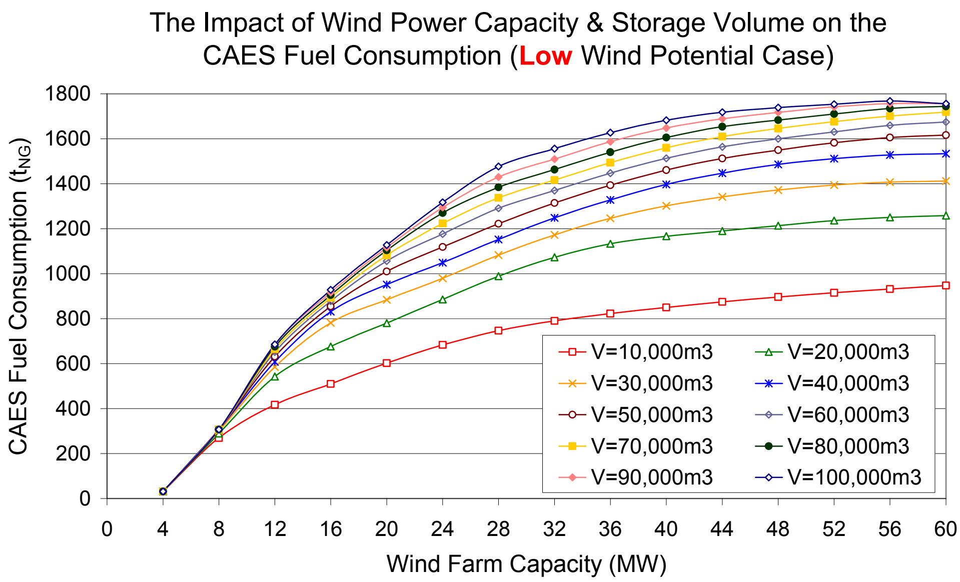


Figure 4.11: CAES fuel consumption results (low wind case)

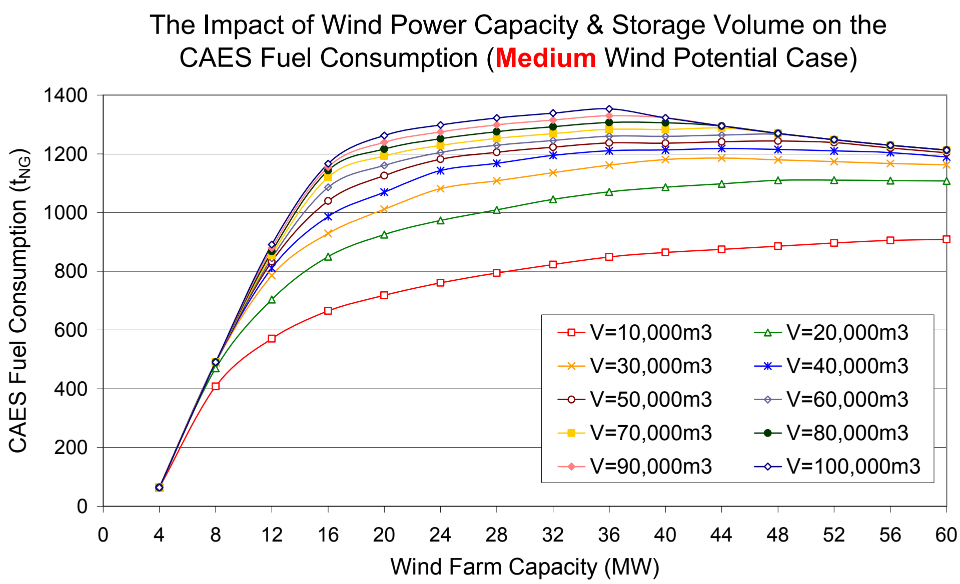


Figure 4.12: CAES fuel consumption results (medium wind case)

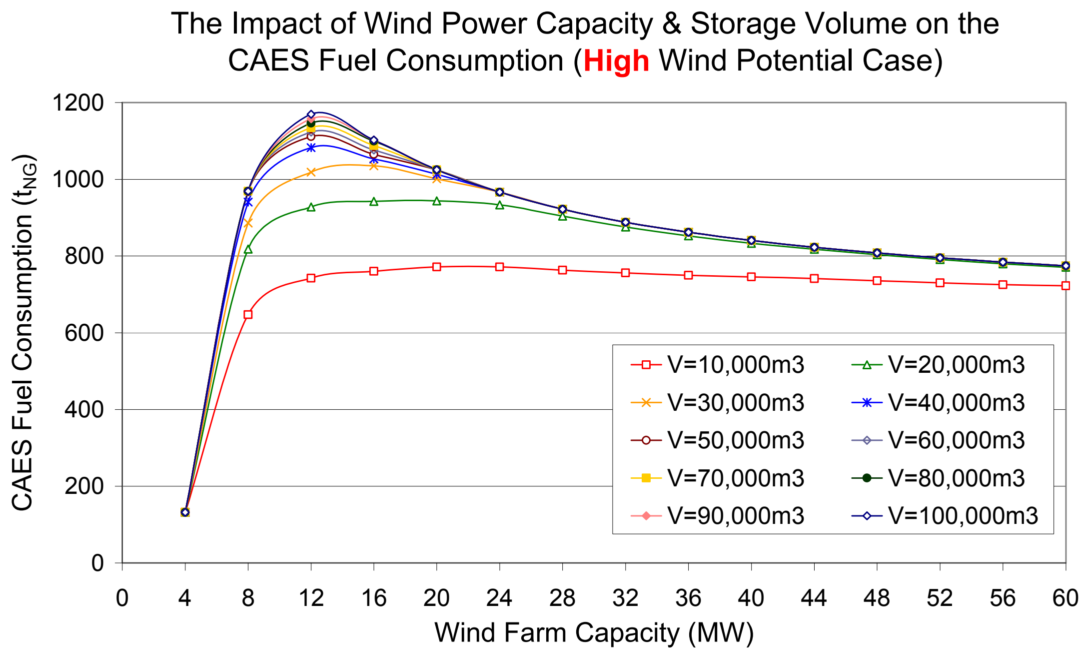


Figure 4.13: CAES fuel consumption results (high wind case)

The impact of the local wind potential is of primary importance, with the required amount of natural gas approaching 1800 tonnes for the low wind potential and the highest storage volume achieving full energy autonomy (Figure 4.11). The medium wind potential area (Figure 4.12) requires approximately 1350 tonnes and the high wind potential area (Figure 4.13) only 1000 tonnes per year. If the wind farm capacity is increased further, CAES contribution (and fuel consumption) is reduced remarkably, falling to 800 tonnes of natural gas per year. The algorithm also calculates the fuel consumption attributed to the complementary operation of the dual-mode CAES cycle, i.e. the typical gas-turbine cycle (Figures 4.14-4.16).

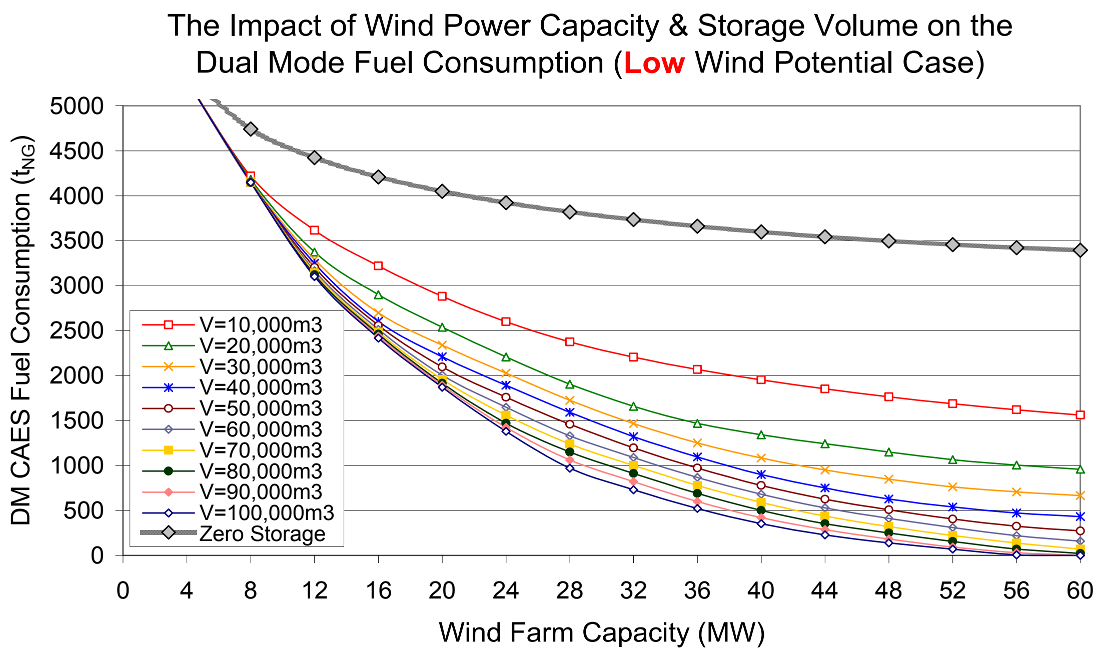


Figure 4.14: Dual-mode cycle fuel consumption (low wind case)

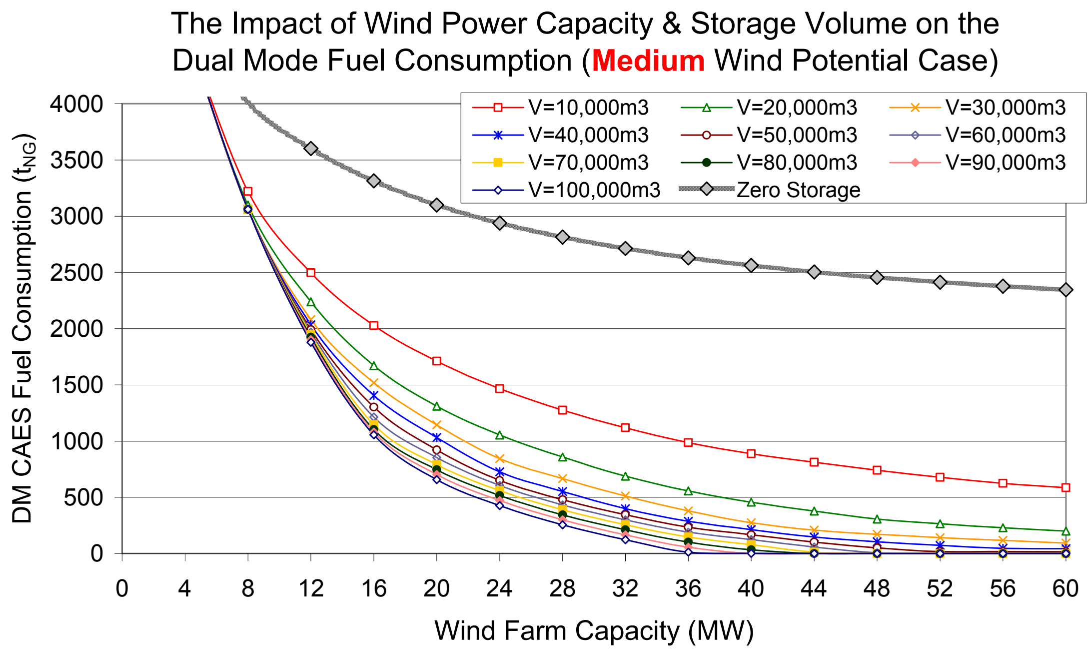


Figure 4.15: Dual-mode cycle fuel consumption (medium wind case)

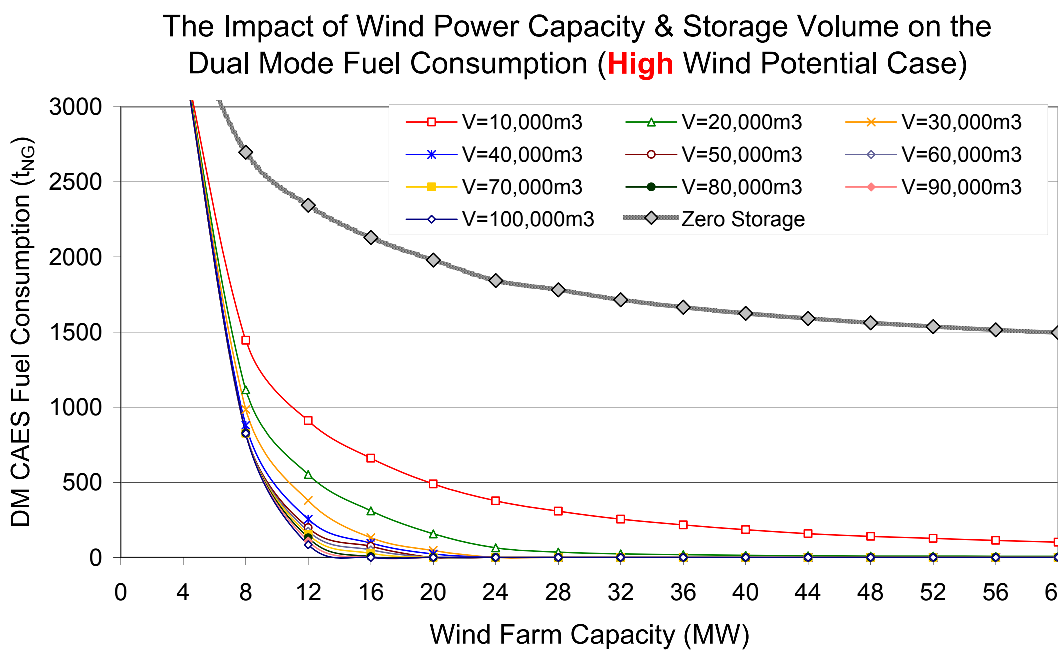


Figure 4.16: Dual-mode cycle fuel consumption (high wind case)

In this regard, storage capacity is zeroed, and thus the system operates without the option of storage. This corresponds to the parallel operation of the wind farm and a typical gas-turbine plant. The results show that the impact of using even 10,000m^3 of storage volume is critical for the reduction of the dual-mode CAES fuel consumption (see for example the 60MW wind power case), by more than 54%, 75% and 93% for the low, medium and high wind potential cases respectively (Figures 4.14-4.16). The corresponding contribution of the pure CAES cycle is presented in Figures 4.11-4.13. Besides that, as expected, dual-mode fuel consumption is eliminated once hourly load rejections are eliminated, since from that point onward, the system relies on the operation of the Wind-CAES scheme only (Figures 4.7-4.9).

Economic evaluation results

Similar to previous studies (Kaldellis and Zafirakis, 2007a), evaluation of energy results is performed using the economic criterion of electricity production cost. The necessary input data is presented in Table 4.2. Three alternative energy solutions are evaluated, i.e. the dual-mode Wind-CAES scheme, the gas-turbine only scheme and finally the currently existing diesel-only operation (Figures 4.17-4.19). To facilitate interpretation the economic performance of different dual-mode Wind-CAES configurations and the participation of the dual-mode cycle in terms of fuel consumption (in comparison with the total including also fuel consumption of the pure CAES cycle) are given on the right axis of the figures. The electricity production cost of the dual-mode Wind-CAES solution presents in all cases examined a minimum optimum point in the area of N_{WP}=8MW-12MW. Additionally, a transition point in each Wind-CAES electricity production cost curve (Figure 4.18), is owed to the fact that the contribution of the dual-mode cycle becomes zero at that point. This eliminates the cost assigned to the extra compression power and the need to oversize the gas turbine component to operate the compressor. As a result, the curve presents an abrupt drop that temporarily suspends the electricity production cost increasing trend.

Table 4.2: Cost-related problem inputs (Cavallo, 2007; Jubeh and Najjar 2012; Kim et al., 2011; Lund and Salgi, 2009; Lund et al., 2009; Zafirakis and Kaldellis, 2010)

Parameter	**Assigned Value**
System service period (years)	25
Wind power cost (€/kW)	1,000
Energy storage cost (€/kWh)	15
Specific gas turbine cost (€/kW)	300
Specific compressor cost (€/kW)	300
State subsidy (%)	0
BOS cost component coefficient (in relation to total capital cost)	15%
Return on investment index	0.08
Wind farm M&O coefficient	0.01
CAES M&O coefficient	0.04
Dual-mode cycle M&O coefficient	0.04
M&O inflation rate	0.04
Natural gas cost (€/MWh_{fuel})	35
Diesel-oil cost (€/bbl)	80
Fuel price annual escalation rate (%)	0.05

At the same time, the cost of the gas-turbine-only option is estimated at almost 160€/MWh. This makes it the most cost-efficient option in case that the wind power capacity exceeds a certain limit. The average, operational-only cost of diesel-fired power stations on the islands reaches 225€/MWh, assuming a diesel-plant efficiency of 28% (PPC, 2012b). Furthermore, the most cost-efficient option is the dual-mode Wind-CAES, with a storage volume of 10,000m^3 that implies substantial gas-turbine cycle participation. On the other hand, as the quality of the local wind potential is improving, additional dual-mode Wind-CAES configurations of greater storage capacity become cost-competitive to both the gas-turbine-only and the wind park & gas-turbine solutions. They achieve minimum participation of the dual-mode cycle, which may even become zero; thus minimize fuel consumption (e.g. high wind potential case; V_{ss}=40,000m^3 and N_{WP}=24MW).

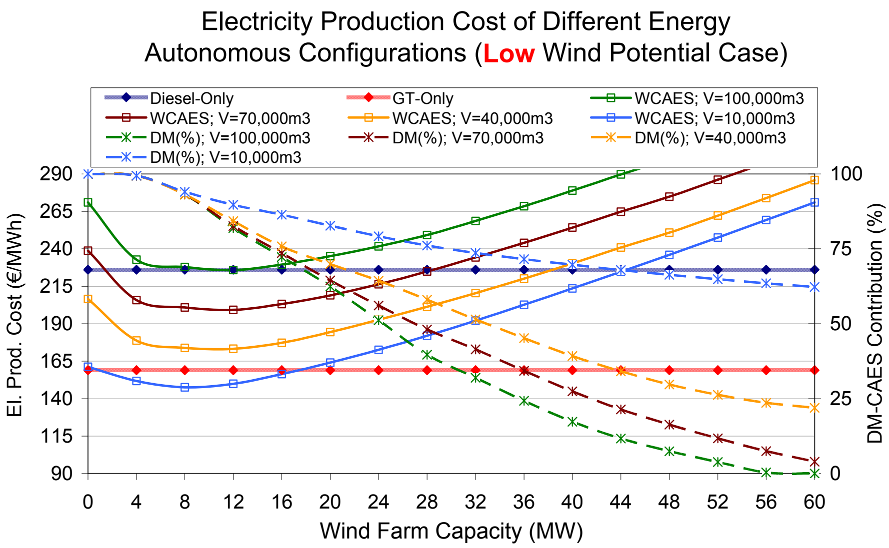


Figure 4.17: Economic evaluation results (low wind case)

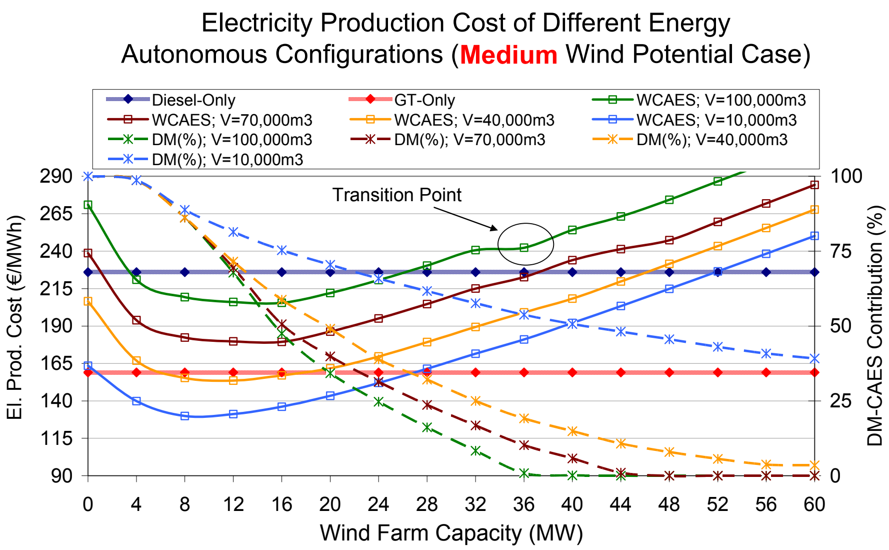


Figure 4.18: Economic evaluation results (medium wind case)

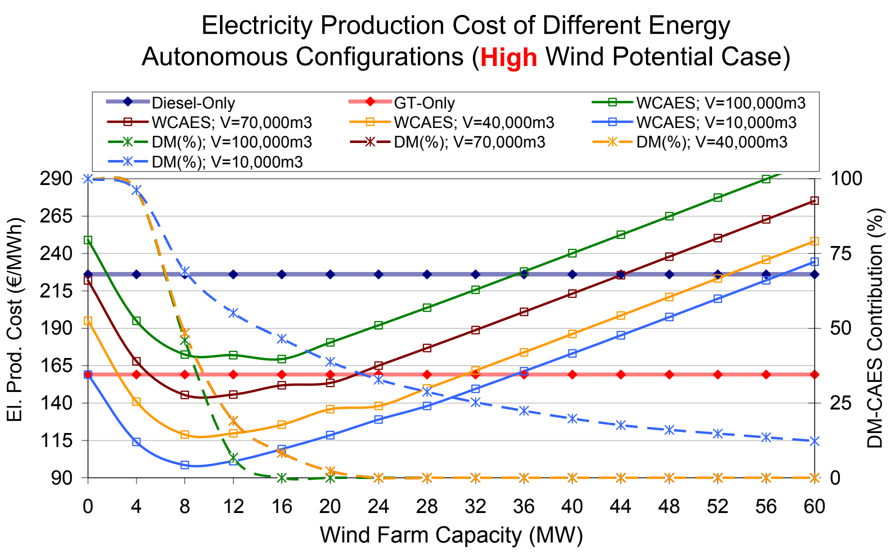


Figure 4.19: Economic evaluation results (high wind case)

<u>*CO_2 emission results*</u>

The considerable fuel savings achieved signal proportionate reduction of CO_2 emissions for two different reasons; first owed to the participation of wind energy and secondly owed to the reduced heat rate of CAES in comparison to typical gas turbine systems. In this context, the heat rate of CAES is estimated at approximately 0.112kg-fuel/kWh$_e$, compared with 0.218kg-fuel/kWh$_e$ assigned to the typical gas turbine cycle. This is more than 50% less CO_2 emissions, corresponding to emission factors of 0.31kgCO_2/kWh$_e$ for the CAES cycle and 0.61kg CO_2/kWh$_e$ for the typical cycle (given a factor of 2.8kgCO_2 per kg of fuel of natural gas combusted). The respective average CO_2 emission factor for the diesel-fired power stations in the area of the Aegean is 0.8kgCO_2/kWh$_e$ (Kaldellis and Zafirakis, 2007b).

In view of the above, for a given storage capacity and wind potential the Wind-CAES CO_2 emissions vary considerably, depending on the wind farm capacity. Figure 4.20 presents the energy contribution of the wind farm, CAES and dual-mode system, as well as the total annual CO_2 emissions deriving from the operation of a diesel-fired power station and a GT-only installation dedicated to the satisfaction of the local annual load demand (i.e. almost 30GWh).

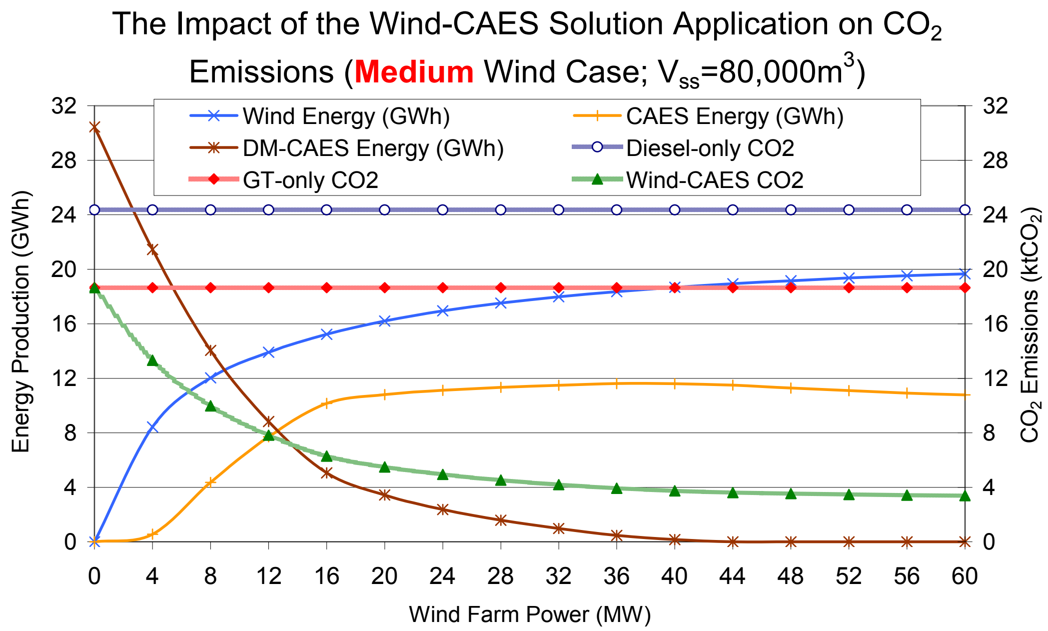


Figure 4.20: CO_2 emission savings vs CAES contribution (medium wind case example)

The parallel increase of the wind farm and the CAES system contribution, up to the point of 16MW, results in vast reduction of CO_2 emissions (from 18.6ktCO_2 for zero wind power to 6.3ktCO_2 for 16MW of wind power) that afterwards follows an asymptotic trend, depending on the increase of wind power and reaching a minimum level of 3.4ktCO_2 per annum. Therefore, CO_2 savings achieved in the case of energy autonomous Wind-CAES configurations are vast and can reach 85%.

The impact of storage capacity and wind potential on the resulting CO_2 emission savings is investigated (Figures 4.21-4.22) with the minimum and maximum storage volumes being set to V_{ss}=10,000m^3 and V_{ss}=100,000m^3 respectively. Since the employment of 10,000m^3 of storage capacity suggests considerable fuel savings (even exceeding 50% for the low wind potential scenario-Figure 4.14), the contribution of the Wind-CAES system to the reduction of CO_2 emissions is noticeable.

Depending on the wind farm capacity, the maximum emission savings achieved in comparison to the diesel-only solution correspond to 22ktCO_2 (high wind potential case); 20ktCO_2 (medium wind potential case); and 17ktCO_2 (low wind potential case). Moreover, the respective savings achieved by the Wind-CAES configurations when compared with the GT-only solution are 16ktCO_2 (high wind potential case); 14ktCO_2 (medium wind potential case); and 11ktCO_2 (low wind potential case). Finally, increase of storage capacity with the parallel increase of wind power capacity tends to eliminate the impact of wind potential in terms of annual CO_2 savings (Figure 4.22). This demonstrates the importance of the maximum exploitation of wind energy excess. The obvious outcome is that a suitably designed and configured Wind-CAES system can achieve significant CO_2 emissions' reduction in autonomous areas, independently of the local wind potential quality.

