Value of flexibility in systems with large wind penetration

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Declaration

This is to certify that:

1. No part of the work referred to in this thesis has been presented in support of an application for another degree or qualification in this or any other University

2. This thesis is less than 100,000 words in length excluding References.

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Abstract

The focus of this thesis is the quantification of the value of operation flexibility in systems with large penetration of wind generation. This begins with the quantification of the impact of wind generation (WG) uncertainty on the system's needs for frequency regulation and reserve. This is done by combing the stochastic behaviour of wind generation, demand uncertainty and generation outages. Two different approaches are compared to access the implications of using normal distribution approximations or direct representations of different sources of uncertainty. This is followed by an investigation of the relative impact of different sources of uncertainty on the reserve levels. For large wind penetration, wind becomes the dominant source of uncertainty driving most of the need for reserve. Procuring such large requirements increases the need for flexibility and the overall system operations cost. To mitigate these additional costs and improve system flexibility, the study explores the use of a combination of spinning and standing reserve to meet the increased reserve requirements. This combination minimises the cost of reserve and increases system flexibility. These benefits are more pronounced if a more accurate representation of uncertainty is used.

Following this, a detailed analysis of the value of generation flexibility is performed. The analysis is based on the modification of traditional scheduling models to include WG and to take into account the relevant features of system operation flexibility. The value of flexibility is quantified for different conventional generation mix, different response and reserve technology compositions and generation technology flexibility, across a wide range of wind penetration levels. The key drivers for the value of flexibility are shown to be the increased response and reserve requirements (especially reserve requirements), the conventional generation mix and the inherent flexibility of must-run generation. This is driven mostly by the system's need for curtailing wind to maintain the generation/demand balance. To obtain a significant reduction of carbon emissions, however, a combination of must-run generation with a large penetration of wind is required. This results in a high economic and environmental value being placed on must-run generation flexibility.

The high economic and environmental value attributed to flexibility is seen as an opportunity to explore alternative sources of flexibility, such as storage and demand side flexibility (DSF). To this end, this work also investigates the role that such enabling technologies can play in enhancing system flexibility, by contributing to standing reserve and load-levelling. For this purpose a new system operation tool is developed. This tool simulates system operation for forecasted and realised wind generation to optimise reserve scheduling and utilisation. This is required to quantify the value of using storage and DSF to provide reserve. This tool is used to quantify the economic and environmental value of these technologies for different conventional generation mix and wind penetration. The studies show that both technologies have economic and environmental benefits and this is more pronounced for low flexible conventional generation mix and higher wind penetration. The value is driven mostly from increasing the system's

ability of using WG. This highlights the role that storage and DSF can play in enabling low carbon systems composed by a combination of low flexible conventional generation with a large wind penetration.

Finally, the thesis also examines the role of storage and DSM to support network operation, particularly in systems like the UK where the connection of WG capacity is limited by network constraints. The use of these technologies, to increase network flexibility in situations of congestion, is explored through the development and application of a multi-period optimal power flow with storage and DSM included as part of the optimisation constraints. The study concludes that both technologies present benefits and have a complementary role. Its value is maximised under different conditions and depends on the cost of generation and location of demand, across the network.

Table of Contents

List of Figures

List of Tables

List of Publications

Conference Papers:

M. Black, **V. Silva** and G. Strbac, "The role of storage in integrating wind energy", in Proc. of International Conference on Future Power Systems, Amsterdam, 2005

V. Silva, V. Stanojevic, D. Pudjianto and G. Strbac, "Storage and DSM Benefits in Transmission Congestion Management in Systems with High Wind Penetration", in Proc. of Proceeding of the 7th International Workshop on Large Scale Integration of Wind Power and on Transmission Network for Offshore Wind farms, Madrid, Spain, 2008

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Book Chapter:

V. Silva, V. Stanojevic, M. Aunedi, D. Pudjianto and G. Strbac, "(In press) Smart domestic appliances as enabling technology for demand side integration: modelling, value and drivers", ed. M. Pollit, Cambridge University Press, Cambridge, 2010

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"Cigre Technical Brochure on Demand Side Integration", A. Baitch, S. Karkkainen, C. Alvarez, A. Gabaldon, C. Schwaegerl, R. Belhomme and **V. Silva**, 2010, (to be published), CIGRE, Paris

Abbreviations

AGC	Automatic generation control
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
COPT	Capacity outage probability table
CS	Control schemes
DD	Dynamic demand
DG	Distributed generation
DLC	Direct load control
DSF	Demand side flexibility
DSI	Demand side integration
DSM	Demand side management
DSP	Demand side participation
DW	Dish washer
ED	Economic dispatch
ENS	Energy not supplied
GS	Generation scheduling
HF	High flexible
ICT	Information and communication technologies
IPCC	Intergovernmental panel in climate change
LF	Low flexible
MF	Medium flexible
MILP	Mixed integer linear programming
MLE	Maximum likelihood estimate
MRC	Maximum registered capacity

MSG	Minimum stable generation
NGET	National grid electricity transmission
OCGT	Open cycle gas turbine
OPF	Optimal power flow
SCUC	Security constrained unit commitment
SO	System operator
SP	Stochastic programming
SR	Spinning reserve
StR	Standing reserve
V2G	Vehicle to grid
VOLL	Value of lost load
WAM	Wide area monitoring
WD	Washer dryer
WF	Wind farms
WG	Wind generation
WM	Washing machine
WP	Wind penetration

List of Symbols

Sets

$\mathbf{N_G}$	set of generators
$\mathbf{N_{GC}}$	set of generators committed
$\mathbf{G_{BUS}}$	set of buses with generation
$\mathbf{NG_b}$	set of generators connected to bus *b*
$\mathbf{N_{BUS}}$	set of network buses
$\mathbf{N_{BR}}$	set of network branches
$\mathbf{M}$	set of demand side management control schemes
$\mathbf{L_{type}}$	set of types of controllable devices
$\mathbf{L_{BUS}}$	set buses with demand connected

Indices

t	index of time periods running from 1 to T, T_{24}
i	index of generators running from 1 to N_G
ic	index of generators committed running from 1 to N_{GC}
b	index of network buses running from 1 to N_{BUS}
j	index of demand side management control schemes running from 1 to M
k	index of types of controllable devices running from 1 to L_{type}

Variables

$u_{i,t}$	binary variable that defines the status of generation unit *i* at time *t* (1: committed, 0: decommitted)
$p_{i,t}$	power generated by unit *i* at time *t*
$p_{ic,t}$	dispatched power output at committed generator ic at time t
$\Delta p_{i,t}^{-}$	decrease of the production of generation unit i at time t
$\Delta p_{i,t}^{+}$	increase of the production of generation unit i at time t
$p_t^{fast\_plant}$	power generated by fast plant at time *t*
$r_{i,t}^{pr}$	contribution to primary response of generation unit *i* at time *t*
$r_{i,t}^{hf}$	contribution to high frequency response of generation unit *i* at time *t*

$r_{i,t}^{up}$	contribution to upward spinning reserve of unit *i* at time *t*
$r_{i,t}^{dn}$	contribution to downward spinning reserve of generation unit *i* at time *t*
$w_t^{f,c}$	aggregated system wide wind generation curtailed for forecasted wind at time *t*
$w_t^{a,c}$	aggregated system wide wind generation curtailed for realised wind at time *t*
$r_{w,t}^{pr}$	contribution to primary response of wind generation at time t
$r_{w,t}^{hf}$	contribution to high frequency response of wind generation at time t
l_t^{shed}	involuntary load disconnection at time *t*
$l_t^{a,shed}$	realised involuntary load disconnection at time *t*
$l_{t,b}^{shed}$	involuntary load disconnection in bus *b* at time *t*
e_t^{over}	excess of generation at time *t*
$e_t^{a,over}$	realised excess of generation at delivery time *t*
$\theta_{b,t}$	voltage phase angle at bus b at time step t
$P_{bp,t}$	active power flow in branch bp at time step t
S_t^d	power discharged by storage at time step t
S_t^c	power charged by storage at time step t
$S_{b,t}^d$	power discharged by storage at bus b at time step t
$S_{b,t}^c$	power charged by storage at bus b at time step t
ES_t	energy available in storage at time step t
$ES_{b,t}$	energy available in storage at bus b at time step t
dev_j	number of devices controlled by control scheme *j*
X_{tjk}	number of type k devices that were originally expected to be connected at time step t and are shifted to time step j (j $\geq t$);
X_{bwj}	number of devices (or groups of devices), of load control program j, at bus b, initiated at time step w (function of *t*)

Functions

$s_{i,t}$	start up cost of unit *i* at time *t*
w_t^f	aggregated system wide wind generation output forecasted at time *t*
w_t^a	aggregated system wide wind generation output realised at time *t*
R_t^{pr}	primary response requirement at time *t*

R_t^{hf}	high frequency response requirement at time *t*
R_t^{up}	upward reserve requirement at time *t*
R_t^{dn}	downward reserve requirement at time *t*
$R_t^{sp,up}$	upward spinning reserve requirement at time *t*
$R_t^{st,up}$	upward standing reserve requirement at time *t*
λ	split of the upward reserve requirement between spinning and standing reserve
net_d^t	net demand, at time *t*
d_t^f	system wide demand forecasted, at time t
d_t^a	system wide realised demand at time *t*
$d_{b,t}$	active power total demand at bus b at time step t
$d_{b,t}^{DSM}$	demand after DSM actions are applied at bus b at time step t
A_j^t	control schemes of a group of aggregated demand at interval *t* interval when the *j* control scheme is exercised
$d_t^{controled}$	demand profile from controllable load after DSM actions are applied at time *t*
d_t^c	demand reduction after DSM actions are applied at time t
d_t^p	demand paid back after DSM actions are applied at time step t
$d_{b,t}^r$	demand reduction at bus b at time step t after DSM actions are applied
$d_{b,t}^p$	demand paid back after DSM actions are applied at bus b at time step t

Constants

Cost input parameters

c_i	marginal cost of generation unit i
c_{ic}	marginal cost of committed generation unit ic
$c_{nl,i}$	no load cost of generation unit i
$\mathrm{c_i^-}$	is the marginal cost of negative adjustment (due to congestion) of generation unit *i*
$\mathrm{c_i^+}$	is the marginal cost of positive adjustment (due to congestion) of generation unit *i*
c_i^{start}	fixed cost of bringing online the generation unit *i*
$c_{ful\,l_{load}}$	is the marginal cost of the generation unit when running at full load
$c_{par\,t_{load}}$	is the marginal cost of the generation unit when fully part loaded

$c_{residual}$	is the marginal cost of the generation unit that is partly backed off
$c_{fas\,t_{plant}}$	is the marginal cost of standing generation plant
$VOLL$	value of lost load
α	penalty to avoid excess of generation

Generation input parameters

R_i^{pr}	maximum contribution of generation unit *i* to primary response
m_i^{pr}	slope of the function that defines the contribution of generation unit *i* to primary response, when its production output approaches its maximum production level
m_i^{hf}	slope of the function that defines the contribution of generation unit *i* to high frequency response, when its production output is close to MSG
R_i^{hf}	maximum contribution of generation unit *i* to high frequency response
V_i^{up}	ramp-up rate of generation unit *i*
V_i^{dn}	ramp-down rate of generation unit *i*
τ	time constant for generation units to ramp up or down
t_i^{on}	minimum up time of generation unit *i*
t_i^{off}	minimum down time of generation unit *i*
P_i^{max}	maximum production level of generation unit *i*
P_i^{min}	minimum stable generation of generation unit *i*
P_{back_off}	power of part loaded generation unit providing spinning reserve

System input parameters

P_G^{max}	capacity of the largest generation unit in the system
D_{peak}	system wide peak demand
σ_{demand}	standard deviation of demand imbalances
σ_{wind}	standard deviation of wind imbalances

Network input parameters

$\mathrm{Bbranch}_{\mathrm{bp}}$	reactance of network branch bp connecting bus b to bus p
C_{bp}	capacity limit of network branch bp

Storage input parameters

$S_b^{\max}$	power rating of the storage connected to bus b

$ES_b^{\max}$	maximum energy capacity of the storage connected to bus *b*
ES_b^{INI}	energy in store for the storage connected to bus *b* at the fist optimisation time step
ES_b^{FIN}	minimum energy in store for the storage connected to bus b at the end of the day
η_b	efficiency factor of storage attached to bus *b*
Δ	time resolution used in the simulation (1 h)

Demand side flexibility input parameters

M	number of control schemes in the aggregated load scheduling model
N^{dev}	total number of controllable devices
$A_{j,t}$	demand modification for the aggregated thermal load for control scheme *j* at time *t*
m_j	available controllable power for control scheme *j*
d_j	duration of control period for control scheme *j*
pd_j	duration of payback period for control scheme *j*
q_j	amount of load reduction resulting from the control of one unit (group) using control scheme j.
$c_{j,n}$	load reduction $(n-1)$ time steps after initiation of a unit of control scheme *j*
$p_{j,n}$	load recovery n time steps after initiation of a unit of control scheme *j*
D_{tk}	the number of type *k* devices available for control time step *t*
$delay_k^{max}$	maximum allowed time for shifting device type *k*
d_k	operating cycle length for device type *k*
p_{ik}	consumption pattern for device type k
s_{tk}	first possible time step where the device of type *k*, starting consumption at time step *t*, can be shifted to
w_{tk}	number of successive time steps (starting from s_{ik}) which are possible connection times

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Dedication

To my beloved daughter

Francisca

CHAPTER 1: Introduction

1.1 Motivation

In recent years, political willingness to tackle climate change has been increasing across the world. The European Commission (EC) has responded to this urgent need by imposing binding targets on the use of energy from renewable sources. As part of this, the EC directive of March 2008 [1] proposes an overall binding target of having 20% of the energy consumed in the EU coming from renewable energy sources by 2020.

Within these overarching targets, individual countries have been given the opportunity to define their own contributions. The UK, for example, has set a target of having 15 % of its total energy consumption coming from renewable energy sources by 2020. This represents a large increase considering that the current share of renewable energy (RE) in the energy mix is limited to 1.5 %. In parallel to this, the 2008 Climate Change Act [2], sets legally binding targets to reduce UK greenhouse gas emissions by 26% by 2020 and by at least 80% by 2050, when compared to 1990 levels.

Meeting these targets will require radical changes. The UK Climate Change Committee [2] has indicated that to achieve the 2050 CO_2 reductions target the electricity sector needs to become almost completely de-carbonised by 2030. At the same time, many future energy scenarios anticipate a greater use of electricity in transport and heating and cooling [3]. In effect, electricity will need to become the dominant vector for transfer of low carbon energy.

Renewable energy will need to play a key role in this process. The UK Renewable Energy Strategy (RES) [4], proposes increasing the electricity produced from renewable energy sources from 5.5 % currently to more than 30% by 2020. Among this, wind generation (WG) is expected to experience a very high growth [5]

Characteristics of Wind Generation

Intermittency and non-controllability are inherent characteristics of intermittent renewable energy based electricity generation such as WG. As with other intermittent renewable energy technologies (such as tidal, wave, solar, run-of-river hydro) the output of wind generation is characterised by high variability[1], due its dependence on the availability of the energy resource. In the case of WG, its output is governed by atmospheric conditions. This makes it hard to perform long and mid-term forecast of WG output, meaning that WG is also characterised by high uncertainty[2].

The variability of WG, changes the daily commitment of conventional generation. The increased variability in net demand will require more frequent plant start/stop, and part loaded operation and ramping capability. At the same time, uncertainty in WG output due to wind forecast errors changes the system overall uncertainty. To deal with this the system operator needs to ensure additional response and reserve services to keep a pre-specified security level. In both cases, the system will need to become more flexible.

1.2 The Challenge of Flexibility

In general terms, the flexibility of the system represents its ability to accommodate increasing levels uncertainty while maintaining satisfactory levels of performance at minimal additional cost for any timescale. Flexibility can be viewed from either from a system planning[3] or system operation perspective.

When looking specifically at operation flexibility, the general concept remains unchanged. In this case flexibility is related to the system's ability to deal with uncertainty within system operation timescales. For the sake of clarity, a definition for operation flexibility, as it is approached in the course of this work, is presented as follows:

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[1] In this work variability of intermittent generation represents the changes in plat output over a pre-specified period of time (from seconds to minutes, hours, days, seasons and even years).

[2] In this work uncertainty (or unpredicted variations) represents the forecast error of the expected plant output considering a pre-specified forecast lead time. The forecast lead times typically considered are within operational time scales and vary from day-ahead to minutes ahead of delivery time. The relevant lead times are connected to system operation decision time steps, such as time required for starting a new plant or market gate closure time.

[3] For example, in [90] flexibility is looked from the planning perspective and is defined as the ability of the system to accommodate the fluctuations in parameters such as availability of different fuel resources, demand growth and evolution of fuel prices within the planning time horizon.

> Operation flexibility is the ability of the system to adapt its operation to both predictable and unpredictable fluctuating conditions, either on the demand or generation side, from timescales of seconds to hours, within economical boundaries [6].

Operation flexibility has always been present in power systems to manage fluctuations in demand and generation, and is crucial for a reliable operation and good economic performance of the system. In the past, the majority of operation flexibility came from conventional generation which was flexible enough to follow demand variations and adapt its output to respond to contingencies such as a large generation or demand loss.

1.2.1 Flexibility needs to integrate WG

The presence of wind generation will lead to greater demands of the system for operational flexibility. An example of the need for additional flexibility to accommodate wind is shown in the following figures. The outputs of different types of generation to meet a specific level of demand in a system containing a high penetration of WG, if no additional uncertainty is considered, is shown in Figure 1.1. In periods of low demand the sum of inflexible "must run" generation[4] and WG output may exceed demand. In the example, wind is curtailed to maintain the balance between supply and demand.

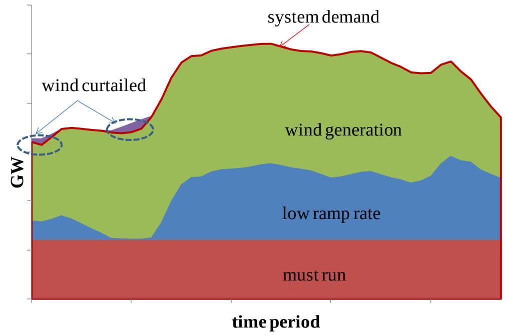

Figure 1.1 Placement of technologies in the load diagram – no reserve and response

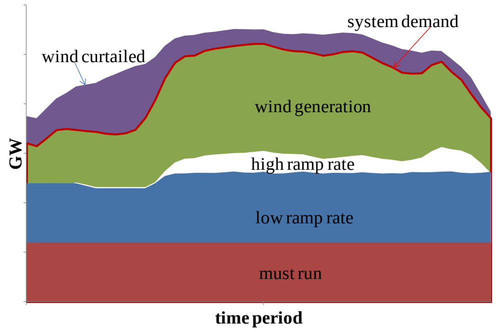

Figure 1.2 Placement of technologies in the load diagram – with response and reserve

The need for flexibility becomes more significant when system uncertainty (including wind forecast errors) is also considered. In this case, additional synchronised part-loaded plant is needed to provide reserve and response services. The provision of reserve and response services from synchronised conventional generation reduces the margin available for WG to

[4] The inflexible "must-run" generation corresponds to the output of generators that have very long start-up times (days) and are typically operated with constant output. An example of this is the existing nuclear power plant in the UK.

be used to meet demand, increasing the amount of wind curtailed (shown in Figure 1.2). This situation is worsened as WP increases, due to the corresponding need for additional response and reserve required to maintain system security.

The demands for extra flexibility represent a cost to the system. Traditionally flexibility is provided by part loaded synchronised plants and fast start plants, such as Open Cycle Gas Turbines (OCGT). Typically, this plant has very high marginal cost and low utilisation factor. With larger penetration of intermittent renewable generation, such as WG, more plant needs to operate part loaded to cope with the additional uncertainty, leading to higher efficiency losses and lower load factor. At the same time, combining large amounts of WG with low flexible generation plant may lead to an undesirable waste of WG, which in turn increases cost of balancing wind and its overall integration cost.

1.2.2 Flexibility needs of low carbon generation

The drive towards low carbon electrical networks is likely to heighten this issue. As indicated, low carbon electrical systems are likely to contain large amounts of renewable generation, in particular, WG. The contributions from renewables alone, however, will not be sufficient to achieve the desired de-carbonisation of the UK's electricity sector. Instead, meeting the electricity demand will require the continuing use of a large share of electricity produced from thermal sources such as nuclear plant or fossil fuelled conventional generation fitted with carbon capture and storage (CCS).

Both types of low-carbon thermal generation are likely to have lower operation flexibility, when compared to the existing coal and combined gas cycle turbine (CCGT) plant. Even when it is technically viable, operating these plants in a flexible way is economically undesirable [7-9]. Consequently, the business as usual approach to system operation is not an option since it will lead to prohibitively high costs and potentially low utilisation of generating plant and networks. Clearly the additional system flexibility which needs to be provided to deal with the intermittent nature of WG will have to come from the use of both traditional and new sources of flexibility.

1.2.3 Alternative sources of flexibility

Some alternative approaches for enhancing operation flexibility to reduce the costs of WG have already been identified [10, 11]. These include:

- making use of interconnections;
- providing a more adequate market framework; and
- incorporating the demand side and storage into system balancing and support of network operation.

Each of these sources potentially can make a contribution to achieving a reliable and affordable low carbon generation based power system.

The role of interconnections

The use of interconnections between neighbouring systems to enhance system security has been a common practice. With the uptake of intermittent generation this has gained even more relevance. Interconnections help to reduce variability of WG output due to the "smoothing effect" obtained by aggregating outputs spread through a wider geographical area. Interconnections can also increase flexibility by allowing balancing of a system in coordination with other system operators.

The effectiveness of interconnections can be limited by several factors. Correlations in the availability of renewable sources across geographic regions will limit their effectiveness. Alternatively, an interconnection may be found to have limited capacity and the increase of this capacity may take time. This second problem is particularly relevant for the case in the UK. This suggests that the use of interconnections cannot be a general solution to the flexibility challenge.

Impact of Regulatory and Market Framework

In contrast to technical approaches to enhance flexibility; it has been recognized by the IEA [6] that an adequate regulatory framework and an efficient market designed to improve the access to flexibility can play an important role in the integration of large penetration of WG. A more flexible approach to trading reduces the impact of forecast errors and increases the access to flexibility resources either from the supply or demand side, reducing the need for expensive fast response plant. This is important to ensure that the existing technical flexibility is used optimally. To ensure the good development of flexibility, however, this process needs to be preceded and/or complemented by the quantification of the system level needs for technical flexibility.

1.2.4 Storage and DSF

While flexibility resources of a power system are commonly found on the supply side in the form of flexible plant and interconnections with neighbouring power system, there is also the possibility of "shaping" the demand to meet generation fluctuations. Storage and demand side flexibility (DSF), obtained by DSM actions (or demand side integration[5]), have been used in the past to support system planning and operation. The need for innovative solutions to support the transition towards a more flexible system operation, required in low carbon generation based systems, creates a new role for these enabling technologies. In addition, recent advances of information and communication technologies (ICT) together with governmental decisions to roll out smart meters [13, 14] created a new window of opportunity to make better use of the demand side as a resource for flexibility.

Storage and DSF can play a number of important roles in supporting the development of future power systems. A summary of the potential applications of storage and DSF is presented in Table 1.1.

Table 1.1 Potential applications of DSF and storage

Generation/Balancing	**Transmission network**	**Distribution network**	**Islanded systems**
Increase economic viability of intermittent generation	Congestion management	Support the development of active distribution networks	Increase the penetration of intermittent generation
Reduce CO2 emissions	Increase the connection of intermittent generation	Support DG connection	Provide ancillary services
Reduce requirements for stand by and peak generation	Deferral of network investment	Deferral of network reinforcement and asset replacement	Reduce the requirements for stand-by plant

Among the different services available, there is a potential of reducing wind integration costs by increasing the flexibility available for system balancing and network management. This has been previously recognised but, due to the lack for quantitative studies to demonstrate its economical benefits, these services remain underexploited to date. The key question is whether DSF and storage can meet the needs for operational flexibility in an economically viable manner. Accordingly, new techniques will be required to provide a quantitative analysis of the economical and environmental benefit of using Storage and DSF as alternatives to improve system flexibility.

[5] The traditional term demand side management has been gradually replaced by the term demand side integration (DSI) to reflect the changes in the power system since the liberalisation of the electricity sector. This terminology shift is proposed by Chuang & Gellings in [12]

1.3 Scope of the Work

Operating future low carbon systems will be a challenging task. Large penetrations of WG lead to large increases in uncertainty in systems' generation output, driving a need for even greater flexibility from the remaining generation. This flexibility will need to come either from plants that are inherently less flexible or from alternative sources of flexibility. This is likely to increase wind integration costs and could potentially compromise the economic viability of power systems with large wind penetration (WP).

Ensuring sufficient operation flexibility, in such a technology mix, requires major changes in system operation. The "predict and provide" approach, where sufficient generation is used to supply an inflexible demand side, will not be cost effective. A new perspective over system flexibility where control functions are shared between conventional generation, storage, demand side and networks seems to be the way forward. It is important that we understand how each of these sources can potentially make a contribution to achieving a reliable and affordable low carbon generation based power system.

This thesis focuses on the development of a whole system approach to quantify the value of flexibility from conventional generation, storage and the demand side, in systems with large wind penetration. An analysis of centrally operated systems is used to reveal the amount of technical flexibility required in future low carbon generation based power systems, to ensure a secure and economic operation. This will establish how the needs for and value of different flexibility evolve with increasing WP.

To meet these objectives, this work:

- identifies the problems caused by intermittent generation with reference to ensuring adequate flexibility;
- highlights the key flexibility services required in a secure system, namely: energy balance; response and reserve and network congestion management;
- quantifies systems costs of providing this flexibility for different generation alternatives and different flexibility providers considering the technical characteristics of both conventional generation, storage and DSM;
- studies the modelling issues of integrating DSF into system operations namely type of control strategies to be used, technical characteristics of devices (including modelling of smart appliances) and understanding the effects of consumer acceptance and flexibility.

This is done by performing a comprehensive study of system operation to over a full year to adequately identify the impact of different flexibility technical aspects and services on the overall system performance. Innovative simulation tools are developed, to incorporate the different impacts of WG together with relevant conventional generation parameters, storage operation, demand side scheduling and the effect of transmission network constraints. The value of the different sources of flexibility is determined both economically, in terms of the reductions in the cost of balancing WG, and environmentally, in terms of the abatement of CO_2 emissions.

Overall, this innovative study provides a broad perspective of the potential of these enabling technologies encompassing both system balancing and transmission network operation. The outcomes of the work can be used to support policy makers and regulating authorities on the development of cost effective low carbon power systems.

1.3.1 Whole system approach

The uniqueness of the work is providing a whole system approach to identify how the different parties can contribute to flexibility and improve the system's ability of accommodating WG. Assessing the flexibility of future systems requires new quantitative models to evaluate system performance whilst taking simultaneously into account all the significant system operation constraints and requirements including: wind generation, detailed representation of generation costs (start up, no load costs and incremental fuel costs); generation dynamic parameters (minimum stable generation (MSG), maximum output, ramping capability); operation inter-temporal constraints (minimum up and down times); generator response characteristics over different time scales; response and reserve requirements provided by a combination of conventional generation, WG and storage and DSF technologies. The value of different flexibility sources can be quantified only by considering their added value for each of these aspects of flexibility in the system.

This is a difficult question since some of these services may be conflicting and by benefiting system operation at one level of the system, they might have a negative impact on a different level of the system. Instead, an overarching system level approach where storage and DSF compete with conventional generation will be needed to enable the quantification of system value of each technology and support an informed decision in terms of the viability of different options.

1.3.2 Research Questions

The objectives of the work are realised by addressing four research questions. These research questions are outlined as follows.

RQ1a: How does uncertainty resulting from large penetrations of wind generation alter the need for operation flexibility?

Answering this question requires an adequate representation of the main changes that WG brings to traditional system operation. This is based on the quantification of the impact of wind variability and uncertainty on system operation.

The specific processes required to respond to this question include:

a) understanding how the system is currently operated and studying how previous research addressed the modifications required to operate systems with WG.

b) developing an approach to characterise the stochastic nature of WG output for different forecast lead times, and applying this to quantifying new levels of response and reserve to ensure that system operation security stays unaltered.

c) developing an approach to calculate the optimal composition of reserve, in terms of synchronised and fast plant, and examining how this enhances the use of generation flexibility.

d) quantifying the value of using wind farms to provide frequency response and along with the value of fast plant to provide standing reserve, as means to improve the use of flexibility from generation.

RQ1 b: How does the value of flexibility relate to the operation flexibility of conventional generation?

Addressing this question puts the focus on the traditional source of operation flexibility. Aspects considered include:

a) analysing how the system's ability of integrating WG and the wind intermittency balancing cost change with the generation mix flexibility and generation technology flexibility.

b) understanding how the increase of response and reserve requirements needed to cope with wind uncertainty drive the value of flexibility.

c) identifying the relative impacts of the penetration of inflexible technologies in the generation mix on the system's ability of accommodating WG output.

d) quantifying the value of operation flexibility from different plant technology and identifying the key parameters that drive this value.

RQ2: What is the economic value of using storage to increase of system flexibility in systems with WG?

To assess the economic viability of using storage to share with conventional generation the role of maintaining the demand/generation balance, in systems with WG, a quantitative assessment its economic value to the system, taking into account its relevant operation constraints, is required. This permits the identification of system drivers towards the value of storage and the specific influence of storages' own characteristics.

To this end the following specific aspects need to be addressed:

- investigating the economic value of storage, as a competing technology providing operation flexibility, in terms of a capitalised value per kW of installed capacity and reduction wind curtailment and CO_2 emissions.
- conducting an analysis of the influence of the generation mix flexibility on the value of storage.
- identifying the main drivers for the value of storage including the impact of storage characteristics such as round trip efficiency, maximum power rating and energy storage capability and wind penetration. .

RQ3: What is the value of integrating demand side flexibility into the power system operation as a means for the integration of wind generation?

Changing the traditional system operating paradigm of providing sufficient flexibility on the generation side to supply an inflexible demand will requires large modifications to the existing practices. Such changes need to be driven by clear economic and environmental benefits to the system. This research investigates the development of new system operation simulation tools that can be used to determine the potential economic and environmental benefit of using the demand side to provide part of the flexibility required to balance WG. The specific objectives of this study include:

- the definition of optimal strategies for load shifting to avoid negative effects of disturbing demand diversity, by carefully addressing the payback effect [6].
- investigating the environmental and economic value of using demand side flexibility to provide part of the reserve required to cope with WG imbalances
- studying how the value of DSF changes for generation mixes with different levels of flexibility.
- quantifying how demand side constraints, such as the demand profile of different devices, consumer usage patterns and flexibility, affect the value of demand side flexibility.

RQ4: What is the value of using storage and DSF to increase network operation flexibility to optimise the use of transmission capacity and how does it relate to the system's ability of integrating wind generation in areas with transmission bottlenecks?

This section of the work extends the investigation of the role of storage and DSF from system balancing to the value of network congestion management. The possibility of coordinating the need for generation output adjustments, including the need for curtailing wind, with storage and DSF, to unlock latent transmission capacity, is explored. An example of the UK is used to support the quantitative analysis of the economic value of this concept. Addressing this question involves the meeting the following objectives:

- developing a network operation model, based on an optimal power flow, where generation dispatch takes into account network constraints, which performs a simultaneous optimisation of generation output adjustments due to congestion problems, demand shifting actions and storage charge and discharge, in all buses of the network.
- analysing how these technologies contribute to the reduction of wind curtailment and congestion costs. This includes exploring the drivers for the value of each technology and identifying how this value can be increased.

[6] The payback effect is the increase in peak power demand due to power restoration of controlled loads that appears in the period immediately after reconnecting to the system loads that were disconnected. This phenomenon is mainly related with thermostatic loads and is a function of the time of disconnection and load characteristics.

- identifying the contribution of these technologies to improve the loading factor of system branches and consequently increase the utilisation of existing network capacity.

1.4 Contributions of the Research

The following main results can be considered as original contributions to knowledge:

Contribution 1: A critical contribution of this work is the assessment of the economic value of system flexibility for the integration of large penetrations of WG, when the role of the supply and demand side is combined. An innovative approach bringing together different aspects of operation flexibility in power systems with large WP is presented. This involved the following specific contributions:

- The definition of new response and reserve requirements based on the statistical analysis of wind historical data, taking into consideration factors such as geographical dispersion of wind farms, wind forecast lead times and the level of risk accepted by the system operator.
- The analysis of the impact of approximating (using a normal distribution) the non-normal distribution of wind uncertainty on both the total reserve requirement and the optimal combination of spinning and standing plant used to meet the requirements and the subsequent system cost and CO_2 emissions.
- The development of an annual system scheduling tool able to balance the need for a low computational time, with the consideration of all the operational constraints that define system flexibility. This is based on a modified security constrained unit commitment which includes a detailed modelling of generator dynamic ratings, the deterministic response and reserve requirements, wind farm participation in frequency response and integration of WG into the generation-demand balance.
- The impact of wind uncertainty on reserve and response constraints in terms of cost of accommodating WG and of CO_2 emissions in order to understand how wind uncertainty drives the value flexibility.
- The identification of the main drivers to the value of flexibility, quantified in terms of wind intermittency balancing costs and CO_2 emissions. This clarifies how the value flexibility is affected by different generation operation flexibility characteristics and how these compare in terms of their relative impact on wind balancing costs.

Contribution 2: The second main contribution of the thesis is the quantification of the economic and environmental benefits of using Storage and DSF as a means to increase operation flexibility. This allows their contribution to increasing the system's ability of using WG to be quantified in terms of wind integration cost and CO_2 emissions. This required the development of new system operation simulation tools able to optimise simultaneously the contribution of both conventional generation and these enabling technologies to the generation-demand balance.

This development of new tools involved the following contributions:

- The development of a model to quantify the contribution of storage and DSF to reserve services by including the effects of reserve deployment in system scheduling. This model extends existing models, traditionally focused on the contribution of these technologies to load-levelling, to include the quantification of their contribution to reserve services. This required the simulation of the effect of wind forecast error in terms of wind imbalances between forecast and delivery time. These imbalances were simulated using a stochastic approach to produce synthetic time series of wind realised.
- The completion of a quantitative assessment of the contribution of smart domestic appliances to wind integration, using realistic data of appliance electricity demand, usage patterns and consumer acceptance and flexibility.

Contribution 3: In the third area of contribution of the thesis, the concept of using storage and DSF to provide flexibility to cope with wind variability and uncertainty is extended to include the management of transmission network congestion. A new methodology for congestion management that permits coordinating the need for generation output adjustments and WG's intermittent output with the operation of storage and DSF, throughout all network buses, to optimise the existing capacity is presented. As part of the contribution of this work, an innovative network operation simulation tool, based on a multi-period optimal power flow incorporating the operation of storage and DSF distributed through different network locations, is also developed. The effectiveness of these algorithms is illustrated by addressing congestion in the UK transmission system.

1.5 Thesis Structure

Based on the objectives presented and the approach proposed, this thesis is made up of eight chapters and seven appendixes whose contents are summarised below.

Chapter 2 illustrates the significance of potential system operation changes and associated costs required to accommodate WG through a structure analysis of previous studies of wind integration. This is supported by a survey of applications of storage and different forms of demand side management (DSM) or demand side integration (DSI), as a means of reducing these wind integration costs.

Chapter 3 presents an approach to quantify new levels of response and reserve required with WG to ensure that system operation security stays unaltered. It then examines how an optimal composition of reserve, in terms of synchronised and fast plant, can enhance the use of generation flexibility.

Chapter 4 provides a detailed description of a methodology that can used to determine quantitatively the value of generation flexibility needed to integrate WG. Using the developed methodology, the economics of system flexibility, in terms of wind intermittency balancing costs, are investigated considering different response and reserve mix, conventional generation mix scenarios along with an analysis of the sensitivity to the penetration of inflexible generation in the generation mix and flexibility levels of different generation technologies.

Chapter 5 describes the modifications to the methodology of Chapter 4 that are needed to take account of the constraints and specific operation requirements of storage. This will allow the quantification of the value of electricity storage providing flexibility in systems with large wind penetration (WP), considering its sensitivity to WP, conventional generation flexibility and the size and efficiency of storage.

Chapter 6 presents a methodology for assessing the quantitative value of DSF providing part of the flexibility in systems with large WP and its application. Building on the methodology described in Chapter 5, the chapter describes the development of two different models for representing DSF. Case studies for identifying which system parameters drive the value of DSF and the conditions where the demand side represents a better option for providing flexibility complete the chapter.

Chapter 7 presents the methodology and models developed to examine the implications of using storage and DSF as non-network solution to improve the use of existing network capacity. An investigation of the role of these technologies in the UK transmission network is used to determine the main drivers for the value of storage and DSF and identify under which conditions this value is higher.

Chapter 8 details the conclusions from this work and proposes directions for future work.

The main document is complemented by several Appendices.

Appendix A describes the derivation of the reserve cost function used to determine the allocation between spinning reserve (SR) and standing reserve (StR) used in this thesis.

Appendix B presents the linearization of the convex generation cost function, required to solve the unit commitment optimisation algorithm as a mixed integer linear problem.

Appendix C provides a description of the nature of generator contribution to frequency response. In particular, factors controlling generator contribution are described in detail.

Appendix D lists the generation parameters and wind generation data used in the simulation studies of Chapters 4 to 6.

Appendix E presents the data used to compare the performance of different demand side management algorithms for peak reduction, which are used in Chapter 6.

Appendix F gives a description of the disaggregation algorithm used to estimate the number of smart - devices connected at each point in time, a necessary step in the assessment of the value of smart domestic appliances used in Chapter 6

Appendix G lists the data for the representative Great Britain (GB) 16-bus transmission system used for the investigation of congestion management in Chapter 7.

CHAPTER 2: Flexibility and Large-scale Wind Integration into Power Systems

2.1 Introduction

Developing an overarching approach to the value of system operation flexibility requires a whole system analysis where different alternatives to provide flexibility are explored. The fundaments of such a techno-economic study need to be based on a careful understanding of:

- operation flexibility in traditional system operation;
- the main changes required for a secure operation of systems with large penetration of WG and how this affects the need for flexibility; and
- the potential role of new sources of flexibility of such as storage and demand side flexibility.

Considering the broad scope of the approach required, this chapter analyses previous works to evaluate if the existing system operation tools and methodologies are suitable to perform this whole system analysis. It starts by analysing the impact of WG on system operation by means of a brief description of the operational practices used in the power systems today. The significance of potential system operation changes, required to accommodate WG, is then studied through a survey of methodologies and a structured analysis of previous work directed towards modelling the impact of WG on:

- frequency response and reserve requirements; and
- generation commitment and dispatch.

It will be shown from these initial reviews that the integration of wind (by providing sufficient flexibility) is fundamentally an economic challenge, dominated by the additional costs of wind intermittency.

To highlight the significance of intermittency costs a review of previous studies regarding its quantification, centred in the United Kingdom (UK) case studies, is performed. This provides an overview of the current landscape of wind integration costs along with indicating the significance of the costs incurred in different parts of the system, such as generation and network capacity and system balancing costs. This illustrates the importance of mitigating these costs to ensure the economic viability of WG.

Finally a critical analysis of previous work about applications of storage and different forms of demand side management (DSM) or demand side integration[7] (DSI), to support wind integration, as a form of reducing these costs, is presented. Together these analyses will help to ensure that the methodologies developed in later chapters focus on the critical factors driving the techno-economic viability of system flexibility options.

2.2 Wind Generation Impact on System Operation

The role of the system operator is to ensure that the balance between demand and supply is kept at all times. A widespread system blackout is extremely damaging for society and leads to very high costs. System security involves operation practices, including appropriate levels of reserves and flexibility, necessary to keep the integrity of the system under a range of conditions including: credible plant outage; predictable and uncertain variations in demand and availability of primary generation resources. Broadly, security means providing customers with a supply of electricity, while meeting the quality of supply requirements at all times.

To this end, enough generation needs to be available and sufficient ancillary services need to be procured. This task is not limited to real time but is spread over a long-term period Figure 3.1. provides an illustrative example of the operations planning timeline[8]. For the sake of clarity in terms of technical system operation, the main decision time steps based on centralised planning are illustrated.

[7] The term demand side integration has been used lately as an alternative to the traditional term demand side management to reflect the changes of the role of demand side after the liberalisation of the electricity sector. This terminology shift is proposed by Chuang & Gellings in [12] and adopted by CIGRE in its upcoming technical brochure on Demand Side Integration [15]

[8] These time-scales can change from system to system, for example system balancing is exemplified here as starting 1 hour before actual delivery but this can be more or less than an hour depending on the system.

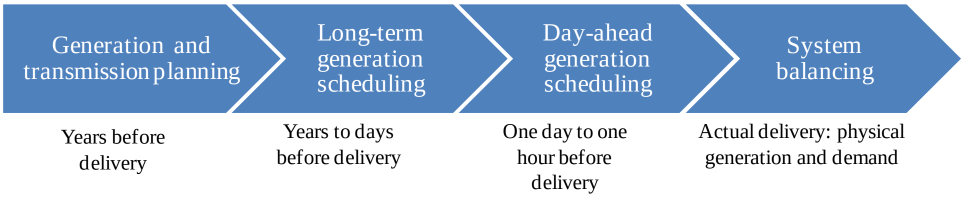

Figure 2.1 Power system operations planning timeline

In competitive power systems, different market arrangements define the commercial and energy physical delivery rules, for the different steps of this timeline. If perfect competition is achieved in the market, the same minimum cost solution would be obtained for both centralised planning and competitive systems.

To integrate large amounts of WG the system operator (SO) will need to deal with a system where generation needs to meet a more variable demand (represented by net demand[9]) and higher overall system uncertainty [16-18]. These impacts are such that a full re-assessment of power system operation methodologies and standards, especially in setting response and operational reserve requirements, is required. At low penetration this impact is negligible or very low, but at large penetration this may significantly affect the amount of operating reserves and regulating capability to maintain balance between supply and demand. The SO deals with uncertainty in the demand-generation balance by ensuring sufficient response and reserve services to maintain security. Considering that WG output is hard to predict at various time-scales – minutes, hours, days, years – it will impact short and long term system reserves requirements.

2.2.1 Quantifying the impact of wind on frequency response and reserve requirements

The impact of WG within the response time-scales from seconds to minutes has been found to be low [16]. For large wind penetration (WP), however, the short term wind variation becomes more significant. This increases the dispatch error that needs to be neutralised by the automatic generation control (AGC), placing additional requirements for continuous frequency response.

To quantify this impact, the dynamic behaviour of wind turbines following a system disturbance, and the impact of large penetration of WG on system inertia, needs to be simulated. Moreover, the effects of wind on net demand variability require the re-assessment of system

[9] Considering that WG is seen as an inflexible generation traditionally this generation is included by subtracting the wind output to the system-wide demand. The remaining generation will then be scheduled to supply the remaining demand designated as net demand.

dynamic frequency requirements. The quantification of the impacts of WG in frequency response is an active topic of research [19-22]. Accurately determining the effects of wind generation on frequency response is not a trivial question, and significant research in terms of dynamic modelling of different wind generators and its incorporation into system dynamic simulation models is needed. This becomes more relevant as the expected WP increases. In addition, considering the high capacity of new wind farms, the sudden loss of its full output becomes a contingency with similar effect as to the loss of a large conventional generator. The probability of losing a wind farm (WF), due to very high wind or storms, needs to be taken into account in future power systems.

Reserve requirements are related to operation time-scales of minutes to a few hours ahead of energy delivery and are traditionally estimated by the SO using statistical methods [23]. Commonly, to estimate reserve requirements, the fluctuations of wind and demand are combined to define the overall uncertainty of net demand, and forced outages may be included.

The additional reserve required depends on the expected WG output change. Statistical properties of output fluctuations of wind farms need to be estimated to define a correct reserve requirement. These fluctuations are affected by two main factors: correlation between the output of different WF, defined as wind diversity, and the forecast lead time used when predicting the expected WG output.

Estimating the reserve requirements with WG has been the subject of significant research over the years. Two main approaches can be identified:

- Reserve requirements are defined *a priori* to guarantee a desired reliability levels using:
    - offline calculations based on Monte Carlo simulations as seen in [24, 25] or
    - analytical methods of varying levels of complexity
- Reserve requirements are computed online using a stochastic security criterion

In the research based on analytical methods different approaches have been used and are characterised by various levels of complexity. Table 2.1 presents a classification of these methods according to the way the wind uncertainty is incorporated into the reserve requirements.

Table 2.1 Different analytical approaches used to determine reserve requirements

Approach	References
% of wind forecast error + deterministic rule-of-thumb	[26, 27]
Maximum expected wind imbalance + deterministic rule-of-thumb	[28, 29]
Stochastic representation of wind historical data + deterministic rule-of-thumb	[30-36]
Calculation of COPT[10] including wind uncertainty	[38, 39]

These approaches compute the reserve level based on a pre-specified reference risk level, which represents the probability of not meeting system demand. Consequently the reserve levels consider the same risk for all operation scenarios.

Analytical methods have the advantage of obtaining a computationally fast estimate of the impact of wind uncertainty in the overall reserve requirements. However it has been shown in [40] that these methods tend to be conservative and lead to a high cost of reserve.

Alternatively, reserve levels can be determined online (as an output of the generation scheduling problem), using stochastic security metrics [40-46]. These have the potential of capturing the effects of all possible sources of uncertainty through direct simulation of system behaviour. The main limitations to this approach are that, unless properly designed, these techniques can be computationally intensive and slow. Furthermore, if not correctly tuned, the simulation techniques may not capture the effects of different sources of uncertainty.

This means that to simulate system operation over large periods of time (for example one year) the reserve requirements need to be defined offline, since stochastic optimisation would require unacceptable computational times. The studies will, however, need to consider large WP so wind uncertainty needs to be properly modelled. Simplistic methods as low complex analytical approaches are not suitable as they fail to consider a realistic representation of uncertainty. Finally, to study the value of system operation flexibility it is important to consider all sources of uncertainty (wind, demand and generation outages) to calculate the overall reserve requirements. This, however, needs to be done in such a way that computational times are kept low. None of the works previously referenced meets all the needs for detailed representation of system operation with low computational times. Consequently, an approach to set reserve

[10] Capacity outage probability table (COPT) – considering that power systems are composed by a sets of generation units that form a generation model, the COPT is the reliability generation model used for loss of load assessment. Further detailed about this model can be found in [94].

requirements offline, considering a probabilistic representation of wind and demand forecasts errors and generation credible outages, is developed and described in Chapter 3.

2.2.2 Scheduling of power systems with wind generation

Generation Scheduling (GS) problems involve solving a security constrained unit commitment (SCUC) problem and adjusting its solution as electricity delivery time approaches [47]. This is done by solving a large optimisation problem where system costs are minimised or alternatively social welfare is maximised.

Traditionally, a simple UC involves ensuring enough committed generation to supply the forecasted level of demand without taking uncertainty into account. To implicitly consider system uncertainty reserve constrains are added to the UC problems and this then forms a SCUC. This ensures that a certain amount of generation capacity is always kept unused to cater for the variations in demand level and credible outages of generators and large transmission lines.

With the current trend towards integrating large penetration of WG, a non-dispatchable and uncertain type of generation, existing GS approaches need to be re-assessed. New approaches, taking into account the intrinsic variability and uncertainty of this resource are required, as recognised in [48, 49], and some publications on this topic can be found. These differ mostly in the way they incorporate WG into the GS problem, especially with respect to setting the reserve levels as discussed in the previous section.

Generation scheduling considering WG can be divided into two main approaches, which differ by either defining system reserve levels *a priori* or as a result of the GS problem. Approaches have been proposed where the reserve levels are calculated online by embedding system uncertainty into the GS problem using stochastic programming (SP) methods [50]. These approaches optimise GS considering system conditions where wind and demand are represented by a set of scenarios of wind and demand realisations characterised by its probability of occurrence. GS is then performed by optimising the expected costs of supplying the demand against the cost of energy not served, using a pre-specified value of lost load (VOLL). The results of this optimisation provide the optimum level of reserve taking into account the cost of security. These approaches differ mostly concerning the type of stochastic modelling used. For example [41, 43, 45] use two stage SP method; [44, 46] use a rolling planning approach based on three stage SP and [51] uses an hybrid dynamic programming method. The selection of different models is mostly driven by the attempt to balance accuracy and computational times.

In an attempt to tackle the computational times experienced by the stochastic methods, whilst capturing system operation uncertainty with probabilistic methods, hybrid approaches may be used, but are still limited by the overall complexity the GS problem solution method. One such approach is proposed in [40], where GS is solved using bi-level stochastic optimisation.

Broadly speaking, if the stochastic nature of WG is explicitly taken into account by the UC algorithm more robust schedules are produced. However SP is computationally slow and solving real size problems involves computational times of several days [46].

The analysis of existing GS algorithms including WG indicated that existing algorithms are not suitable to solve the problems addressed in this thesis because in some cases they do not consider all the features that characterise system flexibility and others have excessive computational times.

In this thesis a modified SCUC is developed to obtain low computational times and take into account the relevant aspects of system operation with large WP is developed. These modifications concern mostly the simultaneous scheduling of response and reserve considering both upward and downward services (downward reserve gains special significance for large WP). In addition, options for the provision of response and reserve that increase system flexibility are considered by the GS. Such options include the optimisation of the contribution of wind and conventional generation to response and the scheduling of an optimised mix of spinning and standing reserve. The proposed algorithm is detailed in Chapter 4.

2.3 Additional Costs of Wind Generation

Wind generation has the particularity of having a variable output linked to the availability of the resource. Its output depends upon atmospheric conditions making it variable and hard to predict both for long-term and mid-term. Altogether these impacts affect the overall system costs. Identifying and quantifying these costs has been subject of active research and a considerable amount of work on has been published.

Holttinen in [17, 18] classifies system costs and impacts according to different time-scales and system parties affected by WG. These are divided into short and long term impacts. The first are related to power system operation timescales and the second to system reliability concerning mostly system adequacy. The areas identified as being the most affected are:

- capacity expansion for long-term energy balancing;
- short term energy balancing and ancillary services mainly concerning generation operation patterns, response and reserve requirements;
- network operation and planning.

The quantification of system integration costs of WG for the European region can be found in [17, 18, 52-56]. From these studies it is possible to conclude that WG brings additional costs to the system. These costs are related to the changes required in the power system to accommodate wind variability and uncertainty while keeping the levels of system security[11] and adequacy[12] observed in today's systems. These costs are however a function of the wind resource in the region under consideration as well as the characteristics of the system in question. The additional costs will therefore be system specific and the conclusion about the economic viability of WG cannot be generalised for all systems. The key drivers for these costs have been identified by different studies as being:

- diversity of the wind resource, influenced by the geographical spread of WF; load factor[13] of WG (depending on the characteristics of the wind resource, for example offshore typically has a higher load factor);
- location of the wind resource with respect to the existing network infrastructure;
- conventional generation mix of the region, specifically regarding its flexibility (for example regions with large hydro resources are capable of accommodating WG at lower cost).

The common conclusion of these studies is that there will be additional costs for different power systems time-scales (from increased needs for peaking plants and network capacity to daily wear and tear of conventional units). Considering the vast amount of quantitative studies looking at different regions, a more detailed analysis of how these costs are distributed through different areas of the power system is presented using the UK example, which is the region that serves the basis for the case studies of this thesis.

2.3.1 System capacity issues in the UK

Ensuring the existence of spare capacity, on both short-term and long-term time-scales leads to higher system costs and lower asset utilisation. In the specific case of generation in the UK, 20 GW of conventional generation currently operate with a load factor lower than 10 %. These plants experience difficulties in recovering investment costs and the increase of WG installed is expected to further reduce plant load factor due to its low capacity credit as explained below.

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[11] A system is considered secure if it can withstand system single or multiple components outages.

[12] A system is adequate if there is sufficient power supply capacity to meet demand.

[13] Plant load factor is the percentage of the energy the plant is able to generate if producing at full output that is actually generated, for the period of one year.

System capacity analysis requires an estimate of demand and production. The latter is based on availability data of generation units. The contribution of a given generation unit to system adequacy is defined as capacity credit or capacity value. The capacity credit of any generator is defined as the amount of additional load that can be served, keeping the system reliability target, if that generator is added to the system.

For WG, as any other generator, the capacity credit indicates the increase of load that can be served by wind, maintaining the reliability levels. This is uses as a measure of the amount of conventional plant that can be displaced by WG. Its value depends on the probability of availability of WG at peak periods. Due to difficulties of variable and hard to predict wind power output, especially years, months and days ahead, its capacity credit is much lower than conventional plant. For a small level of WP the capacity credit of wind is roughly equal to its capacity factor[14] and as WP increases the capacity credit decreases. As previously mentioned the results change with the region depending on the characteristics of the wind resource.

The System Cost of Additional Renewables (SCAR) [55], UK Energy Research Centre (UKERC) [56] and Business Enterprise Regulatory Reform (BERR) [8] reports presents the quantification of the additional capacity cost and the results are summarised in Table 2.2.

The lower cost, presented for the BERR Generation Scenarios report is related to the cost assumed for “back up” or “shadow plants” plants used to guarantee the required plant margin[15].

The lower the capacity factor, the larger the plant margin that is required to maintain reliability levels. This will lead to low plant utilisation. This situation is worsened for large WP.

Table 2.2 Summary of wind capacity credit and costs presented by different UK reports

	SCAR Report	UKERC	BERR Scenarios
Wind Capacity Credit WP < 20 % in	35 %	20 – 30 %	5 %
Wind Capacity Credit WP[16] >20 %	20 %	-	5 %
Capacity Costs (£/MWh[17])	3 to 5	3 to 5	0.97 to 2.24

[14] The capacity factor is often confused with capacity credit. These are however different concepts. The capacity factor is the ratio between the total annual energy that can be produced by a plant over a period of time (typically a year) and its output if it had operated at full capacity during the same period. This is usually expressed in percentage.

[15] The cost of plant margin represents the overall cost of having spare capacity provided by “back up” or “shadow plants”.

[16] The penetration of intermittent renewable generation is calculated in terms of percentage of the total annual demand that is supplied by energy produced by this type of generation

2.3.2 Network reinforcement cost

Wind farm developments, as other intermittent generation, are limited to locations where the primary resource is more abundant. If these are located close to areas of high demand it can have a positive impact on the network, by supplying energy closer to the end user, reducing losses and releasing capacity. This is not a usual case, and often the wind resource is located in remote areas, distant from demand centres and with weak network connections. This leads to transmission bottlenecks [57, 58] creating a need for additional network capacity to accommodate WG. This causes additional system costs.

The UK is a typical example of this. The onshore and part of the offshore wind resources are distant from demand centres and network reinforcement is required. The additional transmission network costs to connect WG, for different wind location scenarios, are quantified by Strbac et al. in [59]. This study concluded that accommodating 8 GW and 26 GW of wind will require a capital investment raging from £275 to 615 million and £1.7 to £3.3 billion, respectively. The higher cost scenarios are driven by a lower dispersion of wind farms, with the large majority located in Scotland and North of England.

As the renewable energy targets increase, the expected penetration of WG increases accordingly. A recent report in the UK [5] estimated a cost of £4.7 billion to connect 34 GW of WG by 2020. This is a large investment that needs to be spanned over a relatively short period of time, if the 2020 wind targets are to be met. This represents a major challenge to network expansion planning and implementation.

The role of enabling technologies as storage and DSM in deferring such investment has been mentioned and innovative work on the quantification its value has been performed by the author [58, 60] and is detailed in Chapter 6.

2.3.3 Additional system balancing costs

Wind generation variability[18] and uncertainty[19] affect system balancing over several time-scales. Intrinsic characteristics of wind require the daily commitment of conventional generation to be

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[17] The unit used to quantify the additional costs is £/MWh of energy produced from intermittent (including wind) generation output. This metric is used throughout this thesis.

[18] In this work variability of intermittent generation represents the changes in plant output over a pre-specified period of time (from seconds to minutes, hours, days, seasons and even years).

[19] In this work uncertainty (or unpredicted variations) represents the forecast error of the expected plant output considering a pre-specified forecast lead time. The forecast lead times typically considered are within operational time scales and vary from day to minutes/seconds - ahead, of delivery time. The relevant lead times are linked to system operation decision time steps, such as time required for starting a new plant or market gate closure time.

modified, to meet the variability of net demand (demand minus wind) and enable the system to cope with uncertainty. This changes the utilisation of the remaining plant, the overall system efficiency and operation costs.

Since wind is assumed to be uncorrelated to demand, forecast imbalances of both variables can have either positive or negative correlation. As a consequence net demand has higher variability than system demand. In addition, the wind forecast error within system operation time-scales, significantly increases system overall uncertainty and leads to higher system response and reserve requirements, to maintain a pre-specified security level. These effects lead to more frequent plant start-ups and shut-downs, higher need for generation ramping capability and additional need for part loading plant. This changes traditional plant operation and increases system need for operation flexibility. At low penetration these effects can be negligible or very low but for large-scale penetration it may significantly affect system costs. Several studies were performed to quantify these additional costs for the UK system and a summary of the results is presented in Table 2.3. Current estimates of additional costs of integrating intermittent WG are already seen as a barrier to its economic attractiveness. Moreover, system balancing costs were identified [55] as important contributors to the total intermittency cost in the UK. In this context identifying how these costs relate to operational flexibility is of paramount importance.

Table 2.3 Summary of results obtained in UK wind integration studies for additional balancing costs

	SCAR Report[55]	UKERC [56]	BERR Scenarios [5]
Wind Penetration (%)	20 – 30	20	27, 33, 42
Balancing Costs (£/MWh)	2.85 to 3	5	4.5, 5.3, 6.5

Methodologies and models applied in previous studies are based on simplified representations of the power system. These are adequate for estimating system costs of WG but do not appropriately model all the relevant features of system operational flexibility. Failing to consider these may lead to underestimating intermittency costs especially when large WP are analysed.

Furthermore exploring alternative sources of flexibility, that have the potential of reducing these additional costs will largely influence the costs of providing the flexibility required to integrate WG. Addressing these questions requires the development and application of new methodologies and tools, as recognised in [6], and is the central objective of this thesis.

2.4 Role of Storage and Demand Side Flexibility to Support Wind Integration

As shown in the previous section, integrating WG leads to additional system costs. Considering that WG integration cost plays an important role for its economical viability, there is a strong incentive to explore solutions for mitigating this cost. This necessity has driven an interest for the use of enabling technologies such as storage and demand side flexibility (DSF) obtained through DSM actions. The possible benefits and applications of Storage and DSF as means of supporting wind integration have been discussed and several publications can be found in the open literature. However, the quantitative value of these technologies, as an alternative to traditional flexibility sources, is not clear. With the purpose of analysing existing work and identifying the need for new methodologies and tools, this section presents a review of previous work on this topic.

2.4.1 Flexibility from storage

Storage seems a natural option to support the integration of WG since it has the ability of modifying the system-wide demand, by charging and discharging energy, is particularly suitable to deal with the increases in net demand variability and uncertainty. Depending on the specific application different sizes and technologies are selected ranging from flywheels, super-capacitors, small hydro and batteries for small scale and pumped hydro, compressed air energy storage (CAES) and some flow batteries for system-wide bulk applications. All of these have very high installation costs and part of the energy stored is wasted due to round trip efficiency losses. The decision of the economic viability of storage requires a careful quantification of its benefits using adequate tools.

Previous work investigated the potential benefits in using storage to support wind integration. These cover different services as net demand levelling, reducing wind imbalances to improve market integration, enhancing the utilisation of a generation portfolio and managing transmission bottlenecks. These studies can be divided into back-to-back and system-wide approaches. Table 2.4 lists the different studies classified according to the applications of storage investigated.

Several publications address the use of bulk energy storage to support market integration, as shown in Table 2.4. The main difference between them is the optimisation technique used. References apply linear optimisation techniques [61-64] and references [43, 57] use stochastic optimisation. The last is used to incorporate uncertainty in WG and market prices into the optimisation to obtain more robust results. As mentioned in earlier section, this is obtained at the expense of large computational times.

Table 2.4 Studies about applications of energy storage to support wind integration

	Application	Benefits	Reference
Small storage	back-to-back applications at WF level, or a small group of WF in the same region,	reduce wind variability increase WF owner's profit manage network congestion at the connection points	[122-127]
	support small-size islanded systems	smooth wind variability	[128-129]
Bulk energy storage	balancing WG with storage to improve the use of a portfolio of generators	improves utilisation of mid-merit plant reduces the use of peaking plant	[61]
	support market integration of WG	reducing the cost of wind imbalances increase the benefits of both storage and wind generation	[43, 57, 61-64]
	load-levelling[20] standing reserve	increase system operation flexibility support wind integration reduction of CO_2 emissions	[30, 63, 65, 66]
	increase the usage of wind generation in areas where transmission constraints	deferral of network investment optimise use of network capacity reduction of wind curtailed reduction of congestion costs reduction of CO_2 emissions	[58, 67, 68]

The role of storage to increase operation flexibility, in systems with high WP, has been explored [63, 66]. These investigations limited to the attempt of modifying demand according to marginal prices to increase the use of cheap wind. This does not permit capturing the full contribution of storage to increase system flexibility since the benefits of providing reserve services are not considered. It will be shown in Chapters 3 and 4 of this thesis that reserve has a large impact on the value of operation flexibility. To perform a more complete quantification of these benefits a new methodology and models, able to quantify the value of storage providing standing reserve

[20] Load levelling corresponds to the adjustments on the generation output to follow the changes in demand. Storage can perform load levelling by discharging and discharging to avoid using expensive generation or curtailing wind. Similar effect can be obtained by modifying demand with DSM.

and compare it with other alternatives, are presented in [11, 30, 65]. The author was involved in this work and in the subsequent efforts to enhance it. The methodology, model and case study results are presented in Chapter 5.

Storage applications in network have also been investigated. These are based on the coordination of storage facilities with WG located in the same area that is being affected by the congestion with the purpose increasing the WG output. The work presented in [68] addressed the problem from a market participant point of view and quantifies the value of coordinating hydro-pumped storage WG to increase its profit. In [67] the goal is to access how to maximise the value of CAES storage by comparing different locations and market strategies. The previous works do not consider complete network operation modelling. They are based on import/exports of a single line to which storage is connected. This does not permit the assessment of the value of storage distributed throughout the network. Considering that the questions investigated in this thesis are addressed from a system level perspective the quantification of the optimal storage contribution to the overall system flexibility and consequent reduction of network congestion costs should be done using a multi-bus model, able to represent the whole network. Developing such model is one of the objectives of this work. This is presented in [58] and detailed in Chapter 6.

2.4.2 Role of demand side flexibility

The use of the demand side to support the power system was introduced in Central Europe during the 1940s and received special attention during the 1980s due to the need for reducing the dependence on fossil fuels [69]. However, it has not yet experienced a broad application due to the challenges involved in its implementation [70]. Recent technological development in information and communication technologies (ICT) alongside with the challenges currently experienced by power systems, such as ageing assets, large-scale integration of intermittent generation and pressure to reduce carbon emissions, create a window of opportunity to integrate the demand side into system operation and development. To this end, a comprehensive quantitative analysis of its economical and technical performance needs to be carried out.

While the potential of DSF to improve WG integration has been widely discussed, few quantitative studies are currently available. Previous work focused on the use of DSF to unlock latent network capacity and increase the connection of distributed generation (DG), load levelling and provision of frequency response services. The different applications and the publications where these are described are presented in Table 2.5

Table 2.5 Applications of DSF to support wind integration

Application	Benefits	Reference
load-levelling frequency response standing reserve	provides flexibility to increase WG reduces the impact of inflexible must-run generation reduce the use of fossil fuels reduce CO_2 emissions	[66, 71-73, 74, 75, 76]
support network management	improve the use of network capacity support wind integration	[58, 60, 77, 78]

From the bulk power system balancing perspective, the use of DSF has been of particular interest in Denmark and the Netherlands [66, 71-73], where a significant part of the electricity is generated by a mix of combined heat and power plants (CHP) with WG. These systems have a particular problem created by the link between heat and power production in CHP plant these can be regarded as inflexible must-run generation. Considering that this represents a large proportion of their generation the system does not have sufficient flexibility to accommodate the increasing WG. This creates a need for additional flexibility and several studies [66, 71-73] investigate the role of technologies such as heat boilers, heat pumps, electrolysers with CHP, electric vehicles and vehicle to grid (V2G[21]) to modify system demand according to the WG available. These studies broadly conclude that large-scale heat pumps and V2G technologies are the most efficient options in terms of WG integration and CO_2 emissions reduction. As a complement to these works this thesis investigates the value smart domestic appliances similar applications, as part of a broader range of services, with the advantage of incorporating within the optimisation framework consumer behaviour and acceptability constraints [79].

A less explored area is the use of DSF to provide frequency response and reserve. Recent attention has been given to the use of appliances with frequency sensitive relays to respond to sudden frequency changes, providing part of the system frequency response services with Dynamic Demand (DD) [74, 75]. This is based on the use of domestic thermal loads (refrigerators and freezers) to respond to frequency changes to displace part of the frequency response services provided by conventional generators. The work presented by Aunedi [74] , in

[21] “Vehicle-to-grid” power technology is an energy storage system built on top of plug-in electric drive vehicles. This is based on a two way electricity exchange between the vehicle and the grid controlled according to the needs of the power system using real-time signals.

which the author has been involved, represents an improvement of previous work by adequately modelling the payback[22] effect of refrigerators and perform an economic valuation based on a detailed year-long simulation of system operation. This study pointed out that the use of this technology brings benefits to the system, by increasing the overall system flexibility however the payback effect impacts the secondary frequency response requirements, which may reduce this value.

