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Reserve services provision by demand side resources in systems with high renewables penetration using stochastic optimization

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Engineering

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Thesis submitted in fulfillment of the requirements for the degree of
Doctor of Philosophy in
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Resumo

As fontes de energias renováveis irão possivelmente representar uma parte significativa do mix de produção de muitos sistemas de energia, em todo o mundo, pelo que é esperado um aumento desta tendência nos próximos anos devido às questões ambientais e económicas. Entre as diferentes fontes renováveis endógenas, a produção eólica tem sido uma das opções mais apontadas com o intuito de, não só reduzir a pegada de carbono, oriunda do sector energético, mas também de contribuir para um aumento da eficiência económica do mix de geração.

Embora a integração destes recursos possa apresentar vários potenciais benefícios para os sistemas de energia, a sua integração em larga escala poderá acarretar problemas adicionais, uma vez que esta produção é altamente volátil. Como resultado, para além das típicas fontes de incerteza que os Operadores de Sistemas enfrentam, recorrendo a níveis suficientes de geração de reserva, como por exemplo sistemas de contingência e variações de carga intra-horárias, reservas extras têm de ser mantidas com intuito de garantir o equilibro entre a geração e o consumo. Para além disso, surgem uma série de outros problemas como, por exemplo, a perda de eficiência devido ao *ramping* de unidades convencionais, custos ambientais, devido ao aumento de emissões resultantes da afetação e despacho de unidades subótimas, e um sistema mais dispendioso em temos de operação e manutenção. Para além da geração, tem-se vindo a reconhecer que vários tipos de carga podem ser implementadas com intuito de fornecer aos serviços do sistema, especialmente para os diferentes tipos de reservas, recorrendo da resposta à demanda. É expectável que a contribuição das reservas, por parte da demanda, para acomodar altos níveis de penetração de produção eólica, tenha uma importância substancial no futuro, sendo, por isso, necessário um estudo aprofundado da integração destes recursos na operação do sistema.

Assim sendo, esta tese lida com aspetos relacionados com a resposta à demanda no que diz respeito à integração de produção eólica no sistema de energia elétrica. Em primeiro lugar, é apresentado o enquadramento do estado atual da resposta à demanda em termos internacionais, seguindo-se de uma discussão sobre as oportunidades, benefícios e barreiras de uma adoção alargada dos recursos da demanda. Seguidamente, várias combinações de energia e estruturas de mercado de reserva são desenvolvidas, incorporando explicitamente os recursos da resposta à demanda que poderão contribuir para serviços e reservas energéticas. Com intuito de contemplar a incerteza associada à geração eólica é aplicada a programação estocástica de duas etapas. Adicionalmente, vários aspetos são tidos em conta na resposta à demanda como, por exemplo, a capacidade de providenciar contingência e as reservas de seguimento de carga, a modelação apropriada da carga de processos de consumidores industriais e o efeito de recuperação de carga. Por último, esta tese investiga o efeito dos recursos da resposta à demanda no risco que é associado às decisões do operador de sistemas através das técnicas apropriadas de gestão de risco, propondo assim uma nova metodologia de lidar com o risco como alternativa às técnicas habitualmente usadas.

Palavras-chave

Efeito recuperação de carga; Fontes de energias renováveis; Gestão de risco; Optimização multi-objetivo; Produção eólica; Programação estocástica; Programação linear inteira mista; Reservas de seguimento de carga; Reservas de Contingência; Resposta à demanda; Resposta à demanda industrial; Sistemas de energia.

Abstract

It is widely recognized that renewable energy sources are likely to represent a significant portion of the production mix in many power systems around the world, a trend expected to be increasingly followed in the coming years due to environmental and economic reasons. Among the different endogenous renewable sources that may be used in order to achieve reductions in the carbon footprint related to the electricity sector and increase the economic efficiency of the generation mix, wind power generation has been one of the most popular options.

However, despite the potential benefits that arise from the integration of these resources in the power system, their large-scale integration leads to additional problems due to the fact that their production is highly volatile. As a result, apart from the typical sources of uncertainty that the System Operators have to face, such as system contingencies and intra-hour load deviations, through the deployment of sufficient levels of reserve generation, additional reserves must be kept in order to maintain the balance between the generation and the consumption. Furthermore, a series of other problems arise, such as efficiency loss because of ramping of conventional units, environmental costs because of increased emissions due to suboptimal unit commitment and dispatch and more costly system operation and maintenance. Recently, it has been recognized that apart from the generation side, several types of loads may be deployed in order to provide system services and especially, different types of reserves, through demand response. The contribution of demand side reserves to accommodate higher levels of wind power generation penetration is likely to be of substantial importance in the future and therefore, the integration of these resources in the system operations needs to be thoroughly studied.

This thesis deals with the aspects of demand response as regards the integration of wind power generation in the power system. First, a mapping of the current status of demand response internationally is attempted, followed also by a discussion concerning the opportunities, the benefits and the barriers to the widespread adoption of demand side resources. Then, several joint energy and reserve market structures are developed which explicitly incorporate demand side resources that may contribute to energy and reserve services. Two-stage stochastic programming is employed in order to capture the uncertainty of wind power generation. Moreover, several aspects of demand response are considered such as the capability of providing contingency and load following reserves, the appropriate modeling of industrial consumer processes load and the load recovery effect. Finally, this thesis investigates the effect of demand side resources on the risk that is associated with the decisions of the System Operator through appropriate risk management techniques, proposing also a novel methodology of handling risk as an alternative to the commonly used technique.

Keywords

Contingency reserves; Demand response; Industrial demand response; Load following reserves; Load recovery effect; Mixed-integer linear programming; Multi-objective optimization; Power systems; Renewable energy sources; Risk management; Stochastic programming; Wind power.

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Acronyms

4CP	Four Coincident Peak
AC	Air-conditioner
ACT	Air Conditioned Trial
ADRP	Automated DR Program
AEMC	Australian Energy Market Commission
AEP	American Electric Power
AER	Australian Energy Regulator
AHU	Air Handling Unit
AMI	Advanced Metering Infrastructure
AML	Algebraic Modelling Language
ANEEL	Brazilian Electricity Regulatory Agency
ARIMA	Auto-Regressive Integrated Moving Average
AS	Ancillary Services
AUGMECON	Augmented Epsilon Constraint (method)
BIP	Base Interruptible Program
BMS	Building Management System
BPDB	Bangladesh Power Development Board
CAISO	California ISO
CFE	Comisión Federal de Electricidad
CPP	Critical Peak Pricing
CSRP	Commercial System Relief Program
CVaR	Conditional Value-at-Risk
DADRP	Day-ahead DR Program
DBP	Demand Bidding Program
DLC	Direct Load Control
DLRP	Distribution Load Relief Program
DM	Decision Maker
DOE	(U.S.) Department of Energy
DR	Demand Response
DRP	Demand Response Provider
DRS	Demand Reduction Strategy
DSASP	Demand Side Ancillary Services Program
DSM	Demand Side Management
EDA	Electricity of the Azores
EDP	Extreme Day Pricing
EDRP	Emergency DR Program
EED	Energy Efficiency Directive
EMA	Energy Market Authority
EMS	Energy Management System
ENTSO-E	European Network of TSOs for Electricity
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EU	European Union

EV	Electric Vehicle
FEBELIEC	Federation of Beligan Industrial Energy Consumers
FIL	Firm Service Level
FPL	Florida Power&Light
GAMS	General Algebraic Modeling System
HAN	Home Area Network
HEMS	Home EMS
HVAC	Heating Ventilation and Air Conditioning
ICT	Information and Communications Technology
IESO	Independent Electricity System Operator (Ontario)
IP	Internet Protocol
IR	Instantaneous Reserves
ISO	Independent System Operator
ISO-NE	ISO New England
LMP	Locational Marginal Price
LP	Linear Programming
LSE	Load Serving Entity
MILP	Mixed-integer Linear Programming
MISO	Midcontinent ISO
MO	Market Operator
MOOP	Multi-objective Optimization Problem
NAN	Neighbourhood Area Network
NEMS	National Electricity Market of Singapore
NERC	North American Electric Reliability Corporation
NIST	(U.S.) National Institute of Standards and Technology
NYISO	New York ISO
OBMC	Optional Binding Mandatory Curtailment
OpenADR	Open Automated DR
PDPD	Peak Day Pricing Program
PG&E	Pacific Gas&Electric Company
PJM	Pennsylvania New Jersey Maryland (Interconnection)
PLC	Power Line Communication
PV	Photovoltaic
RES	Renewable Energy Sources
RTP	Real Time Pricing
SCE	Souther California Edison
SCR	Spacial Case Resources
SDGE	San Diego Gas&Electric Company
SHEP	Small Hydroelectric Power Plant
SLRP	Scheduled Load Reduction Program
SMP	System Marginal Price
SOP	Standard Offer Program
STOR	Short-Term Operating Reserve
TDSP	Transmission and Distribution Service Providers
TECO	Tampa Electric Company
TOPSIS	Technique for Order Preference By Similarity to Ideal Solution
TOU	Time-of-Use

TSO	Transmission System Operator
UPS	Uninterruptible Power Source
V2G	Vehicle-to-Grid
VaR	Value-at-Risk
VFD	Variable Frequency Drives
WAN	Wide Area Network
WECC	Western Electricity Coordinating Council

Nomenclature

The main notation used in Chapters 3, 4 and 5 is listed below. Other symbols are defined where they first appear. Note that in order to state that a constraint holds ”for every” element of a set, instead of e.g., $\forall i \in I$, for the sake of brevity, $\forall i$ is used, unless strict notation is required to identify the domain of a constraint.

Chapter 3

Sets and indices

b ($B(n, nn)$)	index (set) of transmission lines.
B_b^n	set of sending nodes of transmission line b.
B_b^{nn}	set of receiving nodes of transmission line b.
f (F^i)	index (set) of steps of the marginal cost function of unit i.
i (I)	index (set) of conventional generating units.
j_1 (J_1)	index (set) of LSE of type 1.
j_2 (J_2)	index (set) of LSE of type 2.
n (N)	index (set) of nodes.
N_n^x	set of resources of type $x \in \{i, j_1, j_2, r, w\}$ connected to node n.
r (R)	index (set) of inelastic loads.
s (S^w)	index (set) of scenarios of wind farm w.
t_1 (T_1)	index (set) of time intervals in the first stage of the problem.
t_2 (T_2)	index (set) of time intervals in the second stage of the problem.
w (W)	index (set) of wind farms.