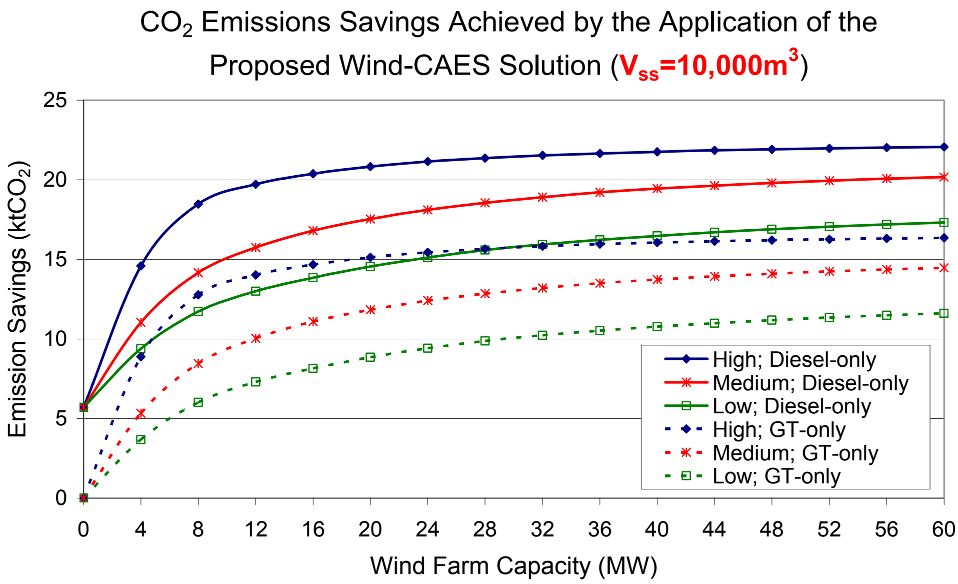


Figure 4.21: CO_2 emission savings from the application of the Wind-CAES solution (small-scale storage case)

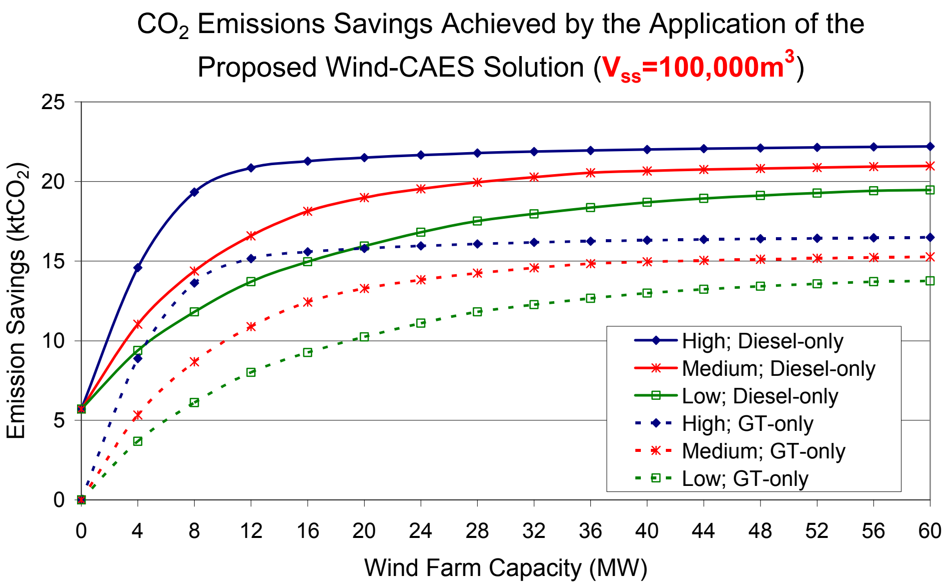


Figure 4.22: CO_2 emission savings from the application of the Wind-CAES solution (large-scale storage case)

Benefits for energy supply security

While it is an important issue for all regions, energy supply security is more pronounced in isolated electricity networks, such as islands regions. This is a result of their overreliance on imported energy resources and lack of resource diversity, with most islands meeting all of their energy needs such as transport, domestic heating and electricity generation, with fuel oil. As it has been demonstrated the immediate effect of the Wind-CAES system is the reduction in fuel consumption for electricity generation. At the same time, the impact on energy supply security of the island is also important, predominantly because the Wind-CAES system reduces import dependence. Furthermore, such schemes also increase dependence on wind energy which is indigenous. However, energy supply security is not just evaluated on the basis of dependence; diversity plays a key role as well. In this context, the introduction of natural gas and the larger role for wind both contribute to improved energy diversity. Even if a Wind-CAES system is installed, oil imports will continue on the island in order to sustain the transport sector, agriculture and domestic heating. Nevertheless, the benefits are not limited to improved energy availability. At least equally important is the reduced exposure to price volatility of natural gas and oil. Reduced consumption and higher diversity contribute to decreased vulnerability of the isolated communities.

4.1.7 Summary

Taking into account the recent discussion about the introduction of natural gas in island regions as well as the need to increase wind energy integration in these areas, the solution of Wind-CAES was thoroughly investigated. More precisely the proposed system considers not only the Wind-CAES operation but also the classic gas-turbine cycle. It does so in order to ensure high level of demand satisfaction without oversizing the system. For this purpose, a new calculation algorithm was developed and applied in an area of major interest, i.e. the Aegean Sea. To this end, three different areas based on their wind potential were examined. Their characteristics cover a wide range of low, medium and high wind potential areas met in the Aegean islands and elsewhere in the world. The proposed system entails considerable fuel savings and best utilisation of wind generation facilities. The corresponding financial benefits are significant since there is reduced fuel consumption and optimum infrastructure use. Concurrently, the reduced fuel use results in significant reduction of CO_2 emissions and control of the regional environmental degradation that fossil fuel-fired power generation bares. The environmental benefits are strengthened by the potential introduction of natural gas that could gradually substitute oil and thus provide a cleaner alternative fuel in other sectors than just electricity.

Finally, it is also noteworthy that the electricity sector in small islands can provide a testing field for investment growth as it can potentially feed into transport, domestic heating and desalination (Kaldellis and Kondili, 2007, Kaldellis et al., 2004). In this context a suitably configured Wind-CAES system can contribute to the broader energy independence of the islands, especially if considering that certain amounts of wind energy surplus cannot be stored due to available stotrage capacity limitations and thus could be exploited to feed secondary loads, electric vehicles etc. The positive impacts extend to improved energy supply security and subsequently water supply security (assuming investment in desalination).

4.2 Energy Storage and DSM to Increase RES Integration in Autonomous Grids

4.2.1 Introduction

Distributed generation (DG) can combine the operation of RES and energy storage technologies (Kaldellis and Zafirakis, 2007a). Owed to the variable generation characteristics of RES, oversizing is a common issue for such configurations to effectively cover the load demand of a remote area. Most off-grid local power supply of remote areas is based on the operation of oil-fired power stations, responsible for increased electricity production costs (Kaldellis and Zafirakis, 2007b) and polluting emissions. To this end, although up to now emphasis has been given to the optimum sizing of RES-based configurations from the supply point of view (Kaldellis and Zafirakis, 2012a), the concept of DSM has recently attracted the attention of several researchers (Moura and De Almeida, 2010; Pina, 2012). DSM refers to the use of a wide range of techniques (Figure 4.23), aiming to achieve a balance between electricity supply and demand. In fact, DSM mechanisms (Strbac, 2008) vary from direct-load control and load limiters, to time-of-use pricing and demand bidding programs. Furthermore, as Rae and Bradley (2012) point out, the greatest benefit of DSM is its ability to support improved performance and greater flexibility of renewable energy systems, which in the absence of support (provided by energy storage or DSM) introduce highly disruptive temporal mismatches between supply and demand. In this study a new DSM algorithm is developed based on the application of load-management techniques that will emphasize the potential for downsizing of RES-based energy storage configurations. More precisely, combination of peak shaving (clipping) and load shifting is applied at the system level, considering variable implementation level that the residential sector may reach. The developed methodology is accordingly applied to a small-medium scale island grid of medium-high quality RES potential, with our results indicating that the appropriate level of DSM application can yield considerable benefits in terms of energy autonomy and system size for both wind-storage and hybrid wind-PV-storage configurations.

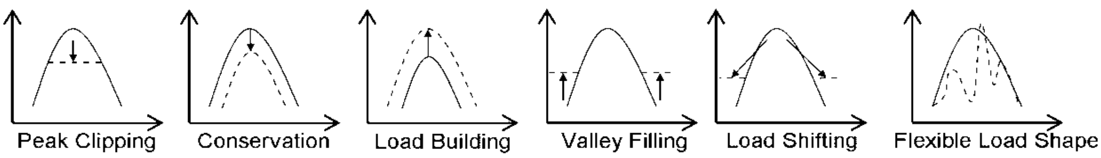


Figure 4.23: Different aspects of DSM

4.2.2 Methodology – Proposed Strategies

DSM techniques presently applied focus on peak clipping / shaving and load shifting during hours of lower load demand. More precisely, by determining the monthly peak load demand, a peak limit signal is used in order to cut load from the peaks and shift it in subsequent periods of lower demand. The maximum peak limit signal is determined as a percentage of the monthly hourly peak demand, while load shifting occurs under the precondition that subsequent loads can only be increased up to the maximum peak level selected, otherwise load cuts are accumulated. When load cuts cannot be shifted entirely, which in essence means that the revised load demand is lower than the respective original, the peak limit signal has to be reduced, up to the point that the current condition is satisfied.

Evaluation of DSM is accordingly undertaken using as a criterion the system size of different RES-based energy storage configurations. Extending an algorithm used for the sizing of hybrid wind-PV-storage configurations (Kaldellis et al., 2012), DSM is added in order to measure the impact of the latter in system sizing. At the same time, the energy autonomy level is recorded through the estimation of hours of load rejection per year. In this context, the parametrical analysis uses the size of main system components (i.e. installed capacity of wind and/or solar power along with energy storage capacity) as well as the maximum peak shaving limit signal.

4.2.3 Case study Characteristics

The methodology is applied to a typical small-medium scale island grid of the Aegean Archipelago Sea. The entire area of the Aegean Sea presents medium to high quality solar potential (1300-1800kWh/m^2.a) while several locations present medium to high quality wind potential (Fantidis et al., 2013; Vogiatzis et al., 2004). To this end, Figure 4.24a presents the RES potential of the entire Greek territory while in Figure 4.24b the load demand of the area under investigation is given. The annual energy consumption reaches approximately 11.2GWh with the respective annual peak load demand being equal to 3MW. Furthermore, hourly wind speed data used are provided in Figure 4.25a (annual average wind speed approaching 9m/sec), while Figure 4.25b gives the respective solar irradiance measurements, (total annual available solar energy at the horizontal plane being equal to ~1570kWh/m^2.a).

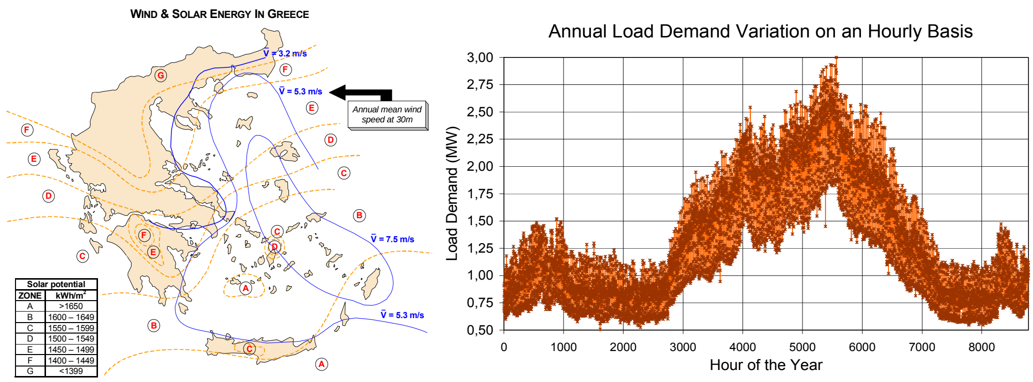


Figure 4.24: RES potential of the entire Greek territory (a) and annual load demand variation of a typical small-medium Aegean island grid (b)

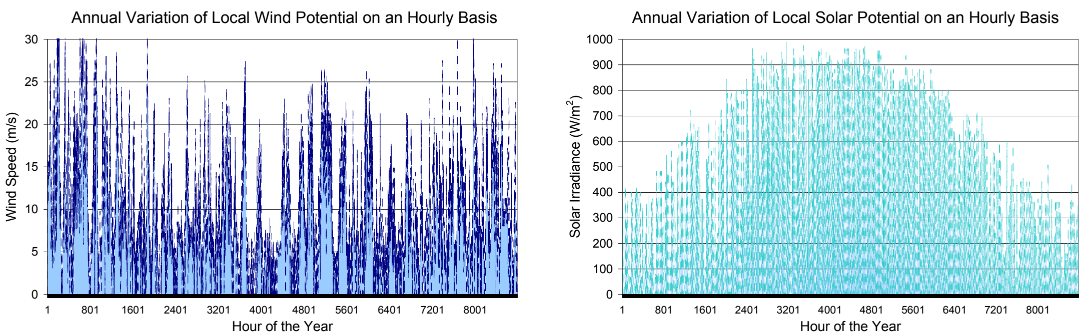
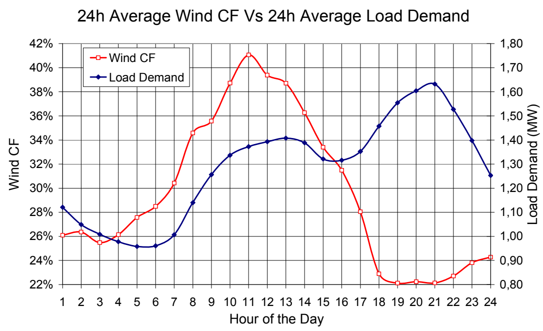


Figure 4.25: Annual variation of wind potential (a) and solar potential (b) for the typical area of investigation on an hourly basis

4.2.4 Application Results

The first application focuses on the examination of wind-energy storage configurations, employing battery storage of round-trip efficiency in the order of 65% and a maximum depth of discharge of 60%. The complementarity between the annual average 24 hour wind CF and load demand is illustrated in Figure 4.26a, where there is an inverse pattern with higher, night-time load demand coinciding with comparatively lower wind production periods. At the same time, in Figure 4.26b, the levels of seasonal complementarity are evaluated by comparing the respective daily averages of wind CF and load demand. According to the figure, the wind CF appears to be higher during the winter period and lower during the summer, i.e. when the load demand increases considerably, challenging in this way sizing of the storage component and thus encouraging investigation of DSM.



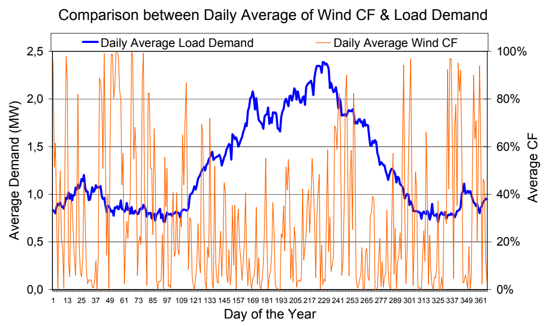


Figure 4.26: Comparison between wind CF and load demand on the average hourly (a) and daily (b) time scales

In this context, application of DSM could have significant impact on the dimensions of wind-battery configurations and energy storage capacity. Furthermore, in addition to the peak limit signal, a wind speed signal is also investigated in order to avoid implementation of DSM during hours of high wind speed. Illustration of the two DSM strategies, i.e. with (revised load-2) and without (revised load-1) the use of a wind speed signal is given in Figure 4.27 for a 30% peak limit signal.

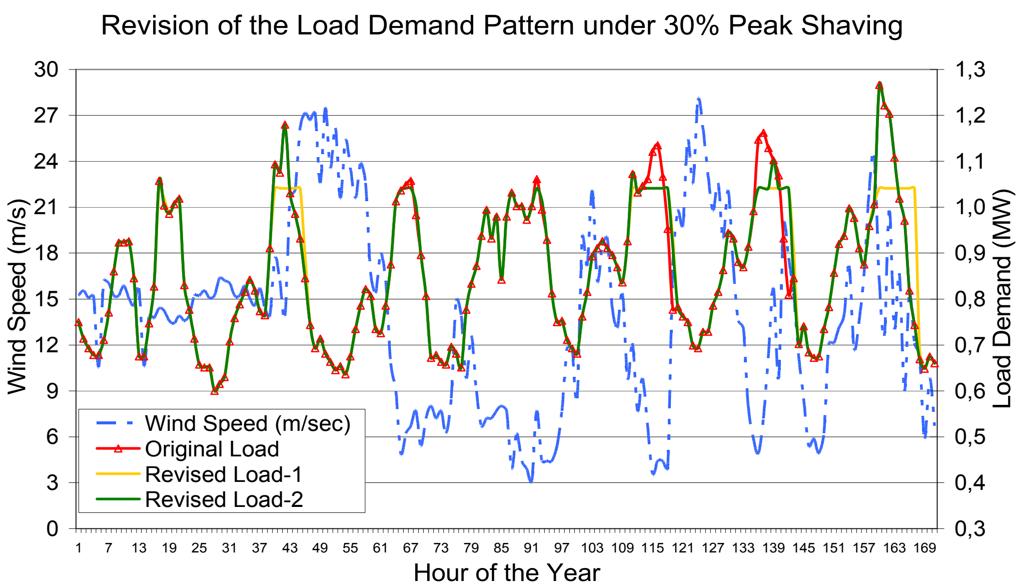


Figure 4.27: Revision of the load demand pattern vs wind speed variation

The wind speed signal is set at 12m/s and corresponds to the rated wind speed of the wind turbine, while the respective cut-in and cut-out speeds are 4m/s and 25m/s. Whenever demand exceeds 70% of the respective monthly peak demand, DSM is applied to reduce it to the desirable maximum load (i.e. 70% of the corresponding monthly demand). When the wind speed signal is activated, DSM (peak shaving) is permitted only when wind speed drops below 12m/s (see hours 37-45 and 160 to 167). By allowing for a variation range for the system i.e. wind power capacity between 10 and 24MW and energy storage capacity between 150 and 350MWh, the energy autonomy achieved by each of the examined combinations with and without DSM is presented (Figure 4.28a). Energy autonomy is measured in hours of load rejection due to insufficient wind energy production or low levels of energy stores. A peak shaving limit of 30% is found to have a significant impact on the hours of load rejection per year, even reducing them by 15%. Moreover, configurations of wind park capacity such as those exceeding 22MW while employing storage capacity of 350MWh could become completely energy autonomous, i.e. achieve zero load rejection. The impact of peak limit increase for two distinct configurations, i.e. a wind park of 10MW and 20MW, combined with a fixed storage capacity of 150MWh has been estimated (Figure 4.28b) while both strategies, i.e. with (Str2) and without (Str1) considering the wind speed signal are taken into account. To this end, the peak limit reduces load rejection hours only if it exceeds 26% (up to 10% load rejection is constant). However, in certain cases DSM has an adverse effect on energy autonomy since hours of load rejection appear to increase.

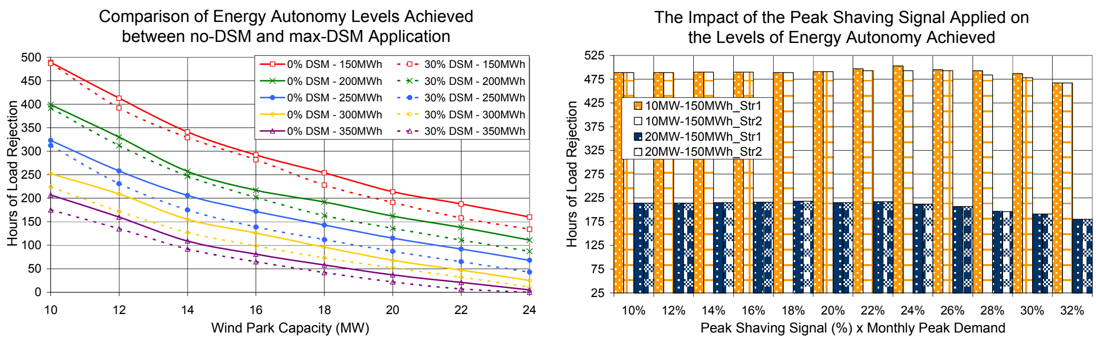


Figure 4.28: Energy autonomy levels achieved from a wind-battery system (a) and the impact of increasing the DSM peak limit (b)

Finally, the impact of the wind speed signal (Str2) has a positive but very small effect on load rejection reduction. Additionally, representative hybrid RES configurations, employing both wind and solar power have been tested (Figure 4.29).

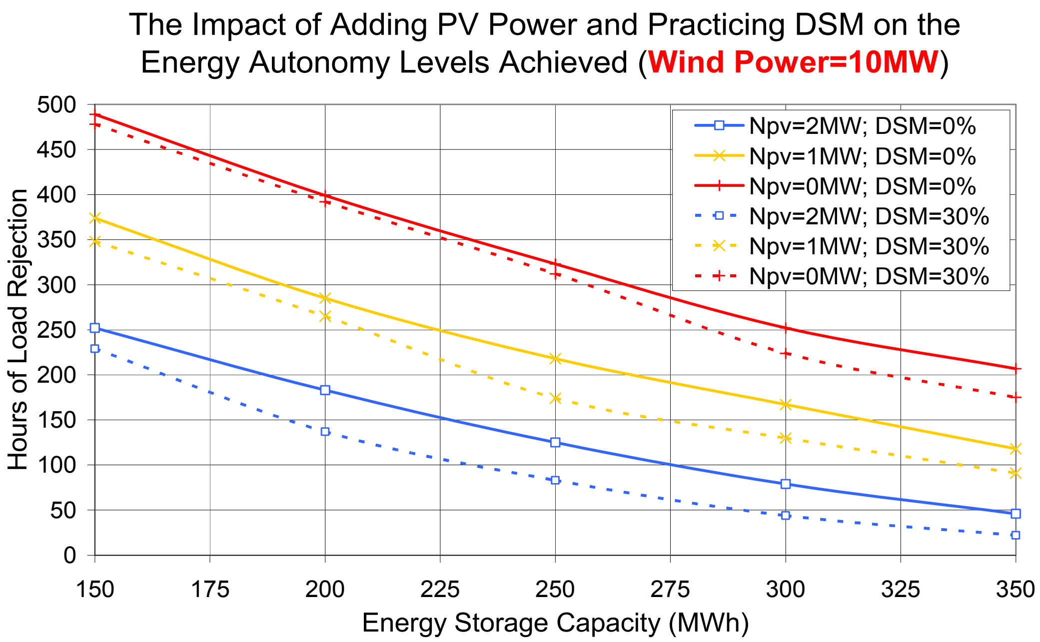


Figure 4.29: The impact of DSM on the energy autonomy achieved by hybrid wind-PV systems

More precisely, a fixed 10MW wind power capacity has been combined with 1MW and 2MW PV power and energy storage capacity varying between 150MWh and 350MWh. The extreme scenarios of 0% and 30% DSM application are considered, while for comparison purposes, the wind-only case (i.e. 0MW of PV power) is included. Despite the fact that addition of solar power reduces -in comparison to the wind-only case- load rejection considerably, the role of DSM remains important, especially for the medium scale storage capacity where DSM may even yield reduction of load rejection by 20%.

4.2.5 Summary

By applying peak shaving and load shifting techniques, the impact of DSM on the sizing of RES-based energy storage configurations is studied. For this purpose, a sizing algorithm for hybrid RES configurations is extended, through the addition of DSM attributes. The revised algorithm is accordingly applied to a typical remote island grid area of medium-high RES potential in order to measure the impact of DSM on system size and energy autonomy levels achieved. It is also demonstrated that the appropriate level of DSM produces substantial benefits in energy autonomy reaching up to 15% for wind-battery configurations. At the same time, despite the fact that addition of solar power increases the levels of energy autonomy considerably on its own, the role of DSM in the performance of hybrid wind-PV systems still remains important. To this end, further work is required to improve the effectiveness of prognostic tools so that they can expand the current ex-post approach considering perfect prognosis of both load demand and RES potential information. On top of that, the specific methodology can be further improved by considering specific time rules as well as the stochastic behaviour of electricity consumers if given the opportunity to adopt certain DSM attributes.

4.3 Conclusions

The main conclusions of Chapter 4 are synopsized in the following:

According to the application results obtained, the introduction of RES-based energy storage configurations in autonomous grids, where electricity is met by oil-based thermal power units, comprises a promising prospect for energy storage technologies, private actors and system operators. More precisely, owed to the increased electricity production cost in remote electricity systems, introduction of energy storage can prove cost-effective, depending of course on the available RES potential quality. As a result, all stakeholders could benefit provided that energy supply security is ensured.

On the other hand, if the local RES potential is not of medium to high quality, the energy storage components will have to be oversized considerably, implying significant increase of investment costs that can jeopardize the overall system cost effectiveness. In this context, DSM techniques can contribute to the downsizing of energy storage components and the achievement of increased security of supply under the application of a smart grid concept, calling for the active or passive participation of the demand side as well. Such concepts call for further advancements in the field of forecasting, which will lead to more effective and reliable power generation and demand management signals allowing for the optimum management of energy storage assets and especially battery storage.

Acknowledging the above, the implementation of similar projects and applications could use autonomous grids and island regions as ideal test-benches for the evaluation of various energy storage technologies' performance, challenged by the limited or entirely absent electricity interconnections.

5. Energy Storage Strategies at the Utility Scale / National Grid Level

Chapter 5 focuses on the development and evaluation of novel energy storage applications at the utility-scale, capturing different aspects of the role that energy storage can play at the level of national grids. For this purpose, PHS, comprising the most mature bulk energy storage solution is adopted in all three studies included in this chapter. These are:

1. Development and evaluation of a novel RES-energy storage strategy for the satisfaction of base load at the national grid level.
2. Investigation of the regulating capacity of bulk energy storage in electricity markets.
3. Development of a novel energy storage strategy linked with national, cross border electricity trade and embodied CO_2 emissions.

More precisely, in the first of three studies, PHS is used with wind power to replace base-load thermal power plants. For this purpose, the UK national grid is used and extensive simulations are carried out to examine the economically optimum level of base-load satisfaction by the proposed wind-PHS scheme. Similar configurations are expected to effectively support the increased RES integration under secure terms of operation, while also eliminating a large share of the variable RES power generation handled by system operators.

In the second study, the regulating capacity of bulk energy storage assets for electricity market operation is investigated. Energy storage is seen from the system operator point of view, and aims at the satisfaction of certain goals such as increased energy diversity and independence, lower CO_2 emissions, moderate spot price volatility, etc. The Greek electricity market is selected to demonstrate the potential of energy storage to perform such grid services. PHS and wind are used to stress base-load power generation at the expense of more expensive peak power plants. In this way, the regulating potential of energy storage is studied in relation to the employed capacity and the specific grid characteristics, with interesting results arising with regards to the conflicting character among different optimization goals for the system operator.

Finally, in the third study the role of energy storage is investigated in relation to cross-border, national electricity trade and the underlying trade of embodied CO_2 emissions. In this context, the entire European network is studied in order to reassess the map of national CO_2 emissions, considering also cross-border electricity trade. Accordingly, using the national potential of PHS, an exercise is performed to define optimum levels of energy storage capacity that can "protect" cleaner countries from the more carbon intensive ones. The proposed concept lies on the idea that energy storage could be used for cleaner countries to limit clean exports in an effort to avoid CO_2-intensive imports. The results are evaluated economically and the respective CO_2 tax that could marginally support investments in the field is estimated.

Finally, the same approach concerning modelling, simulation and valuation of the strategies investigated as in the previous two chapters is followed, which is defined as deterministic/retrospective, meaning that use of past (historical) prices patterns is considered in order to evaluate the performance of the configuration each time examined.

5.1 Base Load Strategies for Utility Scale, RES-based Energy Storage

5.1.1 Introduction

Security has become an increasingly important topic in societal sciences, as we enter a post-normal period, characterised by complexity, chaos and contradictions and during which uncertainty and high-risk affect many decisions (Sardar, 2010). The security of energy supply is a key priority for both developed and developing countries (Brown and Sovacool, 2012; Chalvatzis and Hooper, 2009; Nuttall and Manz, 2008; Söderbergh et al., 2010; Winzer, 2012). Imbalanced availability and the accessibility of global energy resources produce inequalities and give rise to more frequent energy crises (Alpanda and Peralta-Alva, 2010; Stegen, 2011). This is also true for other resources and there are now increasing issues around water and food security (Beck and Walker, 2013; Lobell al., 2010). The risk of exposure to such crises needs to be minimized.

To facilitate a secure future energy supply, there is a need to develop new, more efficient and sustainable patterns of supplying energy (Smith et al., 2013; Turton and Moura, 2008; Zafirakis and Chalvatzis, 2014) and arguably, the large-scale introduction of RES has been the greatest shift towards a sustainable future (Kaldellis and Zafirakis, 2011). Wind power and solar energy have come a long way, with utility-scale wind energy and PV installations reaching grid parity (Lund, 2011). Despite the progress exhibited during this period, the contribution of renewable energy generation is still limited. The main reason is the inherent deficiencies of such technologies, with their performance largely depending on the instantaneous availability and intensity of the primary energy resource (e.g. wind speed, solar irradiance, etc) (Rahimi et al., 2013). It is this variable or even stochastic nature of RES that limits their potential to replace fossil-fuelled power generation.

Acknowledging uncertainty as a major obstacle to effective decision making and taking into account that certain power generation technologies are, or may soon reach, a stage of saturation in terms of technological progress (Islam et al., 2013; Kaldellis and Zafirakis, 2012b), it is argued that "architectural innovation" (Henderson and Clark, 1990) rather than radical or discontinuous innovation could now be a better approach in the energy sector (Winskel et al., 2013). Architectural innovations are reconfigurations of existing products, created through new interfaces between existing components. The technological basis of the components remains largely unchanged. This approach can integrate different, mature technologies to produce higher efficiency under reduced risk (Zhang et al., 2013). Such integrating approaches support the notion of a near steady-state technological transition that puts emphasis on optimizing or incrementally improving existing solutions through the application of novel integration strategies (Hyard, 2013). Architectural innovations tend to fit within the existing regimes of innovation and require reconfigurations of existing solutions and technologies, rather than the development of totally new technologies, and yet they can lead to significantly different and innovative concepts (Kern, 2012; Negro et al., 2012). For this study, an approach termed interindustry architectural innovation, defined as the first-time configuration of existing technologies from different industries or sectors, will be used (Jaspers et al., 2012).