To complement the previous applications the use of DSF to provide standing reserve is presented by the author in [76, 79]. As shown in Chapter 3 using a combination of spinning and standing reserve increases the system flexibility and improves system's ability of integrating WG. Considering that fast plants, typically used for standing reserve, have high exercise costs DSF is seen as an alternative that in addition has the advantage of providing both up and down reserve. Chapter 6 presents a methodology to quantify the value of flexible demand and its application to a generic load with thermal inertia and to smart appliances.

Alongside with system balancing, network applications of DSF were investigated. Westerman in [78] investigates the benefits of new ICT technologies by combining wide-area monitoring (WAM) and control systems with demand management applications and Veldman [77] investigates the potential role for non-time-critical controllable demand. Both aim at increasing the use of network capacity. These works, however, fail to consider the full network models and optimise the use of DSM spread throughout different network locations. In addition they are limited to thermal loads. To provide a more detailed analysis of the potential of DSM for increasing network operation flexibility, Stanojevic [60] and Silva [58], address this question by combining the use of distributed storage with DSF actions. This is done by developing an optimal power flow based simulation tool, which optimises the operation of storage and demand side control actions to increase the flexibility available to manage network congestion. All studies show that DSF improves the utilisation of network capacity reduces congestion cost. Chapter 7 presents the description of this work.

[22] The payback effect is the increase in peak power demand due to power restoration of controlled loads that appears in the period immediately after reconnecting to the system loads that were disconnected. This phenomenon is mainly related with thermostatic loads and is a function of the time of disconnection and load characteristics.

2.5 Conclusions

This chapter has presented the fundaments required for understanding the impacts of large WP on system operation, concerning mostly operational flexibility needs and associated additional costs. In addition, an examination of the possibility of providing flexibility from generation and/or storage and demand side is discussed through an analysis of previous studies available in the open literature.

From this analysis, several key points become clear.

- Existing approaches to determine response and reserve requirements, which do not consider wind uncertainty, have already been found to be unsuitable for systems with large WP. As WG reaches even higher penetration, its impact both in frequency response and reserve needs to be taken into account.
- Although there is a clear need to consider wind's stochastic behaviour in defining system reserve requirements, there are still questions as to what computational method should be used. While published studies suggest that setting system reserve as part of the GS leads to lower cost solutions, this requires large computational times. Consequently, in spite of their higher accuracy, these approaches are difficult to apply to perform studies that require the consideration of realistic size systems, under alternative scenarios and over a large number of time periods. Instead, to obtain lower computational times needed for the proposed methodology, it appears necessary to treat the wind's stochastic behaviour outside the GS. This will be addressed in the following chapter.

The second key outcome has been the identification of the factors driving the cost of wind integration. The surveyed work highlighted that:

- integrating WG increases system costs through a need for peaking generation and transmission expansion costs along with increased system balancing costs.
- balancing costs are important contributors to wind integration cost and considering that in future systems, changes in the generation mix are likely to lead to even larger shares of WG, these costs are likely to increase significantly.
- the increases in balancing cost will be linked closely to the flexibility of the system.

Accordingly, in order to understand the underlying economics of future power system with large wind penetration and different levels of generation flexibility, this work will give focus to quantifying the system balancing costs for different scenarios of increase in wind penetration and system flexibility levels.

Finally, the chapter looked at possible ways of reducing the costs of wind integration. The surveyed work indicated that the use of storage and DSF, to increase the system's flexibility and consequently its ability to accommodate WG economically, are promising options. These studies did have some limitations:

- the majority of the applications considered are focused on small scale solutions such as back-to-back storage application to support a specific generator;
- the investigations into the potential of bulk energy storage to support system balancing are limited to load-levelling and energy arbitrage;
- the value of DSF is exploited even less frequently and up to date more attention has been given the use of DSF for network applications;
- limited attention was given to the role of DSF technologies to support system balancing by providing frequency response and reserve, in systems with WG. and
- there is a clear need to put more effort into modelling specific characteristics of load and include aspects such as consumer acceptance and flexibility.

In contrast, for a robust assessment of the viability of storage and/or DSF, their benefits in terms of the provision of different services, such as network congestion management, load-levelling, response and reserve services, need to be quantified. Studies which fail to consider the aggregated value of using storage and DSF to provide different services do not fully assess their economic value. Instead, these specific challenges are tackled by the subsequent chapters where the development of common framework for assessing the viability of providing operation flexibility from generation, storage and DSF, in systems with large WP, is addressed.

CHAPTER 3: Determination of Response and Reserve Requirements and Reserve Composition with Wind Generation

3.1 Introduction

The role of response and reserve is to ensure that the system is able to cope with uncertainty in the generation-demand balance without affecting security of operation. To ensure system integrity all sources of uncertainty need to be taken into account when setting the right amount of response and reserve that needs to be procured. Typically the sources of uncertainty that must be considered include credible generation and large transmission line outages and demand forecast errors.

The introduction of wind generation (WG) into the overall generation mix brings a new source of uncertainty (wind forecast error). Wind is a highly variable and hard to predict form of generation. The principal aim of this chapter is to develop a methodology that quantifies the effect of WG uncertainty on total system response and reserve requirements. This methodology will capture the impact of the additional uncertainty introduced by WG on the total uncertainty in the generation – demand balance, which drives system response and reserve requirements.

Once overall system requirements are determined, the next question is how these services can be procured economically. The chapter also presents a methodology for determining a suitable composition of system reserve that leads to enhanced flexibility while minimizing the expected cost of reserve. This process leads to a division of total reserve in the form of spinning reserve and standing reserve, which will act as inputs into generation scheduling tools used in later chapters.

In either case, the need for response and reserve is dependent upon the specific regulatory framework supporting system operation. In this thesis, the United Kingdom (UK) system is used as a case study. Consequently, the chapter first examines the response and reserve services currently used in the UK, as defined by the Grid Code [80]. This will give a context to the methodologies developed.

3.2 Frequency Response and Reserve Services in the UK

The management of frequency requires the use of a combination of response and reserve services provided at minimum economical and environmental costs. Frequency control in the British system is managed by National Grid Electricity Transmission (NGET), as the system operator (SO), through instructions to individual generation units for energy commitment, response and reserves. In the short term, over the operational time-scales from a second over to an hour and a day, adequate response and reserve needs to be procured from generators and demand, to maintain the system functioning in the event of an outage. The difference between these services is shown in Figure 3.1.

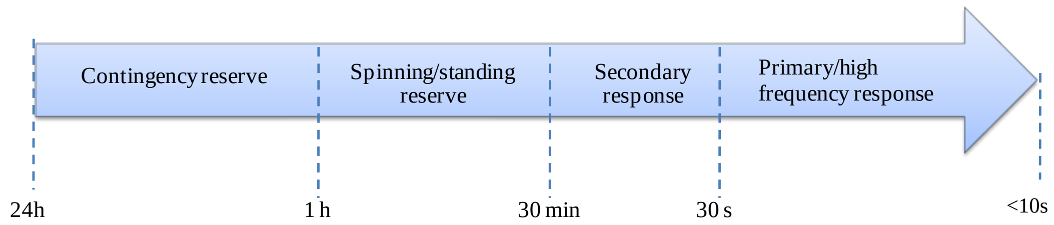

Figure 3.1 National Grid reserve and response time-scales

3.2.1 Response requirements

The electricity supply regulation requires the system frequency to be maintained at ±1% of the nominal system frequency (50Hz), except in abnormal or exceptional circumstances. This is ensured through frequency response services. These services are deployed automatically and can be categorized either according to their control type, i.e. continuous (dynamic response) or occasional (post incident dynamic and non-dynamic service), or according to speed of deployment.

In the UK, the Grid Code [80] defines three response types including primary, secondary and high frequency response services. **High Frequency Response** needs to be deployed in less than 10 s and serves to arrest an initial frequency overshoot and contain the frequency rise that follows a loss of demand. **Primary Response** must be deployed within 10 s and be sustained for a further 20 s. Its purpose is to arrest an initial frequency dip, limiting it to –0.5Hz for a significant or -0.8Hz for an abnormal event, following a loss of generation, until secondary response becomes available. In turn, **Secondary Response**: must be deployed within 30 seconds (from the time of the frequency fall) and sustained for at least further 30 minutes.

Secondary response is used to contain and partially recover the frequency after the initial fall has been contained. The comparative timeframes of the different response and reserve services are illustrated in Figure 3.2.

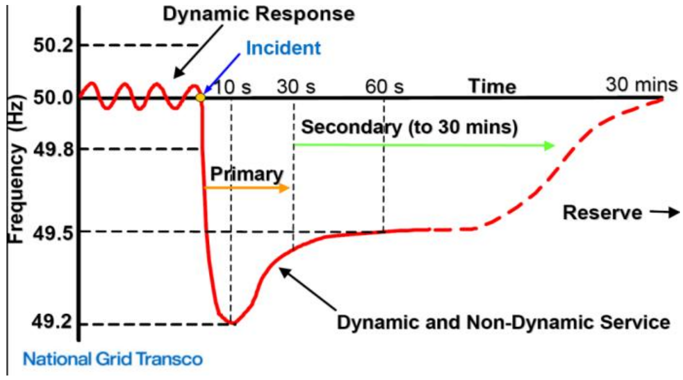

Figure 3.2 Typical response to a large plant failure in the UK system

Considering the current UK generation mix, conventional plants can provide primary frequency response of 10 to 15%, secondary response of 13 to 15 % and high frequency response in the amount of 13 to 14 % of the plant maximum registered capacity [81]. This means that for periods of low demand (when frequency response requirements are higher) many plants need to run part-loaded to provide the required levels of response.

3.2.2 Reserve requirements

Reserve is used to take over from the frequency response services and re-establish the level of response capability following a generation outage. Reserve services include:

- Spinning reserve, which corresponds to the unused capacity of the scheduled part-loaded plants and is required to be delivered in time-scales of 5 to 10 minutes; and
- Standing reserve provided by non-synchronised plants along with demand side and storage. This must be delivered in time-scales of less than 20 minutes.

The combination of spinning and standing reserve forms the operational reserve. The requirements for operational reserve are traditionally related to the statistics of credible generator outages, along with demand forecast errors. The volume of reserve procured is based on the probability of demand levels and available generation as delivery time approaches. Effectively, the amount of reserve procured represents the level of operational risk that is being accepted and varies with the time of day, type of day and time of year.

The comparative costs of different sources of reserve will control when they are utilised. For instance, the operational reserve energy to be deployed first is likely to be spinning reserve which has low utilisation cost, allowing it to cover more frequent and smaller imbalances. Standing reserve, however, has a lower holding cost and higher utilisation cost. Thus it is likely to be deployed for less frequent but larger imbalances. The correct allocation between spinning and standing reserve must be made by looking both at the available plants and alternative solutions to ensure that a minimum cost solution is obtained.

3.3 Incorporating Wind Generation Uncertainty into the Calculation of Response and Reserve Requirements

The introduction of WG into the generation mix brings a new source of uncertainty - wind forecast error - that must be accounted for when defining response and reserve requirements. A need for additional response and reserve is driven by wind variability and uncertainty. The factors affecting these two different parameters need to be examined carefully.

3.3.1 Factors affecting wind variability and uncertainty

Wind variability

As highlighted previously, wind variability is the change in WG output from one period to the next (for example from one hour to the next). It is related directly to wind diversity, a parameter representing the correlation between the outputs of wind farms (WF) across a geographical region. This correlation represents wind diversity. The more uncorrelated the output of different WF the higher is the diversity of the aggregated WG output.

Typically large geographical dispersion of WF tends to reduce the overall variability in the aggregated output. This effect is shown in Figure 3.3.

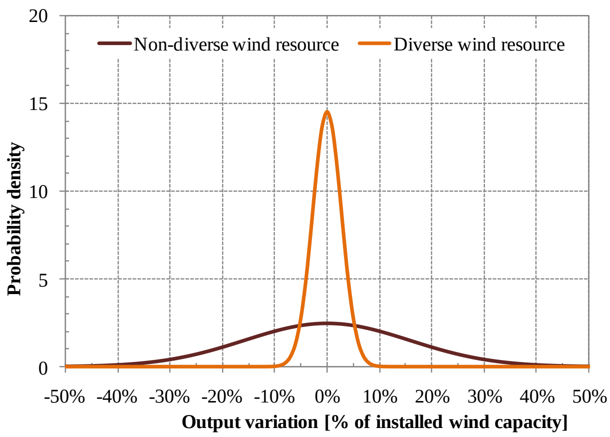

Figure 3.3 Impact of the diversity of the wind source on the pdf of wind hourly variability[82]

These results were obtained from the work of Shakoor [82] where a statistical analysis of wind historical data from the UK from both diverse and non-diverse WF was carried out. The hourly variations, in the form of probable wind variability, increase the need for operation flexibility. A more variable wind profile requires a more flexible output from the remaining plant and demand side (if demand side flexibility is available).

Wind forecast uncertainty

Response and reserve requirements are affected by wind forecast error. If wind power was perfectly predictable, the cost of operating the system with large WG penetration would be limited to ensuring enough flexibility to follow wind variability. Wind output however, depends on atmospheric variables (i.e. wind speed and direction, air density) and is hard to predict. This uncertainty must be taken into account.

Wind forecast error, over different system operation time scales, has a significant effect in the system uncertainty and impact system response and reserve levels. The forecast errors depend on prediction time scales. For very short time scales, seconds to minutes (response time scales) wind variation is small given that there is significant diversity in WF output. Larger time scales from minutes to several hours (reserve time scales) can result in higher forecast errors due to the higher probability of WG output changes for higher forecast lead time. Given the importance of this issue, significant improvements in wind forecast techniques have been achieved in the past years [83] and this continues to be an active research field.

While wind forecast for larger time scales require techniques based on meteorological information, it has been found that times scales lower than 4 hours simpler techniques can be used. One such approach includes persistency based techniques. Persistency based techniques use the assumption that the expected wind value at a chosen time period in the future equals the wind at the time period from which the prediction is made (for example wind output in 4 hours time remains the same as the current one). Within forecast times lower than 4 hours, persistency techniques have acceptable performance when compared to more complex wind forecast techniques [130].

This makes the persistency model suitable for use in the time frame in which decisions regarding commitment of generators need to be taken. For example, typically a thermal unit takes around 4 hours to start up. Consequently, this work focuses on system reserve requirements for up to 4 hours forecast lead time. Persistency based model is then used to characterise wind uncertainty in this time frame.

A statistical analysis of wind output changes, over various time scales, can be performed to illustrate the stochastic behaviour of wind output. Using a sample of wind historical data for the UK and persistence based forecast techniques the difference between forecasted and realised wind -wind imbalances- for a yearly wind times series, with half hourly resolution are determined, for different forecast lead times. Figure 3.4 illustrates the *pdf* of these imbalances, over different time horizons (from ½ hour to 4 hours). In all cases, the fluctuations of WG output are expressed as a percentage of total wind installed capacity.

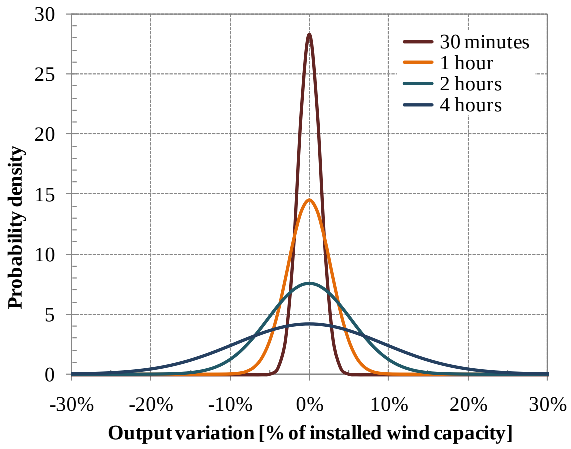

Figure 3.4 Fluctuation of WG output over different time horizons

Looking at the figure, it is possible to see that the variance (and/or σ - standard deviation[23]) of the imbalances increases significantly with the forecast interval. For larger wind forecast lead times, there are significant possibilities of having large wind imbalances. The *pdf* used to characterise wind forecast take the form of a "Bell shaped – curve" but with "thicker" tails than a "normal" distribution.

To summarise, there are two issues that influence the need for holding spare capacity to ensure system operation security in systems with WG. These are: wind variability due to diversity and wind forecast errors. The sources of uncertainty must be accounted for as they represent the additional costs of wind balancing. The following sections examine how this uncertainty affects two aspect of operation security i.e. response and reserve.

3.3.2 Incorporating wind generation uncertainty into system response

Accurately determining the effects of wind in response is not a trivial question and significant research in terms of the impact of wind into system dynamics is required. While these dynamic studies lie outside the scope of this work, some points can still be addressed.

Currently the impact of WG fluctuations within response time scales is considered to be limited. This assumption is valid for low to moderate wind penetration (WP) but for the large penetration envisaged in future systems there is a need to take this impact into account.

[23] The standard deviation is a statistical measure that defines how widely distributed (dispersed) a set of data points are away from the mean (average) of the data.

Considering that this work looks at large WP an estimate of the impact of wind uncertainty in response requirements is done. To this end frequency response requirements are modified to take into account the variability of wind over ½ hr forecast horizon (which covers the overall period in which response services are needed).

The two sources of uncertainty driving response requirements, which in this case are generation and large demand outage and wind fluctuations, are assumed to be independent and approximately normally distributed. An estimate of the increase in frequency response requirements is made by using half-hourly variance of wind output uncertainty (see Figure 3.4) and combining this uncertainty with existing requirements to cover for generation and large demand outages. Again, assuming the two sources of uncertainty are uncorrelated and approximately normally distributed, the resulting response requirements are as follows:

$$R_t^{pr} = \sqrt{\left(R_{conv,t}^{pr}\right)^2 + \left(3\sigma_{wind,1/2}\right)^2} \qquad 3.1$$

$$R_t^{hf} = \sqrt{\left(R_{conv,t}^{hf}\right)^2 + \left(3\sigma_{wind,1/2}\right)^2} \qquad 3.2$$

Here R_t^{pr} denotes the primary and R_t^{hf} denotes high frequency response requirements, set by the system operator only, respectively. $\sigma_{wind,½}$ is the standard deviation of the normal distribution used to represent wind output uncertainty. Under these assumptions, in 99.73% of cases, the wind output will be within $\pm 3\sigma_{wind,½}$. The value $3\sigma_{wind,1/2}$ is then an estimate of the maximum possible uncertainty in half-hourly wind variations. The modified frequency response requirements ensure that the level of operational risk accepted by the system operator remains unchanged.

3.3.3 Determination of reserve requirements with wind generation

Traditionally, power system reserve requirements were driven by two phenomena:

- sudden generation failures; and
- deviations in demand levels away from the forecasted values

With the introduction of WG into the generation mix, reserve is also required to cover sudden changes in its output.

As indicated above, the additional uncertainty introduced by WG affects response requirements. The impact of this additional uncertainty on reserve requirements is even more pronounced. In order to analyse the impact of this additional uncertainty on system reserve levels it is required that wind power output changes expected over different time scales for various penetrations of WG can be known and characterised. The amount of reserve required will depend on the expected output change of WG in addition to the normal variations of demand and conventional generation.

This section describes two approaches to determining the total system reserve requirements. Initially analytical methods are used to capture the stochastic characteristics of historical wind data along with uncertainties in demand and generation capacity. An important part of this process will be the selection of appropriate representations of the different sources of uncertainty. The analytical method is used to determine the significance of changing WP levels on total reserve requirements. Following this, a second method is described where wind uncertainty, along with demand and generation uncertainty, is characterised using numerical methods. The numerical method is used to examine the effectiveness of the analytical approach.

Analytical method for determination of reserve requirements

To use analytical methods to capture reserve requirements, analytical models for the each different source of uncertainty must first be selected.

Characterising Uncertainty in Demand Forecasting

Electricity demand forecasting is an established and mature process. As a result, demand forecast errors are relatively small and are often represented by a normally distributed random variable with zero mean and standard deviation of typically 1% of current demand [84, 85]. Given this probabilistic model of demand forecast errors, in 99.73% of cases, forecasted demand should deviate from actual demand levels by no more than ±3% of current demand (i.e. 3 standard deviations). To ensure security of supply, reserve levels should cover this potential variability[24].

Characterising Uncertainty in Wind Forecast Errors

The presence of WG introduces an additional element of uncertainty to system operation that must be accounted for in setting reserve requirements. Differences between forecast and realised outputs from installed WG must be covered by system reserve.

In general, the wind imbalances can be characterised by a "bell shaped", but not strictly normal, distribution. In addition, the mean value of the imbalances is usually approximately zero. The precise form of the distribution will depend upon the forecast time horizon, as previously show in Figure 3.4.

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[24] According to [23] to determine how much reserve needs to be scheduled for each half hour of the following day, risks with respect to uncertainty in prediction need to be considered and a risk level needs to be defined. To set the risk criterion Central Electricity of Great Britain (CEGB), in the past, performed a statistical examination of the distribution of changes in the plant / demand margin, which showed them following a near normal distribution (without wind generation). Based on this, reserve was set as 3 standard deviations of the uncertainty (assuming a normal distribution) as that captures 99.73% of the imbalances.

Two possible representations of wind imbalances were considered. The first approach used was to approximate wind imbalances directly using a normal distribution. Taking the 30 min ahead wind forecast example, Figure 3.5 presents both a histogram of the uncertainty associated with a ½ hr forecast of wind and the normal distribution that best fits the data. The parameters of the fitted distribution are obtained using maximum likelihood estimation (MLE) process.

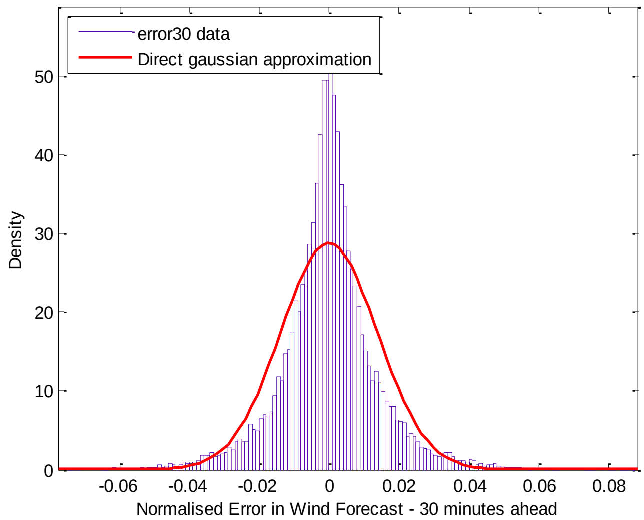


Figure 3.5 Direct Gaussian approximation of wind imbalances for 30 min ahead forecast error

This figure shows that the fitted normal distribution under-estimates the comparative likelihood of both near zero (due to higher Kurtosis of error data) and large (plus or minus) imbalances (due to “fat tails” of error data). Of these two issues of divergence, the inability to capture the "fat tails" of the actual distribution in forecast errors is more significant. Choosing a normal distribution fitted directly to the data means that the imbalances in wind should be within 3 standard deviations either side of the mean in 99.73% of cases (according to the characteristics of any normally distributed random variable). It can be seen from Figure 3.5 that large imbalances are more common than is predicted by a normal distribution fitted directly to the data. Allocating a level of reserve based on the fitted normal distribution could leave the system without sufficient reserve to cover very large wind forecast error, posing a risk to the security of supply.

Comparative studies performed by [10, 30, 35, 36, 82, 86] also recognize this issue. To deal with this, the reserve allocated to cover wind imbalances is set as perhaps 3.5 to 4 times the standard deviation of wind imbalance data. Similar approaches have been used in several wind integration studies [33, 54, 55, 59, 87]. This takes the "fat tails" of the distribution in forecast errors into account in setting reserve. These approaches, though, rely upon a specific set of data. Using different wind data sets leads to different multiples of the standard deviation required to cover for wind imbalances. In addition; different values of reserve will be used depending upon the level of risk (or there not being sufficient reserve to cover wind imbalances) that is accepted.

The actual approach used in this work is a formalisation of the methods used in [30, 55, 59, 65, 82], where 99.73 % wind imbalances are assumed to be covered by 3.5 σ_{WIND} used, with σ_{WIND} being the standard deviation of the MLE fit of wind imbalance data. Rather than trying to match the overall characteristics of the original wind imbalance data, it was felt that it is more important to use an analytical model that captures the "variation" of imbalances accurately. For example, for the case study above, in 99.73% of cases, the wind forecast error lie between -0.0581 and 0.0513 (these are normalised wind errors)[25]. This variability could be captured by a normally distributed random variable with a mean of:

$$\mu_{WIND} = -0.0581 + 0.0513 \approx 0 \tag{3.3}$$

and a standard deviation of:

$$\sigma_{WIND} = {(0.0513 - 0.0581)}/{6} \tag{3.4}$$

making use of the fact that the 99.73% of normally distributed random variable is contained within ±3 standard deviations about the mean. The comparison between this analytical representation, designated by "the equivalent risk fit" of the wind forecast error and the "best-fit" (using MLE) is shown in Figure 3.6.

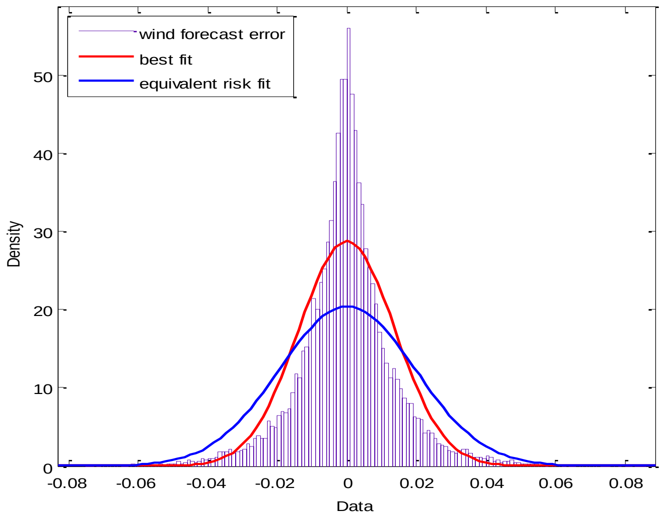


Figure 3.6 Direct and equivalent risk fit Gaussian approximation of wind imbalances

[25] The values of -0.0581 and 0.0513 are the 0.135th percentile ($P_{0.135}$) and 99.865th percentile ($P_{99.865}$) of the wind imbalance data.

The equivalent risk fit, now provides a conservative estimate of the wind forecast error across the majority of ranges. If used to characterise reserve requirements, the level of risk of accepted (with regards to the reserve being sufficient to cover variability in wind imbalances) will match more closely variability in the wind imbalance data. In addition, the level of risk is consistent with the analytical model used to capture demand uncertainty.

Reserve Requirements Covering Wind and Demand Uncertainty

It is usually reasonable to assume that variations in wind output are not correlated with demand uncertainty (or the likelihood of unit failures as well). In such cases, the total reserve requirements can be determined as the sum of the independent random variables characterising uncertainty in load forecast and WG forecast (and eventually unit failures), respectively. Using the analytical representations for demand forecast and wind forecast error described previously, (and making use of the properties of independent normal random variables) the total uncertainty also can be characterised by a normally distributed random variable with zero mean and a standard deviation calculated by equation 3.6.

$$\sigma_{total} = \sqrt{(\sigma_{demand})^2 + (\sigma_{wind})^2} \qquad 3.5$$

$$\sigma_{total} = \sqrt{\left(D_{peak}/_{100}\right)^2 + (\sigma_{wind})^2} \qquad 3.6$$

Setting system reserve to three times this parameter should ensure that reserve requirements are sufficient in 99.73% of cases.

Representing Generation Outages

Reserve requirements would be incomplete if the impact of generation outages was not considered. Individual generator units fail rarely. The probability of an operating generator unit failing within the next hour is usually in the order of 10^{-3} to 10^{-4} [88]. When considering the whole power system, which contains tens or hundreds of units, the likelihood of some generation capacity failing when required becomes significant.

Rather than determining a probable loss of usable capacity, system operators often use a simpler “rule-of-thumb”. In the UK The “rule-of-thumb” used is that system needs to hold reserve of at least equal to the size of the largest unit in operation, e.g P_G^{MAX}.[26] Using this definition means

[26] Our calculations show that this rule of thumb is valid mainly in system with high diversity in generation size. In the UK, the largest unit is Sizewell B - chance of losing capacity greater than Sizewell B - would be low as it would require the outage of two or more large thermal units, which there is comparatively low probability. This rule of thumb would work less well in system with a more uniform distribution of unit sizes.

that the likelihood of losing more than one unit simultaneously is considered to be very low. In such case, a reserve of P_G^{MAX} should be able cover the loss of any single generation unit.

Setting of reserve levels to cover P_G^{MAX} is essentially a risk assessment process, such that it is very unlikely that a loss of generation would exceed this level. To incorporate generator outages in probabilistic reserve calculations an appropriate probabilistic model must be selected. Two different options were considered. These differ in the way we consider the bounds on the reserve and how the reserve requirements vary within those bounds. The graphical representation of the different options is presented by Figure 3.7.

Option 1: Represents the (N-1) criterion and corresponds to having a deterministic reserve criterion to cover for the larger generation loss. It's modelled as a "dirac delta function" (which is limiting case of normal distribution).

The problem with this first option is that it ignores the probabilistic behaviour of capacity outages. Instead an amount reserve, required to generation outages, will be kept that is in addition to the reserve requirements need to cover demand and wind uncertainty. Using this approach does not take into account the possibility that excess wind (or even unexpectedly low demand) could be used to cover for generation outages.

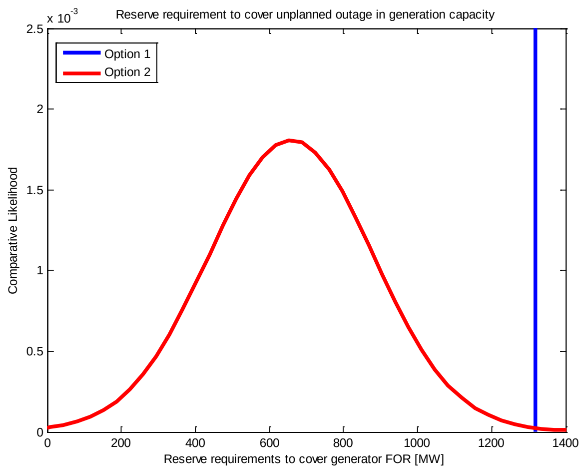


Figure 3.7 Different options to model reserve requirements to cover for generation outages

Option 2: Reserve requirements used to cover unit outages are modelled by a Gaussian distribution with a mean of 660MW (= 1320/2) and a standard deviation of 220 MW (= 1320/6). This second option reflects a situation where the chance of needing more than 1320 MW of additional reserve to cover loss of units is believed to be very low (i.e. less than 0.27% based on the characteristics of a normal distribution). This option does not correspond directly to any observed physical behaviour. The actual loss of capacity due to generation outages would be determined by a capacity outage probability table (COPT). Instead Option 2 allows the impacts of the use of some excess wind to cover for generation outages to be assessed in general terms. Its main goal is to show the impact on the overall reserve requirements of using a less conservative option.

Analytical Calculation of Total Reserve Requirements

The analytical models for the different sources of uncertainty in the generation – demand balance all have the form of normally distributed random variables. This makes it possible to combine them to determine the total uncertainty. Assuming that these are independent random variables the mean of the total uncertainty is given by equation 3.7 and the standard deviation characterising the total uncertainty is given equation 3.8.

$$\mu_{total} = \mu_{demand} + \mu_{wind} + \mu_{gen\_outages} \tag{3.7}$$

$$\sigma_{total} = \sqrt{(\sigma_{demand})^2 + (\sigma_{wind})^2 + (\sigma_{gen\_outages})^2} \tag{3.8}$$

For the first option for modelling the loss of generation, these parameters become:

$$\mu_{total} = 0 + 0 + P_G^{MAX} = 1320 \text{ MW} \tag{3.9}$$

$$\sigma_{total} = \sqrt{(\sigma_{demand})^2 + (\sigma_{wind})^2 + 0^2} \tag{3.10}$$

For the second option for modelling the loss of generation, this becomes:

$$\mu_{total} = 0 + 0 + \frac{P_G^{MAX}}{2} = 660MW \tag{3.11}$$

$$\sigma_{total} = \sqrt{(\sigma_{demand})^2 + (\sigma_{wind})^2 + \left(\frac{P_G^{MAX}}{6}\right)^2} \tag{3.12}$$

where P_G^{MAX} represents the capacity of the largest unit in the system, which in the UK case is 1320 MW. In either case, the total reserve that should be allocated is determined by:

$$R_{total} = \mu_{total} + 3\sigma_{total} \tag{3.13}$$

It is not possible to say that one option is better than other and the choice of the option to be used depends mostly on the level of risk that is accepted. Instead, to indicate the significance of the different choices, a numerical example is presented.

3.3.4 Illustrative examples of the impact of different sources of uncertainty on reserve requirements

From a set of examples it is possible to discuss the implications of different sources of uncertainty under increasing levels of WP. The data used in the examples is presented by Table 3.1.

The total reserve requirement is calculated, using the analytical approach summarised in Equation 3.7 – 3.9, for the two options described for capacity loss modelling. Variability in wind forecast uncertainty was characterised using the “equivalent risk fit” normal distribution.

Table 3.1 Data for numerical example 1

Demand uncertainty	Wind forecast lead time	Capacity of Largest Unit
σ_{demand} = 670 MW (1% of 67 GW peak demand)	4 hours	1320 MW

Impact of different models of generation outages

The results are presented in Table 3.2, where w_{fe} represents the wind forecast error. In each case it is summarised by the standard deviation of the normal distribution that captures the variability in the distribution in wind forecast errors generated using the persistency based approach.

Table 3.2 Results with wind forecast error modelled using normal distribution (equivalent risk fit)

Wind Capacity	w_{fe} (MW)	Reserve requirements (MW) – different options for forced outage representation	
		Option 1	Option 2
10GW	σ_{W2} = 1260.7	5603	4994
20GW	σ_{W2} = 2521.4	9147	8514
30GW	σ_{W2} = 3782.0	12843,7	12202

Impact of wind penetration in the overall reserve requirement

It is clear that reserve requirements increase with wind as shown by Figure 3.8. The trends are unaffected by manner in which generator outages are modelled and the difference between the possible options becomes less relevant for higher levels of WG.

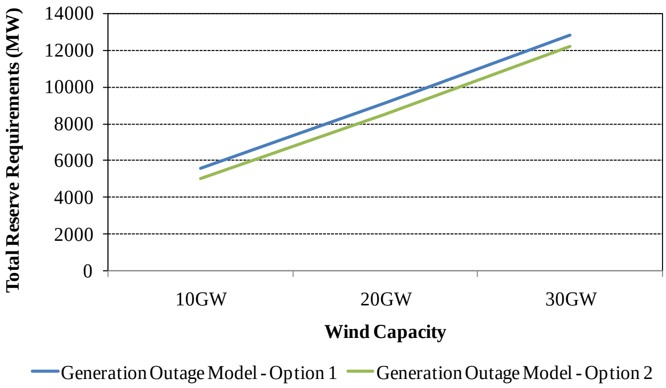


Figure 3.8 Overall reserve requirement for different representations of generation outages

Sensitivity of reserve requirements to the different sources of uncertainty

A set of calculations were performed to understand the relative impact of different sources of uncertainty into the overall reserve requirement. This is done by calculating the total reserve requirement when each of the sources of uncertainty is removed. Such an analysis is important to identify what drives a higher need for reserve and how this changes with WP. Such knowledge can be useful when trying to decide which source of uncertainty will contribute the most to a more accurate modelling of reserve requirements. Figure 3.9 present the results of this exercise in terms of new requirement obtained when each of the sources of uncertainty is removed in percentage of the base case requirement obtained when all sources are considered. In each case, two curves are shown to indicate the impact of the two methods for representing generation outages. Firstly, demand uncertainty has a consistent, but limited affect. The model used to model loss of generation has a higher effect. For 10 GW of wind the total difference between the two approaches corresponds to 609 MW. At these lower WP levels; allowing some generation outages to be covered by excess wind (i.e. generation outage option 2) reduces reserve requirement by over 10%. In absolute terms, the difference between reserve requirements increases slightly with WP. Proportionally, however, the impact of choice of model for generation outages becomes less pronounced. In any case, these difference are not insignificant and would affect the overall reserve cost. Therefore the SO would need to perform cost/benefit analysis studies to select the more suitable option.

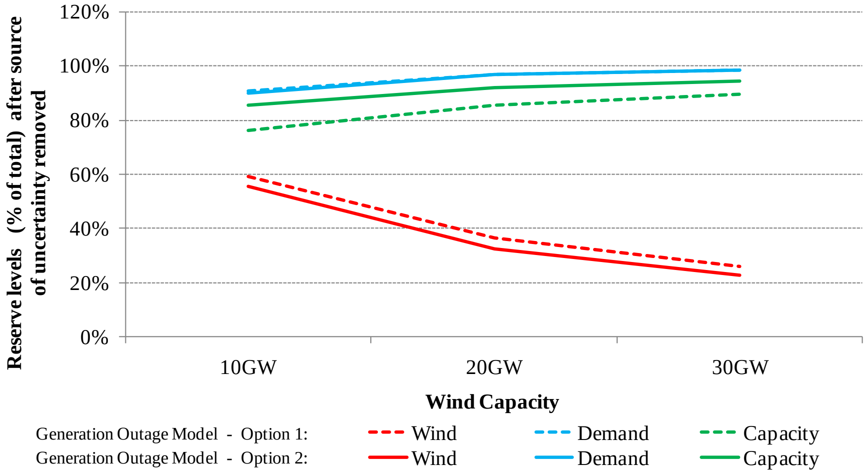


Figure 3.9 Impact of different sources of uncertainty on the overall reserve requirement

It is clear though that wind has a dominating role. Increasing WP reduces the significance of other sources of uncertainty. Considering that wind drives from 40 to 80 % of the reserve requirements, lowering wind uncertainty will bring a more significant impact into reserve requirement. The reduction of this uncertainty may obviously come from better wind forecast techniques but may also come from a better representation of wind uncertainty, when calculating the reserve requirement.

The importance of the model used to approximate wind forecast errors is highlighted by the following table. The total reserve requirements are quantified using the two possible approaches to characterising wind forecast uncertainty. The results shown in Table 3.3 are obtained using the first model for the generation outages

Table 3.3 Results with wind forecast error modelled using normal distribution approximated with LSE and equivalent risk fit

Wind Capacity	LSE fit		Equivalent risk fit	
	w_{fe} (MW)	Reserve Requirement σ_{W1} (MW)	w_{fe} (MW)	Reserve Requirement σ_{W2} (MW)
10GW	$\sigma_{W1} = 923.8$	4744	$\sigma_{W2} = 1260.7$	5603
20GW	$\sigma_{W1} = 1847.7$	7216	$\sigma_{W2} = 2521.4$	9147
30GW	$\sigma_{W1} = 2771.5$	9874	$\sigma_{W2} = 3782.0$	12843,7

Using the equivalent risk approximation leads to higher overall reserve requirement by 20% for a 10 GW wind capacity. As wind capacity increases this becomes more significant rising up to a 30% higher requirement. This would be expected since for higher wind capacity a higher share of reserve is driven by wind uncertainty consequently, the way its error is approximated has a higher impact. Again selecting the process to use will depend on the risk accepted by the SO.

Reserve requirements using a numerical approach

From these examples it was seen that neither analytical model used is entirely satisfactory since the direct approximation of wind uncertainty by normal distribution does not capture correctly the risk of large forecast errors and the equivalent risk fit representation is quite conservative driving a significant increase in reserve. Given the impact that wind uncertainty can have on reserve requirements, alternative approaches may need to be considered.

An alternative to the analytical approach presented is to avoid the approximation of the wind forecast imbalances. A possible approach is to incorporate the observed variability in wind forecast error directly. The total uncertainty is the sum of three random variables representing wind (W) and demand (D) forecast errors and generation outages (G). Assuming that the sources of uncertainty are un-correlated the reserve requirements can be set if the total uncertainty can be calculated through the sum of independent random variables:

$$Uncertainty = W + D + G \tag{3.14}$$

This can be evaluated through the process of convolution of the different probability distributions (*pdf*). If the *pdfs* can be discretised the convolution can be evaluated numerically. In this way, the distributions are not required to be Gaussian. This permits capturing more accurately wind and generation outages uncertainty (i.e generation outages can be modelled by its COPT).

The numerical process used to form a discrete probability mass function that captures the total uncertainty of the different variables is carried out by following the steps presented in Figure 3.10. This shows the basic method of calculation for reserve requirements based on a discrete approximation of wind uncertainty characteristics for a 30 min operational time horizon (although the process would be unchanged if different time horizons were considered). The final two steps are repeated for the two possible options for representing generation outages.

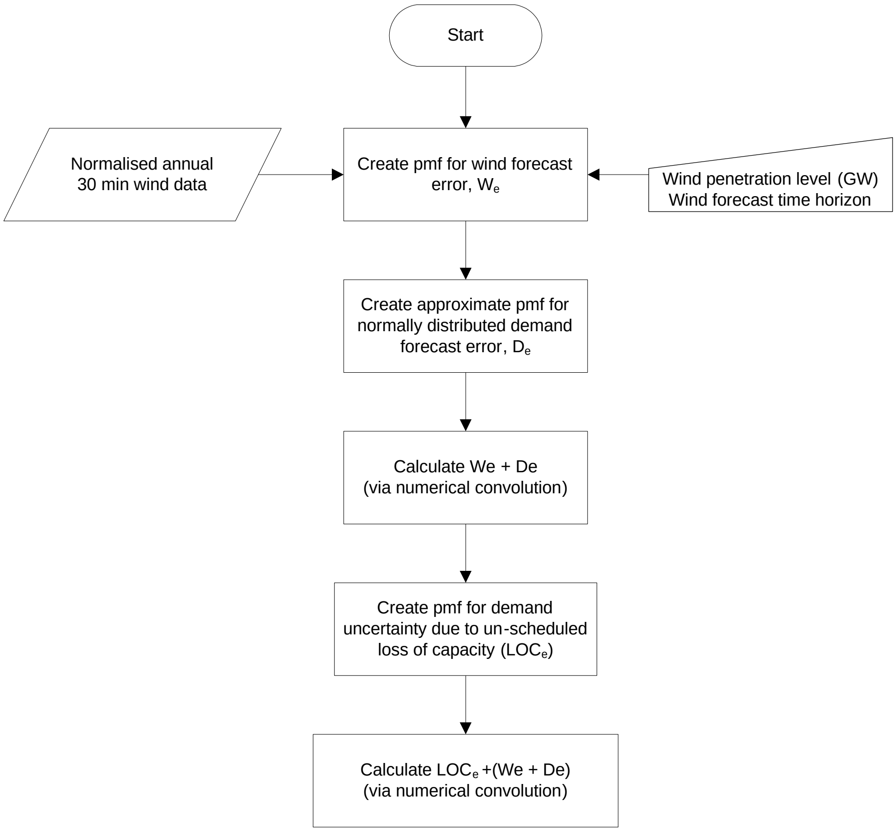


Figure 3.10 Basic process for the numerical convolution of wind, demand and capacity outage

As described earlier, the wind forecast error is determined through a persistency based method. This can be replaced by any alternative forecast technique. The total range of the possible wind forecast errors is divided into 10 MW steps. A histogram is then created to represent the comparative frequency of the wind forecast error falling into any one of these 10 MW bins. By dividing each comparative frequency by the total number of samples in the wind forecast error data, an approximate probability mass function can be created for the wind forecast error[27].

This approximation process is repeated for the other sources of uncertainty, i.e. demand forecast and generation outages. This allows the combined uncertainty to be calculated according to:

$$P(U_{TOTAL} = W + D + G = u) = \\ = \sum_{u_{W+D}=-\infty}^{\infty} \left(\sum_{u_W=-\infty}^{\infty} P(W = u_W) \cdot P(D = u_{W+D} - u_W) \right) \cdot P(G = u - u_{W+D}) \quad 3.15$$

where U_{TOTAL} is a random variable representing the combined uncertainty in wind, demand and generation. The parameters, u_w and u_{w+d} and u are respective instantiations of the random

[27] The resulting p.m.f distribution is quite spiky. This, however, does not seem to reduce its accuracy. The *cdf* formed from this approximate distribution is almost identical to the *cdf* produced by applying a kernel smoothing method to create an empirical version of the original data. This suggests that the approach described is accurate enough.

variables representing wind uncertainty, wind and demand uncertainty and total uncertainty. The numerical process used to determine the previous expression is a numerical convolution – a process that is commonly found in numerical simulation packages.

The use of numerical methods to determine the combination of different random variable, although more computationally intensive, is more robust. It allows the use of non-standard distributions for either wind forecast error or loss of capacity (with equal ease as more commonly used *pdf*, such as normal, exponential etc). Different probabilistic models for capacity outages, such as a COPT, could be used. Later sections of the chapter will examine the value of this approach.

Comparison between analytical and numerical methods

The use of numerical methods avoids using an optimistic or conservative approximation in the process of setting total reserve requirements. The difference in terms representation of uncertainty is illustrated in the following examples shown in Figure 3.11 and Figure 3.12, respectively. These figures show the distributions of total uncertainty that must be covered by reserve, considering wind, demand and generation outages, for different wind capacity. The distributions are obtained, for wind capacities of 10 GW and 30 GW. Both distributions are bell shaped with “fat” tales but for 10 GW wind the distribution is closer to a Gaussian shape. This shows the bigger impact of wind on the overall distribution of uncertainty for higher wind capacity.

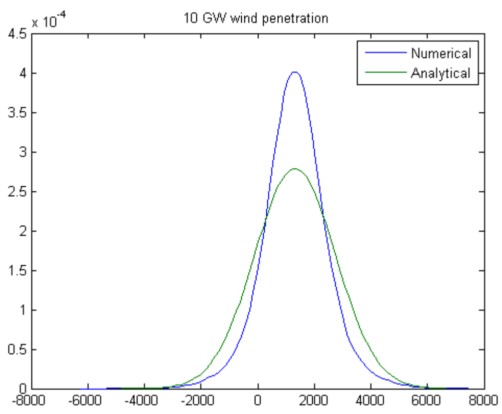


Figure 3.11 Total uncertainty - 10GW wind

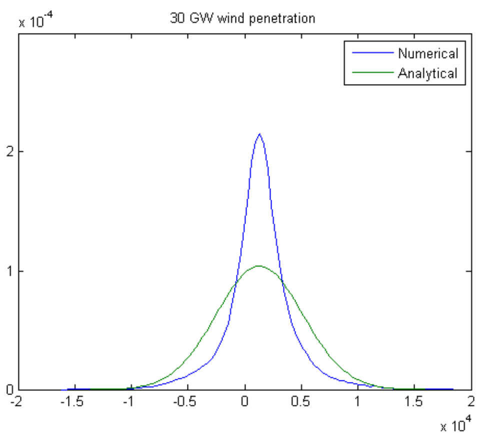


Figure 3.12 Total uncertainty- 30GW wind

Table 3.4 presents the comparative levels of reserve determined using the analytical and numerical methods. In this case, the comparison is made between the levels of reserve determined using the numerical approach and the analytical model which uses the equivalent risk criteria for characterising wind uncertainty and option 1 for generation outage model. In either case, the overall reserve requirement is set such that 99,73% of the total uncertainty is covered for.

Table 3.4 Comparison between overall reserve requirement obtained using analytical and numerical methods

Wind	Reserve requirements (MW) – different options for forced outage representation	
	Analytical	Numerical
10GW	5603	5571
20GW	9147	9207
30GW	12843	12948

The total reserve requirements, as determined by numerical combination of random variables are very similar to the reserve requirements determined using analytical methods based on the equivalent risk models for wind forecast error. This shows that the bounds to system uncertainty are well represented by the analytical methods.

The distributions of uncertainty, however, are quite different due to the "fat" tales of the one obtained with numerical methods and this difference increases with wind capacity. If the representation of loss of capacity used is replaced by other methods (such as the COPT) the difference between the two methods could become more significant. This may not affect the overall reserve requirement but is likely to affect the reserve composition, as discussed in the following sections.

3.4 Optimal Spinning and Standing Reserve Requirements

In the previous sections different approaches to define the overall reserve requirement were presented. The next question is how to provide this reserve. The decision about the composition of system reserve needs to be based on economical and technical aspects. In reality reserve is traditionally composed by a combination of synchronised generators and standing units with fast start (start up between 10-20 min). In this work the reserve contribution from synchronised part loaded plants will be designated as spinning reserve (SR) and the contribution from non synchronised plant will be designated as standing reserve (StR).

Ultimately, the more beneficial combination for reserve provision will be the one that minimises the total cost of reserve. StR will be used to displace SR whenever this reduces the cost of reserve and, consequently, the system operation cost. This cost reduction will come from two sources of value: reduction of part loading efficiency losses and, in systems with large WP, reduction of wind curtailed.

Reducing part load efficiency losses

The first source of value of StR is the reduction of the number of generators operating part-loaded. The efficiency of a generator is proportional to the ratio between the generator output in MW and the fuel cost. By solving a set of points from the generation cost function it is possible to derive a representation of the plant efficiency losses as represented by Figure 3.13.

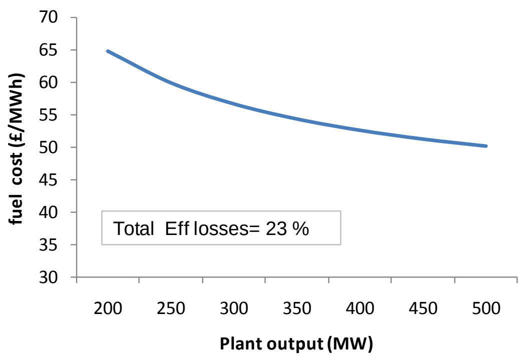


Figure 3.13 Example of plant thermal efficiency losses in terms of fuel cost for different loading levels

The efficiency losses change with the technology and affect both system cost and CO_2 emissions. Producing a fixed amount of power from a full loaded plant leads to lower cost and emissions than producing the same amount of power from two part loaded plants. Reducing the need for part loading generation increases the overall efficiency of generation and reduces the fuel costs and CO_2 emissions.

Increasing system's ability of integrating wind generation

The second benefit of StR is to increase the system ability of accommodating WG. This becomes especially visible for systems with large WP.

The main issue regarding system's ability of accommodating WG is that its output added to inflexible generation output is lower or equal to demand. Whenever this is not verified wind needs to be curtailed. Inflexible generation output corresponds to the total generation that cannot be reduced, due to plant technical limits, at each time interval and is composed by:

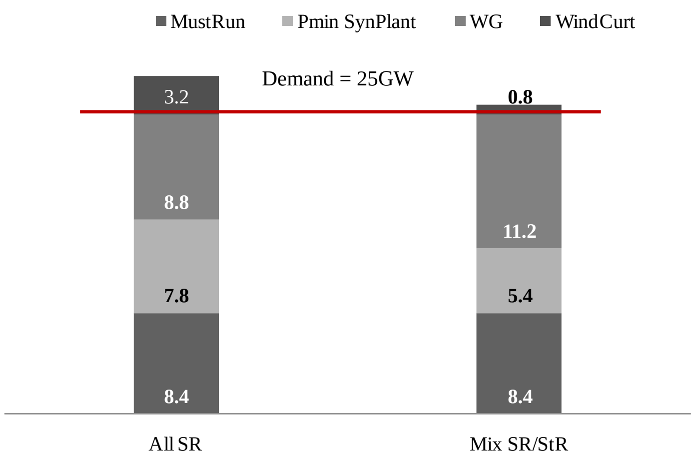
- Minimum output of must run plant;
- Minimum stable generation of synchronised plants;

WG has priority on the dispatch (since it is assumed to have zero marginal cost) but it is technically viable to reduce its output if required to maintain the generation-demand balance.

Consequently holding large amounts of reserve in part-loaded plants implies that these plants will need to inject into the system a significant amount of power than can't be reduced. This problem is aggravated if the generation mix also includes inflexible must run generation that produces a constant output at all times.

For low WP, periods when wind curtailment is required are rare. For higher WP this problem becomes more frequent, because on one the hand more reserve is required and on the other hand there are larger amounts of wind energy to be accommodated.

Standing reserve is an alternative to reduce the number of part loaded plants without compromising system security. If part of the reserve can be provided by StR plant less units need to be part loaded and system efficiency losses and wind curtailment can be reduced. This is illustrated in Figure 3.14 by an example of how the use of a combination of SR and StR increases system's ability to accommodate WG. This example uses two snapshots of system operation: the first case all reserve composed by SR and the second case is composed by a mix of SR and StR (provided by fast plant). By reducing the amount of inflexible generation output from part-loaded synchronised plants less wind needs to be curtailed to maintain the demand/supply balance. This shows the importance of using StR to increase system efficiency and reduce the amount of wind wasted.



	All SR	Mix
Reserve Req (GW)	6.5	6.5
Nr Syncr Units SR[28]	26	18
Gen Sync (GW)	7.8	5.4
WG (GW)	12	12
Must Run (GW)	8.4	8.4
StR (GW)	0	2
Demand (GW)	25	25
Surplus Gen (GW)	3.2	0.8

Figure 3.14 Snapshot of generation dispatch for all SR and a mix of SR and StR

The decision of the right combination between SR and StR is needs to be obtained through a cost/benefit analysis. A procedure to perform this analysis is presented in the following section.

[28] Each synchronised conventional unit can be operated between: 300 < P < 550 (MW) meaning that each part loaded unit provides 250 MW of reserve. To meet a total reserve of 6.5 GW 26 units need to be synchronised and producing a fatal generation of 26 × 300 = 7.8 GW.

3.4.1 Allocation between spinning and standing reserve

The determination of the optimal combination of SR and StR is a non trivial task and different parameters need to be taken into account. To determine the minimum cost allocation between the two, the cost of providing each type of reserve needs to be obtained from the economic difference between synchronised and fast start plants represented by its holding[29] and exercise[30] cost. In this work the holding cost of SR corresponds to the cost of efficiency losses due to plant part loaded operation and the exercise cost corresponds to plant marginal cost. The cost of StR is represented by the exercise cost of standing plant. These costs depend on the technology.

Traditionally synchronised plants deal with more frequent and small deviations from normal operation while standing reserve deals with less frequent large deviations. Figure 3.15 represents overall system imbalances as a normal distribution with mean zero and standard deviation obtained by equation 3.8. The split between SR and StR (represented in the figure as λ) should be such that it minimises the total cost of reserve. The following sections present an approach to estimate the value of λ.

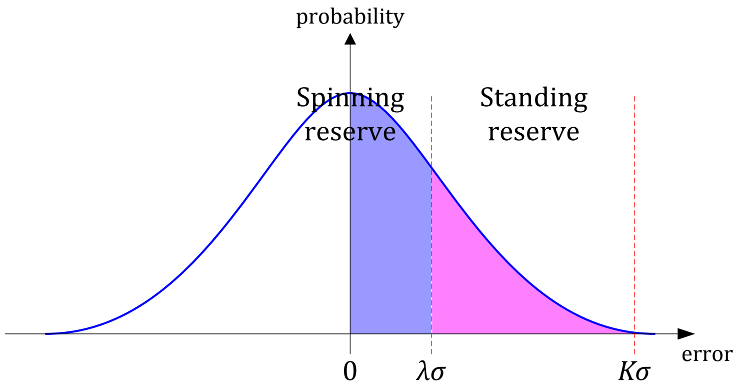


Figure 3.15. Reserve allocation to cover for system imbalances

Reserve cost calculation

The cost of standing reserve is obtained as a function of the differential between the marginal cost of full load synchronised units and the marginal cost of standing units.

Considering that SR takes the more frequent and smaller imbalances and StR the less frequent and larger imbalances the amount of each type of reserve will be:

---

[29] Holding costs represent the cost of having unused spare generation capacity, or other form of stored energy, to supply reserve services.

[30] Exercise costs represent the cost of the energy supplied (cost/ MWh) when the reserve services are called upon by the SO.

$$R = K\sigma \tag{3.16}$$

$$SR = \lambda\sigma \tag{3.17}$$

$$StR = (K - \lambda)\sigma \tag{3.18}$$

R is the system total reserve equal to a number K of standard deviations (σ) of system imbalances. Even if the distribution of imbalances is not Gaussian, an equivalent standard deviation is used to characterise variability in imbalances. To allocate the amount of SR and StR that leads to the minimum operation costs a reserve cost function combining SR and StR cost is derived. Details of this derivation can be found in Appendix A. The cost function obtained is represented by equation 3.19.

$$\begin{cases} \Big((\lambda_i\sigma - r)\big)\big(c_{par\,t_{load}} - c_{ful\,l_{load}}\big) + (P_F - r)\big(C_R - c_{par\,t_{load}}\big)\Big) & for\ k_i \leq 0 \\ \quad ((\lambda_i\sigma - r))\big(c_{par\,t_{load}} - c_{ful\,l_{load}}\big) + (P_F - r)\big(c_{residual} - c_{par\,t_{load}}\big)) + & \\ + (\big(c_{ful\,l_{load}} - c_{par\,t_{load}}\big)\,k_i\sigma & for\quad 0 > k_i < \lambda_i \\ \Big(c_{ful\,l_{load}} - c_{fas\,t_{plant}}\Big)\lambda_i\sigma + \Big(c_{fas\,t_{plant}} - c_{ful\,l_{load}}\Big)k_i\sigma & for\ k_i \geq \lambda_i \end{cases} \tag{3.19}$$

Where σ is the standard deviation of imbalances, k_i is a random imbalance, λ_i is a random number representing the split between SR and StR, r is the residual reserve held by a partly loaded plant.

The cost of reserve is a function of the split between SR and StR represented by λ. For each λ_i a different solution is found for the total cost of reserve. The optimal allocation between SR and StR will be represented by the value of λ_i that minimises the cost function, for a specific scenario of SR and StR cost.

Finding this minimum requires solving equation 3.18 for a large set of scenarios of imbalances k_i and reserve split λ_i.This is done using a simplified stochastic optimisation following the process described by Figure 3.16.

For each possible split between spinning and standing reserve, represented by different λ_i the expected cost of reserve corresponds to the average of the cost obtained for the different random imbalances. These are drawn from a representation of the distribution of demand/supply uncertainty U_{TOTAL}. The imbalances could be normally distributed if analytical methods are used to characterise total uncertainty. Alternatively; the imbalances may have different distribution; as determined by the numerical method described in Section 3.3.3.

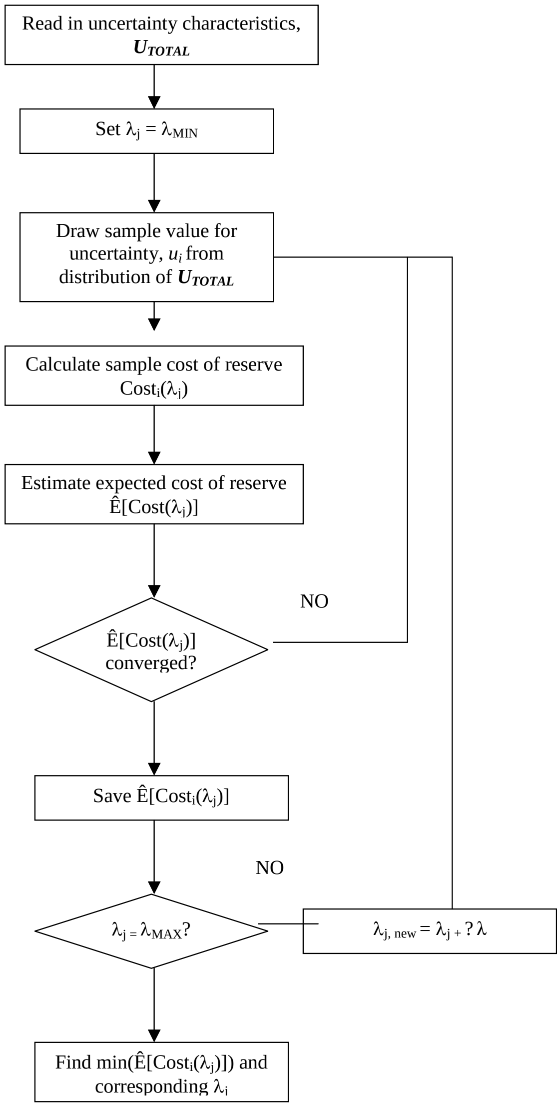


Figure 3.16 Flowchart of the process to obtain the optimum – λ_{min}[31]

A graphical representation of an example relationship between the expected cost of reserve and λ is presented in Figure 3.17.

The preferred split between spinning and standing reserve is the value of lambda which leads to the lowest expected cost of reserve. This allocation represents the relative cost of plant efficiency losses when compared with the cost of standing plant. This point can be determined by finding the minimum of the set of values of $E[Cost(\lambda_i)]$ that represent the outcome of the algorithm described above.

[31] In the implementation of the algorithm, the convergence of E[Cost(λj)] is not calculated formally. Instead; the inner loop of the algorithm is run for 10000 times as off-line studies showed that this many iterations are sufficient.

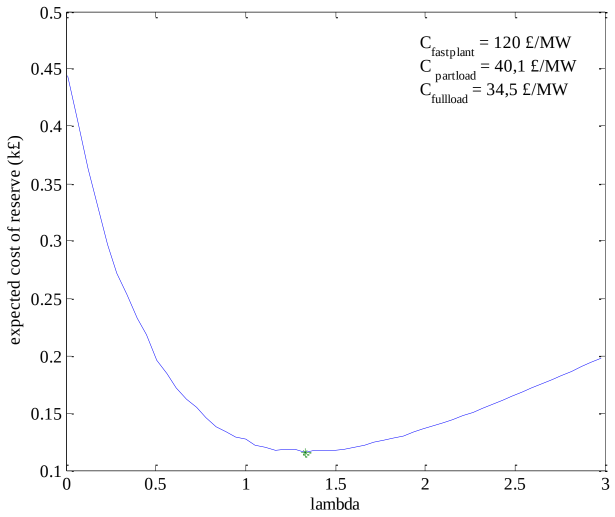


Figure 3.17 Expected cost of reserve as a function of λ

The significance of this calculation in illustrated in Figure 3.17. In this specific case, the minimum expected system operating cost is achieved when lambda is equal to 1.41. This corresponds to the situation in which 47% of the reserve requirements are met by SR and 53% are met by StR. Reducing the amount of SR (corresponding to values of lambda lower than 1.825) increases the cost of reserve because the higher cost generators used for StR are exercised more often. Alternatively, increasing the amount of generation held as SR also increase reserve costs due to synchronised plant part-load efficiency losses. The calculation of the optimal value of the lambda captures the trade-off between these costs.

3.4.2 Factors affecting reserve composition

The results shown in Figure 3.17 indicate a possible relationship between the expected cost of reserve and possible ways that this could be allocated. The nature of this relationship depends upon a number of interacting parameters including:

- Wind forecast time horizon
- Wind capacity
- No load cost of spinning reserve (c_{nl})
- Incremental cost of spinning reserve (c_i)
- Cost of standing reserve ($c_{fast_{plant}}$)
- Representation of the uncertainty in the generation – demand balance

The following sections explore the impact that changes in these different parameters can have on the optimal combination of spinning and standing reserve.

This discussion addresses two limit cases for the different operational time horizons used to set reserve: 30 minute and 4 hours ahead of electricity delivery time. The majority of the discussion will again focus on the 4 hour operational time horizon. Likewise the numerical results shown are determined using the first of the options for generation outages described in section 3.3.3.1, although the trends were consistent for both models.

Short time horizon forecasts

The simpler case to examine is the short operational time horizons of the 30 minutes. Within this operational time horizon, reserve requirements are driven mostly by the need to cover for generation outages. The additional uncertainty introduced by WG has only limited impact, even as WP levels increase[32].

The characteristics of the plant providing SR will, however, have some impact on the composition of reserve that will minimize expected system reserve cost. In this work thermal plants are divided in two groups characterized by plant flexibility:

- High flexible plant: characterised by high no-load cost of £4900 and a marginal cost of 40 £/MWh
- Low flexible plant characterised by lower no-load cost of £1850 and a lower marginal cost of 30 £/MWh

These characteristics correspond approximately to combined cycle gas turbine (CCGT) and coal plant, respectively.

These different plant characteristics will affect the proportion of reserve that is covered by either spinning or standing reserve. In the case of 30 GW of wind capacity, when the marginal plant is assumed to be “high flexible” plant, expected system operational costs are minimized when spinning reserve makes up 52 – 60% of total reserve requirements. The proportion of spinning reserve increases to 65 – 70% of total reserve requirements if the marginal plant is considered to be “low flexible”. For 30 min forecast lead times these differences though represent an absolute change of only around 500 MW.

Long time horizon forecast

It was shown above that for short operational time horizons, total reserve is relatively insensitive to wind capacity and wind characteristics. Additionally reserve composition is relatively insensitive to the characteristics of the marginal plant (in quantitative terms). These factors become more important when longer time horizons of up to 4 hours are considered.

[32] For example, increasing the level of wind penetration from 10 GW to 30 GW increases the system reserves requirements by around 500 MW. This is the same size as the variations in reserve requirements that occur for even a fixed level of wind penetration, depending upon the method used to model generation outages.