Parameters

B_{i,f,t_1}	size of step f of unit i marginal cost function in period t_1 (MW).
$B_{b,n}$	susceptance of transmission line b (per unit).
C_{i,f,t_1}	marginal cost of step f of unit i marginal cost function in period t_1 (€/MWh).
$C_{i,t_1}^{R,DN}$	offer cost of down spinning reserve by generating unit i in period t_1 (€/MWh).
$C_{j_1,t_1}^{DN,LSE1}$	offer cost of down reserve by LSE of type 1 j_1 in period t_1 (€/MWh).
$C_{j_2,t_1}^{DN,LSE2}$	offer cost of down reserve by LSE of type 2 j_2 in period t_1 (€/MWh).
$C_{i,t_1}^{R,NS}$	offer cost of non spinning reserve by generating unit i in period t_1 (€/MWh).
$C_{i,t_1}^{R,UP}$	offer cost of up spinning reserve by generating unit i in period t_1 (€/MWh).
$C_{j_1,t_1}^{UP,LSE1}$	offer cost of up reserve by LSE of type 1 j_1 in period t_1 (€/MWh).
$C_{j_2,t_1}^{UP,LSE2}$	offer cost of up reserve by LSE of type 2 j_2 in period t_1 (€/MWh).
D_{r,t_1}^1	demand of inelastic load r in period t_1 (MW).
D_{r,t_2}^2	demand of inelastic load r in period t_2 (MW).
DT_i^1	minimum down time of unit i (h).
DT_i^2	minimum down time of unit i (min).
$E_{j_1}^{req}$	energy requirement of LSE of type 1 j_1 (MWh).
f_b^{max}	maximum capacity of transmission line b (MW).

LC_{b,t_2}	transmission line b contingency parameter — 0 if transmission line b is under contingency in period t_2, else 1.
$LSE1^{max}_{j_1,t_1}$	maximum load of LSE of type 1 j_1 in period t_1 (MW).
$LSE1^{min}_{j_1,t_1}$	minimum load of LSE of type 1 j_1 in period t_1 (MW).
$LSE2^{max}_{j_2,t_1}$	maximum load of LSE of type 2 j_2 in period t_1 (MW).
$LSE2^{min}_{j_2,t_1}$	minimum load of LSE of type 2 j_2 in period t_1 (MW).
$N^{call}_{j_2}$	maximum number of calls of LSE of type 2 j_2.
P^{max}_i	maximum power output of unit i (MW).
P^{min}_i	minimum power output of unit i (MW).
$P^{WP}_{w,t_2,s}$	power output of wind farm w in period t_2 in scenario s (MW).
$P^{WP,max}_w$	maximum amount of wind that may be scheduled in the day-ahead market (MW).
RD_i	ramp down rate of unit i (MW/min).
RU_i	ramp up rate of unit i (MW/min).
SDC_i	shutdown cost of generating unit i (€).
SUC_i	startup cost of generating unit i (€).
$T^{dur}_{j_2}$	maximum duration of contingency reserve provision by LSE of type 2 j_2 (min).
UC_{i,t_2}	unit i contingency parameter — 0 if transmission line i is under contingency in period t_2, else 1.
UT^1_i	minimum up time of unit i (h).
UT^2_i	minimum up time of unit i (min).
V^{LOL}_{r,t_2}	cost of involuntary load shedding of inelastic load r in period t_2 (€/MWh).
V^{spill}_{w,t_2}	wind spillage cost of wind from wind farm w in period t_2 (€/MWh).
$\Delta\mathrm{T}_1$	length of time interval in the first stage (min).
$\Delta\mathrm{T}_2$	length of time interval in the second stage (min).
$\lambda^{LSE1}_{j_1,t_1}$	utility of LSE of type 1 j_1 in period t_1 (€/MWh).
$\lambda^{LSE2}_{j_2,t_1}$	utility of LSE of type 2 j_2 in period t_1 (€/MWh).
π_s	probability of occurence of wind power scenario s.
T^{NS}	non spinning reserve deployment time (min).
T^{S}	spinning reserve deployment time (min).

Variables

b_{i,f,t_1}	power output scheduled from the f-th block by unit i in period t_1 (MW).
$CA_{i,t_2,s}$	additional cost incurring due to a change in the commitment status of unit i in period t_2 in scenario s (€).
$f_{b,t_2,s}$	active power flow through transmission line b in period t_2 in scenario s (MW).
$L^{shed}_{r,t_2,s}$	load shed from inelastic load r in period t_2 in scenario s (MW).
$LSE1^{DN}_{j_1,t_1}$	total down reserve scheduled from LSE of type 1 j_1 in period t_1 (MW).
$LSE1^{DN,load}_{j_1,t_1}$	down reserve scheduled to balance load deviations from LSE of type 1 j_1 in period t_1 (MW).
$LSE1^{DN,wind}_{j_1,t_1}$	down reserve scheduled to balance wind deviations from LSE of type 1 j_1 in period t_1 (MW).
$LSE1^{UP}_{j_1,t_1}$	total up reserve scheduled from LSE of type 1 j_1 in period t_1 (MW).
$LSE1^{UP,load}_{j_1,t_1}$	up reserve scheduled to balance load deviations from LSE of type 1 j_1 in period t_1 (MW).
$LSE1^{UP,wind}_{j_1,t_1}$	up reserve scheduled to balance wind deviations from LSE of type 1 j_1 in period t_1 (MW).

$LSE1^{ac}_{j_1,t_2,s}$	actual consumption of LSE of type 1 j_1 in period t_2 in scenario s (MW).
$LSE1^{d}_{j_1,t_2,s}$	total down reserve deployed from LSE of type 1 j_1 in period t_2 in scenario s (MW).
$LSE1^{sch}_{j_1,t_1}$	scheduled consumption of LSE of type 1 j_1 in period t_1 (MW).
$LSE1^{u}_{j_1,t_2,s}$	total up reserve deployed from LSE of type 1 j_1 in period t_2 in scenario s (MW).
$LSE1^{d,load}_{j_1,t_2,s}$	down reserve deployed to balance load deviations from LSE of type 1 j_1 in period t_2 in scenario s (MW).
$LSE1^{d,wind}_{j_1,t_2,s}$	down reserve deployed to balance wind deviations from LSE of type 1 j_1 in period t_2 in scenario s (MW).
$LSE1^{u,load}_{j_1,t_2,s}$	up reserve deployed to balance load deviations from LSE of type 1 j_1 in period t_2 in scenario s (MW).
$LSE1^{u,wind}_{j_1,t_2,s}$	up reserve deployed to balance wind deviations from LSE of type 1 j_1 in period t_2 in scenario s (MW).
$LSE2^{DN,con}_{j_2,t_1}$	down reserve scheduled from LSE of type 2 j_2 in period t_1 (MW).
$LSE2^{UP,con}_{j_2,t_1}$	up reserve scheduled from LSE of type 2 j_2 in period t_1 (MW).
$LSE2^{ac}_{j_2,t_2,s}$	actual consumption of LSE of type 2 j_2 in period t_2 in scenario s (MW).
$LSE2^{d,con}_{j_2,t_2,s}$	down reserve deployed from LSE of type 2 j_2 in period t_2 in scenario s (MW).
$LSE2^{sch}_{j_2,t_1}$	scheduled consumption of LSE of type 2 j_2 in period t_1 (MW).
$LSE2^{u,con}_{j_2,t_2,s}$	up reserve deployed from LSE of type 2 j_2 in period t_2 in scenario s (MW).
$P^{G}_{i,t_2,s}$	actual power output of unit i in period t_2 in scenario s (MW).
P^{sch}_{i,t_1}	power output scheduled for unit$i$ in period t_1 (MW).
$P^{WP,S}_{w,t_1}$	scheduled wind power for wind farm w in period t_1 (MW).
R^{DN}_{i,t_1}	total down spinning reserve scheduled from unit i in period t_1 (MW).
$R^{DN,con}_{i,t_1}$	contingency down spinning reserve scheduled from unit i in period t_1 (MW).
$R^{DN,load}_{i,t_1}$	down spinning reserve scheduled to balance load deviations from unit i in period t_1 (MW).
$R^{DN,wind}_{i,t_1}$	down spinning reserve scheduled to balance wind deviations from unit i in period t_1 (MW).
R^{NS}_{i,t_1}	total non spinning reserve scheduled from unit i in period t_1 (MW).
$R^{NS,con}_{i,t_1}$	contingency non spinning reserve scheduled from unit i in period t_1 (MW).
$R^{NS,load}_{i,t_1}$	non spinning reserve scheduled to balance load deviations from unit i in period t_1 (MW).
$R^{NS,wind}_{i,t_1}$	non spinning reserve scheduled to balance wind deviations from unit i in period t_1 (MW).
R^{UP}_{i,t_1}	total up spinning reserve scheduled from unit i in period t_1 (MW).
$R^{UP,con}_{i,t_1}$	contingency up spinning reserve scheduled from unit i in period t_1 (MW).
$R^{UP,load}_{i,t_1}$	up spinning reserve scheduled to balance load deviations from unit i in period t_1 (MW).
$R^{UP,wind}_{i,t_1}$	up spinning reserve scheduled to balance wind deviations from unit i in period t_1 (MW).
$r^{G}_{i,f,t_2,s}$	reserve deployed from the f-th block of unit i in period t_2 in scenario s (MW).
$r^{dn}_{i,t_2,s}$	total down spinning reserve deployed from unit i in period t_2 in scenario s (MW).
$r^{dn,con}_{i,t_2,s}$	contingency down spinning reserve deployed from unit i in period t_2 in scenario s (MW).
$r^{dn,load}_{i,t_2,s}$	down spinning reserve deployed to balance load deviations from unit i in period t_2 in scenario s (MW).