Using this concept of interindustry architectural innovation, this research combines two established electricity technologies under novel terms of integration with the first one, i.e. wind energy, coming from the RES sector, and the second one, i.e. PHS, coming from the energy storage sector. The improved characteristics of the proposed integrated solution are identified and by considering broad adoption and diffusion, its potential for increased energy supply security is presented. The UK is used as a case study because of its commitment to decarbonisation and the ongoing electricity market reform (UKDECC, 2013a), while the implementation of a novel strategy concerning supply of base-load electricity through the combination of wind power and PHS installations is proposed. At the same time, an explicit parametrical analysis that considers a number of retrospective scenarios for the UK energy system is undertaken, including the investigation of different scale base-load supply along with variation of wind power and PHS capacity. The scenarios are then evaluated under the application of different criteria (e.g. environmental and economic indicators), with emphasis given to the discussion of energy security benefits, deriving from the increased participation of wind power and its secure, base-load supply through the employment of energy storage.

Following the introductory section, this chapter continues with a short discussion on the integration of wind energy and energy storage in section 5.1.2. Section 5.1.3 analyzes the proposed base-load wind energy storage strategy, while in section 5.1.4 the electricity sector of UK is described and the methodology is discussed. Finally, in section 5.1.5 of the chapter, the results are presented and the chapter concludes in section 5.1.6.

5.1.2 Wind Energy and Energy Storage

For the last twenty years, there has been tremendous growth in RES and wind energy in particular (Dincer, 2011). The cumulative world-wide installed wind capacity has now reached 280GW (2012), with ambitious targets (e.g. 400GW in the EU by 2030) signalling a growing need for the large-scale integration of wind energy. However, the considerable progress in wind energy technology (Kaldellis and Zafirakis, 2011) has not yet resolved the question: Can wind energy and other RES shift from the side lines of conventional thermal power and support a reliable and secure electricity supply?

Until recently, wind energy and other RES enjoyed the privilege of acting as ancillary power sources. This allowed them to obscure their inherent limitations that would be more pronounced if they were required to play a greater role (Georgilakis, 2008). More specifically, large-scale integration of wind energy entails that a significant proportion of electricity generation relies on a stochastic and intermittent energy supply source which cannot always meet demand. As a result, support has to be provided mainly through the introduction of flexible, back-up power capacity (usually fuel-based) that can compensate for any sudden loss of wind energy production. In addition, large-scale wind energy integration may impact negatively on power quality in vulnerable electricity grids (Singh et al., 2011). In terms of market operation, it can also result in increased spot price volatility and extreme price events (e.g. spikes), when wind energy production is not adequate to meet the inelastic electricity demand (Green and Vasilakos, 2010). Finally, there are also cases when wind energy output cannot be absorbed by the grid either because of low demand or because of inadequate flexible back-up power.

Some research studies have sought solutions to achieve large-scale integration of wind energy by developing or adjusting various methods and support tools for the realization of such a scenario (Chen et al., 2014; Tian et al., 2011). Dominant and ready-to-use solutions, in addition to flexible thermal power generation, include DSM (Moura and De Almeida, 2010), broad geographical dispersion of wind power (Drake and Hubacek, 2007), upgrade of cross-border transmission (Weigt et al., 2010) and utility-scale energy storage (Hasan et al., 2013). Amongst these, increased interest has recently been noted in energy storage (Zafirakis, 2010), largely encouraged by the introduction of distributed generation and smart grids which challenge current electricity supply patterns (Wade et al., 2010).

Research in energy storage is ongoing and focused on both mature (e.g. PHS and battery storage) and newer technologies (e.g. hydrogen-based storage, advanced batteries etc.). These technologies come with a set of different scale applications in every stage of the electricity supply chain (i.e. generation, transmission, distribution and demand). Some of the most common applications (Figure 5.1) are energy management, spinning reserve, grid frequency control, and transmission/distribution deferral through better exploitation of existing grid assets, with all of them encompassing support of RES at some level.

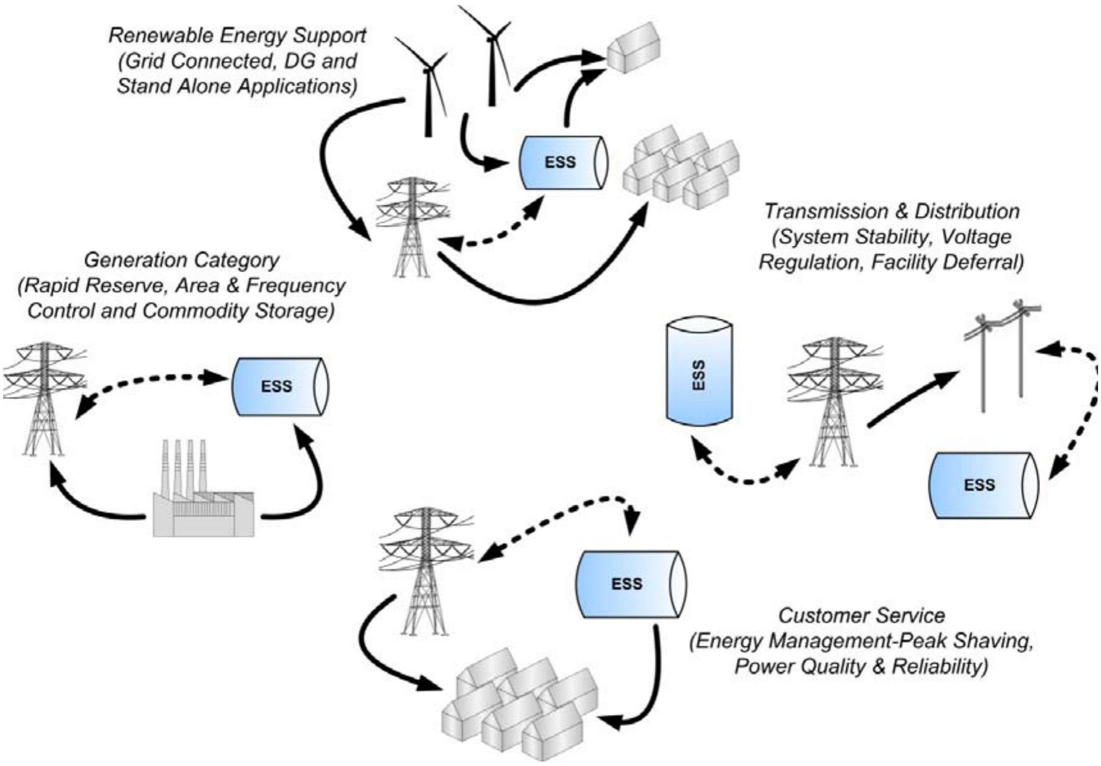


Figure 5.1: Energy storage applications

Although energy storage can provide multiple services, the absence of concrete rules and regulations about the operation of such systems in electricity grids hinders expansion of the energy storage market. This was recently elevated by many researchers studying the performance of prospective, private-owned energy storage (Sioshansi et al., 2009; 2011). According to their results, the value stemming from arbitrage (i.e. the most commonly studied service of energy storage concerning application of energy trade strategies in the spot market) provides an inadequate investment incentive. For this reason, the welfare attributes of energy storage (e.g. contribution to the increased penetration of green energy) need to be taken into consideration to stimulate the development of appropriate financial support tools and policies (Zafirakis et al., 2013). The role of energy storage to support wind energy has been established, with the investigation of several different scale configurations reflecting the potential of several technologies to do so (e.g. wind-PHS, wind-CAES, wind-battery, etc.) (Kaldellis and Zafirakis, 2007a; Kapsali and Kaldellis, 2010; Zafirakis and Kaldellis, 2010). These applications are predominantly recommended for either isolated (off-grid) consumers or communities relying on weak grids (Zafirakis and Chalvatzis, 2014).

On the other hand, the relatively limited participation of wind energy in the electricity fuel mix of most countries has not yet made grid-scale energy storage necessary. This validates the argument of Purvins et al. (2011), raising the issue of the improper management of otherwise available solutions. In this context, it is argued that the welfare attributes of energy storage could become useful, i.e. reach the wider society of consumers, only if applied at the grid level, rather than at the installation/private actor level. Moreover, it is suggested that the integration of existing technologies can, under the application of novel integration and operation strategies, support the concept of interindustry architectural innovation and promote energy supply security. For this purpose, the case for the integration of wind power and PHS is put forward as explained in the following section.

5.1.3 Case Study

The Achilles' heel of wind power lies in its stochastic availability and variable output. Certain energy storage strategies have been put forward to support the further penetration of wind energy. They most commonly suggest that excess wind energy can be used to diurnally charge energy storage systems. Subsequently, the stored energy can be used instead of thermal peak power units. It is important to mention at this point that existing studies (e.g. Kapsali and Kaldellis, 2010; Madlener and Latz, 2013) have focused on the installation and private investor's point of view using profit maximization as their main objective. Although in that case the utilization factor of the energy storage facility is low, since it operates only during peak demand hours, profitability could be counterbalanced by the increased electricity production cost of peak power plants that are replaced (Zafirakis et al., 2013). However, such energy storage strategies support only moderate wind energy contribution. In this context, the large-scale wind energy contribution that can be achieved with the use of novel integrated wind energy and storage systems could serve goals such as increased energy security, market and system regulation and the achievement of national RES and climate change targets. Energy storage comprises a regulating asset of the electricity grid that alongside other applications (e.g. peak shaving, frequency control, transmission deferral, etc.) can provide the flexibility required to facilitate the increased penetration of wind energy.

Our recommendation is for the integration of wind energy and energy storage to support base-load generation and to contribute to energy supply security. It is argued that the combined operation of wind power and energy storage at a national level could provide reliable capacity. This can be achieved by the use of dedicated energy storage facilities that eliminate a considerable part of the stochastic wind energy production and turn it into steady power output throughout the year. This approach benefits energy security at a national level, primarily by increasing the contribution of wind energy which is an indigenous resource. It minimizes the drawbacks of stochastic wind power generation and can replace fossil fuel-based power plants that rely on energy imports. The extent to which this strategy can be applied is a question of optimization of the most important criteria together with system boundaries and the characteristics of the technologies involved.

The technology of PHS

In terms of energy storage technology pumped hydro is selected. PHS is by far the most mature energy storage technology, with a global capacity of approximately

130GW (i.e. almost half the capacity of wind power) (Deane et al., 2010) and a relatively abundant potential when compared to other energy storage options. It is estimated (Gimeno-Gutiérrez and Lacal-Arántegui, 2013) that the realizable potential in the EU reaches 80TWh, which is equivalent to 2.5%-3% of the respective annual electricity consumption. Stated differently, if fully exploited, the PHS potential can provide the entire EU with electricity autonomy of 10 days.

The first PHS plants were built in the 1930s. With the introduction of nuclear power, the operation of PHS to recover excess nuclear power generation during low demand periods became necessary in countries such as Japan and the USA. Nowadays, due to the recently increased interest in energy storage, a detailed mapping of PHS potential across different regions is available (Gimeno-Gutiérrez and Lacal-Arántegui, 2013). This, along with the relatively low specific installation cost of bulk scale energy storage PHS systems, offers energy storage solutions for various applications, potentially including wind energy management at the grid-level.

PHS reliability is already demonstrated, since it is based on technology similar to that used in hydro power plants. More precisely, in a PHS system the energy surplus in times of low demand, either deriving from the electrical grid or any given generation unit (such as wind parks), is exploited to pump water into an upper reservoir with the use of pumps or reversible hydro-turbines. During peak demand, water is released from the upper reservoir and hydro-turbines operate to produce electricity. As a result, the system is able to cover appearing deficits with energy previously stored. The cycle efficiency of modern PHS is in the order of 70-80% (Bjarne, 2012; Rangoni, 2012), while such systems are able to take up load in just a few seconds and they also feature a high rate of extracted energy. In general, PHS systems are suitable for applications of energy management, spinning reserve and frequency control; thus, they are also suitable to support large-scale wind energy integration (Anagnostopoulos and Papantonis, 2008; Bueno and Carta, 2006; Kaldellis et al., 2010; Katsaprakakis et al., 2012).

The UK as a case study

The United Kingdom (UK) has ambitious targets for RES integration, which is planned to reach 15% of the UK total energy consumption by 2020 (UK Government, 2009). At the same time, the discussion about the UK's electricity sector decarbonisation by 2030 is due for 2016 (UKDECC, 2013b). In the longer term, the UK has committed to reducing its total emissions by 80% between 1990 and 2050 (UKDECC, 2008). In addition, the UK's electricity sector suffers from a forthcoming production capacity reduction due to the planned shutdowns of aging power stations and environmental restrictions (European Parliament and Council, 2011) imposed predominantly on its coal-fired power stations (Office for Gas and Electricity Markets, 2013).

In this context, it is estimated that over the next decade, the UK's electricity sector will need approximately £110 billion of capital investment that will be used to secure energy supply (UKDECC, 2013b). Renewable energy is expected to play a key role, assisted by the fact that the UK has excellent quality of onshore and offshore wind energy potential. At the same time, the local PHS potential is substantial, at approximately 5.3TWh (Gimeno-Gutiérrez and Lacal-Arántegui, 2013). Energy storage, which comprises the core element of the suggested model, has been advocated and considered within UK political discussions (Parliamentary Office of Science and Technology, 2008), while the UK hosts a number of pioneering projects in this specific field (ESA, 2013; EurActiv, 2013). It is thus this combination of natural resources and policy complexities that makes the UK an excellent test-field for the application of the proposed base-load wind energy storage strategy.

Currently, the power generation system of the UK is largely dependent on imports of energy resources such as coal, natural gas and uranium (Table 5.1). In 2012, the UK imported approximately 65% of its coal, 45% of its natural gas and 100% of its uranium, which together with direct electricity imports led to a total electricity sector dependence of approximately 64% (UKDECC, 2012). Moreover, the diversity of the national electricity fuel mix is low since coal, nuclear and gas provide nearly all of the generating capacity (with a combined share of 90%) (Figure 5.2).

Therefore, in the long term, the power sector is exposed to the volatile prices of the respective options, which may present severe fluctuations in the future. For example the evolution of the UK natural gas spot price and the French electricity spot price affect the gas-fired power generation and cost of imports from the UK-France interconnector (Figure 5.3). As a result security and efficiency are jeopardized, while at the same time the national CO_2 emission factor of approximately 475gr/kWh compares unfavorably with the average of OECD European countries, in the order of 330gr/kWh (IEA, 2012).

Table 5.1: Import-based energy supply characteristics by fuel type (ELEXON, 2013; IEA, 2012; UKDECC, 2012).

Fuel type	**Supply Share**	**CO_2 Emission Factor (gr/kWh)**	**Imports' Share**
Coal	43.2%	800	65%
Natural gas	26.1%	420	45%
Nuclear	20.7%	0	100%
Oil	0.01%	670	30%
Electricity Imports	4.2%	-	100%

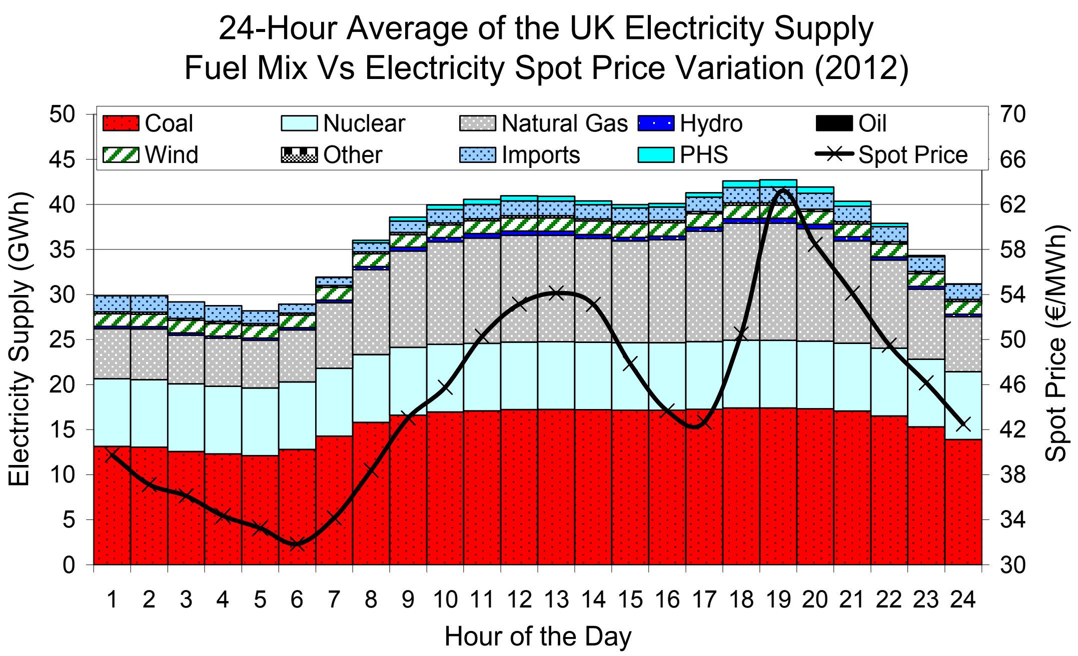


Figure 5.2: Mean hourly electricity supply fuel mix and spot price for the UK in 2012

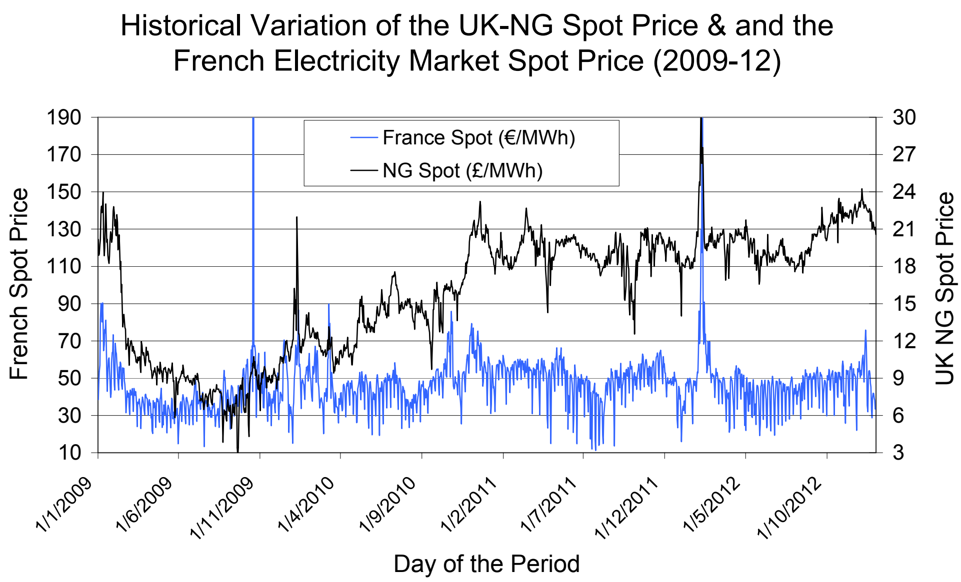


Figure 5.3: Different aspects of exposure for the UK national electricity sector

5.1.4 Methodology

<u>*Innovative operation of wind energy and energy storage*</u>

For the application of the proposed strategy, the detailed CF of the UK wind parks on an hourly basis for an entire year is determined, using electricity supply data from Elexon (ELEXON, 2013) and the daily time evolution of installed wind power capacity for the same period (Renewable UK, 2013) (Figure 5.4).

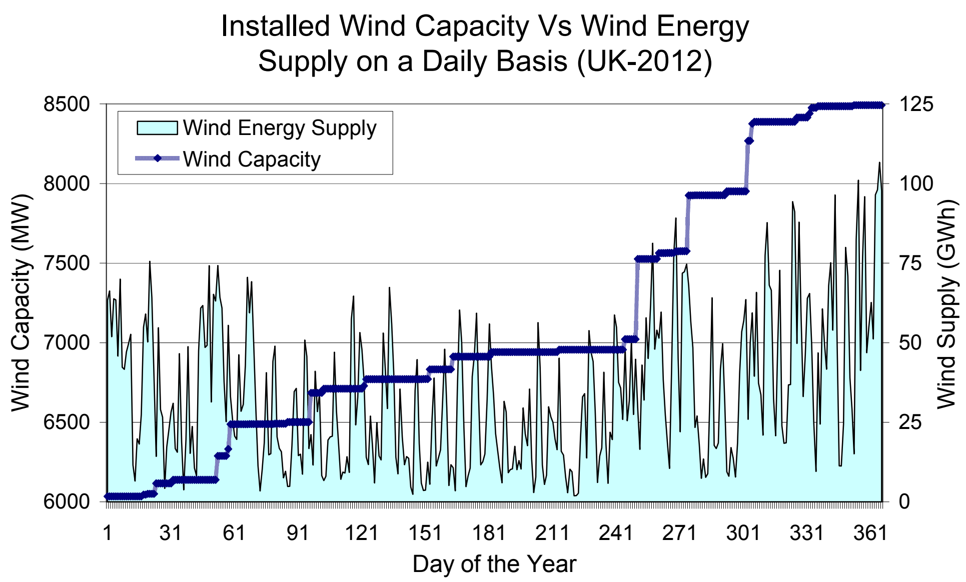


Figure 5.4: Daily variation of wind capacity and wind energy supply for UK (2012)

Next, wind energy supply results are produced using the detailed CF pattern and the variable wind power capacity, different base-load scenarios and the variable energy storage potential. Electricity demand data for 2012 (ELEXON, 2013) is used to estimate the economic, environmental and energy security performance results. Finally, energy losses during the conversion stages of PHS operation are determined by a round-trip efficiency of ~77%, and an average elevation of 390m is adopted (Gimeno-Gutiérrez and Lacal-Arántegui, 2013). In detail, the methodology includes the following steps:

- Estimation of hourly wind energy CF ("CF_i") at a national level for the entire year of 2012, using the respective wind power output "E_{wi}" and the daily evolution of wind power capacity "N_{wj}", i.e. $CF_i = E_{wi} (N_{wj} \cdot \Delta t)^{-1}$, with "Δt" being equal to 1h.
- Use of the wind energy CF pattern to produce new hourly wind energy production "E'_{wi}" under the assumption of variable installed wind power capacity "N'_{wi}".
- Comparison of the extra wind power output (on top of the already available) with the respective base-load requirement on an hourly basis from the combined operation of wind parks and PHS facilities.
- In the case of excess wind energy production, PHS is called to absorb it until fully charged. Further wind energy surplus, i.e. after PHS is fully charged, is considered to be fully curtailed, although this suggests an extreme case scenario.
- In the case of wind energy deficit (wind energy production is insufficient to cover the base-load demand), PHS is called to contribute the missing energy.
- The output of the combined wind power and PHS solution under the base-load condition is used to replace thermal power plants of equivalent contribution, giving priority to the replacement first of coal and then of natural gas power stations.
- Execution of a parametrical analysis focusing on wind power capacity, energy storage capacity and base-load output.
- Evaluation of each different configuration on the basis of economic, environmental and energy security criteria.

Estimation of energy security using supply diversity

Similar to the approach of Stirling (1994) and Grubb et al (2006), the Shannon-Wiener (SWI) and Herfindahl–Hirschman (HHI) indices are used to measure electricity sector diversity (see also equations 5.1 and 5.2).

$$SWI = -\sum_{f=1}^{n} e_f \cdot \ln e_f \tag{5.1}$$

$$HHI = \sum_{f=1}^{n} (e_f \cdot 100)^2 \tag{5.2}$$

In this context, "e_f" represents the electricity supply contribution share (per cent values) by fuel type "f" (e.g. coal, natural gas, nuclear, wind energy, etc.) over a number of "n" fuels, using the aggregated result of the respective hourly fuel mix dataset. Essentially, HHI is a measure of concentration and SWI is a measure of diversity; thus HHI decreases and SWI increases when diversity increases. When HHI is below 1500, the result suggests moderate-high competitiveness, while HHI>2500 suggests moderate-high concentration. Moreover, an increase of SWI further than 1.5 implies a relatively diverse fuel mix, with its reduction well below that point signalling non-competitive characteristics (Grubb et al., 2006).

Estimation of energy security using the electricity sector dependence

The electricity sector dependence is estimated as the sum of dependence on direct electricity imports and imports of energy resources that are used for electricity generation.

$$DI = D_e + D_f = \sum_{f=1}^{n} e_f \cdot d_f \tag{5.3}$$

Therefore "*DI*" is the electricity dependence index of a country, "D_e" is the dependence on direct electricity imports and "D_f" is the dependence on primary fuel imports for electricity generation. To this end, "*DI*" may also be expressed as the sum-product of the contribution "e_f" of each fuel type (including electricity imports) to the overall electricity supply multiplied by the specific fuel's import share "d_f" (Chalvatzis and Hooper, 2009).

<u>*Cost assessment*</u>

PHS investments are capital intensive and their specific cost (cost per installed capacity) can be estimated in relation to their potential to allow autonomous operation for periods when there is no wind energy generation (i.e. hours of full-load operation, related to the power output they need to fulfil). The available elevation "*H*" (including losses) and storage volume "*V*" are the two main parameters determining the energy storage capacity "E_{PHS}" of such systems (see also equation 5.4 where "ρ" represents water density and "*g*" is the gravitational acceleration).

$$E_{PHS} = \rho \cdot g \cdot V \cdot H \tag{5.4}$$

The hours of energy autonomy "*h*" correspond to the time period (successive hours) that the system can release energy at its nominal power output "N_{PHS}" (equal to the base-load output) using its exploitable/net energy storage capacity. The efficiency of PHS "η_{out}" is considered to be 90% and the maximum depth of discharge "*DoD*" is equal to 90% (see also equation 5.5).

$$h = \frac{E_{PHS} \cdot \eta_{out} \cdot DoD}{N_{PHS}} \tag{5.5}$$

The specific cost of different configurations, considering variation of the available elevation and the hours of autonomy that the system can cover, is given in Figure 5.5, taking also into account that the average elevation for the UK is estimated at 390m (Gimeno-Gutiérrez and Lacal-Arántegui, 2013).

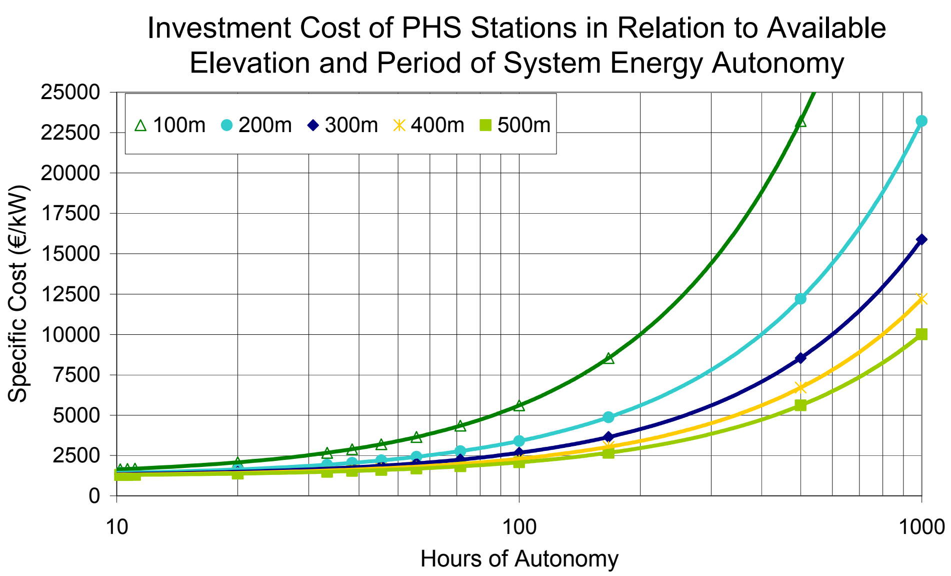


Figure 5.5: Variation of PHS investment cost in relation to system energy characteristics

Using the aforementioned information, both the investment and the LC (e.g. 20 years) electricity production cost (€/kWh) can be estimated. To this end, the annual M&O coefficient is taken under consideration as a share of the initial investment (Table 5.2), while for the investment cost of the installed wind power capacity to be estimated, the specific cost used captures the shift towards offshore wind power (Toke, 2011) (see also Table 5.2). At this point it is important to note that introduction of offshore wind power is expected to signal improved performance of the national, average wind power production (since high quality wind potential will be exploited), suggesting in this way that the wind CF profile currently adopted can be considered as pessimistic.

Table 5.2: Main input cost parameters (Kapsali and Kaldellis, 2012)

Cost parameter	**Assigned value**
Specific cost of wind power (€/kW)	1700
Service period of PHS (years)	20
Annual M&O cost factor (% of investment cost)	5%

5.1.5 Application Results

Based on daily data about the development of installed wind capacity in the UK (Renewable UK, 2013) and the respective wind energy supply for 2012 (Figure 5.4), the national wind power CF is calculated (Figure 5.6). The hourly wind park CF follows a seasonal variation that is similar to the variation of electricity demand (Figure 5.7).