Importance of plant costs (c_{nl} and c_i)

In the models considered, SR can be provided by either "high flexible" plant or "low flexible" plant type. As indicated previously, the difference between the two plants includes both the incremental (c_i) and no-load costs (c_{nl}). The comparative influence that these changes in plant characteristics have on the optimal level SR, when the system is operated with 30GW of wind is shown in Figure 3.18 where c_i is reduced from 40 to 30 £/MWh and c_{nl} is reduced from 4900 to 1850 £.

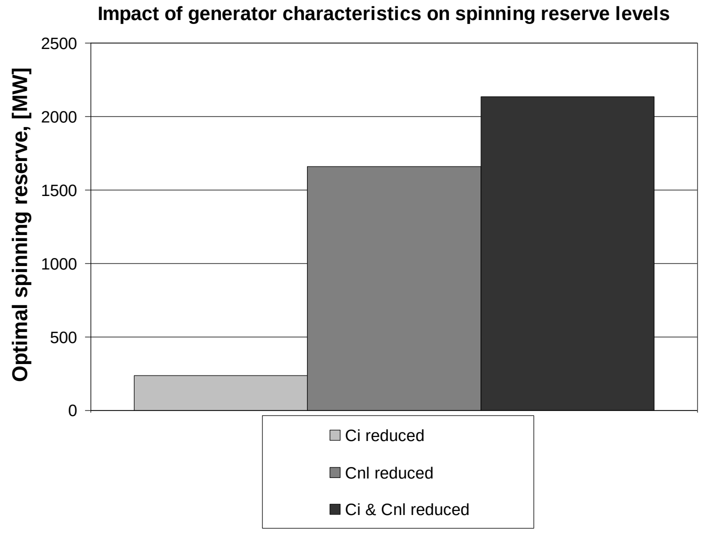


Figure 3.18 Comparative influence of different parameters on optimal SR in terms of variation of SR requirement

Clearly, the change in optimal levels of SR resulting from the change in plant costs is due mostly to the change in no-load costs (i.e. holding cost). Reducing the no-load cost but keeping the incremental cost unchanged leads to an increase in the optimal spinning reserve of over 1500 MW. The impact of incremental cost of the marginal plant relatively limited. Reducing the incremental cost, but keeping the no-load costs fixed leads to an increase in the optimal spinning reserve of less than 500 MW. These trends were found to be consistent for all wind installed capacities.

The preceding trends are also consistent irrespective of method used to model the uncertainty in generation-demand balance (i.e. the total uncertainty due to wind forecast error, demand forecast error and unplanned generation outages).

Importance of cost of standing reserve ($c_{fast_{plant}}$)

The previous changes in marginal plant characteristics were done with a fixed cost of StR provided by open cycle gas turbine (OCGT) (i.e. constant $c_{fast_{plant}}$). The cost of StR can also change. It is important then that the comparative influence of c_{nl} (cost of holding SR) and $c_{fast_{plant}}$ (cost reserve of using StR) is also examined.

Figure 3.19 illustrates the result of a numerical sensitivity study considering the effect of changing $c_{fast_{plant}}$ (between 50 and 250 £/MWh) and c_{nl} (between 1850 and 7500 £) on the optimal amount of SR (λ_{min}). The system was assumed to contain 30 GW of wind.

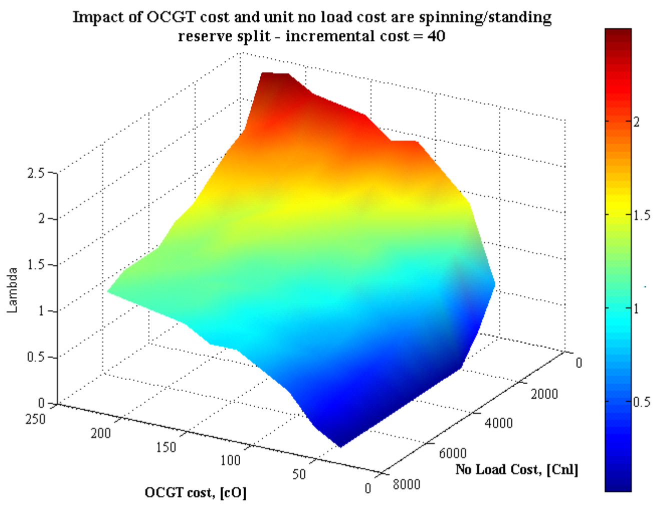


Figure 3.19 Sensitivity of the composition of reserve to different plant costs

It is clear that changing the costs of OCGT (fast plant) and the no-load cost of synchronised plant can both have big influences on the optimal split. For cheap OCGT and high no-load cost, using SR is un-economic. As the cost of SR decreases and OCGT cost increases, the optimal amount of SR increase to over 80% of total reserve requirements. At the same time, reducing no-load cost makes the split between spinning and standing more sensitive to OCGT costs as it now becomes more economic to use a higher proportion of SR.

Repeating the calculation with a lower incremental cost of the marginal plant produces a similar set of results.

These results were produced with the uncertainty in the generation-demand balance characterised using numerical methods. Similar trends would be observed if the uncertainty in the generation-demand balance was approximate using analytical methods.

Impact of characterization of generation – demand balance uncertainty

In the preceding sections it has been found that the use of analytical techniques to approximate the characteristics of the uncertainty in the generation – demand balance changes the shape of the distribution of imbalances. This affects the optimal split between spinning and standing reserve. The use of approximate methods, i.e. representing the uncertainty in the generation – demand in a Gaussian manner, will lead to the system allocating more SR. This is in comparison to when the uncertainty in the generation – demand is characteristics directly using numerical methods (i.e successive numerical convolution). The following Figure 4.20 shows the optimal levels of SR determined using the two different methods for wind capacities of 10 GW to 30 GW. .

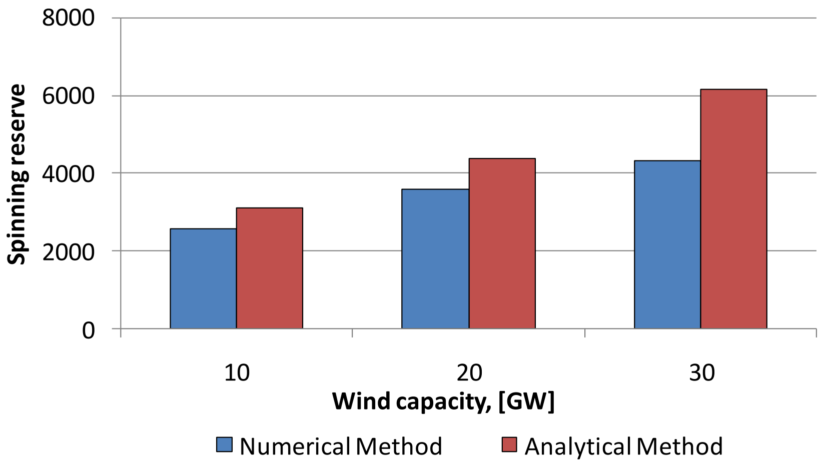


Figure 3.20 Impact of the method for characterising uncertainty on optimal SR requirement

Clearly if the generation – demand balance uncertainty is modelled using analytical methods, the apparent optimal level of SR is higher than if the uncertainty is characterised using numerical methods. In some cases the SR is almost 40% higher if the analytical approximation is used. As the total reserve requirements are equal in both cases, the use of analytical methods to characterise the uncertainty also leads to a lower level of StR.

The reason for these difference lies in the comparative shape of the *pdf* used to characterise uncertainty obtained using analytical and numerical methods. The actual distribution (characterised using numerical methods) in the generation – demand uncertainty *pdf* has:

- a large number of possible uncertainties clustered in a tight band either side of the mean (higher kurtosis); and
- long tails in which the comparative likelihood of different uncertainties changes only slowly

This should be compared with a normal distribution which covers the same range (corresponds to the uncertainty representation using analytical methods). The normal distribution presents a lower likelihood of small deviations either side of the mean and a more pronounced probability of “mid-sized” deviations. The shape of the two distributions used to characterise the uncertainty is illustrated in Figure 3.21.

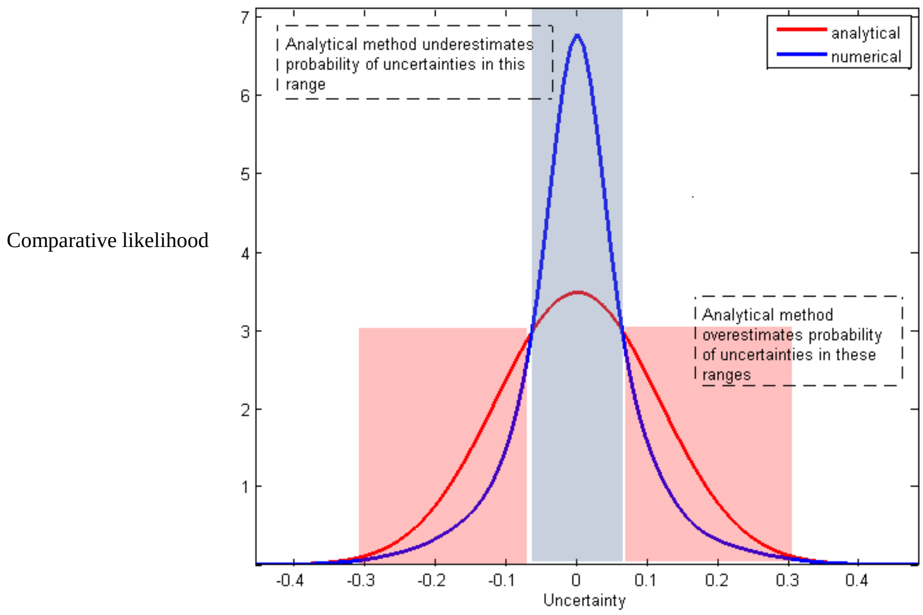


Figure 3.21 Probability distributions of imbalances obtained using analytical and numerical methods

The main implication of these differences is that SR covers the common small imbalances (around the mean). The extent to which these imbalances cluster around the mean is underestimated by the analytical method used to characterise uncertainty. Instead these imbalances either side of the mean are more evenly spread (see the red region). These differences are then reflected in the amount of SR allocated.

The problem with over-allocation SR is that there are costs involved. This is mainly because a large of amount of part loaded plant is kept available to cover imbalances which occur only infrequently. This is emphasized in Figure 3.22. This figure shows a comparison of the optimal levels of SR with the cumulative distribution function for the generation-demand balance uncertainty. The blue region represents SR allocated if uncertainty characterised numerically (i.e more accurately). The red region represents SR allocated if uncertainty characterised analytically (i.e approximately). In both cases, SR covers the 80% most frequent imbalances (i.e. 10% - 90%). For the example shown, however, SR allocated based on the analytical method covers 90% of all actual imbalances (5% - 95%). This additional reserve is used very infrequently and represents an additional cost to system operation.

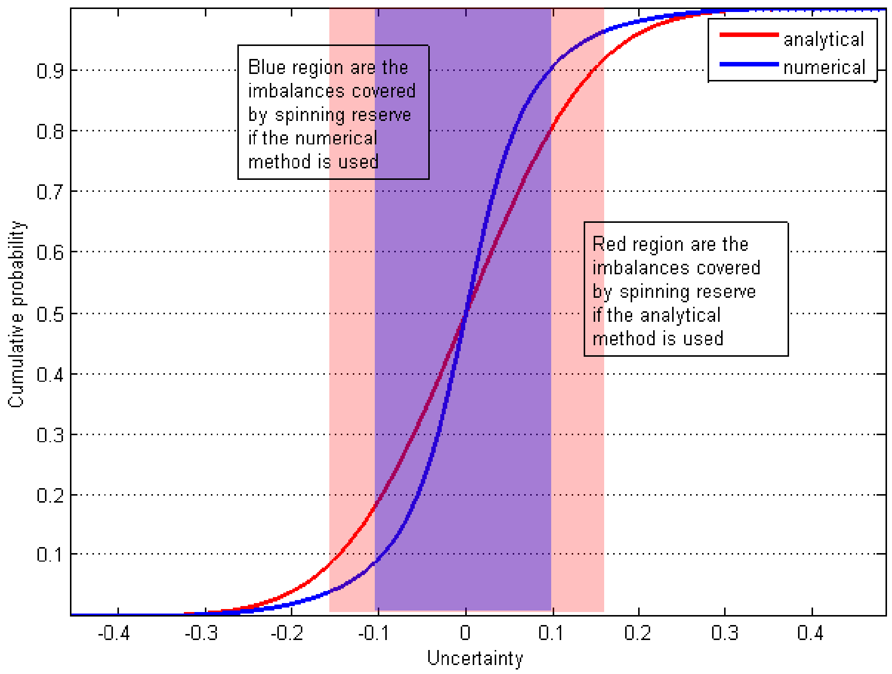


Figure 3.22 Cdf of the total uncertainty in the generation- demand balance obtained with analytical and numerical methods

A quantitative example of the value of numerical methods is developed using the simulation scheduling tool presented in Chapter 4. This consists of performing a set of annual simulations for different values of spilt between SR and StR ranging from all SR to all StR. The generation mix used has 24 % WP and the marginal plant is of low ramp type. The results for system operation cost and wind curtailed are presented are shown in Figure 3.23.

In addition the optimal split between SR and StR is determined offline using the approach proposed in this section using the uncertainty representation obtained from by analytical and numerical approaches. The value of λ that leads to the minimum cost of reserve obtained is:

- Numerical methods for characterising uncertainty : $\lambda = 1.5$
- Analytical methods for characterising uncertainty: $\lambda = 2.0$

The results obtained offline using each method are overlapped with the results obtained using system operation simulation as shown by Figure 3.23.

From this example it is possible to conclude that the numerical methods lead to a more accurate representation of system uncertainty since the value of λ_{min} obtained corresponds closely to the minimum cost split obtained from a full simulation of system operation.

Using the results obtained from this simulation it is possible to see that the split obtained from analytical methods leads to higher system operation cost and higher wind curtailed. Instead using numerical methods for offline determination of the optimal mix of SR and StR led to a reduction of 1 % in the total system operation cost (83 £million/year) and a reduction of wind curtailment of 3.5 % of the total annual wind energy. This represents an increase in system operation flexibility obtained by using a better combination of spinning and standing reserve.

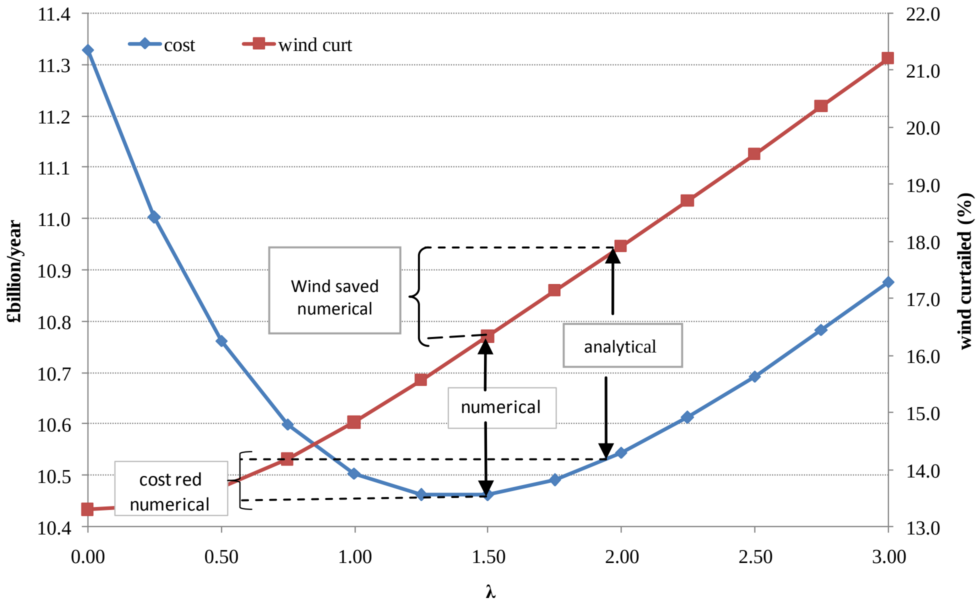


Figure 3.23 Value of numerical methods in terms of fuel cost and wind curtailment reduction

This illustrative example showed that there are benefits of having an accurate representation of uncertainty when setting the combination of SR and StR used to meet the total reserve requirement. Consequently numerical methods can be applied to avoid performing full system simulations to obtain the optimal λ. This in turn is used as an input to the system scheduling algorithm and avoids the cost the over-allocation of SR obtained if analytical methods are used.

The significance of the over-allocation will vary from case to case, depending upon characteristics of the marginal plant, cost of fast plant, wind uncertainty characteristics, WP, demand uncertainty, and other parameters. In general, at low WP, the approximation may have limited impact. As WP increase, the significance of the approximation is likely to become more important as wind will have a greater influence on the overall shape of the distribution of generation-demand balance uncertainty.

3.5 Conclusions

The introduction of WG into the overall generation mix brings a new source of uncertainty (wind forecast error) that needs to be taken into account. This is especially relevant for high WP. To operate a system with WG, new response and reserve requirements, need to be determined. Ultimately setting these requirements is a risk assessment process (or trade-off) made by the system operator in terms of what risk they believe is acceptable.

In this chapter, an approach to set off-line response and reserve in a quantitative fashion is developed. Both analytical and numerical methods are used to characterise the uncertainty in the demand-generation balance. Particular attention is given to an examination of the risk associated with the way we characterise uncertainty due to wind. The approach is then applied to an example of the UK by using the same risk levels to set response and reserve requirements. UK historical wind and demand data and generation mix characteristics are used to calculate the distributions of uncertainty needed to indicate the implications of using different approaches.

Three main findings of the study of wind's impact on response and reserve requirements should be highlighted:

- Wind forecast errors may not follow a strictly normal distribution - and assuming that forecast errors are normal exposes the system to (unintended) risk. More conservative approximations can to be used (such as the equivalent risk fit distribution) but this leads to higher response and reserve requirements;
- Reserve increases appreciably with WP since wind drives the majority of reserve requirements especially for several hours ahead forecast horizons;
- The way that generation outages are represented has an impact on the uncertainty in the demand-generation balance for short term (tens of minutes) forecast horizons and low WP but its effect is limited for higher forecast horizons and large WP. For low WP there is the potential for reductions in reserve if we describe the uncertainty in generation outages more accurately.

Considering that for high WP, as wind is driving the uncertainty, there are also potential costs involved in using approximate methods to characterise the uncertainty in wind forecast errors. To avoid treating wind as normally distributed, a numerical direct convolution of wind, demand and generation outages distributions of imbalances is used. Both analytical and numerical methods obtain similar total reserve requirements if the same risk criterion is used in both cases.

This chapter also discusses the composition of the overall reserve using a combination of spinning and standing reserve as a mean of increasing system flexibility and its importance in systems with large WP. A methodology to determine the optimal allocation of spinning and standing reserve is developed. The methodology is based on the minimisation of the expected cost of reserve, where cost of reserve is represented as the trade-off between part-load efficiency losses of synchronised plant and the cost of fast start plant. The methodology is used to investigate which parameters influence the optimal allocation of spinning and standing. The same methodology is used to discuss the implications of different representations of uncertainty.

The results showed that no-load cost of synchronised plant and the marginal cost of standing plant have a high impact while the marginal cost of part-loaded plant has less influence. These trends are consistent irrespective of method used to model the uncertainty in generation – demand balance (i.e. the total uncertainty due to wind forecast error, demand forecast error and unplanned generation outages).

The results also showed that the use of analytical approximations for the uncertainty in generation – demand balance leads to a higher allocation of spinning reserve. The implications of this depend on the cost of spinning reserve. If spinning reserve is cheap when compared to standing reserve, allocating excess of spinning reserve will not have significant impact on system costs. Nonetheless, a numerical example has shown that the value of a more accurate characterisation of the uncertainty in generation – demand balance can be reflected in terms of a reduction in system operation cost and wind curtailed.

In summary, both an accurate representation of the uncertainty on the demand-generation balance and the correct allocation of spinning and standing reserve affect system flexibility. This impacts system’s ability of accommodating WG in a cost effective manner. The relevance of these aspects increases significantly for large WP. The methodologies and findings of this chapter will be used in the following chapters, to support a deeper investigation of the value of operation flexibility in systems with large penetration of WG.

CHAPTER 4: Value of Generation Flexibility in Systems with Large Wind Penetration

4.1 Introduction

It has been recognised by previous work [6, 10, 89] that to operate power systems with large wind penetration (WP), extra levels of flexibility will be required. The economic impacts of providing this extra flexibility need to be quantified and options to provide it in a cost effective way need to be investigated.

To address this problem, a better understanding of the features that characterise system operation flexibility is important. In today's system, the principle source of flexibility is the conventional generation. Accordingly, the chapter presents a methodology to determine quantitatively the value of generation flexibility to integrate wind generation (WG). This takes into account the impact of wind uncertainty into response and reserve services and the value/impact of parameters that make up operational flexibility, given that it is a multi-faceted system property.

The main goal of this methodology is to provide a framework to quantify the needs and economic value of flexibility in the generation-demand balance and how this is affected by increasing penetration of WG. Such analysis requires the simulation of system operation over long enough periods of time to capture weekly and seasonal changes in system flexibility. In addition, a representation of WG intrinsic characteristics and operational flexibility parameters of conventional generation need to be considered. Moreover, operation risk margins currently accepted by the system operator (SO) need to be maintained to comply with existing regulatory frameworks. Thus, as a first step, a definition and characterisation of the events, actions and sources of operation flexibility in the power system is presented.

Following this, the structure of the proposed framework is described as well as its main assumptions and the metrics proposed to quantify the economic value of flexibility. At the core of the analysis framework is a modified security constrained unit commitment (SCUC).

A detailed mathematical description of the algorithm is provided including description of the generator constraints (ramp rates, minimum up and down time), and security constraints (response and reserve).

Considering that the objective of the methodology is to assess the flexibility required to integrate large WP, the algorithm description also addresses different options for flexibility in the demand balance constraints used to enlarge the space of feasible solutions. Likewise, wind's stochastic behaviour needs to be considered by the system operation model. Further explanation is provided in the methodology of the modified response and reserve requirements, calculated offline taking into account uncertainty from wind and demand forecast errors and generation outages. These are included in the main optimisation as deterministic constraints.

With this methodology in hand, and the respective simulation tool, we proceed with the study of the value of generation flexibility. The quantification of this value is done from the perspective of wind integration cost. Therefore the metrics applied should provide a clear view of how the impact of WG on system operation drives the need and value of flexibility. As a consequence, the economic value of flexibility is quantified in terms of wind intermittency balancing cost and the environmental value of flexibility is quantified in terms of the percentage of CO_2 emissions driven by wind uncertainty. Finally, the impact of wind uncertainty on the system ability of integrating WG is shown in terms of wind curtailed due to wind uncertainty. A large set of studies are performed to capture the challenges of operating systems with large WP, identify the aspects that drive most of the need and cost of flexibility and quantify the value of different alternatives for using generation to provide it. This supports the identification of the key flexibility parameters that enhance or limit the system's ability of integrating WG and illustrates how these parameters evolve as WP increases.

4.2 Characterization of System Flexibility

Broadly speaking, flexibility is the ability of a power system to deal with variability and uncertainty at different time scales. Flexibility is characterised by the system characteristics and parameters which define its ability to change the generation output and system demand (if there some type of demand side flexibility available) in order to maintain the generation – demand balance at all times. These parameters vary from system to system and across different timescales. Flexibility is therefore a time-dependant and system-specific characteristic. At the same time, while system flexibility is characterised by technical parameters, the amount of operational flexibility available is also dependant on the level of operational security maintained by the system operator (SO).

In order to characterise more fully flexibility, Table 4.1 presents a list of flexibility-related events that require the use of operational flexibility, along with the services used to make this flexibility available and their respective time scales. As this chapter focuses on flexibility from conventional generation, for each event, the table lists relevant generation flexibility parameters. Flexibility can also be provided by sources other than conventional generation, such as Storage and demand side flexibility (DSF). These alternatives, however, will be investigated in the following Chapters 5 and 6.

Table 4.1 Characterisation of operational flexibility from conventional generation

Events	Services	Time scales	Flexibility sources	Flexibility parameters	
				Down	Up
Demand and generation fluctuations (eg wind)	Load-levelling	Seconds to days	Synchronised plant, Fast start plant	Minimum up time Plant ramp down rate Plant minimum stable generation	Minimum down time Plant ramp up rate Plant maximum generation
Plant outage Demand and wind uncertainty	Primary response	Seconds	Plant primary response capability	-	% of P^{max} available for primary response
	Secondary response	Seconds to minutes	Plant secondary response capability	-	% of P^{max} available for secondary response
	Reserve	Minutes to hours[33]	Synchronised plant, Fast start plant	$P^g - P^{min}$, Plant ramp down rate, fast plant shut down time	$P^{max} - P^g$, Plant ramp up rate, fast plant start time
Large load outage Demand and wind uncertainty	High frequency response	Seconds to minutes	Plant response capability	Plant high frequency response capability (% of Pmax)	-

It is clear from Table 4.1 that there are a wide range of events that drive the needs for operational flexibility and services to deploy it. More importantly, the time scales in which operational flexibility is required vary greatly, ranging from seconds to hours/days. To quantify the value of operation flexibility and identify its main drivers, all interactions between events, services and flexibility parameters need to be considered.

[33] This represents the time interval since the deployment of tertiary reserve until the full recovery of the system (for example starting a new plant to fully restore all reserves).

The level of flexibility available to be deployed needs to be higher or equal to the need for deployment driven by all the different events. Making sure that this flexibility is available comes at a cost that varies from system to system depending on the cost of the means used to provide it. Moreover the value of flexibility varies when one of the system drivers for the need for flexibility changes. Examples of this are the change of variability from demand or generation due a change in demand patterns or the appearance of a new form of generation and the modification of the security constraints (response and reserve) by setting new operation risk levels.

Considering that the need for flexibility changes with time it can be said that a more flexible system is one that can provide the required flexibility, in a cost effective manner for existing conditions and can accommodate changes in the need for flexibility, with a lower cost variation. This has been first discussed by Hobbs [90] with respect to planning generation investment. In this example, the value of flexibility is linked to the long term uncertainty of fuel cost. In this work a similar reasoning is used for the value of flexibility for accommodating WG uncertainty within operation time-scales. This notion is illustrated in Figure 4.1.

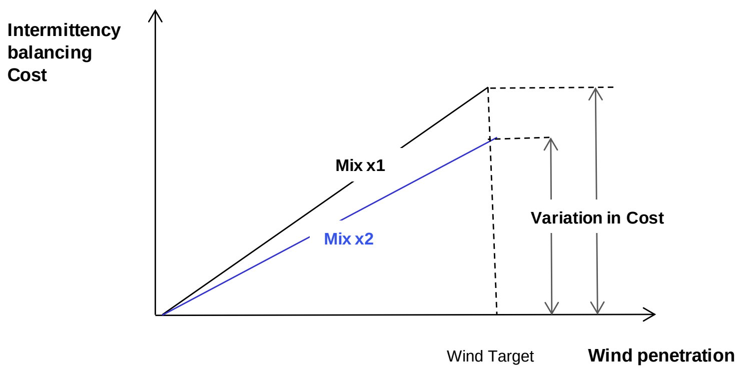


Figure 4.1 Metric for value of flexibility for wind integration - intermittency balancing cost

The figure shows how the value of flexibility, represented in terms of intermittency balancing cost, evolves when one of the characteristics of the system changes. The system represented by generation Mix x2 has lower intermittency balancing cost. It can be said that system with Mix x2 is more flexible that Mix x1. The value of adding more flexibility, however, is higher for the Mix x1. Considering that this cost variation is driven by different aspects of system flexibility it can be used as a measure of the economic value of adding extra flexibility to the system or the cost of not having sufficient flexibility.

There are several further reasons for using intermittency costs to characterise flexibility. Intermittency balancing costs are the additional costs of operating the system with WG (or any other type of intermittent generation) and are driven by the variability and uncertainty of this type of generation. These are usually determined by comparing the system costs if intermittent generation output is constant and perfectly predictable, against the costs of operating the system considering its output variation and forecast errors. This metric is used to quantify the cost impact of additional flexibility required to balance the system within operational time-scales when an intermittent form of generation, such as WG, is added to the generation mix. This cost includes the cost of additional response and reserve, start-ups, energy not supplied (ENS) and wind (or other form of intermittent generation) curtailment. The intermittency balancing cost is determined by the cost difference of operating the system with and without taking into account wind variability and uncertainty. The following equation is used to calculate this difference:

$$Cost_{intermittency\_balancing} = \frac{\left(Cost_{wfe} - Cost_{no\_wfe}\right) + \left(Cost_{var\_wind} - Cost_{flat\_wind}\right)}{Annual\ Wind\ Energy\ Available} \qquad 4.1$$

where $Cost_{wfe}$ is the annual system cost obtained considering the impact of wind forecast error on response and reserve requirements, $Cost_{no\_wfe}$ is the annual system cost obtained assuming that wind forecast error is zero (i.e. no increase in response and reserve), $Cost_{var\_wind}$ is the annual operating cost with variable wind, $Cost_{flat\_wind}$ is the operation cost obtained assuming a flat WG output corresponding to the same annual energy. $Annual\ Wind\ Energy\ Available$ is considered here the total energy that can be produced by the aggregated wind farms during the year minus the wind that would be curtailed if wind was not uncertain nor variable (this is zero or very low in most cases).

In this work the cost of balancing wind variability is not taken into account since it is significantly lower than the cost of uncertainty[34], as shown in [91]. Since the focus is on the impact and cost of uncertainty wind curtailed due to uncertainty is used. The intermittency balancing cost will be used throughout the chapter to quantify the value of flexibility required to integrate WG.

As shown in this section, flexibility is a multi faceted property represented by complex interaction of different aspects of system operation. A quantitative analysis of the cost and value of system flexibility then requires a methodology based on the multi-temporal simulation of system operation that considers all these aspects. The following section describes such methodology.

[34] As most systems already possess sufficient flexibility to deal with demand variability, which can be quite pronounced, especially in the first hours of the morning, it is expected most systems would be able to cope with wind variability.

4.3 Methodology for Valuing Operational flexibility

This section describes a methodology to quantify the system value of operational flexibility in systems with large-scale WP. This methodology takes a whole-system approach where the value of operational flexibility is quantified in the context of the minimisation of the annual operation cost.

The general structure of the methodology is presented in Figure 4.2. At the core of this methodology is a detailed annual simulation of the system operation. The simulation of system operation is done for the period of a year to capture weekly and seasonal changes in system flexibility. In addition, a representation of WG intrinsic characteristics and operational flexibility parameters of conventional generation are considered. The system scheduling algorithm optimises system operation for a large number of time intervals (in total one year of operation at half-hour resolution). At the core algorithm is a modified SCUC solved using mixed integer programming (MILP). The problem is solved using DashXpress solver [111] and the solution is obtained using simplex.

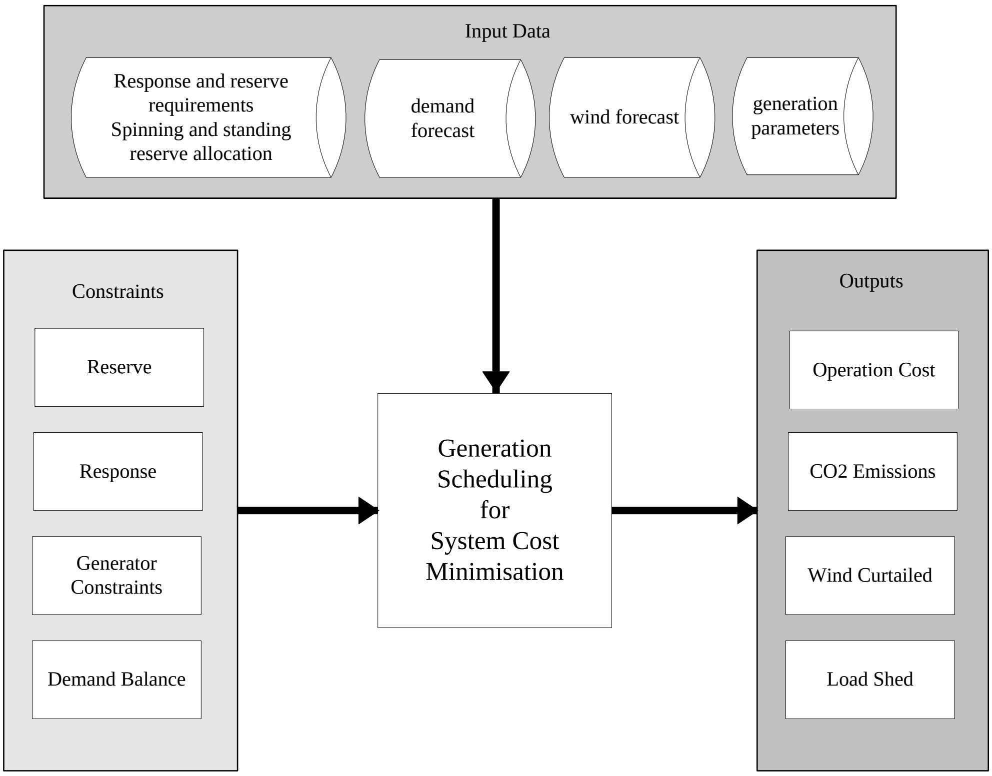


Figure 4.2 Structure of the methodology for valuation of flexibility

To properly simulate system operation, and include the effect of varying the relevant parameters that characterise system flexibility, the system scheduling process includes the following considerations:

- Generator costs are represented by marginal fuel cost, no-load cost and start-up cost;
- Generation operation is constrained by generators dynamic parameters (ramp-rates, min-up and -down times) and technical limits (P^{min} and P^{max});
- CO2 emissions from fossil fuel-based electricity generation are modelled considering Intergovernmental Panel on Climate Changes (IPCC) emission factors [92][35].
- Wind and demand time series have half-hourly resolution meaning that both demand and WG output are represented by half-hour average level of WG output and system wide demand.
- The annual variation of WG is taken into account by using an appropriately constructed wind time series based on historical UK values, and simulating wind outputs for different future WP levels by scaling-up the normalised data.
- Reserve and response requirements are incorporated into the model as deterministic constraints. The requirements are determined off-line taking into account probabilistic factors using the process described in Chapter 3[36]. These constraints take the following form:
    - Response is represented by primary and high frequency response constraints.
    - Reserve is represented by upward and downward requirements and is composed by a mix of spinning reserve (SR) provided by synchronised and standing reserve (StR) provided by fast start plant. The allocation between the two types of reserve is determined using an optimisation procedure, which was detailed in Chapter 3;

Finally, the value of operational flexibility is quantified in terms of:

[35] The emission factors are based on a proportional relationship between primary energy used for generating electricity and the CO_2 emissions caused by the process. They also imply that CO_2 emissions per unit of electricity output depend on the efficiency of the technology, meaning that emissions per megawatt-hour of electricity generated increase when power plants are part loaded;

[36] The off-line determination process take into account the effect of the stochastic behaviour of wind, along with demand uncertainty and the likelihood of generation outages. The requirements are calculated so that the the risk of violating frequency limits remains unchanged when compared to existing risk levels and that reserve levels cover the uncertainties in the generation/demand balance in all but 0.3 % of cases;

- Intermittency balancing cost in £/MWh of wind available energy (total annual wind energy minus wind curtailed when wind perfect forecast is assumed);
- CO_2 emissions driven by wind uncertainty in % of total annual emissions;
- Wind curtailment driven by wind uncertainty in % of total annual wind energy;

The preceding section has described the features that must be included in the methodology in order to value operational flexibility. As stated previously, the core of this methodology is an annual system scheduling tool. The following section will present how these features are incorporated into the mathematical formulation of the optimisation algorithm.

4.4 Generation Scheduling Model

The generation scheduling model is a SCUC algorithm, solved as a mixed integer linear programming (MILP). In this work, the solution of the MILP problem is obtained using the Dash Xpress optimisation solver [93].

The contribution of this thesis is the modification of the traditional SCUC algorithm to obtain a model that is suitable to schedule a system with large WP in a time efficient manner. To this end, some key modifications to the traditional SCUC are introduced to permit the optimisation of the use system flexibility and to ensure that WG impact on system scheduling is properly represented. These modifications include: introducing dynamic reserve requirements adjusted according to the level of wind forecasted; use of a combination of spinning and standing reserve; the contribution from WG to response and simultaneous scheduling of both response and reserve services (including the possibility of having both services provided by the same generator). In addition, an increase in the space of feasible solutions is obtained by allowing wind and load curtailment.

Considering the multi-faceted nature of operation flexibility the investigation of the implications of large WP requires a large number of annual studies, covering alternative levels of generation mix flexibility, plant flexibility and WP. In addition, a significant number of sensitivity studies with respect to various system operation parameters needs to be performed. To perform a complete assessment of the value of flexibility based on this large number of studies, the computations times need to be kept within acceptable time scales (seconds to minutes). As discussed in Chapter 2 stochastic optimisation gives more robust results but implies excessive computational times (from several hours to days [46]). In this work, however, the goal is to obtain quantitative estimates that indicate relevant trends and orders of magnitude therefore determinist methods are used to keep acceptable computation times.

Concept of net demand

Considering the low cost and the renewable nature of WG, its output has priority in the generation commitment and dispatch. This is taken into account in the algorithm by subtracting WG output from the system wide demand[37]. The remaining generation is then scheduled to supply a forecasted net demand. The net demand forecast is calculated from demand and WG forecasts. Assuming both forecasted quantities do not change within a unit time interval *t* (in this case 30 min) the net demand forecast can be defined as the difference between demand and WG forecasts:

$$net_{d,t}^{f} = d_t^{f} + w_t^{f} \qquad 4.2$$

The variability of $net_{d,t}^{f}$(t) represents the aggregated variability of WG and demand over time, which needs to be accommodated by the remaining generation to maintain the generation/demand balance.

4.4.1 The objective function

The objective function of the generation scheduling involves the minimisation of the cost (or maximisation of social welfare) of supplying net demand. The function used in our model is formulated as follows:

$$f = \min_{i,p,l^{shed},e^{over}} \sum_{t=1}^{T} \left\{ \sum_{i=1}^{N_G} \left[s_{i,t}(u_{i,t}) + c_i(p_{i,t}, u_{i,t}) \right] + VOLLl_t^{shed} + \alpha e_t^{over} \right\} \qquad 4.3$$

The objective function, represented by equation 4.3, can be divided into three different terms. The first term, which is surrounded by square brackets, represents the sum of the cost of running synchronised generation units (fuel cost) and the cost of starting new units. The start-up cost is represented by:

$$\begin{gathered} s_{i,1} \geq c_i^{start}\,(u_{i,1} - u_{i,0}) \\ s_{i,t} \geq c_i^{start}\,(u_{i,t} - u_{i,t-1}) \end{gathered} \qquad 4.4$$

The generator cost function modelled is the non-convex thermal generation cost function approximated by a convex quadratic function in the UC and economic dispatch (ED)

[37] This approach differs from the fuel saver approach where the system generation is committed ignoring the existence of wind and this is, in turn, introduced at the dispatch stage. The generation adjusts its output to accommodate wind. Such approach may be sufficient for low wind penetration but is not suitable when the penetration increases to the levels already achieved (ex: Denmark, Germany, Spain and Portugal).

solution algorithms [47]. The quadratic cost function and it's piecewise linear approximation are presented in Appendix B.

The second term of equation 4.3 represents the cost of load shedding. This has a very high cost per MWh of curtailed load, represented by the value of lost load (VOLL) that corresponds to the presumed monetary value attached to the value of supply by customers[38]. Considering the typically high values of VOLL, load shedding is applied only if the generation capacity available is insufficient to supply the demand or, if under certain circumstances it is more economical to disconnect a portion of customers.

The third term of equation 4.3 is introduced to avoid infeasibilities in extreme scenarios of system operation. This can be interpreted as a need for "generation curtailment" or "artificial demand" and occurs when the demand becomes very low in certain time periods, and for various technical constraints, such as ensuring sufficient online generation to provide response and reserve, the generation units cannot reduce their total output. This situation is not encountered in realistic systems and is considered here with the sole purpose of avoiding infeasibilities. A generation excess penalty is introduced in the objective function to ensure that this situation is encountered only as a last resort but its real cost to the system is the cost of generating unnecessary energy.

The optimum is sought with respect to non-negative real matrices $\boldsymbol{p}$, l^{shed} and $\boldsymbol{e}^{over}$, and the binary matrix $\boldsymbol{u}$.

The objective function needs to be minimised respecting a set of constraints that ensure that the solution fits within the space of feasible solutions with regards to system operation. These constraints can be divided into system level constraints that ensure the generation-demand balance and response and reserve and generation technical limits constraints that ensure that the units operate safely.

4.4.2 System level constraints

The system level constraints used with the global optimisation are described as follows.

Generation/demand balance constraint

Equation 4.5 represents the demand balance constraint:

[38] This can be seen either as the maximum amount the customers would be willing to pay for avoiding the interruption in their electricity supply, or as the penalty that the system operator is obliged to pay if it fails to supply a portion of demand.

$$\sum_{i=1}^{N_G} p_{i,t} + w_t^f = d_t^f \quad -l_t^{shed} + e_t^{over} + w_t^{f,c} \qquad 4.5$$

$p_{i,t}$ is the total output for unit *i* across all segments (its derivation is detailed in Appendix B), and does not appear directly in the objective function 4.3, but is linked to segment outputs via generator-level constraints. The meaning of l_t^{shed} and e_t^{over} is the same as before and they represent the lack of or surplus of energy in the demand-generation balance, respectively. The forecasted output from WG, at time *t*, is represented by w_t^f .

To maintain the system balance, the possibility of curtailing wind, during time period *t* is introduced through the variable $w_t^{f,c}$. Resorting to wind curtailment seems counterintuitive since it is free energy. In certain conditions, however, such as very high wind and low demand, this may be required. For low penetration of WG, this seems to be an unlikely event but it becomes more frequent for large penetration.

Load shedding and wind curtailment, during time period *t*, are bounded from below by zero and from above by the total demand and WG, respectively:

$$0 \leq l_t^{shed} \leq d_t \qquad 4.6$$

$$0 \leq w_t^c \leq w_t \qquad 4.7$$

System wide primary and high frequency response constraints

The need for system response services was described in Chapter 3. The scheduling algorithm ensures that sufficient primary (*upward*) and high frequency (*downward*) response is held by the system. This ensures that the scheduling algorithm reflects the automatic response of synchronized generation plants that increase or decrease their output within seconds after a loss of a generation unit or large demand, respectively.

To ensure that sufficient response (primary and high frequency) is available, constraints 4.8 and 4.9 are added to the model. Variables $r_{w,t}^{pr}$ *and* $r_{w,t}^{hf}$ denote the contribution of WG to primary and high frequency response at time *t*, respectively. Variables $r_{i,t}^{pr}$ and $r_{i,t}^{hf}$ denote the upward and downward contribution to frequency response by generator *i* at time *t*. Their respective sums over the committed units, at time *t,* plus the contribution of WG need to cover system-level response requirements R_t^{pr} and R_t^{hf} defined for that time.

$$\sum_{i=1}^{N_G} u_{i,t} r_{i,t}^{pr} + r_{w,t}^{pr} \geq R_t^{pr} \qquad 4.8$$

$$\sum_{i=1}^{N_G} u_{i,t} r_{i,t}^{hf} + r_{w,t}^{hf} \geq R_t^{hf} \qquad 4.9$$

The values of the parameters R_t^{pr} and R_t^{hf} are determined using the procedure detailed in chapter 3 (section 3.3.2), which ensures that the requirements defined are consistent with the UK Grid Code.

System-wide upward and downward reserve constraints

In addition to response, the system also needs to ensure that sufficient reserve is available to replace response within minutes following a disturbance and ensure that the system is able to withstand a new contingency and manage the uncertainty of demand and WG. Like response, reserve requirements can be divided between *upward* and *downward* requirements. Respectively, these represent:

- the system's ability of increasing generation output to handle an un-forecasted increase in demand or having less generation available, due to generation outages and wind over-forecast (i.e wind realised being lower than wind forecasted); or
- the system's ability to reduce generation output to handle an un-forecasted decrease in demand or higher generation output coming from wind under-forecast (i.e wind realised being higher than wind forecasted).

With increasing penetration of WG downward reserve gains a new significance since the system will be expected to accommodate wind under-forecasts.

Both upward and downward reserve requirements, for each time interval *t*, can be incorporated into the model in the form of system-level constraints equal to R_t^{up} and R_t^{dn}, which are represented by equations 4.10 and 4.11.

$$R_t^{sp,up} + R_t^{st,up} \geq R_t^{up} \qquad 4.10$$

$$R_t^{sp,dn} + R_t^{st,dn} \geq R_t^{dn} \qquad 4.11$$

The precise values for R_t^{up} and R_t^{dn} are defined offline using the approach presented in Chapter 3. Within the methodology, the total annual uncertainty in the generation – demand balance, taking account wind forecast error, generation outages and demand forecast error, was characterised. A level of reserve was then selected using a risk criterion to ensure, annually, sufficient reserve to cover 99.865% of the imbalances of the combined distribution of uncertainty. Using this level of reserve at all times could be considered too conservative.

For example, when setting the upward reserve, wind and demand forecast errors are considered along with generation outages. For setting the downward reserve, on the other hand, only wind and demand forecast errors need to be used, since it is not physically possible to experience a sudden large excess of generation capacity.

This allows a less restrictive requirement for downward reserve of:

$$R_t^{dn} = 3\sqrt{(\sigma_{demand})^2 + (\sigma_{wind})^2} \tag{4.12}$$

where σ_{demand} and σ_{wind} have the same meaning as in section 3.3.3.1.

The overall requirements calculated are then adjusted for each optimisation period. This requires the use of information about hourly wind forecast. As stated above, upward reserve covers un-forecasted increase in demand or having less generation available, such as having less wind than forecast. The importance of a having less wind than forecasted, however, depends on the amount of wind forecast. If a low amount of wind is forecasted, upward reserve is mostly required to cover demand uncertainty and generation outages and it would be too conservative since in reality the worst case would be that none of the forecasted wind is realised at delivery time. To take this into consideration the need for upward reserve is modified in the model by re-defining R_t^{up} according to:

$$R_t^{up} = 3\sqrt{(\sigma_{demand})^2 + \left(\sigma_{gen\_outages}\right)^2 + \left(\min\left(w_f, \sigma_{wind}\right)\right)^2} \tag{4.13}$$

For high wind levels, this constraint will be consistent with reserve determined according to chapter 3. The same reasoning is used for downward reserve. In this case, if a large amount of wind is forecasted, there is a lower need for downward reserve since the worst case of under forecast is low. This dynamic adjustment of the requirements gives less conservative reserve requirements, whist maintaining the desired risk level and is more suitable for systems with large WP.

As discussed in the previous chapter, the system-wide upward reserve requirement are met by a combination of reserve provided by synchronised units, designated as *spinning reserve*, and reserve coming from fast-start units or other non-spinning providers, which is designated as *standing reserve*. Accordingly this split can be incorporated in the model as defined as:

$$R_t^{sp,up} = \lambda R_t^{up} \tag{4.14}$$

$$R_t^{st,up} = R_t^{up}(1 - \lambda) \tag{4.15}$$

where the parameter λ represents the split of the reserve requirement between spinning and standing reserve. The optimal split is determined offline using the optimisation process described in chapter 3.

The system wide SR requirements are met by part loaded thermal plan and consists of both upward and downward reserve provided by synchronised plants.

$$\sum_{i=1}^{N_G} u_{i,t} r_{i,t}^{up} \geq R_t^{sp,up} \tag{4.16}$$

$$\sum_{i=1}^{N_G} u_{i,t} r_{i,t}^{dn} \geq R_t^{sp,dn} \tag{4.17}$$

In contrast, StR is supplied by fast plant. Since these plants are assumed to start from zero when reserve deployment is required, they contribute only to upward reserve such that:

$$p_t^{fast\_plant} \geq R_t^{st,up} \tag{4.18}$$

4.4.3 Generator level constraints

Besides the power balance and response and reserve constraints, each generation group is also subject to its own technical constraints which define its feasible operational regions. This set of constraints defines:

- the on/off status of the generator, which is governed by its minimum up- and down- time limits;
- the power output of the generator, which is restricted by its maximum and minimum generation limits as well as inter-temporal ramping constraints; and,
- the amounts of response and reserve services which can be provided by the generator.

These limitations will affect generation scheduling, and are introduced into the optimisation model through an additional set of constraints.

Thermal and wind generators response constraints

Equations 4.8 and 4.9 ensure that the scheduled generation provides at least the required amount of upward and downward frequency response. In addition to these, constraints regarding the individual contribution of each generator[39] need to be added:

[39] The contribution to upward and downward frequency regulation from each unit is subject to its technical characteristics. These technical characteristics are described in Appendix C.

$$r_{i,t}^{pr} \leq \min\{u_{i,t}R_i^{pr}, m_i^{pr}\left(u_{i,t}P_i^{max} - p_{i,t} - r_{i,t}^{up}\right)\} \quad 4.19$$

$$r_{i,t}^{hf} \leq \min\{u_{i,t}R_i^{hf}, m_i^{hf}\left(p_{i,t} - r_{i,t}^{dn} - u_{i,t}P_i^{min}\right)\} \quad 4.20$$

To fully use the response and reserve capability from generation units, this model considers that the same unit is able to provide both response and reserve services. This needs to be carefully modelled in order to avoid counting the same capacity as being available for both services. This is avoided by introducing terms $r_{i,t}^{up}$ and $r_{i,t}^{dn}$ into equations 4.19 and 4.20 to ensure that the capacity that is allocated to provide reserve services is deducted before determining the capacity available for response services.

In this work WG is considered as capable of providing upward frequency regulation up to the limit of some percentage "X %", of the total power installed, in periods when wind curtailment is expected. Wind is also able to provide downward response up to the level of "X %" of the total installed capacity. The percentage of the total capacity available for response, represented in the equations below by X, is defined either by the wind farm owner or by a Grid Code requirement. The influence of this parameter is captured in the constraints:

$$r_{w,t}^{pr} \geq min(w_t^c, X \times W_{inst\_capacity}) \quad 4.21$$

$$r_{w,t}^{hf} \geq min((w_t^f - w_t^c), X \times W_{inst\_capacity}) \quad 4.22$$

Generator reserve constraints

The contribution of thermal generators to upward and downward reserve is limited either by their ramp rates or the remaining generation capacity available when operating part-loaded.

The contribution of thermal generators to spinning reserve can be included. Let $r_{i,t}^{up}$ and $r_{i,t}^{dn}$ denote the contribution of unit *i* to upward and downward SR, respectively. The contribution is limited by:

$$r_{i,t}^{up} = min\{u_{i,t}\left(P_i^{max} - p_{i,t}\right), u_{i,t}(\tau V_i^{up})\} \quad 4.23$$

$$r_{i,t}^{dn} = min\{u_{i,t}\left(p_{i,t} - P_i^{min}\right), u_{i,t}(\tau V_i^{dn})\} \quad 4.24$$

Where V_i^{up} and V_i^{dn} are the ramp rates of unit *i*, and τ is the amount of time available for the generators to ramp their output up and down.

Power Output Limits

The power that can be scheduled to a unit *i* at period *t* is limited to a range between a minimum and maximum output (P^{min} and P^{max} respectively). This means that to have a unit in synchronised operation, it needs to generate a minimum amount of power, often referred to as minimum stable generation (MSG). There is also a maximum power that can be generated by the unit, often referred to as maximum registered capacity. These values vary with the technology and are among the parameters that characterise the unit's operation flexibility. These issues are taken in account by constraint 4.25.

$$u_{i,t}P_i^{min} \le p_{i,t} \le u_{i,t}P_i^{max} \qquad 4.25$$

Minimum-up and down times

The following constraints are used to capture the fact that a unit that has been committed (or de-committed) in a previous time interval needs to remain committed (de-committed) for a minimum number of time intervals (t_i^{on} and t_i^{off} , respectively). The standard formulation of minimum up and down time constraints is used, as presented in [94].

The minimum up time (t_i^{on}) constraints for unit i are given by

$$\begin{gathered} u_i^m = 1 \quad \forall m \in [1,\dots,t_i^{on} + t_i^H] \quad t_i^{on} > t_i^H > 0 \\ u_i^t - u_i^{t-1} \le u_i^{t+1} \\ u_i^t - u_i^{t-1} \le u_i^{t+2} \\ .. \qquad \forall t = 2,3,\dots,T-1 \\ u_i^t - u_i^{t-1} \le u_i^{min\{t+t_i^{on}-1,\mathrm{T}\}} \end{gathered} \qquad 4.26$$

The minimum down time (t_i^{off}) constraints for unit *i* are given by :

$$\begin{gathered} u_i^m = 0 \quad \forall m \in [1,\dots,t_i^{off} + t_i^H] \quad -t_i^{off} < -t_i^H < 0 \\ u_i^{t-1} - u_i^t \le 1 - u_i^{t+1} \\ u_i^{t-1} - u_i^t \le 1 - u_i^{t+2} \\ .. \qquad \forall t = 2,3,\dots,T-1 \\ u_i^{t-1} - u_i^t \le 1 - u_i^{min\{t+t_i^{off}-1,\mathrm{T}\}} \end{gathered} \qquad 4.27$$

Where t_i^H represents the number of periods in which the generation unit *i* was committed/de-committed, up to *t*=0, depending on the sign.

Ramp- up and -down constraints

A thermal generator has thermal and mechanical restrictions that limit its ability to change its output from one time period to the following. Typically the rating at which a unit can increase/decrease its power output, within a given time interval are designated by ramp-up/ramp-down rates, and are given in units of power per units of time (e.g. MW/h). This restriction is taken into account by the UC formulation with V_i^{up} and V_i^{dn} representing the ramping rates in megawatts per unit time interval for an individual unit *i*.

Ramp-up limits

$$\forall \;\; P_i^{min} \geq V_i^{up}\; \tau \;\begin{cases} p_{i,t} - p_{i,t-1} \leq u_{i,t-1}\; \mathrm{V_i^{up}}\;\; \tau \; + \left(u_{i,t} - u_{i,t-1}\right) P_i^{min} \\ p_{i,t} \leq u_{i,t-1}\, P_i^{max} \; + \left(u_{i,t} - u_{i,t-1}\right) P_i^{min} \end{cases} \qquad 4.28$$

$$\forall \;\; P_i^{min} \leq V_i^{up}\tau \wedge V_i^{up}\tau \leq P_i^{max} \;\begin{cases} p_{i,t} - p_{i,t-1} \leq u_{i,t-1}\; V_i^{up}\tau \\ p_{i,t} \leq u_{i,t-1}\, P_i^{max} \; + \left(u_{i,t} - u_{i,t-1}\right) V_i^{up}\tau \end{cases} \qquad 4.29$$

Ramp-down limits

$$\forall \;\; P_i^{min} \geq V_i^{dn}\;\; \tau \qquad p_{i,t} - p_{i,t-1} \leq u_{i,t}\;\; V_i^{dn}\;\; \tau \; + \left(u_{i,t} - u_{i,t-1}\right) P_i^{min} \qquad 4.30$$

$$\forall \;\; P_i^{min} \leq V_i^{dn}\tau \wedge V_i^{dn}\tau \leq P_i^{max} \qquad p_{i,t} - p_{i,t-1} \leq u_{i,t}\;\; V_i^{dn}\;\; \tau \qquad 4.31$$

In summary, the model described by the objective function of equation *4.3* along with its constraints, which are listed in equations *4.4 - 4.31*, represents the generation scheduling model applied. With this model in hand, the remaining of this chapter is devoted to the quantification of the value of operation flexibility and its main drivers, based on a comprehensive set of studies and interpretation of the results obtained.

4.5 Quantification of the Value of Operational Flexibility

Adding wind to a generation mix is expected to reduce system operation cost. Wind, which is assumed to have zero marginal cost, displaces conventional generation fuel cost. This reduction is expected to increase as more wind is added to the mix. This trend, however, is not always observed. There are two main reasons for this.

1) For systems with a large level of must-run inflexible generation and high WP, in periods of high wind and low demand, some wind needs to be curtailed to maintain the generation-demand balance,

2) In the scenario with high WP, a large number of part-loaded plants are required to provide additional response and reserve. The power produced by these generators (that need to produce a MSG to be synchronised) needs to be added to the inflexible must-run generation output. This reduces the wind that can be

used because some wind must be curtailed to maintain the generation-demand balance.

These two situations are shown in Figure 4.3 and Figure 4.4, respectively, using results of the generation scheduling obtained for one illustrative day. This shows why the decrease of operation costs driven by WG can be hindered by the cost of additional response and reserve and the cost of wind curtailment. This increases wind integration cost.

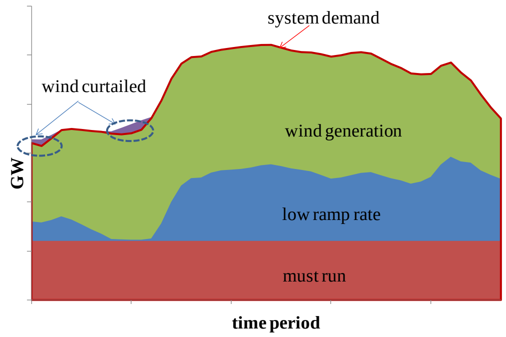


Figure 4.3 Placement of technologies in the load diagram – no reserve and response

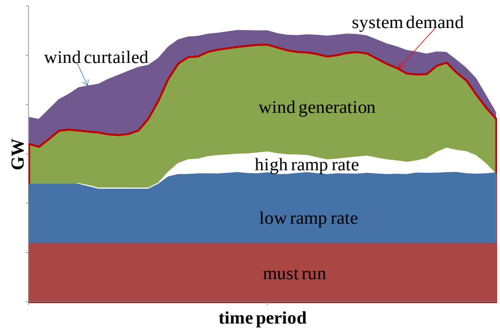


Figure 4.4 Placement of technologies in the load diagram - with response and reserve

It is clear that the economic and environmental benefits of wind are influenced by different operation constraints associated with system operation flexibility. This suggests that to realise the expected economic and environmental benefits of WG, sufficient flexibility need to be available in the remaining generation mix.

As indicated previously, adding flexibility may imply additional costs. To know how much flexibility needs to be added to the system in a cost effective way, its value needs to be assessed. This is done in this work, using the methodology described earlier, to quantify how the wind intermittency balancing cost changes with:

- two different conventional generation mix’s with different levels of flexibility (with and without inflexible must-run generation);
- the increased response and reserve requirements to take into account wind uncertainty;
- using WG contribution to frequency response;
- using a combination of synchronised and standing plant to provide reserve;
- increasing the levels of inflexible must run generation in the generation mix;
- modifying the flexibility of must run generation;
- modifying the flexibility of non must-run generation;

These studies will provide a broad quantitative analysis of the value of system operation flexibility, its implications for the cost of integrating WG into a generation mix and the influence of the parameters outlined above. These results can be used to inform the discussion about the techno-economic viability of low carbon generation mix with large penetration of WG.

4.5.1 Case study data

The system used is characterised by a wind-thermal generation mix. It has a similar size to the UK system (assuming an increase in demand compared to today's level) with a minimum demand of 26 GW, a peak demand of 67 GW and total annual energy demand of 382 TWh. A representative annual demand profile with half-hourly resolution was used, representing the UK system demand. The generation installed capacity is 82 GW and the largest unit in the system (used to quantify response and reserve requirements) has a capacity of 1320 MW.

The generation mixes used are composed by different penetration of three representative technologies. These have different parameters which are not intended to replicate a specific technology, but to represent technologies with different dynamic ratings, part-load efficiency losses, fuel costs and carbon emissions. This provides a "realistic" representation of the diversity of factors present in a generation mix. A more detailed description of each technology is presented below.

- Inflexible must-run generators:

  These generators do not provide operation flexibility in the base case. Once started, they need to be running close to their maximum output, have very limited ramping capability and large minimum up and down times. They cannot provide frequency response or reserve. Also, they have zero CO_2 emissions and low marginal costs. Their role in the mix is to represent low emissions technologies with limited operation flexibility such as existing nuclear plant in the UK and possibly future carbon capture and storage (CCS) equipped plant.

- Low flexible generators:

  These generators are characterised by a low ramping capability and can provide frequency response and reserve. They have low part-load efficiency losses, high start up costs and high CO_2 emissions. The penetration of these units is constant in the different mix analysed. Their purpose in the mix is to analyse the impact of having these units used as base load or marginal and how their utilisation changes with WP. Their characteristics are close to existing coal technology.

- High flexible generators:

  These generators are characterised by high ramping capability and are able to provide frequency response and reserve. They have high part-load efficiency losses, high marginal costs and low start-up costs. Their carbon emissions are lower than the low flexible generators. Their role in the mix is to represent an alternative to increase the system flexibility. In addition they permit understanding the impact of using high flexible generation as marginal plants and how their utilisation changes with WP. Their characteristics are close to existing combined cycle gas plant.

Generator parameters for all technologies are presented in Appendix D.

The impact of WP is investigated, by simulating the operation of the system with different wind installed capacity as presented in Appendix D. A representative wind time series, first described by Shakoor [82], was made available for this work. This represents a typical wind output profile, obtained using wind data collected from 39 sites in the UK with an averaging period of half an hour, over a consistent one-year period. Diversity of national wind output was accounted for by adding temporal shifting of the time segments of aggregate half hourly wind profiles, resulting in new diversified profiles. The resulting annual load factor of wind is 35 % and assumes a combination of offshore and onshore wind sites.

Each of the generation scenarios and sensitivity studies are broken down into different levels of WP which correspond to annual wind energy of $\{0, 8, 16, 24, 32, 40\}$ % of energy demand.

Broadly, the case studies address two main questions. The first is to understand how the value of flexibility evolves for two different technology mixes. In these cases changing the technology mix changes the operation flexibility of the aggregated plant mix and also the carbon emissions, fuel costs and part-load efficiency losses. These variations are intended to provide a realistic representation of the impact of selecting different technologies for the generation mix, in particular the interaction between different parameters and how they affect system operation costs, emissions and WG utilisation. These interactions are quantified in the first section of the case-study results and cover different questions including the value of flexibility for different generation mix, the impact of holding additional response and reserve on the value of flexibility and the value of providing these services using a combination of WG and synchronised plant for response and fast plant and synchronised plant for reserve.

The case studies continue by addressing the second question regarding the value of flexibility from both must-run and non must-run plant. Considering that previous studies in which the author was involved [30, 65, 74] have shown that inflexible must-run generation has a considerable impact on a system's ability to accommodate WG, studies about the sensitivity of the value of flexibility to the penetration of must inflexible must-run generation and the flexibility of must-run plant are performed. Finally, since the amount of inflexible generation produced by synchronised plant providing response and reserve affects the amount of wind accommodated by the system, the case studies conclude with the quantification of the value of flexibility from such plant.

4.5.2 Value of the generation mix flexibility

The main objective of these first studies is to investigate the impact of the flexibility of the system conventional generation technology mix on the system's ability and cost of integrating WG. To gain a better insight into the resulting trends, itemised system operation costs (fuel, start-up and energy not supplied costs) are quantified. In addition, the impact of wind on the operation of conventional generators is investigated by analysing the changes of the number of start-ups/shut-downs and plant utilisation.

Two different generation mixes are considered and are composed by different installed capacities of the technologies described in the previous section such that:

- Low Flexible (LF) mix : 15 GW of must-run, 20 GW of low flexible and 47 GW of high flexible generation;
- High Flexible (HF) mix: No must-run, 20 GW of low flexible and 62 GW of high flexible generation.

The key difference between the two mixes is the presence of inflexible must-run plant. The two conventional generation mixes are combined with six different levels of wind penetration: $\{0, 8, 16, 24, 32, 40\}$ % .

Intermittency balancing cost, wind curtailed and CO_2 emissions

The results obtained for the intermittency balancing cost, for different WP levels, in the LF system are presented in Figure 4.5. This cost is expressed in £/MWh of wind available energy (obtained by subtracting any wind energy curtailed for the case with perfect wind forecast to the total annual wind generation output). This cost corresponds to the increase in system operation cost driven mostly by the increase in response and reserve requirements due to wind uncertainty. The same figure presents the % of the total wind available energy that is curtailed to maintain the generation demand balance. From the results obtained it is possible to conclude that:

- the intermittency balancing cost increases with a rate that varies with the WP. The increase is slow up to 16 % penetration and is more accentuated beyond this penetration;
- the intermittency cost changes varies from 0 to 5 £/MWh from WP between 1 and 16 % penetration. For WP above 16 % the intermittency balancing costs experiences a steep increase and varies between 5 and 27 £/MWh. These value show that, for high WP, there is a high value placed on adding more flexibility to the system;
- the percentage of wind energy curtailed due to the additional response and reserve is zero or nearly zero up to 16 % WP. It increases significantly from 16 to 40 % WP, at which point nearly 50 % of the wind energy available is curtailed.