$r^{dn,wind}_{i,t_2,s}$	down spinning reserve deployed to balance wind deviations from unit i in period t_2 in scenario s (MW).
$r^{ns}_{i,t_2,s}$	total non spinning reserve deployed from unit i in period t_2 in scenario s (MW).
$r^{ns,con}_{i,t_2,s}$	contingency non spinning reserve deployed from unit i in period t_2 in scenario s (MW).
$r^{ns,load}_{i,t_2,s}$	non spinning reserve deployed to balance load deviations from unit i in period t_2 in scenario s (MW).
$r^{ns,wind}_{i,t_2,s}$	non spinning reserve deployed to balance wind deviations from unit i in period t_2 in scenario s (MW).
$r^{up}_{i,t_2,s}$	total up spinning reserve deployed from unit i in period t_2 in scenario s (MW).
$r^{up,con}_{i,t_2,s}$	contingency up spinning reserve deployed from unit i in period t_2 in scenario s (MW).
$r^{up,load}_{i,t_2,s}$	up spinning reserve deployed to balance load deviations from unit i in period t_2 in scenario s (MW).
$r^{up,wind}_{i,t_2,s}$	up spinning reserve deployed to balance wind deviations from unit i in period t_2 in scenario s (MW).
SDC^1_{i,t_1}	shutdown cost of unit i in period t_1 (€).
$SDC^2_{i,t_2,s}$	shutdown cost of unit i in period t_1 in scenario s (€).
SUC^1_{i,t_1}	startup cost of unit i in period t_1 (€).
$SUC^2_{i,t_2,s}$	startup cost of unit i in period t_1 in scenario s (€).
$S_{w,t_2,s}$	wind spilled from wind farm w in period t_2 in scenario s (MW).
u^1_{i,t_1}	binary variable — 1 if unit i is committed in period t_1, else 0.
$u^2_{i,t_2,s}$	binary variable — 1 if unit i is committed in period t_2 in scenario s, else 0.
y^1_{i,t_1}	binary variable — 1 if unit i is starting up in period t_1, else 0.
$y^2_{i,t_2,s}$	binary variable — 1 if unit i is starting up in period t_2 in scenario s, else 0.
z^1_{i,t_1}	binary variable — 1 if unit i is shutting down in period t_1, else 0.
$z^2_{i,t_2,s}$	binary variable — 1 if unit i is shutting down in period t_2 in scenario s, else 0.
$\delta_{n,t_2,s}$	binary variable — voltage angle of node n in period t_2 in scenario s (rad).
$\zeta^{LSE2}_{j_2,t_2,s}$	binary variable — 1 if LSE of type 2 j_2 stops providing contingency reserve in period t_2 in scenario s, else 0.
$\upsilon^{LSE2}_{j_2,t_2,s}$	binary variable — 1 if LSE of type 2 j_2 is providing contingency reserve in period t_2 in scenario s, else 0.
$\upsilon^{dn}_{j_2,t_2,s}$	binary variable — 1 if LSE of type 2 j_2 is providing down contingency reserve in period t_2 in scenario s, else 0.
$\upsilon^{u}_{j_2,t_2,s}$	binary variable — 1 if LSE of type 2 j_2 is providing up contingency reserve in period t_2 in scenario s, else 0.
$\psi^{LSE2}_{j_2,t_2,s}$	binary variable — 1 if LSE of type 2 j_2 is called to provide contingency reserve in period t_2 in scenario s, else 0.

Chapter 4

Sets and indices

$b\,(B(n,nn))$	index (set) of transmission lines.
B^n_b	set of sending nodes of transmission line b.
B^{nn}_b	set of receiving nodes of transmission line b.

d (D)	index (set) of industrial loads.
f (F^i)	index (set) of steps of the marginal cost function of unit i.
g (G^d)	index (set) of groups of processes of industrial load d.
i (I)	index (set) of conventional generating units.
j (J)	index (set) of inelastic loads.
n (N)	index (set) of nodes.
N_n^x	set of resources of type $x \in \{i, j, d, w\}$ connected to node n.
p (P^d)	index (ordered set) of processes of industry d.
P_{type}^h	set of process types: $h = 1$ for continuous, $h = 2$ for interruptible.
s (S^w)	index (set) of scenarios of wind farm w.
t (T)	index (set) of time intervals.
w (W)	index (set) of wind farms.

Parameters

$a_{p,g,d}^{max}$	positive integer — maximum number of available production lines for process p of group g of industrial load d.
$a_{p,g,d}^{max,h}$	positive integer — maximum number of production lines per hour for process p of group g of industrial load d.
$B_{i,f,t}$	size of step f of unit i marginal cost function in period t (MW).
$B_{b,n}$	susceptance of transmission line b (per unit).
$C_{i,f,t}$	marginal cost of step f of unit i marginal cost function in period t (€/MWh).
$C_{i,t}^{R,D}$	offer cost of down spinning reserve by generating unit i in period t (€/MWh).
$C_{i,t}^{R,U}$	offer cost of up spinning reserve by generating unit i in period t (€/MWh).
$C_{i,t}^{R,NS}$	offer cost of non spinning reserve by generating unit i in period t (€/MWh).
$C_{d,t}^{R,D,In}$	offer cost of down reserve by industrial load d in period t (€/MWh).
$C_{d,t}^{R,U,In}$	offer cost of up reserve by industrial load d in period t (€/MWh).
$C_{d,t}^{R,NS,In}$	offer cost of non spinning reserve by industrial load d in period t (€/MWh).
$D_{d,t}^{min}$	minimum power of industrial load d in period t (MW).
DT_i	minimum down time of unit i (h).
f_b^{max}	maximum capacity of transmission line b (MW).
$L_{j,t}$	demand of inelastic load j in period t (MW).
P_i^{max}	maximum power output of unit i (MW).
P_i^{min}	minimum power output of unit i (MW).
$P_{p,g,d}^{line}$	power of production line of process p of group g of industrial load d (MW).
$P_{w,t,s}^{WP}$	power output of wind farm w in scenario s in period t (MW).
$P_{w,t}^{WP,max}$	maximum amount of wind that may be scheduled in the day-ahead market (MW).
RD_i	ramp down rate of unit i (MW/min).
RU_i	ramp up rate of unit i (MW/min).
SDC_i	shutdown cost of generating unit i (€).
SUC_i	startup cost of generating unit i (€).
T^{NS}	non spinning reserve deployment time (min).
T^S	spinning reserve deployment time (min).
$T_{p,g,d}^{c,max}$	maximum completion time of process p of group g of industrial load d (h).
$T_{p,g,d}^{g,max}$	maximum time interval between processes p and $p+1$ of group g of industrial load d (h).

$T_{p,g,d}^{g,min}$	minimum time interval between processes p and $p+1$ of group g of industrial load d (h).
UT_i	minimum up time of unit i (h).
V^{LOL}	cost of involuntary load shedding for inelastic loads (€/MWh).
V^s	wind spillage cost (€/MWh).
α	confidence level ($CVaR$ calculation).
β	weighting factor ($CVaR$ calculation).
ΔT	length of time interval (min).
$\lambda_{d,t}^{D}$	utility of industrial load d in period t (€/MWh).
π_s	probability of occurence of wind power scenario s.

Variables

$a_{p,g,d,t}$	integer variable — number of production lines scheduled from process p of group g of industrial load d in period t.
$a_{p,g,d,t,s}^{2}$	integer variable — number of production lines scheduled from process p of group g of industrial load d in period t in scenario s.
$a_{p,g,d,t}^{down}$	integer variable — number of production lines scheduled from process p of group g of industrial load d in period t to provide down reserves.
$a_{p,g,d,t,s}^{down,rt}$	integer variable — number of production lines that are used to deploy down reserves from process p of group g of industrial load d in period t in scenario s.
$a_{p,g,d,t}^{ns}$	integer variable — number of production lines scheduled from process p of group g of industrial load d in period t to provide non spinning reserves.
$a_{p,g,d,t,s}^{ns,rt}$	integer variable — number of production lines that are used to deploy non spinning reserves from process p of group g of industrial load d in period t in scenario s.
$a_{p,g,d,t}^{up}$	integer variable — number of production lines scheduled from process p of group g of industrial load d in period t to provide up reserves.
$a_{p,g,d,t,s}^{up,rt}$	integer variable — number of production lines that are used to deploy up reserves from process p of group g of industrial load d in period t in scenario s.
$b_{i,f,t}$	power output scheduled from the f-th block by unit i in period t (MW).
$CVaR$	conditional value-at-risk (€).
$f_{b,t,s}$	active power flow through transmission line b in period t in scenario s (MW).
$L_{j,t,s}^{shed}$	load shed from inelastic load j in period t in scenario s (MW).
$P_{i,t,s}^{G}$	actual power output of unit i in period t in scenario s (MW).
$P_{d,t,s}^{ind,C}$	actual power consumption of industrial load d in period t in scenario s (MW).
$P_{d,t}^{ind,S}$	scheduled consumption of industrial load d in period t (MW).
$P_{p,g,d,t,s}^{pro,C}$	actual power consumption of process p of group g of industrial load d in period t in scenario s (MW).
$P_{p,g,d,t}^{pro,S}$	scheduled consumption of process p of group g of industry d in period t (MW).
$P_{i,t}^{S}$	power output scheduled for unit i in period t (MW).
$P_{w,t}^{WP,S}$	scheduled wind power for wind farm w in period t (MW).
$R_{i,t}^{D}$	down spinning reserve scheduled from unit i in period t (MW).
$R_{d,t}^{D,ind}$	down reserve scheduled from industrial load d in period t (MW).
$R_{p,g,d,t}^{D,pro}$	scheduled down reserve from process p of group g of industrial load d in period t (MW).

$r^{D,pro}_{d,g,p,t,s}$	down reserve deployed from the process p of the group g of industrial load d in period t in scenario s (MW).
$r^{D}_{i,t,s}$	down spinning reserve deployed from unit i in period t in scenario s (MW).
$r^{G}_{i,f,t,s}$	reserve deployed from the f-th block of unit i in period t in scenario s (MW).
$R^{NS}_{i,t}$	non spinning reserve scheduled from unit i in period t (MW).
$R^{NS,ind}_{d,t}$	non spinning reserve scheduled from industrial load d in period t (MW).
$R^{NS,pro}_{p,g,d,t}$	scheduled non spinning reserve from process p of group g of industrial load d in period t (MW).
$r^{NS,pro}_{d,g,p,t,s}$	non spinning reserve deployed from the process p of the group g of industrial load d in period t in scenario s (MW).
$r^{NS}_{i,t,s}$	non spinning reserve deployed from unit i in period t in scenario s (MW).
$R^{U}_{i,t}$	up spinning reserve scheduled from unit i in period t (MW).
$R^{U,ind}_{d,t}$	up reserve scheduled from industrial load d in period t (MW).
$R^{U,pro}_{p,g,d,t}$	scheduled up reserve from process p of group g of industrial load d in period t (MW).
$r^{U,pro}_{d,g,p,t,s}$	up reserve deployed from the process p of the group g of industrial load d in period t in scenario s (MW).
$r^{U}_{i,t,s}$	up spinning reserve deployed from unit i in period t in scenario s (MW).
$S_{w,t,s}$	wind spilled from wind farm w in period t in scenario s (MW).
$u^{1}_{i,t}$	binary variable — 1 if unit i is committed during period t, else 0.
$u^{2}_{i,t,s}$	binary variable — 1 if unit i is committed during period t in scenario s, else 0.
$y^{1}_{i,t}$	binary variable — 1 if unit i is starting up in period t, else 0.
$y^{2}_{i,t,s}$	binary variable — 1 if unit i is starting up in period t in scenario s, else 0.
$z^{1}_{i,t}$	binary variable — 1 if unit i is shutting down in period t, else 0.
$z^{2}_{i,t,s}$	binary variable — 1 if unit i is shutting down in period t in scenario s, else 0.
$\delta_{n,t,s}$	voltage angle of node n in period t in scenario s (rad).
$\zeta^{1}_{p,g,d,t}$	binary variable — 1 if process p of group g of industrial load d is terminated in period t, else 0.
$\zeta^{2}_{p,g,d,t,s}$	binary variable — 1 if process p of group g of industrial load d is terminated in period t in scenario s, else 0.
η_{s}	non negative auxiliary variable ($CVaR$ calculation) (€).
ξ	auxiliary variable ($CVaR$ calculation) (€).
$\upsilon^{1}_{p,g,d,t}$	binary variable — 1 if process p of group g of industrial load d is in progress in period t, else 0.
$\upsilon^{2}_{p,g,d,t,s}$	binary variable — 1 if process p of group g of industrial load d is in progress in period t in scenario s, else 0.
$\psi^{1}_{p,g,d,t}$	binary variable — 1 if process p of group g of industrial load d is beginning in period t, else 0.
$\psi^{2}_{p,g,d,t,s}$	binary variable — 1 if process p of group g of industrial load d is beginning in period t in scenario s, else 0.