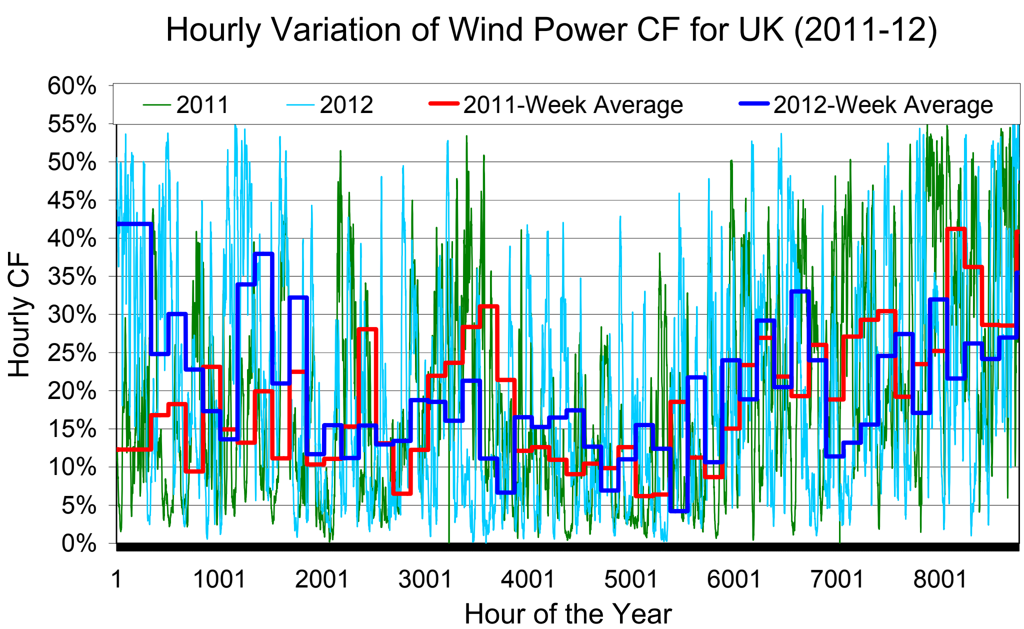


Figure 5.6: Detailed CF of wind parks operating in UK

The wind energy output (Figure 5.7) refers to that segment which was absorbed by the grid; thus it excludes wind energy curtailments. In this context the similarity in seasonal variation implies that the system operator may, in periods of low demand, choose to curtail part of the wind energy production. The outcome of this practice produces a relaxed –during the middle of the year- weekly average CF, which coincides with the summer season of lower demand.

The wind energy hourly CF of 2012 is used to implement the base-load wind energy storage strategy in which our parametric analysis integrates the variability of wind energy capacity, storage capacity and base-load output (Table 5.3). For wind energy capacity, the selected range is between 10 and 50GW on a 5GW step. This compares with approximately 8.5GW that were operational in the UK by the end of 2012, also included in the analysis. The storage capacity is considered to be 200, 500 and 1000GWh, which compares with current PHS capacity of ~30GWh (Strbac et al., 2012) and which also corresponds to ~0.23, 0.57 and 1.14 days of autonomy (if taking into account the daily average load demand of the UK national grid). Finally, the base-load that our integrated system can satisfy is targeted to 1.5, 3, 5 and 7GW which compares with the minimum expected load demand of approximately 20GW (see Figure 5.2).

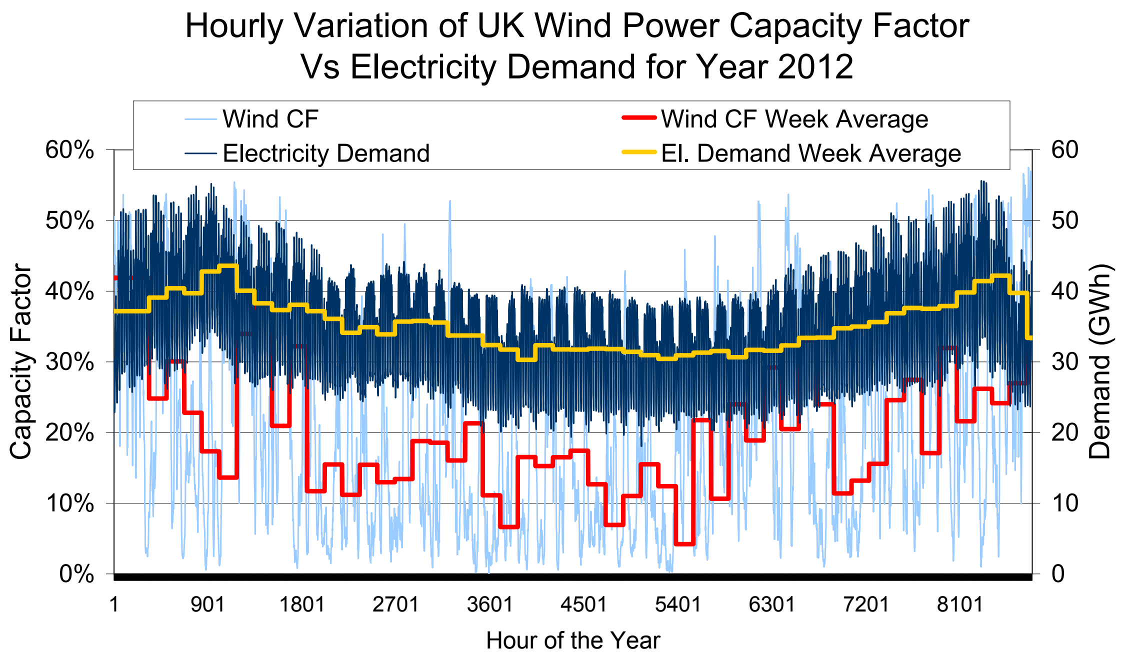


Figure 5.7: Detailed CF of wind parks operating in UK in relation to the respective national load demand

Table 5.3: Parametrical analysis input values

Parameter	**Range of Variation**
Wind Energy Capacity (GW)	10-50 at a step of 5GW
Storage Capacity (GWh)	200; 500;1000
Base-Load (GW)	1.5; 3.0; 5.0; 7.0

Energy management

Each of the examined configurations is simulated on an hourly basis for the entire year of 2012 (see for example Figure 5.8) and is evaluated for its potential to satisfy a certain base-load condition. Unless it does so, hourly base-load rejections per year are recorded (Figure 5.9a) and they reflect the number of hours per year that the base-load condition cannot be satisfied by the combined operation of wind power and energy storage. When the annual base-load rejection is zero, the examined configuration satisfies the base-load condition set and is able to respond to that year-round. Another way of expressing the ability of different configurations to satisfy the base-load is by recording the annual energy deficit, i.e. the aggregated amount of energy (given as a percentage of the annual energy that is delivered to the local grid under the base-load condition) (Figure 5.9b).

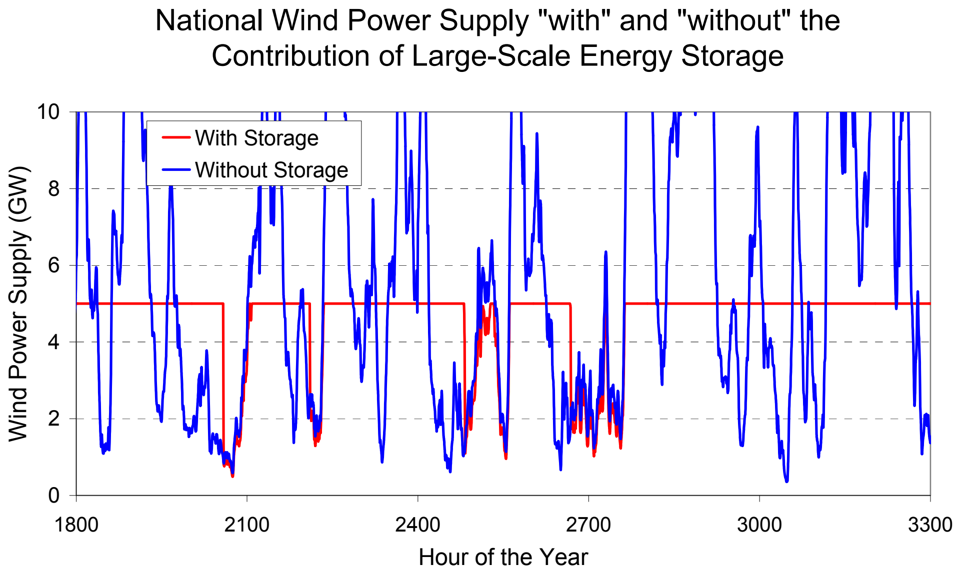


Figure 5.8: Difference between the "with" and "without" energy storage wind power supply patterns (Scenario of 5GW base-load, 40GW wind power and 500GWh storage capacity)

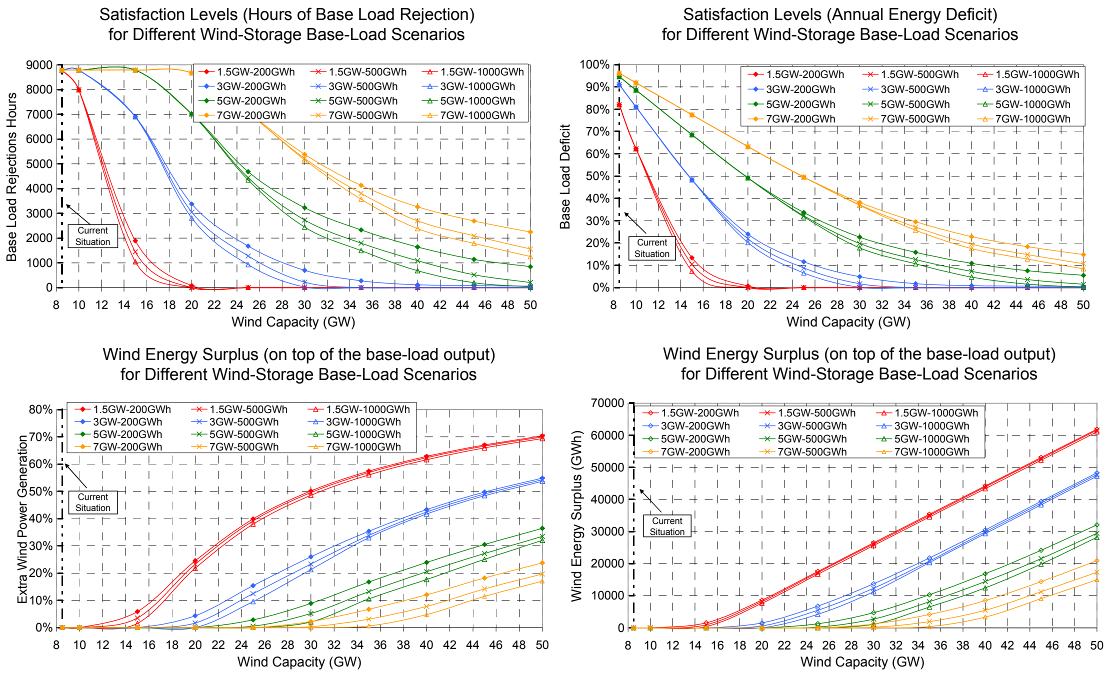


Figure 5.9: Base load satisfaction and energy surplus in relation to the application of different wind-energy storage base-load scenarios

In this context, a parallel increase of wind power and energy storage capacity leads to the gradual reduction and elimination of the energy deficit. This according to Figures 5.9a and 5.9b implies that the base-load condition is satisfied throughout the entire year for base-load output of up to 5GW. At the same time, even when the base-load is assumed to be 7GW, the respective energy deficit does not exceed 10% for the higher energy storage capacity examined (i.e. 1TWh).

It is also possible that after the base-load condition is met, a certain amount of wind energy may not be used for storage, because the available (remaining) storage capacity at that time is inadequate. As expected, this wind energy surplus (see also Figure 5.8), expressed as either the total amount of non-stored wind energy (Figure 5.9c), or its share in the total wind energy supply (Figure 5.9d), is found to increase considerably with the reduction of the base-load output. The increase of the wind energy surplus suggests less frequent operation of PHS, which essentially occurs for the lower base-load output requirements, increasing also the possibility of wind energy curtailments. Furthermore, the percentage of wind energy surplus may even reach 70% of the total wind energy generation for the case of 1.5GW. To this end, it should be underlined that to achieve high levels of energy security, predominant interest should be placed on those configurations that both satisfy an increased base-load requirement and eliminate the surplus of wind energy production, since the latter implies an increased probability of wind energy curtailments, currently considered to be valid for the entire amount of surplus, considering an extreme case scenario in our analysis.

The results of Figure 5.9 are provided in Figure 5.10 as well, this time conveying a more general aspect. More precisely, instead of the absolute values used in Figure 5.9, in Figure 5.10 wind capacity is expressed as a percentage of the local grid annual peak demand, energy storage capacity as hours of autonomy comparing with the average hourly load of the national grid, and finally, base-load provided by the system as a percentage of the local grid annual peak demand.

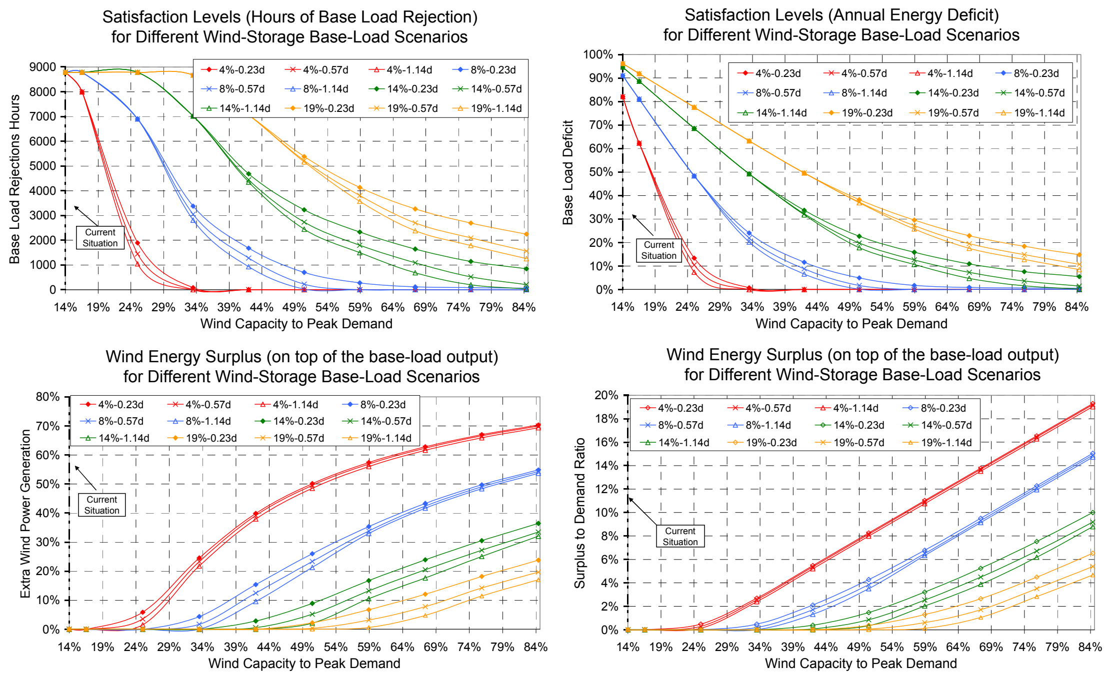


Figure 5.10: Base load satisfaction and energy surplus in relation to the application of different wind-energy storage base-load scenarios (generalized aspect)

__Energy supply security__

Before assessing the energy supply security results, it is important to explain the role of time and temporality for this domain. Stirling (2009; 2012) makes the distinction between short-term shocks and long-term stresses in the way that threats are regarded. This distinction is crucial for adjusting to the appropriate style of action against possible supply disruptions. Typical examples of vulnerability sources that can be treated as shocks are price spikes occurring either in the wholesale electricity or gas markets (assuming that gas contributes significantly to the electricity fuel mix). Natural disasters which can destroy transmission cables are also in the same category. Examples of long term stresses include long term demand shifts or climate changes that have a gradual impact on renewable energy generation (such as changes in precipitation, wind patterns or cloud coverage). In this context, deciding on temporality (short-term shock or long-term stress) defines to some extent the appropriate course of action. For vulnerabilities that involve short-term shocks and cause disruption in otherwise stable trajectories, the course of action should be to maintain the trajectory in question. In the case of electricity supply security, the trajectory is the uninterrupted supply of power to consumers. A power station outage (shock) could be handled with adequate energy storage. Given that this is a short-term price shock, stored energy could be used to protect the electricity sector from exposure to high prices until they return to normal levels. However, gradually increasing international gas prices that could eventually make power generation unaffordable would be responsible for supply vulnerability that would be classified as a long-term stress. The course of action in that case should be different and could include a fuel mix shift in order to reduce reliance on gas.

Energy security assessment

The energy security metrics used in this study relate directly to the concept of temporality and the results must be interpreted accordingly. Diversity (and its improvement) is a strategic response to possible short term shocks in electricity supply. It is the energy policy equivalent of the proverbial phrase "do not put all of your eggs in one basket". In the face of uncertainty, relying less on each single source of energy is a good strategy. Independence (and its increase) at the same time is a strategic response to gradual long-term stresses in electricity supply. According to our methodology placed in the context of decarbonisation (Jewell et al., 2014), first coal and then natural gas power stations of equivalent electricity supply contribution are replaced by the combined solution of wind power and PHS, omitting nuclear power due to its low carbon characteristics (see also Table 5.1).

Prioritising the replacement of coal-fired power stations has multiple benefits. Reducing coal’s dominance in the electricity fuel mix increases supply diversity, which in turn benefits security. Coal has the highest CO_2 emission factor and is also the second most import dependent fuel (see also Table 5.1); therefore lowering its contribution to electricity generation has a considerable impact on the sector’s import dependence. Furthermore, coal power plants present the sharpest plant retirement expectancy among all fossil fuelled plants (approximately 10GW of coal until 2015 and another 8GW until 2023), mainly due to the European Union's Large Combustion Plant and Industrial Emissions Directives coming into full effect in 2015 and 2023 respectively (Bloomberg New Energy Finance, 2012). As a result, prioritising the replacement of coal-fired power stations is in line with the expected plant closures and also comes with considerable environmental and energy security benefits. In this case study both the electricity sector’s diversity (Figure 5.11) and import dependence are measured (Figure 5.12).

HHI and SWI (Figure 5.11) present similarly positive results with the gradual increase of the wind-storage base-load in the system. This reflects diversity improvements, which for base-load output of 1.5GW and 3GW suggest considerable increase/decrease of the SWI and HHI, up to 20GW and 25GW respectively. The corresponding optimum wind power capacity increases in the cases of 5GW and 7GW base-load output, in the order of 40GW of wind power.

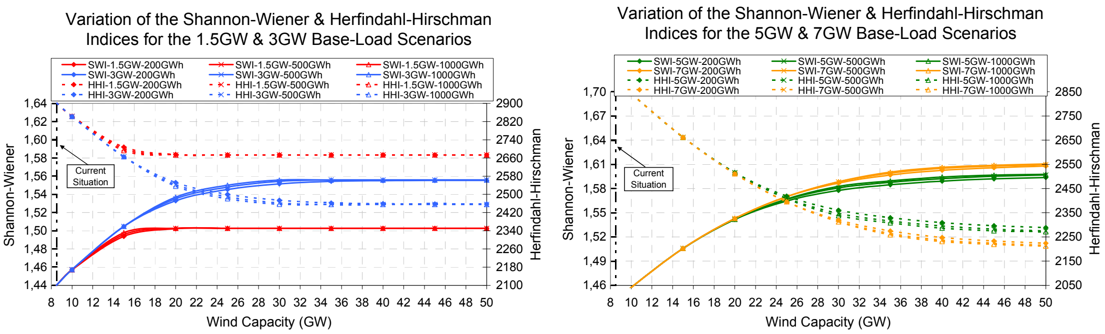


Figure 5.11: Variation of the national electricity supply diversity for different base-load wind energy storage configurations

For the lower output base-load scenarios (1.5GW and 3GW), the increase in base-load output signals noticeable increase in terms of diversity, independently of the energy storage capacity (GWh) employed. For the higher base-load requirements, the role of energy storage capacity becomes important, with a higher capacity facilitating more frequent operation of PHS, which in turn has a positive impact on diversity. This is validated because, as already mentioned (Figure 5.9c), higher storage capacity suggests a reduction of wind energy surplus for the higher base-load scenarios. At the same time, as already discussed, minimization of the stochastic wind energy production, i.e. wind energy production that is not filtered through storage, is desirable, since despite the increased energy conversion losses in the storage process, wind energy curtailments are minimized. The real degree of absorption for the stochastic part of wind energy depends of course on a number of factors, including transmission capacity, market operation, fuel mix, etc. Accordingly, the relation of installed wind energy capacity and dependence appears to be almost linear, for as long as wind energy substitutes imported energy resources in the electricity fuel mix (see also Figure 5.12 where the case of 1000GWh storage capacity is examined).

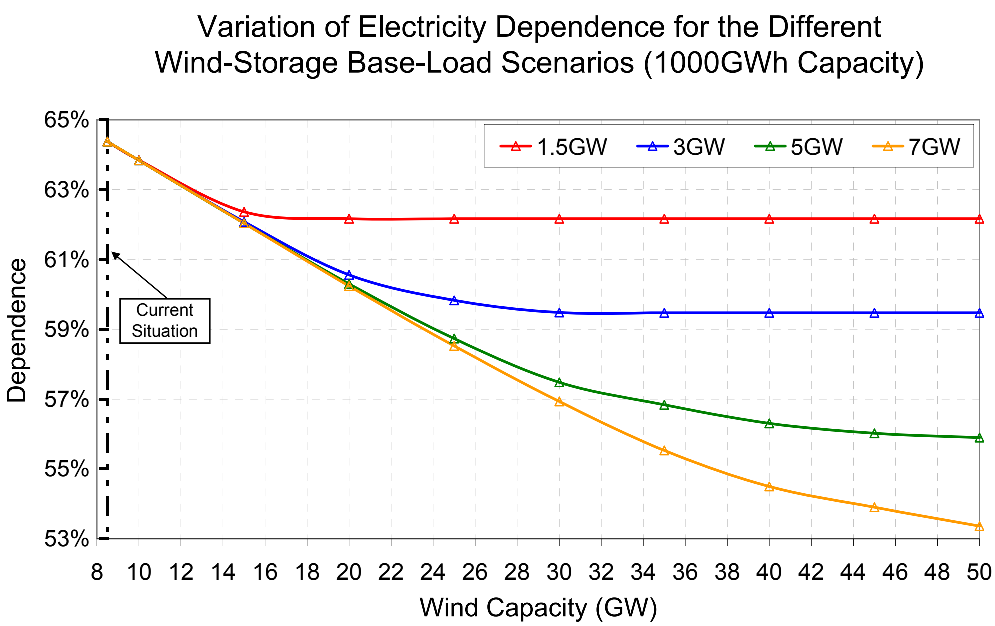


Figure 5.12: Variation of the national electricity supply dependence for different base-load wind energy storage configurations

On the other hand, due to the limitation of non-absorption for the produced wind energy surplus, see also Figure 5.9c and 5.9d, the dependence curves stabilize once considerable wind energy surplus appears (Figure 5.12), except for the case of the 7GW base-load, where wind energy surplus minimizes. For wind capacity at approximately 40GW, which was earlier identified as the optimum range for diversity in the case of the higher base-load values, dependence is reduced to even 53% (Figure 5.12).

CO_2 results

As previously stated, the suggested base-load system of wind energy and storage replaces the existing base-load power stations fuelled by coal and natural gas. Giving priority to the replacement of coal has a significant impact on reducing the electricity sector's CO_2 emissions. As expected, the CO_2 emissions reduction is inversely related to the installed wind capacity (Figure 5.13). Diversity was optimised for approximately 20GW (low base-load cases) and 40GW (high base-load cases) of wind capacity for which the electricity sector's CO_2 emission factor drops by approximately 30gr/kWh and 130gr/kWh, i.e. from 470gr/kWh[18] to 440gr/kWh and 340gr/kWh respectively, which also approximates the average of the OECD European countries (IEA, 2012).

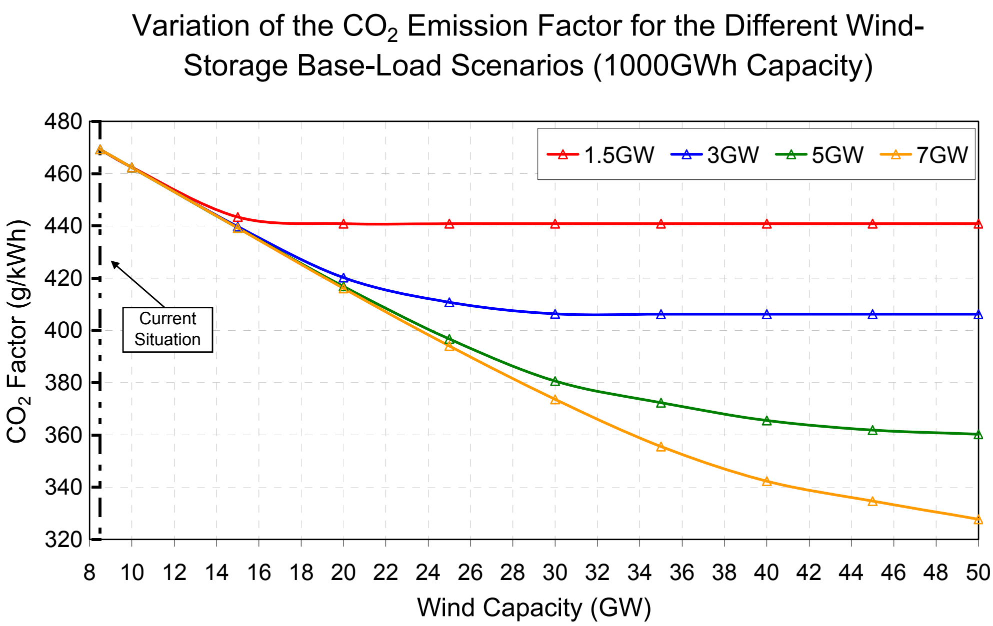


Figure 5.13: Variation of the national electricity generation CO_2 emission factor for different base-load wind energy storage configurations

Furthermore, as for the discussion on energy security, the role of storage is to enable an increased contribution of wind energy to the fuel mix. Either the grid infrastructure should be able to accommodate stochastic wind power shocks effectively, with the upgrade of transmission lines, or the current practice of curtailments together with wind energy exports should be applied. Nevertheless, the risk of encountering such events could be minimised, depending on the extent to which the proposed wind energy storage base-load scenario is applied (i.e. higher base-load requirements imply more frequent PHS operation and thus minimization of the stochastic wind energy part).

[18] The specific value considers 8.5GW of wind power, while the value of 475gr/kWh presented earlier takes into account the variation of wind power during 2012, i.e. from 6GW to 8.5GW, and thus appears to be higher.

Financial results

Both investment costs and the present value of LC electricity production cost for each of the examined configurations are estimated (Figures 5.14 and 5.15). Concerning the estimation of the investment cost, existing wind power is considered as part of the investment, with new wind parks to be installed being as already mentioned predominantly offshore (Toke, 2011) (reflected in the cost values of Table 5.2).

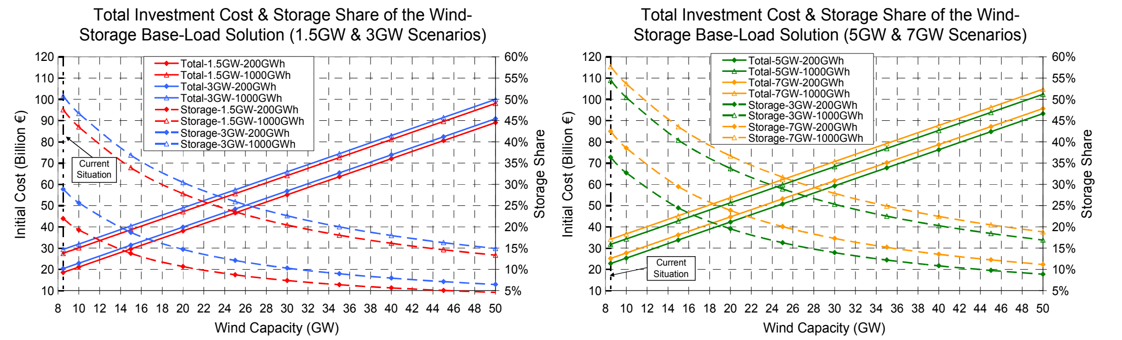


Figure 5.14: Investment cost of the different base-load wind energy storage configurations

According to the results obtained, the investment cost is, as expected, mainly driven by the increase of wind capacity, with the share of PHS cost gradually reducing to drop to 5-10% for the higher wind power values. At the same time, investment costs rise to exceed 100 billion € for the extreme scenario of 50GW wind power. A rapid reduction of electricity production costs is noted in the early stages of the respective curves (see also Figure 5.15), followed by an abrupt increase since wind energy surplus is not considered to be exploitable under the given load demand. Minimum values obtained for both low and high base-load cases are estimated in the range of 120-140€/MWh, which is illustrative because if also taking into account exploitation of the wind energy surplus, the proposed configurations could reach grid parity and thus be competitive to other alternatives.