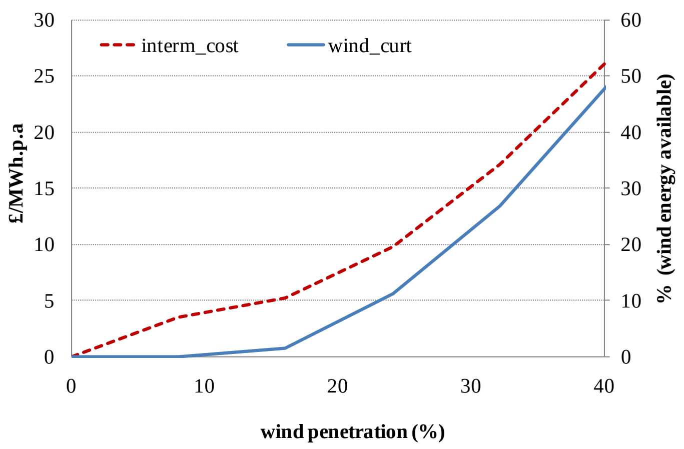


Figure 4.5 Intermittency balancing cost and wind curtailed for increasing WP - LF system

The trends obtained are similar and are linked to the cost of holding additional response and reserve to take into account wind uncertainty. This cost is driven by

- the cost of plant part-load efficiency losses of plant holding primary response and SR and,
- the fuel cost of generating the energy needed to replace the wind energy curtailed.

The relative importance of each of these cost drivers can be seen in Figure 4.5. Observing the trends in the increase in wind balancing cost and wind energy curtailed it is possible to conclude that the cost is low and its increase is moderate for all WP levels that do not lead to wind curtailed. When the WP reaches a level in which wind needs to be curtailed, the trend changes and the cost increases significantly. The growing increase in cost is matched by a similar steady increase in wind curtailed. This indicates that the main driver for the high wind balancing costs, and consequently the value of flexibility, is the wind energy curtailed. In contrast, the cost of the part-load losses is modest when compared to the fuel cost of producing the energy required to compensate for wind energy curtailed.

The impact of wind uncertainty on system operation is also examined in terms of CO_2 emissions. The potential increase of emissions, due to wind forecast uncertainty, is caused by the additional efficiency losses of part-loaded synchronised plant providing the extra response and reserve, and the increase in fossil fuel plant output to replace the wind energy curtailed. The Figure 4.6 presents the evolution of CO_2 emissions driven by the increase in response and reserve requirements, in percentage of the total annual emissions of the full system operation. It is possible to see that up to 16 % WP almost no increase is observed. From 16 % to 40 % WP there is a significant increase that reaches 23 % of the total annual CO_2 emissions. Comparing Figure 4.5 and Figure 4.6 it is possible to see that the increase of CO_2 emissions is consistent with the changes in the wind curtailed. The impact of part-load efficiency losses in CO_2 emissions is modest when compared to the impact of wind curtailed.

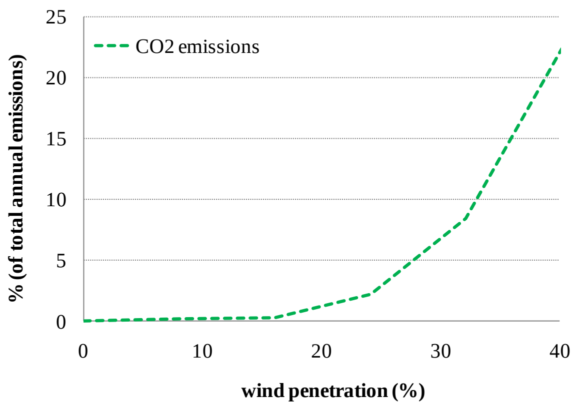


Figure 4.6 CO_2 emissions driven by wind uncertainty for increasing WP - LF system

To understand the role of the generation mix, to which wind is integrated, the same studies as the ones described above are performed for a system with a more flexible generation mix (without inflexible must-run generation). The results obtained for the intermittency balancing cost, for different WP are presented in Figure 4.7. The same figure presents the wind energy curtailed driven by the wind forecast error, in percentage of the total wind available energy. From the results it is possible to conclude that:

- in a similar manner to the results observed in the LF system, the intermittency balancing cost increases with a rate that varies with the WP. For WP lower than

25 % the increase is smoother. For WP higher than 25 % the increase becomes more significant;

- the intermittency cost changes varies from 0 to 6 £/MWh from WP between 0 and 25 % penetration. This value increases to 17 £/MWh for WP between 25 and 40 %.
- the percentage of wind energy curtailed due the additional response and reserve is zero or up to 25 % WP. It increases from 25 to 40 % WP reaching 15 % of wind energy available curtailed. This confirms that there is clear relation between intermittency balancing cost and wind curtailed.

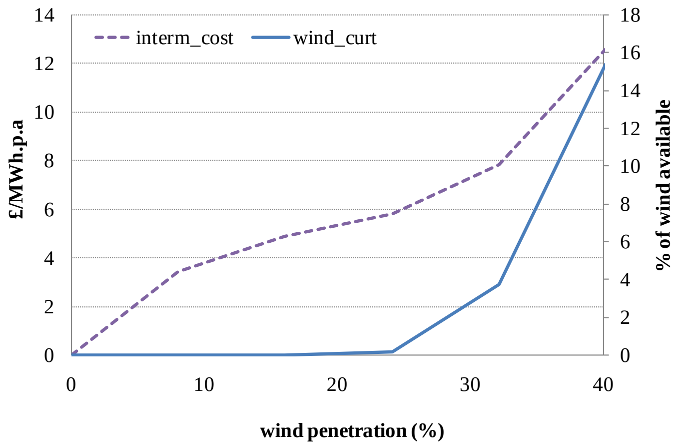


Figure 4.7 Intermittency balancing cost and wind curtailed for increasing WP - HF system

When compared to the LF system the intermittency balancing cost is similar for WP up to 16 %, but becomes significantly lower for high WP. The intermittency balancing cost observed in the two mixes diverges for WP above which the amounts of wind energy curtailed in the two systems also diverges. For the case of 40 % WP, the total annual wind energy curtailed for the HF system is 15 % and for the LF system is 50%. This is a clear indication of the impact of the generation mix on system's ability of integrating WG.

The presence of wind uncertainty, as seen in the LF system, also affects CO_2 emissions. Figure 4.8 shows the percentage of the total annual emissions that are caused by the increase in response and reserve driven by wind forecast error. As before, the emissions increase significantly with wind curtailed. When comparing these results with the LF mix, it is possible to observe that the emissions obtained for scenarios with no wind curtailed are higher for the HF system. This is explained because the HF mix is dominated by high-flexible plant. This type of plant will be used to provide response and reserve all the time whist in the LF system a large share of these services is provided by low-flexible plant.

Considering that high-flexible plant has higher part-load efficiency losses, the fact that more of these plants are operated part-loaded in the HF system explains this difference in terms of CO_2 emissions.

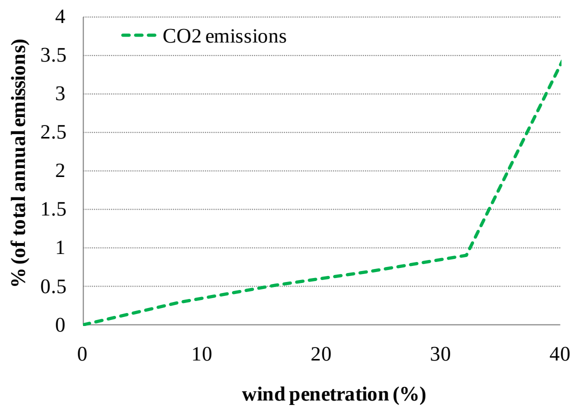


Figure 4.8 CO2 emissions driven by wind uncertainty for increasing WP - HF system

The results obtained in the two systems show that wind curtailed is the main driver for the intermittency balancing cost and as a consequence for the value of flexibility for both generation mixes. The intermittency balancing cost and consequently the value of flexibility, however, is lower in systems with more flexible conventional generation mix. Considering that the same response and reserve increase is required, and that the MSG of low-flexible and high-flexible plant is the same the inflexible generation output, produced by part-loaded plant providing response and reserve is the same for the LF and HF systems. The difference between the systems is the existence of must-run inflexible generation which increases the total inflexible generation output. This reduces the difference between demand and inflexible generation output and increases the frequency and volume of wind energy curtailments. Consequently, must-run inflexible generation limits the ability of accommodating WG and has a large impact on intermittency balancing cost and the value of flexibility.

These values obtained for the intermittency balancing cost can be compared to the ones from previous wind integration studies whose results are shown in Table 4.2.

Table 4.2 Intermittency balancing costs obtained by different UK based wind integration studies

	SCAR Report[55]	UKERC [56]	BERR Scenarios [5]
Wind Penetration	20 – 30 %	20 %	27, 33, 42 (%)
Balancing Costs £/MW	2.85 to 3	5	4.5, 5.3, 6.5

It is possible to conclude that for WP up to 16 % for the LF system and 25 % for the HF system, the results are similar. For WP higher that these, the intermittency balancing costs obtained in this work are significantly higher. This is explained because previous studies used simplified system operation models that do not capture all the aspects of system flexibility. These simplified models tend to underestimate the cost impact of WG in system operation leading to optimistic results. This finding shows that while for lower WP simplified models may be sufficient to estimate intermittency balancing costs, these are not suitable for high WP and more complex models, such as the one proposed here, are required.

In summary, insufficient flexibility in the conventional generation mix defeats the purpose of investing in WG to reduce costs and emissions. If the system is not flexible enough to accommodate WG there are high wind balancing cost and, wind is not able to displace the expected of fossil fuel pant. Consequently the expected reduction in emissions and operation cost is not realised.

It is clear then that the expected benefits of adding this zero cost / zero CO_2 emissions technology may not be realised for all systems and all WP. Instead, the relationship between WP and the reduction in costs and emissions cannot be generalised. The results have shown, however, that a high value can be allocated to sources of additional flexibility that facilitate better use of WG output mainly in low flexible mixes and high WP scenarios. In these cases, extra flexibility, which reduces the need for curtailing wind, will be important to unlock the economic and environmental benefits of WG.

Itemised operation costs

The objective function of the model used in the chapter is focused on minimising the overall system operation cost composed by different components. To gain further insight into the results obtained, an examination of these components such as fuel cost, start-up cost and costs of energy not supplied (ENS), is presented. Considering that similar trends are obtained for both systems, the evolution of the cost components for the LF generation mix only is shown in Figure 4.9 - Figure 4.11

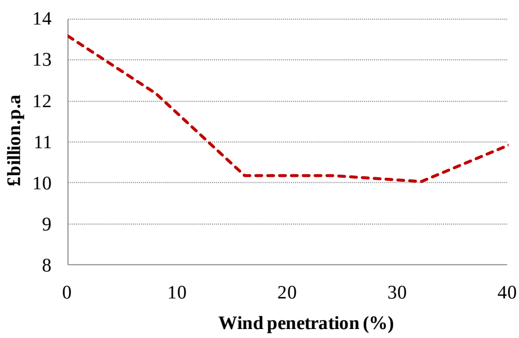


Figure 4.9 Annual fuel costs - LF system

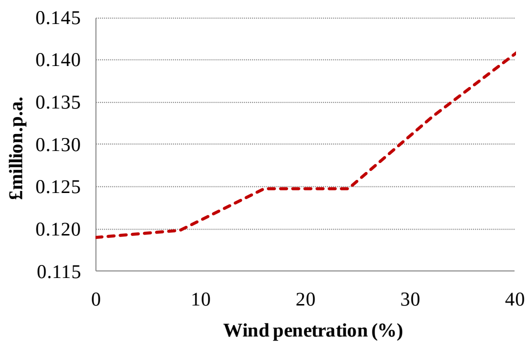


Figure 4.10 Annual start up costs - LF system

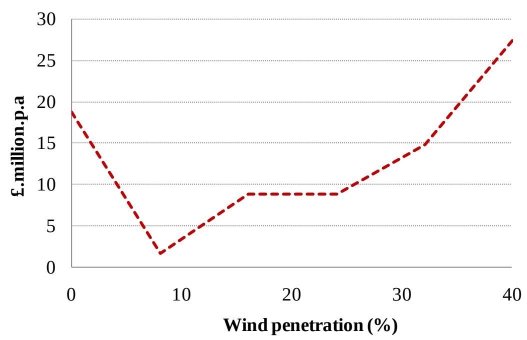


Figure 4.11 Annual cost of energy not served - LF system

The significance of the results is explained as follows.

- Fuel cost represents 99% of the total operation cost therefore the trends obtained presented in Figure 4.9, correspond to the evolution of the total annual system operation cost. The main driver for the increase in fuel cost as WP increases is wind curtailment (shown in Figure 4.5). This reflects the fact that, on one side, there is an increase of response and reserve cost, and when wind is curtailed this energy needs to be generated by fossil fuel plants at higher cost.

- Start-up costs increase in series with WP as shown in Figure 4.10. This is expected because the increased variability of net demand increases the need for plant start-ups and shut-downs. The contribution to overall cost remains low.

- The cost contribution of ENS is shown in Figure 4.11. The results show that the system resorts to load shedding more frequently for the cases with no wind or high WP. There are two reasons for this. For low wind, in some periods, it is more economic to disconnect some demand than starting a new plant. For high WP there are periods in which the output of some generators is limited due to the high response and reserve requirements. Simultaneously, starting a new plant incurs start-up cost and increases the total inflexible generation output, which leads to additional wind curtailed. As a consequence, under these conditions, load shed becomes the best economic option.

The analysis of the itemised costs shows how the challenges of operating systems with high WP affect different operation cost components. Clearly, fuel costs dominate system costs and as a consequence, the increase of start-up costs with WP due to the higher net demand variability has a limited impact. Importantly though, the nature of relationship between fuel costs and WP is not the same as the nature of the relationship between costs of ENS or start-up costs. The difference in these relationships could become more important in other systems where fuel costs are comparatively lower.

Impact of WG on conventional generation: number of start ups and plant utilisation

Clearly, WG has a large impact on system operation. WG displaces the output of conventional generation plant. It increases the variability of net demand, and drives a need for more response and reserve. These changes have implications on the operation patterns of other generators. Considering that must-run plants are preferably operated with a flat output, the remaining conventional generators have the task of providing response and reserve and cope with the variability of net demand. Quantifying the significance of these changes is important as they represent an additional cost associated to system flexibility.

Considering that similar trends are observe to all generation mixes and that this discussion focused on the technology, the example of the LF mix is chosen because it includes the three representative technologies used in this work. Figure 4.12 and Table 4.3 present the average number of annual plant start-ups/shut-downs and the average annual plant load factor, for increasing WP, respectively.

Several observations can be made based on these results. The values suggest that for low WP (up to 8 %) low-flexible plants are used as base load and mid-merit generation, so they experience fewer start-ups and high utilisation rates. High-flexible plants are used as marginal generators, and supply response and reserve, so they have a higher number of start-ups and lower utilisation rates. The utilisation of both technologies changes when WP increases. The utilisation of low-flexible plant is reduced and the total number of start-ups increases – the role of this type of plant seems to change from mid-merit to marginal. High-flexible plants' utilisation is significantly reduced so the plant is still marginal but more of its energy output is displaced by wind. For high WP (above 24 %) the utilisation of low-flexible plants drops significantly, and the number of start-ups also increases considerably – the trend of changing from mid-merit to marginal is accentuated. For large WP, high-flexible plant shares response and reserve with low-flexible plant to supply the enlarged response and reserve requirements. A more detailed discussion of the issues of response and reserve is provided in section 4.5.3.

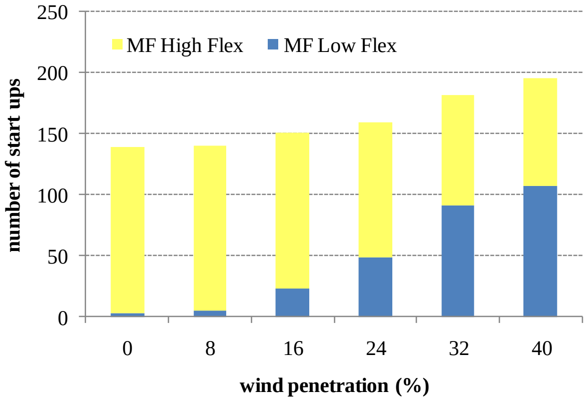


Figure 4.12 Average number of plant start ups per year for conventional generators - MF system

Table 4.3 Annual plant utilisation - LF system

	Wind Penetration (%)					
	0	8	16	24	32	40
Low Flexible Plant Utilisation (%)	98.4	96.0	89.7	79.7	69.8	64.5
High Flexible Plant Utilisation (%)	23.7	17.7	13.4	12.7	15.0	20.6

Overall, these changes highlight certain economic issues concerning the viability of lower utilisation of conventional plants, which in turn cannot be fully displaced since they need to provide response and reserve. In addition, a large increase of the number of plant start-ups and shut-downs may adversely affect the need for maintenance and plant forced outage rates. As said previously, this represents a further potential cost linked to flexibility, which must be taken into account once more detailed knowledge about this impact from the technology side is available.

4.5.3 Impact of response and reserve on the value of flexibility

The increased use of WG drives either a need for additional operational flexibility or higher system costs if this flexibility cannot be provided. The need for extra flexibility comes mostly as a result of covering the system against the extra uncertainty in the demand/generation balance introduced by WG[40]. In system operation, these requirements are captured by the response and reserve constraints, which, in turn, affect the usage of conventional plants and the solicitation of operation flexibility.

Impact of increased response and reserve requirements

To access the impact of these constraints on system flexibility, two sets of studies are performed. In the first set of simulations the increase in response requirements are ignored and simulations are run for all generation mix scenarios. In the second set of studies the process is repeated considering the reserve requirements only. These results are compared with the base case studies, which take into account the additional response and reserve requirements, in order to see how the increase of these requirements affects the system's needs for flexibility and its value. The impact is quantified in terms of the intermittency balancing cost obtained first when the increase in response requirement is ignored and second when the increase in reserve requirement is ignored. This shows the drop in the intermittency cost obtained by ignoring the impact of the wind forecast error on system security constraints.

The impact of the increased response and reserve requirements on the intermittency balancing cost, for the LF and HF system is shown in Figure 4.13 and Figure 4.14, respectively. Figure 4.13 shows the reduction in the intermittency balancing cost, for the LF system, when the impact of wind uncertainty on system response requirements is ignored. The same figure shows the reduction in the intermittency balancing cost when the increase in reserve due to wind uncertainty is not taken into account.

The results show that, for the LF system, intermittency balancing costs are reduced by 30 % to 40 % over the range of WP used, if no additional response is considered. The evolution in intermittency balancing costs in the case where no additional response is considered is consistent with the evolution in the costs for the base case. This indicates that there is a simply a lower volume of wind curtailed. Accordingly, wind curtailment still increases with increasing WP, but at a lower rate than was observed in the base case.

Like the provision of response, the provision of additional reserve increases the intermittency balancing cost. The impact of the increased reserve constraint for the LF is also shown in Figure 4.13. The results show that there a very significant drop in intermittency balancing cost if no additional reserve is considered, when compared to the base case. When no

[40] There is also an increase in net demand variability, however, in the majority of cases the system has enough flexibility to accommodate it, since the frequency of ramping and start-ups may increase but not the gradient of the changes that need to be met by ramping capability as shown in [91].

additional reserve is considered, the intermittency costs are reduced by as much as 70 to 88 % of the base case costs, for the range of WP examined. In contrast to the base case, the intermittency cost remains almost constant for all WP. This means that the intermittency balancing cost depends less on WP. The reason for this is that if no additional reserve is considered, there are fewer plants operating part-loaded and less wind is curtailed. In this situation, the intermittency cost is driven mostly by part-load efficiency losses which incur a significantly lower cost and the increase of these losses with the WP has a less significant impact on intermittency balancing cost.

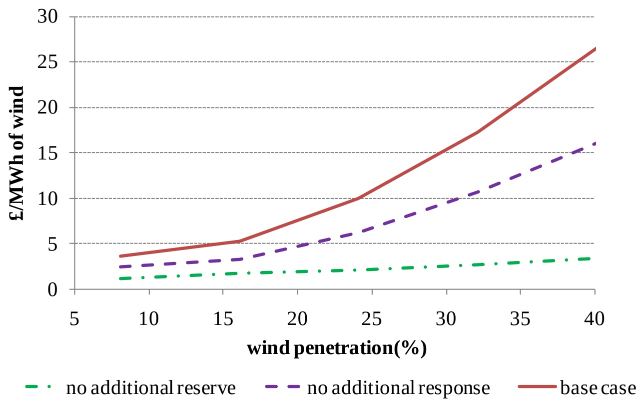


Figure 4.13 Intermittency balancing cost for the base case and the cases with no additional response and no additional reserve -LF system

Figure 4.14 presents the results obtained for the HF system if either no additional response or reserve is considered. For the case of response, the trends obtained are similar to the LF system with a cost decrease that ranges from 30 to 50 %, compared to the base case, over the WP considered. The trend followed by the intermittency cost in the system without increased response is again similar to the one of the base case. When comparing the basic trends in the evolution of costs in the contrasting cases of system flexibility it is verified that:

- for low WP the HF system has higher cost since response is provided by plant with higher efficiency losses (high-flexible plant that dominates the mix);
- for high WP the cost is higher for the LF system because, as shown in the previous section, more wind is curtailed.

For the HF system, the cost reduction when no additional reserve is considered is also presented in Figure 4.14. The changes in intermittency cost follows a different trend, when compared to the base case cost, experiencing a much smoother increase with the increasing WP, for the same reasons described for the LF system. The drop in cost for the HF system is lower than the one for the LF system since on one hand, this system is dominated by high-flexible plant with higher efficiency losses and on the other hand the increased reserve drives comparatively lower volumes of wind curtailed.

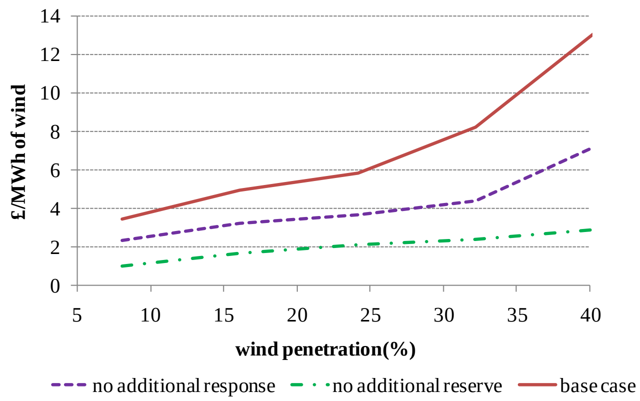


Figure 4.14 Intermittency balancing cost for the base case and the cases with no additional response and no additional reserve - HF system,

These studies have shown that both the increased response and reserve constraints contribute to the intermittency balancing costs. Moreover the impact of reserve is comparatively higher than the impact of response due to the higher volumes of energy involved. In either case, failing to consider either additional response or reserve overestimates system's ability to accommodate WG and underestimates the value of flexibility. Likewise, considering only one aspect of the constraints (e.g. only additional response or reserve) may give an overly optimistic picture of the intermittency balancing cost. This implies that the impact of wind in system operation cannot be captured using simple energy stacking models or simplified representations of the security constraints. Models that neglect security constraints or replace these by rough approximations, lead to a risk of making erroneous conclusions regarding the value of the flexibility required to integrate large WP.

Options to meet response and reserve requirements to enhance system flexibility

Clearly, there is a large cost associated with the provision of additional response and reserve required to deal with wind forecast uncertainty. This cost becomes more relevant for high WP, is linked to the flexibility of the system and is reflected in terms of CO_2 emissions. At the same time, however, there is a need for achieving a reduction of CO_2 emissions in a cost efficient manner without reducing system security levels. Consequently, a significant interest is placed in finding more flexible alternatives for the provision of response and reserve. The following section explores options for enhancing system flexibility.

Value of wind contribution to frequency response

In thermal generation based systems response services are typically provided by part-loaded thermal plant. The installation of wind farms (WF) with a large number of wind turbines, and turbines with high MW rating[41] is now driving the development and implementation of frequency control from wind turbines. According to the UK Grid Code, for a +/- 0.5 Hz frequency variation, request for frequency control should be applied equally to all plant greater that 50 MW of installed capacity [80], including WF. The minimum volume required for frequency response is 10% of its MW maximum registered capacity (MRC). Frequency response tests commissioned by National Grid [95] have shown that WF are now able to provide this service.

Although it is possible to de-load WF to provide primary response, it is also considered to be environmentally undesirable, despite it being economically preferable or technically necessary in some cases. Therefore, in this thesis, the possibility of having primary response provided by wind is considered only when, due to technical constraints, wind needs to be curtailed. In such cases, the excess wind is considered available for primary response, since the WF can change its set point to increase its output in response to a frequency drop. The use of WF to provide high frequency response is also expected. The WF can change its set point to reduce its output in response to a frequency rise. The main issue encountered is the difficulty of ensuring a constant contribution from WG, since its available output has a stochastic nature. Different solutions have already been discussed [95] and it seems inevitable that in the future WF will need to provide frequency response.

Given these developments, it was decided to include a contribution from wind to response services within the methodology. Based on the UK Grid Code and the above considerations, the contribution of wind farms to frequency response is assumed to be as follows:

- Primary response: part-loaded plant + up to 10% of wind capacity (in periods of wind curtailment);
- High frequency response: part-loaded plant + up to 10% of wind capacity (in periods when wind output is >0);

This permits the use of WG to displace part of the contribution from conventional generation and improve the efficiency of plant operation.

The value of having wind providing frequency response is quantified from an aggregated system balancing perspective. Rather than looking at technical issues, which are outside the scope of this research, we estimate quantitative orders of magnitude of this value. Again, the

[41] The largest turbines installed are the 5 MW turbines and the largest consented WF in the UK is the London Array with project output of 1000 MW.

system scheduling tool is used and the value is quantified in terms of reduction of intermittency balancing costs, wind curtailment and carbon emissions.

The division between the response provided by wind and conventional generation is determined by the optimisation, considering the system operation conditions (demand, wind forecasted output, forecasted wind curtailed), at each time period.

The value of the frequency response provided by wind, in terms of reduction of intermittency balancing costs, for the LF system, is shown in Figure 4.15. It can be concluded that this value depends on the WP and follows closely the trend observed for the reduction of wind curtailed. For WP up to 8 % there is no visible benefit, in spite of having wind providing part of the HF response. This happens because the cost of providing high frequency response from part-loaded plant is zero since the plant is being used to supply demand and no wind is curtailed due to the provision of response. One can say that up to 15% WP there is no visible value for using WG to provide frequency response. For WP higher than 8 % the value of the flexibility provided becomes more visible and reaches 12.8 £/MWh. This is a significant value and corresponds to a cost reduction of 48 % when compared to the base case (all response provided by part-loaded synchronised plant).

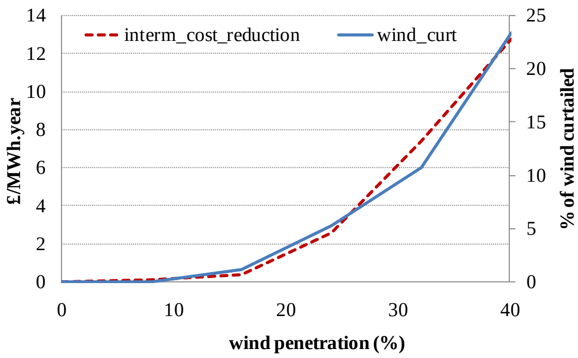


Figure 4.15 Reduction of intermittency balancing cost and wind curtailed due to WF participation in frequency response – LF system

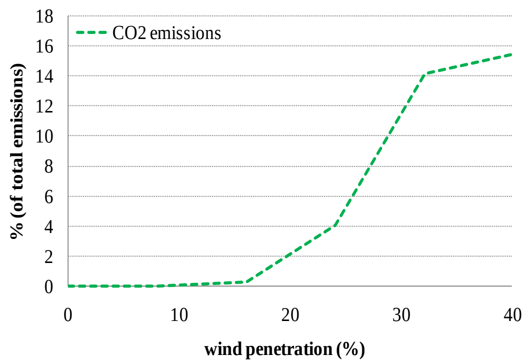


Figure 4.16 Reduction of CO_2 emissions due to WF participation in frequency response - LF system

Figure 4.15 also presents the reduction of wind curtailed. The additional flexibility provided by WF participation in frequency response contributes to the reduction of wind curtailed which ranges from 0 to 23 % of the total wind energy curtailed. As for previous analysis the value of flexibility is closely related to the reduction of wind curtailed.

The increase of flexibility, and consequent wind curtailed avoided, is translated into a corresponding reduction of CO_2 emissions. The results obtained are presented in Figure 4.16 where it is possible to see that a reduction of up to 16 %.of the annual emissions can be obtained. The comparative results obtained for the HF system are presented in Figure 4.17 and Figure 4.18. For this system the value of flexibility from wind participation in frequency response becomes visible only for WP above 25 %. In proportional terms, this represents up to a 48 % reduction of intermittency balancing costs. This reduction, in monetary terms, is lower than the one obtained for the LF system, reaching only 6 £/MWh. This shows that the value of adding extra flexibility is lower if the generation mix is more flexible. The value, in terms of cost reduction and CO_2 emissions avoided, is closely linked to the reduction of wind curtailed. This can be seen by comparing Figure 4.17and Figure 4.18.

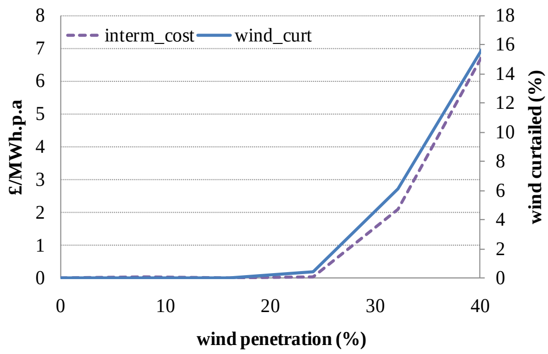


Figure 4.17 Reduction of intermittency balancing cost and wind curtailed due to the participation WFs in frequency response - HF system

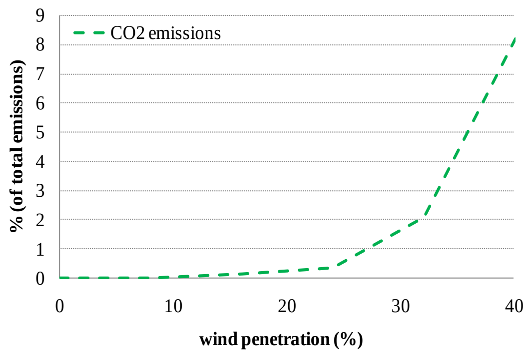


Figure 4.18 Reduction of CO_2 emissions with the participation of WFs in frequency response - HF system

In conclusion, the participation of WF in frequency response was shown to increase system flexibility. This increase translates into a reduction of intermittency balancing cost, wind curtailed and CO_2 emissions. For high WP (between 30 and 40 %), the impact is particularly pronounced in LF systems where a value of between 6 and 12.8 £/MWh is attributed to WF participation in frequency response. This shows that for high WP there are clear benefits, especially in less flexible systems, in developing the technology and regulatory and market frameworks to enable the participation of WF in frequency response.

Benefits of using a combination of spinning and standing plant for reserve

It has been shown by previous work [30, 65] that using a combination of SR and StR improves the system's ability of accommodating WG by reducing the number of part loaded plant. The optimal combination of SR and StR minimises the cost of reserve whilst increasing the wind used. In this work this optimal combination is determined using the approach developed and described in Chapter 3. In the same chapter it was shown how the cost of reserve changes with the SR/StR split to illustrate the potential economic benefits of finding an optimal combination of spinning and standing reserve. This analysis is extended in this section, by assessing the validity of the approach and quantifying the benefits of the reserve mix through full simulation of system operation.

Considering that both upward and downward reserve constraints are taken into account, the first step is to define the potential providers of each type of reserve. Upward reserve is provided by part-loaded synchronised plant and standing plant. Typical providers of standing reserve are fast plants (such as open cycle gas turbine (OCGT)). As they are called upon as additional generation, they are only able to contribute to upward reserve. Instead, downward reserve is provided only by de-loading synchronised plant.

With these considerations, the system operation is simulated with different allocations of SR and StR, ranging from an all standing to an all-spinning solution. The operation costs and wind curtailments for each allocation, in the case of the LF system with 24 % WP, are shown in Figure 4.19. As can be seen, operating costs reach a maximum for the “all standing” case. This is due to the high exercise cost of fast plant.

The overall trends obtained for the total system operation cost are similar to the ones shown in Chapter 3 for the expected cost of reserve. The operation cost reaches its minimum when using a particular split between of SR and StR, characterised as λ_{min}. This value is approximately the same as the λ_{min} calculated in Chapter 3, which represent the minimum expected cost of reserve.

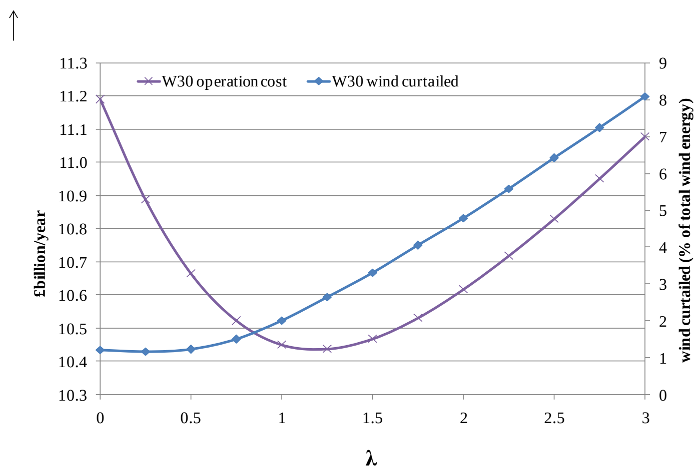


Figure 4.19 Variation of system operation costs and wind curtailed for the LF system with 24 % WP

This consistency supports the validity of the offline approach proposed, allowing us to avoid performing a very large number of annual system operation studies in order to determine an optimal split between SR and StR. Instead, the offline numerical method presented in Chapter 3 is used to calculate λ_{min} for different WP and system flexibilities. The results obtained are presented in Table 4.4. These values are used as an input to the system scheduling in order to define the total spinning and standing reserve requirements for each scenario.

Table 4.4 Values of λ_{min} for all generation mix scenarios

	λ_{min}					
	WP0	WP8	WP16	WP24	WP32	WP40
LF	1.5	1.5	1.25	1.25	1.25	1.25
HF	1.5	1.5	1.5	1.5	1.25	1.25

In contrast, as seen on Figure 4.19, the relationship between wind curtailed and the split in reserve, i.e. λ, does not follow the same trend as the cost. Wind curtailed is at its lowest for the combination with maximum operation cost (the case of all standing). This is because if there are no synchronised part-loaded plants, the system is more capable of accommodating wind. Considering that we are attempting to ensure that sufficient flexibility is available, in a cost effective way, the minimum cost solution is pursued. In this way, system operating flexibility is increased, while operating costs are reduced.

The value of the flexibility obtained by using this combination of SR and StR, can be quantified in terms of reduction in intermittency balancing cost, wind curtailed and CO_2 emissions. This reduction corresponds to the difference between the case where reserve is fully provided only by synchronised part-loaded plant (all SR case) and the combination of SR and StR that leads to the minimum cost solution. The benefits of splitting reserve in the LF system are presented in Figure 4.20 and Figure 4.21.

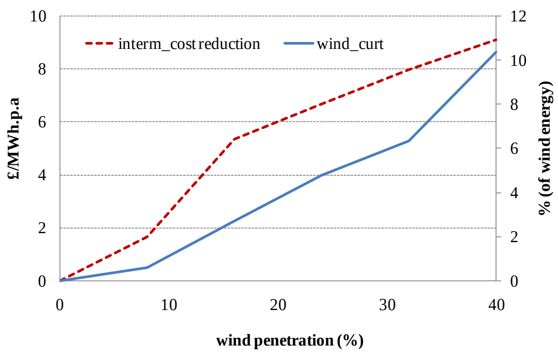


Figure 4.20 Reduction of intermittency balancing cost and wind curtailed by using a mix of SR and StR- LF system

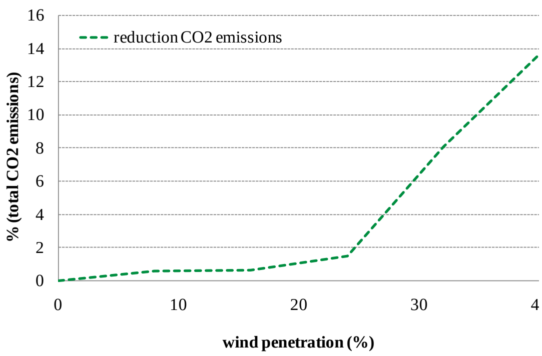


Figure 4.21 Reduction of CO_2 emissions by using a mix of SR and StR - LF system

The benefits in terms of reduction of wind integration cost, for the LF system, are clear. A reduction is obtained for all wind scenarios, reaching a maximum of 9.13 £/MWh at 40%

WP. When looking at the reduction of wind curtailed, it is possible to see that there is a nearly linear increase in the reduction for increasing WP reaching maximum reduction of 10 % of the annual wind curtailed due to wind uncertainty. By comparing the trends obtained for cost reduction and wind curtailed it is possible to see that cost reductions are driven mostly by avoiding wind curtailed. The reduction of part-load efficiency losses and wind curtailed leads to a reduction in CO_2 emissions presented in Figure 4.21. This also increases with the reduction of wind curtailed.

The results showing the value of using a mix of SR and StR in the HF system are presented in Figure 4.22 and Figure 4.23.

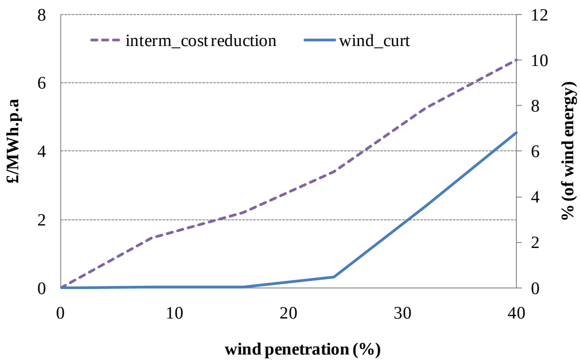


Figure 4.22 Reduction of intermittency balancing cost and wind curtailed by using a mix of SR and StR - HF system

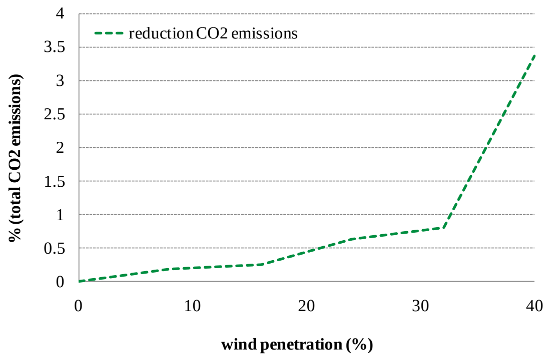


Figure 4.23 Reduction of CO_2 emissions by using a mix of SR and StR - HF system

Again, the value of flexibility, expressed as a reduction of intermittency cost, increases with the WP. This increase, however, follows a different trend to the one obtained for the LF system. This is because there is a higher value associated with the reduction of part-load efficiency losses, as the units providing SR are the high-flexible units which have higher efficiency losses than then low-flexible units which provide most of the SR in the LF system. Moreover, the overall value of flexibility in the HF system is lower, having a maximum value of 6.2 £/MWh. This can be explained by observing the reduction obtained for wind curtailed. In the HF system the reduction is lower, with a maximum of 7 % of the total annual wind energy curtailed due to wind uncertainty. Finally when looking at the reduction of CO_2 emissions it is possible to see that the trend obtained is similar to the trends in the wind curtailed. The overall reduction is modest, with up to 3.5 % of the total annual carbon emissions driven by the wind forecast error saved due to splitting reserve.

The results show that it is possible to increase system flexibility by making a better use of the flexibility of existing plant. Having WG participate in response services led to a reduction of intermittency balancing costs, wind curtailed and CO_2 emissions. Similarly, providing reserve using a combination of synchronised and fast plant, rather using SR only, reduced significantly the intermittency balancing cost, wind curtailed and CO_2 emissions. In either case, the benefits dependent upon the flexibility of the existing generation mix. The value of both options is higher in the LF system. This highlights the importance of optimising the use of existing flexibility before investing in additional sources of flexibility.

4.5.4 Value of flexibility from must-run plant

The results of the previous sections have indicated that generation mix flexibility and in particular the characteristics of must-run generation are important drivers for wind curtailment and consequent intermittency balancing cost. It is assumed commonly that must-run plant will have low flexibility. An example of must-run generation is the nuclear plant portfolio currently available in the UK. Moreover, even for existing more flexible nuclear plant the more frequent solicitation of this flexibility will have a significant impact on plant wear and tear. In a similar way, at the current technological stage, CCS such as discussed in [7, 8] will need to operate at full load in order to sustain a constant carbon capture mode. This implies CCS will also have low flexibility.

In spite of this, it is not clear how flexible CCS and future nuclear plant will be. In contrast to previous sections which explored the value of flexibility in systems with different proportions of generation technologies but unchanging operation flexibility of the plants that compose the mix, the following studies investigate the value of plant's flexibility. This will reveal the value of operational flexibility from nuclear and CCS plant.

At the same time, this inflexible must-run plant (such as UK nuclear and potentially future CCS) has zero emissions and low cost. Consequently there is an interest in maximising it's penetration in the mix. To this end, the following section presents a set of studies that start by analysing the impact of must-run generation if it is fully inflexible and the value of increasing its flexibility by firstly reducing its MSG and secondly by increasing its ramping capability.

Impact of the penetration of inflexible must-run generation

To investigate the impact of must-run plant, four different generation mixes with increasing must-run penetration are used. All mixes have the same generation capacity and are composed of a nominal amount of low flexible plant (20 GW), along with five different levels of must-run installed capacity (5, 10, 15, or 20 GW which to 6, 12, 18, or 25 % of total generation capacity). To maintain the same total installed capacity, at each increase must-run generation capacity, an equivalent amount of high-flexible plant capacity is reduced. These sensitivity studies are repeated for all WP considered.

The results of the intermittency balancing cost, presented in Figure 4.24, show that must-run generation has a significant impact on the value of flexibility. For low WP (up to 10 %) the intermittency balancing is the same for all scenarios and corresponds to a value of 5 £/MWh, which is close to the results obtained in different wind integration studies in the UK (as seen in Table 4.2). For higher than 15 % WP the cost increase diverges for the different scenarios. Increasing amounts of must-run generation drive higher intermittency balancing costs. The increase in cost does not evolve linearly with MR penetration. Instead, the comparative cost increase between must-run penetrations of 15 –20 GW is higher than the increase observed between must-run levels of 10 – 15 GW, for example. This can be explained by the amount of wind that is curtailed for each scenario.

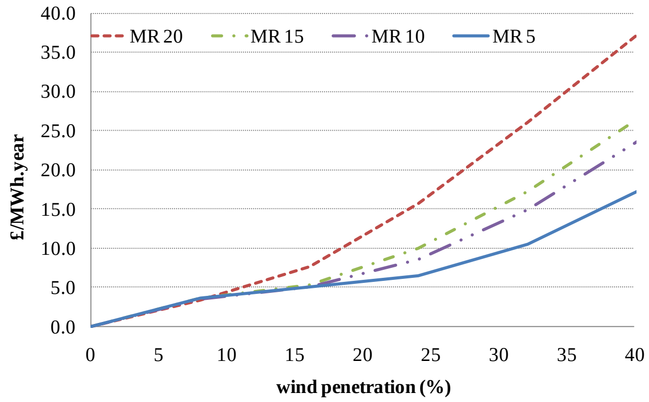


Figure 4.24 Impact of inflexible must-run generation on intermittency balancing cost

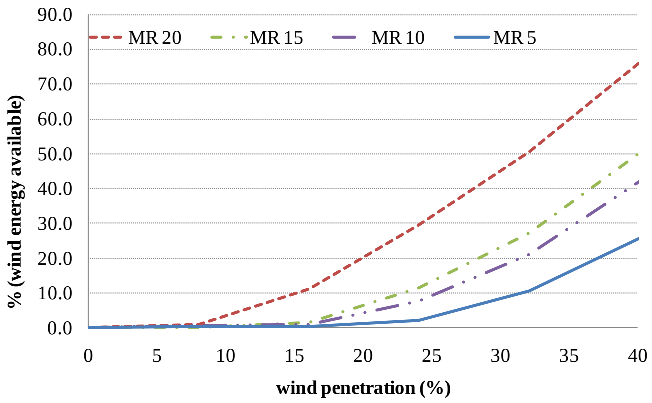


Figure 4.25 Impact of inflexible must-run generation on the wind curtailed

The results of the percentage of wind curtailed due to wind uncertainty for all the scenarios considered are presented in Figure 4.25. The trends observed are similar to the behaviour of intermittency balancing cost, suggesting wind curtailed is the main cost driver. In addition, the size of the increases of wind curtailed, which are driven by increases in must-run penetration, are not uniform. For example, increasing must-run generation from 10 – 15 GW produces a less significant change than when must-run generation is increased from 5 – 10 GW. This is due to the presence of a threshold in the difference between net demand and inflexible generation output, which once passed, the difficulties of accommodating wind are accentuated. The increase from 15 to 20 GW must-run seems to represent a breaking point beyond which the system is much less capable of integrating WG. It is clear that if the system has a high penetration of must-run generation it is not able to accommodate WG and for 40 % WP the results show that 80 % of wind available energy is curtailed to maintain the demand-generation balance.

When looking at CO_2 emissions the trends are again similar to the increase in wind curtailed (Figure 4.26). For high WP and 20 GW of must-run, wind uncertainty becomes responsible for a large share of the total annual CO_2 emissions.

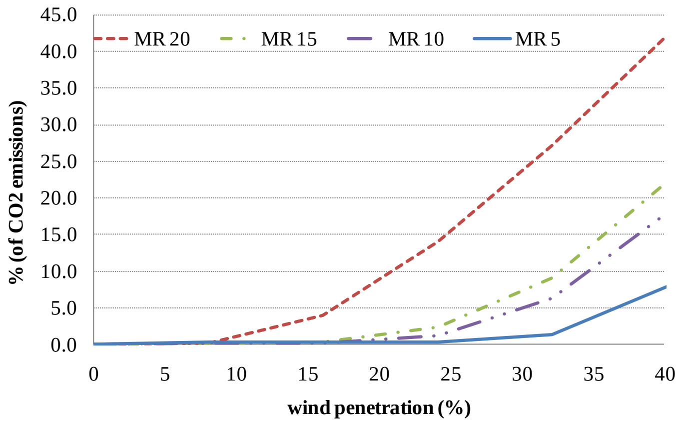


Figure 4.26 Impact of inflexible must run generation on CO_2 emissions

In spite of this, the results of the simulation have shown that the total annual emissions are lower for the case of 20 GW of must-run combined with 30 % WP. This shows that there is a large interest in improving the flexibility of must-run generation to allow a combination of both technologies. A quantitative analysis showing the importance of this technology development is presented in the following sections.

Value of must-run minimum stable generation

A set of studies with different value of must-run plant MSG with fixed ramping capability are performed. These intend to quantify the value of reducing the amount of inflexible generation which is produced by must run plant and allowing it to have some capability of adjusting its output by considering that these plants can ramp-up and -down.

The generation mix used is composed by 20 GW of must-run plant, 20 GW of low flexible plant and 42 GW of high flexible plant. For the base case, must-run plant is considered to be inflexible. Must-run plant provides neither frequency regulation nor reserve services which instead are ensured by remaining plant. The impact of the flexibility of must-run plant is assessed by considering that MSG can vary in three steps corresponding to 70, 50 and 30 % of P_{max}. In all cases, must-run plant has an upward and downward ramping capability of 100 MW/h[42].

Figure 4.27 and Figure 4.28 present the value of the flexibility obtained by reducing the MSG of must-run plant. The value is shown in the reduction of intermittency balancing costs and wind available energy curtailed. The results show that there are two main trends in the impact. These trends vary according to wind penetration levels.

Low wind penetrations

For low WP, the cost reductions are similar for all cases of MSG. Reducing MSG of must-run plant brings no additional value until WP exceeds 8%, due to the fact that since must-run plant has the lower marginal cost it is operated at P_{max}. The value of extra generation flexibility, however, increases linearly for between 8 % and 20 % WP, although in this range there is no difference in the impact between the different levels of MSG. This indicates that, considering that there is an interest for producing the maximum energy from must-run, the output of this plant does not need to be reduced below 70 % of P_{max}. to reduce wind curtailment.

High wind penetrations

A large change occurs in the relationship between WP and the value of changes in MSG as WP exceeds 20 %. At this point, the value of must-run generation flexibility becomes sensitive to plant MSG. This happens because when large amounts of wind are available, the output of must-run plant needs to be further reduced to maintain the generation - demand balance without curtailing wind. This is confirmed by looking at the relationship between wind curtailed and MSG levels, which is shown in Figure 4.28. There is a further increase of value when MSG is reduced up to 50 % P_{max} and another lower increase when this is further reduced to 30 % P_{max}. This indicates that most of the value of lowering MSG is obtained by reducing it to 50 % of $P_{max.}$

In conclusion flexibility provided by must-run plant, which is achieved by reducing their MSG, has a high value for high WP. Adding flexibility in this way can reduce intermittency balancing cost by up to 40 and 52 %, depending on the MSG. This represents an important

[42] Note that compared to the base case both MSG and ramp rates are modified. The results are non-separable in terms of benefit from MSG and ramp rates. It is however possible to understand the comparative value of MSG since the ramp rate is the same and the sensitivity is performed around MSG. This consideration is valid to the section about the value of ramping capability from must-run plant.

change on the cost of operating the system with large penetration of WG. The optimal amount of additional flexibility that needs to be added depends on the WP level and in many cases a reduction of 30 % of the MSG is sufficient.

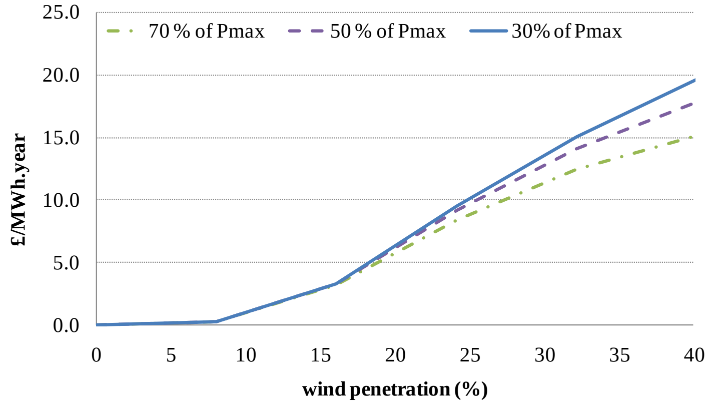


Figure 4.27 Reduction of intermittency balancing cost obtained by reducing the MSG of must-run plant

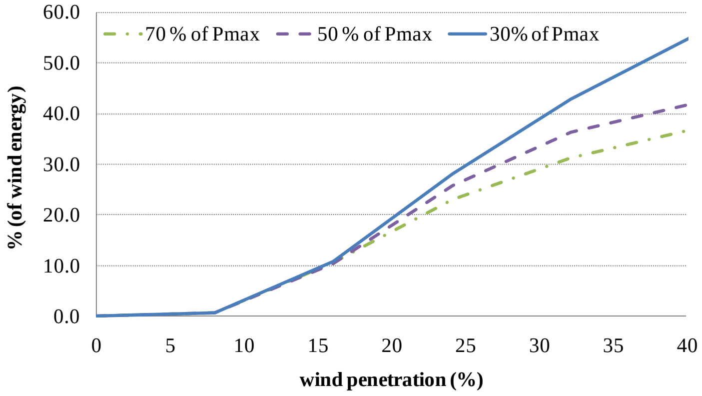


Figure 4.28 Reduction of wind curtailed obtained by reducing the MSG of must-run plant

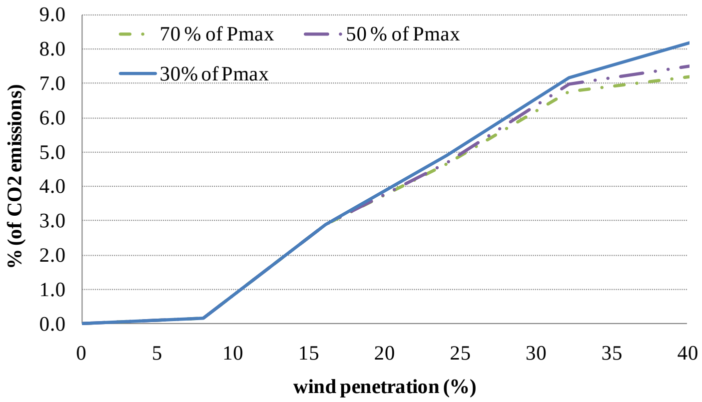


Figure 4.29 Reduction in CO_2 emissions obtained by reducing the MSG of must run plant

The value of this additional flexibility is also translated in terms of environmental gains since it contributes to the reduction of the CO_2 emissions driven by wind uncertainty. Figure 4.29 illustrates the impact of increasing must-run flexibility on carbon emissions. The results show that this flexibility can help in reducing carbon emissions by allowing a higher WP to operate along with low-carbon generation.

Value of must-run generation ramping capability

It is clear that flexibility from must-run generation plays an important role. In addition to MSG, ramping capability is also an important parameter that defines plant flexibility. In this section a set of studies, with different values of must-run plant ramping capability with a fixed MSG are performed. The purpose of this is to quantify the value of increasing the flexibility from must-run plant by increasing their ability to adjust their output according to the variation of net-demand.

For these studies, the generation mix used is made-up of 20 GW of must-run plant, 20 GW of low flexible plant and 42 GW of high flexible plant. For the base case of this comparison must-run plant is inflexible. Must run plant provides neither frequency regulation nor reserve services, which are instead provided by the remaining plant. The flexibility scenarios of must-run plant include three different levels of ramping capability. These correspond to 50 MW/h (Low ramp), 100 MW/h (Medium ramp) and 150 MW/h (High ramp). In all cases must-run plant has a MSG of 70 % of P_{max}.

Figure 4.30 and Figure 4.31 illustrate the value of the flexibility obtained by increasing plant ramping capability for a fixed MSG of must-run plant. The value is presented in terms of reduction of intermittency balancing cost and wind available energy curtailed, respectively.

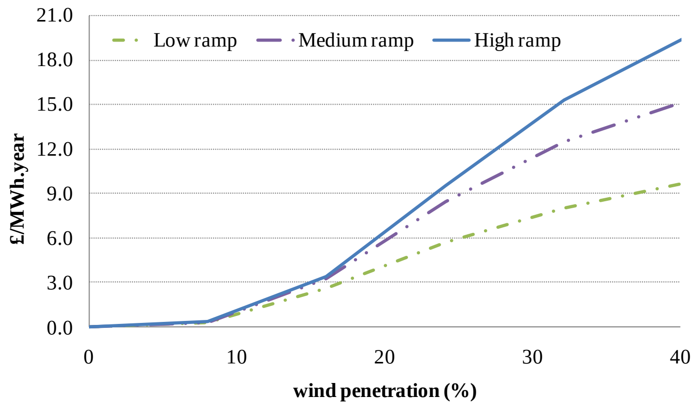


Figure 4.30 Reduction in intermittency cost obtained by increasing must-run plant ramping rates

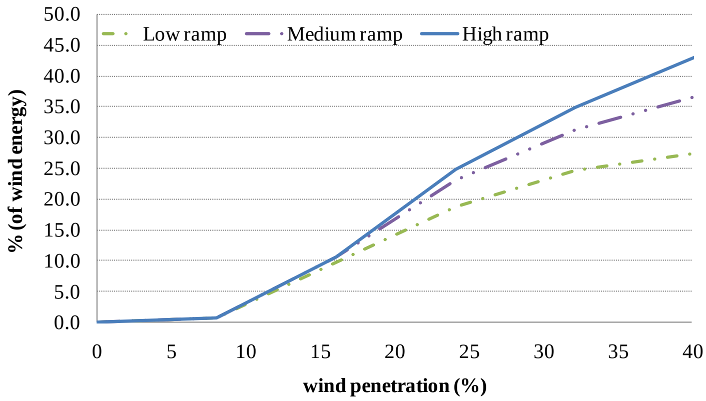


Figure 4.31 Reduction in wind curtailed obtained by increasing must-run plant ramping rates

Again, the results can be divided according to WP levels.

Low wind penetrations

For low WP, the size of the ramping rate has limited impact on the cost reduction. There is no additional value obtained up to 8% WP. This can be explained because, since must-run plant has the lower marginal cost it needs to be operated at a constant output as close as possible to P_{max}. For 8 - 15% WP, the increased ramping rates allow the system to accommodate more WG, although the system is not sensitive to the actual value of ramp-rate. This is confirmed by the results obtained for the reduction in wind curtailed. For WP between 8 and 15 % there is little difference between the different ramping levels. Instead, the presence of must-run which can operate with a lower MSG and slowly adjust its output is sufficient to reduce wind curtailed and intermittency balancing cost. As a consequence there is none or very little value in increasing ramping rates from low to medium or high.

High wind penetrations

For WP above 20 % there is a clear value in increasing ramping capability since the ability of reducing wind curtailed and intermittency cost increases with the ramping capability. This becomes even more significant for high penetration (above 30 %). The reason for this is that when large amounts of wind are available the output of must-run plant needs to be reduced to avoid wind curtailment. When WG increases and/or demand decreases significantly from one period to the following the output of must-run plant must be reduced as much as possible to maintain the generation/demand balance. In such cases, the fact that the output of must-run plant can be reduced by either 25, 50 or 75 MW/30 min (considering that the optimisation has half hourly resolution) makes a difference in terms wind curtailment and consequently balancing cost. The higher the WP, the more significant variations of net demand are experienced and the higher the value of must run ramping capability.

The results have shown that increasing flexibility from must-run generation by increasing its ramping capability reduces the intermittency balancing cost by up to 26 % and 50 %, depending on the ramping capability added. More flexible plant, able to adjust its output quickly improves the generation's ability of adjusting its output to the variation of net demand and consequently the system's ability of accommodating WG.

The value of this additional flexibility can be translated into the form of environmental gains since it contributes to the reduction of the CO_2 emissions. Figure 4.32 presents the impact of increasing must-run flexibility on carbon emissions.

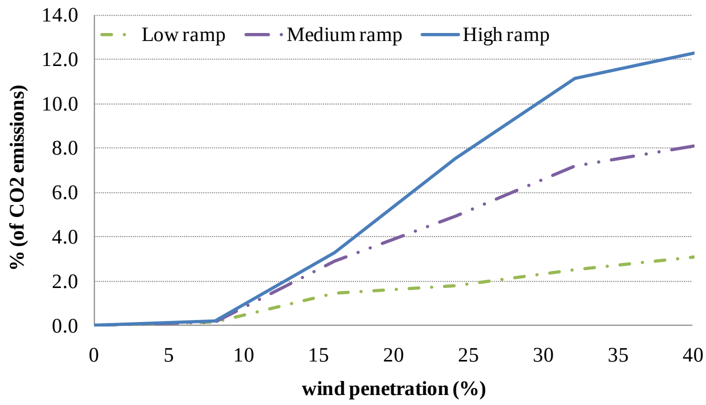


Figure 4.32 Reduction in CO_2 emissions obtained by increasing must-run plant ramping rates

Results from the simulation model for both case studies about the value of must-run generation flexibility indicate that, the cases with lowest annual CO_2 emissions are:

- must-run generation has a ramping capability of 100 MW/h and MSG of 30% of P_{max}.
- must-run generation has a ramping capability of 150 MW/h and MSG of 70% of P_{max}

For both cases the annual CO_2 emissions are in the order of 55 $MtCO_2$/year. When compared to current annual emissions from the UK power sector, which are about 145 $MtCO_2$/year [96], this represents a significant reduction (approximately 67 %). This result is similar to the best case obtained for the reduction of MSG case study. This again highlights the important role that must-run flexibility plays for reducing carbon emissions.

4.5.5 Value of flexibility of conventional generation providing response and spinning reserve

In addition to must-run generation, as shown earlier in this chapter, the synchronised conventional generation providing response and reserve services also have a significant impact on system flexibility. The output of these plants must be constrained to allow them to hold response and reserve. This significantly limits the system's ability of accommodating WG output.

To understand the role of the operation flexibility of synchronised plant, a set of studies addressing the sensitivity of system behaviour to plant flexibility parameters is performed. The parameters of interest of the non-must run plant, consisting of both high-flexible and low-flexible plant, are the technical limits P^{min} (MSG) and P^{max} (MRC) and dynamic ratings defined by the ramping capability and minimum up and down times. The impact of changes to these parameters will be considered in turn. In all cases, the data for the base case parameters correspond to that presented in Appendix D.

Value of Minimum Stable Generation (MSG):

For the purpose of wind integration the lower limit (MSG) has particular importance since it defines the amount of inflexible generation output that a plant needs to produce to be synchronised to provide response and reserve. Plants with high MSG generate a large output, which limits the system's ability of using WG output and more plants need to be part loaded. In this study the impact of changing this parameter on system flexibility and the system's subsequent ability of incorporating WG is assessed. The value of flexibility is expressed in terms of the reduction of intermittency balancing cost, wind curtailed and CO_2 emissions obtained when no MSG constraint is considered. Doing this is equivalent to considering a large increase in the secure operation regions of the generator which are limited by its minimum and maximum generation output.

The impact of MSG is analysed here by considering that all generators apart from the must-run generators have a P^{min} of zero. This means that units do not need to produce a minimum output to supply response and reserve. The results in terms of reduction intermittency balancing cost and carbon emissions driven by wind forecast errors are presented in Figure 4.33 and Figure 4.34, respectively.

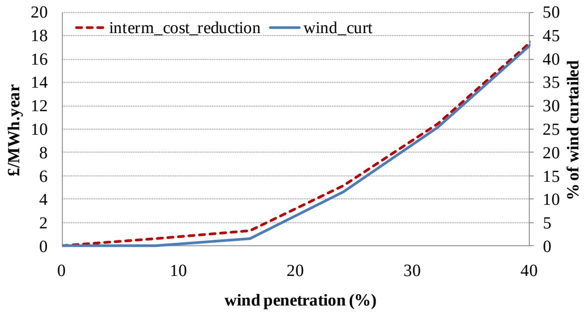


Figure 4.33 Reduction of the intermittency balancing cost and wind curtailed if MSG is zero – LF Mix

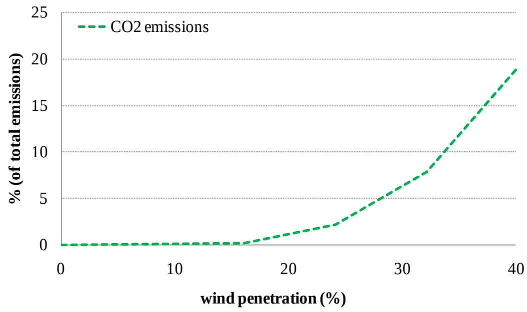


Figure 4.34 Reduction in CO_2 emissions if MSG is zero - LF Mix

These results show that a significant reduction of intermittency cost and wind curtailment reduction is obtained for the LF system for WP above 15%. This indicates that, as discussed before, the need for accommodating the inflexible output of part-loaded synchronised plant significantly reduces the system's ability for integrating WG. The benefits in terms of reduction of CO_2 emissions are also significant for WP above 15 %, reaching nearly 20 %. These CO_2 reductions are closely linked to the reduction of wind curtailed.

The same analysis was done for the HF generation mix and the results obtained are presented in Figure 4.35 and Figure 4.36 for the reduction in intermittency balancing costs and wind curtailed and the reduction in CO_2 emissions, respectively.

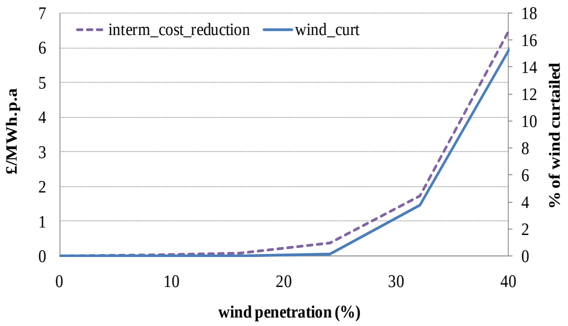


Figure 4.35 Reduction of the intermittency balancing cost and wind curtailed if MSG is zero – HF Mix

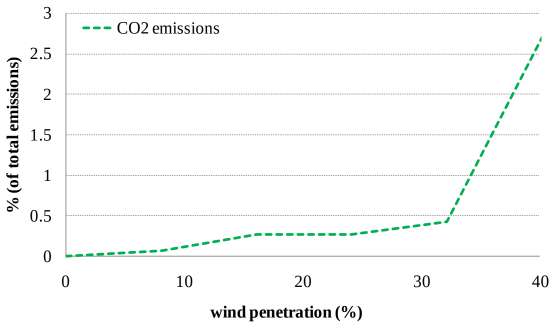


Figure 4.36 Reduction in CO_2 emissions if MSG is zero - HF Mix

The trends obtained are broadly similar to the LF mix in that the value of flexibility increases with increasing WP and the trend observed is closely related to the reduction in wind curtailed. The reduction in CO_2 emissions is also related to wind curtailed.