Chapter 5

Sets and indices

$b\,(B(n,nn))$	index (set) of transmission lines.

B_b^n	set of sending nodes of transmission line b.
B_b^{nn}	set of receiving nodes of transmission line b.
f (F^i)	index (set) of steps of the marginal cost function of unit i.
i (I)	index (set) of conventional generating units.
I^{NS}	set of generating units capable of providing non spinning reserves.
j (J)	index (set) of loads.
J^0	set of inelastic loads.
J^1	set of demand response providers of type 1.
J^2	set of demand response providers of type 2.
n (N)	index (set) of nodes.
N_n^x	set of resources of type $x \in \{i, j, w\}$ connected to node n.
s (S^w)	index (set) of scenarios of wind farm w.
t (T)	index (set) of time intervals.
w (W)	index (set) of wind farms.

Parameters

$B_{b,n}$	susceptance of transmission line b (per unit).
$B_{i,f,t}$	size of step f of unit i marginal cost function in period t (MW).
$C_{i,t}^{G,D}$	offer cost of up spinning reserve by generating unit i in period t (€/MWh).
$C_{i,t}^{G,U}$	offer cost of down spinning reserve by generating unit i in period t (€/MWh).
$C_{i,t}^{G,NS}$	offer cost of non spinning reserve by generating unit i in period t (€/MWh).
$C_{j,t}^{DRP,U}$	offer cost of load reduction scheduling from demand j in period t (€/MWh).
$C_{i,f,t}^{G}$	marginal cost of step f of unit i marginal cost function in period t (€/MWh).
$c_{j,t}^{DRP,U}$	cost of load reduction deployment from demand j in period t (€/MWh).
$D_{j,t}$	nominal load of demand j in period t (MW).
DT_i	minimum down time of unit i (h).
f_b^{max}	maximum capacity of transmission line b (MW).
N_j^{in}	maximum number of interruptions of demand j.
P_i^{max}	maximum power output of unit i (MW).
P_i^{min}	minimum power output of unit i (MW).
$P_w^{W,max}$	maximum amount of wind that may be scheduled in the day-ahead market (MW).
$P_{w,t,s}^{WP}$	power output of wind farm w in scenario s in period t (MW).
p	maximum participation of demand side resources in reserves (%).
$R_j^{DRP,U,m}$	minimum load reduction of demand j (MW).
RD_i	ramp down rate of unit i (MW/min).
RD_j^{DRP}	load pickup rate of demand j (MW/min).
RU_i	ramp up rate of unit i (MW/min).
RU_j^{DRP}	load drop rate of demand j (MW/min).
SDC_i	shutdown cost of generating unit i (€).
SUC_i	startup cost of generating unit i (€).
T^{NS}	non spinning reserve deployment time (min).
T_j^{rec}	duration of the load recovery period (h).
T^S	spinning reserve deployment time (min).
UT_i	minimum up time of unit i (h).
V_j^{ENS}	cost of energy not served/not recovered of load j (€/MWh).
V^S	wind spillage cost (€/MWh).

α	confidence level ($CVaR$ calculation).
β	weighting factor ($CVaR$ calculation).
γ_j	load recovery rate with respect to load reduction of load j (%).
ΔT	length of time interval (min).
$\xi^D_{j,t}$	maximum downward demand modification of demand j in period t (%).
$\xi^U_{j,t}$	maximum upward demand modification of demand j in period t (%).
π_s	probability of occurrence of wind power scenario s.

Variables

$b_{i,f,t}$	power output scheduled from the f-th block by unit i in period t (MW).
$CVaR$	conditional value-at-risk (€).
$D^A_{j,t,s}$	actual consumption of demand j in period t in scenario s (MW).
$ENR_{j,s}$	energy of demand j not recovered in scenario s (MWhh).
$f_{b,t,s}$	active power flow through transmission line b in period t in scenario s (MW).
$L^{shed}_{j,t,s}$	load shed from inelastic load j in period t in scenario s (MW).
$P^G_{i,t,s}$	actual power output of unit i in period t in scenario s (MW).
$P^{sch}_{i,t}$	power output scheduled for unit i in period t (MW).
$P^{W,sch}_{w,t}$	scheduled wind power from wind farm w in period t (MW).
$R^{DRP,D}_{j,t}$	load recovery scheduled from demand j in period t (MW).
$R^{DRP,U}_{j,t}$	load reduction scheduled from demand j in period t (MW).
$R^{G,D}_{i,t}$	down spinning reserve scheduled from unit i in period t (MW).
$R^{G,NS}_{i,t}$	non spinning reserve scheduled from unit i in period t (MW).
$R^{G,U}_{i,t}$	up spinning reserve scheduled from unit i in period t (MW).
$r^{DRP,d}_{j,t,s}$	load recovery of demand j in period t in scenario s (MW).
$r^{DRP,u}_{j,t,s}$	load reduction of demand j in period t in scenario s (MW).
$r^G_{i,f,t,s}$	reserve deployed from the f-th block of unit i in period t in scenario s (MW).
$r^{G,d}_{i,t,s}$	down spinning reserve deployed from unit i in period t in scenario s (MW).
$r^{G,ns}_{i,t,s}$	non spinning reserve deployed from unit i in period t in scenario s (MW).
$r^{G,u}_{i,t,s}$	up spinning reserve deployed from unit i in period t in scenario s (MW).
$S_{w,t,s}$	wind spilled from wind farm w in period t in scenario s (MW).
$u^1_{i,t}$	binary variable — 1 if unit i is committed during period t, else 0.
$u^2_{i,t,s}$	binary variable — 1 if unit i is committed during period t in scenario s, else 0.
$u^{DRP,d}_{j,t,s}$	binary variable — 1 if demand j is recovering in period t in scenario s.
$u^{DRP,u}_{j,t,s}$	binary variable — 1 if demand j is curtailed in period t in scenario s.
$y^1_{i,t}$	binary variable — 1 if unit i is starting up in period t, else 0.
$y^2_{i,t,s}$	binary variable — 1 if unit i is starting up in period t in scenario s, else 0.
$z^1_{i,t}$	binary variable — 1 if unit i is shutting down in period t, else 0.
$z^2_{i,t,s}$	binary variable — 1 if unit i is shutting down in period t in scenario s, else 0.
$\delta_{n,t,s}$	voltage angle of node n in period t in scenario s (rad).
η_s	non negative auxiliary variable ($CVaR$ calculation) (€).
$\kappa_{j,t,s}$	auxiliary variable used to linearize load recovery (MW).
ξ	auxiliary variable ($CVaR$ calculation) (€).

Chapter 1

Introduction

1.1 Thesis Motivation: Challenges and Opportunities Under Large-Scale Penetration of Renewable Energy Sources

It is widely recognized that Renewable Energy Sources (RES) are likely to represent a significant portion of the production mix in many power systems around the world, a trend expected to be increasingly followed in the coming years [1]. There are two main reasons that have motivated the adoption of RES:

1. *Environmental issues.* Concerns regarding the climate change have led the international community to take actions in order to control the greenhouse gas emissions. The fossil-fuel electricity sector is a major contributor to environmental degradation and therefore, increasing the share of RES is perceived as an environmentally friendly alternative in order to achieve the carbon footprint reduction targets.
2. *Scarcity and increased cost of conventional fuels.* Many countries and regions rely heavily on the import of external energy resources and especially oil. An apt example of this is the case of the Canary Islands, the electricity generation of which depended by 94% on imported fuels in 2010 [2]. Similarly, Cyprus uses almost exclusively heavy fuel oil and diesel for electricity generation [3]. The price of imported fuels is in turn dependent on geopolitical factors and transportation costs. These issues are likely to contribute to the electricity price volatility. For example, the cost of electricity for residential and commercial end-users was approximately 31 cents per kWh in September 2010, 40 cents per kWh in December 2012, and 42 cents per kWh in the third quarter of 2013 in American Samoa [4]. This increase in the price of electricity was mainly caused by the high and variable cost of fuel per barrel. Given that providing low-cost electricity is essential for the economic development of a country, such an increase in the electricity prices may prove detrimental. On the other hand, there are many autochthonous energy sources that may be used according to the specific needs and peculiarities of each system in order to mitigate imported fuel dependence and to diversify the production mix.

However, despite the potential economic and environmental benefits that arise from the integration of these resources into the power system, large-scale integration of RES leads to additional problems due to the fact that their production is highly volatile and unpredictable. Although leading RES technologies such as wind and solar generation are mature and able to compete with conventional power plants, they are associated with significant variability due to their intrinsically stochastic nature. Wind and solar production depend on wind speed and irradiation values, which in turn fluctuate according to weather changes and spatial characteristics. As a result, instantaneous, seasonal and yearly fluctuations affect the generation output of RES. The integration of high levels of non-dispatchable resources in power systems and especially in relatively small sized, non-interconnected systems such as the insular ones, poses operational and economic challenges that need to be addressed. The magnitude of the problem depends on the penetration of RES in the production mix, while its mitigation is reflected on the "flexibility" of the power system.