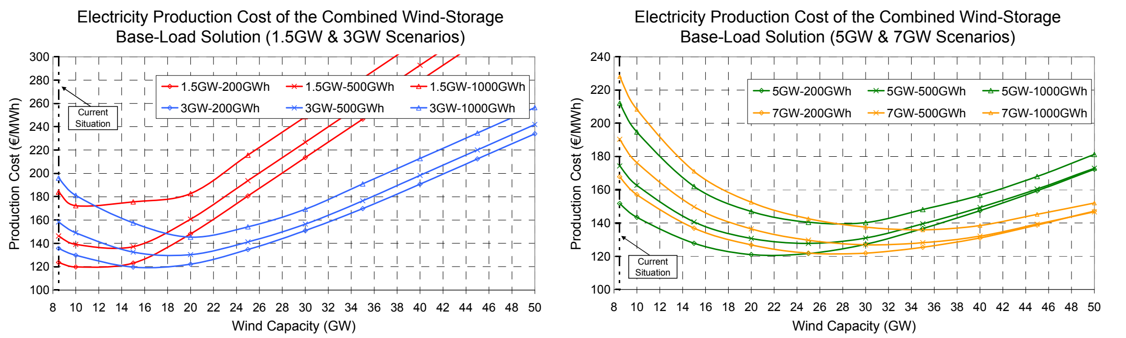


Figure 5.15: LC electricity production cost of different base-load wind energy storage

An increased wind energy contribution, in the form of base-load power, is also expected to contribute to the elimination of market volatile characteristics. This vitiates the theory that large-scale wind energy integration adds to volatile characteristics and eventually increases electricity prices due to the need for support by expensive thermal-based units such as open cycle gas turbines (Forrest and MacGill, 2013).

5.1.6 Discussion and Conclusions

This study uses the principle of interindustry architectural innovation, which is the novel integration of existing technologies from different sectors or industries. This approach reduces the risk and potential implementation timescale associated with developing radical new technologies for the electricity generation sector. Although there may be some changes required to allow for the integration of the pre-existing technologies, this would present less challenge than developing and integrating new radical innovations. Although the concept of architectural innovation is well-established, the concept of interindustry architectural innovation has received less research attention. To explore this concept in the energy sector, this chapter presents a retrospective exercise to integrate existing wind power and PHS technologies within the context of the UK national electricity system. In this study, the performance of the wind energy storage base-load concept is evaluated. In this case study, energy supply security is used as optimization criterion and the applicability of the proposed strategy in light of its financial and environmental performance is investigated. Further research would be required to consider the interconnectivity of the two technologies and the regulation required to enable such interindustry collaboration and integration.

The proposed strategy ensures large-scale wind energy integration, eliminates the intermittency drawbacks of wind energy generation and reduces energy imports. At the same time, the electricity production cost could reach grid parity if wind energy surplus exploitation is also considered, with the increase of wind energy contribution expected to also counter the volatile characteristics of the local electricity market that relies on coal and natural gas imports. Energy storage enables large-scale wind energy penetration and PHS is a mature technology that can potentially play this role. However, the focus of this study on PHS should not disregard that other types of storage may need to play a significant role in the mid or long-term future.

At present, the UK government subsidises the purchase of all electric and long-range hybrid vehicles. The absence of widespread smart grid infrastructure or policy provisions does not currently allow these vehicles to contribute as mobile storage systems. However, when their market share and related infrastructure are developed there is an expectation that their role could be developed to include the facilitation of large-scale energy storage. Further research and policy development should take this potential role for electric vehicles into account and consider how to facilitate the coordination between the vehicle owners and the grid balancing mechanism. Moreover, further research is required to investigate the potential of the local grid to facilitate wind power generation shocks that although largely eliminated by high base-load output scenarios could still appear for the higher wind capacity scenarios. Finally, our proposal suggests that energy security indices should be improved to also take into account the contribution of energy storage in providing guaranteed amounts of green energy, while countering the vulnerabilities of RES power generation.

5.2 Energy Storage Strategies at the Utility Scale / National Grid Level

5.2.1 Introduction

Increased interest is recently demonstrated on the role of energy storage in contemporary electricity markets (Zafirakis, 2010, Zafirakis et al., 2013). To this end, utility-scale energy storage, such as PHS (Kaldellis et al., 2010; Kapsali and Kaldellis, 2010), may satisfy a number of applications (see also Figure 2.2) that are of interest to either the system operator or private investors. Concerning the latter, emphasis is given on energy storage trading strategies, known as arbitrage (Sioshansi et al., 2009), that in the absence of a solid support framework concerning private energy storage investments (e.g. FiTs for collaboration with RES plants) are thought to comprise the main source of revenues. The practice of arbitrage by energy storage investors aims at the maximization of net revenues through the exploitation of electricity price spreads presenting both short-term and long-term seasonality. On the other hand, use of energy storage from the system operator point of view mainly concerns support of large-scale integration of RES (Daim et al., 2012; González et al., 2012) and transmission deferral (Denholm and Sioshansi, 2009) with similar systems not yet extensively considered for market regulation purposes. The current study focuses on the use of energy storage by the system operator to regulate the market, taking into account market efficiency criteria such as price volatility, system energy dependence, fuel mix diversity and CO_2 emission factor. For this purpose, a comprehensive data-set of hourly spot price and fuel mix for the Greek electricity market is used. Subsequently, a spot price prediction model is built (with the use of fuel mix components as independent variables) that allows application of different energy storage strategies exploiting the available fuel mix data and the predicted spot price. Results obtained designate contradictions among the application of different criteria, while also providing some indication on the capacity of PHS required in order to satisfy certain criteria goals.

5.2.2 Methodology - Proposed Storage Strategies

The independent parameters taken into account include hourly electricity fuel mix data for lignite, natural gas, oil, hydro, PHS, net imports and day-hours, used to predict the hourly electricity spot price through regression analysis. Following the prediction of the spot price time series, energy storage and PHS in specific is used in order to regulate the local market. In doing so, different criteria are examined including energy dependence, fuel mix diversity, market volatility and CO_2 emissions, giving priority to the increase of energy security levels. Under the proposed methodology, power generation by indigenous power sources (conventional ones) is stretched to charge PHS plants of variable storage capacity and use energy stores in order to replace power generation based on energy imports. Based on the above, an extensive parametrical analysis is carried out, based on two main variables, i.e. the energy storage capacity of PHS plants to be employed and the minimum limit to be set concerning stretching (i.e. the minimum desirable loading) of thermal indigenous power generation. To this end, any maintenance needs of the operating power plants during the year are neglected and the problem is approached from the point of view of a system operator exercise. Finally, for the application of the methodology, the case study of the Greek national electricity generation system (mainland-only) is used, largely based on the use of local lignite to serve electricity demand needs.

5.2.3 Case Study Characteristics

The electricity generation system of Greece is divided into two main sectors, i.e., the mainland and the island sub-systems. As far as the mainland electricity grid (interconnected system) is concerned, centralized power generation is mainly based on indigenous lignite reserves (Kaldellis et al., 2009b). In this regard, national dependence on fossil fuels is confirmed by the employment of approximately 6GW of steam turbines using indigenous lignite reserves, 2.3GW of combined cycle power plants using imported natural gas, and a total of 1.3GW of oil and gas based generation (gas turbines and internal combustion engines) mainly used for the service of non-interconnected Aegean island grids (Kaldellis and Zafirakis, 2007b).

Additionally, the mainland electricity grid is supported by the operation of large hydropower plants that exceed 3GW and are used as peak shaving units, on top of which there are also two PHS plants of almost 700MW. Besides that, there are wind energy (~1.8GW) and photovoltaic (PV) installations (~2.5GW), and a small proportion corresponds to small-hydro, biogas and industrial waste installations. At the same time, the Greek electricity market, although being deregulated since 2002, is largely monopolistic at both the wholesale and the retail level, with the greatest power generator-retailer holding approximately 90% of the local market share. In this regard, the spot price series for a representative year (i.e. 2009) is given in Figure 5.16a, with the respective probability density curve provided in Figure 5.16b.

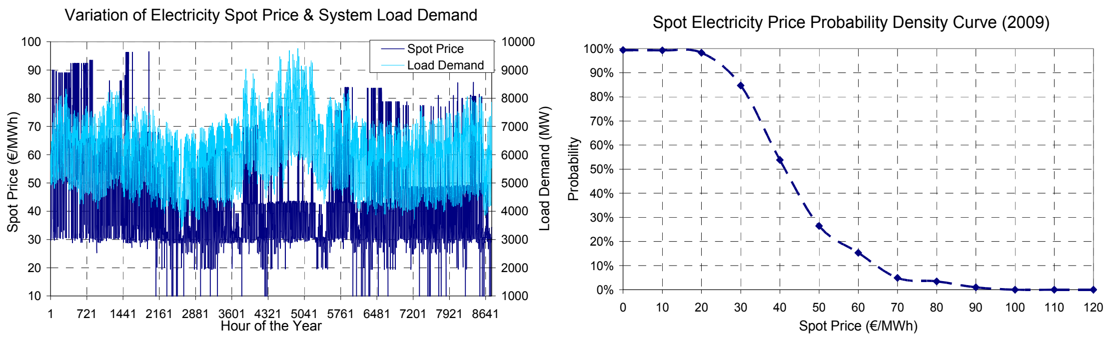


Figure 5.16: Hourly electricity spot price variation (a) and probability density curve (b) for 2009

Fuel mix data for the reference year is given in Figure 5.17, where both the 24 hour average fuel mix and the respective 24 hour production pattern (as % of the maximum appearing value for each power generation source during this average day of the year) are given in relation to the respective electricity spot price variation.

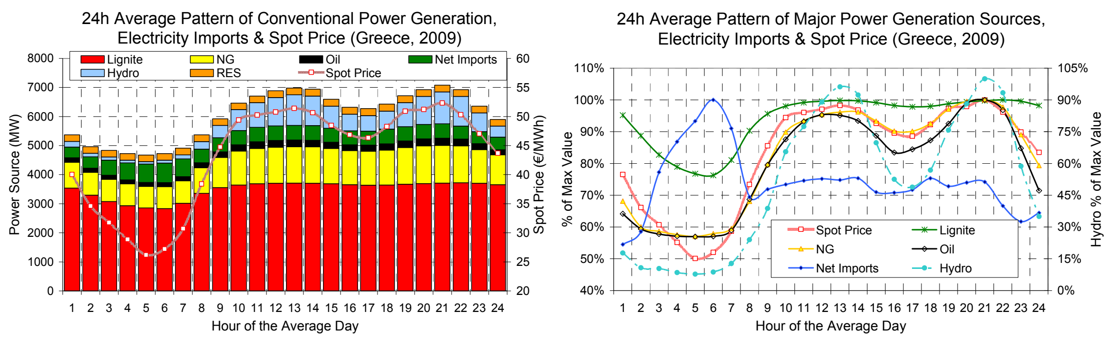


Figure 5.17: Annual 24h average fuel mix (a) and production pattern (b) in relation to the respective electricity spot price variation

Spot price values present significant scattering during the year, which cannot be sufficiently explained by the respective load demand variation, at least at the seasonal level. At the same time, inefficient market behaviour is also reflected by the appearance of price spikes (i.e. >75€/MWh~5% of the year) as well as near-zero price events (less than 1% of the year). With regards to the electricity fuel mix, lignite maintains a dominant role, followed by natural-gas based power generation.

5.2.4 Application Results

Using the data of the Greek mainland electricity system and applying multiple polynomial regression analysis, prediction results were produced with the help of the STATISTICA software and the implementation of a second order equation given in the following.

SPOT PRICE (€/MWh) = -19,538687+,291307642*HOUR -0,00867403 * HOUR^2 + 0,022476869 * LIGNITE - 0,26238E-5 * LIGNITE^2 + 0,015181219 * OIL + 0,421843E-4 * OIL^2 + 0,002864330 * NG + 0,252995E-5 *NG^2 + 0,010303639 * HYDRO -0,38170E-5* HYDRO^2 + 0,011047783 * RES -0,13410E-4 * RES^2- 0,00974147 * PUMP + 0,807412E-5 * PUMP^2 - 0,00238013 * NET IMPORTS - 0,33008E-5 * NET IMPORTS^2 (5.6)

The predicted spot time series is found in most cases to underestimate the value of observed spot price, while also not capturing observed spot price values below 10-15€/MWh (Figure 5.18).

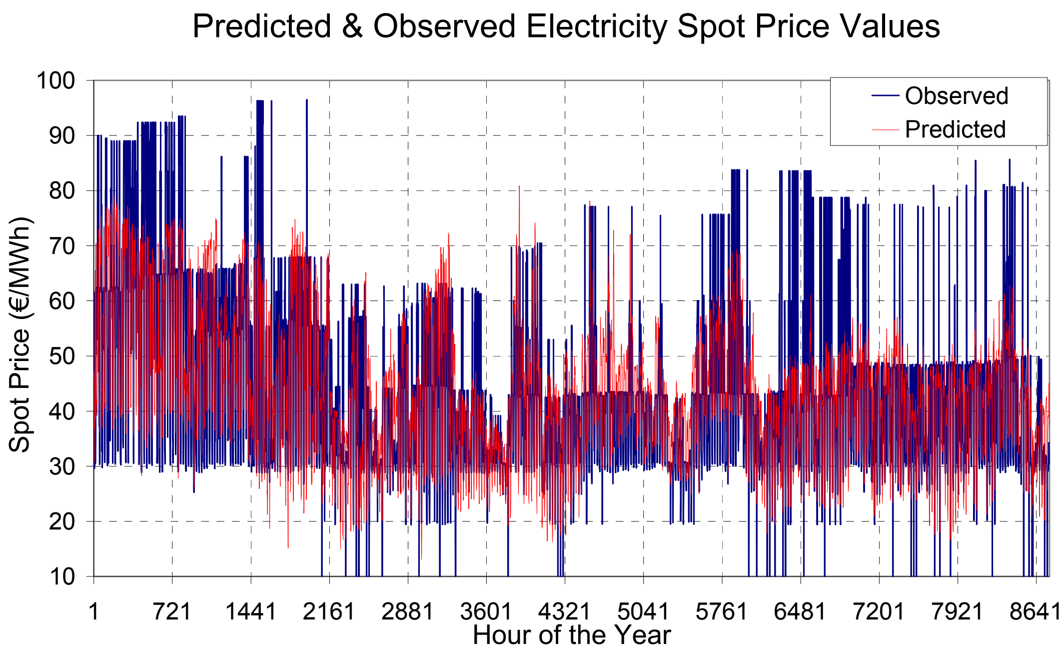


Figure 5.18: Comparison between the observed and predicted spot price values

The above conclusion is validated by the linear regression comparison between observed and predicted values (Figure 5.19). In this context, R^2 equals to 0.645, with the red regression line clearly indicating overestimation and underestimation of the low and high electricity spot prices respectively (see also Figure 5.20 for representative weeks).

The majority of the cumulative probability of obtaining certain residual values (more specifically the level of residual's deviation from the actual observed value) is concentrated in the area of +/-30%, with the probability of meeting zero residual marginally exceeding 50% (Figure 5.21). In conclusion, despite the fact that the developed equation is not accurate for the entire range of spot price values, it must be kept in mind that the spot price pattern presents remarkable scattering together with a considerable number of spikes and near-zero events.

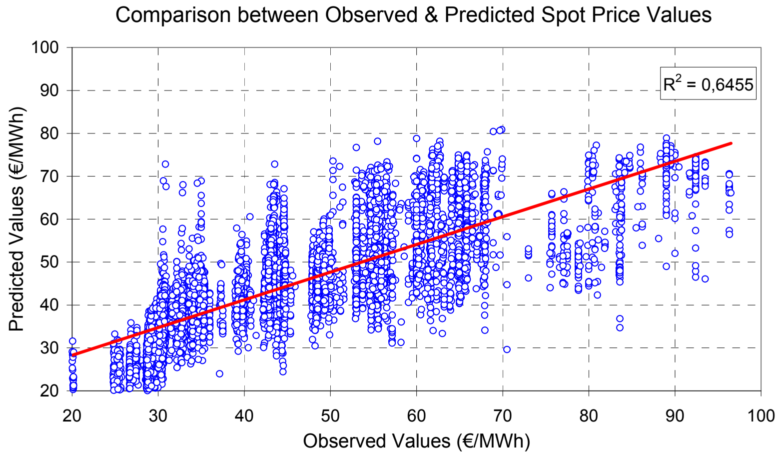


Figure 5.19: Accuracy levels of observed spot price prediction

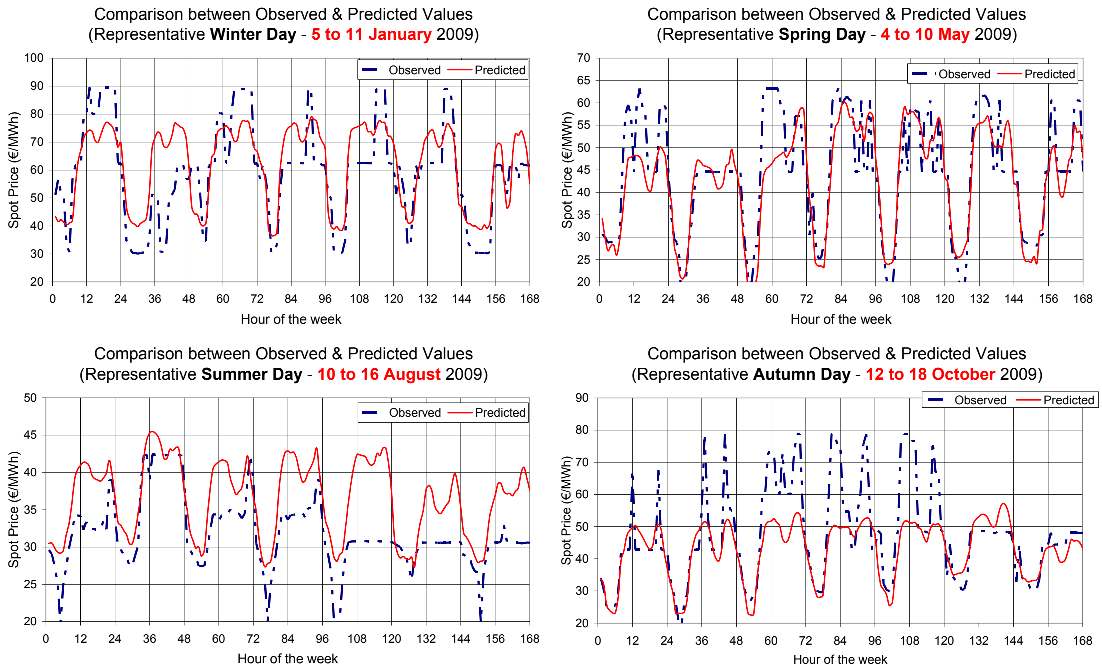


Figure 5.20: Comparison between observed and predicted spot price values for representative weeks of the year

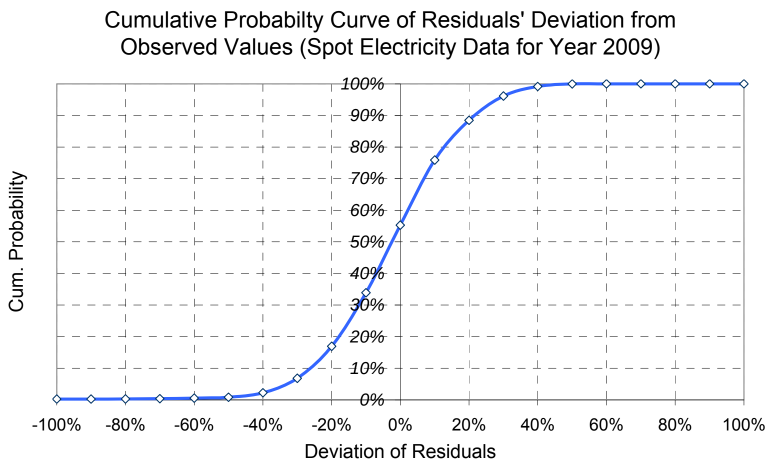


Figure 5.21: Cumulative probability curve of observed spot price prediction residuals

Based on the produced spot price equation, off-peak lignite power production is stretched to replace power generation based on energy imports during peak demand hours (considered to be 13:00, 14:00, 21:00 and 22:00 pm), giving priority to natural gas, oil and finally electricity imports affecting net imports. The maximum lignite-fired load is set to not violate the maximum net capacity of 4.5GW and is applied only during off-peak periods (only for 1:00 am). At the same time, the available PHS storage capacity is variable, ranging from 0 to 5GWh, with the respective input and output efficiency being 80% and 85%.

By applying the proposed strategy both the total demand and the fuel mix are revised. The former owed to the stress imposed to the lignite power stations and the latter due to the increase of lignite and PHS production (treated as hydropower plant concerning production) along with the respective reduction of natural gas and oil-based power stations as well as of electricity imports. Using the revised fuel mix considering also increase of load demand, the spot price prediction equation is applied, this time to estimate a new spot time series under the implementation of the proposed strategy that gives priority to the criterion of energy independence. The first set of results is found in Figure 5.22, where the impact of the imposed strategy is presented in terms of market efficiency, expressed by annual volatility (i.e. the standard deviation of price returns multiplied by the square root of the respective sample which is 8760hours) and number of spikes per year (currently considered as >75€/MWh). To this end, by increasing the lignite loading limit, annual volatility is increased (Figure 5.22a), while the impact of storage capacity gradually fades out asymptotically. The same is valid for the number of spikes which are increased inconsiderably, owed to the replacement of natural gas plants with the use of PHS peak units.

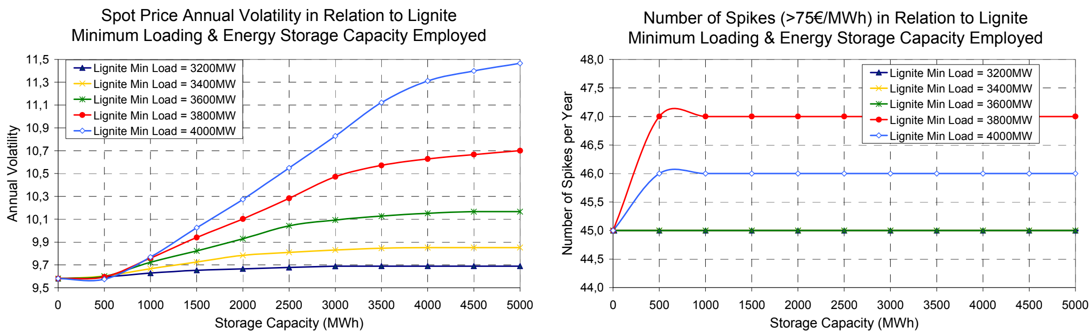


Figure 5.22: The impact of lignite loading and storage capacity on the annual spot price volatility (a) and the number of price spikes per year (b)

The inverse behaviour is shown in the energy dependence of the local electricity system, which presents a proportionate reduction to the increase of lignite production at the expense of power generation based on energy imports. Furthermore, fuel mix diversity is also estimated using SWI (Stirling, 1994), with maximum values achieved for the highest lignite loading and medium storage capacity, corresponding also to optimum fuel mix balance that together with the increase of energy dependence increase energy security overall (Figure 5.23). Finally, in Figure 5.24, the electricity system CO_2 emission factor is presented, with increase of the lignite loading limit leading to reduction of the CO_2 factor, owed to the increase of the local power generation rather than the reduction of emissions (since lignite is CO_2-intensive in comparison to all other participating fuels).

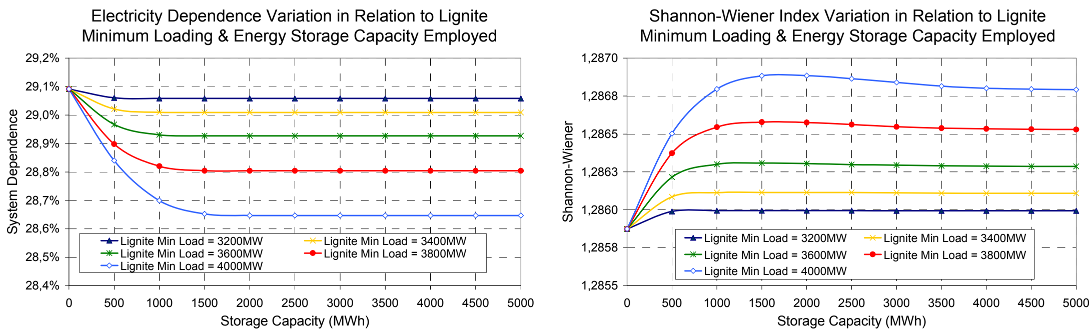


Figure 5.23: The impact of lignite loading and storage capacity on the system energy dependence (a) and fuel mix diversity (b)

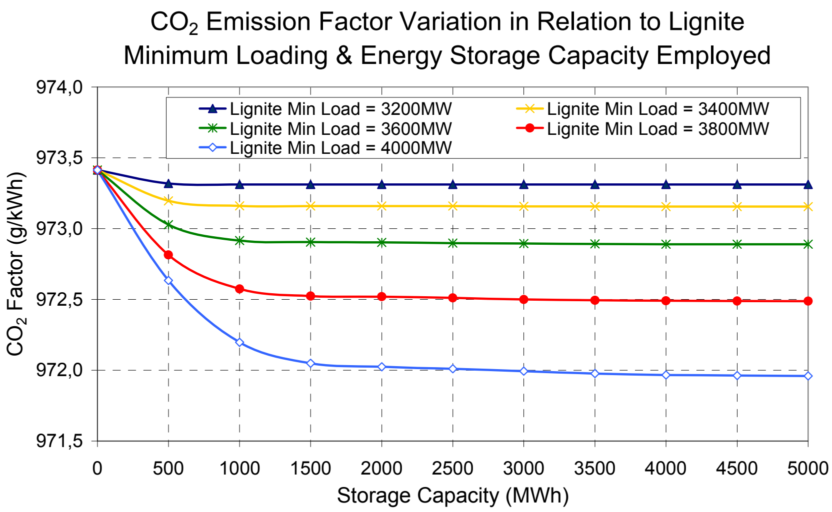


Figure 5.24: The impact of lignite loading and storage capacity on the system CO_2 emission factor

5.2.5 Summary

Based on the use of multiple polynomial regression analysis, fuel mix data were used for the prediction of spot price in the Greek electricity system. Following the prediction of the spot price time series for an entire year under satisfying uncertainty levels, employment of utility storage was examined for the regulation of the local market. More precisely, by giving priority to the increase of energy security levels, off-peak power generation based on indigenous lignite reserves was stretched to replace energy imports-based production. In doing so the levels of minimum lignite loading and PHS storage capacity varied and results in terms of energy security, CO_2 emission factor and market efficiency were recorded.

With this in mind, it is concluded that an increase of energy security is counterbalanced by the increase in market volatility and extreme price events, while negligible changes met in the CO_2 emission factor reflect the simultaneous increase of CO_2 emissions and total demand, both owed to the increase of lignite power generation. Overall, the contradictions among different criteria were demonstrated, while also providing some indication on the capacity of storage required in order to satisfy certain criteria goals. Further work is required to distinguish the contribution of natural gas based peak-plants and give priority to their replacement, while finally, the proposed methodology should be applied to different types of fuel mix, examining the collaboration between large-scale RES integration and PHS plants.

5.3 Utility-Scale Storage and EU Electricity Trade CO_2 Emissions

5.3.1 Introduction

Increased concern on climate change has stimulated investigation of comprehensive assessment methods for the estimation of national CO_2 emissions that capture trade balances and introduce life cycle (LC) implications for various sectors and products (Baiocchi and Minx, 2010; Sánchez-Chóliz and Duarte, 2004; Steinberger et al., 2012; Yan and Yang, 2010). However, the methodologies used for the estimation of national electricity CO_2 emissions so far neglect the impact of electricity trade between neighboring countries (Jiusto, 2006; Soimakallio and Saikku, 2012). Instead, they rely on the national electricity production rather than on the actual consumption that takes into account net imports of electricity. This in turn affects ranking of the countries in terms of CO_2 performance considerably and creates inefficiencies in the development of decarbonization mechanisms, since, in many cases, electricity trade implies significant changes in the volume of CO_2 emissions attributed to the actual electricity consumption of a given country.