The main difference between the LF and HF cases is that for the HF case, the benefits of the reduced level of MSG are visible only for WP above 25 %. In addition, the benefits are significantly lower than in the LF system for WP above this. Interestingly, in the HF system there is a noticeable reduction of CO_2 emissions even for the cases when no reduction in wind curtailed is observed. The driver for this behaviour is the high-ramp plant, with higher part-load efficiency losses, which used to provide response and reserve. Reducing the MSG means that fewer of these high-ramp plants are needed for response and reserve services, thereby avoid their efficiency losses. This has a noticeable impact on emissions.

Value of Ramping Capability

The impact of increasing the ramping capability of the plant providing response and reserve was also examined for different generation mixes. In all cases, even when the plant is able to ramp from MSG to P_{max} in the period of 30 min, the impact was very low. At best, the reduction of wind curtailment reaches a maximum of 0.5 % for the LF system. In the HF system, the impact is even more limited. This occurs because this type of plant has a base ramping capability which is already sufficient to cover the solicitations for increases/decreases in their output in the large majority of cases.

Value of Minimum up and down time:

The significance of this parameter was found to be very low. Considering that there is a large number of relatively small size plants (MRC of 500 MW) there are always sufficient plants that can be started up or shut down when required. This meant that changing minimum up and down time had little influence. Different results may be obtained in systems with different compositions of generation.

4.5.6 Comparison of the results obtained for the value of flexibility

To support the identification of the parameters that most influence the value of flexibility, the results obtained in previous sections are summarised in the following tables. Table 4.5 summarises the value of using alternative generation technology mix to provide response and reserve over different WP levels for system with different generation mixes. Table 4.7 and Table 4.6 present the comparative results for the value of flexibility from must-run plant and synchronised plant providing response and reserve, respectively.

The importance of system flexibility is shown clearly in Table 4.5. The value of the alternatives to enhance flexibility is at least twice as high in the generation mix with must-run (LF) as compared to the mix without must-run (HF). Similar trends are also seen in Table 4.7. The results also show the value of using WG to provide frequency response and a combination of SR and StR, are particularly interesting for the LF system. This shows the importance of reducing the amount of part-load plant.

Table 4.5 Value of flexibility in terms of reduction of intermittency cost and CO2 emissions obtained with WG participation in frequency response and the use of a mix of SR/StR

	WG participation in frequency response[43]		Mix of SR/StR	
	Cost (£/MWh)	CO_2 emissions (%)	Cost (£/MWh)	CO_2 emissions (%)
LF	[0.1 – 12.8]	[0– 15.5]	[1.7– 9.1]	[0.6– 13.7]
HF	[0.05 – 6.3]	[0– 8.2]	[0.6– 6.2]	[0.2– 3.3]

Table 4.6 Value of flexibility in terms of reduction of intermittency cost and CO_2 emission obtained by increasing the flexibility of must-run generation

	Must-run MSG (from 30 to 70 % P_{max})[44]		Must-run Ramp rates (from low to high)[45]	
	Cost (£/MWh)	CO_2 emissions (%)	Cost (£/MWh)	CO_2 emissions (%)
25% Must-run capacity	[0.26 – 19.6]	[0.2– 8.6]	[0.3– 19.4]	[0.1– 12.3]

Table 4.7 Value of flexibility in terms of reduction of intermittency cost and CO_2 emission obtained by increasing the flexibility of synchronised plant providing response and reserve

	Plant MSG (removed)		Plant Ramp rates (removed)		Plant min up and down times	
	Cost (£/MWh)	CO_2 emissions (%)	Cost (£/MWh)	CO_2 emissions (%)	Cost (£/MWh)	CO_2 emissions (%)
LF	[0.6 – 17.5]	[0.1– 19.1]	No value	[0 – 0.5]	No value	No value
HF	[0.1 – 7.0]	[0.1– 2.7]	No value	No value	No value	No value

The results of Table 4.7 also highlight that the value of additional flexibility from plant providing response and reserve comes only if the MSG limits can be removed. The value of this flexibility is, however, very high. This reinforces the importance of the amount of inflexible generation that the system needs to accommodate in the form of synchronized plant providing response and reserve.

In general, though, it would seem that there are two main alternatives to enhance the flexibility provided by generation in order to integrate large WP:

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[43] Value obtained when WP varies from 8 to 40 %.

[44] Value of flexibility in a range that varies from the extreme low case (higher MSG lowest WP) to the extreme high case (highest MSG and highest WP).

[45] Value of flexibility in a range that varies from the extreme low case (low ramp lowest WP) to the extreme high case (high ramp and highest WP).

1. maximise the use of existing flexibility by exploring alternatives to displace part of the reserve and response services provided by synchronised conventional generation. In particular, there seems to be a high value in using WF to provide response and having an optimal amount of fast plant participate in reserve;
2. increase the flexibility of different types of plant. Among possible options to achieve this, changes to the MSG and ramping rates of must-run generation along changes to with MSG of conventional plant providing response and reserve were identified as approaches having the most influence on the value of generation flexibility.

A robust decision regarding an overarching approach to provide flexibility, however, should also consider the value of non - generation alternatives. Accordingly, the quantification of the value of storage and demand side flexibility will be addressed in the following chapters.

4.6 Conclusions

This chapter proposed a methodology to quantify the economic and environmental value of operation flexibility in systems with large WP. The methodology is based on the application of a generation scheduling tool which uses a modified SCUC that considered all the features relevant to model flexibility. Through application to a large set of case studies, the methodology was used to:

- provide a clear view of the economic value of system flexibility and its relationships to both flexibility in the conventional generation mix and WG penetration levels;
- quantify the impacts of increased response and reserve due to wind uncertainty on the needs for system flexibility;
- quantify the benefits of resorting to using WG and a combination of conventional plant to meet the response and reserve requirements; and
- identify the key drivers for the value of flexibility;

Throughout this, the value of flexibility is quantified both in terms of wind intermittency balancing cost and in terms of the percentage of CO_2 emissions driven by wind uncertainty.

Considering first the relationship between flexibility in the conventional generation mix and WG penetration levels, it is clear from the results that the expected benefits of adding zero cost / zero carbon emissions technology may not be realised for all systems and all wind penetrations. If the system is not flexible enough to accommodate WG the cost of balancing wind becomes prohibitively high and wind is not able to displace the output of fossil fuel pant. Consequently the expected reduction in CO2 emissions is not realised.

Clearly, for high WP, the generation mix into which wind is integrated plays an important role and, as a consequence, the intermittency costs for a low flexible and a high flexible generation mix are very different. In particular, must-run inflexible generation limits the system’s ability of accommodating WG and has a large impact on intermittency balancing cost and the value of flexibility. The intermittency costs are dominated by the fuel costs of fossil plant needed to compensate for the wind curtailed due to the lack of flexibility. This indicates that ultimately, the main driver for the cost of balancing intermittency is the amount of wind curtailed.

The studies also highlighted a further potential cost in terms of the low-utilisation and increased number of start-ups of low flexible plant with increase in the WP. The increase of start-up and shut-down may affect the mechanic fatigue of generators and lead to higher maintenance cost and more frequent outages. The reduction of the annual load factor (utilisation) will affect plant revenues.

The numerical values of the intermittency balancing costs obtained were consistent with those obtained from previous wind integration studies, especially for lower WP. For higher WP, the values obtained in this work are significantly higher. This is explained because previous studies used simplified system operation models that do not capture all the aspects of system flexibility. For high WP more complex models, as the one proposed in this work, are required to characterise the relationship fully.

Considering now the impacts of increased response and reserve due to wind uncertainty, the results again highlighted that operating the system with increased requirements has a large impact on costs and emissions and leads to wind curtailment. If wind forecast error is not considered in response, there is a reduction in intermittency cost of 30 to 40 %. When the same is done for the impact of wind forecast error on reserve, this reduction ranges between 80 to 90 %. The impact of reserve is comparatively higher due to the higher volumes of energy involved. In either case, failing to consider either additional response or reserve overestimates system’s ability to accommodate WG and underestimates the value of flexibility. Likewise, considering only one aspect of the constraints (e.g. only response or reserve) may give an overly optimistic picture of the intermittency balancing cost.

Finally, the results also provide a detailed quantitative comparison of the value of the different alternatives to reduce the system’s limitations to accommodate WG. As indicated previously, the main limitations are the additional reserve that needs to be provided to cater for wind forecast error and the penetration of inflexible must-run generation. When looking at alternatives based on optimising existing flexibility, it was shown that both WG participation in primary response and the use of an optimal combination of SR and StR successfully improve the use of available flexibility. Alternatively, when looking at the generation intrinsic parameters that present a higher value to system flexibility, must-run generation flexibility (with higher emphasis to ramp rates) and the MSG of plant providing response and reserve (mostly in systems with inflexible must-run) are shown to be the most significant.

The results have shown that a high value can be allocated to sources of additional flexibility that facilitate better use of WG output. In many cases, extra flexibility, which reduces the need for curtailing wind, will be important to unlock the economic and environmental benefits of WG. The options identified above represent two main alternatives to enhance the flexibility provided by generation in order to integrate large WP. It is also worth considering other sources of flexibility. Hence, there is interest in assessing the viability of Storage and DSF technologies to provide additional flexibility. This issue is addressed in the next chapters.

CHAPTER 5: Value of Storage in Enhancing System Flexibility

5.1 Introduction

It was shown in the previous chapter that there is a strong link between flexibility and the system's ability to accommodate wind generation (WG) in a cost effective and environmentally sound way. The results presented in Chapter 4 focused on flexibility provided by generation. Along with generation, however, electricity storage also has the potential to be a source of flexibility.

Past studies [23, 97] have investigated the benefits to the system of the use of electricity storage. In many cases, such studies arrived to the conclusion that, due to the cost of efficiency losses and high investment cost, storage is not economically viable in the existing generation mix. Considering that future low carbon generation mixes are likely to have a combination of intermittent generation, as WG, combined with less flexible low carbon conventional generation there will be an increase in system balancing requirements. In this context, the value of flexibility increases and so does the economic potential of alternative sources of flexibility, especially ones that do not contribute to increase CO_2 emissions. Given this, the strategic implications and the role of electricity storage need to be re-assessed.

This chapter, then, is concerned with the quantification of the value of electricity storage providing flexibility in systems with large wind penetration (WP). This is complemented with a comparative analysis of storage with its closer competing technology, the conventional generation fast plant. The value of flexibility from storage is based on the use of this technology to support the system in dealing with the increased balancing services driven by WG variability and uncertainty.

The specific role of storage, in this context, is to provide part of the reserve requirement and alter system net demand to facilitate wind integration. This analysis builds on the results presented in Chapters 3 and 4 of this thesis. In Chapter 3 it was shown that the requirements increase for high WP with wind uncertainty driving the greatest share of the overall reserve requirements. In the same chapter it was shown that using a mix of spinning reserve (SR) and standing reserve (StR) increases the system flexibility and reduces the overall cost of reserve. Following this; the results of Chapter 4 point out that the value of flexibility increases with WP and this increase is particularly important for less flexible conventional generation mixes. Together these findings indicate that there is a clear opportunity for the use of devices, like storage, which can add flexibility in systems with large WP.

In spite of this promising role, a decision over the real potential of storage needs to be based on quantitative studies of its economical and environmental value. Such studies require the development of a purpose built approach and system operation simulation tools able to represent specific aspects of system operation with WG and storage. In this Chapter, an approach to assess the value of storage is developed. This builds on the model described in Chapter 4, which is modified to take into account storage constraints and specific operation requirements such as the inter-temporal link between power generated and energy available in store. This requires the simulation of system operation for forecasted and realised WG consequently a purely deterministic approach is not suitable. The deterministic model used in Chapter 4 is extended to simulate both reserve scheduling and utilisation by doing a security constrained unit commitment (SCUC) for forecasted and a re-dispatch for realised wind.

The model is fed with the reserve requirements computed using the approach described in Chapter 3, with the difference being that only uncertainty from wind is considered. This permits the quantification of the value of storage for the purpose of mitigating wind balancing costs.

Case studies with the purpose of calculating the economic and environmental benefits of obtaining flexibility from storage and identifying which system parameters drive this value complete the chapter. The parameters that affect the value of storage include WP, conventional generation flexibility and the size and efficiency of storage. These factors are all considered in the sensitivity analysis. Finally a comparative study between storage and fast plant is performed which is used to identify the conditions where storage represents a better option for providing flexibility

5.2 Contribution of Storage to Operation Flexibility

Flexibility is defined by system’s intrinsic characteristics, which are represented by a set of parameters that define the system’s ability of changing the generation output and system demand (if there is some type of demand side flexibility available) in order to maintain the generation - demand balance at all times. Electricity storage technologies operate by charging and discharging electrical energy. By doing this, they are able to increase or decrease system demand for electricity, thus contributing to the generation-demand balancing. In this way, storage can provide flexibility to the system.

This flexibility is controlled by the amount of the power consumed and produced in the charge and discharge processes and the duration of these processes. These parameter are, in turn, controlled by power and energy rating of the storage devices. Specifically the total duration of the charge and discharge processes are constrained by the size of the "store"[46], represented by the device's power/energy rating[47]. Figure 5.1 presents the power/energy rating of different storage technologies. As shown by the figure the power and energy provided depends greatly on the technology used.

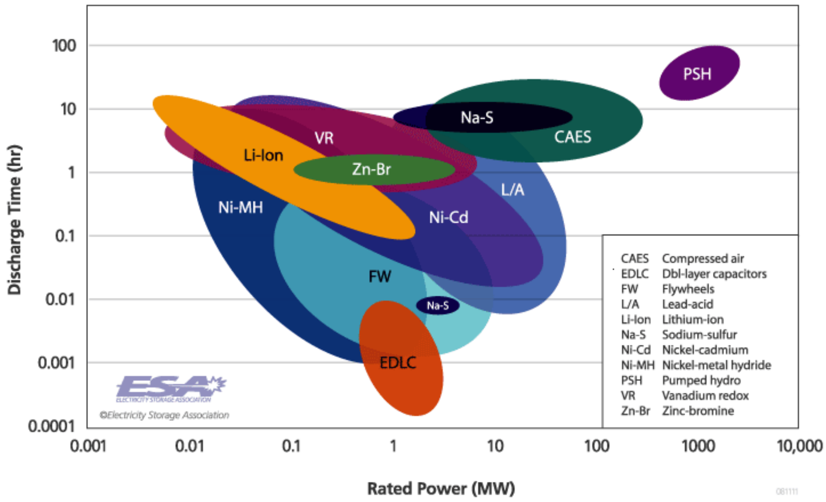

Figure 5.1 Storage Power/Energy ratings for different technologies (source: Energy Storage Association)

Based on its role within the system, storage can then be categorised as bulk (consisting of, for example, hydro pumped storage, compressed air energy storage (CAES) and large Na-S batteries) or distributed (such as battery banks and flywheels, among others). Distributed storage, which generally consists of small storage devices for local applications, can have small power ratings and short discharge times. In contrast, as this thesis is concerned with storage's contribution to provide flexibility for wind integration at system level, our focuses is on bulk electricity storage technologies and the services these can provide. Distributed storage applications are also studied by the author but are not described in this document as they lie outside the scope of the thesis. Details of this work can be found in [60].

[46] The type of store changes with the technology, for example for hydro pump-storage it is the water reservoir and for Compressed Air Energy Storage (CAES) it is the cavity where the compressed air in stored.

[47] The power/energy rating of a storage facility is defined as the total time that storage can charge/discharge electricity at its maximum power rating. For example, a storage with a rating of 100 MW/10 h is able to discharge (produce) 100 MW of electricity during 10 hours or alternatively charge (consume) 100 MW electricity during 10 h (minus energy lost due to efficiency). In addition this means that this storage has an energy capacity of 1000 MWh.

Applications of storage for system balancing

To analyse the applications investigated in this work, without loss of generality, all storage devices are modelled as a mean to store energy which can be readily converted both to and from electricity. Characteristics such as efficiency losses, response times and power/energy ratings are considered as these parameters are assumed to be directly relevant to the value of storage. The complex details of a specific technology, however, are seen as of peripheral interest. In any case, this generic model can be easily substituted by a more complex one if a specific technology is to be studied.

To capture the potential benefits of storage for system wide applications, specific market arrangements are not taken into account. Alternatively, the economic and environmental value is quantified in terms of benefits to the whole system. This allows the identification of the overall potential and underlying economics of storage.

The question of the use of storage to support system operation has been addressed by several works [97-100]. Specifically [97] follows a global approach similar to the one used in this thesis, however, WG and some of the relevant parameters and constraints that characterise system flexibility are not considered. To highlight the traditional and new roles of storage a summary of the typical and new uses is presented in Table 5.1. The economic interest of such services depends largely on the round trip efficiency losses of storage.

The economic interest in using storage for the services such as described in the Table 5.1 depends largely on the round trip efficiency losses of storage. The above referenced past studies arrived at the common conclusion that, in the majority of the systems, most of the time the differential between minimum and maximum system marginal cost is too small to overcome inefficiency of existing storage technologies.

It is also concluded though that this situation may change if large proportions of inflexible generation are added to the system. As shown in Chapter 4, operating a system with large shares of WG increases the solicitation of plant operation flexibility (e.g. the need for start-ups, shut-down, ramping) and the response and reserve requirements. This generates a need for additional flexibility to be provided by the remaining plant, which themselves, in future systems, may be less flexible if current thermal plant tends to be replaced by less flexible low-carbon generation. Instead, part of this flexibility can be provided by energy storage, if and when it brings economic benefits. The remaining sections of the chapter present the development of such models to analyse quantitatively the role of storage. The models are then applied to a set of representative cases to assess the value of storage in systems with large WP.

Table 5.1 Traditional and new applications of storage for system balancing

	Traditional applications	**Applications for WG**
Load-shaping	The charge/discharge cycles are daily, weekly and seasonal demand variability: -charge during periods of low demand (for example overnight to use cheaper plants) -discharge in periods of high demand (peak times to avoid the use of expensive plant).	The charge/discharge cycles smooth net demand variability and reduce wind curtailment: -charge during periods of high wind and low demand (use of excess of wind) -discharge in periods of low wind and high demand (displace fossil fuel generation)
Peak shaving	used in merit order with conventional generation plant to meet peak demand	used in merit order with conventional generation to meet peak demand and avoid the use of peaking plant when WG is low.
Reserve	provide upward reserve by discharging or interrupt the charge when there is lack of generation capacity (due to a generation outage or demand forecast errors)	provide upward reserve: in case of wind over-forecast by discharging provide downward reserve when there is a wind under-forecast by charging

5.3 Approach to Quantify the Value of Flexibility Provided by Storage

A major objective of this work is to provide order of magnitude estimates of the value of storage for balancing systems with large WP. Building on the methodology presented in the previous chapter, an approach to quantify the benefits of energy storage for providing short-term demand-supply balancing capability is developed. Considering that our analysis is focused on the use of storage to provide additional flexibility to integrate WG, only the events that require the deployment of flexibility driven by WG are considered. These include using storage for load-shaping and standing reserve to deal with the increased net demand variability and the positive and negative wind imbalances generated by wind forecast errors, between the time when unit commitment (UC) decisions are taken and the electricity delivery time.

This approach is based on [11, 30, 65] with the following improvements:

- the priority list unit commitment (UC) is replaced by a mixed integer linear programming (MILP) algorithm to include relevant features of system operation flexibility (ramp-rates, min-up and down times);
- Start-up and no load costs are now considered;
- Both upward and downward reserve constraints are modelled;

In order to simplify the modelling process and to abstract out major trends of storage's role for enabling wind integration, a number of assumptions are made:

- a system cost based approach is used (market arrangements are not considered);
- the balancing task is performed at the system level considering aggregated wind power output and a single aggregated storage;

It should also be noted that the model assumes a single bus bar system and management of network constraints are not considered (this will be explored in Chapter 7 of this thesis).

As explained in the previous section, storage is different from a generator since the duration of the periods in which it can charge/discharge is limited by the amount if energy available in store. Due to this characteristic storage is often designated as an energy limited device. To quantify the contribution of storage to reserve without overestimating its contribution a purely deterministic approach, as the one used in Chapter 4, is not suitable as it is not able to capture the effects of the energy available in store after the deployment or reserve. In order to identify both power injected and energy available in store, the unit commitment phase and economic dispatch phase (reserve utilisation) need be modelled. Consequently a semi-deterministic approach, able to model reserve scheduling and deployment, the second in an approximate way, is developed. This is done performing a two-step annual system operation optimisation that follows the structure described in Figure 5.2.

Step 1 of the optimisation performs a security constrained unit commitment (SCUC) that schedules enough generation to supply demand for every hour of the year, based on a forecasted net demand and schedules reserve to handle imbalances caused by wind forecast errors[48]. This optimisation step decides how many units need to be committed in order to supply the forecasted net demand and hold a pre-defined level of SR. This SR can correspond to the total system level reserve requirement or a part of it, depending on the reserve procurement strategy

[48] Different wind forecast lead times can be considered to characterise distribution of the uncertainty and wind to set the required reserve levels. In this work a four hours lead time is assumed considering that this is the estimated time to start a combined cycle gas turbine (CCGT). This means that for periods from 4 hours ahead no more decisions regarding synchronising new units can be taken consequently the imbalances between forecasted and realised net demand need to be covered by re-dispatching already committed generators or using alternative sources such as fast plant and storage.

used. If all reserve is to be supplied by synchronised plant, the UC schedules a reserve level that corresponds to the total reserve requirements that must be procured. If a mix of SR and StR is to be used to satisfy reserve requirements, the UC stage considers only the SR requirements.

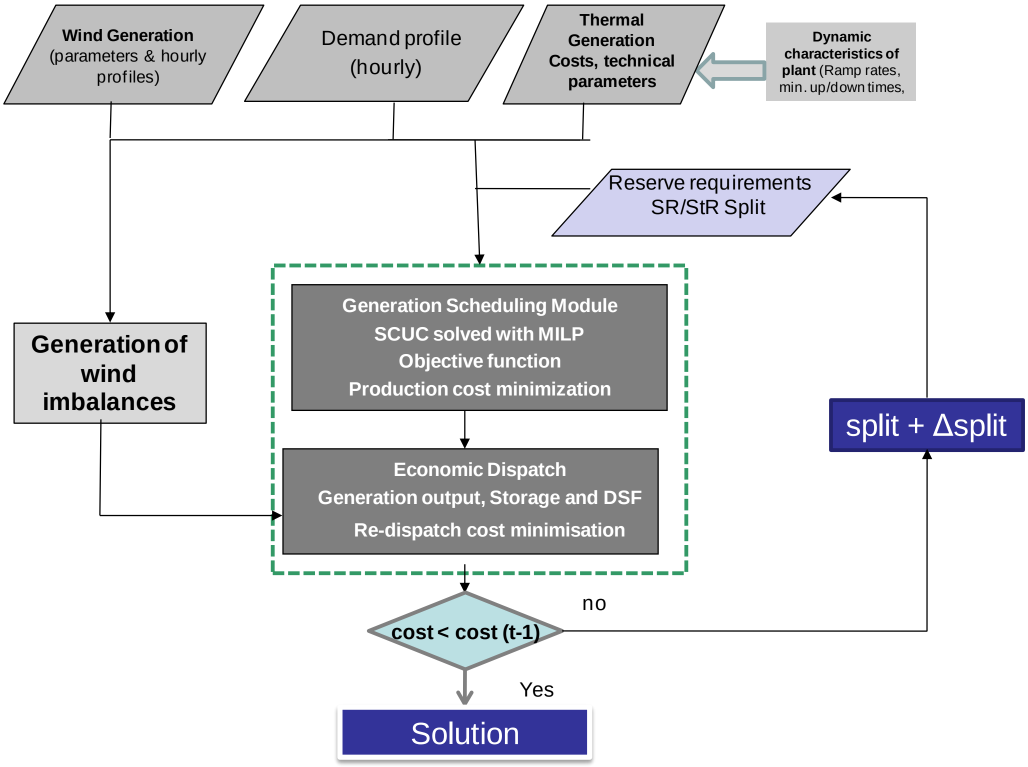

Figure 5.2 Structure of the optimisation model

Step 2 of the optimisation involves an economic re-dispatch at electricity delivery time, based on realised wind profile. This step allocates the hourly power output necessary to supply the realised net demand among the scheduled generators, wind generators, storage and/or fast plant. This step adjusts the output of the already committed generators, charges/discharges storage and uses fast plant to meet the realised net demand. These actions contribute to increase or decrease of the generation output depending on whether net demand is lower or higher than predicted. Specifically, if a part of the reserve is provided by storage, it is in this stage that storage is charged and discharged to meet the imbalances between forecast and realised net demand. This corresponds to the utilisation of the reserve scheduled to cope with net demand uncertainty and permits the quantification of an estimate of the value of using storage to provide StR.

The link between Step 1 and Step 2 corresponds to the change in system conditions between the period when UC decisions are taken and electricity delivery time due wind imbalances. As discussed in Chapter 3, these imbalances have a stochastic nature that corresponds to the wind forecast error.

The optimisation problem is then composed by a set of loops in which SR contribution is reduced and replaced by StR provided by Storage and/or fast plant. The iterative process stops when the system operation cost, as a function of the SR/StR split, reaches a minimum. This means that there is no economic interest in increasing StR further.

Wind imbalance generation

The difference between forecasted and realised net demand is determined by generating random imbalances that follow a normal distribution. The chronologically corresponding value in the randomised wind profile is generated merely by adding the imbalance to the original value in the forecast wind profile. Thus each value is independent, and we have,

$$y_t^r = y_t^f + (\sigma \varepsilon_t) \tag{5.1}$$

In the equation y_t^r, y_t^f are the realised and forecasted values, respectively. To generate the differential between these values a drift term is introduced. This term is computed, for each time t, by multiplying a normally distributed random number of standard deviations ε_t by a factor σ representing the standard deviation size obtained from the distribution of net demand uncertainty. This quantity represents the displacement from the original value in the forecast wind profile. Note that it can be positive or negative. The approach used ensures that the general shape of the realised distribution of imbalances is similar to the one of the forecast.

Model input data

- Conventional generators costs: fuel, no-load and start-up;
- Conventional generator constraints: ramp-rates, min-up and -down times and technical limits (P^{min} and P^{max});
- Storage characteristic: power and energy rating, efficiency losses;
- Fast plant: power rating and marginal cost;
- Demand and wind forecast: annual time series with hourly resolution
- CO_2 emissions from fossil fuel-based electricity generation are modelled considering Intergovernmental Panel on Climate Changes (IPCC) emission factors [92].
- Reserve requirements: total reserve requirements are determined offline using the equivalent risk based approach described in Chapter 3. These requirements ensure that uncertainties in the generation/demand balance are covered in all but 0. 3 % of cases;

For each time period, a dynamic adjustment of reserve, according to the level of wind forecasted, is performed. The actual amount of reserve scheduled in each hour is determined by taking into account the predicted output of WG. For example, in the case of a maximum amount of 5.7 GW of reserve is calculated using the procedure of Chapter 3, if the predicted wind output is below 5.7 GW then the amount of upward reserve can be reduced such that it equals the predicted WG output. Similar reasoning is used for downward reserve. The total reserve requirements are procured from a combination of SR provided by synchronised conventional plant and StR provided by fast plant or storage or a combination of both.

On the quantification of the contribution of storage to standing reserve

The quantification of the optimum combination of SR and StR, when storage is involved is not straightforward and the specific characteristics and limitations of this technology need to be carefully represented. As it is an energy-limited device, the amount of storage providing reserve depends on the actual deployment of reserve in the previous time periods. To illustrate this, a simplified example of the dispatch of energy and reserve for a forecasted wind output, and the re-dispatch for realised wind, over a 4 hours period is presented. This example intends to illustrate the limitations of having an energy constrained device providing reserve and does not intend to illustrate the performance of the scheduling algorithm. The system operation conditions at the dispatch stage are:

- demand: 7 GW (constant during 4 h)
- wind forecast: 4 GW (constant during 4 h)
- conventional generation used to supply demand: 3 GW
- reserve composition: 1 GW of conventional generation and 1 GW of storage

System operation conditions at re-dispatch stage are:

- demand is the same as forecasted: 7 GW;
- wind realised: 2 GW (corresponds to a forecast error of 2 GW that lasts for 4 hours).
- conventional generation are available to supply demand: 4 GW.

To maintain the demand-generation balance the deployment of reserve composed by 1 GW from synchronised plant and 1 GW from storage, is required.

Figure 5.3 illustrates the (a) dispatch solution for forecasted wind; (b) re-dispatch solution for realised wind and (c) the utilisation of storage in terms of power and energy. Observing b) it is possible to see that the generation/demand balance is maintained, during the first 3 hours, by increasing the output of conventional plant and discharging storage however, in the last hour there is a need to disconnect 1 GW of demand.

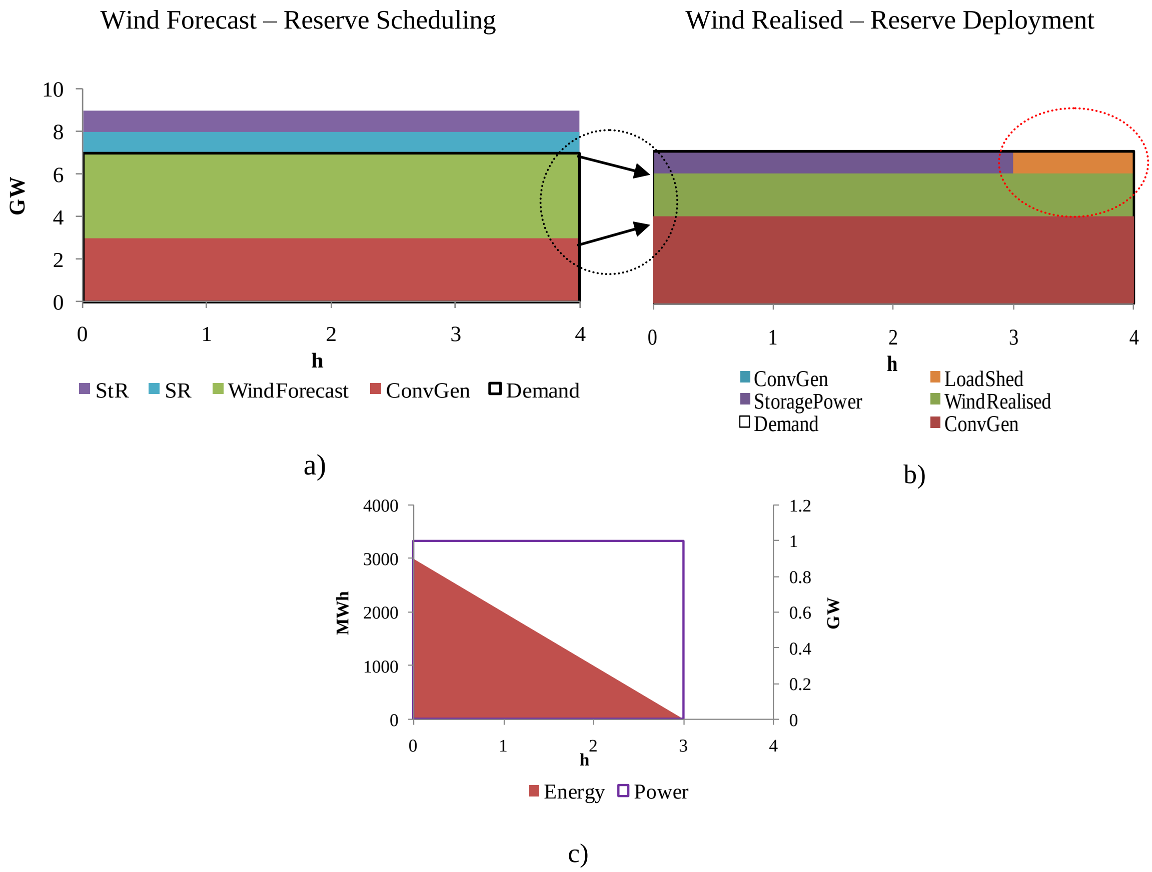

Figure 5.3 a) Example of solution of the economic dispatch for a) forecasted wind b) realised wind c) power output of storage and energy available in store

This need for load shed can be explained observing the energy available in the storage in c). It is possible to see that before the reserve deployment the storage had 3000 MWh of energy. To respond to the request of 1 GW of reserve storage starts discharging at a rate of 1000 MW per hour and after 3 hours storage is empty and consequently unable to continue providing reserve. This means that, unlike a generator constrained only by ramping rates and generation limits, storage's ability of producing a specific power during a fixed period is limited by the energy available in store. This is a limitation regarding the security that this technology can provide when used to provide part of the reserve requirements.

The simple example described above showed that storage discharge is constrained by the energy available in store, the same way as storage charge is constrained by the maximum energy limit. As a consequence, to quantify the contribution of storage to standing reserve, the utilisation of storage needs to be simulated over the whole optimisation period. This requires the simulation of the realisation of the events that require the deployment of reserve.

Clearly, the selection of a suitable optimisation model to quantify the value of storage depends on the uses for storage to be considered. If storage is used for load shaping only, its value can be quantified using a single-step[49] generation scheduling as the one used on Chapter 4. In contrast, if storage is used to provide reserve, using a single-step model there is a risk of obtaining reserve scheduling solutions, as the one in the example above, that lead to having insufficient reserve and expensive load shed. This clearly shows that both reserve scheduling (for forecasted values of wind, demand, and generation availability) and reserve deployment (for its realised values at delivery time) need to be considered. This reinforces the need for a two-step[50] system operation, such as is used in this thesis. Without loss of generality, considering that the goal of this study is to quantify the value of storage for balancing wind forecast imbalances, the only source of uncertainty considered is WG. The reserve requirement is calculated using the approach described in Chapter 3 considering only wind uncertainty. The deployment of reserve is done when there is a positive or negative imbalance between the wind forecasted and realised.

Model Outputs

The simulation model is run for a time horizon of one year with hourly resolution and generates the following results:

- hourly and annual energy produced by conventional plant,
- hourly and annual generation cost,
- hourly and annual energy not supplied,
- hourly and annual WG curtailed,
- hourly and annual charge and discharge energies,
- hourly and annual energy produced by fast plant,
- hourly and annual CO_2 emissions.

[49] Single step simulation is considered in this thesis corresponds to the SCUC for the full period of analysis for system forecast conditions (demand, wind and generation available).

[50] Two-step simulation is considered in this thesis to correspond to optimisation of system operation for the full period of analysis for system forecast and realised conditions (demand, wind and generation available). During the first step decisions regarding the units-committed and how reserve is provided. During the second step (economic dispatch), the output of the committed available units is adjusted to meet the realised net demand.

The outcomes of the individual studies can be compared in order to obtain a number of key results. These include:

- the *value of standing reserve* (for *both* forms - storage and fast plant) which is quantified by the *difference* in the fuel cost and CO_2 emissions when net demand imbalances are managed via synchronised reserve only, against the performance obtained using a mix of SR and StR.
- the increase in system's ability of accommodating WG which is measured by comparing the annual wind energy used to supply demand in systems with and without storage providing standing reserve[51].
- the *capitalised value* of storage in £/kW of installed capacity which is calculated using present worth analysis.
- the *relative competitiveness* of storage against fast plant which is then evaluated as the *difference in savings* in fuel cost delivered by storage versus fast plant.
- the contribution of storage to system flexibility quantified using intermittency balancing costs.

The mathematical formulation of the model used to generate these results is described in the following section.

5.4 Mathematical Formulation

This model is aimed at scheduling systems with large WP and bulk electricity storage. The model comprises two optimisation steps. The first step is a SCUC algorithm, solved as a mixed integer linear programming (MILP) problem solved with simplex and using the DashXpress solver [111]. In this step units are scheduled to supply net demand and hold a pre-defined level of reserve determined taking into account wind stochastic nature. The second step solves a

[51] It should be noted that we calculate the amount of wind that would need to be curtailed in order to maintain a stable operation of the system. However, the reduction of wind curtailed cannot be used to directly measure the benefits of storage because part of the wind energy charged is wasted in round trip efficiency losses. For example, having a very large but very inefficient storage facility could largely reduce the amount of wind curtailed (as all surplus energy can be stored) but very little of the wind stored would be actually available to supply demand and consequently reduce the output of fossil fuel plant. Therefore reductions by storage in the amount of energy produced by conventional plant are used to measure the net effect of wind energy saved. In effect this reduction in energy comprises the utilisation of wind, as shown by the reduction in wind curtailment, but with the deduction of energy lost due to storage efficiency losses.

linear economic dispatch problem that optimises the cost of adjustments of generator output and the deployment of alternative sources of flexibility, to supply the realised net demand.

5.4.1 Generation scheduling – forecasted net demand

In the first step of the optimisation, the same generation scheduling model described in Chapter 4, excluding response constrains, is used to solve a day-ahead generation scheduling to meet the forecasted net demand. In addition, reserve constraints ensure that a pre-specified level of reserve is held in synchronised plant. The solution obtained from this step consists of the set of units committed at each time period *t* and the generation outputs to meet the forecasted generation/demand balance. The reserve held in synchronised plant is defined by the total SR requirement.

5.4.2 Re-dispatch for realised net demand

The second step of the optimisation is the economic dispatch. The solution regarding the synchronised units obtained in the previous step is used as an input for this step. The objective function for this process is described as follows.

Objective function

The objective function minimises the system re-dispatch cost. The generators marginal cost is modelled using piecewise linear curves. In order to ensure feasibility of the problem solution, if the generation flexibility available is insufficient to meet the demand balance constraints, at certain time period, the possibility of load shedding or having a "slack" of generation is considered. This is formulated as follows:

$$f = \min_{i,p,l^{shed},e^{over}} \sum_{t=1}^{T} \left\{ \left[\sum_{ic=1}^{N_{GC}} c_{ic}\left(p_{ic,t}\right) \right] + VOLLl_t^{shed} + \alpha e_t^{over} + c_{fast\_plant}\, p_t^{fast\_plant} \right\} \qquad 5.2$$

The optimum is sought with respect to non-negative real matrices p_{ic}, p^{fast_plant} , and, e^{over} .

Demand balance

Equation 5.3 represents the demand balance constraint for realised net demand.

$$\sum_{ic=1}^{N_{GC}} p_{ic,t} + w_t^a + S_t^d + p_t^{fast\_plant} = d_t^a - l_t^{a,shed} + e_t^{a,over} + S_t^c + w_t^{a,c} \qquad 5.3$$

$p_{ic,t}$ is the total output for committed unit *ic*. The meaning of variables l_t^{shed} and e_t^{over} represent the lack and surplus of energy in the demand-generation balance, respectively. Besides generation also electricity storage contributes to the generation/demand balance by increasing generation by discharging S_t^d and increasing demand by charging S_t^c. The realised output from

WG, at electricity delivery time *t*, is represented by w_t^a. To maintain the system balance, the possibility of curtailing wind, during time period *t* is introduced through the variable $w_t^{a,c}$. Load shedding and wind curtailment, during time period *t*, are bounded from below by zero and from above by the total demand and WG, respectively:

$$0 \le l_t^{a,shed} \le d_t^a \quad 5.4$$

$$0 \le w_t^{a,c} \le w_t^a \quad 5.5$$

Generator constraints

The generator constraints considered, at the re-dispatch stage, are the output limits and ramping rates. These are the same as the ones used in Chapter 4 described by Equations 4.25 and Equations 4.28 to 4.31.

In addition to the synchronised conventional generation fast plant can be used. Fast plant can be added to the scheduled generation supplying demand in real time, in the same way as storage can be discharged, but the consideration in terms of economics in this case is the fast plant marginal cost. If it is used then it must deliver power within its ratings. These characteristics are captured in Equations 5.6 and 5.7.

$$p_t^{fast\_plant} \le P^{fast\_plant\_Max} \quad 5.6$$

$$p_t^{fast\_plant} \ge 0 \quad 5.7$$

Storage Constraints

The storage model is represented by equations 5.8 to 5.12. To take into account both power and energy constraints of an electricity storage device Equations 5.8 and 5.9 are included in the optimisation algorithm.

$$0 \le S_t^c, S_t^d \le S^{max} \quad 5.8$$

$$0 \le ES_t \le ES^{max} \quad 5.9$$

The energy balance constraint is applied to storage whereby at each time interval during the day, the amount of energy stored after charging or discharging cannot exceed the maximum capacity of the storage device, and cannot be less than zero. The initial state of storage, ES^{INI} , is set outside of the optimisation. For all other days in the year, the initial energy of the storage is set to be equal to the energy available in store at the end of the previous day. Efficiency losses during charging are taken into account via this energy balance constraint, by multiplying the efficiency factor with the power used to charge the storage. In this model the efficiency losses are assumed to happen during the charge stage. The total energy store at any instant of time is calculated as the energy previously stored, plus energy charged (multiplied by efficiency), minus energy discharged during the time interval *t*, shown by equations 5.10 and 5.11.

$$ES_{t=1} = ES^{INI} \quad 5.10$$

$$ES_t = ES_{(t-1)} + (\eta_s \cdot S_t^c - S_t^d) \times \Delta \quad 5.11$$

In addition a minimum amount of energy in storage at the end of a desired period of time, for instance at the end of each day, can be defined. This is done using equation 5.12.

$$ES_{(t=k\cdot 24)} \geq ES^{FIN}\ , \quad k = 1,2,\dots,365, \quad 5.12$$

The end state of storage ES^{FIN} is constrained to be a given value which, in our modelling, is a chosen fraction of the total energy size of the storage facility and defines a final (minimum) energy at the end of each day k.

In summary, the model two-step is described by equations:

- First stage: objective function 4.3 constraints 4.4 to 4.7, 4.10 to *4.18* and 4.23 to 4.31 and,
- Second stage: objective function 5.2 and constraints 5.3 to 5.12 and 4.28, 4.31 and 4.25

With this model in hand, the remaining of this chapter is devoted to the quantification of the value of the flexibility from using storage to balance wind uncertainty and its main drivers. This is based on a comprehensive set of case studies and interpretation of the results obtained.

5.5 Quantification of the Value of Flexibility from Storage

The results obtained in Chapter 4 have shown that the reduction in operation costs and carbon emissions expected when large WP are added to the overall generation mix do not always materialise. To take advantage of the benefits of WG, the remaining generation mix needs to be sufficiently flexible to cope with wind variability and uncertainty at different time scales. At the same time, the results showed that the options to increase the operation flexibility available are the optimisation of existing generation flexibility, increasing the penetration of high-flexible plant in the mix and increasing the flexibility of conventional generation. All these bring benefits but several technical and economic barriers need to be overcome before these can materialise. A possible alternative or complement to these is to consider generation storage as a source of operation flexibility.

This section presents a set of case studies that apply the approach described in the previous sections to quantify the value of flexibility from storage. The value of storage is quantified through consideration of:

- cost and emissions reduction and increase of the wind used by the system;
- capitalised value of storage in £/MW of installed capacity obtained using present worth analysis;
- sensitivity of the previous results to storage efficiency and power/energy rating;
- sensitivity of the value of storage to WP;
- value of storage's in terms of intermittency balancing cost;
- comparison of the performance of storage with fast plant.

This analysis is based on reducing the amount of reserve provided by synchronised conventional plant and correspondingly increasing the standing reserve portion that is then provided by storage or fast plant. The time horizon used for quantifying operational reserve is 4 hours given the assumption that this is the expected start up time of a large conventional plant.

5.5.1 System data

A system with a similar size to the UK is used, with a total of 82 GW of conventional generation installed capacity, a peak demand of 57 GW, minimum demand of 26 GW and an annual energy consumption of 323.2 TWh. The generation mix is wind/thermal and differs in terms of flexibility of conventional units and WP. The conventional generators parameters chosen are not intended to replicate a specific technology, but to represent technologies with different dynamic ratings, part-load efficiency losses, fuel costs and carbon emissions. This is aimed at providing a "realistic" representation of the diverse factors present in a generation mix. The scenarios used are presented in Table 5.2 and are composed by three representative technologies similar to the ones used in Chapter 4. These are classified in terms of flexibility levels: low flexibility (LF), medium flexibility (MF) and high flexibility (HF). The different levels of flexibility are obtained by changing the installed capacity of different technologies. The LF mix has higher penetration of must-run generation and the HF mix is composed by high flexible plant only.

An historical wind time series of one year with hourly resolution is used. This represents a system level aggregated WG with a load factor of 35 %. The base WP is 25 % of total annual energy demand and a 4 hours forecast lead-time is used when calculating the overall reserve requirements.

Table 5.2 Generation mix scenarios

Generation System	Inflexible Generation	Low Flexible	High Flexible
LF	12 GW installed, has to run at 100% of max capacity	26 GW installed, minimum stable generation 60% of max capacity	>25.6 GW installed, minimum stable generation 50% of max capacity
MF	8.0 GW installed, has to run at 100% of max capacity	26 GW installed, minimum stable generation 60% of max capacity	>25.6 GW installed, minimum stable generation 50% of max capacity
HF	None	None	>60 GW installed, minimum stable generation 50% of max capacity

Storage is represented by its installed capacity, power/energy rating and efficiency. A set of installed capacities is considered { 2, 3, 4, 5} GW, all of them with energy/power rating of 20 h and 70 % efficiency.

The marginal costs, dynamic ratings, efficiency and emission factors of conventional technologies are presented in Appendix D. The marginal cost of fast plant used is 120 £/MWh.

The results of the case studies, described in the following sections, start with the discussion of the role of storage in the utilisation of surplus WG and provision of standing reserve for 25 % WP. Following this, the sensitivity of these results to storage efficiency and energy/power rating and to the level of WP is analysed. These results are then complemented with the presentation of storage's contribution to the reduction of balancing intermittency costs. Finally storage is compared with fast plant as one of its competing technologies.

5.5.2 Applications of storage to increase system flexibility

In the previous studies conventional generation was assumed to be the sole source of flexibility therefore its output was adjusted over time to follow the variation of net demand. Previous results showed that whenever there wasn't sufficient flexibility to maintain the demand/generation balance, WG had to be curtailed. The key factors that condition generation flexibility were shown to be the minimum stable generation (MSG) of plant providing response and reserve and the penetration and must-run generation flexibility (MSG and ramp rates).

Electricity storage cannot generate electricity but is able to modify system demand by charging and discharging. This can be used to provide part of the flexibility required to maintain system demand/generation balance as a complement or alternative to generation. For the case of systems with WG this flexibility can be used to deal with wind fluctuations and imbalances caused by wind forecast errors, by charging/discharging to compensate for the deviation from the forecast on the generation side caused by wind.

On the benefits of storage for load-shaping in system with WG

The potential application of storage is illustrated as follows Figure 5.4 presents a snapshot of generation dispatch for a period of the year characterised by high wind and low demand followed by a period where wind drops and demand increases. The figure shows the original and modified system level demand. The zoom area overlapped to the main plot corresponds to the solution obtained for the same period if no storage is available (base case). Storage usage patterns (charge and discharge) can be observed as well as their impact in the results of system dispatch and aggregated demand. This leads to two main conclusions:

- In periods of low demand and high wind storage is charged. This increases system demand and reduces the need for wind curtailment. The energy charged is then discharged when demand increases, which reduces the output of fossil fuel plant.
- In the period when wind decreases and demand increases there is no wind curtailment. In these periods storage is used to reduce the use of high-flexible plant with higher fuel cost by smoothing the demand profile.

This illustrative example shows the benefits of adding storage as a source of flexibility to share with the conventional generation the role of maintaining the generation/demand balance. Such flexibility is used both to reduce wind curtailed and fuel costs.

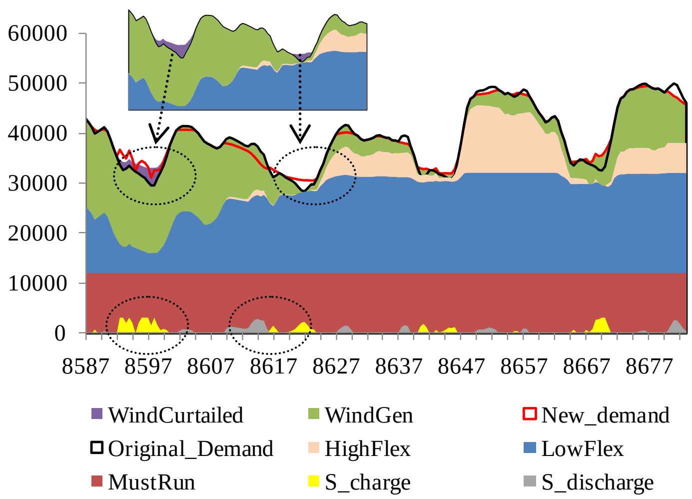

Figure 5.4 Reduction of wind curtailed and load-levelling obtained by charging and discharging storage

On the benefits of using storage to provide standing reserve

Chapter 3 discussed the potential benefits of using a mix of SR and StR to increase system flexibility. This was confirmed in the system operation studies of Chapter 4 that showed that the need for part loading plant to provide SR has a significant impact in system flexibility and the ability of integrating WG. It was also shown in this work, however, that the optimal mix between the two types of reserve is largely influenced by the high exercise cost of standing plant. In addition, such plant cannot provide downward reserve since it is considered to be offline until reserve deployment is required.

Storage plant has the advantage over fast plant of having the ability of providing both upward and downward regulation by discharging energy in periods where forecast errors lead to lack of generation and charging in periods where it leads to excess of generation. The snapshot based example used in Chapter 3, presented in Figure 5.5 and Table 5.3, is used here to illustrate the advantage of using storage over fast plant for StR.

Table 5.3 Dispatch solution of the system operation snapshot

	Reserve Req (GW)	Nr Syncr Units SR	Gen Sync[52] (GW)	WG (GW)	Must Run (GW)	StR (GW)	Demand (GW)	Surplus Gen (GW)
All SR	6.5	26	7.8	12	8.4	0	25	3.2
Mix	6.5	18	5.4	12	8.4	2	25	0.8

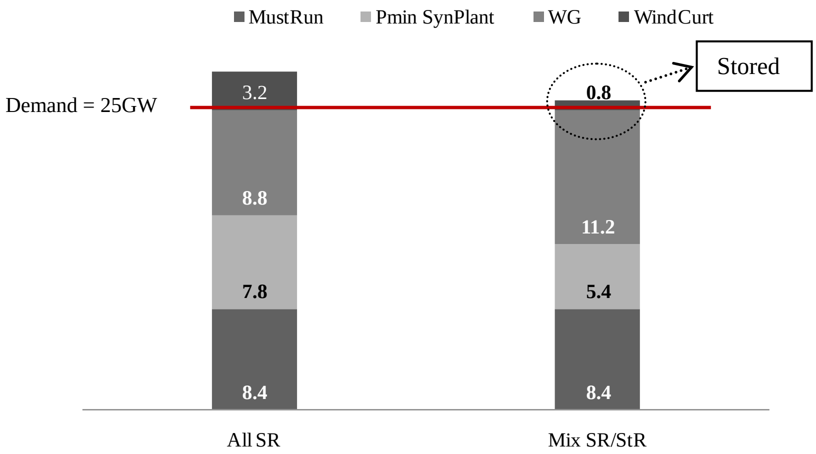

Figure 5.5 Snapshot of generation dispatch for all spinning and a mix of spinning and standing reserve

As for fast plant storage displaces part of the reserve provided by synchronised generation reducing the need for part-loaded plant and the need for curtailing wind due to the inflexible generation output that these must produce in order to be synchronised. In addition, storage can also store the extra 0.8 GW of wind that would otherwise be curtailed. The example illustrates the potential of storage's contribution to system flexibility and improves system's ability of

[52] Each synchronised conventional unit can be operated between: 300 < P < 550 (MW) meaning that each part loaded unit provides 250 MW of reserve. To meet a total reserve of 6.5 GW 26 units need to be synchronised and producing an inflexible generation output of 26 × 300 = 7.8 GW.

accommodating WG. To access the value of this flexibility quantitative studies are required. In this work a set of annual studies of system operation with storage, for different conventional generation mix flexibility presented in the following sections are performed to quantify the value of storage as a sources of system flexibility.

5.5.3 Environmental and economic value of storage

Using the approach proposed in section 5.3 the quantitative value of storage providing standing reserve and load-levelling is determined for the LF, MF and HF conventional generation mix, for a WP of 25 % (corresponding to 26 GW is installed capacity). The base case is the case without storage and all reserve is provided by synchronised plant. The different scenarios with storage consider standing reserve, provided by storage. The amount of SR displaced by storage is such that the split between SR and StR leads to the minimum system operation cost. The results are presented in terms of the:

- reduction of fuel cost (in % of total annual operation cost for the base case);
- capitalised value of storage (in £/kW of storage capacity);
- increase of the wind used by the system (in % of annual wind available energy);
- reduction of CO_2 emission reductions (in % of annual CO_2 emissions for the base case);
- intermittency balancing cost (£/MWh of annual wind available energy);

The increase in the wind used by the system is not obtained directly from the reduction of wind energy curtailed. This is because when using storage to charge part of the wind and discharge it later, some of the wind energy charged is lost due to round trip efficiency losses. Instead the increase in the wind that is used to supply demand is calculated by quantifying the reduction of energy produced by fossil fuel plant.

The composition of total reserve in terms of SR and StR, that minimises the expected system operation cost, varies with the capacity of storage available in the system. In this same way as was described in Chapter 3, the split is characterised by the parameter λ which indicates the proportion of total reserve that is represented by SR. This is obtained by running full system operation for different λ and keeping the solution that led to the lower expected cost. Table 5.4 shows how reserve composition, represented by the split λ_{min}, varies with storage capacity. It is clear that proportion of StR increases in an almost linear fashion with increasing storage capacity. For the lower storage capacity reserve is composed mainly with SR and for higher capacity the composition is shared between SR and StR in approximately equal parts.

Table 5.4 SR and StR optimal split for different storage capacity

Storage power rating (GW)	2	3	4	5
λ_{min}	2.3	2	1.6	1.4

Using the minimum cost reserve combinations, the methodology described in the previous section is used to determine different quantitative measures of the value of storage for increasing storage capacity.

The economic value of storage corresponds to the reduction of operation costs obtained by reducing plant part-load losses and increasing the fossil fuel generation displaced by WG by increasing the wind used by the system. The results obtained are presented in terms of reduction of system operation cost and capitalised value of storage in Figure 5.6 and Figure 5.7, respectively. The results show that storage contributes a reduction of the total annual operation cost. This reduction is significantly higher for the LF system and increases with the storage installed capacity. When comparing these results with the value obtained for the increase of wind used by the system (Figure 5.9) it is possible to see that the value of storage is highly linked to its ability of increasing the wind used. As a consequence, the operation cost savings are higher in less flexible systems with less ability of accommodating WG.

While the reduction of operation cost gives an indication of the economic benefit to the system the decision about the economic viability of the technology needs to be based on a different metric. To this end the gross reduction of cost is translated into capitalised value per kW of storage using present worth analysis. The capitalised value is calculated, assuming a technology life span *a*=20 years and a capital interest rate *ir*=10 %, using 5.13.

$$PWV_{storage} = \frac{1-\left(\frac{1+a}{1+ir}\right)^{n}}{ir-a} \times \left(\frac{Cost\_reduction}{Storage\_Inst\_Cap}\right) \quad for\ a \neq ir \tag{5.13}$$

The results are presented in Figure 5.7 and the trends obtained are explained by:

- The LF mix is less able to accommodate WG output, because the generation output is not sufficiently flexible (due to must run, MSG and ramping constraints) to provide reserve and simultaneously adjust its output in response to wind imbalances. As a consequence part of the WG output is curtailed to maintain the generation/demand balance. Under these conditions storage contributes both to the reduction in plant part-load efficiency losses and wind curtailed;

- The MF mix faces similar problems as the LF storage but is a lower extend since plant providing reserve has lower MSG and mix has less inflexible must-run plant. Storage contributes to the reduction in plant part-load efficiency losses and wind curtailed (in a lower magnitude than in the LF system);
- The HF mix has no must-run generation and all plant providing reserve has lower MSG, when compared to previous cases. Consequently the mix is naturally able of accommodating all WG and no wind is curtailed. In this case storage contributes solely to the reduction in plant part-load efficiency losses by displacing part of the SR.

Observing the results it is possible to see that a higher value of storage is linked to its contribution to increase the wind used by the system. Consequently, systems that are sufficiently flexible to accommodate WG attribute a lower value to the additional flexibility provided by storage.

The results show that even though higher cost savings are obtained when storage capacity is increased, the capitalised value per kW of storage decreases. This shows that the highest value is obtained by the first MWs of storage that are used more often to deal with small and frequent wind imbalances. The extra capacity is used for higher and less frequent imbalances and consequently adds less value. When distributing the savings by a larger installed power a lower value per kW is obtained. In addition, the LF presents a value approximately two times higher than the MF and four times higher that the HF systems. This shows that there is a significantly larger economic potential for storage in systems with low flexible generation mix.

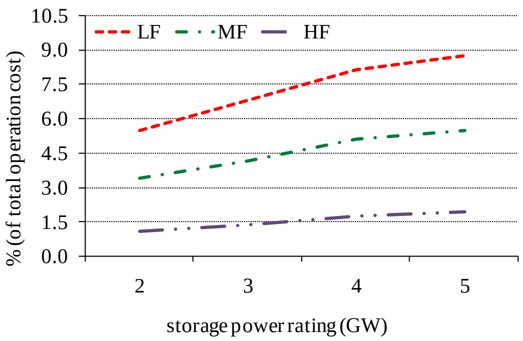

Figure 5.6 Reduction of operation cost obtained using storage

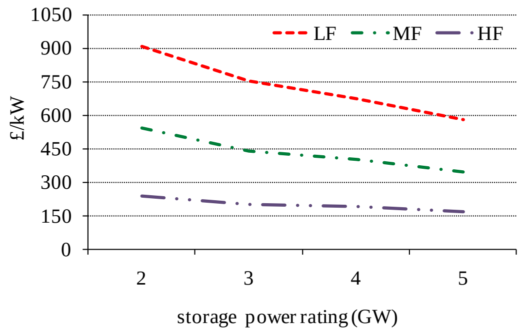

Figure 5.7 Capitalised value of storage for 25 % WP

The results obtained for the capitalised value can be used as an indicator of the economic viability of investing in new storage capacity. If the capitalised value is lower than storage investment plus operation cost, investing in the technology is not economically viable. Taking the example of hydro-pump storage the investment plus operation cost of the technology is around 1000 £/kW. For all the results obtained it is difficult to justify an investment in new capacity, however, in the LF system the capitalised value of 2GW of storage is close to the minimum required to justify the investment.

In addition to the economic value of storage the environmental value can be quantified in terms of increase of wind used by the system and reduction of CO_2 emissions. Figure 5.8 shows the environmental value of storage in terms of tonnes/kWp.a of CO_2 savings for one year. This represents a contribution to CO_2 targets and can be converted into an additional economic gain using carbon prices. The higher CO_2 emission savings are obtained for the inflexible generating system these being twice as high as the savings obtained for the MF and four times higher than for the HF system. This shows that, as for economic benefits, the environmental benefits are also higher in a less flexible system. This reduction is driven by the increase in wind energy used and the reduction of part loaded plant[53] efficiency losses. Figure 5.9 show that the increase of the wind used by the system is the main driver for the reduction of CO_2 emissions. In this case, no increase is obtained for the HF system because the system has sufficient flexibility to accommodate the 25 % penetration of WG and no wind is curtailed even in the base case. As a flexible generating system is able to accommodate WG, smaller CO_2 reductions are obtained from reducing SR since these are limited to the reduction of plant efficiency losses.

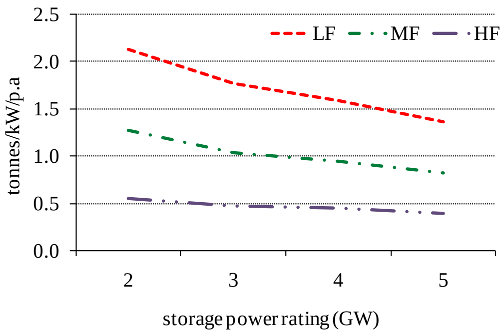

Figure 5.8 Reduction of CO_2 emissions per kW of storage capacity for 25 % WP

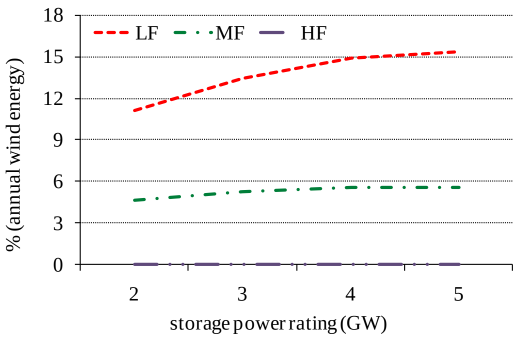

Figure 5.9 Increase in wind used by the system obtained using storage

[53] Note that, as said earlier, having a thermal plant producing with different loading levels changes its fuel efficiency and consequently the carbon emissions emitted. This means that if we have the same amount of power produced by a fully loaded plant or two part loaded plants the emissions per kWh are higher in the second case. Consequently if less plant is part loaded to produce the same aggregated output the total emissions are lower.

5.5.4 Sensitivity studies

To understand how different factors affect the value of storage, the previous studies are complemented with a sensitivity analysis. The previous sections have already analysed the impact of different storage power rating and conventional generation flexibility. Consequently, this sensitivity study aims to cover the remaining parameters that are likely to change with storage technology and future WG targets. These parameters include storage's characteristics represented by round trip efficiency losses and the energy/power ratio and to WP levels. The sensitivity analysis is done around the base case of the previous section with storage of 3 GW, energy of 60000MWh (20 h energy/power rating) and efficiency 0.7 (30 % round trip losses). The WP of 25 % used in the previous section is extended to a range between 15 and 55 % to access the impact of WP on the value of storage.

Sensitivity to efficiency losses

It is readily agreed that storage efficiency plays an important role in storage economic viability. To quantify the impact of efficiency losses on the value of storage, sensitivity studies were carried out. These studies are summarised in Figure 5.10 which shows the impact of efficiency on the fuel reduction obtained using storage when compared with the base case without storage.

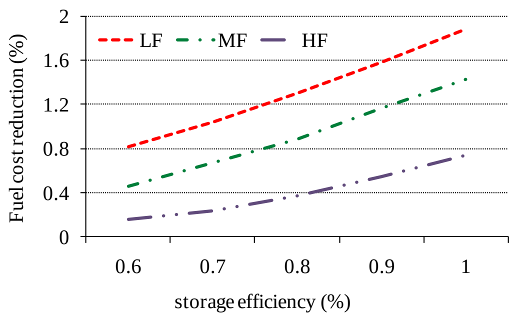

Figure 5.10 Sensitivity of the fuel cost savings to storage efficiency

Figure 5.10 presents the variation of the operation cost savings obtained by a storage device with different efficiency (in percentage of total system cost) for different scenarios of generation mix. The results indicate that the value of storage is highly sensitive to storage efficiency. Its value more than doubled when efficiency changes from 0.6 to 1.0. The absolute value of the savings obtained is lower for higher flexibility mixes but the sensitivity trend obtained is similar. Storage efficiency is one of the key drivers of its economic viability. Taking the example of the LF system for 25 % WP and 3 GW of storage with an efficiency of 70 %, a capitalised value of 752 £/kW of installed capacity was obtained. Considering that the full cost (investment plus operation) of a hydro-pump storage is close to 1000 £/kW it was clear that the value obtained does not compensate the cost. If the same device has higher efficiency 90 % and

100 % this value would increase to 1005 and 1600 £/kW, respectively. Considering the same capital cost the investment in new capacity would become viable for both cases but with a clear gain for the 100 % efficiency. These quantitative results confirm that the value of storage increases significantly if round trip efficiency losses are reduced.

Storage power/energy rating

Storage energy/power rating represents the total time duration that a storage facility can charge/discharge at its maximum power rating. To understand the sensitivity of the value of storage to this parameter, starting from a base case of a 20 h, the charge/discharge time is both reduced to 10 h and increased to 30 h. These energy/power ratings are chosen to be in line with "bulk" power storage technologies. The results obtained showed that the impact of this variation is very small, in the order of 1 to 2 % variation of the capitalised value of storage obtained for the base case. This means that for applications of storage to compensate wind imbalances an energy/power rating above 10 hours brings little benefit. This is an important consideration since this affects the choice of technology and the investment cost of a storage facility.

Wind penetration

As shown earlier in this work, flexibility plays a key role in enabling the system to assess WG economic and environmental benefits. As a consequence, the value of flexibility required to integrate WG will be largely influenced by the WP that is added to the generation mix. To understand the extent of the impact of WP on the value flexibility provided by storage, a set of sensitivity studies is performed. This impact is quantified in terms of fuel cost reduction, capitalised value of storage, CO_2 emissions reduction and increase in WG used by the system. Figure 5.11 and Figure 5.12 show results obtained for fuel cost reduction and capitalised value of storage for increasing in WP. The results show that storage contribution to fuel cost reduction increases with the WP and is higher for the LF system. This is because a larger forecast uncertainty increases the balancing task and thus the benefits of the flexibility provided by storage are also increased.