The variable production from RES affects the operation of conventional generators [5],[6],[7]. Under high levels of penetration conventional units are likely to operate in a suboptimal commitment and dispatch. Fluctuation of RES output power leads to cycling of conventional units and shortens the life of their turbines, while causing increased generation costs. The emission reduction potential is also suppressed. Furthermore, reserve needs are increasing with the penetration of RES and especially ramping requirements (load following) because of the uncorrelated variation of wind generation and load demand. For instance, a case study for the power system of Cyprus [8] concluded that the available reserve capacity is not adequate to balance the real-time fluctuations of wind, while higher penetration of wind power generation would further constrain the downward ramping capability of the system due to the part loading of generators. This example reveals another challenge for the system stemming from the increasing penetration of RES: the inability of conventional generators to boundlessly reduce their output when the non-dispatchable RES production is high. Typically, diesel-fired generators have a minimum output limit of 30% of their installed capacity. Forcing a load following unit to shut down in order to retain the generation and demand balance may compromise the longer-term reliability of the power system. Thus, to avoid such a deficit in the inertia of the system, RES generation is normally curtailed instead of switching off synchronous generators, at the expense of economic losses [9]. The penetration of RES may also affect voltage stability because power sources such as fixed-speed induction wind turbines and PV converters have limited reactive power control. Surely, additional operational reserves (spinning or non-spinning) are required. Apart from frequency regulation, load-forecasting error, sudden changes (ramps) in the production of RES units, forced or scheduled equipment outages need also to be confronted. To deal with these issues adequate generation or demand side capacity should be kept.

Motivated by the increasing penetration of RES and especially wind power generation in power systems, as well as by the operational problems that have been briefly discussed, this thesis deals with the development of reserve mechanisms that directly incorporate several types of demand side resources in order to cope with the uncertainty of RES production. Prior to delving into the investigation of several aspects of the participation of demand side resources in the power system operations and presenting relevant mathematical models, this introductory chapter aims at providing an overview of the necessary framework of the thesis. First, a short overview of RES based production technologies and basic definitions regarding the participation of the demand side and electricity markets are presented in Sections 1.2, 1.3 and 1.4 respectively. Then, the necessary background on the methodology utilized in this thesis is briefly introduced in Section 1.5. Finally, the research questions together with the novel contributions of this thesis are listed in Section 1.6. The chapter concludes by outlining the structure of the thesis in Section 1.7.

1.2 Green Energy Production Options

1.2.1 Solar energy

Solar radiation may be used directly in order to produce energy either through direct conversion of the solar energy to electrical (through photovoltaics - PV) or to provide energy for side applications (e.g., water heating, solar drying, solar cooling systems). Essentially, most RES (wind, ocean and biomass energy) are indirect forms of solar energy [10]. Solar energy systems may be considered a suitable generation opportunity in different forms for areas with considerable solar energy potential. Naturally, according to the location generation potential differs from place to place. For example, all the Greek islands are characterized by high solar irradiance, varying from 1500 kWh/m^2 to 1700 kWh/m^2. Furthermore, the annual variation of the solar potential is in many cases correlated to the annual variation of the load demand of the system [11], rendering it an appealing green energy option.

There are several ways to integrate PV modules. They can be installed on the rooftops of buildings (several kW) or, if larger scale production is required, in collective solar power plants (e.g., municipal), such as concentrated photovoltaic or concentrated solar power plants. There are two major drawbacks concerning electricity generation using solar energy. First, it is still an expensive technology and subsides are required in order to render it competitive. However, there are initiatives by leading country governments in order to reduce the relevant costs [12]. Second, as a result of its relatively low energy density, significant space is required in order to achieve adequate electricity production from solar potential.

Several initiatives regarding the integration of RES consider vast investments in solar energy. In 2010, 112 MW of PV capacity were installed in the Canary Islands. The Canary Islands Energy Plan aims to achieve having 30% of the electricity needs covered by RES, mainly solar (160 MW) and wind (1025 MW) [2]. Most recent data (2013) regarding the RES share in the power system of Cyprus suggest that it stands only for 1.2% of the total electricity production. Production of rooftop PV systems and PV parks amounts only to approximately 7.7% of this small share. However, due to the commitment of Cyprus to comply with the EU 2020 goals, the country developed a program (National Renewable Energy Action Plan of Cyprus) that among others targets to install 192 MW of solar PVs and 75 MW of concentrated solar power by 2020 [3]. Furthermore, the island of Crete is expected to have 140 MW of solar energy installed by 2030 [13]. Also, in 2010 60 GWh were produced in Reunion Island by the PV systems installed (80 MW), both stand-alone and interconnected [10]. Recently, the Hawaiian islands of Oahu, Maui and Kauai had significant solar resources, reaching a penetration of 10% in Oahu [14]. Finally, the example of the U.S. Virgin Islands, where PV installations are considered an economic way for the reduction in fossil fuel consumption, is very important to realize the potential of the solar energy, especially for the electrification of non-interconnected power systems [15].

1.2.2 Wind energy

It is estimated that the world's wind resources have the capacity to generate 53000 TWh of electrical energy per year which accounts for three times the global electrical energy consumption [16]. Because of the increasing interest (due to national and international targets) in reducing their carbon footprint, many countries motivated the development of this type of RES over the past decade. Many areas have exploitable on-shore and off-shore wind potential. In the non-interconnected Greek island of Rhodes, approximately 6% of the energy production comes from the 11.7 MW installed wind power [17]. The biggest Greek island, Crete, in 2006 had an installed wind capacity of 105 MW which accounted for 12.5% of the total capacity and the twelve wind farms could instantaneously provide up to 39% of the total generated power. However, the total licensed capacity exceeds 200 MW [13] and currently (2015) the installed capacity reaches 194 MW. In 1998 Samso Island was chosen by the Danish Government as a demonstration of a 100% RES based electricity production island. As an evidence of this successful endeavor, Samso Island currently has 23 MW of offshore wind power generation and 11 MW of onshore wind power generation while all its demand needs are covered by RES. The Spanish El Hierro Island is also subject to an ambitious target of becoming a 100% renewable energy dependent island and currently wind power penetration reaches 30% [18]. The South Korean Jeju Island is also an example of high wind power generation penetration. There is the goal of installing 250 MW of wind power and in 2010 88 MW of wind power generation were already installed [19]. Finally, plans for increasing the RES penetration in many areas are set by other countries as well. Canary Islands, the American Hawaiian Islands and the German Pellworm Island are a few indicative examples.

The major challenge that needs to be addressed when planning to utilize wind energy to produce electricity is the intermittent and variable nature of this kind of production. Intermittency refers to the unavailability of wind for a considerably long period while volatility describes the smaller, hourly oscillations of wind. Due to the reduced control over the wind energy production, some quality characteristics of the power system such as frequency and voltage may be affected. Also, to balance the lack of production during some periods, generation adequacy has to be reserved, leading the power system to a vulnerable state, especially in the case of non-interconnected power systems. Nevertheless, intermittency management is performed using sophisticated tools and wind could be considered a reliable source of energy in the long-run [20].

1.2.3 Wave energy

During the last decades great effort has been devoted to develop solar and wind energy generation. However, the idea of exploiting the high energy potential of the waves has recently drawn significant attention. Wave energy has been recognized as more reliable than solar and wind power because of its energy density (typically 2-3 kW/m^2 compared to 0.4-0.6 kW/m^2 of wind and 0.1-0.2 kW/m^2 of solar potential). Besides, wave energy offers several advantages in comparison with other RES. First of all, waves can travel long distances without losing much of their energy and as a result wave energy converters can generate up to 90% of time compared to 20-30% for wind and solar converters. This fact renders wave energy a credible and reliable energy source. Furthermore, there are also specific advantages that make it an appealing choice for the electrification of power systems of countries having access to the sea and insular power systems. Firstly, the resource is available in multiple locations (from shoreline to deep waters). Secondly, the proximity of the demand to resource (distance between generation and load) is high in near-sea areas and islands. Finally, this type of RES has less environmental impacts (e.g., aesthetic) than other alternatives.

The main challenge towards the large scale integration of wave energy is the infant phase of the relevant technologies. To provide high quality power to the grid, frequency and voltage have to be of appropriate levels. Together with the fact that the wave power is uncertain, special storage systems are needed to support the output of such plants. To efficiently exploit the wave power, especially in off-shore applications where energy flux is greater, infrastructure has to withstand severe stress due to intense environmental conditions. Regardless of the attractive features of wave energy, lack of funding poses a further hindrance to the development of the required technology. Other RES are more competitive since their respective markets are mature, whilst large investments are still required to construct wave energy harnessing plants.

Wave power varies with the location and the season and therefore the placing and the technology of such plants should be carefully considered. Also, the variability of the resource changes significantly according to the same parameters. However, several applications are already routed. For instance, for the year 2015, the Canary Islands Energy Plan establishes that 30% of the electricity generation should be supplied by RES, mainly wind and solar. This plan establishes among others that wave energy has to reach a capacity of 50 MW [2].

1.2.4 Other technologies

Apart from exploiting the solar and wind potential and harnessing energy from the waves, there are also several other options to produce electrical energy from RES: geothermal energy, biomass and small hydroelectric power plants (SHEP).

Geothermal energy comes from the natural heat under the crust of the earth and is linked to earthquakes and volcanic activity and therefore the thermodynamic characteristics (e.g., temperature, enthalpy, etc.) of geothermal resources may significantly vary among different areas. However, the available technology to exploit geothermal energy has evolved and is capable of adapting to the specific characteristics of the local resources and therefore, it may be considered mature. Geothermal energy has a potential to be used for electric energy generation in non-interconnected insular power systems. For example, based on several studies, a 2.5 MW geothermal power plant may be considered to be installed in the Island of Pantelleria (Italy). It may be possible to achieve a production of 20000 MWh/year that stands for about 46% of the island's consumption [21]. Also, the Government of Azores has launched an ambitious plan to achieve 75% of sustainable electricity production by 2018. The Electricity of the Azores (EDA) strategy, among others, includes additional investments in geothermal plants in the major islands (São Miguel) [22]. In February 2009 approximately 20.6% of the total produced energy was generated by geothermal energy in Hawaii (Big Island) [23]. Significant geothermal power is installed in Jeju Island (South Korea) where 130.1 MW of geothermal energy contribute to the total RES generation by 15% [19]. Geothermal plants are characterized by high capital investments (exploration, drilling, plant installation). However, operation and maintenance costs are low and thereof, geothermal plants may serve as base load units [24]. Recently, several hybrid systems combining geothermal energy have attracted research interest in order to achieve a more efficient usage of this resource. Hybrid fossil-geothermal plants have been developed but they led to a compromise of the environmental benefits that standalone geothermal plants have to offer because of the increased greenhouse gases emissions. To maintain the advantage of sustainability, combining other RES (e.g., solar and biomass) with geothermal energy production has been proposed [25].

Biomass is considered a mature and promising form of RES. It offers the advantages of controllability, the possibility of creating liquid fuels and the flexibility to adapt to any raw material that is locally available (agricultural and livestock residuals, urban garbage, etc.). The major challenge is that the installation should be strategically located near a populated area in order to guarantee the constant availability of the raw input resource. A recent study indicates that based on agricultural residues (olive kernel, citrus fruits, etc.) and forestry material, Crete has the potential to develop up to a total of 60 MW of biomass power plants around the island [13]. In the Hawaiian Islands two biomass stations operate having a total installed capacity of 103.1 MW. Currently, two more are under construction and have a total rated capacity of 30.7 MW. Especially, the 6.7 MW station that is being constructed in Kauai Island will provide 11% of the island's annual energy needs [26].