At the same time, increased use of the existing cross-border electricity transmission infrastructure throughout Europe facilitates non-traceable exchange of CO_2 emissions and signals better single-market integration, with convergence of prices (Zachmann, 2008) already noted in regional markets such as Nord Pool. On the other hand, large-scale penetration of renewables (Brancucci et al., 2013; Schaber et al. 2012) and heavy congestion of several interconnectors (Ehrenmann and Smeers, 2005) encourage the expansion of cross-border transmission (Supponen, 2012). These projects require extreme investment for the different regulatory frameworks and market characteristics among European countries, which could lead to trade inefficiencies (Battaglini et al., 2012; Creti et al., 2010).

In the meantime, energy storage demonstrates fast progress (Krajačić et al., 2011; Connolly et al., 2011b; Zafirakis and Chalvatzis, 2014;). To this end, despite the fact that contemporary energy storage technologies (Zafirakis, 2010; 2014) are capable of providing firm support to the promotion of large-scale renewable energy integration, the essential market mechanisms and financial incentives (Zafirakis et al., 2013) required for their broad adoption have not yet been put forward. Taking into account the argument of Haller et al. (2012, p. 283) that "*Investment decisions regarding renewable energy generation, transmission and storage capacities are tightly interconnected*", a novel aspect is examined of how utility-scale energy storage can increase its value by contributing to the decarbonization efforts of European countries, satisfying at the same time services such as deferral of cross-border transmission upgrade (Steinke et al., 2013).

In this context, the importance of CO_2 emissions embodied in cross-border electricity trade is stressed and national CO_2 emission factors of European countries, originally estimated on the basis of electricity production, are revised. Accordingly, energy storage is used to “protect” countries with low carbon intensity from carbon intensive electricity imports through the exploitation of national electricity exports. For this purpose, the impact of different energy storage levels on national CO_2 emissions is examined while applying priority cut-downs of imports from the most CO_2-intense interconnector. Finally, by using recently published results concerning the national potential of PHS in European countries, optimum, realizable storage capacity levels are investigated and the CO_2 price that could marginally support investments in the field is determined.

The chapter is organized as follows. Section 5.3.2 provides a short description of the current EU transmission network and electricity trade and section 3 analyzes the developed methodology. Next, revised national CO_2 emission results are given in section 5.3.4. In section 5.5.5, the impact of using energy storage is investigated in detail. Section 5.5.6 gives an overview of the PHS technology and section 5.5.7 investigates the prospects of the proposed solution on the basis of PHS. Finally, results are discussed in section 5.5.8 and the main conclusions of the study are given in section 5.5.9.

5.3.2 The European Cross-Border Electricity Transmission Network

The European electricity transmission network is operated by ENTSO-E, i.e. the European Network of Transmission System Operators for Electricity, comprising the association of Europe's transmission system operators (TSOs). The European Commission proposed the European Union's Third Energy Package as a legislative package for an EU internal gas and electricity market aiming to encounter energy market concentration (2007). The package adopted by the European Parliament and the Council of the European Union in July 2009 initiated the creation of ENTSO-E that became operational on July 1st 2009. Today, the role of ENTSO-E is to enhance cooperation between 41 national electricity TSOs from 34 countries across Europe in order to assist in the development of a Pan-European electricity transmission network.

The volume of electricity exchange during 2012 reached a total of approximately 436TWh (in comparison to 453TWh and 416TWh for the years 2011 and 2010), divided in 398TWh exchanged between ENTSO-E member countries and 38TWh coming from electricity trade with external countries, overall corresponding to almost 13% of the total net electricity production of ENTSO-E country members during the same year (ENTSO, 2013a) (see also Figure 5.25). Among all interconnected countries, Italy is the highest net importer with approximately 43.2TWh of net electricity imports, while France is the most important exporter with total net exports in the order of 43.5TWh (Figure 5.26).

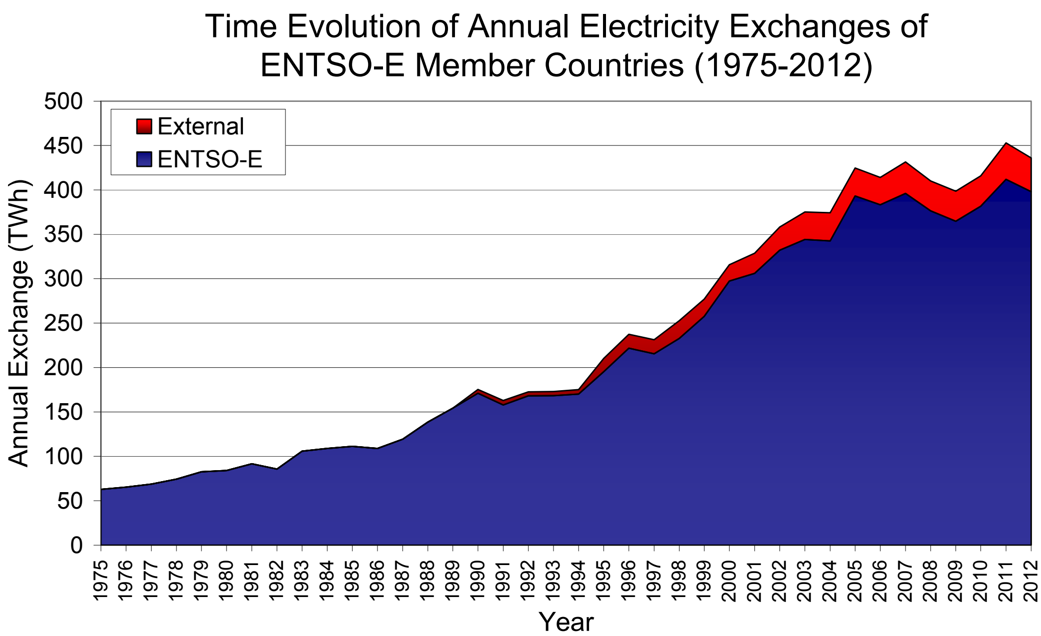
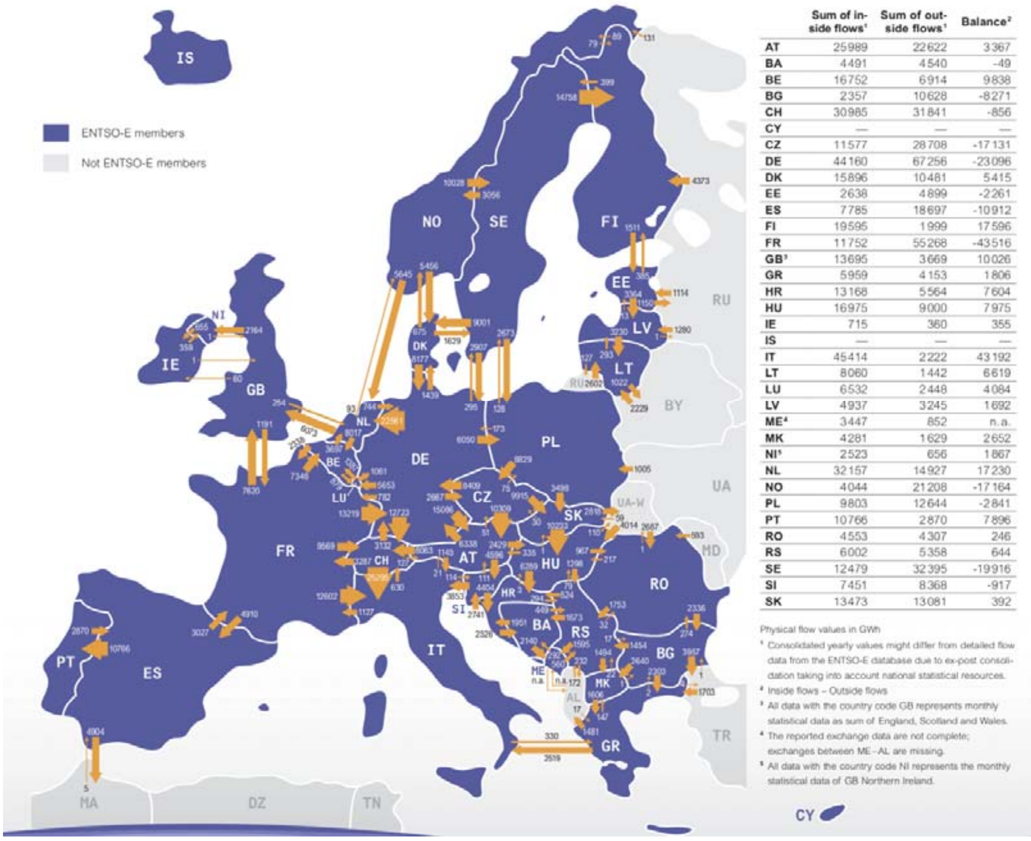


Figure 5.25: Time evolution of total volume of energy trade in ENTSO-E member countries

Imports and exports relative to indigenous production is a useful index to highlight the importance of electricity trade for certain countries (Figure 5.27). Lithuania, Luxembourg, Croatia and Montenegro present the greatest imports to production ratios, with the last three demonstrating also significant exporting activity together with Slovenia, Latvia and Switzerland. Overall, it is almost half the countries that present importing/exporting activity higher than 20% of their local national electricity production.



	Sum of inside flows[1]	Sum of outside flows[1]	Balance[2]
AT	25989	22622	3367
BA	4491	4540	-49
BE	16752	6914	9838
BG	2357	10628	-8271
CH	30985	31841	-856
CY	—	—	—
CZ	11577	28708	-17131
DE	44160	67256	-23096
DK	15896	10481	5415
EE	2638	4899	-2261
ES	7785	18697	-10912
FI	19595	1999	17596
FR	11752	55268	-43516
GB[3]	13695	3669	10026
GR	5959	4153	1806
HR	13168	5564	7604
HU	16975	9000	7975
IE	715	360	355
IS	—	—	—
IT	45414	2222	43192
LT	8060	1442	6619
LU	6532	2448	4084
LV	4937	3245	1692
ME[4]	3447	852	n.a.
MK	4281	1629	2652
NI[5]	2523	656	1867
NL	32157	14927	17230
NO	4044	21208	-17164
PL	9803	12644	-2841
PT	10766	2870	7896
RO	4553	4307	246
RS	6002	5358	644
SE	12479	32395	-19916
SI	7451	8368	-917
SK	13473	13081	392

Figure 5.26: Cross-border physical energy flows between European countries for the year 2012

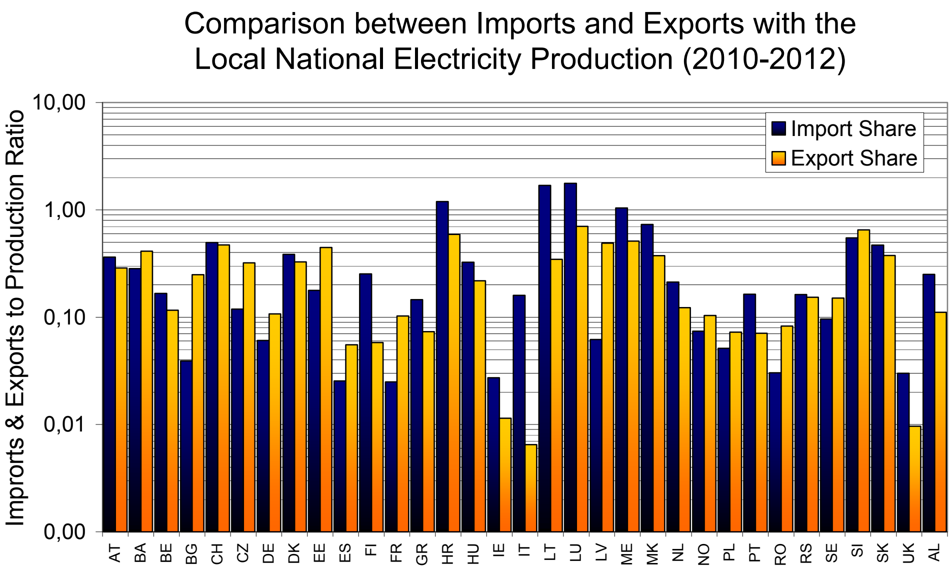


Figure 5.27: Ratio of electricity imports and exports to the national local electricity production for the period between 2010 and 2012

Moreover, by taking into account the maximum net transfer capacity of each country's sum of interconnectors (ENTSO, 2013b) along with the corresponding physical energy flows during the period 2010-2012, the respective load (or capacity) factor is presented (Figure 5.28). Luxembourg and Italy present the highest national import CF that exceeds 80% and 65% respectively, while at the same time Spain together with Bulgaria exploit their interconnectors for exporting energy at an average CF in the order of 55%. These numbers, although not providing information on the operation of each single interconnector -rather on the operation of national interconnector capacity- do provide some evidence on levels of congestion risk across the European transmission network.

Nevertheless, for a more clear view of congestion problems, more detailed data is required, such as hourly exchange across the Italy-Greece interconnector given for the period between 2009 and 2012 (HTSO, 2013) (Figure 5.29). The 163km High Voltage Direct Current (HVDC) interconnector of 500MW operates at its maximum capacity for a considerable part of the time examined, reflecting the need either for congestion management or for line upgrade in the case of higher exchange activity expected in the future.

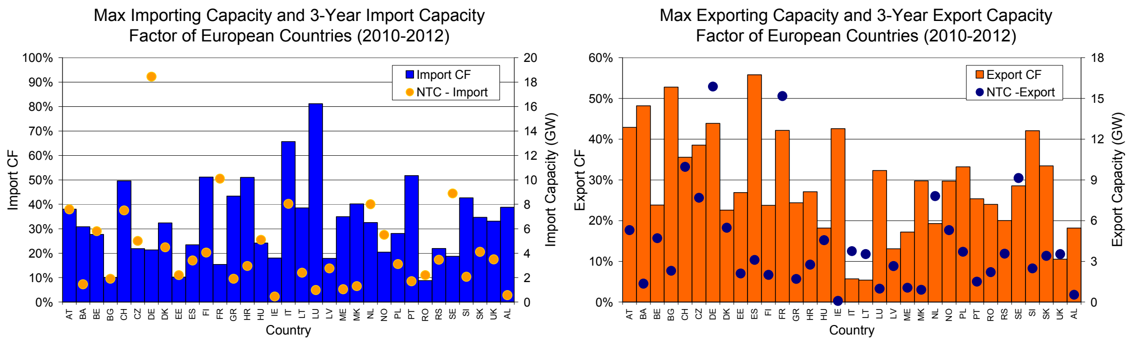


Figure 5.28: Maximum importing/exporting capacity and 3-year (2010-12) CF of import/export transmission for European countries

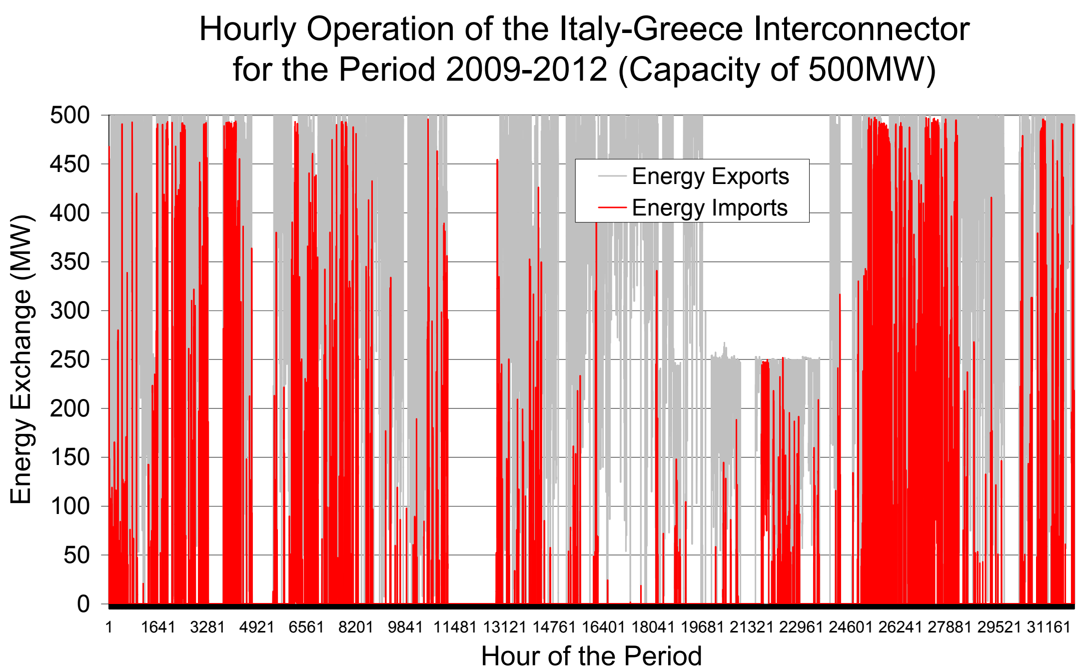


Figure 5.29: Hourly operation of the Italy-Greece interconnector (2009-2012)

Considering the current operation aspects of the European transmission network, the almost constantly increasing volume of energy trade (Figure 5.25) and use of transmission lines (Figures 5.27 and 5.28), while underlining the need for advanced congestion management and construction of new cross-border transmission capacity, they also imply the hidden exchange of considerable amounts of CO_2 emissions between interconnected countries. In this context, it is argued that this significant exchange of CO_2 emissions seriously affects national performance in terms of tackling climate change and should be considered in the assessment of national CO_2 emissions. With this in mind, an exercise is performed in order to both protect "cleaner" countries from CO_2-intensive electricity imports and assign utility-scale storage with new, value-adding features. For this purpose PHS is used and the optimum energy storage capacity at the national level is determined. Prior to that, national emissions are revised, based on the methodology developed in the following paragraph.

5.3.3 Methodology

Revision of national CO_2 emissions

To revise national emissions on the basis of CO_2 exchanged through cross-border electricity trade, all cross-border interconnectors (Figure 5.26) are examined and monthly energy flows (imports and exports) covering the period of 2010-2012 (ENTSO-E) are used. Furthermore, all country members of ENTSO-E are considered, excluding Cyprus and Iceland, which present zero cross-border transmission capacity and thus remain unaffected.

Turkey, Ukraine and West Ukraine, Belarus, Russia (incl. Kaliningrad) Morocco and Moldova are treated as exporters (external countries) only (i.e. the effect that these countries have on ENTSO-E member countries is assessed without determining the changes they are subject to). Great Britain and Northern Ireland are considered as a single electricity system (UK). Finally, although not a country member of ENTSO-E, Albania is also included, since it is surrounded by ENTSO-E country members and is thus unaffected from other external countries.

Concerning the estimation of CO_2 embodied in electricity trade and the revision of national CO_2 emissions, the following steps are undertaken:

a) Export of monthly electricity generation fuel mix data as well as monthly imports and exports provided for each country from the database of ENTSO-E at the level of interconnector and the entire period 2010-2012.
b) First approximation of monthly emissions only for 2010, using the respective monthly electricity generation fuel mix values provided by the database of ENTSO-E and the IEA average fuel CO_2 emission factors per unit of generated electricity output (gr/kWh) (see also Table 5.4).
c) Estimation of the annual emission factor per unit of generated electricity output for 2010 using the results of the previous step and the total monthly electricity generation provided by ENTSO-E for the same year.
d) Comparison between the resulting approximation of annual emission factors and the official national emission factors provided by IEA for 2010 (see also Table 5.5), and estimation of a correction factor that applies to all monthly values of emissions previously estimated (step (b)) for the period between 2010-2012.
e) Estimation of monthly emission factors for the entire period of 2010-2012 for all country members and external countries.
f) Application of the respective monthly emission factors to the imports and exports of all countries and interconnectors examined.

g) Revision of monthly CO_2 emissions of step (d) taking into account the impact of electricity trade, meaning the balance of CO_2 emissions embodied in the imports/exports of each country (i.e. addition of imported CO_2 and subtraction of exported CO_2).
h) Estimation of national electricity consumption on a monthly basis using the original monthly electricity generation values along with monthly imports and exports (added and subtracted respectively).
i) Estimation of the revised 3-year (2010-2012) national emission factors using the respective monthly values of step (g) and step (h).
j) Comparison of 3-year (2010-2012) national emission factors both under the consideration and without taking into account the influence of electricity trade.

Application of national level energy storage

The steps of the application of utility-scale energy storage are described below:

a) Simulation of the energy storage installation operation on a monthly basis, considering that exports -or part of the exports- of the current month are used to avoid imports of the next month.
b) During the first month of the period examined, no cut-downs of imports are carried out in order to allow the storage installation to charge and create a safety buffer that will also facilitate scheduling of charging and discharging periods for the rest of the examined period.
c) The share of energy exports to be exploited for storage purposes is variable, based on the storage capacity each time examined. More specifically, storage capacity ranges from 0% to 100% of the maximum appearing monthly export (during 2010-2012) of the country examined at a 5% step.
d) Input and output efficiencies of energy storage installations are assumed to be constant, with the respective round-trip efficiency η_{rt} taken equal to 80%, while no depth of discharge limitation has been considered.
e) Energy exports stored are then used to perform priority cut-downs of imports, starting from the most to the least CO_2-intensive.
f) For the entire range of storage capacities examined, the respective CO_2 emission reduction ($MtCO_2$/year) and CO_2 emission reduction efficiency (tCO_2/MWh of storage per year) is estimated (only relevant to countries which import energy from at least one interconnected neighbour with a higher emission factor).
g) Use of the PHS potential of European countries, providing the realizable PHS potential as well as the national average available head of the specific sites based on a GIS-based methodology (JRC, 2013).
h) Determination of optimum PHS configurations using the criterion of maximum CO_2 emission reduction per year ($MtCO_2$/year) under the minimum storage capacity and the limitation of realizable national potential (step (g))[19].
i) Estimation of installation costs attributed to the different optimum PHS configurations using literature information about the required equipment (pumps, hydro-turbines and BOS) and civil engineering works (reservoirs, penstock, etc.).
j) Estimation of the break-even CO_2 prices required to marginally support investment in optimum PHS configurations under the assumption of constant annual emission savings and a simple payback period of 30 years.

[19] In case of asymptotic patterns noted in the variation of CO_2 emission savings after a certain point of storage capacity increase, the optimum storage capacity selected does not correspond to the capacity ensuring maximum savings but to the one ensuring maximum savings under the condition of avoiding extreme system oversizing. Selection of storage capacity in such cases follows the condition that savings achieved cannot be lower than 90% of the respective maximum potential savings.

Table 5.4: IEA CO_2 emission factors per fuel type and electricity generation output

Fuel	**CO_2 Emission Factor (gr/kWh)**
Anthracite	920
Coking coal	780
Other bituminous coal	860
Sub-bituminous	920
Lignite	990
Coke oven coke	770
Coal tar	720
BKB/peat briquettes	800-1500
Gas works gas	420
Coke oven gas	420
Blast furnace gas	2200
Other recovered gas	2000
Natural gas	400
Crude oil	630
Natural gas liquids	480
Refinery gas	400
Liquefied petroleum gases	500
Kerosene	650
Gas/diesel oil	690
Fuel oil	670
Petroleum coke	1000
Peat	750
Industrial waste	400-2000
Municipal waste (non renewable)	450-3500

5.3.4 Revised CO_2 Emission Results

Applying the first part of the developed methodology, the impact of electricity trade on national emissions is quantified. To better illustrate the sequence of methodological steps, the example of Austria (AT) is used (Figures 5.30-5.31). To this end, Austria is connected to (see also Figure 5.26) Czech Republic (CZ), Germany (DE), Italy (IT), Slovenia (SI), Hungary (HU) and Switzerland (CH). The 3-year electricity trade on a monthly basis with each of the interconnected countries is given in Figure 5.30, where imports, exports and the respective balance for Austria are presented. Austria is a net importer overall, with net exports appearing usually during the summer period (Figure 5.30c).

The greatest share of imports derives from Germany and Czech Republic, with contribution of the rest of countries being negligible. On the other hand, Austria exports electricity mainly to Switzerland and Germany, followed by Slovenia, Hungary and Italy, with exports towards Czech Republic being negligible (~390GWh for the entire 3-year period).

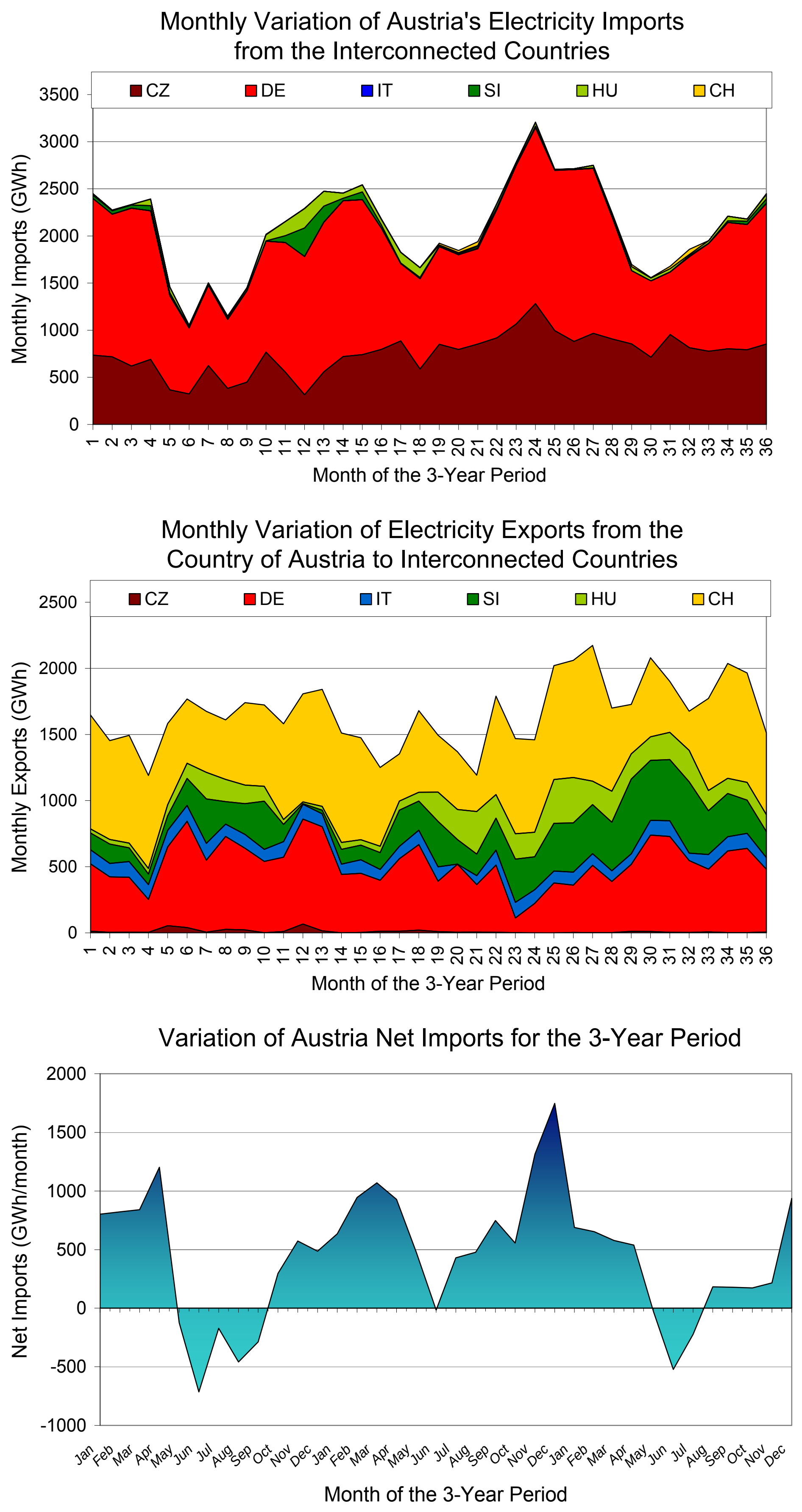


Figure 5.30: Monthly energy imports (a), exports (b) and balance (c) for the country of Austria (2010-2012)

Next, by applying the first part of the methodology (steps (a)-(e)), the respective monthly CO_2 emission factor variation is presented for both Austria and its interconnectors in Figure 5.31a. Austria maintains a lower emission factor for the entire 3-year period when compared to the five out of six of its interconnectors, i.e. except for Switzerland, while also presenting significant periodicity in terms of emission factor variation (owed to the seasonal operation of hydropower contributing to the local monthly production from 40% to 70%; the remaining electricity demand is covered by fossil-fuel power stations and imports).