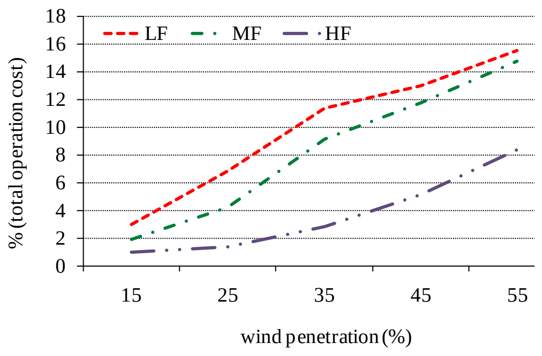

Figure 5.11Reduction of annual operation cost obtained using storage for different WP

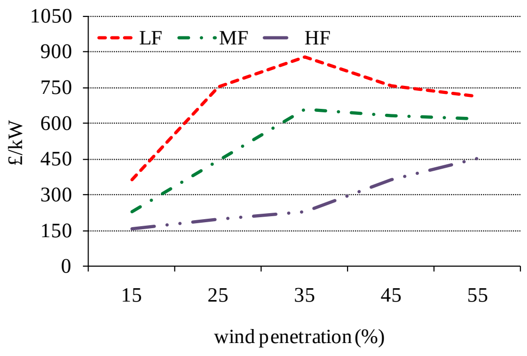

Figure 5.12 Capitalised value per kW of storage capacity for different WP

Of particular interest is the reduction in the rate of increase of the fuel costs savings, in the LF system, for WP above 35 % that shows that the benefit of storage drops for high WP. When fuel cost savings are translated into capitalised values in £/kW the trends obtained for fuel cost savings change for the LF and MF system. For WP above 35%, the capitalised value of storage diminishes. This happens for two reasons:

- the rate of increase in fuel cost savings, above 35 % WP, is low and the base storage power rating of 3 GW has to be increased to 5 and 6 GW for the MF and LF systems, respectively, to obtain visible benefits of storage;
- if 3 GW power rating is maintained no benefits are obtained because storage is always full. To increase the opportunities for storage to discharge, larger storage capacity is required.

The implications of a combination of large wind and low flexible conventional generation mix with high WP on the value of storage are further discussed below.

The results obtained for increase of wind used by the system and the reduction of CO_2 emissions are presented in Figure 5.13 and Figure 5.14, respectively. From the results two main aspects should be highlighted:

- For the LF and MF systems the rate of increase of the wind used by the system follows a different trend to the one obtained for the HF system. The increase is steeper for WP up to 35 % and for WP higher than this, the increase becomes smoother. For the HF system the opposite trend is observed. Again this indicates that the contribution of storage to flexibility is less prominent for high WP in less flexible systems.

- When comparing the CO_2 savings with the increase in wind used, in the HF system this trend is closely linked to the increase of the wind used by the system. The results show that the reduction of emissions increases significantly for WP higher than 35 % when storage starts contributing to increase the wind used to supply demand. For the LF and MF systems, as for the fuel cost, the benefits in terms of reduction of CO_2 emissions, in tonnes/kW of storage capacity, decrease for high WP. Again this is justified by the fact that the contribution of storage to the increase of wind used by the system becomes more limited for high WP.

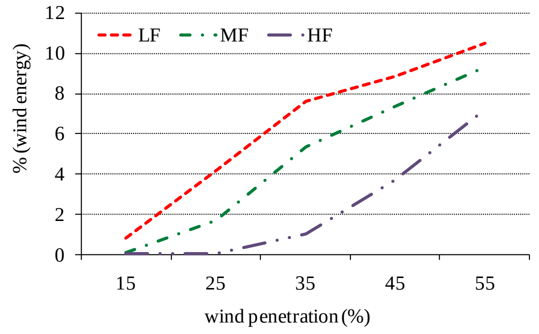

Figure 5.13 Increase in wind used by the system obtained using storage for different WP

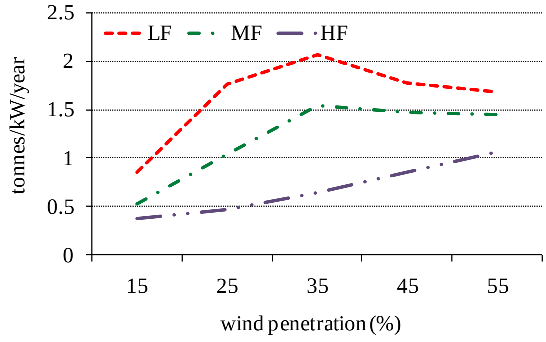

Figure 5.14 Reduction of CO_2 emissions obtained using storage for different WP

The results have shown that even though the gross benefits of storage in terms of annual operation cost reduction and increase of wind used by the system increase with the WP for all systems, the rate of increase is different. For the LF and MF system the rate on increase of these benefits is significantly reduced for high WP and, instead, for the HG system the rate of increase is higher for high WP. For this reason the economic and environmental value of storage, for the LF and MF systems decreases for WP higher than 35 %. The explanation of this is further detailed below.

Limitations of storage for low flexibility generation mix and high wind penetration

For high WP to meet the large reserve requirements more units are part-loaded and simultaneously more WG is available. Moreover there is inflexible must-run generation whose output needs to be added to the synchronised generation. This leads to a higher incidence and larger amounts of surplus wind. Under these circumstances storage is charged up to its maximum energy rating during the first periods of surplus wind but will not have the opportunity to discharge since the periods of surplus wind persist, as shown in Figure 5.16. Instead, for flexible generation mix, storage is charged with this surplus wind and discharged later when there is less wind and or higher demand. This problem is not observed for lower WP since the volumes or surplus wind and lower therefore storage is able to charge and discharge, as shown in Figure 5.15.

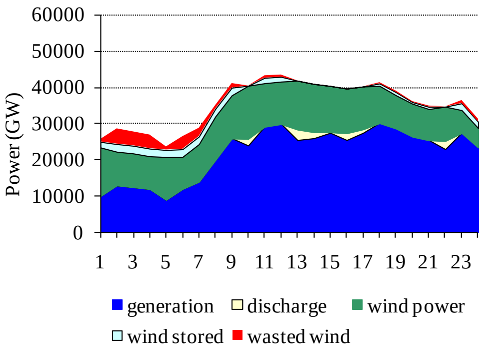

Figure 5.15 Snapshot of generation dispatch for an high wind day and 25 % WP

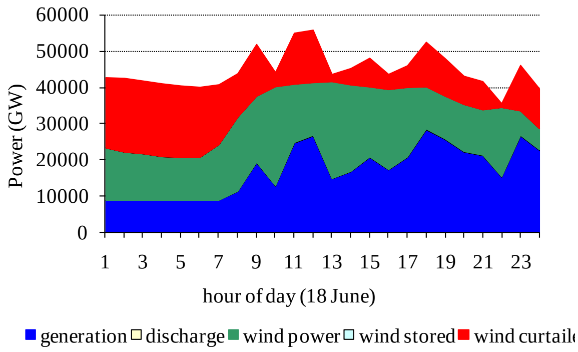

Figure 5.16 Snapshot of generation dispatch for an high wind day and 55 % WP

These results are different to the ones obtained in chapter 4 for the value of flexibility from generation, where the value was higher for low flexible systems and high WP. Again, the fact that storage is an energy limited device becomes important since some conditions, such as low flexible generation mix and high WP the value of storage does not follow the expected trend and decreases for high WP. This confirms the importance of performing quantitative studies using detailed system operation models to extract the value of storage and identify the factors that influence it. This effect could be reduced if the opportunities to discharge storage are increased by aggregating different services such as congestion management and arbitrage.

5.5.5 Reduction of intermittency costs using flexibility from storage

It has been discussed earlier in this thesis the importance of intermittency balancing cost as a metric of the value of flexibility. This metric was used to quantify the value of different options used to increase the flexibility available to integrate WG on the generation side. In this section this metric is applied to quantify the value of the flexibility provided from storage to mitigate the additional impacts/costs of balancing a system with WG.

The results of the reduction of the intermittency cost obtained using storage for increasing installed capacity are presented in Figure 5.17. These are calculated using equation 4.1 and correspond to the difference between the intermittency cost obtained without and with storage, for 25 % WP. The results show that the value of storage is higher for the LF system and increases with storage installed capacity. For 2 GW of storage the intermittency balancing cost is reduced by 4 £/MWh of wind available energy. This corresponds to a reduction of nearly 50 % of the intermittency cost. The MF and HF, in turn present lower values corresponding to 2.5 and 1 £/MWh, respectively. This shows that the value of storage is lower in more flexible systems since these have lower intermittency costs due to its higher ability of accommodating WG. Since wind curtailed has been shown to be one of the main drivers for the intermittency balancing costs the value of the flexibility provided by storage is lower. Increasing storage installed capacity leads to additional cost reduction. The rate of increase is however very low. This indicates that the major contribution of storage for intermittency cost reduction is obtained by the first GW.

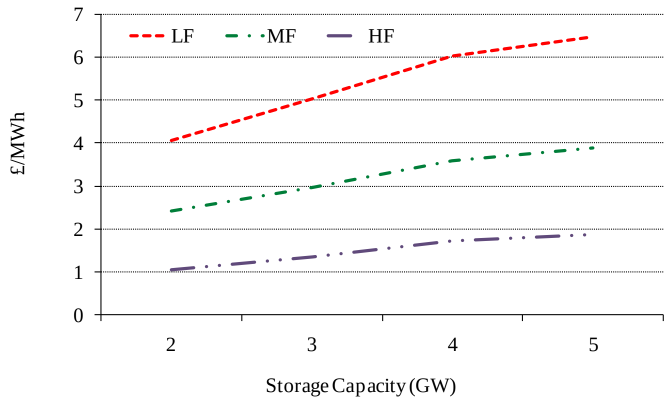

Figure 5.17 Intermittency balancing cost reduction obtained using storage for 25 % WP

In conclusion, storage reduces the cost of integrating WG by displacing part of the requirements set upon synchronised generation to provide the increased reserve services and re-shaping the net demand. Storage however, has some drawbacks since it is an energy limited device and also part of the energy charged is wasted due to round trip efficiency losses. To understand how storage compares to fast start plant, a classic source of flexibility in existing systems, a comparative study is presented in the following section.

5.5.6 Comparison of storage with fossil fuelled fast plant

As shown earlier in this chapter, intuitively, storage has a clear advantage over fast plant based on its ability of both reducing the need for part-loaded plant and utilising surplus wind. This, however, needs to be confirmed by quantitative results. To this end, a set of studies where storage was replaced by fast plant are performed to permit comparing the performance of these two technologies. Considering that fuel cost reduction and increase of wind used by the system are the metrics that more clearly show the potential of each technology, in terms of improving system’s ability of accommodating WG. The operation cost savings and increase of wind used by the system are used for the comparative analysis. Figure 5.18 and Figure 5.19 show the results obtained in terms for the differential of operation cost reduction and increase of wind used, translated in terms of % of the value obtained with storage. For example for HF and 15 % WP fast plant has a value, in terms of operation cost reduction, 10 % higher than the value of storage. The results show that in the majority of cases storage performs better than fast plant, as intuitively expected, but this conclusion cannot be generalised. An example of this is that for low WP fast plant performs better, especially for the more flexible systems. This is verified for cases when little or no wind is curtailed, thus the cost of storage efficiency losses is high (equal to the marginal cost of fossil fuelled plant used to charge storage). Under such circumstances the impact of energy wasted in efficiency losses is higher as consequence storage is a less suitable option. This is confirmed by the results obtained for the increase of wind used to supply demand presented in Figure 5.19. Instead, storage performs better for WP that lead to more frequent periods of wind curtailment. For low flexible systems this trend is inverted for high WP since, as discussed earlier due to the frequent and large volumes of surplus wind once full storage cannot discharge therefore it can only provide upward reserve thus it is similar to fast plant. Finally for HF systems and large WP storage clearly performs better since there are several periods of wind curtailment alternated with periods without it consequently storage can charge and discharge to provide both upward and downward reserve.

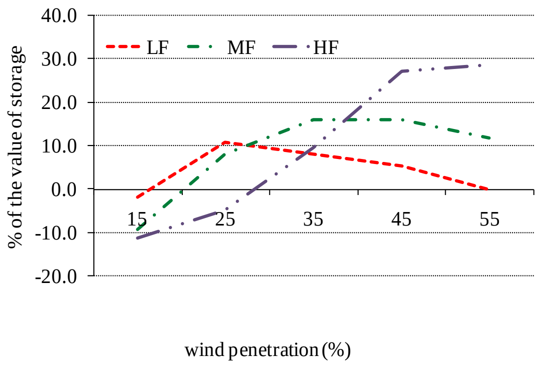

Figure 5.18 Advantage of storage over fast plant in percentage of fuel cost savings

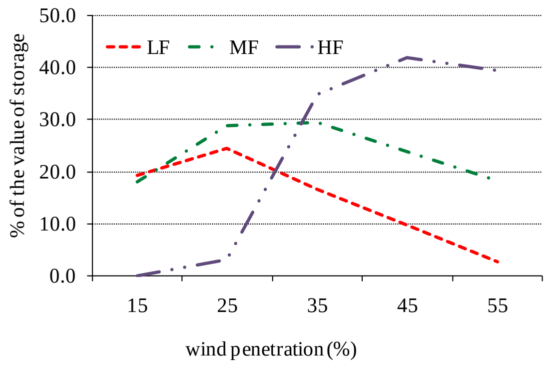

Figure 5.19 Advantage of storage over fast plant in percentage of wind used

In conclusion, storage does not always outperform fast plant because of the intrinsic characteristics of each technology. For the cases of low WP fast plant has higher value. For high WP and low flexible systems both technologies have the same value. As a consequence, the decision of which technology is more suitable needs to be supported by quantitative studies performed using suitable models.

5.6 Conclusions

In this chapter we presented a study of the value of flexibility from storage in systems with different conventional generation flexibility and WP levels. To this end we proposed an approach to quantify the value of storage in terms of reduction in system operation costs, capitalised value per kW of storage capacity, increase of wind used by the system and reduction of CO_2 emissions. Moreover, the value of the flexibility provided by storage is also quantified in terms of the reduction of intermittency balancing cost. At the core of the approach is a system operation tool based on a two-step optimisation that performs the scheduling of generation to meet a forecasted net demand and re-dispatches the generation for the realised net demand profile at delivery time. This simulates both reserve scheduling and utilisation to permit the quantification of the value of storage in displacing part of the flexibility required from the remaining flexibility resources to deal with wind imbalances due to forecast errors. The value of storage will be driven by its contribution to increase system operation efficiency by reducing part-load losses and increase the wind used by the system.

To begin with, the value of storage for a fixed WP, increasing installed capacity and variation in the flexibility of the conventional generation mix was considered. It was seen that that the benefits of storage, in terms of reduction of CO_2 emissions, are significantly higher for the LF generation mix. This is justified because low flexible systems have lower ability to integrate WG and consequently more wind curtailed. Wind curtailed is the main driver for the increase of costs and CO_2 emissions driven by wind forecast errors. As a consequence the benefits of additional flexibility provided by storage are more visible. This also explains why the economic and environmental value of flexibility from storage is significantly lower for the HF system which is naturally able to integrate 25 % WP. When these benefits are translated into a capitalised value per kW of storage it is seen that this value decreases with the increase of generation mix flexibility.

Regarding its variation with storage capacity, it was observed that, in absolute terms, the cost reduction driven by storage increases when more capacity is available. The capitalised value per kW of storage, however, decreases. This is explained because the more frequent and smaller imbalances between generation and demand are covered by the first GW and the additional capacity is used less frequently, generating a comparatively lower value.

Among storage’s intrinsic parameters, efficiency is found to have a key impact on its value. The value of storage is significantly higher if perfect efficiency is assumed when comparing with typical levels of storage of efficiency. It was concluded that, for the LF system, if efficiency could be increased to value higher than 90% the investment in new storage capacity would become profitable. At this point the capital value per kW of storage would be higher than the reference investment plus operation cost per kW. Comparative behaviour, however, was not verified for the more flexible systems.

The impact of varying WP on storage value was also considered. It was found that storage adds value in terms of saving fuel costs and reducing CO_2 emissions, for all WP levels and all generation mix flexibilities. The trend in the evolution of the value of storage is different depending on the levels of WP. For 25% WP storage has a higher value for the less flexible generation mix. This is not maintained consistently as wind penetration levels get higher. In contrast, for high WP and a LF system storage and fast plant have the same value. In contrast, for the HF mix the value of storage is higher.

The change in behaviour is primarily due to the ability of the different systems to take advantage of storage’s flexibility. In a low flexible mix, for high wind and low demand, there is a surplus of wind most of the time. As a consequence, storage has little opportunity to discharge and, subsequently, is not able to charge during periods of surplus of wind. The behaviour in the HF system is different. For low WP, no surplus wind is available to be used by storage. Storage would need to charge fossil fuel energy at plant marginal cost and the cost of losses is higher than the benefit that storage could bring. In contrast, for high WP the high flexible mix experiences more frequent periods of surplus wind and due to the flexibility of the system, there are also periods without wind surplus. In this case storage can be used to reduce wind curtailed. This explains the differences in value obtained for the LF and HF system.

Finally when comparing the performance of storage with fast plant, which was the technology used for StR in Chapter 4, it was found that in the majority of the cases, storage has a higher value. This reflects storage’s ability of increasing and decreasing the energy demand during periods of surplus and lack and WG, respectively. This represents the main advantage of storage over fast plant, as a technology able to provide both upward and downward reserve. Exceptions to this are the scenarios with low WP, without wind curtailment and the high WP and LF generation mix where storage cannot be discharged and consequently, as with fast plant, storage is only able to provide upward reserve.

In summary, it is clear that storage is naturally suited to provide part of the reserve required to compensate for the imbalances on the generation side caused by wind forecast errors. This ability is translated in an economic and environmental value to the system by reducing the cost of accommodating WG and CO_2 emissions.

Storage, however, still has some limitations. Due to round trip efficiency losses its benefits are mostly linked to the use of “free” wind and its high capital costs which limit its economic viability. These results indicate that there is still a need to search for other alternative sources of flexibility which may be used as a complement or alternative to storage.

One natural alternative is to resort to demand side flexibility, which, similarly to storage has the ability of compensating for both positive and negative imbalances on the generation side by altering system demand. The economic value of this option and its comparison to storage are presented in the following chapter.

CHAPTER 6: Value of Demand Side Flexibility

6.1 Introduction

In Chapter 5 the role of storage to provide additional flexibility and to mitigate the costs of WG balancing was explored. The results have shown that storage presents benefits and in the majority of cases, it is a better option than the traditional sources of flexibility, such as fossil fuel fast plant.

An alternative or a complement to using storage to provide flexibility involves altering system demand directly. The principle of using the demand side to provide operation flexibility, as for storage, is based on modifying the system electricity demand. Now, instead of having a separate device that “stores” electricity, according to the imbalances caused by forecast errors, system demand is re-shaped by modifying the energy consumed by different loads. This re-shaping is obtained by performing control actions over the loads at the consumer’s premises through interaction with the loads themselves. It can be said that demand side flexibility (DSF) is a form of storage since electricity is in fact stored, using the example of domestic demand, in the form of heat, hot water or even dirty clothes. The flexibility required is obtained by scheduling the loads in the same way as generators, i.e., by scheduling the loads according to systems needs while respecting a set of pre-defined conditions such as comfort levels.

As such a process can be challenging to implement, it is important that we understand the conditions where DSF will bring value. The main purpose of this chapter is to develop a methodology for assessing the quantitative value of DSF providing part of the flexibility in systems with large WP. This approach builds on the methodology described in Chapter 5, with changes made to capture the characteristics of DSF.

A critical step in this process is the development of DSF models which need to be incorporated into the Generation Scheduling (GS) problem to obtain a reliable quantification study. This chapter also describes the development of two different models for representing DSF. These models are used in the methodology developed to determine the value of the DSF in systems with large WP.

Case studies with the purpose of calculating the economic and environmental benefits of DSF and identifying which system parameters drive this value complete the chapter. Finally a comparative study between DSF, storage and fast plant is performed which is used to identify the conditions where the demand side represents a better option for providing flexibility and how this compares with competing technologies.

6.2 Potential of Using Flexibility from the Demand Side

Demand side management[54] (DSM) initiatives have been used to provide Demand side flexibility[55] (DSF) to support the power system operation and development, since the 1940s in Central Europe, and experienced a particularly strong interest in the United States in the 1980s [69, 101]. Such flexibility can be obtained from programs direct load control (DLC)[56] and/or market incentives to encourage demand side participation[57] (DSP).

In spite of the clear potential benefits of sharing the task of providing flexibility between supply and demand, until now DSF has not experienced a large scale use. This can be explained partly because, without the right amount of information on the demand side, the consequences of disturbing demand's natural diversity can be damaging to the system. The risk of disturbing the diversity of demand is related to the payback[58] effect produced when the operation of a group of loads is interrupted for a period of time and subsequently reinstated. This phenomenon is illustrated in Figure 6.1 using data collected for a group of water heaters in a study described in [108]. In this example the payback phenomenon represents the sudden increase in demand when the heaters are re-connected to reinstate the water temperature. The spike is the result of the fact that most water heaters work simultaneously when reconnected. This type of behaviour limits the potential of DSM programs deployment since without a "smarter" load control the payback spikes generate problems to the system.

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[54] Demand side management is a traditional definition that has been superseded by demand side integration. Still used where controlling body is managing the load (in those countries where electricity industry is still vertically integrated.

[55] Demand side flexibility is defined in this thesis as the total flexibility that can be obtained by influencing system demand to support system operation and planning, electricity markets functioning and the integration of renewable generation. This flexibility is considered to be obtained through demand side management (DSM) actions/programs.

[56] Strategies where customer loads are externally controlled. End-users are provided with the required hardware and communication infrastructure to allow direct load control. In DLC programs customers' load is interrupted by remotely shutting down or cycling consumers' electrical appliances such as air conditioners and water heaters.

[57] Demand side participation composed by a set of strategies used in a competitive electricity market by end-use customers to contribute to the economic, system security and environmental benefit.

[58] Payback corresponds to the increase in peak power demand due to power restoration of controlled loads that appears in the period immediately after reconnecting to the system loads that were disconnected. This phenomenon is mainly related with thermostatic loads and is a function of the time of disconnection and load characteristics.

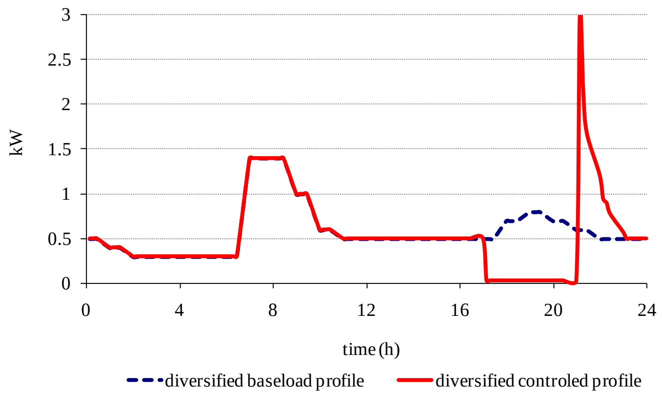


Figure 6.1 Payback effect after load reconnection

Recent developments of information and communication technology (ICT) available to support power systems operation and control will enable a "smarter" communication with the consumer that may change the level of control over the demand. In addition recent government decisions and regulatory changes, such as the decision for domestic smart meters roll-out in the UK [102], and the interest in developing smart-grids will dramatically change the level of communication with consumers.

This is seen as an opportunity to integrate the demand side into the overall system and network operation [103]. Demand can become an important source of flexibility that can be accessed through well designed programs and the widespread deployment of "smart" loads such as smart white goods, electric vehicles and heat pumps. Examples where this potential has already been accessed can be found in [58, 60, 71-74, 75, 104, 105], as described in Chapter 2. These studies however, have not fully quantified the contribution of DSF to flexibility in systems with large WP since its contribution to balancing services to deal with wind uncertainty has not yet been investigated. In this work an approach to perform such quantitative studies is presented.

6.3 Approach to Quantify the Value of Demand Side Flexibility

As highlight previously, DSF can be thought of as a form of storage. Demand side flexibility, however, has operational constraints distinctive to storage. Consequently, specific studies are required to quantify its value. For this purpose, a dedicated approach is developed to quantify the value of DSF.

The general structure of the methodology is represented in Chapter 5 in Figure 5.2. The approach for the quantification of the value of storage, described in the same chapter, is modified to consider the particular characteristics of DSF. The following discussion describes the modifications of the methodology performed to include DSF.

In a similar way to storage, DSF cannot provide the exactly the same type of flexibility of a generator, since the power reduced/increase and duration of the periods of demand reduction/increase are limited by available controllable demand. To quantify the contribution of DSF to standing reserve a purely deterministic approach, as the one used in Chapter 4, is not suitable since the utilisation of reserve is not modelled. Consequently a semi-deterministic approach, able to model reserve scheduling and deployment is used for the quantification of the value of both Storage and DSF.

As described in Chapter 5 the optimisation is performed in two steps. Step 1 of the optimisation performs a security constrained unit commitment (SCUC) that schedules enough generation to supply demand for every hour of the year, based on a forecasted net demand profile and schedules reserve to handle imbalances caused by wind forecast errors[59]. Step 2 performs an economic dispatch at electricity delivery time, for realised net demand. This second step allocates the hourly power output necessary to meet realised net demand among the scheduled generators and DSF control actions. This step adjusts the output of the generators already committed, including the need for curtailing wind, to meet the realised net demand.

Part of the operational reserve can be provided by standing plant or DSF. The contribution of DSF to reserve is done by modifying demand according to a need for upward or downward reserve. In the first case demand reduction signals are sent to controllable load so that the required amount of demand reduction is obtained. Downward reserve is provided by sending signals to controllable devices that are waiting to be reconnected to obtain the required demand increase. This corresponds to the utilisation of the standing reserve provided by DSF.

As described in Chapter 5 the link between Step 1 and Step 2 corresponds to the change in system conditions between the period when SCUC decisions are taken and electricity delivery time change due to uncertainty in generation and demand. Considering that this work aims at quantifying the value of DSF to provide part of the flexibility required to cope with the additional balancing requirements posed by wind uncertainty, the reserve requirements are set using wind forecast error only, using the equivalent risk fit approximation described in Chapter 3. The approach is, however, general enough to consider all sources of uncertainty but this would require the simulation of demand forecast imbalances and more importantly of generation outages.

[59] Different wind forecast lead times can be considered to characterise the distribution of the uncertainty of wind to set the required reserve levels. In this work a four hours lead time is assumed considering that this is the estimated time to start a combined cycle gas turbine (CCGT). This means that for periods from 4 hours ahead no more decisions regarding synchronising new units can be taken consequently the imbalances between forecasted and realised generation and demand need to be covered by re-dispatching already committed generators or using alternative sources such as fast plant, storage and DSF.

The wind imbalances, between the time when wind is forecasted and electricity delivery time have a stochastic nature. To model these imbalances and thus simulate the utilisation of reserve the stochastic process described in Chapter 5 is used.

The optimisation problem is then composed by a set of loops in which SR contribution is reduced and replaced by StR provided from DSF, storage or fast plant. The iterative process stops when the minimum system operation cost, as a function of SR/StR split, is reached. This means that there is no economic interest in increasing StR any further.

Model input data

The data is the same as the one used for the valuation of storage with the exception of the DSF data that depends on the type of model used and devices studied. This will be detailed in the following sections.

Model Outputs

The simulation model is run for a time horizon of one year and the outputs obtained are similar to the ones of Chapter 5. In addition, outputs related to DSF are also obtained. The make-up of additional outputs will depend on the type of demand side modelling used.

On the quantification of the contribution of DSF to standing reserve

The quantification of the optimum combination of SR and StR, when DSF is involved is not straightforward and the specific characteristics and limitations of this technology need to be carefully represented. This was discussed in the previous chapter for the example of storage. Considering that the broad question is the same and to avoid unnecessary repetition we will illustrate this, using the same example presented for storage.

It was shown that the amount of energy available in store changes if reserve is called upon. Consequently a purely deterministic model would over-estimate the contribution of storage and there would be a risk of not having sufficient reserve.

DSF is similar to storage, since it is based on the principle that electricity is stored at consumer premises in the form of, for example hot water or dirty clothes. The energy available is this type of storage will depend on how much of the controllable load was utilised is the previous time steps. Once a device is controlled it is not available for control until it reached its original state (for example water is hot again or there is another load of washing to do). As a consequence, to quantify the contribution of DSF to system flexibility, the deployment of demand side control action needs to be simulated over the whole optimisation period.

This time-sequential methodology is used to quantify the value of DSF. In addition, a detailed model of the demand side, taking into account realistic devices and its operation constraints need to be included in the generation scheduling model. Developing such model is not a trivial question and significant research effort is put on its development.

6.4 Modelling Demand Side Flexibility

Existing load scheduling models have already been described in published literature. These differ mostly in the level of detail put on the representation of loads and the type of loads they can be applied to. Among these three models, presented in [106-108], are chosen as the most representative of such research efforts. These models differ mostly regarding the level of optimisation of DSM actions obtained which partly reflects the level of communication required for its implementation.

For instance, the model presented in [106] by Lee does not optimise the start up time of each control scheme[60] (CS), which is an input of the model, but instead optimises the number of devices allocated to each of them. This model is mostly suitable for thermal load and has the ability of reducing the payback effect. The model presented in [107] by Kurucz builds on the previous one and is able to optimise both the start time and the number of devices allocated to each CS. Again, the main purpose is to avoid the payback effect and is suitable for thermal loads. The first two models do not require a sophisticated communication infrastructure since it requires only a unidirectional signal to be sent to the participating appliances. More recently, models such as described by Cobelo in [108, 109] permit the individual or grouped scheduling of appliances considering operation constraints for individual or groups of devices. In contrast to the other models, the practical implementation of such model requires bidirectional communication with the devices.

To understand the importance of the level of optimisation of the control actions in the different models, a simple example, taken from a study presented by Stanojevic in [110], based on a peak shaving application, is used. The data used for this study is presented in Appendix E. Figure 6.2 shows the results obtained by the above mentioned study. From these results it is possible to see that greater levels of optimisation lead to better results. All models achieved a reduction of the peak but Cobelo's model obtains a better load redistribution.

[60] A control scheme represents the control strategy applied to a specific device (or group of devices). This defines time and duration of interruption of service, as well as dynamic of energy recovery pattern.

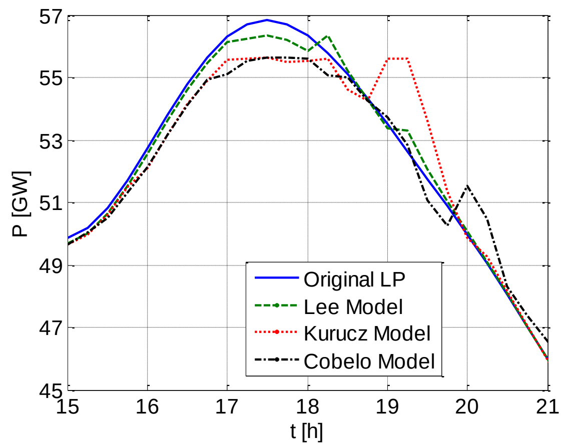


Figure 6.2 Comparative performance of different DSF models - peak shaving application

This example shows the importance of using detailed models, able to schedule devices in a similar fashion to generation. This, however, implies a need for detailed input data and leads to larger computational times since the individual device scheduling adds extra decision variables to the problem. Consequently, the selection of the most suitable model should be done according to the objective of the study. In this work two different models are used:

- The model developed by Lee, is used to perform a set of high level studies to obtain trends and orders of estimate of the value of controllable aggregated thermal loads, a process designated as aggregated thermal demand scheduling;
- The model developed by Cobelo is used to quantify the value of smart appliances. This choice is justified because the quantification of the value of a specific technology requires detailed representation of appliance characteristics such as electricity demand and flexibility levels. In addition, better results can be obtained if the scheduling of DSF is done at the level of individual appliance, or groups of similar appliances with the same flexibility;

The mathematical formulations of the two models are presented as follows.

6.4.1 Aggregated thermal demand scheduling model

The DSF model used for aggregated thermal demand scheduling is based on the one presented in [106] where a case study of water heater direct control is detailed. The model is based on the optimisation of the number of devices controlled by a control scheme, which defines the time and duration of the control actions inputs to the model. This model is described by equations 6.1 to 6.3. Equation 6.1 shows that the modification of the system wide demand is obtained by DSM actions corresponds to the original demand profile added to the total change in demand at each hour. This change is represented by $d_t^{controled}$ and will be negative is the aggregated change in demand is dominated by load reduction and positive if the aggregated change is dominated by load recovery.

$$d_t^{DSM} = d_t + d_t^{controled} \quad 6.1$$

$$d_t^{controled} = \sum_{j=1}^{M} A_j^t \, dev_j \qquad where\ \lambda_j \geq 0 \quad 6.2$$

$$\sum_{j=i}^{M} dev_j \leq N^{dev} \quad 6.3$$

The aggregated changes in demand are obtained by multiplying the optimum number of devices, A_j^t , by each CS. The number of devices is set by the optimisation so that the optimal demand changes are obtained. Figure 6.3 presents an example of how these CS are formed. In the x axes are the CS which vary from 1 to k and in the y axes are the time periods of the optimisation horizon (for daily optimisation these go from hour 1 to 24). For each CS the black colour areas denote the time periods where the load is disconnected from power supply, and grey areas denote payback periods. The white areas represent the periods when demand flexibility is not available.

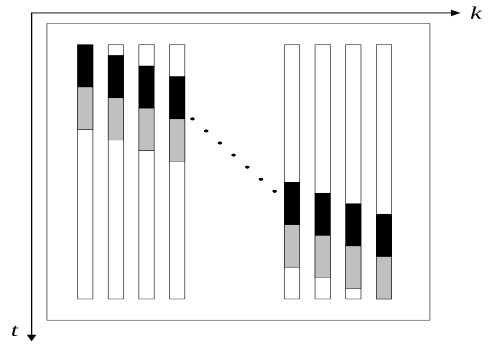


Figure 6.3 Example of a set of control schemes

The principle of the model is that the use of each CS is scheduled by allocating an optimum number of controlled devices to each one of them. The overlapping effect of these CS permits obtaining the desired modification of the demand profile. This effect is shown in Figure 6.4 where two control schemes (control scheme A and control scheme B) are added. CS A is activated at first time step and involves a reduction of 1 unit of load during two time periods. CS is initiated at the second time period also involving 1 unit of load reduction during two time periods. The addictive effect of these CS, which is shown as the most right-hand side chart in the figure and results in a reduction of 2 units of load at the second time period which represents a more pronounced load reduction obtained by overlapping two CS. At the third time period, the first control scheme starts its payback of 0.5 unit of load. Simultaneously there is 1 unit of load reduction from CS B. This overlap results in half of unit of load disconnected which is lower that the reduction obtained by a single CS. The total power reduction of each individual CS is of 4 units but due to the overlap of load reduction of control scheme B and load recovery of CS A a net reduction of 3.5 units of power demand is obtained. This shows how the total demand reduction and recovery viewed from the system is obtained. The total energy reduced and recovered for each total scheme, however, is the same, unless some “efficiency loss” driven by DSM actions is considered.

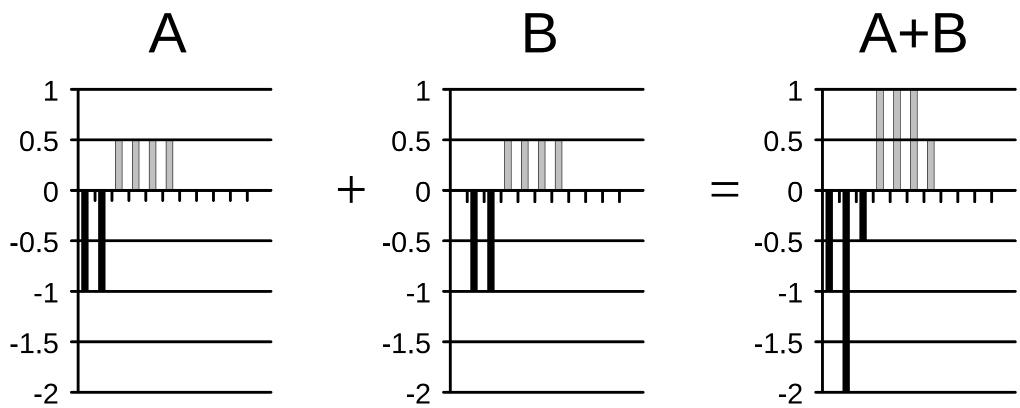


Figure 6.4 Effect of overlapping two control schemes

The system wide modified load profile, obtained by the optimization, for each hour of the day, is such that the objective function is minimized while meeting all the problem constraints.

The fact that the control schemes are defined as inputs to the optimization reduces the flexibility of demand re-shaping. This is the major drawback of the model which results in the more limited performance in terms of peak reduction shown in Figure 6.2. The model, however, presents significant advantages in terms of simplicity of implementation and reduction of computational times which makes it suitable for high level studies to estimate the value of DSF.

6.4.2 Individual load scheduling model

If the value of specific technology is to be investigated individual load scheduling based on a more detailed representation of devices is required. In this work an algorithm for scheduling individual devices or groups of similar devices is used. Its main advantage is the possibility of optimising both the number of devices to be controlled at each time step *t* and optimum time device operation time step within a set of consumer usage patterns and constraints. These constraints define the flexibility allowed for device control, energy demand per operation cycle and operation patterns in terms of time of the day in which the device is available for control. To set these constraints a quite extensive set of data is required, including:

- The demand profile of each device per operation cycle;

- The expected number of devices to be connected at each optimisation time interval t;
- The first possible time step s_{hk} where an appliance of type k, starting consumption at time step h, can be shifted to. Attention must be paid to the fact that the operating cycle does not fall beyond the maximum delay in appliance operation accepted by the consumer. If it is not given explicitly as an input data, for each type of devices starting their consumption at time step h, this first possible time step is considered to be $s_{hk} = h + 1$.
- The number w_{hk} of successive time steps (starting from s_{hk} determined previously) which are also possible connection times. This number is determined by taking into account the fact that the operating cycle must not fall beyond the time horizon, and it must not last longer than the maximum allowed shifting time for that type of device. This is described by equation 6.4. where index k denotes type of appliance, and h is the time step when the appliance cycle starts.

- $$w_{hk} = min(T_h - s_{hk} - d_k + 1, delay_k^{max} - 1) \qquad 6.4$$

This data is used by the equations that determine the total shifted power Pd_c^t corresponding to the power consumed by devices that are shifted from time t. These equations include two terms:

- The decrease in the load at time step t due to shifting devices that were originally expected to start their consumption at time step t;
- The decrease in the load at time step t due to the cycles of devices that were originally supposed to start their consumption at the time steps before t and were shifted to later periods;

Mathematically, it can be described by equation 6.5.

$$d_t^c = \sum_{k=1}^{\mathrm{L_{type}}} \sum_{f,f>t}^{\mathrm{T}} X_{fkt} \quad p_{1k} + \sum_{k=1}^{\mathrm{L_{type}}} \sum_{\substack{f=1 \\ 0<t-l<f}}^{n} \sum_{l=1}^{d_k-1} X_{(t-l)fk} \cdot p_{(l+1)k} \qquad 6.5$$

Similar expression can be written for power Pd_p^t that represents the increase in demand when the shifted devices then start their operation. This is described by equation 6.6.

$$d_t^p = \sum_{k=1}^{\mathrm{L_{type}}} \sum_{\substack{h \\ h<t}}^{\mathrm{T}} X_{hkt} \quad \cdot p_{1k} + \sum_{k=1}^{\mathrm{L_{type}}} \sum_{\substack{h=1 \\ h<t-l}}^{\mathrm{T}} \sum_{l=1}^{d_k-1} X_{h(t-l)k} p_{(l+1)k} \qquad 6.6$$

Equations 6.5 and 6.6 define the total demand reduced and recovered (payback), respectively that make-up the total DSF. The determination of demand reduced and recovered is constrained by the following set of constraints,

$$X_{hfk} \geq 0 \tag{6.7}$$

where X_{hfk} is an integer number (this is a number of devices of type k, shifted from time step h to time step f).

The devices cannot be moved back in time. To avoid this, a controllability constraint represented by equation 6.8 is added.

$$X_{hfk} = 0 \text{ if } \begin{cases} f < h \\ f < s_{hk} \\ f > s_{hk} + w_{hk} \end{cases} \tag{6.8}$$

The first constraint ($f < h$) allows shifting only forward (to future time periods), the second constraint considers control possibilities of the algorithm (s_{hk} is the first possible time step where the devices can be shifted to) and the third constraint takes into account the fact that the operating cycle of devices must finish within allowed time for shifting and also within the controllability time horizon, whichever expires first (see also equation 6.4).

Finally, at each time step h, the total number of devices of type k that are shifted cannot be higher than the number of devices D_{hk} available to be shifted at time step h as shown in equation 6.9.

$$D_{hk} \geq \sum_{f}^{\mathbf{T}} X_{hfk} \tag{6.9}$$

The above mentioned algorithm will calculate the optimal number of devices shifted from time step h to time step f, for each device type, preserving the maximum shifting time accepted by consumer.

Finally, the controlled demand profile d_t^{DSM} is given by the system wide demand profile, less demand reduced (shifted) plus demand increase (recovery) at a given period t as described in equation

$$d_t^{DSM} = d_t - d_t^c + d_t^p \tag{6.10}$$

The models described above need to be incorporated into a larger system scheduling tool to permit the overall optimisation of system operation taking into account flexibility both from supply and demand side.

6.4.3 Incorporating the demand side models to the system scheduling algorithm

The scheduling model presented in Chapter 5 is modified to include the DSF constraints presented in the previous section. The objective function remains the same as the one presented in equation 5.2, as do all generation and reserve constraints. A new demand balance equation is used to incorporate DSF.

Demand balance for the aggregated thermal demand scheduling

Equation 5.3 represents the demand balance constraint for realised net demand.

$$\sum_{ic=1}^{N_{GC}} p_{ic,t} + w_t^a + S_t^d + p_t^{fast\_plant} = d_t^a + d_t^{controled} - l_t^{a,shed} + e_t^{a,over} + S_t^c + w_t^{a,c} \tag{6.11}$$

$p_{ic,t}$ is the total output for unit ic across all segments. The meaning of variables l_t^{shed} and e_t^{over} is the same as before and they represent the lack and surplus of energy in the demand-generation balance, respectively. During this step, besides generation and electricity storage, the demand side also provides flexibility to meet the generation/demand balance. This is done by modifying demand by the amount $d_t^{controled}$ which is negative during load reduction and positive during payback periods. The value of $d_t^{controled}$ is determined by adding into the overall system scheduling the set of constraints represented by equations 6.2 and 6.3.

Demand balance for the individual load shifting algorithm

In this case, the demand balance constraint is represented by equation 6.12.

$$\sum_{ic=1}^{N_{GC}} p_{ic,t} + w_t^a + S_t^d + p_t^{fast\_plant} + d_t^c = d_t^a + d_t^p - l_t^{a,shed} + e_t^{a,over} + S_t^c + w_t^{a,c} \tag{6.12}$$

The main difference is that the demand side flexibility is represented by two decision variables: demand reduction d_t^c obtained by shifting load (equivalent to increasing generation); demand increase d_t^p (equivalent to reducing generation by reconnecting or starting the previously shifted load). The values of d_t^c and d_t^p are constrained by the set of equations 6.4 to 6.9 that described the DSM model.

Besides the modification of the system scheduling model, additional changes are required to optimise the use of DSM actions on a daily basis, as explained in the following section.

6.4.4 Day-ahead optimisation of DSM actions

The value of DSF algorithm is quantified through annual system operation simulation. However, due to the daily patterns of usage of domestic loads, the system scheduling needs to be done on a daily basis. This means that to obtain the optimum scheduling of DSM actions the optimisation needs to be performed so that the first periods of the following day can be considered.

The importance of this consideration is described as follows. Let us consider a time horizon of NT time steps. For the example of an optimization period of one day and hourly time steps, NT corresponds to 24 time steps. If the goal of the optimization is to reduce the operation cost, such as in the UC problem, the DSM algorithm reduces the maximum possible demand in the last time steps of the optimization horizon. If the algorithm is not designed to prevent this the energy reduced at the last periods of the day is not recovered. Consequently an artificial reduction of the operation cost is obtained by reducing the overall system demand. This represents the negative effect of a badly designed algorithm as shown in Figure 6.5. This can be avoided by adding a constraint that ensures that the total reduced energy during the period in question (24 h in this case) must be equal to the total energy recovered. This solution, however, leads to suboptimal results because all energy needs to be recovered before the last time period since the following day is not "visible" in the daily optimisation.

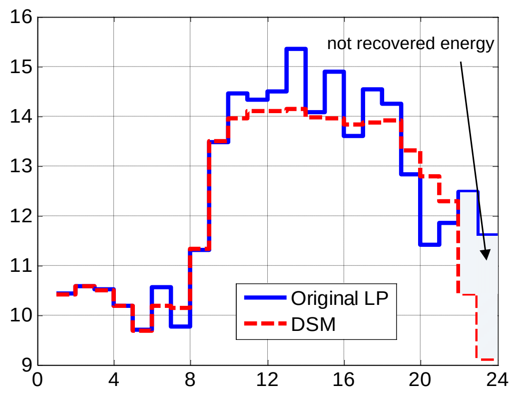


Figure 6.5 DSM with no day-to-day link: the maximum energy is reduce and the end of the day and not paid back

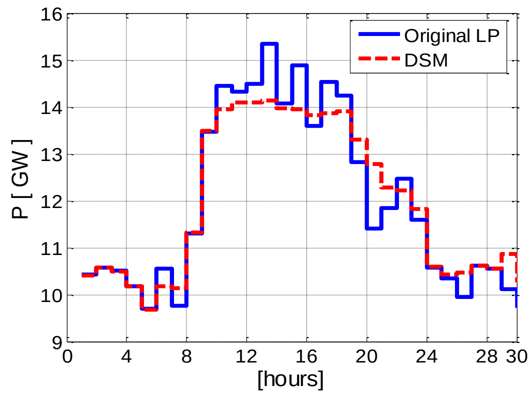


Figure 6.6 Approach of day-to-day link using an expanded optimization time horizon

To overcome this problem, in this work, the optimization horizon is expanded by a number of time steps, equivalent to the longest consumption pattern among the different types of devices or groups of devices. This expansion, however, could be further enlarged for any number of time steps, however, this implies an increase of the number of optimisation periods and consequently of computational time. For example, if there are several types of appliances of which the longest duration pattern lasts 6 hours, then the original optimization period of 24h (T_o) is expanded by 6 hours (T_e) becoming 30h (T_h): $T_h = T_o + T_e$. The only limitation imposed is that devices have to finish their payback within this 30h horizon. This permits obtaining the optimal solution at the end of period 24. Considering that all the devices must finish their full load recovery within the horizon of 30h all energy is recovered. This principle is shown Figure 6.6. The various appliances of different types can be shifted in each time step between 1 and T_e. The power of the appliances shifted within original time horizon T_o that do not finish their consumption before the end of T_o is taken into account by being added (subtracted) to the load profile of the following day. In this way, the demand of the appliances shifted beyond the last period of the day, are taken into account in the following day. This procedure permits the identification of the optimal daily demand scheduling.

The system scheduling algorithm is a mixed integer linear programming (MILP) problem solved using the Dash Xpress optimization tool [111]. The approach and the system scheduling algorithm tool described above are applied to first a set of case studies to quantify the value of an aggregated load providing DSF. This is followed by a second set of case studies to quantify the value of smart domestic appliances.

6.5 Value of Demand Side Flexibility from a Generic Thermal Device

Similarly to what was done for storage, the quantification of the value of DSF is performed using a cost avoidance criteria based on the difference between the results obtained for a scenario where all reserve is provided by synchronized conventional plant (only SR) and a scenario where part of the reserve is provided by DSF (SR and StR mix). The amount of upward reserve provided by DSF at each time step corresponds to the aggregated power of all devices available for control. Instead, the amount of downward reserve from DSF, at each time step, corresponds to the aggregated power of the devices waiting to be re-connected to the system. In this way DSF compensates wind forecast imbalances by increasing/decreasing the total system demand. In both cases, the total reserve requirements are driven by wind uncertainty, allowing the case study to highlight the value of DSF to reduce the impact of wind uncertainty.

In this section a set of studies to quantify the value of DSF are presented. These studies include:

- a scenario with 25 % WP and different DSF capacity;
- a set of sensitivity studies to both CS design and WP.

This first study intends to provide an estimate of the value of DSF obtained using a generic device in order to clarify the potential of resorting to flexibility from both the supply and demand side. The use of different generation mixes permits assessing how DSF value changes with generation flexibility.

The sensitivity analysis performed looks at the variation of the results obtained by the first study when more aggressive or smoother load recovery patterns are used. This parameter is selected since the load recovery pattern, designated as payback, plays an important role on the benefits of DSF. Another sensitivity study, with respect to the WP, is performed. Considering that the key objective of the thesis is to understand the value of flexibility in systems with large WP, it is important to understand the variation of the value of DSF for different WP.

These studies are performed using the same wind and demand data of Chapter 5. A system with a similar size to the UK is used, with a total of 82 GW of conventional generation installed capacity, a peak demand of 57 GW, a minimum demand of 26 GW and an annual energy consumption of 323.2 TWh. The generation mixes are described in Table 5.2 and the generation parameters in Table D.1. These are characterised by different levels of operation flexibility: Low Flexibility (LF), Medium Flexibility (MF) and High Flexibility (HF).

The value of DSF is captured using the following metrics:

- reduction of operation cost in % of annual operation cost;
- capitalised value per kW of flexible demand;
- reduction in CO_2 emissions in tonnes/kW of controllable demand;
- reduction of wind curtailed in % of annual wind available energy;

This reduction corresponds to the difference between a base case without DSF, where reserve is all provided by synchronised plant (all SR), and a scenario where DSF contributes to standing reserve and load-shaping.

Representation of flexible demand

Considering the large diversity of loads available in the consumer side, and the particular characteristics of these, to perform a high level assessment of the value of DSF a generic device designated by 1 kW-DSM-DEV is used. Such device can, in reality, be composed of a set of aggregated thermal loads or a large thermal load that can offer 1 kW of flexibility to the system. This controllable load can be provided by either a household or a group of households, throughout the 24 h of a day. This is based on the assumption that it would be possible to aggregate different types of thermal loads such that 1 kW of demand is available for control during the full daily optimisation horizon.

This seems to be an optimistic assumption however, if proper scheduling of a portfolio of loads, performed at a level between the system operator and the consumer this consistent level of DSF could be obtained.

The representation of the baseline and two possible controlled demand profiles of the 1 kW-DSM-DEV are presented in Figure 6.7. This device, when disconnected during 3 hours leads to a reduction of 1 kW per hour that corresponds to 3 kWh of energy reduced. This period is followed by demand recovery. When re-connected to the system, the device, recovers its original state in 1 hour, for controlled profile 1, and 3 hours for controlled profile 2. In both controlled profiles the 3 kWh are recovered such that a demand increase of 3 kW that lasts for 1 h is observed for controlled profile 1 and an increase of 1 kW for 3 h is observed for controlled profile 2. These increases are obtained in comparison to the device baseline demand. The key difference between the two profiles is that the demand recovery for controlled profile 1 leads to a more pronounced payback effect.

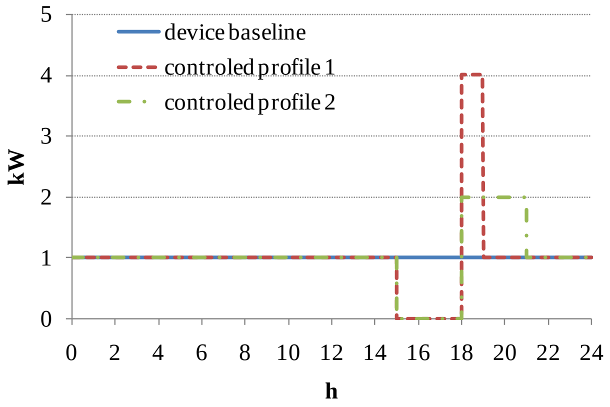


Figure 6.7 Example of baseline and controlled profiles of a 1 kW-DEV load

The total controllable load is represented by the number of 1 kW-DEV with the characteristics described. The distribution of the DSM actions throughout the day is represented by a set of CS which defines the time step and duration of the load reduction and load recovery periods.

6.5.1 Value of DSF for 25 % wind penetration

In this study the value of DSF considering 25 % WP (corresponds to 26 GW wind installed capacity) and the three scenarios of generation mix flexibility is quantified in terms of a reduction of wind curtailed; carbon emissions and operation costs. In addition, the capitalised value of each 1 kW-DEV is presented.

DSF is obtained by controlling a set of 1 kW-DEV using twenty-four different CS. Each CS represents a possible DSM action. By considering a portfolio of twenty-four similar CS shifted by one hour (Figure 6.3), a constant level of flexible demand is available during the day. The device considered provides a demand reduction lasting 3 h and demand recovery with the same duration. This means that the device is disconnected for 3 hours and once reconnected it takes the same time to return to the baseline demand. The CS used to control this device (or a group of devices) defines the optimisation time steps in which the baseline demand is modified. A smaller or larger change in the load, obtained using a specific CS, is determined by allocating to this CS a smaller or larger number of devices. A smoother or more pronounced change in demand is obtained though the allocation of devices through the different CS. This allocation is defined by the system scheduling algorithm such that the overall system operation cost is minimised.

For example, if the algorithm allocates 500 000 devices with controlled profile 1 to the CS that starts at the beginning of the day a reduction of 0.5 GWh of demand from hour 0 to hour 3 and an increase of 0.5 GWh from hour 3 to hour 6 is obtained.

The DSF penetration levels are obtained assuming a different numbers of controllable devices. Depending on the penetration of controllable devices different combinations of SR and StR are used to make up total reserve. Assuming that DSF provides an amount of StR on a MW per MW basis, the split used is presented in Table 6.1.

Table 6.1 SR and StR mix for different DSF penetration

Total reserve requirement (MW)	SR (MW)	DSF contribution to StR (MW)
8451.1	6036.45	1500 (1.5 million devices)
8451.1	5553.534	2500 (2.5 million devices)
8451.1	4829.16	3500 (3.5 million devices)

Note that overall reserve requirement for 25 % WP is calculated using the equivalent risk fit approach proposed in Chapter 3 and considering WG as the sole source of uncertainty to isolate the value of DSF to reduce the cost of balancing wind. Using the reserve mix described, the value of DSF is determined.

The results obtained for operation cost reduction and capitalised values of DSF are presented in Figure 6.8 and Figure 6.9, respectively. The overall annual operation cost savings for the LF are 1.5 times higher than the ones obtained for the MF and nearly 5 times higher when compared to the HF generation mixes. The savings obtained increase with DSF capacity. These results indicate that the value of DSF depends on the flexibility of the generation mix and are significantly higher for low flexible mixes. Similarly to what was observed for storage, in a flexible system a lower value is allocated to additional sources of flexibility, since the system generation is naturally able of accommodating net demand variability and uncertainty. The benefits, for the HF system, however, are not zero since reducing the need for part-loaded plant reduces conventional plant part load efficiency losses[61] and consequently reduces operation costs.

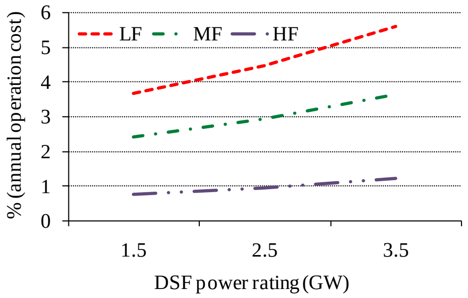


Figure 6.8 Reduction in fuel cost obtained using DSF for 25 % WP

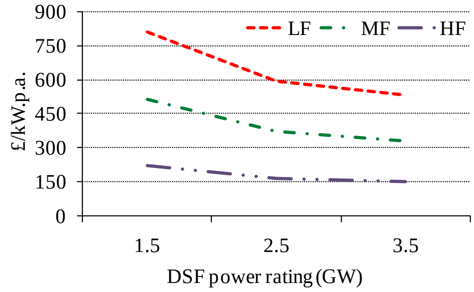


Figure 6.9 Capitalised value per kW of DSF capacity for 25 % WP

This operation cost savings are translated into capitalized value of each 1kW-DEV, expressed in £/kW (which in this case is the same as £/device using a present worth method). This is done using equation 5.13 and replacing storage installed capacity for DSF available power, and assuming an interest rate of 10% over a time horizon of 20 years[62]. The results indicate that the capitalised value of each device or kW of DSF is significantly higher for the LF system. This value reaches nearly 800 £/kW. The value obtained for the MF and HF system are lower with around 500 £/kW for the MF system and 200 £/kW for the HF system. The main implication of these results is that in system with flexible generation mix, the value of DSF is very modest, consequently is would be hard to justify the investment is such technology, unless the value of additional services can be added. Regarding the evolution of this value for increasing capacity of DSF it was shown that the capitalised value decreases because even though higher cost savings are obtained when DSF capacity is increased, the gradient of increase of the cost reduction is lower that the increase in the number of devices. The first device that provides DSF is the one with the highest value and the value decreases from there onwards. As a consequence, to design a profitable DSF program the number of participating devices needs to be carefully defined and a mass market deployment of controllable devices reduces the individual benefit of

[61] Note that, as said earlier, having a thermal plant producing with different loading levels changes its fuel efficiency and consequently the carbon emissions emitted. This means that if we have the same amount of power produced by a fully loaded plant or two part loaded loads to different emissions per kWh, being this higher in the second case. Consequently if less plant is part loaded to produce the same aggregated output the total emissions are lower.

[62] This can be seen as an excessively long time horizon considering that the expected life cycle of the appliances may be low. This can, however, be used as an indicator since it is likely that the main investment will be done only once and lower costs adaptations will be done in shorter term. In addition this assumption permits a direct comparison with the value of storage.

each one of them. The optimal size of the program would in principle be the one that leads to a £/kW of capacity that is sufficient to justify the investment.

This value can be used as an indicator of the economic viability of investing in DSF programs and associated infrastructures. If several devices need to be aggregated to provide 1 kW of controllable load this value needs to then be distributed by the total number of devices. In such case, the individual value of devices is further reduced. If the value needs to be distributed by a large number of devices, a low value-per-device again is obtained and the economic interest of DSF may be low. As a result, devices that are able to provide a higher and more constant level of DSF, such as large thermal loads (for example heat pumps and large water heaters) have a higher potential.

The value of DSF can be expressed in terms of reduction of CO_2 emissions. This is shown in Figure 6.10 for the three different levels of generation flexibility. The figure shows that higher savings are obtained in the LF generation mix comparing to the more flexible mixes. As for storage, the savings are driven by the increase in wind energy used and the reduction of part load efficiency losses. Figure 6.11 confirms these trends by showing an increase in wind used that is significantly higher for the LF system. No increase is obtained for the HF system because the system has sufficient flexibility to accommodate the 25 % WP.

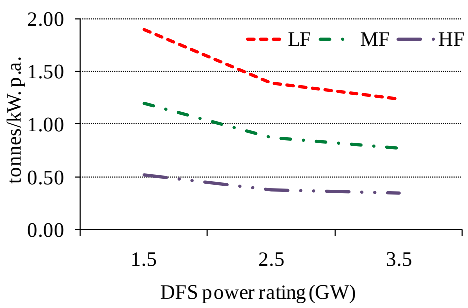


Figure 6.10 Reduction of CO_2 emissions per kW of DSF capacity for 25 % WP

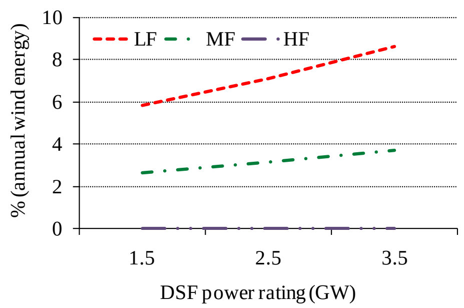


Figure 6.11 Reduction of wind curtailed obtained using DSF for 25% WP

When available DSF power is increased, the benefits in terms of CO_2 emissions and wind used increase, following similar trends. It is important to note that CO_2 emissions for the HF system, with no wind curtailment, are also reduced due to the efficiency losses avoided by having less part-loaded plant, although to a lower extent. Nonetheless this represents an environmental benefit.

This study has shown that, with 25 % WP, the value of DSF is higher for the system with LF conventional generation. There are, however, other factors that may influence this value. The study of the sensitivity of the value of DSF to several factors will permit the identification of a set of conditions under which this value is higher.

Sensitivity to demand control strategy

The demand control strategy in terms of time step and duration of demand reduction and recovery of controlled devices is defined by the design of the CS. In the previous results, a base case set of CS with equal duration of 3 h of load reduction and load recovery. In this section the variation of the results obtained for different CS is presented. To this end, the studies for the case of 2.5 GW of DSF are repeated using two alternatives designs of CS:

- CS – Set 1: load reduction over 3 h and load recovery over1 h (pronounced recovery with payback effect);
- CS – Set 2: load reduction over 3 h and load recovery over 12 h (smooth recovery with no payback effect).

The results obtained are shown in Figure 6.12 in terms of deviation from the base case of the total system operation cost. This deviation is represented in percentage of the total operation cost obtained for the base case CS.

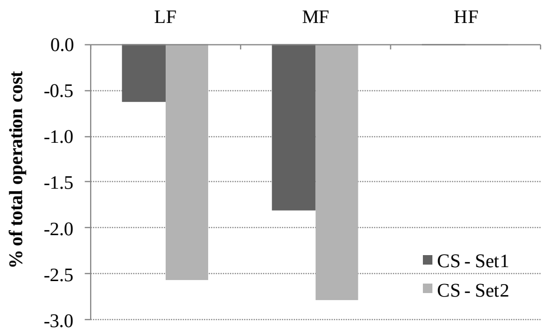


Figure 6.12 Variation of system operation cost reduction for alternative CS

For the LF and MF systems it is possible to observe that the base case design outperformed the more pronounced and smoother load recovery strategies and within the two alternatives the first lead to better results. As for the HF system, no difference was observed mostly because the role of DSF is very limited. The main implication of these results of that having a more pronounced demand recovery is better that the one that is spread over a large amount of time such that demand increase has low impact in the aggregated demand profile. This is because when DSF is used for the purpose of balancing WG demand reduction due to load disconnection and demand increase after load re-connection. In this case both demand reduction and increase have similar benefits since both lack and excess of wind can happen due to forecast errors. Regarding the set of CS with higher payback effect (CS – Set 1) it is shown that the value obtained is lower. This confirms that is there is a strong payback effect the value of DSF decreases since the benefits of load reduction do not compensate the impact of the spikes and consequently the system does not resort as often to DSM actions.

Sensitivity to wind penetration

As shown Chapters 4 the need for flexibility to accommodate WG are closely linked to its penetration level. Moreover Chapter 5 showed that the value of storage varied significantly with the WP. Considering the similarity of the application it is important to repeat this analysis for DSF. To this end a set of studies with 2.5 million 1 kW-DEV, equivalent to 2.5 GW of DSF are performed for 5, 15, 25 and 35 % WP. Figure 6.13 and Figure 6.14 show the economic value of DSF for increasing WP. From the figures it is possible to conclude that the value of DSF is highly dependent on the WP.

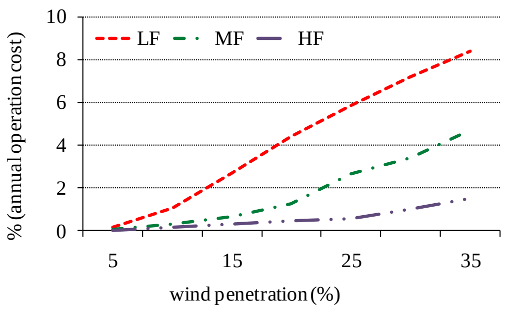


Figure 6.13 Operation cost reduction obtained using DSF for different WP

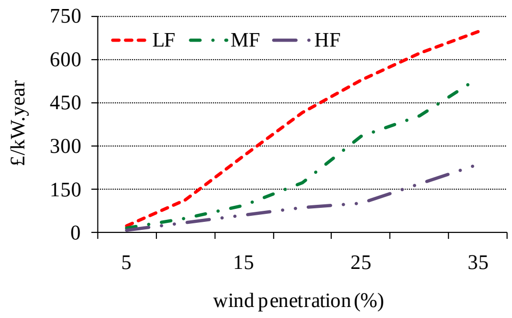


Figure 6.14 Capitalised value per kW of DSF capacity for different WP

For low penetration there is little value in using DSF for all the generation mixes. When the WP increase, the contrast in the behaviour of the different generation mixes becomes more evident and the value of DSF increases at different rates within the different systems. Again, one can see that for the HF mix DSF has limited benefits even for the higher WP. For the MF system the benefits grow at a higher rate and become more significant for WP above 25 %. For the LF system, except for low WP up about 10 % DSF when is less used, generally DSF assumes an increasingly important role for higher WP. The results show that a less flexible generation mix, when combined with medium to high WP, has a higher need for operation flexibility, consequently, places a higher value on additional sources of flexibility.

Figure 6.15 and Figure 6.16 show the contribution of DSF to the reduction of wind curtailment and CO_2 emissions, respectively. It is possible to see that these benefits change significantly with the WP levels and generation mix flexibility. For the HF system, since it is naturally able to accommodate WG until relatively high penetration, DSF does not contribute to reduce wind curtailed up to WP of 25 %. Above this there are some benefits but very low. Instead, the LF system benefits from using DSF to reduce wind curtailment for all WP considered, and the reduction of wind curtailed obtained increases significantly with the WP. The MF system, as expected, follows similar trend to the LF system but the benefits start appearing at higher penetration and are lower.