Finally, SHEPs have small installed capacity (e.g., below 10 MW in Europe) and do not generally use large reservoirs. Thus, the interference with the environment is minimal. Such units exist in several areas. In the island of Crete there exist two SHEPs, while a third one is being considered to be built [13]. In Faial (Azores) a 320 kW hydro power unit exists [27]. In El Hierro Island 9.9 MW of hydropower capacity is installed with pumping capability. In this way excessive wind power is used to pump water in the upper reservoir in order to achieve energy storage and cope with the intermittency and the variability of wind power generation [18].

1.3 Demand Side Management and Demand Response

One of the main concerns of the Independent System Operators (ISOs) has been the fact that electric power demand may significantly vary during the day, season and year and the production facilities should be suitably dispatched in all time periods in order to satisfy it. The demand side has been traditionally considered relatively inelastic and therefore the generation side should be adapted in order to fully supply it. However, a series of drivers such as the climate change, the increasing penetration of RES and the consequent increased need for enhancing the flexibility in the system operations, the target of improving energy efficiency and the need to defer costly investments have motivated efforts aiming to enable the active participation of the demand side in the power system operational procedures.

The activities through which the activation of the demand side is attempted are commonly referred to as demand side management (DSM). The Electric Power Research Institute (EPRI) has defined DSM as follows [28]: *"DSM is the planning, implementation and monitoring of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape, i.e., changes in the time pattern and magnitude of a utility's load. Utility programs falling under the umbrella of DSM include load management, new uses, strategic conservation, electrification, customer generation and adjustments in market share"*. The concept of DSM can be considered mature (especially for industrial consumers) with many efforts to reduce or shift the consumption of the end-users in order to reduce the stress on power system assets, especially in critical peak demand periods. Demand side management comprises four actions: energy efficiency, savings, self-production and load management [29].

Among the DSM solutions, load management techniques and especially demand response (DR) strategies are gaining more attention in power system operations recently, driven by the increasing interest in implementing the smart grid concept. DR is defined as *"changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized"* by the U.S. Department of Energy (DoE) and comprises incentive-based and price-based programs [30]. Facilitated by the advancement in smart grid enabling technologies such as the implementation of Information and Communications Technology (ICT) in the power system, the growing number of intelligent energy management systems (EMSs) in end-user premises, smart grid compatible advanced metering infrastructure (AMI), etc., various DR strategies have been already widely adopted by ISOs in different countries around the world.

Chapter 2 provides an extensive and systematic discussion on different aspects of DR.

1.4 Electricity Market Fundamentals

In the majority of the regions around the world, the electricity sector has historically evolved with primarily vertically integrated monopolies in which all the components of electricity supply, namely the generation, transmission, distribution and retail supply, were possessed by a state-owned or a privately-owned utility. However, during the last decades efforts to liberalize the electricity sector are noticed worldwide [31]. The basic form in which deregulation takes place is the unbundling of generation, transmission, distribution and supply activities and as a result a number of institutional and market agents supersede the vertically integrated utilities, while several floors at which electrical energy and other services are traded emerge.

1.4.1 Market actors

There are two categories of market actors: institutional entities and market participants [32],[33]. The different market actors are listed and briefly defined below:

- Market Operator (MO). The MO has two responsibilities: 1) to run the market and settle the payments of electricity sellers and buyers and, 2) to administer the market rules. Typically, the MO is a non-profit entity; however, some longer-term markets may be run by a for-profit entity.
- Independent System Operator. The primary responsibility of the ISO is to technically guarantee the secure operation of the power system. The designation "Independent" means that this entity should promote equal access to the power system for all market participants. An ISO may also be responsible for the settling of short-term markets such as the regulation market and the ancillary services (AS) procurement. A company that owns transmission assets such as lines, transformers, reactive power compensation devices, etc., but no generating plants may also serve as an ISO.
- Regulator. It is an entity (that may be governmental or not) responsible for ensuring the non-discriminatory and efficient operation of the electricity sector. Furthermore, this entity

is responsible for determining and approving rules based on which the electricity markets operate.

- Producers. These are companies that own power plants that produce electrical energy and sell it to the market. Additionally, producers may sell services such as regulation, reserves, etc., that are necessary to maintain the security of the electricity supply. A producer may own one or more power plants of different technologies, including non-dispatchable resources such as wind and solar farms.

- Transmission and distribution companies. These companies own and operate the transmission and distribution systems respectively. They can be state-owned, independent private companies or subsidiaries of generating companies.

- Retailers. They provide electricity to consumers that do not participate directly in the market and thereof, act as intermediates between the producers and the consumers. Retailers may be independent agents or be owned by generation or distribution companies.

- Consumers. Depending on the size of their consumption, small and large consumers are identified. Small consumers buy energy from a retailer and are served by a distribution company. If more than one retailer is available, consumers may have the right to freely choose their preferred one. As opposed to the small consumers, large consumers may be allowed to purchase electrical energy by directly participating in the market, while it is probable that the largest ones are served by a transmission company.

- Demand Response Providers (DRPs). Given that the market rules allow the participation of demand side resources into different electricity market structures and that a consumer is technically capable of altering its consumption, a large consumer may participate into reserve markets and therefore, provide DR. Smaller consumers (e.g., commercial and residential) can also provide DR services if they are aggregated under an intermediate company that acts as a DRP.

It should be noted that the definition of the different market actors presented in this section is quite generic. In some markets, the definitions may slightly vary, some of the actors may not exist, or the functions performed by several of the aforementioned market actors may overlap.

1.4.2 Market structures

There are mainly three ways in which electrical energy can be traded between a producer and a buyer (retailer or consumer):

- Bilateral trading. As its name implies, bilateral trading involves two parties that freely sign a contract out of the organized market structures without the interference of a third party. Different forms of bilateral contracts are investigated in [33].

- Electricity Pools. In a pool electricity is traded on a short-term basis. A typical pool includes the day-ahead market in which the bulk of energy within a dispatch day is traded and several markets that are cleared closer to the time of the physical delivery of electrical energy (intra-day markets, balancing markets). Furthermore, a pool may include a reserve market that may be cleared jointly or after the energy day-ahead energy market in order to procure standby power to confront system component failures (contingency reserves) and large unexpected deviations of the demand and the production of intermittent resources (load following reserves).

- Futures markets. These are auction based markets which allow participants to buy and sell so-called derivative products in the future (spanning from one week to several years) at today's prices. More information on futures markets can be found in [32].

This thesis focuses specifically on day-ahead joint energy and reserve market structures and therefore the former is subsequently discussed in more detail.

In the day-ahead markets, price-quantity bids are submitted by energy sellers and buyers (consumers or retailers) for every period of the market horizon. The MO collects the bids, ranks them according to their price (ascending order for the seller offers, descending order for the buyer bids). As a result, an upward supply and a downward demand curve are formed. Then, the MO clears the market according to the applicable market-clearing procedure, that is to define the market-clearing prices and the production/consumption quantities. If the market-clearing procedure does not take into account the transmission network constraints, then the result of the market-clearing is the system marginal price (SMP) that is common for all the market participants. In case that the transmission constraints are considered, a locational marginal price (LMP) is defined for each node of the power system. The LMPs are different between the nodes due to losses and congestion [33].

In electricity markets apart from energy several other commodities are traded that are generally referred to as AS. These services are required in order to guarantee that imbalances caused by several factors such as equipment failures, the volatility of the demand and the production of RES. In general, there are many types, designs and definitions for reserves and other AS across different systems. Reserves are usually classified according to their technical characteristics such as the speed of response, the control mechanisms and the type of call they must respond to. A survey on AS in different markets was presented by Rebours et al. [34] and Raineri et al. [35]. Reserve markets are cleared either jointly with the day-ahead market (co-optimization) or in a sequential manner after its clearing. The energy and reserve market separation has two main pitfalls: 1) high opportunity costs for generators and, 2) generators that provide reserves operate part-loaded and their efficiency is potentially limited [36]. The co-optimization of day-ahead energy and reserve markets is more economically efficient than the sequential market clearing since the relation of energy supply to reserve provision is strong and for this reason several market operators (e.g., New York ISO-NYISO, California ISO - CAISO, ISO New England-ISO-NE) have adopted joint dispatch models [37]. In power systems that are characterized by increased penetration of intermittent RES, especially wind power generation, the need for procuring reserves in order to balance their uncertain production increases and reserves acquire a significant economic value. This issue and the potential benefits of demand side resources providing reserves are further discussed in Section 2.3.1.

1.5 Background on the Employed Methodology

The mathematical models developed in this thesis are based on well established methods, namely, mixed-integer linear programming (MILP), multi-objective optimization, two-stage stochastic programming and risk management. In this section the fundamental concepts pertaining the methodology employed in this thesis are briefly discussed.

1.5.1 Mixed-integer linear programming

Since the invention of the simplex method, linear programming (LP) has found a wide range of optimization applications in many scientific fields because of its computational efficiency. Also, the non-linear nature of most of real-life problems and the fact that the efficient solution of large-scale non-linear programs is yet to be addressed, require that the non-linear relations are approximated by linear expressions (linearization). Despite its computational advantages, LP may prove an insufficient framework to model a wide range of real-life optimization problems. On the other hand, the possibility of considering variables that can represent discrete decisions provides an efficient and flexible framework to formulate a range of engineering problems since it allows addressing a range of non-linearities such as defining alternative sets of constraints, formulating conditionals, modeling discontinuous functions, etc. [38]. Linear programs that involve variables that can only take integer values are denominated mixed-integer linear programs (MILP). The standard form of a MILP optimization problem (without loss of generality a minimization problem is considered) is represented by (1.1), where $\mathbf{c}$ is the vector of the objective function cost coefficients, $\mathbf{b}$ is a vector of parameters, A is a matrix and $\mathbf{x}$ is the vector of decision variables, some of which are integers, all of appropriate dimensions.

$$\begin{aligned}
&\min_{\mathbf{x}} \; f(\mathbf{x}) = \mathbf{c}^T\mathbf{x} \\
&\textit{subject to} \\
&A\mathbf{x} = \mathbf{b} \\
&\mathbf{x} \geq \mathbf{0} \\
&\mathbf{y} \in \mathbb{Z} \subseteq \mathbf{x}
\end{aligned} \tag{1.1}$$

If all decision variables are required to be integers, then the aforementioned problem is a (pure) integer linear program, while if all decision variables must take either the value 0 or 1, the problem (1.1) is called a $0-1$ linear program.