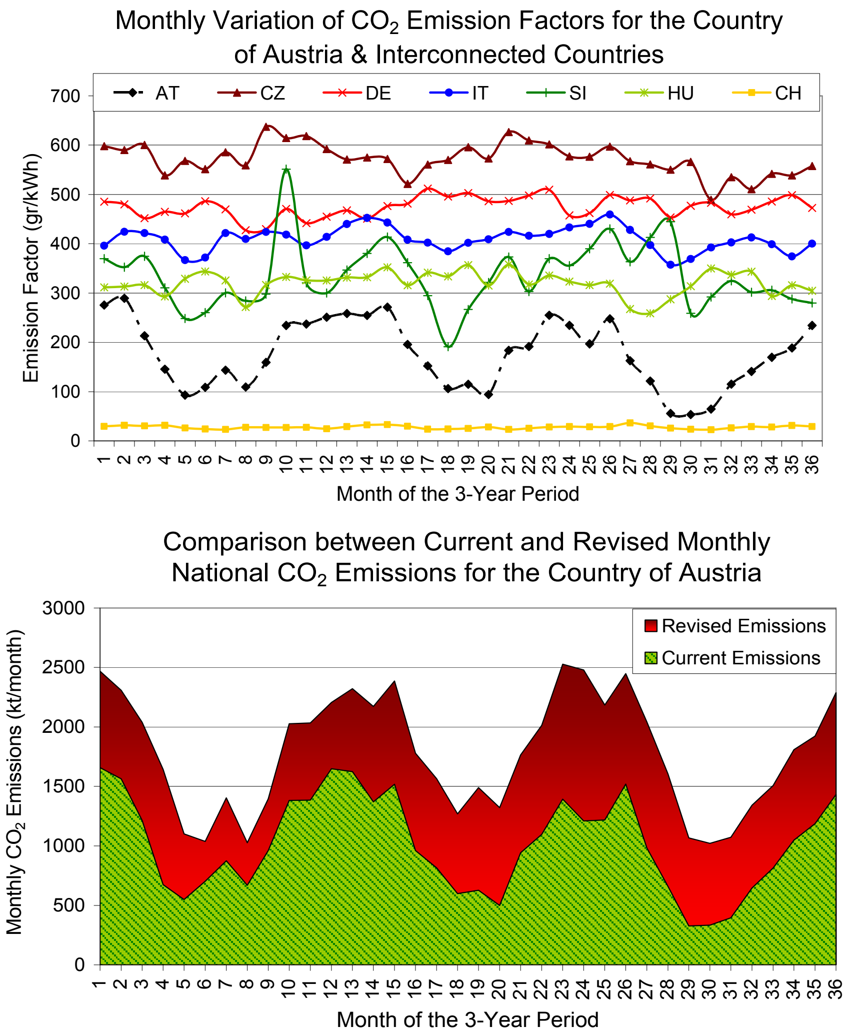


Figure 5.31: Monthly emission factors of interconnected countries and Austria (a) and comparison between current and revised national CO_2 emissions (b)

To this end, by assigning the monthly national CO_2 emission factors of interconnected countries (for the estimation of imported CO_2 emissions) and Austria (for the estimation of exported CO_2 emissions) to the respective monthly imports and exports, monthly national CO_2 emissions are revised for the period of investigation (Figure 5.31b). Austria receives the burden of imported CO_2 throughout the entire 3-year period. In fact, even when Austria presents net electricity exports, the import-export CO_2 balance increases Austria's national emissions, owed to the considerable difference between the emission factors of Austria and its two main importers, i.e. Germany and Czech Republic (Figure 5.31a and Table 5.5). As a result, when considering the balance of CO_2 emissions coming from electricity trade, the 3-year period emission factor of Austria increases from 175gr/kWh to 286gr/kWh, i.e. an increase of approximately 63%.

The respective results for all 33 countries are given in Figure 5.32 and Table 5.5, where current (without considering the impact of cross-border electricity trade) and revised (considering its impact) emission factors are compared. To this end, as expected, countries with significant share of imports (Figure 5.27) from countries with considerably higher emission factors have an increase of their national emissions, reflected (owed to the fact that net consumption may also increase due to the addition of imports and thus cause a reduction of the revised emission factor) in their revised emission factor as well.

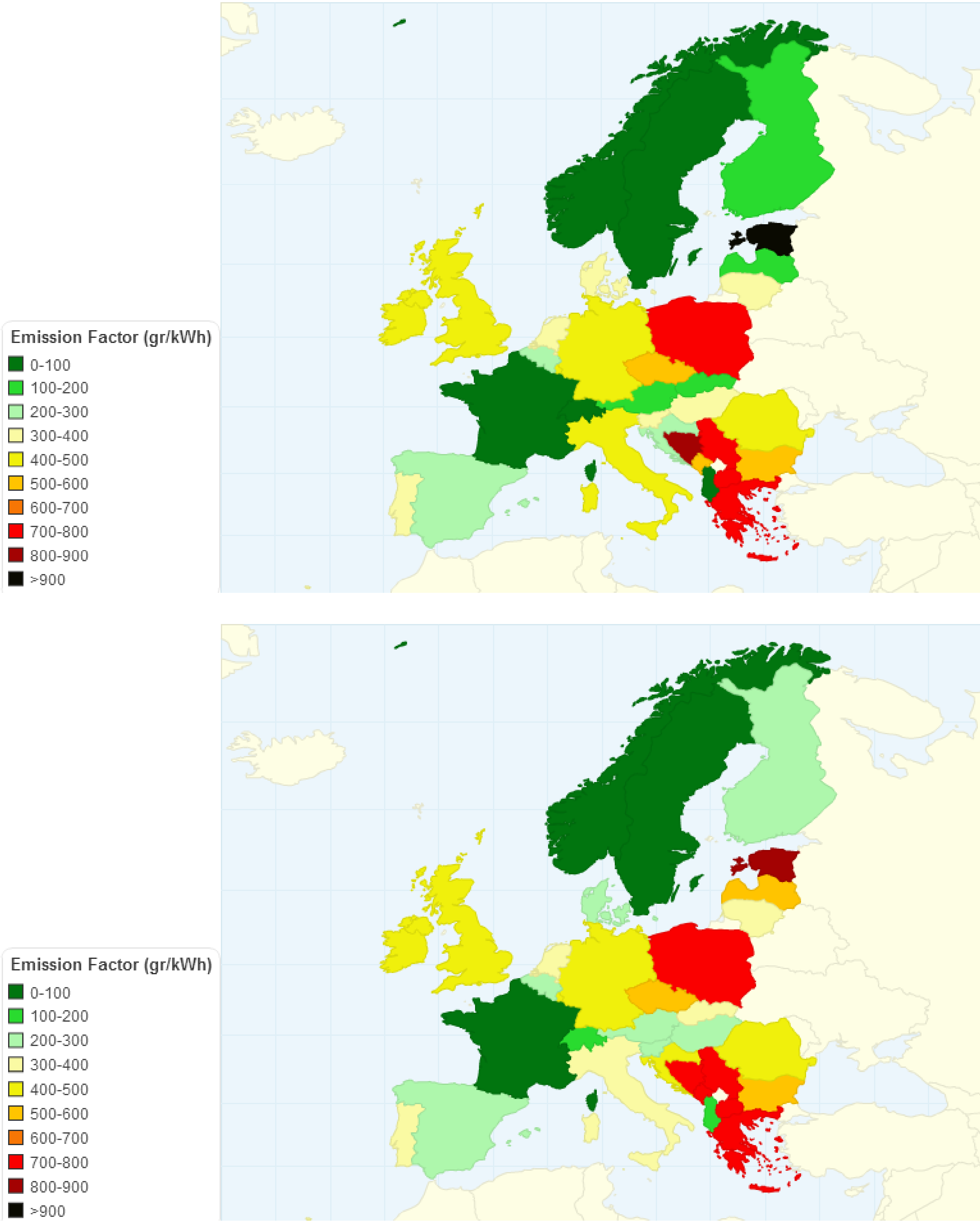


Figure 5.32: 3-year (2010-12) CO_2 emission factor (gr/kWh) variation across EU countries; no CO_2 exchange considered (a); with the impact of electricity trade considered (b)

Table 5.5: CO_2 emission factor results (with and without the impact of electricity trade)[20]

Countries	IEA 2010	Without electricity trade 2010-2012	With electricity trade 2010-2012	Change
ENTSO-E	**gr/kWh**	**gr/kWh**	**gr/kWh**	
AT	187.88	175.35	286.02	63%
BA	722.97	900.17	794.36	-12%
BE	219.56	205.46	214.68	4%
BG	535.46	562.31	558.39	-1%
CH	27.31	27.61	147.05	433%
CZ	589.02	572.99	591.39	3%
DE	460.89	474.44	462.58	-2%
DK	359.67	328.07	259.69	-21%
EE	1014.14	987.08	816.74	-17%
ES	237.98	288.09	284.65	-1%
FI	229.48	191.69	206.92	8%
FR	79.09	72.02	77.47	8%
GR	718.26	720.26	700.71	-3%
HR	236.37	291.53	442.32	52%
HU	317.08	320.21	292.89	-9%
IE	458.04	456.13	456.05	0%
IT	406.31	409.65	368.21	-10%
LT	337.41	344.87	319.22	-7%
LU	409.84	409.80	427.60	4%
LV	119.71	118.09	506.16	329%
ME	405.33	574.89	750.54	31%
MK	685.25	771.41	702.99	-9%
NL	414.85	398.69	387.18	-3%
NO	16.69	13.16	25.16	91%
PL	781.35	767.49	746.88	-3%
PT	255.31	303.67	304.34	0%
RO	413.44	458.03	458.17	0%
RS	717.79	765.57	719.30	-6%
SE	29.57	21.95	39.36	79%
SI	324.91	329.42	270.41	-18%
SK	197.04	199.95	365.48	83%
UK	457.37	454.47	445.82	-2%
Non-Members				
AL	2.15	2.15	161.12	7410%
Externals				
BY	449.42	-	-	-
MO	717.77	-	-	-
MD	517.48	-	-	-
RU	383.60	-	-	-
TR	459.60	-	-	-
UA	390.00	-	-	-

[20] The analysis does not consider for electricity trade between countries that are not interconnected, i.e. the effect of a shadow electricity trade using intermediate countries is not taken into account.

Countries experiencing such a considerable change include Albania, Switzerland, Latvia, Norway, Slovakia, Sweden, Austria, Croatia and Montenegro. The opposite occurs with countries such as Denmark, Slovenia, Estonia, Bosnia Herzegovina and Italy, where greener neighbours help reduce their national emission factor even in the case of countries which have low indigenous emission factors (e.g. Denmark, Slovenia and Italy). Finally, for the rest of the 19 countries, a slight change of ±10% is recorded, owed to the relatively inconsiderable volume of electricity trade and/or the negligible difference noted between the emission factors of interconnected countries holding the greatest share of electricity trade.

5.3.5 The Impact of Using Energy Storage

Following the revision of national CO_2 emissions, the impact of national level energy storage in avoiding CO_2 imports is measured. To demonstrate results, the example of Austria is again used and storage capacity considered is equal to 30% and 60% of the maximum monthly electricity export, i.e. ~650GWh and 1.3TWh respectively (Figure 5.33).

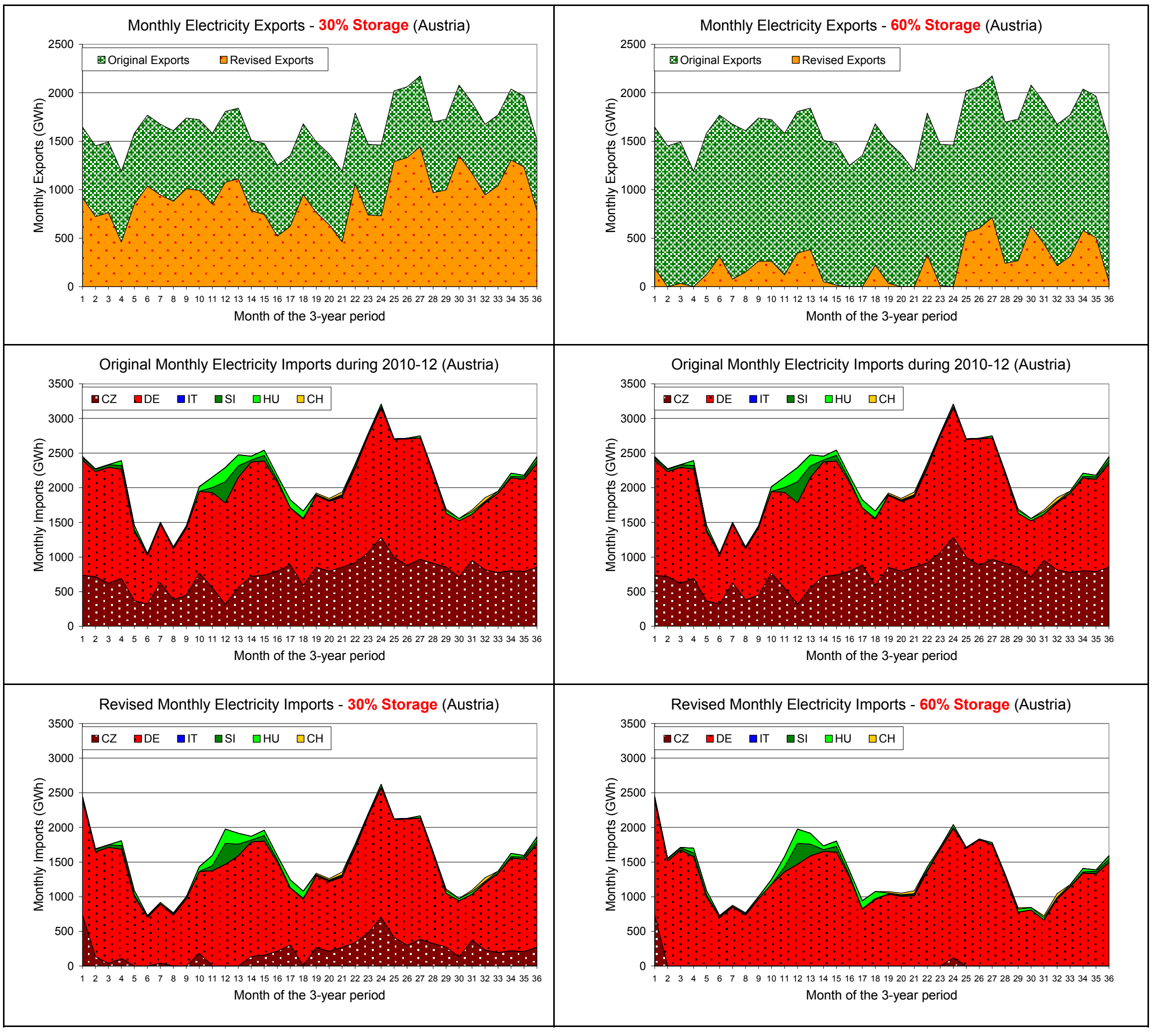
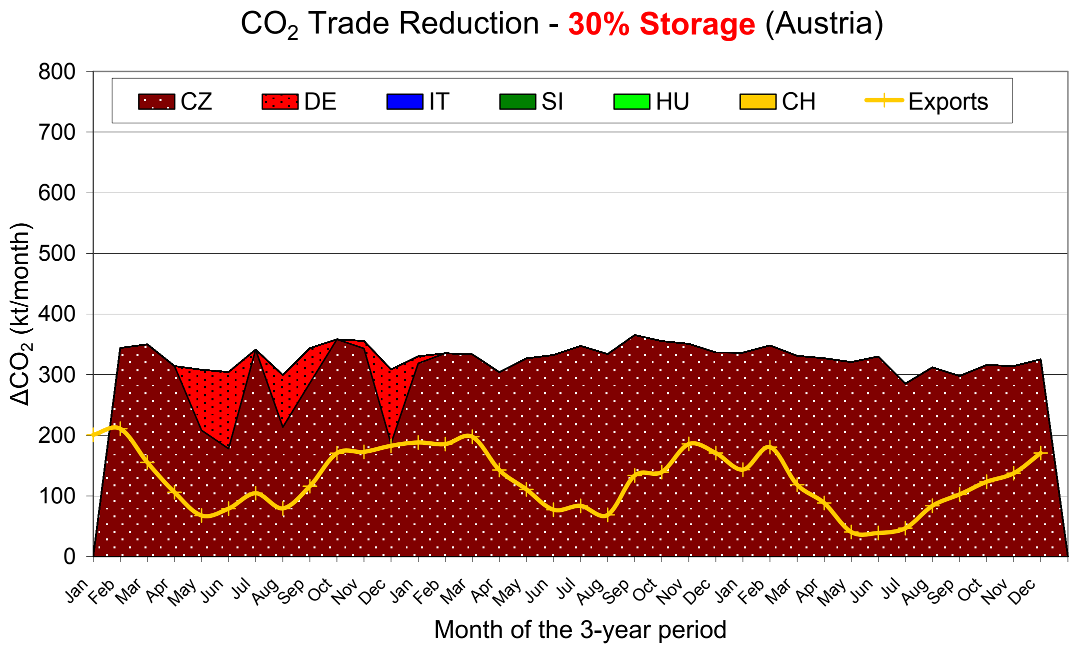


Figure 5.33: Impact of applying energy storage on the cross-border energy trade balance (example: Austria, storage capacity equal to 30% and 60% x max monthly export, round-trip efficiency of 80%)

Application of 30% storage capacity has an immediate impact on the reduction of imports, with cut-downs starting from the interconnector with the highest emission factor, i.e. Czech Republic. Once imports from Czech Republic are eliminated, cut-downs are applied to the second highest emission factor country, i.e. Germany, something that mainly occurs for the 60% storage capacity scenario. The result of this storage exercise is better illustrated in Figure 5.34, where the reduction of CO_2 emissions' exchange is provided for both cases examined. By applying the 30% storage capacity scenario, Austria benefits from emission savings in the order of 310kt/month (deriving from avoided imports) while picking the burden of approximately 130kt/month on average for reducing its exports. The equivalent 3-year result corresponds to net savings of ~6.9Mt of CO_2 emissions, with the respective number increasing to 12.2Mt for the 60% storage capacity case.



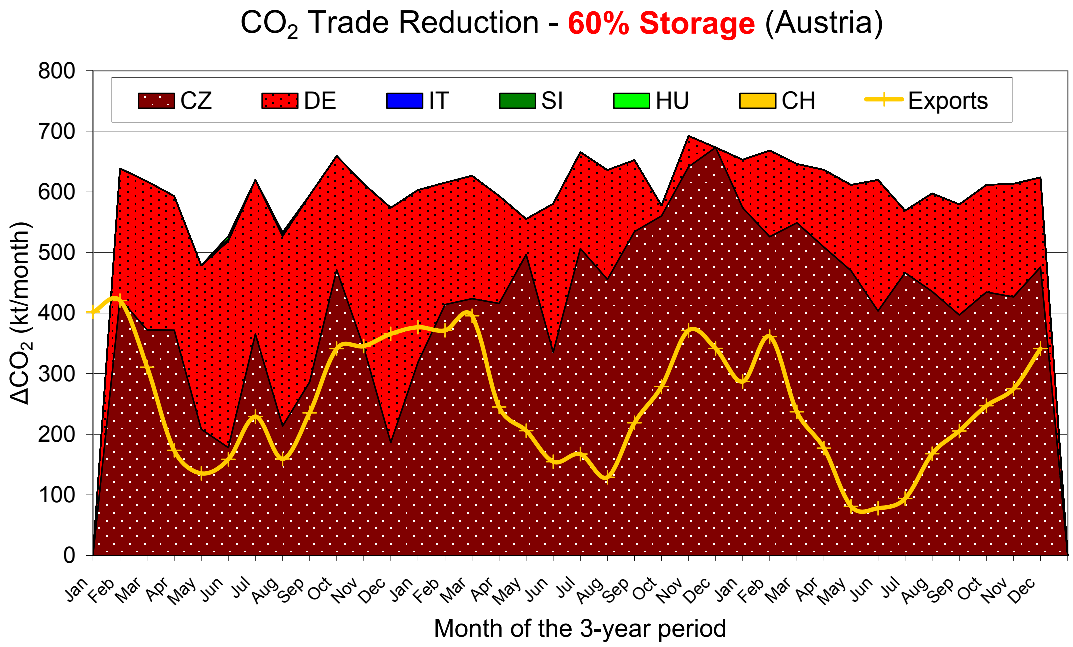


Figure 5.34: Impact of applying energy storage on the balance of CO_2 emissions embodied in cross-border energy trade (example: Austria, storage capacity equal to 30% and 60% x max monthly export, round-trip efficiency of 80%)

Since storage is used to substitute energy imports from sources of gradually decreasing carbon intensity it is expected that its efficiency for emissions reduction (tCO_2/MWh_s) is gradually reduced as well (Figure 5.35). This also suggests the reduction of the national emission factor following an asymptotic trend, owed to the fact that once exports to be exploited are eliminated, no change is expected. At the same time, since Austria is a net importer, the minimum emission factor that could be achieved with the use of maximum energy storage capacity reaches 210gr/kWh, which although being considerably higher than the original emission factor of 175gr/kWh is also quite a bit lower than the revised emission factor of 286gr/kWh.

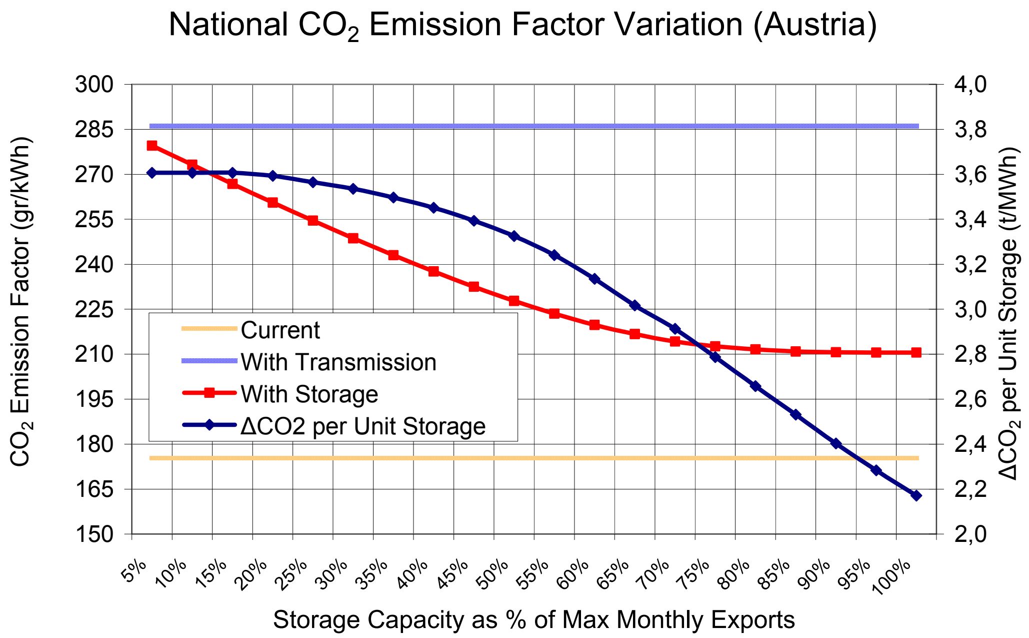


Figure 5.35: Impact of applying different levels of energy storage capacity on the national CO_2 emission factor and CO_2 saving efficiency (example: Austria, round-trip efficiency of 80%, comparison between "current", "with-transmission" and "with-storage" cases)

Switzerland, France and Bulgaria are examined to demonstrate different operation scenarios and impacts that the use of storage can have (Figure 5.36). In this context, Switzerland's emission factor being lower than that of all its neighbouring countries suggests that increase of storage capacity increases national emission savings for almost the entire range of study. An asymptotic behaviour is presented however after a given storage capacity point (e.g. 80% for Switzerland) that depends on the emission factor of the neighbours and the energy trade share they hold. France presents a clear maximum concerning emission savings while also demonstrating an inverse behaviour after a given storage capacity (emission savings become negative). This happens because cut-downs gradually reach interconnected countries that present a lower emission factor (in that case Switzerland) along with the fact that there is no point in storing energy exports - considering also storage losses- that exceed energy imports (France is a net exporter).

Finally, there is Bulgaria, where use of energy storage results in the increase of national emissions. Despite the fact that Bulgaria is interconnected to countries with higher emission factors, (FYROM, the Republic of Serbia and Greece) it does not import substantial energy from them. Actually, Bulgaria imports considerable energy only from Romania, while being an exporter for the rest of countries and Turkey, which is equivalent to the case of being interconnected only to countries with lower emission factors (i.e. similar to Estonia).

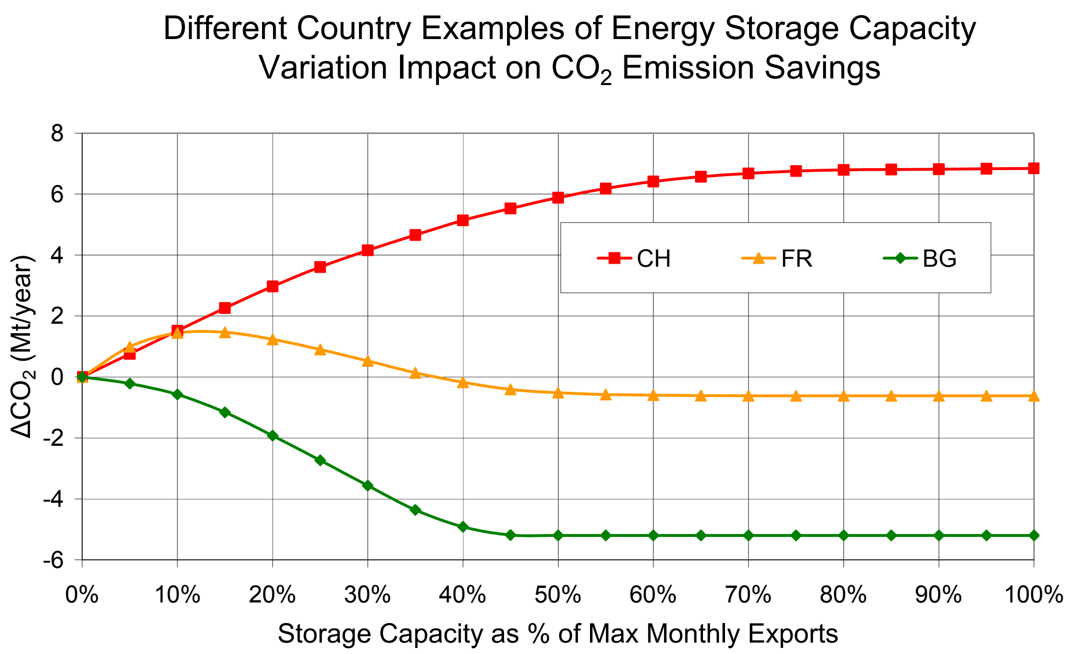


Figure 5.36: The different impact of applying different levels of energy storage capacity on the national annual CO_2 emission savings of certain European countries (comparison between "with-transmission" and "with-storage" cases)

5.3.6 Potential of PHS in European Countries

Although considerable progress is met in the field of energy storage technologies, PHS is still the most mature bulk energy storage technology worldwide, with a total installed capacity of approximately 130GW (Deane et al., 2010). The existing PHS potential across European countries has been compared with the energy storage requirements resulting from the emissions reduction exercise. The PHS potential across European countries was provided by a GIS-based methodology (JRC, 2013).

Short description of PHS

In a PHS system, energy surplus appearing in times of low demand is exploited to pump water to an elevated (upper) storage reservoir with the use of pumps or reversible hydro-turbines. There, energy is stored in the form of potential energy:

$$E_{PHS}(\mathrm{J}) = \rho(\mathrm{kg/m^3})\cdot g(\mathrm{m/s^2})\cdot V(\mathrm{m^3})\cdot H(\mathrm{m}) \tag{5.6}$$

During peak demand, water is released from the upper reservoir and hydro-turbines operate to turn potential energy into mechanical work and feed the connected electric generators. As a result, the system is able to cover energy deficits by supplying the appropriate amount of energy previously stored. In this study, the excess energy comes from the national grid, otherwise exported, and the energy deficit to be covered corresponds to avoided imports. Such systems can take up load in a few seconds' time and feature a high rate of extracted energy. In general, PHS systems are suitable for applications of energy management (including seasonal storage) and spinning reserve, as well as for the support of large-scale renewable energy production (Anagnostopoulos and Papantonis, 2008; Bueno and Carta, 2006; Kaldellis et al., 2010; Kapsali and Kaldellis, 2010; Katsaprakakis et al., 2012). Cycle efficiency of modern PHS is in the order of 70-

80% (Bjarne, 2012; Deane et al., 2010), whereas its main drawback is the high capital cost, directly related to the need for considerable civil engineering works (e.g. the construction of reservoirs). Nevertheless, PHS presents one of the lowest specific installation costs among storage technologies. The existing literature (Katsaprakakis et al., 2012; Zafirakis, 2010) indicates that installation costs for PHS range between 600-1000€/kW of output power for equipment (pumps, hydro-turbines and BOS components) and from 10-30€/m^3 of upper reservoir volume (e.g. construction of reservoir, penstock, etc). However, because of the special features of the PHS technology, determination of actual PHS investment costs is an exercise that requires case-specific information and the execution of a detailed economic study.