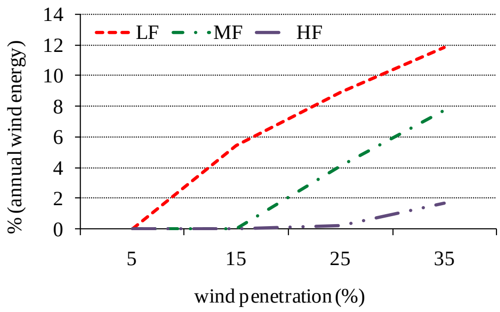


Figure 6.15 Reduction of wind curtailed obtained using DSF for different WP

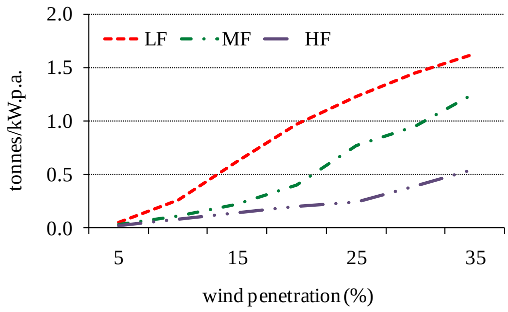


Figure 6.16 Reduction of CO_2 emissions per kW of DSF for different WP

The reduction of CO_2 emissions has been shown by previous studies be closely linked to the reduction of wind curtailed. The results obtained for the reduction per tonnes/kW of DSF, presented in Figure 6.16, confirm this and the benefits are higher for the LF system and increase with WP. There are, however, benefits for the cases where no reduction of wind curtailed is obtained which correspond to the reduction of part-load efficiency losses. These are less significant when compared to the cases where this value is also driven by a reduction of wind curtailed.

The results from this study indicate that the increasing use of WG represents an opportunity to DSF initiatives since accommodating wind requires more flexibility from the remaining system. It was shown that, if the demand side is able to contribute to flexibility by displacing part of synchronised plant providing SR by StR the system is able to use significantly more wind. This is then translated into benefits to the system in terms of a reduction of system operation cost and CO_2 emissions. These economic and environmental benefits are shown to depend significantly on the generation mix and WP levels.

DSF is not the only alternative to provide additional flexibility to accommodate wind imbalances. The previous chapter has shown that storage and fast plant can play a similar role and its value has been quantified. The following section discusses how DSF compares to these technologies.

6.5.2 Comparison of DSF with storage and fast plant

It has been shown that integrating WG uncertainty into system operation increases the need for reserve. This additional reserve increases system balancing cost and increases the overall wind integration cost. Options to mitigate this additional cost, such as fast plant, storage and DSF, by reducing the reserve requirements provided by part-loaded plant have been investigated and its economic and environmental value has been quantified. Considering that these options have different drawbacks and advantages of DSF are compared to its competing technologies represented by storage and fast plant. This is done first using a qualitative assessment of the underlying differences in terms of operation constraints between these technologies, presented in Table 6.2.

Table 6.2 Qualitative comparison of storage, fast plant and DSF applied to balance wind fluctuations

	Advantages	Drawbacks
Storage	Ability to provide upward and downward reserve Flexibility regarding charge and discharge time (if energy constraints are not binding)	Round trip efficiency losses Energy limited device Large investment costs
Fast plant	Full flexibility for providing upward reserve (limited only by its maximum power limit)	High marginal cost Is not able to provide downward reserve
Demand side flexibility	Ability to provide upward and downward regulation No (or low) efficiency losses	Highly constrained by consumer flexibility and acceptance Energy limited (available demand reduction and recovery depend on the previous use of device)

The implications the above outlined advantages/drawbacks of each technology are investigated through a quantitative analysis that compares the capitalised value of storage and fast plant in relation to DSF. The value of the different technologies is obtained using the approaches developed in Chapter 5 and in this chapter. The metric used for this comparison is the deviation of the capitalised value of storage and fast plant from the value of DSF in % of the last. The comparison includes the three generation flexibility mixes, 25 % WP and different installed capacity of each technology. Figure 6.17 presents the results obtained. The results indicate that the value of DSF is lower than the value of storage (positive difference) and higher than the value of fast plant (negative difference). The difference between storage and DSF is significantly lower than the difference between fast plant and DSF, for all generation mix flexibilities and installed capacities. This indicates that the value of DSF is closer to storage than to fast plant. Clearly, the high utilisation cost of fast plant and its inability of providing downward reserve are important drawbacks. Regarding the comparative performance between storage and DSF it is possible to see that, in spite of the efficiency losses storage is still the option with higher values. This is explained if storage is charged with wind curtailed the cost of efficiency losses becomes zero and the fact that it is not constrained by consumer flexibility and load reduction and recovery constraints. The order of magnitude of the differential between technologies changes with the installed capacity showing that the advantages/drawbacks that generate the differential are accentuated with the available capacity.

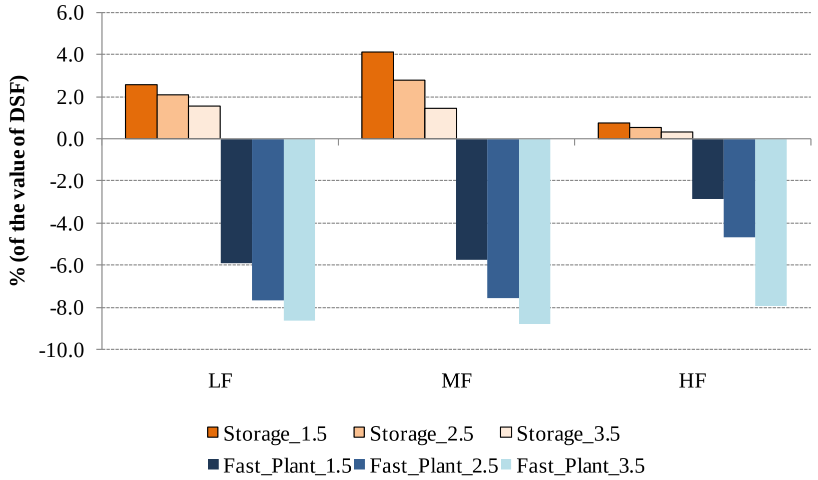


Figure 6.17 Comparative values of storage and fast plant with the value of DSF for different installed capacities and 25 % WP

Regarding the difference between generation flexibility mixes it is possible to see that it differs from case to case. Storage's advantage over DSF is more accentuated for the MF mix. This happens because for this mix the impact of DSF lower flexibility becomes more important. The results of annual system operation have shown that the fact that each device cannot be controlled until its energy balance is fully recovered became a more significant limitation for the MF system. The difference between storage and DSF and its evolution with the installed capacity are smaller for the LF and HF system. This is explained because for the LF system both technologies use mostly used when wind is curtailed, therefore the cost of efficiency losses is less important therefore storage becomes more competitive due to its higher flexibility in terms of when to charge and discharge. For the HF mix, because there is little wind curtailed the importance of storage efficiency losses is more pronounced.

A stated earlier though, adding DSF to a system cannot be achieved by simply adding a new device (as was the case for storage). Instead, it involves interacting with individual loads and consumers. The previous results showed that, while overall system value may increase, the individual value of the participating loads decreases significantly with the number of devices available to be controlled. As these results made use of a generic device, it is hard to allocate value to an individual device, yet this information is needed by consumers. The value of individual devices, of a certain type cannot be determined without using a more detailed representation of the technology. The next section addressed this question by looking at the example of smart domestic appliances.

6.6 Value Flexibility from Smart Domestic Appliances

Household appliances form a significant part of energy demand, representing around 10 % of the total annual energy demand in the UK[63]. Recent technology developments allow for their smart operation. The principle of "smart" operation is to modify appliance operation patterns according to system's needs. Hence, smart appliances can be used as sources of DSF and provide different services to the electricity system.

Today, many appliances are already equipped with delayed start time functions[64]. These could be used by consumers to change their starting times, in order to take advantage of time-of-use tariffs[65]. Smart appliances go beyond this by having more decentralised (automatic) intelligent control that may or may not involve the intervention of the consumer.

6.6.1 Smart appliance technology

Smart appliance technology consists mostly of two modifications of the existing technology:

- the more common and less expensive is to enable the appliances to communicate with external sources that will remotely control its operation using two way communication.
- more recent developments in appliance research involve prototype appliances with a larger thermal inertia that can be used as a form of electricity storage to modify the its demand per operation cycle.

These appliances are able to interact with the electricity system. Such interaction can involve receiving directions to modify their operating cycles such as shifting them over time or interrupting their operation for a limited period of time. These appliances will be comparatively more flexible than the existing ones.

The flexibility provided by different appliances depends on their operating patterns and uses. Some appliances, as refrigerators and freezers, have a nearly constant electricity demand (saw-tooth shape). Others, as water heating and space cooling/heating (air conditioning, space heating and heat pumps), are used during large periods of the day. All these possess thermal inertia. A different type, such as washing machines and dishwashers consume electricity during a fixed duration cycle (for example 2h) required to perform their task. These are typically operated once

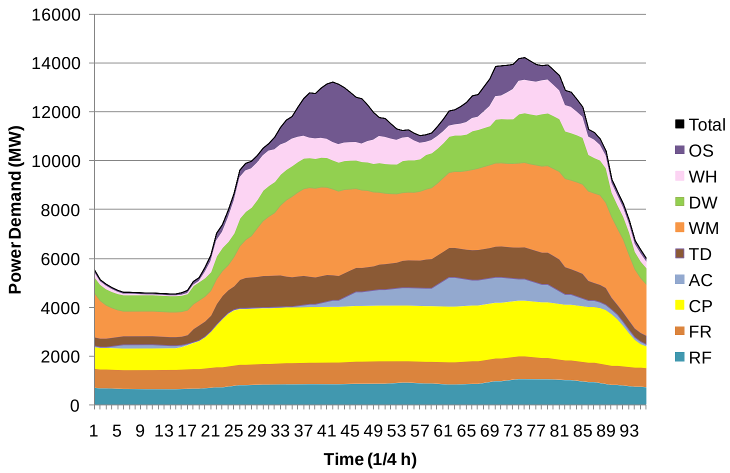
[63] Estimate obtained using the values from [112] regarding the penetration and demand of domestic appliances and the demand data from the UK.

[64] This is a function that allows the consumer to postpone the start time by a fixed time period

[65] Time of use tariffs are electricity tariffs with different pre-defined prices, for different blocks of hours. The Economy 7 in the UK is one example.

per day. The contrasting demand profiles and usage patterns mean that different types of devices provide different contributions to flexibility.

The contribution of an appliance to system flexibility depends on its placement within the daily demand profile. This contribution is higher when their operation pattern coincides with more critical operation periods such as peak demand. An estimate of the diversified daily demand of different appliances, in the UK, is presented by Stamminger [112] and is illustrated in Figure 6.18. It is possible to observe that some appliances, e.g. refrigerator and freezer, have a nearly constant demand while others, e.g. a dishwasher, have a higher demand in the evening.



WM-Washing Machine DW - Dishwasher TD-Tumble dryer RF – Refrigerator FR -Freezer

CP-circulation pump AC-Air-conditioning WH-Water-heater OS –Oven and stove

Figure 6.18 Estimate of the total demand from domestic appliances for one representative day in the UK

The aggregated system demand from domestic appliances is not insignificant reaching a peak of 14 GW. Consequently there is a potential of using this type of loads as a source of demand flexibility. Without loss of generality, this work focuses on a batch of appliances composed by dishwashers, washing machines, and washer-dryer[66] (designated as wet-appliances). These present similar characteristics regarding the type of flexibility they can provide, however, the amount of flexibility available is different during the day, depending on the usage patterns of each device. The common characteristic of such appliances is that they are operated on the basis on a single cycle of use with fixed duration, corresponding to a wash (or wash and dry) action

[66] The WD is a combination of a WM and a TD whose consumption cycle corresponds to the cycle of a WM followed by the cycle of a dryer.

that happens typically once per day[67]. The timing of usage of the device by the consumer is closely linked to living patterns, such as washing clothes in the morning/evening and using the dishwasher after lunch and/or dinner. The flexibility potential of these appliances is limited to the time and duration of the operation cycle. The methodology proposed is, however, sufficiently general to be applied to other appliances.

In order to quantify the value of these appliances information regarding "smart" options in device operation is required. Taking the example of a washing-machine, a number of smart operation options were identified in [112] which include:

- delay the start time of the washing cycle;
- interrupt the heating phase up to a certain time;
- reduce the power demand by automatically choosing a lower temperature for the programme and prolonging the washing time;
- prolong the final rinsing phase;

Considering that options 2 to 4 reduce the efficiency of the appliance per cycle and require more costly "smart" functions, option 1 is chosen for this study.

To obtain an estimate of the available capacity from a specific appliance its diversified demand profile and demand during one cycle is required. An example of this data, for the washing-machine, in the UK, is presented in Figure 6.19 and Figure 6.20, respectively.

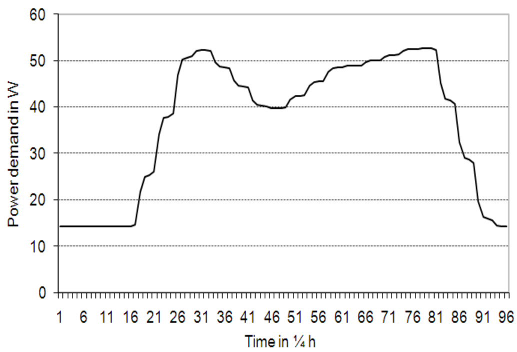


Figure 6.19 Diversified demand of a WM for a representative day in the UK

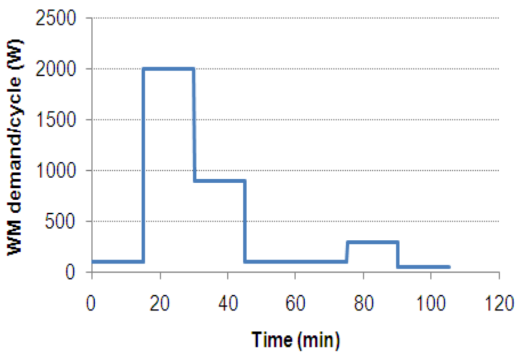


Figure 6.20 Demand per washing cycle of a WM (reference temperature of 40°)

[67] This assumption may seem optimistic since many costumers to not use the device once per day, however, considering that other costumers use it more frequently the diversity of use will smooth these differences. Based on this the assumption is considered to be suitable to obtain orders of magnitude estimates of the value of the appliances. This assumption needs to be done due to the lack of detailed data and if more data it available the same methodology can be applied.

The diversified profile represents the aggregated and normalised demand of a washing-machine as seen from the system. Figure 6.19 shows that most households use their washing machines early in the morning (around 7 am) and in the evening (around 8 pm), reflecting consumers' habits to wash their clothes before leaving to work or after returning home in the evening. The distribution of demand per washing cycle (Figure 6.20) shows that demand is larger during the water heating phase at the beginning of the cycle. A smaller demand rise can be seen in the spinning phase close to cycle completion.

6.6.2 Consumer acceptance

As indicated previously, the potential of providing DSF with smart appliances cannot be explored without consumer involvement. Even if the smart appliance technology is available, economically viable and able to bring environmental benefits, its deployment cannot be done without the engagement of the appliance end-user.

At this stage, given the limited use of DSF in the current system, potential customer involvement can be judged only through acceptance studies, such as the one carried out in the SMART-A project [113]. This study is based on quantitative and qualitative consumer research using interviews, questionnaires and focus groups and is conducted in the UK, among other countries. It is aimed at revealing to which extent consumers will allow load-shifting, including e.g. delay the start of washing cycles or intermediate interruptions of the operation of appliances. The research questions were focused on the readiness and flexibility of consumers to change their behaviour and the benefits they expect from smart appliances.

The study concludes that the acceptance level is very high and consumers have a rather positive attitude towards smart appliance technology. There will, however, always be a gap between real actions and attitudes, so these findings have to be taken with some reservation. In addition, consumers have many objections and preconditions regarding the use of smart appliances. The acceptance of the smart operation mode is highly appliance-specific, and cannot be generalised. Some of the relevant quantitative results are given in Table 6.3.

Table 6.3 Results of the smart wet-appliances acceptance survey

Device type	Shifting Operation	
	acceptance	Delay
Washing machine (WM)	77%	Up to 3h
Washer dryer (WD)	77%	Up to 3h
Dish washer (DW)	77%	More than 3h

In all cases the majority (77%) of the consumers claim they would accept postponing operation cycles, but by different amounts of time for the different appliances. Washing clothes is a very sensitive area because consumers are reluctant to leave the device operating unattended and the clothes wet inside the machine so short delays are allowed. This constraint, in turn, places limits their contribution to flexibility. For dish-washers the flexibility in terms of maximum acceptable operation shifting is comparatively higher (more than 3h) because consumers do not put the same importance on the time when the device operates. This quantitative information about consumer flexibility, for different appliances is included in the process of quantification of the value of smart appliances, enabling the understanding of how consumer acceptance impacts the overall potential of the technology.

6.6.3 Quantification of the value of smart appliances

The methodology and system scheduling models presented in sections 6.3 and 6.4 are used in this section to quantify the value of smart domestic appliances. The system scheduling tool uses the demand side scheduling model described in sub-section 6.4.2 to optimise the use of individual appliances to provide standing reserve to displace part of the reserve provided from synchronised plant. Again, the total reserve requirement is set to cover for wind forecast uncertainty. The generation system data, generation marginal cost, wind and demand are the same used in the previous section. Each the conventional generation mix is combined with four different WP levels {10, 20, 30, 40} % of total energy demand.

A batch of controllable appliances composed by washing machines (WM), dishwashers (DW) and washer-dryers (WD) is considered. The allowed shifting times used, which are presented in Table 6.4 are based on the results of consumer research data and represent the level of shifting that the consumer indicates as acceptable for each type of appliance. The different shifting times defined for the washing-machine represent the diverse consumer attitude towards shifting this type of device.

Smart appliance data includes appliance consumption per cycle and diversified demand profiles and penetration in UK household and is obtained from [112]. Consumer research results that define the maximum shifting time allowed for different appliances are taken from [113]. A total of 25 million households in the UK, were considered. The penetration levels considered for each type of appliance, lead to a total of 41 million appliances that represent an annual demand of 34 TWh, which corresponds to approximately 10% of total system annual demand. The penetration of each type of appliances used is based in statistical data obtained for the UK and is presented in Table 6.4.

Table 6.4 Smart appliances case study data

Type	Penetration Factor	Shifting capabilities	Duration/cycle	Nr of cycles/ day (million)
WM - 1h	1/3 WM	1 h	2 h	5.1
WM - 2h	1/3 WM	2 h	2 h	5.1
WM - 3h	1/3 WM	3 h	2 h	5.1
Aggregated WM	80%	Up to 3 hours	2h	15.3
WD	20%	3 h	4 h	5.4
DW	80%	6 h	2 h	20.4

To perform an intelligent scheduling of appliance operation cycles, an estimate of the number of appliances typically connected to the system at different hours of the day is required. Without this estimate, is not possible to know the amount of controllable demand available at each time period. This is obtained using the disaggregation algorithm detailed in Appendix F. The algorithm uses the diversified demand profile and demand per cycle of each appliance (Figures 6.19 and 6.20 for the WM), to estimate how many appliances of each type are connected, at each time step. The daily results obtained for the different types of appliances in the UK are shown in Figure 6.21.

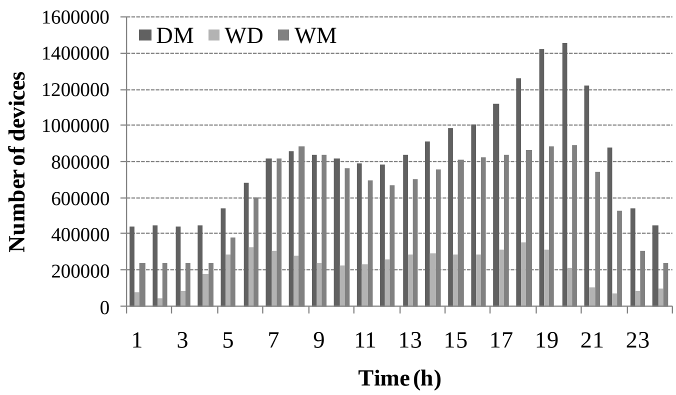


Figure 6.21 Estimate of the number of appliances starting an operation cycle for different hours of a representative day

This process represents an approximation that is assumed to be suitable to estimate the order of magnitude of the economic potential of this technology. The amount of appliances expected to be connected at each time, however, is a stochastic variable. This means, in future, demand side flexibility levels need to be considered as a stochastic variable if these are to be included into real-time system operation.

Value of flexibility from smart domestic appliances

The data presented earlier is then used by the system scheduling tool to quantify the value of smart appliances as a source of flexibility for different conventional generation mixes and WP. The results obtained are presented in Figure 6.22, Figure 6.23 and Figure 6.24 and include both environmental and economic benefits.

The economic value of shifting appliance operation, to increase system flexibility by providing standing reserve, as part of the total reserve required to balance wind uncertainty, and its variation for each conventional generation mix and WP, is show in Figure 6.22. This represents the capitalised value per participating appliance, derived from the operation cost reduction obtained when smart appliances are providing standing reserve using equation 5.13. In this case the total capitalised, for 20 years time horizon and 10 % interest rate, is calculated using the cost reduction divided by the total number of appliances available for control (41.1 millions). The total number of appliances independently from being shifted or not is used to represent a more realistic scenario, since the rewards or incentives need to be attributed to all participating appliances.

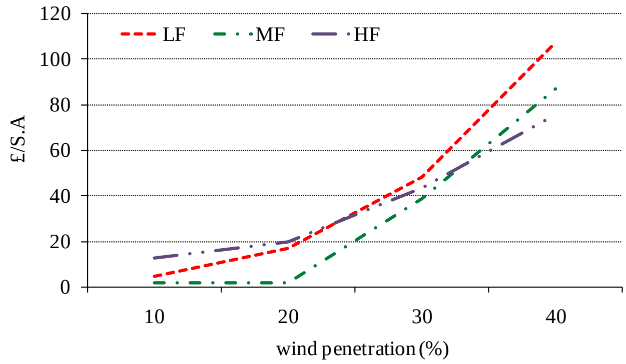


Figure 6.22 Capitalised value per smart appliance for different WP

As for the 1kW-DEV, the value of smart appliances is higher for low flexible conventional generation mix and higher WP. Looking at Figure 6.24 it can be seen that the value of smart appliances is closely linked to its contribution to reduce wind curtailed. This shows that, as for all other sources of flexibility, the value of smart appliances is mostly driven by increasing the amount of WG used to supply demand. Again, the reduction of efficiency losses is shown to have lower value, however, this value is different depending on the composition of the generation mix. For the HF system and for low WP (with no wind curtailed) this value is higher because this system is composed by high-flexible plant with higher part-load efficiency losses. Reducing the need for part-loading such plant has higher value.

Figure 6.23 shows the reduction of CO_2 emissions per appliance for all generations mixes and WP. Again, the contribution of each appliance to reduce emissions depends on the flexibility of the generation mix and the WP. Whenever a smart appliance reduces wind curtailed and consequently displaces some of the generation from fossil fuelled plant it reduces CO_2 emissions. Consequently the environmental benefit of smart appliances is higher in system with lower ability for accommodating WG. These benefits increase for higher WP where the lack of flexibility for accommodating WG leads to higher amounts of wind curtailed.

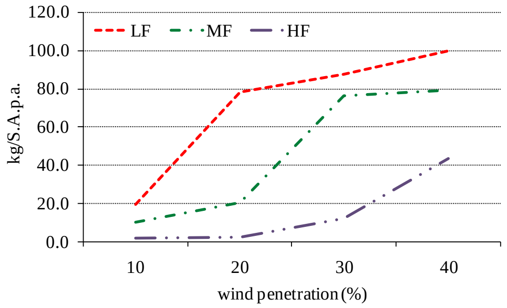


Figure 6.23Reduction of CO_2 emissions per smart appliance

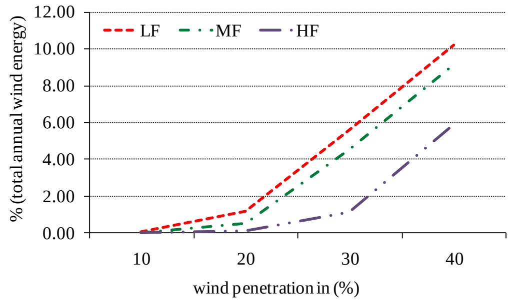


Figure 6.24 Reduction of wind curtailed obtained using smart appliances

Broadly, the results obtained are in line with the ones obtained for storage and DSF provided by a generic appliance (1kW-DEV), however the value per appliance is lower for smart-appliances. This indicates that several appliances need to be aggregated to reach similar benefits.

Impact of appliance characteristics on the value obtained

The previous results, showing the average value per appliance, are obtained by assuming that the total value of DSF can be distributed evenly across all smart appliances. This is unlikely to be the case considering that each smart appliance has different characteristics, including differences in the energy consumed per cycle, the time of the day in which they are used and the maximum allowed shifting time. These differences affect the amount of flexibility provided by different appliances and as a consequence its value.

To analyse how different appliances contribute to the overall value of DSF, the proportion of the total annual energy shifted allocated to the different devices is determined. The results show that the dish-washers are responsible for 48%; washing machine for 23% and washer-dryer for 29 % of the total annual energy demand that is shifted in time.

These show that there is an uneven contribution that needs to be reflected in the value per appliance. A more realistic measure of the value obtained from each device is by using a scaling factor which is applied to the average value obtained in the previous section. This process is described by equation *6.13*.

$$V_i = \frac{V_{DSM}}{N_{dev}} \times \frac{E_i}{E_{DSM}} \qquad 6.13$$

where V_i is the value of type i device; V_{DSM} is the total value obtained in terms of operation cost reduction, N_{dev} is the total number of devices and E_i/E_{DSM} is the scaling factor obtained using the energy shifted by the type i appliance relatively to the total shifted energy.

Figure 6.25 shows the distribution of the value by different appliances for the LF system. The range of value obtained for all system flexibilities for each of the appliances is given in Table 6.5. The largest contribution to the smart appliances value comes from the DW because this device is the one with higher shifting flexibility. The WD has a comparatively higher value than the WM because it has a higher consumption per operation cycle, so each device shifted has comparatively higher value.

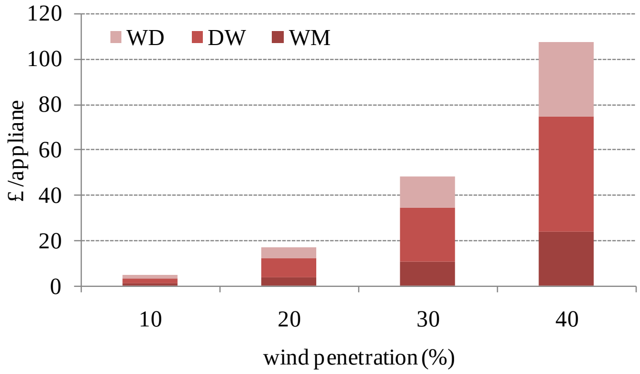


Figure 6.25 Allocation of the capitalised value obtained per appliance to different types of appliances - LF system

The shifting flexibility of the appliance plays an important role. In this case; for the example of the washing-machine, the device is responsible for 6.8 %, 7.8 % or 8.1 % of the total shifted energy shifted depending on whether its shifting time is 1 h, 2 h or 3 h respectively.

Table 6.5 Range of the capitalised value per type of appliance and WP from 10 to 40 %

	WM (£/appliance)	DW (£/appliance)	WD (£/appliance)
LF	[1.0 to 23.7]	[2.2 to 51.0]	[1.34 to 32.5]
MF	[0.4 to 19.5]	[0.9 to 41.5]	[0.5 to 26.2]
HF	[2.8 to 17.0]	[6.1 to 36.6]	[3.7 to 22.1]

In order to determine their economic viability, the economic value of smart appliances needs to be compared to the cost of developing and implementing the control technology needed to ensure the required functionality. An estimated range of the cost of smart appliances is obtained from appliance research studies presented in [114] and modified to reflect the capitalized value of the annual investment cost. A summary of total investment cost, including appliance and communication infrastructure, is presented in Table 6.6. This cost assumes a mass-market smart appliance deployment and the pre-existence of smart metering in all households, so the cost of communication infrastructure included the communication between the meter and the appliance only.

Table 6.6 Example of smart appliances estimated investment cost

	WM	WD	DW
Investment cost (£/appliance)	[2 – 4]	[2-4]	[2-4]

Comparing cost of the technology listed in the table above with the figure of per appliance values shown in Table 6.6 suggests that for the majority of cases, smart appliances are an economically viable option. As can be seen from the per appliance values shown in Table 6.5, this is especially the case in systems with high WP and low flexible conventional generation mix.

Overall, the results obtained show that wet appliances provide some flexibility and improve the system's ability of accommodating WG. The economic value obtained is seen to be sufficient to justify the investment but it is low and would not permit offering an interesting economic reward to consumers in return for their flexibility. This limits significantly the consumer acceptance and the overall potential of this technology. These results are, however, based on a specific type of appliances providing only balancing services. Moreover, this type of appliances has low flexibility potential since these are constrained by its time of operation and consumer flexibility.

The role of smart appliances may be strengthened if appliances that offer flexibility over larger periods that are less dependent on consumer behaviors are used. These devices include heating and cooling devices, such as refrigerators, freezers, air-conditioners, water heaters and heat pumps. Further value can be obtained if additional services are aggregated, such as frequency response and network congestion. A first analysis of the potential of considering both wet and thermal appliances providing different services is provided by the author in [79]. This shows that the role of smart appliance technology, used for the integration of WG, becomes more prominent if a larger portfolio of appliances is available to provide a broader spectrum of flexibility services.

6.7 Conclusions

An approach to assess the value of flexibility from the demand side to increase system's ability of integrating WG has been described. The methodology is based on a system scheduling tool able to schedule both generation and demand to minimise system operation cost. Moreover, to permit the quantification of the value of DSF providing standing reserve this tool simulates both reserve scheduling and utilisation. The algorithm was applied for quantifying the value of aggregated thermal load and smart domestic appliances to increase the flexibility required to deal with wind uncertainty.

In general terms, it was demonstrated that DSF improves system efficiency, reduces operating costs, carbon emissions and increases the utilisation of WG. A range of factors such as different levels of generation flexibility, WP and two different DSF models were considered in the quantification. The results indicate that DSF has the potential of providing flexibility in systems with large WP, providing that a reasonably constant level of flexible demand is available and that consumer constraints are not significant.

The results obtained showed that the value of flexible demand, composed by an aggregation of thermal loads able to provide a constant level of flexibility, follows trends and quantitative values similar to those obtained for storage. This shows that, if properly controlled in order to avoid interference with consumer comfort levels and an undesirable payback effect, DSF behaves similarly to a storage device. As a consequence, DSF can be used as an alternative or a complement to storage to reduce the cost of balancing wind uncertainty.

The main driver for the value of DSF is its contribution to the reduction of wind curtailed. This is higher for systems with a low flexible generation mix and higher WP, since the systems experience larger amounts of wind curtailed. These findings are based in considering constant levels of flexibility available from the demand side, which could be provided by loads with significant storage capacity so that the control of their demand has less impact on consumer comfort or by aggregating and scheduling a portfolio of less flexible loads.

After a comparison of DSF with competing technologies, such as storage and fast plant, it was concluded that the value of DSF is lower than the value of storage for all generation mixes. DSF presents lower flexibility than storage since, unlike storage whose charge and discharge periods are independent, each demand reduction periods is immediately followed by demand recovery. The differential in value between DSF and storage can be kept low if the loads are optimally allocated to different control schemes in such a way that the aggregated flexibility from DSF can approximate a storage device. In contrast, in comparison to fast plant it was shown that for all generation mixes the value of DSF is higher. This is due to the fact that fast plant provides only upward reserve and has high marginal cost, which limits its potential in comparison with DSF.

When considering a physical realisation of DSF, in the form of smart domestic appliances, it was shown again that their value is higher for less flexible systems and higher WP. The capitalised value per appliance, however, is not high and ranges from 0.4 to 51 £/Appliance considering an optimistic life duration. This can be explained by the fact that the flexibility from "wet" domestic appliances is highly constrained by consumer usage patterns (i.e. it is only available at the times when the appliance is typically started) and limited to the maximum shifting time allowed by the consumer.

In general, the characteristics of the smart appliances the main drivers for its value were found to be the shifting flexibility provided (maximum shifting allowed) and the energy consumption per operation cycle. Studies in future work of more flexible appliances that offer a more constant flexibility as refrigerators, freezers and air-conditioners, water heaters alongside with new loads as electric vehicles and heat pumps need to be performed to have the full view of the value of domestic appliances.

CHAPTER 7: Value of Storage and DSF for Network Congestion Management

7.1 Introduction

The preceding chapters have focused on the relationship between flexibility in the system and its ability to integrate wind generation (WG). In some cases, however, the constraints on wind integration come from physical network issues. Wind resources are often found in remote locations distant from the demand centres. Often the network has not been planned to transport this new amount of energy from where the wind farms need to be connected. Furthermore, in many cases, this new plants will replace fossil fuel plants that are located closer to large demand centres. This brings additional stress to the transmission network and generates congestion problems and can compromise the integration of the expected WG.

Processes have been attempted in order to mitigate these additional congestion problems as summarised by Matevosyan [115], these processes have usually fallen in four categories:

- better calculation and use of available transmission capacity,
- wind curtailment in periods of congestion,
- coordination of wind with energy storage in hydro reservoirs, and
- transmission network reinforcement.

Building new network capacity is an expensive and time consuming solution and it is often constrained by environmental requirements. Moreover, as WG has a low load factor, a MW per MW investment strategy, where the bottlenecks are completely removed, leads to low utilization of capacity. In addition, transmission congestion problems associated to wind may typically be of concern for only part of the operation time during periods of high wind. Dynamic transmission ratings, such as described in [116], [117] and [118], have been proposed as a means to increase transmission capacity, in periods of high wind. It is readily acknowledged, however, that for large scale wind integration this measure is insufficient and new capacity is required.

Alternatively, it has been indicated in United Kingdom (UK) based studies [119] that the option of curtailing wind may be an economically viable alternative to investment in transmission capacity. Curtailing wind, though, leads to the waste of low cost and zero carbon energy. This increases the total system operation cost and reduces the potential of reducing emissions.

Another approach, such as is proposed in [68], is to coordinate wind with hydro generation in areas with transmission bottlenecks, Coordination between wind and hydro generation leads to significant reduction in wind curtailments and in a market environment increases the profit of the wind and hydro power producers. This type of coordination is limited to systems with these two generation technologies are in the same area of the congestion.

As an alternative or complement to the approaches above, the economic viability of using non-network technologies, such as storage and demand side flexibility (DSF) obtained through demand side management (DSM) actions, to manage network congestion needs to be considered. In systems with a less flexible generation mix and low hydro resources, such as the UK, storage and DSF can play a particularly important role in providing additional network flexibility to manage transmission congestion.

This chapter presents an approach to quantify the benefits of storage and DSF for transmission congestion management. At the core of this is a network operation simulation tool, based on a linear multi temporal optimal power flow (OPF). The traditional OPF algorithm is modified by introducing storage and DSM models as part of the problem constrains. The model is able to perform annual studies with hourly resolution. The proposed approach provides to the system operator an indication of the more suitable locations across the network to install storage and place DSM initiatives, to reduce the overall operation cost and mitigate the need to curtail wind due to congestion.

The approach developed is applied to a case study based on the UK transmission network, represented by 16 major transmission boundaries. The UK is an example where the connection of new wind farms leads to congestion problems. The majority of onshore wind resources are located in Scotland and offshore wind is located off the North West, North East and north Wales coast and large demand areas are located in the south of England. In spite of having some new offshore wind farms and new plant builds, potentially located closer to demand centres this will not eliminate the need for additional transmission capacity to enable the development of WG. This makes the UK a suitable case study to apply the approached developed. The objective of the study is to quantify the value of using storage and DSM technologies to manage network congestion and increase the utilisation of existing network capacity and reduce the wind curtailed.

This chapter concludes by discussing the implications of using storage and DSF as non-network solution to improve the use of existing network capacity and draws together these findings with a summary of the main drivers for the value of storage and DSF and indicates under which conditions this value is higher.

7.2 Approach for the Quantification of the Value of Storage and DSF

Chapters 5 and 6 explored the potential of storage and DSF to enhance system flexibility and its benefits in systems with large WP. The models used are based on a single bus bar model where supply and demand is both connected and the network is not taken into account.

The single bus models developed in previous chapters also do not permit the assessment of the impact of network on system operation cost and the ability of accommodating WG. In addition, to quantify the value of storage and DSF to increase network flexibility, the devices need to be distributed throughout different network buses. This cannot be done without a proper network simulation tools. To address this question, network constraints need to be incorporated into the optimisation problem to reflect the impact of network congestion in the generation dispatch. In addition, storage and DSF constraints need to be considered so that its operation is optimised for each network bus.

To simulate network operation taking into account the impact of transmission capacity in the generation dispatch and the use of storage and DSF to increase network flexibility, an optimisation model, based on linear OPF, is developed. The model optimises network operation for an annual period with hourly resolution. To clearly show the effect of network congestion in system generation dispatch, the global optimisation is performed in two steps:

In the first step the system is represented as one bus (infinite network capacity) and the economic dispatch of generators is performed. Units are dispatches in merit order according to their marginal cost (£/MWh). The generators with lowest production cost are engaged first, then those with higher production cost etc. Considering that WG is assumed to have zero marginal cost it is dispatched first. The constraints taken into account in this step are the power-balance between demand and generation at every time instant and the technical constraints of power of the generators (minimum and maximum generation limits). The results of the economic dispatch are used as input to the second step.

The second step takes into account the network constraints. The economic dispatch is then replaced by an optimal power flow. Now, whenever the single bus solution leads to line overload (network congestion) the result of the generation scheduling need to be “adjusted” to eliminate this. This is done by adjusting the output of generators in different buses of the network. Congestion is eliminated but a more expensive solution for system cost is obtained. Whenever the congestion is alleviated by reducing the output of a wind generator this means wind is curtailed and replaced by different plant, often a fossil fuel plant, leading to an increase of carbon emissions.

In our study, the linear version of the power flow is used to perform a high level analysis of the impact of network capacity on the wind integrated by the system. DSF and storage models are included into the algorithm as optimisation constraints. The objective function is used to minimize these changes, thus providing the lowest production cost for the whole system. The schematic presentation of this two-stage algorithm is shown in Figure 7.1.

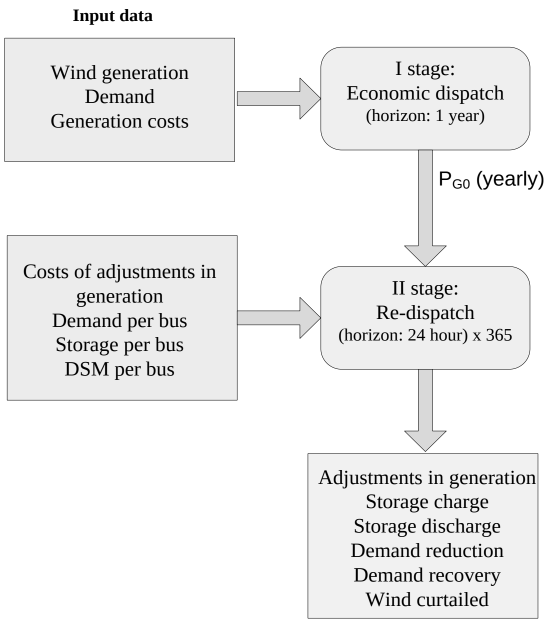


Figure 7.1 Schematic diagram of the congestion management algorithm

The outputs of the algorithm are: generator output power; storage operation (charge and discharge), energy in store, hourly load changes due to DSM actions (reduction and recovery), power flows in network branches, load shed (if required), wind curtailment. All these results are calculated hourly over a period of one year.

The economic dispatch is optimised over the full year. The OPF is performed for horizons of 8760 hours. To take into account the daily operation of DSM actions as detailed in Chapter 5, at the re-dispatch stage, the daily optimisation is done for an extended period (24 h + the duration of longest DSM control scheme) to ensure that an optimal scheduling of DSM control schemes is obtained.

The mathematical formulation of the approach outlined above is detailed in the following section.

7.3 Mathematical Formulation

7.3.1 Economic dispatch

The economic dispatch calculates the output power $p_{i,t}$ for all generators at all periods of time in order to minimise the total production cost assuming infinite network capacity.

The objective function, at this stage, is to minimize the total production cost, for the whole time horizon (one year):

Minimize

$$F_1 = \sum_{t=1}^{\boldsymbol{T}} \sum_{i=1}^{N_G} c_i p_{i,t} \qquad 7.1$$

subject to constraints

$$\sum_{i=1}^{N_G} p_{i,t} = \sum_{b=1}^{\boldsymbol{L_{BUS}}} d_{b,t} \qquad 7.2$$

$$P_i^{min} \le p_{i,t} \le P_i^{max} \qquad 7.3$$

Constraint 7.2 is the power balance between total production $\sum p_{i,t}$. The total demand in the system is obtained by adding the total demand in each bus - $\sum_{b \in \boldsymbol{L_{BUS}}} d_{b,t}$.

Constraint 7.3 enforces the technical limits of power output for each generator. Generators cannot produce power lower than their technical minimum P_i^{min} and higher than their rated power P_i^{max}. At this stage, it is assumed DSF and storage are not available since the objective is to quantify its value to reduce congestion cost.

7.3.2 DC optimal power flow

The output power $\sum p_{i,t}$ corresponds to the lowest cost solution obtained with the combination of all available generators, to supply the demand for all periods of optimization horizon (1 year) considering that the network has infinite capacity.

However, for the cases where network constraints are taken into account, this solution is not always valid. More often than not the solution obtained by the economic dispatch leads to overloading of network branches. Whenever this overload occurs, the output of the generators needs to be adjusted and a more expensive solution is obtained. This is designated as generation re-dispatching.

Objective function

The objective function at the second stage of the algorithm is to minimize total re-dispatch costs. The possibility of load shed is considered for cases when there isn't sufficient generation capacity installed in the system and/or when there is a lack of transmission capacity to supply the load in specific bus. This option has a high cost equivalent to the Value of Lost Load (VOLL). The objective function is described by equation 7.4.

Minimize

$$F_2 = \sum_{t}^{\boldsymbol{T}} \sum_{i}^{\boldsymbol{N_G}} \left(c_i^- \Delta p_{i,t}^- + c_i^+ \Delta p_{i,t}^+ \right) + \sum_{t}^{\boldsymbol{T}} \sum_{b}^{\boldsymbol{L_{BUS}}} VOLL \cdot l_{t,b}^{shed} \qquad 7.4$$

Decision variables are generator negative and positive adjustments $\Delta p_{i,t}^-$ and $\Delta p_{i,t}^+$ and load shed $l_{t,b}^{shed}$ for all load buses and for all time steps t.

Power balance constraints

When the network is considered, the power balance constraints need to be written for all buses of the network. The total power injection into each bus must be equal to total power demand in that bus, including the power exchange with other buses, at all time instances as shown by equation *7.5*.

$$S_{b,t}^d - S_{b,t}^c + \sum_{i}^{\boldsymbol{NG_b}} \left(p_{i,t} + \Delta p_{i,t}^- + \Delta p_{i,t}^+ \right) + l_{t,b}^{shed} = Pd_{b,t}^{DSM}(t) + \sum_{p}^{\boldsymbol{N_{BUS}}} P_{bp,t}$$
$$where \left(\Delta p_{i,t}^- \leq 0, \qquad \Delta p_{i,t}^+ \geq 0 \right) \qquad 7.5$$

The first two terms of the equation represent storage operation: $S_{b,t}^d$ is storage discharge at bus b and $S_{b,t}^c$ is storage charge at bus b. The first one can be considered as an additional generation in bus b, while the second can be regarded as an additional demand in bus b at time step t. The third term represents generation attached to bus b and is the sum of the dispatch solution obtained by the ED $p_{i,t}$ and used as an input, with the power re-dispatched at each bus $\Delta p_{i,t}^-$ and $\Delta p_{i,t}^+$. The last term is the involuntary load shed $l_{t,b}^{shed}$ at bus b.

Network constraints

The power exchange from the considered bus b to all buses p (if bus b and bus p are connected with at least one branch of the network) is given by equation 7.6. It is assumed that power flows from bus b to bus p, so the positive sign for this power is from bus b. In this way, the (positive) exchange of power is added to the total demand in bus b.

$$\sum_{p}^{N_{BUS}} P_{bp,t} = \sum_{p}^{N_{BUS}} B_{bp}\theta_{p,t} \qquad 7.6$$

where B_{bp} is an element of the susceptance matrix **B**, and θ_p is the bus p voltage angle. The value of voltage angle in the reference bus is 0. Matrix **B** is well known from the power system analysis and its' building will not be explained here (for details of building **B** matrix, or, in general, admittance matrix **Y**, see reference [120]).

Constraints 7.7 present the network capacity limits, based on thermal ratings where C_{bp} [MW] is the power limit in the branch connecting buses b and p, whilst P_{bp} is the power flow through the branch.

$$-C_{bp} \leq P_{bp,t} = Bbranch_{bp}\left(\theta_{b,t} - \theta_{p,t}\right) \leq + C_{bp} \qquad 7.7$$

$Bbranch_{bp}$ is the susceptance of a branch bp connecting bus b and p. There may be several branches connecting buses b and p. B_{bp} is the sum of susceptances of all branches connecting b and p, taken with the negative sign (this is how off-diagonal elements of **B** matrix are built).

Generator constraints

The output power of the generators, after re-dispatching, must remain within its technical limits, which are the minimum and maximum active power. Consequently, the constraints imposed to each generator are represented by equation 7.8.

$$P_i^{min} \leq p_{i,t} + \Delta p_{i,t}^{-} + \Delta p_{i,t}^{+} \leq P_i^{max} \qquad 7.8$$

Demand side flexibility constraints

The demand side management model used is based on [107] and modified to be applied in multi-bus problems. This model permits scheduling DSM actions as represented by the reduction and recovery patterns of loads. The shape of the control strategy is the input to the model and need to be defined in advance. Then, the optimisation model decides the time and the amount of the change of demand required by the system.

The mathematical formulation of the model is now incorporated in all different network buses with demand. This permits the definition of different control schemes for different buses, to represent the effect of having different types of demand in different areas of the network. The multi-bus demand side management model is described by equations 7.9 - 7.15.

$$Pd_{b,t}^{DSM} = Pd_{b,t} - Pd_{b,t}^{r} + Pd_{b,t}^{p} \qquad 7.9$$

$Pd_{b,t}$ is the sum of diversified (non-controlled) load profiles for all types of loads $Pd_{b,k}$ attached at bus b at time step t (these load profiles are one of the inputs to the model).

$Pd_{b,t}^{c}$ is the load reduction and $Pd_{b,t}^{p}$ is load payback at bus b and time t calculated by equations 7.10, 7.11.

$$Pd_{b,t}^{r} = \sum_{j}^{\boldsymbol{M}} \sum_{w=a_0}^{t} q_j \, c_{j,(t+1-w)} X_{b,w,j} \qquad 7.10$$

$$Pd_{b,t}^{p} = \sum_{j}^{\boldsymbol{M}} \sum_{w=a_1}^{a_2} q_j \, p_{j,(t-d_j+1-w)} X_{b,w,j} \,, \qquad X_{bwj} \geq 0 \qquad 7.11$$

The parameters a_0, a_1 and a_2 are given equations 7.12, 7.13, 7.14.

$$a_0 = a_0(j,t) = max\{1, t - d_j + 1\} \qquad 7.12$$

$$a_1 = a_1(j,t) = max\{1, t - d_j - pd_j + 1\} \qquad 7.13$$

$$a_2 = a_2(j,t) = t - d_j \qquad 7.14$$

The inequalities 7.15 guarantee that the total controlled load does not exceed the amount of controllable load available for control scheme j. The maximum available power for each control scheme m_j is an input of the model.

$$q_j \cdot \sum_{w}^{T_{24}} \sum_{b}^{Lbus} X_{b,w,j} \leq m_j \qquad 7.15$$

The characteristics of each control scheme (control duration d_j and payback duration dp_j) are defined *a priori* according to the device characteristics and consumer comfort levels. The optimal load scheduling is done by assigning the optimal number of devices (or group of devices) $X_{b,w,j}$ to each control scheme, as defined by equations 7.10 and 7.11. These are used to calculate the modified demand according to equation 7.9.

Storage constraints

The storage model presented in Chapter 6 is modified to be used in multi-bus models. This permits using different storage facilities in different network areas with different installed capacity, power/energy ratings and efficiency losses. The model is represented by equations 5.8 to 5.11 and is incorporated into the OPF.

Equations 7.16 and 7.17 represent the power and energy constraints for all network buses with installed storage.

$$0 \leq S_{b,t}^{c}, S_{b,t}^{d} \leq S_{b}^{max} \tag{7.16}$$

$$0 \leq ES_{b,t} \leq ES_{b}^{max} \tag{7.17}$$

The total energy store at any instant of time and at any bus is calculated as the energy previously stored, plus energy charged, minus energy discharged during the current time interval, shown by equations 7.18 and 7.19.

$$ES_{b,t=1} = ES_{b}^{INI} \tag{7.18}$$

$$ES_{b,t} = ES_{b,(t-1)} + \left(\eta_b \cdot S_{b,t}^{c} - S_{b,t}^{d}\right) \times \Delta \tag{7.19}$$

$ES_{b,t}$ is the energy stored in the storage at bus b at the end of the current time step, $ES_{b,(t-1)}$ is the energy stored in the same storage at the end of previous time step, η_b is storage efficiency and Δ is time interval (1 hour). ES_{b}^{INI} is the initial energy in storage at bus b at the beginning of each day. For the first day of the year, ES_{b}^{INI} is set as part of input data. For all other days in the year, the initial energy of the storage is set to be equal to the energy stored in the storage at the end of the previous day.

In addition a minimum amount of energy in storage at the end of a desired period of time, for instance at the end of each day, is defined by equation 5.12.

$$ES_{b,(t=d\cdot 24)} \geq ES_{b}^{FIN}, \quad d = 1,2,\ldots,365, \tag{7.20}$$

ES_{b}^{FIN} defines a final (minimum) energy at the end of each day d during the year, for storage at each bus.

7.3.3 Solution procedure

Both the ED and the multi-period OPF are linear optimization problems. The ED problem is optimized across a time horizon of 8760 intervals of one hour length covering the full year. The DC-OPF is performed across 365 sub-intervals of 24+t_e hours (being t_e the extension to consider the intra-day DSM actions) to simulate the daily operation of storage and DSM during one year. The solution is obtained using the Dash Xpress solver [93].

7.4 Metrics used to quantify the value of DSF and Storage

The value of each technology is calculated by comparing a base case where no storage or DSF is available with alternative scenarios where storage and DSF are available in the re-dispatch step.

The impact of transmission constraints is measured in terms of re-dispatch cost (£million/year) and wind curtailed (TWh/year). The benefits of storage and DSF are measured in terms of the reduction of re-dispatch costs (£million/year), capitalised value of DSF and storage (£/kW), the reduction of wind curtailed (TWh/year) and increase of line loading factor (%).

Reduction in the volume of energy congested

The reduction of energy congested by using storage and DSF is calculated using:

$$E_{cc} = \frac{1}{2}\left(\left|\Delta p_{i,t}^{+}\right| + \left|\Delta p_{i,t}^{-}\right|\right) \qquad 7.21$$

Reduction in the cost of congestion

The annual cost of congestion is given by equation 7.4. In order to quantify the value of DSF and/or storage, a base case (with neither DSF nor storage) is performed and a minimum cost F_2^B is obtained. A second simulation with the same basic conditions but where DSM initiatives and/or storage facilities are now taken into account is performed and a total cost F_2^N is obtained. The reduction in cost of congestion is defined as:

$$R_{cc} = F_2^B - F_2^N \qquad 7.22$$

Note that $F_2^B \geq F_2^N$, so the R_{cc} is always a non-negative number. The higher the value of R_{cc}, greater the reduction in the re-dispatch cost produced by the addition of DSF and/or storage and, consequently, the higher the value of DSF and/or storage.

Capitalised value of Storage and DSF

The capitalised value of storage is the present worth value of the annual congestion cost savings in £/kW. The present worth value is obtained using the present worth inflation series (PWIS) factor multiplied by the annual saving obtained per kW of installed storage and/or DSF, as described in equation 7.23.

$$PWV_{thechnology} = \frac{1-\left(\frac{1+a}{1+ir}\right)^{n}}{ir-a} \times \left(\frac{R_{cc}}{Inst\_Cap}\right) \quad for\ a \neq ir \qquad 7.23$$

In this equation ir is the minimum interest rate or discount rate, a is the inflation factor and n is the number of years of the expected life cycle of the technology. The installed capacity corresponds to S^{max} or DSF^{max} for storage and DSF, respectively.

Reduction in the wind curtailed in the system

Wind has priority in the ED, so unless wind is higher than demand, all wind is used. When the network limits lead to a negative adjustment of wind generators, part of wind energy is curtailed. The impact of DSF and storage in the reduction of wind curtailed is the difference between the wind curtailed for the base case and the wind curtailed in the case with storage and DSF. This can be summarised according to:

$$R_{ws} = W_s^B - W_s^N \qquad 7.24$$

Line loading factor

The annual loading factor is the metric used to quantify the utilization of the lines in the network. This metric will permit the quantification of the contribution of DSF and/or storage to increase the use of existing line capacity. Load factor is defined as a ratio of the total yearly energy flow (in both directions) through the line, and maximum possible energy that could be transferred by that line (the energy that would flow through the line during one year if the power of the line is at all times equal to the rated power):

$$LF_{bp} = \Delta \frac{\sum_{t \in \boldsymbol{T}} \left| P_{bp,t} \right|}{C_{bp} \cdot 8760} \qquad 7.25$$

The line utilization factor is between $0 \leq LF_{bp} \leq 1$ and the closer the factor to 1, the better utilization of the line. This metric can be used to investigate how DSF and/or storage influences the utilization of the lines by comparing its value for the base case (without DSF and storage) and the values of the line utilization factor for the same line when these facilities are used.

7.5 Case Study -The GB Transmission System

The UK transmission system needs to accommodate a large connection of WG in the northern buses (Scotland area) which will feed into a network that has an already stressed transmission corridor between north and south. This will cause congestion problems and limit the amount of WG that can be used to supply demand since wind needs to be curtailed in periods of congestion to avoid line overload.

Considering that wind power has low load factor (a value around 30 % is usually assumed), the need for the additional network capacity is not required at all time periods. Coordination of wind power with storage operation and/or with DSF may reduce the need for wind curtailment and will optimize the use of the existing capacity.

The objective of this case study is to investigate the extent of the viability of using these non-network technologies to unlock existing network capacity to increase the amount of wind used and reduce the overall system operation cost.

7.5.1 System description

The proposed methodology is tested in a case study based on the simplified Great Britain (GB) 16 network where the GB transmission system is represented by 16 areas, representing the major transmission boundaries [121]. Each area is represented by one bus where generation aggregated and demand is connected following which the 16 bus-bar system shown in Figure 7.2 is obtained.

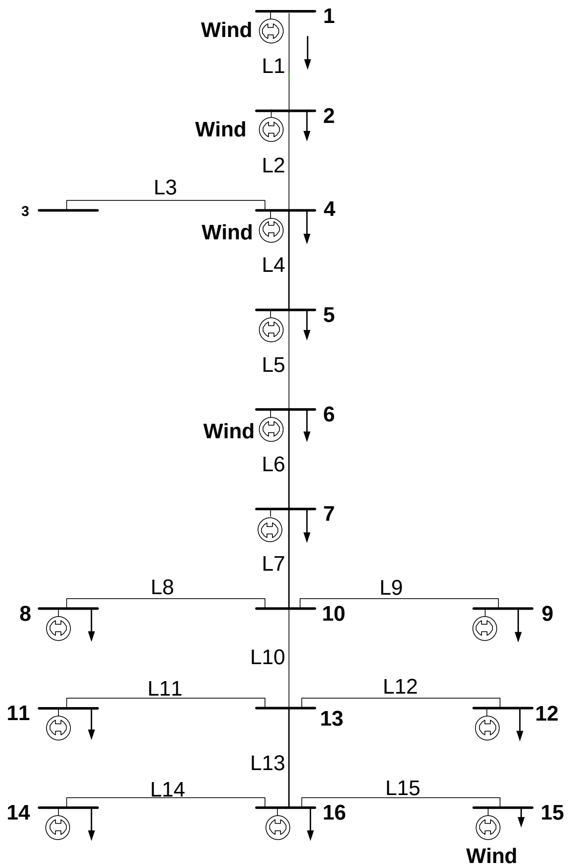


Figure 7.2 Sixteen bus-bar representation of the GB system

The data for the network was obtained from [121]. Wind power production and demand used are based on yearly historical data. The system has 80 generators divided in five types of generators: base generators, coal generators, oil generators, combined cycle gas turbines (CCGT) and wind generators and its marginal and costs are presented in Appendix G. Total peak demand for the whole system is 67.7 GW. System line capacities (in MW) and peak demand per bus are given in Appendix G.

In the northern part of the GB (buses 1 to 6) conventional generation and demand are lower and there is high wind installed capacity. In the southern part of the GB (buses from 7 to 16) there is higher conventional generation and large demand centres. The expected connection of 15 GW of WG and total wind energy of 40TWh, most of it is connected in the north area (buses 1-6), where the wind resource is more abundant, generates congestion problems.

7.5.2 Value of DSF to reduce network congestion cost

In this section, DSF´s role in the reduction of congestion costs and the potential increase of the wind used by the system is investigated. The size of the DSF programs is represented by four different scenarios of maximum controllable load (of 1.5, 3, 4.5 and 6 GW respectively).

The total load participating in the DSF programs is distributed through all demand buses in the system such that the same proportion of the peak demand is each bus is available for control. The loads participating in DSF can be controlled using the control schemes presented in Table 7.1 and Figure 7.3. Details of the control schemes (CS) are given in Table 7.1. The information of different load shifting options and load recovery patterns is included in the control schemes.

Table 7.1 Control schemes' load reduction and recovery duration

Control scheme		1	2	3
duration of load reduction	[h]	4	3	2
duration payback		3	2	1

Taking the example of control scheme 1, during the load reduction period, one unit of demand is disconnected in each of the total four time steps and during the payback period two units of demand are connected during three time steps. During the first time steps of payback two units of demand are reconnected and one unit of demand is reconnected during the remaining two time steps. The shape of the three control schemes are presented in Figure 7.3. Broadly these differ mostly regarding the duration of demand reduction and the shape payback and the total energy involved in each CS. The first CS involves a higher amount of controlled energy (1unit × 4 time steps) and has a payback that involves a larger power increase in the immediate period after demand reconnection and followed by a lower increase for the remaining time steps. The second CS has a similar load reduction and load recovery pattern but involves less energy. The last involves less energy and has a payback pattern that recovers all energy immediately after demand reconnection. These differences intend to represent a set of alternative load flexibility options that could represent a certain type of device or a group of devices.

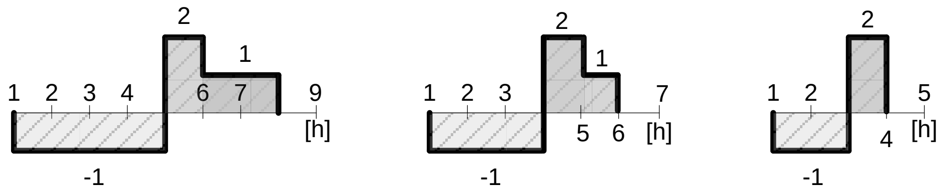


Figure 7.3 Control magnitude and duration of DSM actions

For each scenario of installed capacity of DSF, a simulation using the approach presented in this section is performed. The results obtained for different amounts of available DSF power are presented in Table 7.2. From the results it is possible to conclude that DSF contributes to the reduction of congestion costs and also the amount of energy congested. This seems to indicate that most of the activity of DSM actions is directed to avoiding the use of expensive peaking plants rather than avoiding wind curtailed.

Table 7.2 Benefits of DSF for flexible demand capacity

Controllable demand (GW)	Reduction in re-dispatch cost (£million/year)	Reduction in energy congested (TWh/year)	Reduction in wind curtailed (TWh/year)	Capitalised value of DSF in (£/kW)
1.5	51.49	0.606	0.057	340
3	53.77	1.080	0.066	182
4.5	55.10	1.463	0.069	122
6	55.95	1.793	0.071	93

The annual negative and positive adjustments that make up the re-dispatch actions at each bus are presented in Figure 7.4 for first the base case and then the DSF case using 3 GW of DSF . The impact of DSF on the reduction of congestion cost is obtained by changing the need for and size of energy re-dispatched in each bus by changing the demand shape. The figure highlights first the impact of congestion on the overall generation re-dispatch (base case) due to the lack of capacity in the north south transmission corridor. This congestion forces a reduction of generation output in the north (1 to 7) and increase the output of generators in the south (buses 11 to 15). In Figure 7.4 the changes to the base case adjustments obtained by using DSF are presented. When DSM actions are used there is some reduction of negative adjustments (ΔPg_down and ΔPg_down_dsm) in the north buses, which corresponds to the reduction of wind curtailed. The modifications of positive adjustments (ΔPg_up and ΔPg_up_dsm) in the south buses correspond to a reduction of the expensive generation from oil and some CCGT replaced by positive adjustments neighbour buses with cheaper generation. These changes on the positive and negative generation output adjustments are obtained by modifying the demand profile in different network buses such that a lower re-dispatch cost solution is obtained. The extent of changes in the demand across network buses depends on the demand connected to the bus and the activity of DSM actions (amount of energy shifted). Figure 7.5 shows this activity represented by the total annual energy reduced in each bus (the energy recovered is the same since no efficiency losses are considered).

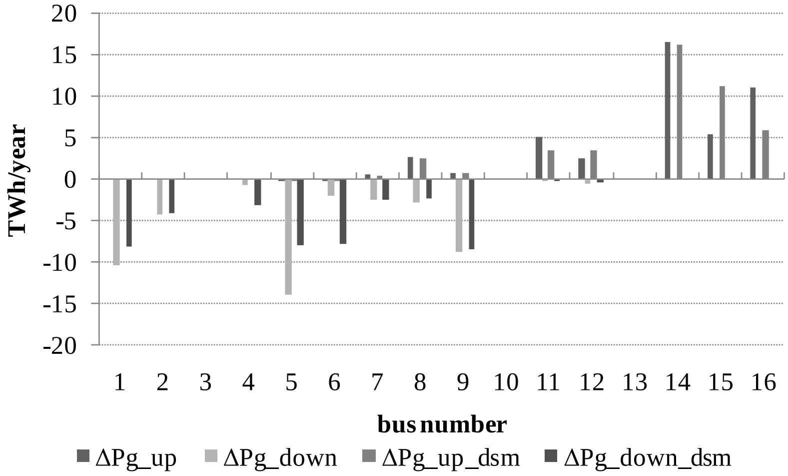


Figure 7.4 Generator adjustments for the base case and DSF case in all buses

The results are shown for different available capacities of DSF (1.5, 3, 4.5 and 6 GW). Clearly, there is a low activity in the north (buses 1 to 5) where most of the WG is connected. In contrast, the buses with higher activity are located in the south region (buses 7 to 16) and the level of the of DSM activity increases as the level of DSF increases. This would be expected since the total demand energy connected in the north is much lower than the demand in the south. DSM actions, however, can be used in the south to perform localised modifications to demand profiles leading to cost effective re-dispatch.

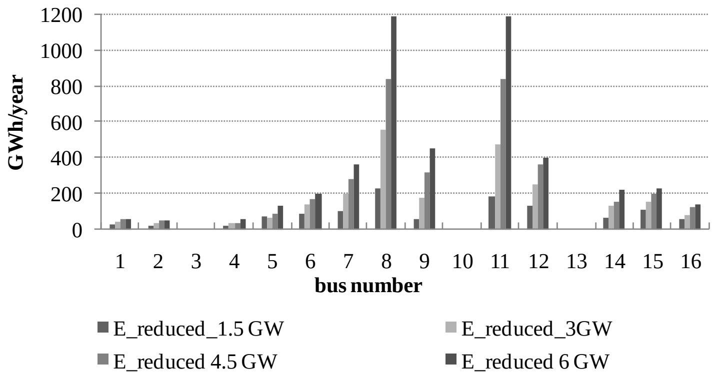


Figure 7.5 Energy reduced in different buses for different flexible demand capacity

Another outcome of the use of DSM actions to modify demand in different buses, in response to congestion, is that it leads to an increase of the use of network capacity. This is reflected in the reduction of the total energy congested, as shown in Table 7.2.

Using the load utilisation factors an overall use of network that corresponds to an average increase of 4.7 % of the use of the total network capacity. This corresponds to releasing 3.4 GW of unused network capacity. By using more of the existing capacity improves the use of existing assets postponing the need for network reinforcement. Clearly, the significance of the trends described in the preceding sections will be related to the level of DSF in the system.

These changes are reflected in terms of cost and wind curtailment reduction. Figure 7.6 presents this reduction for increasing power available for DSM actions. It can be seen that changing DSM levels has a significant impact on the reduction in congested energy but the same does not happen for the reduction of wind curtailed. This is explained by the low demand in the regions where WG is located. As DSF is allocated in proportion to load levels, even by increasing the total level of controllable demand, the DSF used in the north region continues is still comparatively small. On the other hand, increasing controllable demand has a bigger impact on the reduction of congested energy by relieving internal congestion within the southern part of the network and changes the cost of the adjustments by changing the marginal plant.