Nowadays, large instances of MILP problems can be solved efficiently using reliable commercial solvers such as the IBM ILOG CPLEX [39], that may incorporate a variety of solution algorithms such as the branch-bound, Gomory cuts and the branch-cut algorithms or different heuristic-based solution approaches. Furthermore, high-level programming languages known as algebraic modeling languages (AML) such as the General Algebraic Modeling System (GAMS) [40] allow the straightforward computer implementation of large-scale mathematical programming problems. There is an abundant literature concerning the use of the MILP framework in formulating optimization

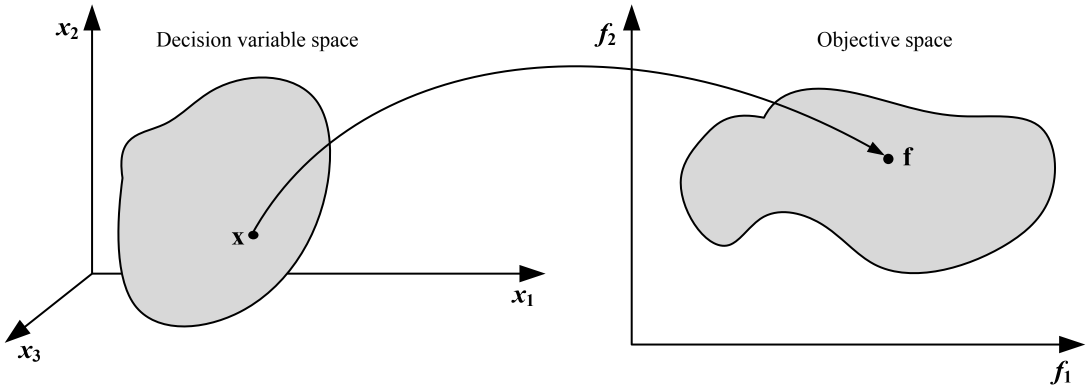

Figure 1.1: Mapping between decision variable space and objective space

models and relevant solution algorithms. Exhaustive treatment of these aspects is out of the scope of this thesis; yet, the interested reader is addressed to [38], [41] and [42],[43].

1.5.2 Multi-objective optimization

The MILP optimization problem described in Section 1.5.1 involves the optimization (minimization or maximization) of a single objective function over the set of the feasible solutions S defined by its constraints. The optimal solution of the minimization problem (1.1) is $\mathbf{x}^* \in S$ such that $f(\mathbf{x}^*) \leq f(\mathbf{x}), \mathbf{x} \in S$. On the other hand, as the name suggests, multi-objective optimization deals with more than one objective. Unlike in the case of the single objective optimization there is not in general a single solution[1] that simultaneously optimizes all the objective functions. Without loss of generality, (1.2) the compact form of a multi-objective optimization problem (MOOP) in which all the objective functions must be minimized is presented.

$$\begin{aligned} &\min_{\mathbf{x}} \mathbf{f}(\mathbf{x}) = [f_1(\mathbf{x}), f_2(\mathbf{x}), ..., f_N(\mathbf{x})] \\ &\textit{subject to } \mathbf{x} \in S \end{aligned} \tag{1.2}$$

As it may be noticed, a vector of objective functions must be optimized. Thus, in addition to the decision variable space, the objective functions constitute a multi-dimensional space, known as the objective space. The mapping between the m-dimensional decision variable space and the N-dimensional objective space is denoted as $\mathbf{f} : \mathbf{X}^m \mapsto \mathbf{F}^N$. Figure 1.1 illustrates the mapping between a 3-dimensional decision variable space and a 2-dimensional objective space. It is to be stated that the mapping between the two spaces is not necessarily one-to-one [44].

The fact that the multi-objective problems constitute a multi-dimensional objective space leads to two cases of multi-objective problems, depending on whether the objectives are conflicting or not. In the special case that the optimization of any arbitrary objective function leads to the improvement of all the objective functions, it is implied that the different objectives are not conflicting. As a result, the MOOP can be solved either by optimizing an arbitrary objective function or the combination of the multiple objectives into a single scalar function. However, in

[1] The models developed in this thesis are MILP and therefore only unimodal optimization problems are of interest.

the majority of multi-objective problems a set of tradeoffs between the different objectives is sought rather than an unique optimal solution. Assuming there exist N different objective functions to be optimized, at least N possible extreme solutions exist, representing the best achievable result for each individual objective at the expense of all the others. Any other existing solutions represent different degrees of relative optimality among the N objectives. It is rendered evident that the classical concept of optimality is not valid in the case of multi-objective optimization. In fact, the evaluation of the solutions is based on the concepts of dominance and Pareto optimality.

1.5.2.1 The concept of dominance and Pareto optimality

As regards dominance, there are three possible relationships between the solutions. More specifically, a solution $\mathbf{f_1} \in \mathbf{F}^N$ may weakly or strongly dominate another solution $\mathbf{f_2} \in \mathbf{F}^N$, or it may be incomparable with it. The dominance relationships are defined as follows:

- $\mathbf{f_1} \in \mathbf{F}^N$ weakly dominates $\mathbf{f_2} \in \mathbf{F}^N(\mathbf{f_1} \preceq \mathbf{f_2})$ if and only if $x_{1,i} \leq x_{2,i} \forall i \in \{1, ..., N\}$,
- $\mathbf{f_1} \in \mathbf{F}^N$ strongly dominates $\mathbf{f_2} \in \mathbf{F}^N(\mathbf{f_1} \prec \mathbf{f_2})$ if and only if $x_{1,i} \leq x_{2,i} \forall i \in \{1, ..., N\}$ and $x_{1,j} < x_{2,j}$ for at least one $j \in \{1, ..., N\}$,
- $\mathbf{f_1} \in \mathbf{F}^N$ is incomparable with $\mathbf{f_2} \in \mathbf{F}^N(\mathbf{f_1} \sim \mathbf{f_2})$ if and only if $x_{1,i} > x_{2,i}$ for at least one $i \in \{1, ..., N\}$ and $x_{1,j} < x_{2,j}$ for at least one $j \in \{1, ..., N\}$.

The aforementioned definitions hold for the case in which all objective functions are to be minimized. The dominance relations for other optimization directions of the objective functions may be trivially deduced.

The dominance relation has the following properties [45]:

- The dominance relation is *not reflexive*, i.e. a solution cannot dominate itself.
- The dominance relation is *not symmetric*, because $\mathbf{f_1} \preceq \mathbf{f_2}$ does not imply $\mathbf{f_2} \preceq \mathbf{f_1}$.
- The dominance relation is *transitive*. This means that if $\mathbf{f_1} \preceq \mathbf{f_2}$ and $\mathbf{f_2} \preceq \mathbf{f_3}$, then $\mathbf{f_1} \preceq \mathbf{f_3}$.
- If $\mathbf{f_1}$ does not dominate $\mathbf{f_2}$, it is not necessary that $\mathbf{f_2}$ dominates $\mathbf{f_1}$

The aforementioned properties qualify the dominance as a *strict partial order* relation, i.e. several pairs of solutions may not be comparable [46].

The concept of domination is graphically explained in Fig. 1.2, assuming a MOOP with two objectives to be minimized. Considering the solution $\mathbf{f}_A \in \mathbf{F}^2$ as a reference, the solutions in the dark grey area are strongly dominated by solution $\mathbf{f}_A$, since $\mathbf{f}_A$ performs better in both objectives. For the same reason, $\mathbf{f}_A$ is dominated by the solutions within the white area. As regards the solutions that are on the boundaries between the darker and lighter grey shaded areas, $\mathbf{f}_A$ weakly dominates them because despite the fact that it performs better with respect to one objective, it has the same value with these solutions for at least one objective. Finally, it is not possible to establish a superiority relationship between $\mathbf{f}_A$ and the solutions that are found in the lighter

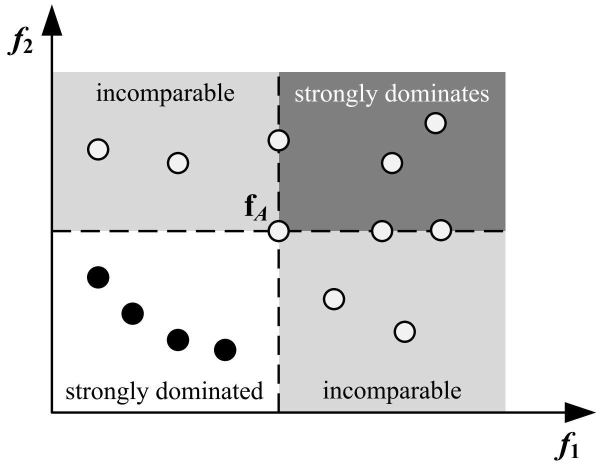

Figure 1.2: Dominance relationship between solution $\mathbf{f}_A$ and other solutions

grey shaded area due to the fact that solutions within the left area are better in objective f_1 and solutions on the right are better in f_2.

The set of solutions that correspond to objective function vectors that are non-dominated, i.e. any component of the objective function vector can be improved only by deteriorating at least one of its other components, is known as Pareto optimal set (also referred to as set of efficient solutions). In mathematical terms, the Pareto optimal set contains the solutions $\mathbf{x}_i^*$ for which holds $\left\{\mathbf{x}_i^* | \nexists \mathbf{F}(\mathbf{x}_j) \prec \mathbf{F}(\mathbf{x}_i^*), \mathbf{F}(\mathbf{x}_j) \in \mathbf{F}^N\right\}$. Furthermore, the set of non-dominated objective function vectors constitute a Pareto optimal front (also referred to as efficient frontier).

1.5.2.2 Solution techniques

The previous discussion has demonstrated that the solution of a MOOP does not generally consist in finding a single optimal solution; several alternative solutions that belong to the Pareto optimal set exist instead. Thus, a decision maker (DM) is required in order to select which of the trade-off solutions will be adopted, potentially by using higher level information. Multi-objective optimization solution methods may be classified into three categories regarding the point at which the DM intervenes to express preferences over the objectives: 1) a priori methods in which the DM expresses preferences (i.e. weights) over the objectives before the solution process, 2) a posteriori or generation methods, where the DM expresses preferences after the Pareto optimal set is discovered and finally, 3) interactive methods, that allow the DM to express preferences during the solution procedure, guiding the method to progressively converge to the most preferable solution [47].

In Chapter 5 a generation multi-objective solution technique, namely the augmented ε-constraint method (AUGMECON), is applied to the two-stage stochastic joint energy and reserve market clearing model of a risk-averse ISO in which two objectives are considered: the minimization of the expected cost of the system and the minimization of a risk metric. Further details on the AUGMECON method may be found in Appendix A. A presentation of several commonly used methods for solving MOOPs can be found in [45].