PHS potential across European countries

For the assessment of the PHS potential across European countries, the results of the EU Commission Joint Research Centre (JRC) are used, examining two different PHS topologies. The first (T1) considers two already existing reservoirs with adequate elevation difference and appropriate distance between them in order to be linked with the necessary pipeline, while the second (T2), takes into account one existing reservoir together with suitable –close enough- sites for building the second reservoir. The scenarios modelled concern different maximum distances between the two reservoirs of prospective installations, i.e. 1, 2, 3, 5, 10 and 20km. Furthermore, by applying certain constraints such as minimum permitted distance from population areas, protected natural sites, transport infrastructure, etc., the estimated theoretical potential is reduced to the respective realizable one. Results obtained from the JRC report at the European level are gathered in Table 5.6, while for the purpose of the specific study, results of the T2 realizable potential are used. The particular information along with the respective national average head of the reported sites are included in Figure 5.37, with Norway, Spain, UK, Italy and France favoured by the highest PHS potential, and with Finland, FYROM, Belgium and Hungary presenting the lowest ones.

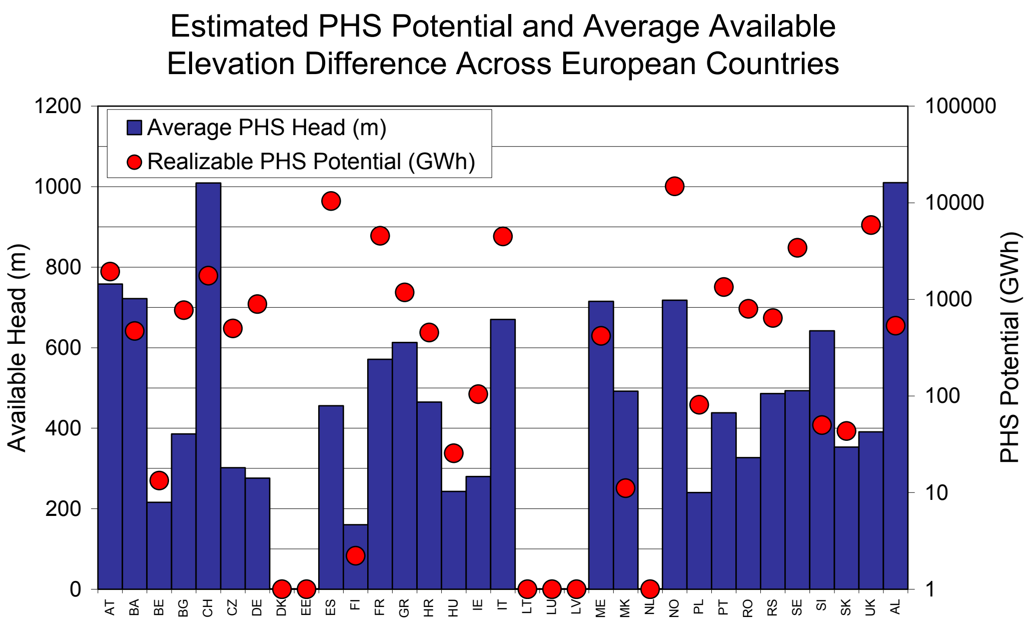


Figure 5.37: Estimated realizable PHS potential across European countries (no data existing for Estonia, Lithuania, Latvia and Luxembourg)

At the same time, Netherlands and Denmark are assumed to have zero potential (due to their orography) while limited information on existing reservoirs of Estonia, Luxembourg, Lithuania and Latvia did not allow for the assessment of their PHS potential.

Table 5.6: Results from the JRC evaluation report on the European PHS potential[21]

T2 - Realisable potential	1km	2km	3km	5km	10km	20km
No. of sites	36	315	670	1330	2499	3551
Average head (m)	222	226	246	278	342	470
Average energy storage (GWh)	4	2	3	3	5	9
Total energy storage (GWh)	4	553	1911	3982	12678	32922

5.3.7 Optimum Energy Storage Potential

The theoretical PHS potential maximizes savings. However, certain countries present an asymptotic pattern when further increase of storage delivers negligible CO_2 savings (see Switzerland in Figure 5.36). This final selection of energy storage capacity constitutes the optimum realizable CO_2 savings maximization. The approximate estimation of installation costs makes use of literature information for equipment costs of 600-1000€/kW of power output and civil engineering costs of 10-30€/m^3 of upper reservoir volume together with the information of Figure 5.37 on the average national head available (equation 5.6). Finally, the break-even CO_2 price required to marginally support such investments under the condition of achieving a 30-year simple payback period.

Maximum savings energy storage potential vs realizable PHS potential

Using the results of our calculations and the realizable PHS potential, optimum energy storage characteristics are first given in Figure 5.38, where two aspects of storage size are presented. In the first figure the optimum storage capacity (subject to the PHS potential and the evaluation of asymptotic patterns) is compared with the respective theoretical maximum saving capacity. In the second figure, the respective power output N_{PHS} is estimated using the 3-year CF of imported energy amounts CF_{imp} (see Figure 5.28), the energy storage capacity E_{PHS} and the output energy efficiency of the system ηout ($\sim\eta_{rt}^{1/2}$) together with the hours h_{month} of a typical 30-day month, i.e.:

$$N_{PHS} = E_{PHS} \cdot \eta_{out} \cdot (CF_{imp} \cdot h_{month})^{-1} \tag{5.7}$$

Note at this point that in the specific graph, only countries benefiting from the application of energy storage in terms of CO_2 savings are included. To this end, for the majority of countries the existing PHS potential approaches or is equal to the respective theoretical maximum saving capacity. Only Belgium, Finland and Slovakia have limited PHS potential together with Denmark (owed to its morphology) and Lithuania and Latvia that are assumed to have zero PHS potential. Nevertheless energy storage potential is not necessarily constrained by PHS potential, since other types of technologies such as CAES (Lund and Salgi, 2009) can provide storage services. Furthermore, in the second chart of Figure 5.38, the influence of the import CF on the estimation of the required power output is reflected, with several countries requiring hydropower only in the order of tens of MWs to support operation of the proposed PHS. The above results are however better interpreted with the use of information provided in the next Figure 5.39.

[21] The average head values provided do not take into account losses of the penstock, the latter being proportional to the distance between reservoirs.

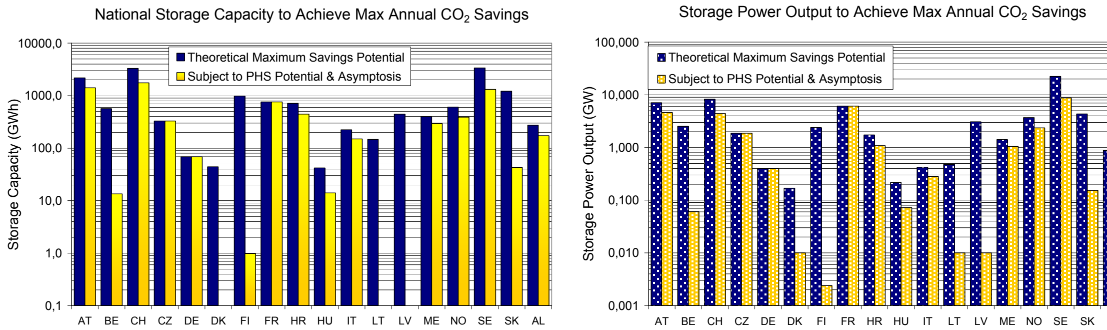


Figure 5.38: Sizing results of energy storage for countries benefiting in terms of cross-border CO_2 emission savings, based on the criterion of maximum annual savings achieved

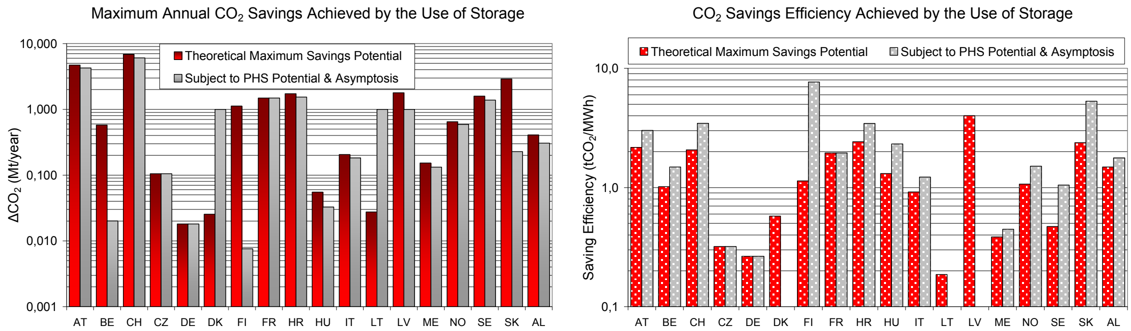


Figure 5.39: CO_2 saving results based on the criterion of maximum annual savings achieved

Austria and Switzerland achieve the greatest annual emission savings, with Finland and Slovakia showing the higher efficiency. This is because the available PHS potential of these countries allows import cut-downs from the interconnectors with the higher emission factor (Figure 5.39). In this context, as one may see, countries determined by low emission saving efficiency are faced with the paradox of a higher emission factor, due to the increased reduction of exports having an immediate effect on the value of net consumption used to define the new revised (with storage) emission factor. On the contrary, countries with sufficiently high efficiency, such as Norway and Switzerland, produce considerably lower emission factors (Figure 5.40).

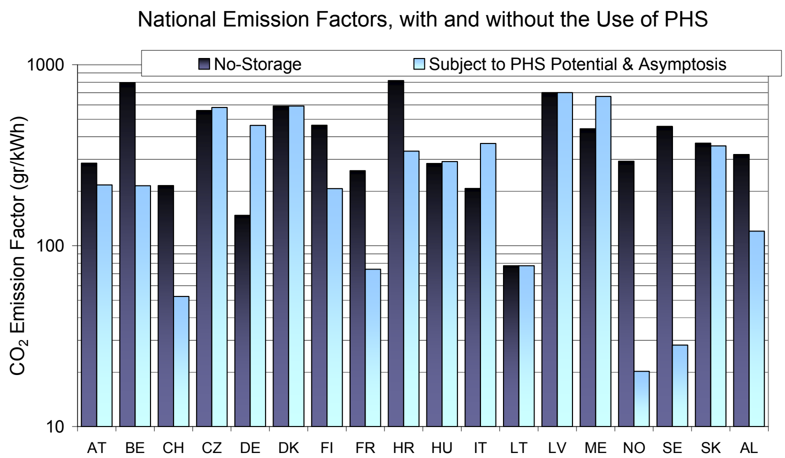


Figure 5.40: The impact of using optimum PHS configurations on national CO_2 emission factors

Determination of the break-even CO_2 price

Lastly, after attempting an estimation of the installation cost of the optimum configurations, the break-even CO_2 prices that could marginally support investment in PHS are determined. For this purpose, the simplification of fixed fuel mix and a 30-year simple payback period for the PHS installations applies while disregarding the price of traded electricity (Figure 5.41).

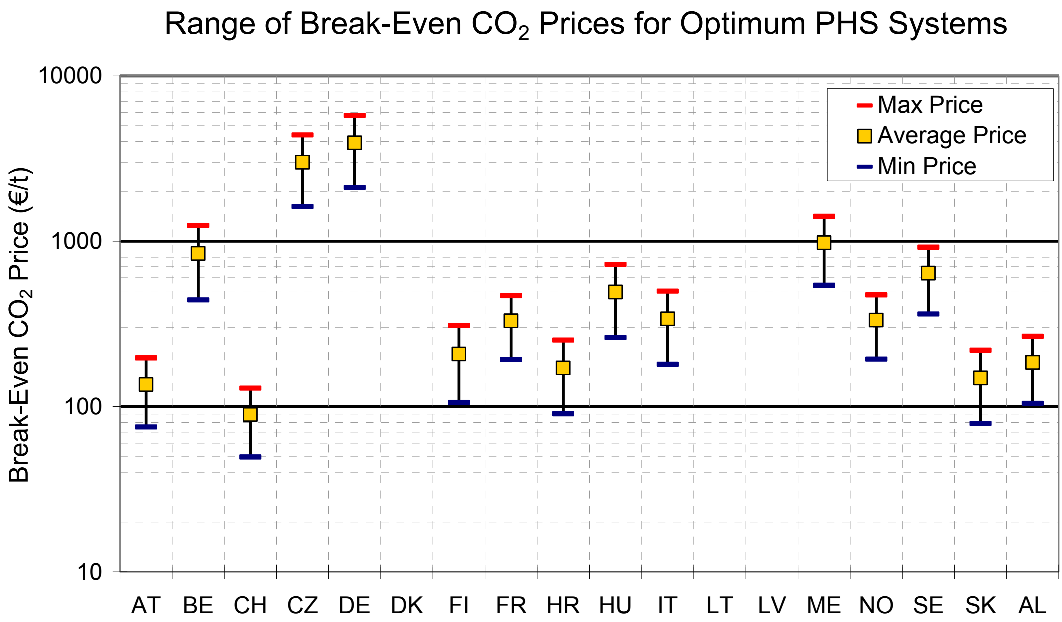


Figure 5.41: Break-even CO_2 prices required to marginally support optimum PHS installations

There is considerable variation in the national break-even CO_2 price, owed to the respective variation of installation costs. According to the minimum and average cost scenario for many countries the CO_2 price is below or close to 100€/t, opposite to the cases of e.g. Czech Republic and Germany (the countries with the lowest CO_2 saving efficiency) for which even the minimum CO_2 price is extremely high. To this end, it is demonstrated that for the majority of countries even marginal investment support cannot be easily satisfied. The break-even CO_2 price should in reality be treated as variable, adjusting to the variation of the CO_2 saving efficiency in the course of time, potentially under a more dynamic market structure (such as in the example of Figure 5.42 where the respective relation is given for the country of Austria and the minimum cost scenario values).

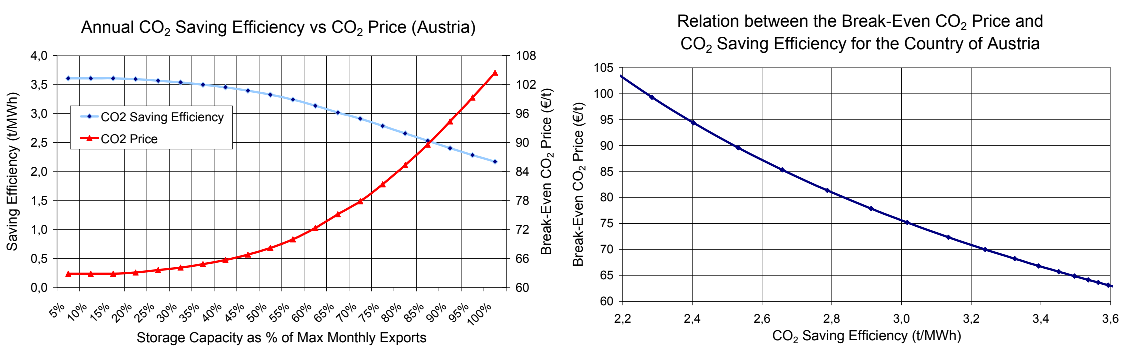


Figure 5.42: Variation of the break-even CO_2 price in relation to energy storage CO_2 saving efficiency

On the other hand, use of monthly data limits the efficient sizing of PHS configurations, since system size could be significantly reduced with more detailed electricity trade information (e.g. hourly data) that would allow the investigation of more frequent cycling, paving also the way for the reduction of the respective CO_2 prices. Moreover, investment appraisal should be informed by more comprehensive cost-benefit analyses including additional gains such as the effective congestion management and cross-border transmission deferral.

5.3.8 Discussion

The simulation results are restricted at the national level, not capturing the European system optimum. As already mentioned, owed to the monthly resolution of the dataset, PHS plants' daily or even hourly cycling cannot be captured, leading to oversizing of storage capacities. This in turn implies significant overestimation of the break-even CO_2 (Figure 5.41), which should be considered when appraising the results of the specific study together with the need to assess the overall benefits deriving from the adoption of the proposed solution. Owed to this, the analysis is also limited with regards to the investigation of simultaneous exports and imports for a given country, which could imply the use of imports for the purpose of serving a third country rather than for the purpose of local consumption. Additionally, the use of energy storage is complementary to the increased participation of renewables, not discouraging new renewable energy investments at the expense of PHS installations. As a matter of fact, it is the increased participation of renewables that is expected to signal the need for energy storage and allow for greater utilization of storage assets, together leading to the systematic reduction of CO_2 emissions at the European level. Moreover, storage assets are complementary to cross-border interconnections for buffering purposes. This allows for more effective energy trade between neighbouring countries, especially in the case of increased renewable energy penetration that will inevitably lead to greater excess of energy production and greater challenges for congestion management. To this end, utility-scale storage assets can, on top of the proposed service, satisfy additional applications such as the provision of grid ancillary services, thus their value can increase significantly, allowing in this way for the acceleration of market growth and investments in the specific sector.

5.3.9 Summary

Acknowledging the fact that cross-border electricity trade is determined by hidden exchange of CO_2 emissions, the impact of electricity trade on national emissions of European countries is estimated. Subsequently, by using utility-scale national energy storage, an exercise is performed in order to protect "cleaner" countries from CO_2-intensive electricity imports. For this purpose, the potential of exploiting "cleaner" energy exports to replace CO_2-intensive energy imports through the use of PHS is examined. By examining the national potential of PHS in European countries, optimum, realizable storage capacity levels are determined and associated with CO_2 prices that could marginally support investment in the field. Our results demonstrate that the required prices of CO_2 are kept below or in the order of 100€/t for certain countries. Nevertheless utility-scale energy storage could, apart from the proposed service, support local renewable energy production and perform additional roles, including grid services and local electricity market regulation that can increase the value of the specific assets and encourage investments.

5.4 Conclusions

The main conclusions of Chapter 5 are synopsized in the following:

According to the the application results of the first thematic study of this chapter, it can be argued that combination of RES power generation with utility scale energy storage, may, from the system operator point of view, cover not just peak demand but also base-load demand. In fact, it was seen that if exploiting already available bulk energy storage, such as PHS, similar configurations are close to achieving grid parity. Furthermore, base-load RES-energy storage systems support the elimination of variability attributed to RES power generation, ensuring at the same time high level of energy security and lower CO_2 emissions.

Apart from the support of increased RES penetration however, utility-scale energy storage can also provide market regulation for the system operator. To this end, energy storage can satisfy multiple goals including price regulation, control of price volatility and increase of fuel diversity and energy independence. At the same time, utility-scale energy storage can contribute towards the direction of protecting national scale electricity grids from CO_2-intensive energy imports. This also stimulates the design and development of a CO_2 taxation system, identifying the problem of the underlying cross-border emission trade through electricity trade.

Considering the realizable potential for PHS at the EU-level as well as the fact that the above services could constitute a portfolio for national, utility-scale energy storage, there is a clear stimulus for system operators to exploit such storage assets, considering however that similar welfare effects could be equally well supported by the diffusion of distributed energy storage systems at the private actor level.

6. Discussion and Conclusions

6.1 Contribution of the Thesis

As the share of RES power generation is increased in the fuel mix of most countries, new challenges arise for the operation of electricity systems and the regulation of electricity markets. Meanwhile, as state support for RES technologies (e.g. FiTs) is phased out, a new era for RES power generation begins that signals the exposure of RES producers to energy markets and dynamic pricing. During this transition, RES investors will seek solutions to shield themselves against the intermittent features of RES power generation and the volatility of electricity prices. At the same time, the large-scale integration of RES will trigger significant changes, calling system operators to perform energy management under more effective terms to maintain the current levels of supply security. To this end, the role of the so-called holy-grail of future energy systems, i.e. energy storage, is becoming increasingly important. In fact, what can be said about energy storage is that nowadays it finds itself in the same place that RES technologies were two decades ago; faced with the expectation for a fast growing market. Opposite to RES however, it is important to note that the energy storage sector has to overcome the barrier of a global environment subject to persisting economic uncertainty. Additionally, emergence of alternative and readily-available energy supply sources such as shale gas in the USA market rapidly transforms the global energy map and shifts the investing interest in different directions. It is this mix that has resulted in the postponement of market diffusion for commercially mature energy storage technologies, causing also considerable delay in the further evolution of developing or developed energy storage systems. To deal with the situation encountered and accelerate the growth of energy storage markets, the evaluation of emerging energy storage applications together with the design of novel dispatch strategies and configurations becomes critical. In this context, emerging and novel energy storage applications have been examined in the current thesis, using energy storage technologies that can effectively perform energy management (including PHS, CAES and typical battery storage).

Concerning private actors, both active and passive use of energy storage was investigated, capturing arbitrage in European energy markets on the one hand and combination of energy storage and DSM in order to protect industrial end-consumers from energy insecurity and high energy bills on the other. As far as arbitrage is considered, evaluation of historical trends, different strategies, different technologies and different system sizes produced a holistic view with regards to its actual value for energy storage across representative European power markets, so far missing from the literature. Furthermore, combination of DSM and arbitrage built on new methodological directions for the development of multiple-service distributed energy storage. To this end, despite that sizing and dispatch strategy optimization entails significant gains in both cases, high risk and capital requirements seems to prevent effective investment so far. Contrariwise, by considering RES and identification of social welfare benefits produced by energy storage promoting RES integration, state support (e.g. in the form of FiTs) would be justifiable and could trigger further investment. The development of a novel policy framework to that direction provides decision makers with a straightforward assessment and evaluation tool, applicable in various instances, although for the moment much hindered due to the financial crisis and subsequent austerity policies.

As a result, it accrues that for private owned energy storage and for the time being, it is a portfolio of services rather than a single source of revenues that can lead to increased profitability under moderate investing risk. Collaboration of energy storage and RES power generation is believed to contribute considerably towards this direction, by assigning power production attributes to private-owned energy storage. This notion is also in line with distributed generation and future microgrid schemes, where the role of energy storage can be twofold; to filter local RES power generation and deliver it to the grid under guaranteed supply terms and to secure the end-consumption from large shares of variable power generation as well as from increased electricity prices. Such a multifunctional purpose for distributed energy storage although increasing its value, it also poses the need for the further development of already available storage technologies so as to withstand the increased operational requirements.

For the investigation of energy storage application from the system point of view, emphasis was first given on autonomous electricity grids. These, small-scale electricity grids are usually supplied by expensive, oil-based power generation that encourages the examination of alternative energy schemes, such as RES-based energy storage configurations. With this in mind, the impact of RES potential quality on the cost-effectiveness of a representative configuration was examined, while the concept of introducing the CAES technology and thus natural gas in island regions was elaborated as an alternative to state-of-the-art proposals on PHS and battery storage. Moreover, the positive influence of DSM on size reduction of the energy storage component was designated, emphasizing on the role of smart-grid attributes when it comes to the optimum sizing of fully or close to autonomous RES-based schemes.

Subsequently, the use of national-level energy storage was used to support the introduction of a novel dispatch strategy, i.e. base-load operation of RES power generation, which can eliminate variable RES power generation and facilitate effective energy management at the system level, using as case study the UK national grid and the local PHS potential. Accordingly, the regulating capacity of utility-scale energy storage was illustrated through the examination of different market efficiency criteria affected by the variation of fuel mix caused by the dispatch of energy storage, using as case study the Greek market and offering decision-makers with the basis for a practical multi-criteria tool.

Finally, the role of national energy storage was also examined in the context of cross-border electricity trade so as to encounter the underlying problem of embodied CO_2 emissions' exchange through national interconnectors. Prior to that, an extensive analysis undertaken measured the impact of cross-border electricity trade on the actual national emissions of European countries by revising the currently adopted national emission factors. The developed methodology concluded with the estimation of break-even CO_2 prices for national scale PHS achieving mitigation of increased CO_2 emissions owed to electricity imports, building also towards the development of a cross-border electricity trade that features CO_2 market attributes. In this way, a bundle of services was revealed for utility-scale energy storage, which from the operator point of view, can provide electricity systems with a valuable, multifunctional asset.

6.2 Policy Recommendations – Energy Storage Roadmap

Acknowledging the above, one may distinguish two main directions for the future of energy storage. Distributed energy storage (both active and passive) for private actors and large-scale utility storage for system operators. The balance between the two in a given electricity system can determine the level at which private actors produce (or are required to produce) social welfare benefits for the operation of the grid, which in turn shall also determine the level of financial state support to private-owned energy storage adopting such welfare-producing services. To this end, the roadmap envisaged for the market uptake of energy storage –and especially scalable energy storage systems such as batteries- is given in Figure 6.1. Exploiting the ground offered by autonomous electricity systems (e.g. island grids), pilot projects employing energy storage and smart grid technologies (e.g. DSM) need to be implemented in order to deal with technical, social and business challenges encountered at the national-grid level as well.

Meanwhile, the introduction of energy storage systems in electricity markets should encompass collaboration with RES in order to reduce inherent risks for both RES and energy storage actors. Such schemes could gradually develop in other sectors as well, e.g. the industrial sector, where the role of energy storage could extend to passive storage attributes (i.e. DSM aspects). Diffusion of the appropriate technologies in the industrial sector and the built environment can then produce positive spill-over effect to other sectors such as the residential. This will result in the gradual development of significant, distributed energy storage and RES power generation stock that can offer multiple services to the entire grid while also providing each individual actor with increased energy security features.

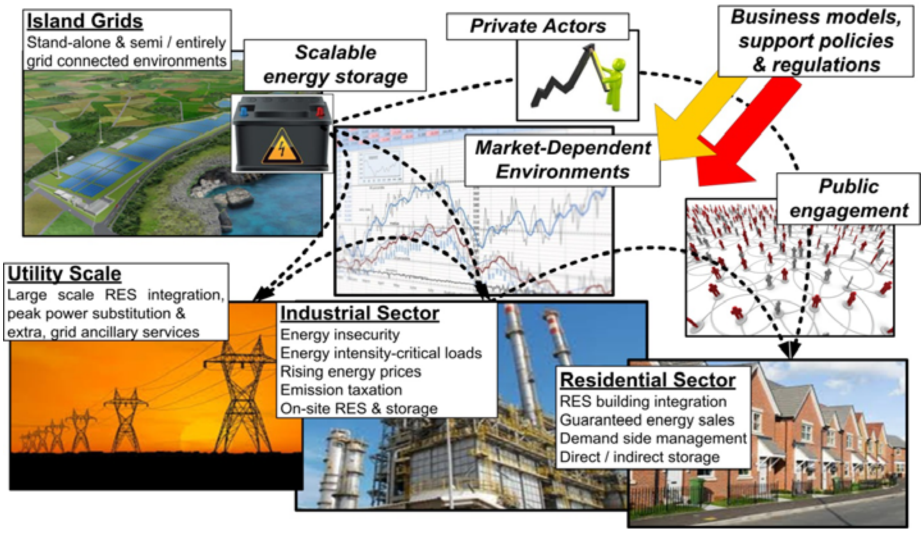


Figure 6.1: The roadmap for the market uptake of energy storage in the near future

6.3 Future Research

Future work in the field of energy storage calls for research in various directions, embracing technology, business, innovation, policy and other disciplines.

- Dispatch strategies of energy storage systems for private actors need to become more sophisticated and better adapted to individual needs, capturing both active and passive energy storage attributes. More advanced dispatch strategies will also have to incorporate the element of sufficient prognosis through the development of appropriate forecasting tools. Combined with the development of new DSM techniques, they will pave the way for the introduction of smart microgrids interacting with central grids.
- At the business and innovation level, engagement of the public is thought to be of high importance. New business models for distributed energy storage need to be developed, that will involve public participation in order for public stakeholders to harvest social welfare benefits produced by energy storage more effectively. Simultaneously, concrete innovation plans need to be put forward in order to exploit

the positive spill-over effects of energy storage and indicate the pathways of market diffusion, from individual pilot projects to the wider public.

- At the policy level, identification and definition of grid and other services for energy storage needs to progress rapidly. This will lead to the development of a policy, planning and legislation framework tailored to the special features of each electricity system and electricity market, linked also to the need for the accomplishment of ambitious RES and energy security targets.
- Although not central to this thesis, research in energy storage technologies is expected to focus on the scalability and life-extension of energy storage systems that will enable more effective diffusion in the wider market. Developments met in the battery sector are believed to be critical to this end, with new battery systems challenged by the introduction of electric vehicles and arising needs in the building sector. Owed to their scalable character, similar efforts are also expected in CAES, with smaller scale facilities targeting distributed generation applications. In the meantime, despite the fact that the further development of FC-HS has experienced considerable delays, mainly owed to the inherent characteristics of the technology (e.g. very low round-trip efficiency), increased RES penetration in the near future shall revive the interest concerning hydrogen applications.

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