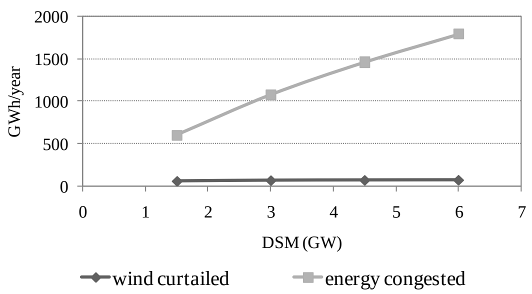


Figure 7.6 Reduction of wind curtailed and volume of energy congested by DSM actions

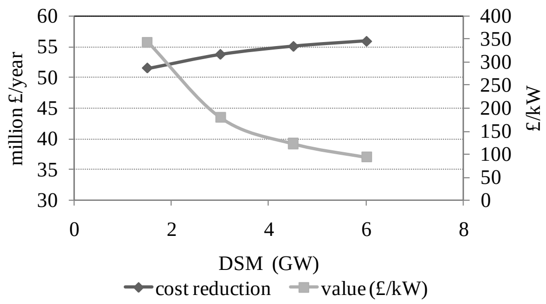


Figure 7.7 Value of DSF per kW of flexible and reduction congestion costs

Figure 7.7 presents the sensitivity of cost reduction and capitalised[68] value of DSM to the increase of controllable demand. It is possible to conclude that there is an increase in the reduction of congestion cost that tends to saturate for higher levels of controllable demand. This shows that the amount of demand that brings benefits tends to stabilise and even if more controllable demand is available it remains unused. Regarding the value of DSF, it decreases with the increase of controllable demand. This happens because the cost savings are divided by a larger amount of DSF power and the comparative increase of cost savings is lower that the increase of DSF capacity.

Overall, these studies shows that DSF brings benefits to network operation by reducing the overall congestion costs and increasing the use of existing assets. This reflects the increase in

[68] The value of DSM is capitalised considering an interest rate of 10 % and a life cycle of 20 years.

network flexibility, which improves the network's ability of dealing with congestion at a lower cost. The main limitation of DSF is that it depends on the location of controllable demand within the network. The location of the controllable demand may not always be the most suitable to mitigate a specific problem. An example of this is presented in the studies above where DSF's low contribution to the reduction of wind curtailment is shown.

In such cases Storage may play a more important role since it is can be connected in the areas where it is needed. This is investigated in the following section.

7.5.3 Value of storage to reduce network congestion cost

In this section, the role of storage for the mitigation of the congestion costs is investigated. The total installed storage is represented by four scenarios of power rating corresponding to 1.5, 3, 4.5 and 6 GW and energy of rating equivalent to 10 h of full power charge/discharge time. Storage is assumed to have 30 % efficiency losses. The overall power rating is distributed evenly by all network buses.

For each scenario of Storage a simulation using the approach presented in the previous section and the benefits using the metrics described above are quantified. The results are presented in Table 7.3.

Table 7.3 Benefits of storage for different installed capacity

Storage installed capacity (GW)	Reduction in re-dispatch cost (£million/year)	Reduction in energy congested (TWh/year)	Reduction in wind curtailed (TWh/year)	Capitalised value of storage in (£/kW)
1.5	48.90	0.257	0.337	326
3	49.04	0.441	0.515	158
4.5	49.34	0.587	0.700	110
6	49.45	0.680	0.837	82

From the results it is possible to conclude that Storage contributes to the reduction of congestion costs. As for DSM, this cost reduction comes from reducing the need for increasing the output of more expensive plant to compensate the reduction of the output of less expensive plant. In the case of Storage, this is driven by the reduction of wind curtailed. Comparing the values in Table 7.4 with the results shown in Table 7.3 it can be seen that storage leads to higher reductions in wind curtailed than DSF. Less wind curtailed means that less energy is produced in more expensive generation plant.

It is important to notice that the reduction of energy congested is lower that the reduction of wind curtailed. This is explained because part of the wind energy that is not curtailed is wasted in storage efficiency losses. This seems to indicate that most of the activity of storage is connected to storing wind energy when there isn't sufficient transmission capacity to export it to the areas of higher demand and discharging it later when there is spare capacity. This wind that would otherwise have been curtailed will be then used by the system. In this case storage efficiency losses do not represent a barrier since storage is charged with "free" WG. In the buses in the southern area of the network, there is little wind installed capacity and no wind is curtailed due to network congestion. In such case storage will be charged at the cost of the marginal plant in the bus, for periods when lower cost plant' output is reduced and discharged in periods when expensive plant's output would be increased due to congestion. In this case the cost of efficiency losses will correspond to the cost of the marginal plant during charge periods. Consequently, storage is used only when the differential between the costs of energy at periods of charge and discharge is sufficient to compensate the cost of efficiency losses. As seen in Figure 7.8, in most cases, the costs differential observed in the southern buses does not justify the use of storage and consequently its activity, represented in terms of total energy discharged by storage in one year, is low.

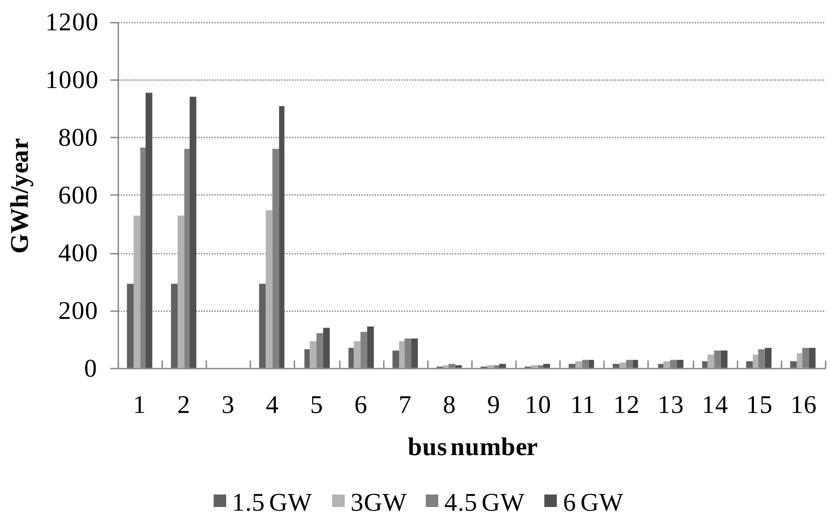


Figure 7.8 Sensitivity of storage activity to its installed capacity for all network buses

Storage activity is significantly higher in the north buses, mostly buses 1, 2 and 4 and it is very low in the remaining buses located in the southern area of the network. This is consistent with the explanation above.

The impact of storage rating on the reduction in congested energy and reduction in wind curtailed is shown in Figure 7.9. Storage is used to charge wind energy in periods of high WP and, later on, to inject this energy (minus efficiency losses) back to the system. It will also increase the reduction in congested energy. The capability of storage to reduce wind curtailed and congestion increases with storage power rating.

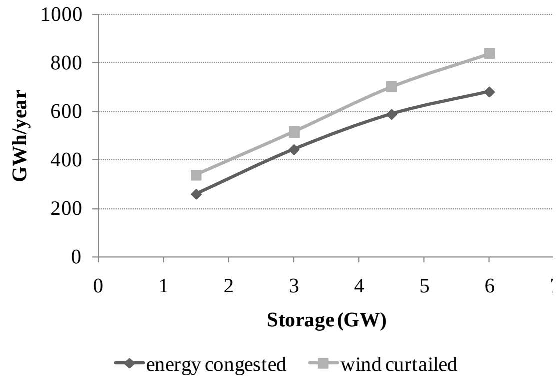


Figure 7.9 Reduction of energy congestion and wind curtailed for different storage capacity

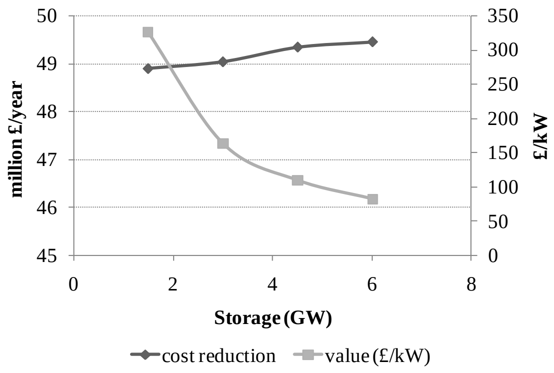


Figure 7.10 Value of per kW of storage capacity and congestion cost reduction for different capacity

The sensitivity of both the value of storage and the reduction in congestion cost to the total installed capacity of storage is shown in Figure 7.10. Similar to trends observed for DSM, the size of the reduction in congestion cost tends to saturate for higher installed storage capacity. This shows that there is a limit on the amount of storage that can bring benefits and that, beyond a certain value, additional storage capacity brings little additional benefit. It is can also be seen that, as the power rating increases, that value of storage per kW of installed capacity reduces. The shows that the increase in cost reduction is proportionally lower than the increase of capacity. It has a repercussion on the value of storage, implying that it decreases with the storage power rating. It means there is a certain amount of storage power can be used to mitigate the congestion problems, and further increase is not possible due to network constraints.

Overall, it would seem that storage, due to the efficiency losses, brings benefits to the system only if it uses wind energy that would otherwise be curtailed, since 30% of energy is wasted. Storage has higher value when the energy losses are not reflected in terms of cost increase. This occurs when storing wind energy, since wind energy has zero cost. It was also shown that storage increased the overall system flexibility by reducing the effect of congestion in the total cost and wind used. However, due to efficiency losses, its economic interest is limited to the areas of the network closer to wind farms so that it can use wind energy that would otherwise be curtailed.

7.5.4 Comparative analysis of storage and DSF

To get a better insight of the role of these technologies in a congested network, a comparative analysis of storage and DSM actions activity in different buses of the network is presented in Figure 7.11. This is done by comparing the results obtained in terms of total annual energy reduced by DSM actions and storage discharged, across all buses, for the scenarios with 3GW of storage with the ones with 3GW of controllable load.

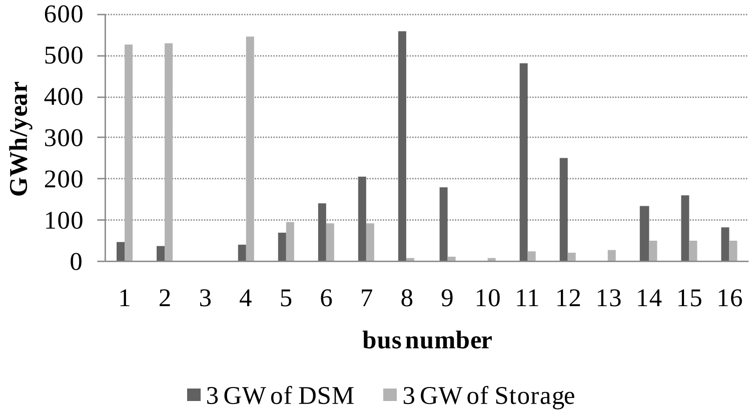


Figure 7.11 Activity of Storage and DSM actions for all network buses

As explained before, the action of storage is mostly visible in the northern buses, i.e. buses 1 - 7. This was explained previously as being due to the WG which is connected in this area that, without storage, would have to be curtailed due to network congestion between north and south. In contrast, DSM actions are mostly used in the centre and south nodes, where it is close to the congested lines. DSF acts to reduce the positive adjustment of expensive peaking plants and increase the positive adjustments of cheaper plant. DSF has the advantage of not having efficiency losses but its operation is constrained by the flexibility provided by load regarding demand available for reduction and the demand recovery pattern at each time period. A summary of the impact of Storage and DSF on several key metrics is given in Table 7.4.

Table 7.4 Comparative results of the benefits of storage and DSF

	Reduction in re-dispatch costs (£million/year)	**Reduction in wind spillage (GWh/year)**	**Reduction in energy congested (GWh/year)**	**Capitalised Value(£/kW)**
Storage	47.6	939.6	476.5	158
DSF	54.6	66.4	1079.9	182

When comparing the economic benefits of storage and DSF, it can be seen that both the cost of congestion and the capitalised value per kW value are of similar order of magnitude but the value of DSF is higher. This can be explained by the specific characteristics of this network. The fact that there is significant congestion between north and south mean that the line capacity is fully used most of the time. This reduces the opportunities for storage to discharge its stored energy in situations where it could displace the more expensive energy generated by the southern generators.

If the number of time periods with spare capacity increases, the value of storage would increase. This increase, though, would have a limit. If the transmission capacity between north and south keeps increasing, WG is naturally used to supply demand in the south. In such cases, storage is not needed.

DSF has a slightly higher value because the peak plants in the south have high marginal cost. Avoiding using these plants by adjusting demand brings high cost savings to the system. Again, if the interconnection capacity between north and south is significantly increased more wind will be used to supply demand in the south. This is likely to avoid the need to use expensive plant, reducing the value of DSF.

It would seem then that storage and DSF can increase system flexibility by enabling it to deal with congestion problems in a more economic way. The value of technologies though is system specific. Consequently the same conclusions may not apply for all networks. It is, however, possible to conclude that storage value is higher in regions with excess of WG where wind that would be curtailed can be used to charge energy. On the other hand, DSF has a potential for more general application since it does not have efficiency losses. Consequently it does not need large differentials in the marginal cost of electricity in the periods of load reduction and load recovery to obtain economic benefits. For DSF though, its utilisation is limited to areas where flexible demand is available.

7.6 Conclusions

This chapter describes a novel methodology for the quantification of benefits of storage and DSF (obtained though DSM actions) in congestion management, thereby contributing to network operation flexibility The approach is based on a multi-period DC-OPF algorithm with storage and DSM actions modelled as part of the optimisation constraints. Most notably this algorithm permits modelling network, generation and Storage and DSF constraints whilst taking into account the inter-temporal aspects of storage charge and discharge and demand reduction and recovery in all network buses.

The methodology was successfully applied to the UK transmission network to quantify the benefits of these technologies to increasing the network flexibility. The case study of the UK is particularly suitable for this study because it has most of the wind resources located in one single area (north) distant from the demand centres (south) and a congested transmission corridor between the two regions. In addition the generation in the south is more expensive that the generation in the north and there are some very expensive peaking plants connected in some of the south buses.

The case studies demonstrate that storage and DSF can reduce network congestion and facilitate wind integration into the system. The reduction in congestion costs is driven by a reduction of the volume of energy congested that is obtained through the modification of system demand by charging/discharging storage and/or reducing/ increasing demand using DSF. The modified system demand profile permits adjusting demand in periods of congestion and increase the use of existing network capacity. This improves network operation flexibility and postpones the need for network reinforcement.

Furthermore it was demonstrated that the benefits of storage and DSF are obtained under different conditions due to the inherent characteristics of each technology. In the case of storage, its economic benefits are closely linked to the cost of efficiency losses. Storage is used only when the cost differential between the generation adjustments obtained without and with storage compensates for the cost of losses. Storage is used mainly when it can be charged using wind energy that would otherwise be curtailed and discharged later when there is spare capacity so that it can displace the fossil fuel generation. For DSF the cost differential required so that it can bring economic benefits to the system is lower since it has no efficiency losses. However the technology is constrained to the locations where flexible demand is available so its utilisation cannot be spread freely throughout the network. In the case study example, DSF has limited contribution to the reduction of wind curtailed because the demand in the north buses is low. Instead, the value of DSF is driven by avoiding increasing the output of expensive fossil fuel plants in the south.

In summary, the results obtained showed that DSF and Storage are able to bring economic benefits to the system by increasing network operation flexibility and wind used by the system. In this particular application, the value of flexibility is linked to the specific network configuration. Thus, while this chapter has demonstrated a valid methodology, the precise results cannot be generalised for all networks.

CHAPTER 8: Conclusions and Further Work

8.1 Introduction

While the exact composition of the future sustainable system up to 2020 and beyond is uncertain, it will need to integrate a large proportion of low carbon generation technologies of different scales, with different operating characteristics, connected in new locations throughout the network. Among these low carbon technologies, Wind Generation (WG) will potentially experience a very high growth. At the same time, the capacity of other low carbon technologies, such as nuclear plant and fossil fuelled conventional generation fitted with Carbon Capture and Storage (CCS), which are likely to be less flexible than existing thermal plant, are also expected to increase.

Operating this future power system will be a challenging task. Large penetration of WG, due to its variable and uncertain nature, will increase the fluctuations and uncertainty on the generation side. At the same time the remaining generation may become less flexible. This will change the operation flexibility available to ensure the demand and generation balance and maintain system security.

The main implication of this is the likely increase of wind integration costs. To obtain a cost efficient system with large penetration of WG, the role and value of different sources of flexibility need to be clearly understood. It is known that different approaches and technologies to providing flexibility can be considered but there is a lack of quantitative studies of their economic and environmental value and how this value evolves with increasing wind penetration (WP).

The scope of this research includes the development of approaches and methodologies to assess, in a quantitative fashion, the system costs of balancing wind and their relation to operation flexibility. This will allow the environmental and economic value of different approaches and technologies for providing flexibility to be examined as WP levels change. The fundaments of the methodologies developed are based on detailed simulation of system operation, over different time-scales and considering different system conditions. This is done with the aim of identifying the parameters that drive the value of flexibility and how the influence of these parameters is reflected economically, in the cost of balancing WG, and environmentally, in terms of CO_2 emissions.

A starting point of this comparison was the development of techniques for the quantification of the extra operating reserves introduced by WG uncertainty. This allows the future needs for operation flexibility to be characterised. Following this, methodologies were developed to assess quantitatively the importance of the different aspects of generation flexibility and how the value of this flexibility will evolve in future systems.

In many ways, the results illustrated that to achieve economic integration of large penetration of WG, the traditional system operation “predict and provide” approach, where sufficient generation is ensured to supply an inflexible demand side, will not be cost effective. In future power systems, flexibility will need to be obtained by improving the use and transferring part of the control functions from generation to different parties. While storage and demand side management have been pointed out as natural alternatives to generation, again there are a lack of quantitative studies to show the benefits that can be obtained by these technologies and how these compare with competing alternatives. Consequently, a part of the scope of the work is the development of methodologies and tools for valuing the flexibility that can be harvested thought the use of storage and the demand side and how this contributes to mitigate the additional costs of operating the systems with WG.

Lastly, it should be highlighted that generation flexibility is not the only factor that might limit system's ability to accommodate WG. In many cases the lack of network capacity and the difficulties of building additional capacity, have been identified as barriers to the deployment of WG. The use of non-network technologies, as storage and DSF, to optimise existing network capacity has been seen as a mean to remove or reduce the extent of this barrier. The real value of these technologies is not yet known due to the lack of methodologies and tools for its quantification. Accordingly, a part of this thesis addressed the development of a methodology and a tool to perform such quantitative studies.

8.2 Contributions and Findings of this Research

This thesis performs fundamental research aiming at quantifying the value of operation flexibility and identifying its main drivers in systems with large WP. The following sections presents the key findings of this work in response to the detailed research question outlined in Chapter 1. This is then followed by a set of global conclusions and recommendations for future work.

8.2.1 Quantification of the requirements and composition of response and reserve in systems with wind generation

While practices have been defined in the past to determine the impact of wind uncertainty on reserve, fewer studies investigate how to combine existing sources of uncertainty (e.g. demand uncertainty and generation outages) with the uncertainty of WG. Even less attention has been paid to the impact of wind uncertainty on response, considered to be very limited for low to medium WP but which may be relevant for very high WP.

A contribution of this work is the development of a computationally efficient approach for the offline quantification of these requirements and the optimisation of its composition. The main advantages of the approaches proposed are:

a) allowing the numerical quantification of the overall requirements while taking account of the direct representation of the distributions of the different sources of uncertainty that drive response and reserve requirements,

The value of this approach comes from avoiding approximating the non-normal “bell” shaped distribution of wind uncertainty by an Gaussian distribution and from having the possibility of representing generation outages using a more rigorous statistical representation such as a capacity outage probability table in contrast to the analytical methods that have previously been used. This comparative advantage is, however, dependant of the composition of the system generation mix (for example comparative size of the largest unit) and the wind data used (which may lead to different levels of non-normality).

When applied to the analysis of the significance of different sources of uncertainty on the overall reserve requirement and its variation with the WP the developed methodology illustrated that at low WP, generation outages can contribute significantly to the overall reserve. In such case, the accuracy of its representation will have higher importance. For high WP, wind largely dominates the need for reserve. In such case there is a significant value in pursuing more accurate wind forecasts and using accurate representation of wind uncertainty.

A minimum cost mix of spinning and standing plant to meet the overall reserve requirements can be obtained through the development and application of a simplified stochastic optimisation process.

Using the minimum cost strategy, it was shown that it is possible to reduce cost of reserve, by finding the optimal trade/off between the cost of plant part-load losses and exercise cost of fast plant. This reserve procurement strategy enhances system flexibility by reducing the amount of part-loaded plant which leads to a reduction of wind curtailed. The generation cost components that most influence this trade-off are shown to be the no-load cost of synchronised plant and the marginal cost of fast plant.

The use of the optimisation process also showed the value in using the direct representation of uncertainty obtained by the numerical methods to obtain the distribution of generation-demand balance uncertainty (which included demand, wind and generation outages). Accurate characterisation of uncertainty leads to both a lower and more flexible reserve composition. Likewise, the value of the direct representation of uncertainty will increase with increasing WP, given the importance of wind uncertainty to overall reserve requirements.

8.2.2 Quantification of the value of generation flexibility

A critical outcome of this work is the assessment of the economic value of the contribution of generation flexibility to system flexibility, in order to allow large penetration of WG. A methodology, which brings together the relevant aspects of operation flexibility within a system scheduling framework, is developed. This algorithm was applied in case studies which are used to determine the relevant value of different aspects of generation flexibility.

The fundamental advantages of the proposed algorithm are as follows.

a) The system scheduling tools balances the need for low computational time (few minutes) alongside the consideration of all the operation constraints that define system flexibility. The constraints captured include generator limits and inter-temporal constraints and deterministic response and reserve constraints. These are in addition to a detailed representation of the characteristics of WG (including its participation in frequency response services).

b) The algorithm is capable of representing the impact of large of amounts of WG over a large operating time horizon (1 year with half-hour resolution), which are essential features for an adequate assessment of the needs for and value of operation flexibility

The algorithm developed was applied to an extensive set of case studies aimed at identifying the factors driving the value of generation flexibility, calculated in terms of intermittency balancing costs, wind curtailed and CO_2 emissions. The findings of the studies are summarised in the following conclusions.

1 The cost of balancing intermittency increases significantly with the amount of wind curtailed. If large amounts of wind are curtailed, the reduction of fuel costs resulting from displacing fossil fuel plant output with zero cost wind are not sufficient to compensate the cost of additional response and reserve (which is necessary to accommodate wind uncertainty into system operation). At the same

time, wind curtailment resulting from lack of flexibility contributes to CO_2 emissions from the conventional generation needed to compensate the wind curtailed.

2 The additional reserve needed to cater for wind forecast errors and the penetration of inflexible must-run generation are the two parameters that most limit the system's ability to accommodate WG. In the first case, the additional reserve corresponds to extra energy that must be held in synchronised part loaded plant. As each of these plants must be producing at least its MSG, this reduces the difference between the inflexible generation output and the aggregated system demand, leaving less "room" to accommodate wind. The presence of inflexible must-run generation further limits the system's ability of accommodating wind since its output must be added to the output of plant providing response and reserve. This reduces even further the difference between conventional generation output and demand meaning that, in order to maintain the generation/demand balance, in many cases wind needs to be curtailed.

3 Given the importance of part-loaded plant providing response and reserve to wind energy curtailment, it is clear that alternatives to reduce to the number of synchronised plant, without compromising system security need to be explored. Resorting to WG to provide both primary response (in periods of wind curtailment) and high frequency response (whenever wind is generating) is shown to have a high economic value. This value corresponds to a maximum reduction of intermittency balancing cost of 12.9 £/MWh[69] when WP reaches 40%, which represents a reduction of 50 % of the total intermittency cost. Such value can be used as an incentive to drive wind participation in frequency response services. Reducing the amount of part-loaded plant by using a combination of synchronised and fast-start to provide reserve was also shown to bring value for high WP of up to 8.6 £/MWh reduction in balancing costs at 40% WP. This corresponds to a reduction of 30 % of the total balancing cost which represents an opportunity for using alternatives to synchronised plant to provide reserve services.

4 When looking at the intrinsic parameters of generation, it was shown that the flexibility of must-run generation contributed the most to the value to system flexibility. Flexibility in must-run generation was enhanced by either reducing

[69] In this thesis, as detailed in Chapter 4, the intermittency balancing cost corresponds to £/MWh of wind available energy. Wind available energy is considered to be the total wind energy after subtracting the wind energy curtailed with perfect wind forecast to the total annual energy that can be generated from the aggregated set of wind farms.

MSG or increasing ramping rates. Reducing MSG of must-run generation down to 30% of P_{max} results in a reduction in intermittency balancing costs of up to 19.6£/MWh at 40% WP, with similar values obtained for increasing ramping rates. This is a clear indication that the increase of intermittency balancing costs for high WP can be reduced if must-run plant is more flexible. Considering that must-run plant has a prominent impact on the reduction of CO_2 emissions from electricity generation its flexibility is of key importance.

5 Reducing the MSG of plant providing response and reserve was also shown to play an important role, resulting in a reduction of balancing costs of up to 17.5£/MWh at 40% WP. This benefit comes from reducing the amount of inflexible generation that needs to be used by the system to ensure system security. This shows that there is also a significant value in having more flexible coal and gas plant to enable the integration of WG in a cost efficient manner.

6 The lower utilisation of conventional plants, whose energy is displaced by WG, which in turn cannot be fully displaced since they need to provide response and reserve, will reduce the profitability of these plants. In addition, a large increase of the number of plant start-ups and shut-downs may adversely affect the need for maintenance and plant forced outage rates.

8.2.3 Quantification of the value of flexibility from storage

Another key contribution of this work is the quantification of the economic and environmental value of using storage to improve system flexibility. The value of storage comes from its ability to contribute to the flexibility required to meet the generation/balance constraint whenever wind forecast errors generates imbalances that increase or decrease the total generation available.

Quantifying the value of additional flexibility obtained from storage involved the development of an innovative system operation simulation tool. This is based on a semi-deterministic approach that permits having low computational time whilst optimising the value of storage over an annual time horizon and to consider the relevant features of system flexibility. The main features of the system scheduling tool developed are:

a) The traditional deterministic security constrained unit commitment is modified to optimise the use of system flexibility for both reserve scheduling and deployment stages. This is done performing a two-step system optimisation that allows scheduling generation and spinning reserve for forecasted wind and re-dispatching the output of committed generators at electricity delivery time. Storage constraints are included at the second stage of the optimisation such that storage operation is optimised to reduce the cost of wind uncertainty. Without this two stage optimisation it would not be possible to quantify the contribution of storage for reserve since it is an energy limited device and the energy available for reserve, at each time step, depends on the usage in previous periods.

b) The need for reserve deployment is simulated taking into account scenarios of wind realised using a stochastic approach to generate wind imbalances between forecast and delivery time.

The algorithm was applied to quantifying the value of storage when this is used to provide part of the reserve required to deal with wind forecast errors. The quantification process considered different thermal generation based conventional mix compositions, storage installed capacity, storage parameters and WP levels. The main findings and conclusions are as follows:

1. The economic potential of storage is largely dependent on the flexibility of the system where it is integrated. The capitalised value of storage when providing standing reserve for three different conventional flexibility mixes and 25 % WP ranges between 908 £/kW (low conventional flexibility LF system) and 236 £/kW (high conventional flexibility HF system). The large difference between systems is linked to storage’s contribution to the reduction of wind curtailed. The HF system is able to use all the WG, leaving storage the sole role of reducing part-load efficiency losses which has significantly lower value. For the LF case, in contrast, there is a need for curtailing wind which is reduced by using storage. This reduction of part-load losses and wind curtailed leads to a reduction of CO_2 emissions which represents an environmental gain.

2. Considering the large investment costs of this technology (for example, around 1000 £/kW for hydro-pumped storage) an investment in new storage to integrate WG is still hard to justify even for less flexible generation mixes.

3. The value of each kW of storage depends on the total installed capacity, and decreases significantly with the capacity installed. The higher share of the value of storage is captured by first the MWs of storage as these cover the more frequent, smaller wind imbalances.

4. Storage round trip efficiency losses play an important role in its economic viability. The results obtained indicate that the value of storage increases very significantly if round trip efficiency changes from 60 to 100 %. The magnitude of this increase is almost independent of the generation mix. This indicates that technology developments which may lead to an increase of storage efficiency would greatly improve its economic viability.

5. In contrast to the results observed for the value of generation flexibility, the way in which the value of storage evolves with increasing WP cannot be generalised for all generation mixes. In LF mixes, it seems that with increasing WP the value of storage increases initially up to a saturation point, with its value dropping for WP beyond this. For the HF system the value increases with the WP and this increase is more significant for higher WP. The LF system with a high WP has a very large number of periods with surplus wind (since it has more inflexible must-run) so storage is fully charged within the first periods of operation and has few opportunities to discharge therefore its value decreases. For the HF system, more frequent periods of wind curtailment do not hinder storage operation and increase its value. This is a clear illustration of the difference in the value of flexibility provided by a device that generates power and a device that stores energy.

6. Finally, it was found that, in the majority of the cases, when compared to the performance of fast plant, storage has a higher value. This reflects the benefits of storage's ability of contributing to both upward and downward reserve. Exceptions to this are the scenarios with low WP and no wind curtailment, and the high WP and LF generation mix, for the reasons described above.

8.2.4 Quantification of the value of demand side flexibility

As part of this work, an innovative methodology and system scheduling algorithm were developed and applied to quantify the value of demand side flexibility (DSF) to provide part of the reserve required to deal with the wind forecast errors. While the core of the system scheduling tool is the same as developed for storage, innovative models of demand side are included to this.

The key features of the modified tool are:

a) This tool is based on the one developed to quantify the value of storage and permits the simultaneous optimisation of generation and demand side flexibility. This permits optimising the available flexibility from the generation and the demand side by scheduling individual generators and individual loads to minimise the cost of providing additional reserve to accommodate wind forecast errors.

b) The characteristics of demand side flexibility are captured in the form of constraints added to the optimisation in a similar fashion to what is done for generator technical and dynamic constraints. This allows the use of a detailed representation of the characteristics of individual devices or a group of devices including its power and energy demand, their technical operation characteristics (such as load reduction and payback patterns), their typical usage patterns (e.g. distribution of the devices' demand during the day) and the flexibility that can be provided (including limits imposed by the consumer in terms of modification of device usage).

The algorithm was applied for quantifying the value of aggregated thermal load and smart domestic appliances. An extensive range of factors such as different levels of generation flexibility, WP and two different demand side flexibility models were considered in the quantification.

The main conclusions of the studies can be summarised as follows:

1. The value of flexible demand, composed by an aggregation of thermal loads, able to provide a constant level of flexibility, follows similar trends as the quantitative value obtained for storage. This shows that, if properly controlled in order to reduce interference with consumer comfort levels and the undesirable payback effect, demand side management behaves similarly to a storage device and reaches similar capitalised value. As a consequence, demand side flexibility can be used as an alternative or a complement to storage to reduce the cost of balancing wind uncertainty.
2. The main driver for the value of demand side flexibility is its contribution to the reduction in wind curtailment. This is higher for system with a low flexible generation mix and higher WP, since these systems experience larger amounts of wind curtailed.
3. The value of DSF is slightly lower than the value of storage for all generation mixes. This shows that the fact that DSF presents lower flexibility, since unlike storage whose charge and discharge periods are independent, each demand reduction periods is immediately followed by demand recovery. Regarding the value of DSF in comparison to fast plant it was shown that for all generation mixes the value of DSF is higher. This has shown that the fact that fast plant provides only upward reserve and has high marginal cost limits its potential in comparison with DSF.
4. When considering a concrete realisation of demand side flexibility, in the form of smart domestic appliances, it was shown that their value is higher for less flexible systems and higher WP. The capitalised value per appliance is not high and ranges from 0.4 to 51 £/Appliance considering an optimistic life duration. This is justified by the fact that the flexibility from wet-appliances is highly constrained by consumer usage and flexibility in terms of shifting time allowed by the consumer. Regarding the characteristics of the appliances the main drivers for its value were

found to be the shifting flexibility provided (maximum shifting allowed) and the energy consumption per operation cycle. When comparing the value obtained per appliance with existing estimates for the investment cost of implementing this technology they were found to be economically viable in the majority of cases.

8.2.5 Development and application of a network simulation tool with a multi-bus distribution of storage and demand side flexibility

As part of the contribution of this work a network operation simulation tool, based on a multi-period optimal power flow, incorporating the multi-temporal operation of storage and DSF is developed. At the core of this tool is an optimal power flow (OPF) algorithm. The innovative contribution of this work is:

a) the incorporation of the storage operation and demand side management constraints into a classic linear OPF to permit the optimisation of the use of these enabling technologies in different network location over large time horizons (one year).

This tool was applied to access the potential of using storage and DSF to enhance network operation flexibility to increase the use of the available capacity and reduce congestion costs and wind curtailed. The case study selected is the United Kingdom transmission network, where the lack of transmission capacity is limiting the connection of new WG. Considering the intermittent nature of WG this study has quantified the value of storage and DSM to reduce network congestion and increase the amount of wind used.

From the results of the studies the following conclusions can be made:

1. Storage and DSF can reduce network congestion and facilitate wind integration into the system. The reduction of congestion cost is driven by a reduction of the volume of energy congested and costs obtained by modifying system demand using storage and DSM actions.

2. The benefits of storage and DSF are obtained under complementary conditions due to the inherent characteristics of each technology. Storage is used mostly in the areas where WG is installed so that it can be charged with “free” wind that would otherwise be curtailed when there insufficient capacity to transfer it. DSF, on the other hand, does not have efficiency losses. Its flexibility is, however, limited to areas with more significant demand so it was found to manage local congestion between different demand centres, independently to the existence of surplus wind.

8.3 General Conclusions

Clearly the expected benefits of adding WG, a zero cost / zero CO_2 emissions technology, may not be realised for all system flexibilities and WP. Instead, the relationship between WP and the reduction in costs and emissions cannot be generalised. The results have shown, however, that a high value can be allocated to sources of additional flexibility that facilitate better use of WG output mainly in low flexible mixes and high WP scenarios. In these cases, extra flexibility, which reduces the need for curtailing wind, will be important to unlock the economic and environmental benefits of WG.

The results illustrated that insufficient flexibility in the conventional generation mix defeats the purpose of investing in WG to reduce costs and emissions. If the system is not flexible enough to accommodate WG there are high wind balancing cost and, wind is not able to displace the expected output of fossil fuel plant and the consequent reduction in CO_2 emissions and operation cost does not materialise. By attributing a monetary and environmental value to flexibility, however, the results have provided an indication of the levels of flexibility that should be provided by future nuclear and CCS plant. At the same time, the underlining of the important role of flexibility showed that there is a significant value in harvesting flexibility from non-generation sources of flexibility such as storage, demand side and networks.

On these non-generation sources, it is seen then that storage is naturally suited to provide part of the reserve required to compensate for the imbalances on the generation side caused by wind forecast errors. Storage, however, presents some limitations justified by the fact that storage has efficiency losses and is constrained by not only its capacity but also the energy available in store.

It is seen that flexibility from the demand side can play an important role on the reduction of intermittency balancing cost and CO_2 emissions especially for high WP and less flexible generation mixes. This potential is however limited by the fact that to unlock this flexibility the impact of the control actions over loads should not impact consumer comfort levels and that the negative effects of disturbing demand diversity (payback effect) is avoided. To unlock this potential it is required to properly schedule loads according to their constraints and characteristics whilst optimising the overall system cost by making use of bi-directional communication between the system operator and the loads.

Importantly, the limitations observed in terms of flexibility that can be obtained from smart “wet appliances”, will be less significant for other appliances which possess thermal inertia such as heat and cold storage. Recently, new types of demand, such as electric vehicles and heat pumps (which represent an additional form of thermal storage) represent an opportunity for unlocking even higher volumes of flexibility from the demand side.

Finally, these non-generation sources of flexibility have also been shown to have the potential of improving the use of network capacity. The roles of each technology rather than being competitive was shown to be complementary since their inherent characteristics make them suitable to address different network congestion costs, located in different areas of the network.

The use of these enabling technologies, however, requires an adequate market and regulatory framework to integrate these into system operation and planning, regulate the access of different services these can provide and permit the maximization of its profit.

8.4 Suggestions for Future Work

In this section some possible directions for future research are presented.

1. In this thesis the response and reserve requirements have been quantified offline and then included into the generation scheduling problem as deterministic constraints. Several improvements can be made to this approach:

   - response requirements including the effect of wind uncertainty can be quantified using dynamic simulation tools for a large number of wind imbalances combined with generation outages;

   - wind forecast error has been modelled using persistency based techniques and consequently an overestimate of wind uncertainty is obtained. Alternative wind forecast techniques can be used to further investigate the role of wind forecast error as a driver for the overall reserve requirements;

   - A simplified stochastic optimisation procedure was proposed to determine the split between standing and spinning reserve that minimises the cost of reserve. This is done in an approximate fashion since the optimal combination is determined assuming that the same type of plant is providing spinning reserve. Instead, considering that in the annual generation scheduling reserve requirements and adjusted to the wind forecast and different plant can be providing reserve in different periods of the day the optimum level of spinning and standing reserve should be determined by the generation scheduling problem. A process to do this is proposed in [89] where the optimal level of standing reserve is optimised by introducing the cost of holding standing reserve into the objective function and adding an extra decision variable corresponding to the output of standing plant.

2. As explained above different improvements to the approach for determining reserve and reserve offline can be performed to improve the solutions obtained. However, some works have shown that more robust solutions can be obtained if these requirements are obtained online, as an output of the optimisation problem [41, 42] by solving the generation scheduling as a stochastic optimisation problem. The main limitation of this stochastic approach is that stochastic optimisation requires large computational times hence it does not permit running a large number of annual simulations. The application of scenario reduction techniques and decomposition methods can reduce the computational times of stochastic optimisation problems. Thus as future work it is proposed to develop a generation scheduling tool based on stochastic optimisation where different scenario of net demand forecast errors and generation outages are used to include system uncertainty into the optimisation problem.

3. The quantification of the value of storage and demand side flexibility providing standing reserve to balance wind forecast uncertainty requires the simulation of both reserve scheduling and deployment. This requires the simulation of wind imbalances which in this work is done using a stochastic process to generate a synthetic time series of realised WG.

   a) This should be improved by using a wider range of wind realised conditions by using real data of wind forecast and realised measurements. Alternatively, a stochastic model for the co-optimisation of energy and reserve, including the contributions of storage and DSF needs to be developed.

4. The demand side flexibility has been focused on a generic thermal device and smart domestic wet-appliances. To provide a more complete vision of the potential of demand side flexibility additional work needs to be developed including:

   - develop of new models to consider a broader portfolio of flexible loads as refrigerators, freezers, water heaters, heat pumps and electrical heaters;

   - optimise the use of demand side flexibility to provide a broader range of services related to flexibility as load-shaping and frequency response.

   - In this work the amount of flexibility provided from the demand side, being this represented by a generic device or smart-appliances, is assumed to be deterministic. In reality, the amount of flexibility from the demand side available at each time period is a stochastic parameter. As future work, models to represent the stochastic behaviour of demand side flexibility need to be investigated. In addition these models need to be validated against realistic data obtained from field tests about the usage patterns of different loads.

5. In this thesis the value of flexibility is quantified considering that all existing technical flexibility is available. In reality, the access to the existing technical flexibility depends on the market design. Future work needs to access how the market design affects the access to technical flexibility and as a consequence its value. This should include the interactions between different actors, such a inflexible actors like WG owners and flexible actors as fast plant owners, and the interaction between them under different market frameworks.

6. Considering that storage and DSF are seen as key technologies for the development of smart grids it is interesting to investigate its full potential by extending the quantification of the value of DSF and storage in network to include additional services as voltage support and reduction of losses. This requires the integration of storage and DSF models into an AC-OPF flow algorithm. This study would permit the development of business cases for the application of distributed storage and DSF, to support network operation, aggregating the value of a portfolio of services that can be provided to the network operator, distributed generation owners, electricity retailers and consumers.

7. It has been shown in this work that storage and DSF contribute to the optimisation of the use of existing network capacity. This has the potential of reducing and/or postponing that need for network reinforcement and asset replacement. Such benefits need to be further explored to permit the quantification of its value for different future demand growth and distributed generation connection scenarios. This gains special relevance because large amounts of WG are expected to be connected, at different network location and voltage levels, and loads from the heat and transport sector are expected to migrate into the electricity sector, with the development of heat storage technologies and electrical vehicles. This represents a major challenge in terms of network development and storage and DSF can contribute to support a more sustainable network capacity expansion. This, however, requires the integration of storage and DSF models into innovative planning tools with a robust representation of the stochastic nature of generation capacity expansion, demand growth and investment costs. Such tools can then be used to quantify of amount of capacity that can be avoided and/or for how long is it economically beneficial to postpone this investment.

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Appendix A Derivation of the reserve cost function

This appendix presents the derivation of the reserve cost function used to determine the allocation between spinning reserve (SR) and standing reserve (StR) used in this thesis.

A.1 Cost of spinning reserve

To determine this allocation firstly a reserve cost function needs to be derived to estimate the cost of SR obtained from part loaded synchronised generators. A simplified function to determine this cost based simply on the cost difference between full and part load unit cost and the amount of reserve to be supplied is derived.

In a system with no reserve N_u units are required to supply a demand of D megawatts. Assuming that all units are identical the cost of meeting, SC this demand is

$$Demand\_Supply\_Cost = N_u \times P_F \times C_F = DC_F \qquad A.\ 1$$

where P_F is the amount of power provided by the generators at full load and C_F is the cost per MW of operating each unit at full load.

If SR is required, then the same demand D must be supplied by a number of fully loaded and some part loaded units. For a total SR of R the number of part loaded units are:

$$N_R \leq \frac{SR}{(P_F - P_B)} \qquad A.\ 2$$

In this case P_B is the amount of power provided by the generator when fully part loaded. In many cases, there will be another unit running part loaded, i.e. backed of by r MW such that:

$$SR = N_R(P_F - P_B) + r \qquad A.\ 3$$

The cost of the power produced by the part loaded generators is given by:

$$C_{part\_load} = P_B N_R C_{MSG} + (P_F - r)C_r \qquad A.\ 4$$

Where C_{MSG} is the cost of running the unit fully part laded and C_r represents the cost of running a single unit part loaded – in our case, this value of C_r is determined according to:

$$C_r = \frac{(C_I(P_F - r) + C_{NL})}{(P_F - r)} \qquad A.\ 5$$

Where C_I the unit is incremental cost and C_{NL} is the no load cost.

The remaining full load generators incur a cost of:

$$C_{full_{loaded}} = (D - P_B N_R - (P_F - r))C_F \qquad A.\ 6$$

This is a slight under-estimate of the cost of production, as some of the power may not be produced by units that are not running fully loaded.

The total cost of provided demand and spinning reserve is:

$$C_{part\_load} + C_{full_{loaded}} = DC_F - P_B(C_P - C_F) + (P_F - r)(C_R - C_P) \qquad A.\ 7$$

The cost of reserve is the difference between cost of provision of reserve plus demand and the original of cost of providing demand only. Combining equations A.1 and A.7 the cost of reserve is represented by:

$$C_{spinning\ \_reserve} = P_B(C_P - C_F) + (P_F - r)(C_R - C_P) \qquad A.\ 8$$

Example of application to a generic unit

This section presents an example of application of this function to illustrate how this relates to the cost of using units operating part-loaded to provide reserve for a specific snapshot of system operation. The data of generation is presented in Table A.1 and Table A.2. In this snapshot demand is 5000 MW and the SR requirement is 700 MW.

Table A.1 Cost of running the unit for different loading conditions

Loading Level	Total unit cost	Cost(£/MWh)
200	12971.37	64.86
250	14986.78	59.95
300	17002.18	56.675
350	19017.59	54.34
400	21033	52.58
450	23048.41	51.22
500	25063.82	50.13

Table A.2 Unit costs

Incremental cost	No load cost	Efficiency losses
40.30816 £/MWh	4909.737 £/h	22.71%

To supply the demand level the following number of units is required:

N_U = 5000/500 = 10 units

N_R = (700)/(500-200) = 2 units + 1 partially backed off = 100

Where C_R is obtained from equation A.5 and the total cost of SR in obtained by equation A.8:

$$C_R = \frac{(C_I(P_F - r) + C_{NL})}{(P_F - r)} = 52.58£ / MWh$$

$$C_{spinning\_reserve} = P_B(C_P - C_F) + (P_F - r)(C_R - C_P) = 6872\,£$$

The equation derived permit the quantification of the cost of holding reserve for different plants, independent from the demand level of the system, using one single equation. For a specific level of reserve to be held the number of fully part loaded plants and partly part loaded plants, is defined. . Using this equation, for each reserve level and type of plants, the cost of holding reserve in part loaded plants is quantified.

This shows that the cost of holding reserve is mainly driven by the differential between the cost of running the units fully loaded and fully (or even partially) backed off. The cost of running units part loaded, to cover the exact amount of reserve, is calculated.

A.2 Cost of Standing Reserve

The cost of standing reserve (StR) is represented by the difference between the marginal cost of standing plant and the full load cost of spinning plant:

$$(C_F - C_O)P_F + (C_O - C_F)P_O \qquad \text{A. 9}$$

Where C_F is the marginal cost of running full load synchronised plant, C_O is the marginal cost of standing plant, P_F is the reserve deployed power generated by synchronised plant and P_O is the power generated by standing plant.

A.3 Reserve cost function formed by a combination of SR and StR

By combining the cost function obtained for SR and StR the complete reserve cost function of obtained. To combine the two functions a new variable, representing the percentage of the total reserve provided by each type of reserve needs to be introduced.

Considering that the total spinning reserve will correspond to a number N of standing deviations (σ)of the *pdf* of imbalances due to uncertainty, represented by Figure A1.

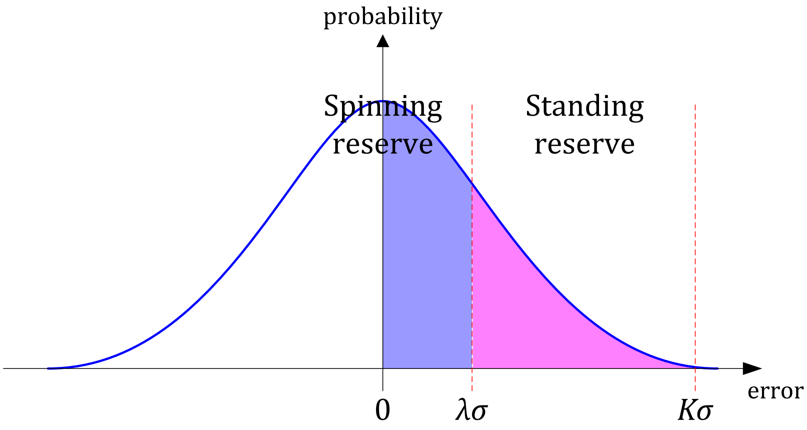


Figure A.1 pdf of the normal distribution of system imbalances due to forecast errors

The total system reserve will be $= K\sigma$ and λ is the split between SR and StR and k_i represents a random imbalance: Considering that SR takes the more frequent and smaller imbalances and StR the less frequent and larger imbalances the amount of each type of reserve will be:

$$SR = \lambda\sigma \tag{A 10}$$

$$StR = (K - \lambda)\sigma \tag{A.11}$$

$$SR = \lambda\sigma = P_B + (P_F - r) \tag{A 12}$$

In this case P_B is the amount of power provided by the generator when fully part loaded. In many cases, there will be another unit running part loaded, i.e. backed of by r MW. See equations A2 and A3.

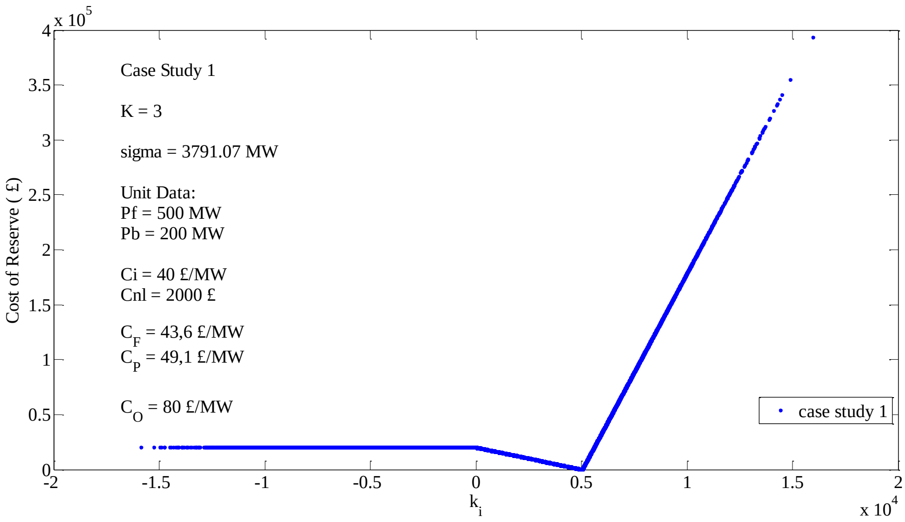
By combining equations A8-A11 the reserve cost function will be represented by:

$$C_{reserv\,e} = \big((\lambda\sigma - r)\big)(C_P - C_F) + (P_F - r)(C_R - C_P)\big) + ((C_F - C_O)\lambda\sigma + (C_O - C_F)(K - \lambda)\sigma) \tag{A 13}$$

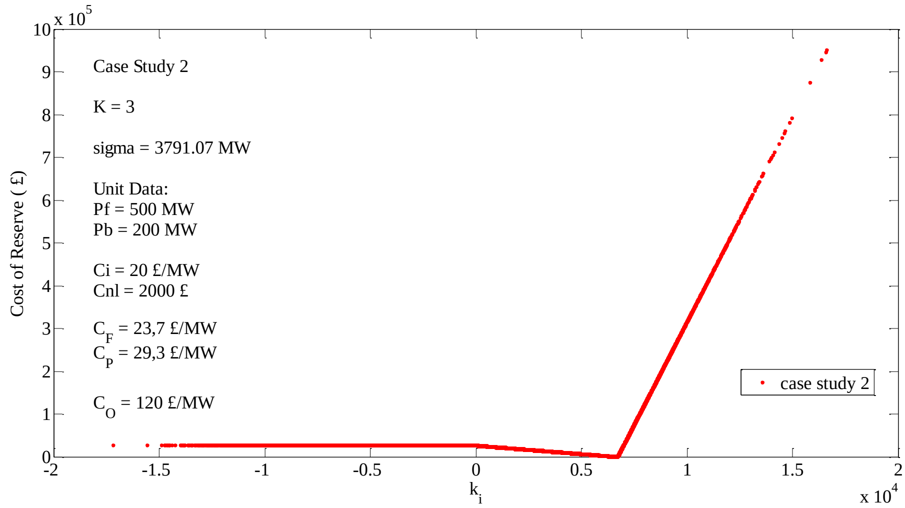
Considering $k_i$as a random imbalance, equation A.13 needs to be decomposed depending on the value of k_i.. The new reserve cost function assumes the form:

$$\begin{cases} \big((\lambda\sigma - r)\big)(C_P - C_F) + (P_F - r)(C_R - C_P)\big) & for\ k_i < 0 \\ \big((\lambda\sigma - r)\big)(C_P - C_F) + (P_F - r)(C_R - C_P)\big) + ((C_F - C_P)k_i\sigma & for\ \ 0 > k_i < \lambda \\ (C_F - C_O)\lambda\sigma + (C_O - C_F)k_i\sigma & for\ k_i > \lambda \end{cases} \tag{A 14}$$

The graphical representation for of reserve costs for large set of random values of k_i, constrained inside de interval $-K\sigma > k_i < +K\sigma$ obtained using two examples of generation costs is presented in Figure A.1 and Figure A.2.



A 1 Reserve cost function – case study 1



A 2 Reserve cost function – case study 2

Comparing the figures it is possible to see the effect of generation marginal costs in reserve costs. Case study 1 has higher costs for synchronised plant and lower costs for standing plant when compared to case study 2. As expected the reserve cost function is different and the cost of SR is clearly lower in case study 2. In both figures it is possible to see the cost of reserve is 0 for one specific imbalance. This corresponds to the point where the size of the imbalance equals the amount of SR. Again comparing the two cases the point with 0 reserve corresponds to a larger imbalance. This shows that for lower marginal costs of synchronised and higher marginal cost for standing plant more SR is used.

Using this function it is possible to determine the cost of reserve for any imbalance for all time intervals considered.

Appendix B Linearization of convex generation cost function

This appendix presents the approach followed to linearise the convex generation cost function, used in this thesis, required to permit solving the unit commitment optimisation algorithm as a mixed integer linear problem.

The relationship between generator output and fuel cost is complex and does not follow and cannot be represented by-linear function. It is often assumed that this relationship can be described by a convex quadratic function of the output of the generator and the respective production cost. This function is described by equation B.1 and Figure B,1.

$$C_i(P_i) = a_i + b_i P_i + c_i P_i^2 \tag{B.1}$$

This type of cost curve is depicted in Figure B.1. Coefficients a_i, b_i and c_i are then specified for each generator.

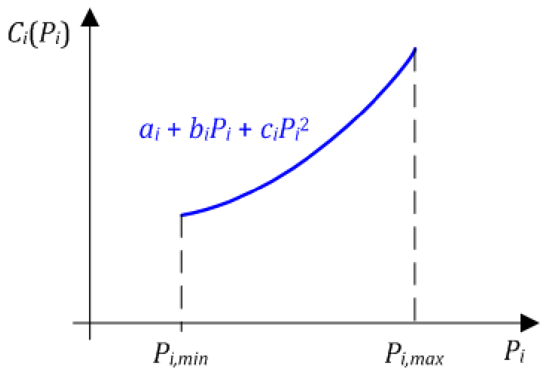


Figure B.1 Quadratic generator cost curve

A quadratic cost function is still only an approximation of real-life input-output characteristics, which can display various discontinuities or non-convexities. However, even the quadratic approximation introduces non-linear terms into the objective function, adding to the complexity of the problem. As discussed in Chapter 2 and 4 there is an interest in keeping the computational time for solving the generation scheduling problem low consequently there is an interest in solving the problem using linear optimisation. This requires approximating the quadratic cost function of Figure B.1 by a linear function. If this approximation is done using a sufficiently large number of linear segments, cost curves can be approximated with high accuracy.

For the above reasons, this approximation is used to model the generator cost curves which are then represented as piecewise linear functions as the one shown in Figure B.. In this case the curve is approximated by three linear segments, i.e. two elbow points ($E_{i,1}$ and $E_{i,2}$) between minimum and maximum power. Each segment j has its own slope $B_{i,j}$, with the slopes increasing when going from minimum to maximum power, to maintain the convexity of the curve. When the line of the lowest segment is extrapolated towards zero power, one reaches the point of "no-load cost" A_i, which will later be used to formulate piecewise linear cost curves in the linear programming framework.

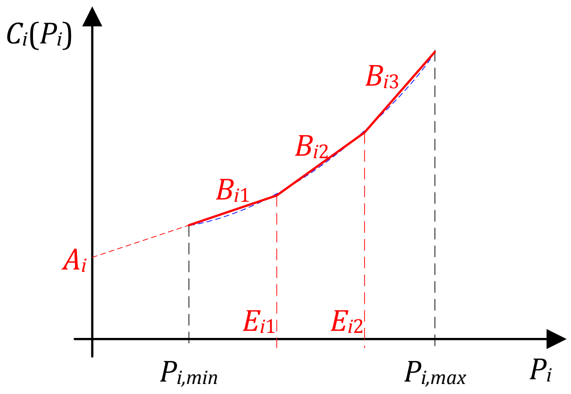


Figure B.2. A piecewise linear generator cost curve

For J linear segments in a cost curve, the total generator output can be expressed as the sum of outputs per individual segment $p_{i,j}$:

$$P_i = \sum_{j=1}^{J} p_{i,j} \tag{B.2}$$

where the first segment output can be between P_i^{min} and $E_{i,1}$, and segment output j can take values between 0 and $\left(E_{i,j} - E_{i,j-1}\right)$, assuming $E_{i,J} = P_i^{max}$. The total cost when generator i is operating can then be found as:

$$C_i(P_i) = A_i + \sum_{j=1}^{J} p_{i,j} B_{i,j} \tag{B.3}$$

Naturally, when the generator is offline, its output as well as cost is zero, and this needs to be accurately taken into account in the overall objective function. Furthermore, the increasing order of slopes (i.e. marginal costs) $B_{i,j}$ when moving from minimum to maximum power ensures that the linear programme will use segment output variables $p_{i,j}$ in the correct order, starting from the lowest segment up to the highest one.

Appendix C Contribution of a generator to frequency response

The contribution of individual generator to frequency response depends on the plant response characteristics. Since the response characteristic of individual plant depends on its loading level the limits of the contribution of the plant are defined as a function of these. These functions are typically obtained through a set of tests based carried out at critical loading points across the whole loading range. The results for different loading points are interpolated to obtain an approximate function of the frequency response capability between plant minimum stable generation and maximum registered capacity. The general shape of this function is illustrated in Figure C.1. This function is then used to define the operation constraints of the plant contribution to frequency response at each time step.

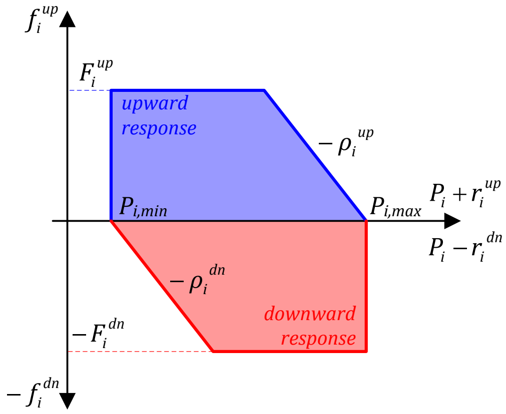


Figure C.1. Limits to generator response contributions

The positive y axes area refers to the plant contribution to upward (primary or secondary) response contribution, while the negative y axes area refers to downward (high frequency) response. As indicated by the figure, in this work, the available response contribution depends not only on the generators scheduled output at a certain time *t*, but also on the reserve contribution it is scheduled to provide at the same time, for upward and downward contributions respectively. In this way the remaining available capacity by the generator is accurately taken into account.

Secondly, the upper limit of the response contribution from individual generator, represented through horizontal lines at F_i^{up} and $-F_i^{dn}$ in Figure C. is an approximation of the typical profile which varies slightly for different plants regarding the contribution close to maximum registered capacity. Such limits represent the physical dynamics of the control process governing the output adjustment. Through the examination of system dynamic requirements under different emergency conditions, the United Kingdom System Operator (National Grid Energy Transmission) quantified the average response capability of current plant in the system [81], presented in Table C.1 .

Table C.1 Frequency response capability of different plant in % of Maximum Registered Capacity

	Primary	Secondary	High Frequency
Coal	12 %	13 %	14 %
Oil	15 %	15 %	13 %
CCGT	11 %	13 %	13 %

Finally, if the sum of unit's output and upward reserve contribution is at P_i^{max} , the unit obviously cannot contribute to frequency response. If the scheduled commitment is now reduced by lowering the output from the maximum level, some of unit's capacity will be released to provide upward response. However, the amount of response contribution will not be equal to the amount by which the output was reduced, but will be smaller. This is represented by slope $-\rho_i^{up}$ in Figure C., whose absolute value, for the above reason, is always less than one. Typically, its value is around 0.5 with slight differences are found for different plant. Analogous consideration can be applied for downward response contribution when increasing output plus downward reserve contribution, and in that case slope $-\rho_i^{dn}$ applies, with absolute value again less than one.

All of the above indicates that there is a strong interdependency between electricity output, reserve contribution and providing response by the generators. Changing any of the three quantities will affect the generator's capability to deliver the other two.

Appendix D Generator data

This appendix presents the data of the generation technologies used in the case studies of this thesis. Table D.1 presents the generation parameters and Table D.2 presents the WG data for the different wind scenarios.

Table D.1 Generation parameters

Technology	P_i^{min} / P_i^{max} (MW)	$NoLoad$ $Cost$ (£)	inc_{cost} (£/MWh)	$start$ $up\ cost$ (£)	t_i^{up} / t_i^{down} (hr)	R_i^{pr} (MW)	m_i^{up}	V_i^{up} /V_i^{down} (MW/hr)	E_i^{max} [70] (kg/MWh)	$P_l^{effloss}$ [71] (%)
Low flexible	250/500	1850	30	15,000	4/4	60	0.6	100/160	925	18
High flexible	250/500	4900	40	8,600	6/4	55	0.6	250/250	394	28
Must Run	480/500	520	20	0	7/12	0	0	2/20	0	1,8

Table D.2 Wind generation scenarios

Wind Installed (GW)	10	20	30	40	50
Wind Penetration (% of total energy demand)	8	16	24	32	40
Wind Energy (TWh/year)	30.66	61.32	91.98	122.64	153.33

[70] E_i^{max} is the emission factor at maximum output for conventional fuel generators, expressed in kilograms of CO2 emitted per MWh of electricity generated.

[71] Fuel efficiency losses when running the plant part – loaded.

Appendix E – Data used for the comparative analysis of different demand side management algorithms

This appendix presents the detailed data used in Chapter 6 to compare the performance of different demand side management algorithms for peak reduction obtained from [110].

The demand data used for this comparison corresponds to a winter day taken from the annual demand data of the UK. This day has a peak consumption of 56.8 GW at 17:30 pm and a total energy consumed on that day of 1085.3 GWh. Table E.1 presents the data used to represent the shiftable devices. Table E.2 presents the structure of the control schemes used and the key outputs of the models used to perform the comparison between them.

Table E.1 Device type features for the Cobelo algorithm

Device type	1	2	3	4	5	6
Consumption cycle [15 min intervals]	6	10	16	24	4	20
Maximum allowed delay [15 min intervals]	16	20	8	0	4	24

Table E.2 Data of the control schemes used as inputs and main outputs of the different models

Model	Control Schemes (15 min intervals)	Control scheme start time	Power of group	Original Peak	New Peak	Max Peak Reduction
Lee and Wilkins	1. (16+8) 2. (16+8)[A] 3. (12+8) 4. (8+8)[A]	15 – 19 14 – 18 16 – 19 17 – 19	Σ = 1200	56836	55636	480
Kurucz at al.	1. (16+7) 2. (12+4) 3. (8+2)	– – –	320 (32) 480 (20) 400 (50)		56356	1200
Cobelo	–	–	Σ = 1200		56356	1200

Appendix F – Disaggregation algorithm for smart appliances data

This appendix presents the description of the disaggregation algorithm used to estimate the number of devices connected at each obtained from [108]. The algorithm is applied at the data pre-processing stage with the aim of obtaining an estimate of the expected number of devices connected at each time step. This can be done by using data of the diversified load curve and consumption cycle pattern for each appliance.

Let t represents the number of time steps in the optimization period (in this case one time step corresponds to a 15 minutes interval, and for the whole day there are 96 such intervals, consequently $t = 96$). From the diversified load consumption curve, a power value $\mathrm{C_q}$ for each time step $q = 1,2,\ldots,t$ is read. Also, let d represent the duration of the device load consumption pattern and $\mathrm{p_w}$, $(\mathrm{w} = 1,2,\ldots,d)$ - the device consumption at each time step. If now $\mathrm{D_q}$ denotes the number of devices starting their consumption at time step q, then the power $\mathrm{C_q}$ at time step q will be composed of the demand of the devices starting their consumption at q and of the demand of the devices that started their consumption on the previous time steps:

$$C_q = \sum_{w=1}^{d} D_{q-(w-1)} \cdot p_w, \quad q = 1,2,\ldots,t$$

The solution of this system of linear equations should be rounded to the nearest integer number.

Appendix G – Data for the 16 bus GB transmission system

This appendix presents the data of the GB 16 bus transmission system used in the Chapter 7 of thesis. This system consists of 16 buses representative of the 14 GB major transmission boundaries. The data for this system was extracted from [121]. Table G.1 presents the generation data and Table G.2 presents the line data.

Table G.1 Generation data

Type	Inst. Cap. (GW)	c_g (£/MWh)	c_g^+ (£/MWh)	c_g^- (£/MWh)
Must Run	15	20	20	15
Wind	15	0	0	0
Coal 1	11	23	23	18
Coal 2	3	24	24	19
Coal 3	10.5	25	25	20
CCGT 1	5	28	28	23
CCGT2	8	29	29	24
CCGT3	17	30	30	25
Oil 1	0.073	48	48	43
Oil 2	12.5	50	50	45

Table G.2 Line thermal power ratings for the 16 bus test system

	L1	L2	L4	L5	L6	L7	L8	L9	L10	L11	L12	L13	L14	L15
Thermal rating (GW)	1.2	2.4	2.3	3.8	4.6	4.7	2.0	5.6	9.9	6.8	5.4	9.1	4.9	5.1