1.5.3 Stochastic programming

The mathematical models that are developed in this thesis are based on MILP formulations that are of the form of the problem presented in (1.1). As it has been discussed, a MILP framework is suitable in order to address both continuous and discrete decisions. Nevertheless, the parameters of the optimization problem must be perfectly known. Since this thesis focuses on the study of day-ahead electricity markets which are cleared one day before the actual dispatch day, several parameters that are involved in the decision making are not exactly known at the time at which the day-ahead market is cleared. Thus, special attention should be paid to the consideration of the uncertainty attributed to several parameters such as load demand, wind power generation, etc. Stochastic programming is a suitable framework to address these concerns and has been a field of intensive study and research [48],[49],[50]. In this section two-stage stochastic programming with recourse and relevant concepts are discussed.

1.5.3.1 Uncertainty modeling

Within the framework of stochastic programming, uncertain parameters are represented as random variables. A random variable that takes different values over time is referred to as a stochastic process. Random processes can be either continuous or discrete, depending on whether the values of the random variables comprising it are countable or not. For instance, the stochastic process describing the output of a wind farm for the next day is continuous, while the stochastic process that describes the availability of a generator is discrete since the random variable has only two possible outcomes (i.e., either a generator is available or not). Technically, it is hard or even impossible to solve stochastic programming problems incorporating continuous stochastic processes [48]. For this reason, a continuous stochastic process should be replaced by an approximate discrete one or, in other words, by a finite set of scenarios.

Let us consider a discrete (or discretely approximated) random variable ξ that takes values from a finite set of scenarios Ω. A possible realization of the random variable is denoted ξ_ω and the set of possible realizations of the random variable is $\Omega = \{\xi_1, ..., \xi_{N_\Omega}\}$. In case that a random variable evolves over time $t = \{1, ..., N_T\}$, one possible realization of the stochastic process is denoted $\xi_{\omega,t}$ and is a vector of dimensions $1 \times T$. Furthermore, each realization ξ_ω is related to a probability $\pi_\omega \in \mathbb{R}^+$ such that $\pi_\omega = P(\omega|\xi = \xi_\omega)$ and $\sum_{\omega\in\Omega} \pi_\omega = 1$.

The cumulative distribution function (cdf) of the random variable ξ can be then defined as the probability that the random variable will be found to have a value less than or equal to ρ and is mathematically expressed as by (1.3).

$$F_\xi(\rho) = P(\omega|\xi_\omega \leq \rho) = \sum_{\omega\in\Omega|\xi_\omega\leq\rho} \pi_\omega, \forall\rho \in \mathbb{R}^+ \tag{1.3}$$

A random variable is also characterized by its statistical moments. Two popular and very useful statistical moments are the expectation (mean, expected value) and the variance of the random variable and are defined by (1.4) and (1.5) respectively.

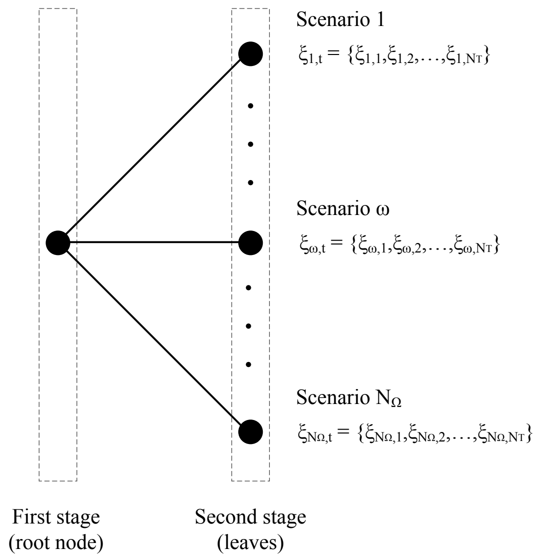

Figure 1.3: Example of a two-stage scenario tree

$$\mathcal{E}\left\{\xi\right\} = \sum_{\omega\in\Omega} \pi_\omega \xi_\omega \tag{1.4}$$

$$\mathcal{V}\left\{\xi\right\} = \sum_{\omega\in\Omega} \pi_\omega (\xi_\omega - \mathcal{E}\left\{\xi\right\})^2 \tag{1.5}$$

Note that $\mathcal{E}$ is expressed in the same unit as the variable ξ, while $\mathcal{V}$ is expressed in the unit of ξ squared. For this reason, the standard deviation, i.e. the square root of the variance is more commonly used. A detailed treatment of stochastic processes can be found in [51].

It is common to represent the set of scenarios using a scenario tree. Figure 1.3 presents an example of a scenario tree of a stochastic process $\xi_{\omega,t}, \omega \in \Omega = \{1, ..., N_\Omega\}, t \in T = \{1, ..., N_T\}$ with two stages, comprising N_Ω scenarios of dimensions $1 \times N_T$. Generally, a scenario tree consists of nodes and brances. Each node has only a single predecessor and may have multiple successor nodes. The first node is called root node and the nodes at the last stage are named leaves. Nodes represent the physical instances at which decisions are made and a path consisting of branches starting from the root node and ending up to a leave corresponds to a realization of the stochastic process. Note also that the number of leave nodes corresponds to the total number of scenarios.

Evidently, it is of utmost importance to adequately describe the random variables through appropriate scenario trees since the optimal decisions are affected by the scenario characterization of the uncertain parameters. Several scenario generation techniques have been proposed in the literature. Another concern regarding the creation is that a very large set of scenarios may affect the computational tractability of the problem and therefore scenario reduction techniques in order to reduce the size of the scenario tree have been also developed. Scenario generation and reduction techniques are not in the scope of this thesis; yet, the state-of-art on these topics can be found in [32] and [52]. In order to generate wind power scenarios that will be used in the stochastic optimization problems that are presented in Chapters 3-5, a technique based on Auto-Regressive

Integrated Moving Average (ARIMA) modeling of historical time series is adopted. More details can be found in Appendix B.

1.5.3.2 Two-stage stochastic programming

In this section the general formulation of a two-stage stochastic MILP problem is presented. Let us consider a random variable ξ that is described by a set of scenarios Ω. The problem involves the variables $\mathbf{x}$ that are the same as the ones of the deterministic MILP of (1.1) and the variables $\mathbf{z}$ that are decided after the realization of ξ and therefore depend on the realization $\omega \in \Omega$ and the decision variables $\mathbf{x}$. Thus, the variables $\mathbf{z}$ are expressed as $\mathbf{z}(\mathbf{x}, \omega)$. There are two sets of decisions:

- A number of decisions that must be made before the realization of the random variable. These decisions are called first-stage decisions or here-and-now decisions and they do not depend on any specific realization of the random variable.
- A number of decisions that must be made after the realization of the random variable. These decisions are called second-stage decisions or wait-and-see decisions and they depend on each specific realization of the random variable.

Thus, the sequence of decisions and events can be represented as: $\mathbf{x} \rightarrow \xi_\omega \rightarrow \mathbf{z}(\omega, \mathbf{x})$.

The formulation of a two-stage stochastic MILP is given by expression (1.6) in which all the matrices and vectors are assumed to have appropriate dimensions and at least one scenario dependent or scenario independent variable receives integer values.

$$
\begin{aligned}
&\min_{\mathbf{x}} \ f(\mathbf{x}) = \mathbf{c}^T\mathbf{x} + \mathcal{E}\left\{\min_{\mathbf{z}(\omega)} \mathbf{q}(\omega)^T\mathbf{z}(\omega)\right\} \\
&\textit{subject to} \\
&A\mathbf{x} = \mathbf{b} \\
&\mathbf{x} \geq \mathbf{0} \\
&\mathbf{y} \subseteq \mathbf{x} \in \mathbb{Z} \\
&\mathbf{y}'(\omega) \subseteq \mathbf{z}(\omega) \in \mathbb{Z} \\
&\mathbf{T}(\omega)\mathbf{x} + \mathbf{W}(\omega)\mathbf{z}(\omega) = \mathbf{h}(\omega), \forall \omega \in \Omega \\
&\mathbf{z}(\omega) \in Z, \forall \omega \in \Omega
\end{aligned}
\tag{1.6}
$$

The objective function contains a deterministic term $\mathbf{c}^T\mathbf{x}$ and the expected value of $\mathbf{q}(\omega)^T\mathbf{z}(\omega)$ over all the possible realizations of the random variable ξ which corresponds to the decisions made after the realized outcome of the random variable is known and therefore expresses recourse decisions. An equivalent form of the problem (1.6) is the so-called deterministic equivalent problem and is presented in (1.7). This form of two-stage stochastic MILP is applied to the problems faced in this thesis.

$$
\begin{aligned}
&\min_{\mathbf{x},\mathbf{z}(\omega)} \; f(\mathbf{x},\mathbf{z}(\omega)) = \mathbf{c}^T\mathbf{x} + \sum_{\omega\in\Omega} \pi(\omega)\mathbf{q}(\omega)^T\mathbf{z}(\omega) \\
&\textit{subject to} \\
&A\mathbf{x} = \mathbf{b} \\
&\mathbf{x} \geq \mathbf{0} \\
&\mathbf{y} \subseteq \mathbf{x} \in \mathbb{Z} \\
&\mathbf{y}'(\omega) \subseteq \mathbf{z}(\omega) \in \mathbb{Z} \\
&\mathbf{T}(\omega)\mathbf{x} + \mathbf{W}(\omega)\mathbf{z}(\omega) = \mathbf{h}(\omega), \forall\omega \in \Omega \\
&\mathbf{z}(\omega) \in Z, \forall\omega \in \Omega
\end{aligned}
\tag{1.7}
$$

The aforementioned discussion has focused specifically on two-stage stochastic MILP since the models presented in this thesis are exclusively of this type. Moreover, several problems can be modeled using more than two stages. Multistage stochastic programming is discussed in [48].

1.5.4 Risk management

Although representing a random variable by its expected value is advantageous in comparison with a deterministic approach, the characteristics associated with the distribution of the outcomes of the individual scenarios are disregarded. As a result, an acceptable expected cost (profit) value may be favorable for the DM; however, there might be the possibility of facing significant costs in several scenarios. To overcome this ambiguity, a risk measure should be incorporated in the optimization problem. A risk measure is a function that results into a real number characterizing the risk associated with the specific expected value of a random variable.

There are various perceptions of risk and therefore, several different risk measures are used. One notion of risk that has been introduced by Markowitz [53] relies on the variance of the distribution of costs (profits) over the different scenarios. According to this rationale, a decision is risky when the variance is large, since there is the probability of experiencing a cost (profit) that significantly differs from the expected cost. Another category of risk measures is based on minimizing the probability of experiencing costs (profits) higher (lower) than a level set by a DM (shortfall probability) or on optimizing the expected value of the scenarios with a cost (profit) higher (lower) than a pre-selected value (expected shortage). Extensive discussion on how to incorporate different risk measures in stochastic programming formulations is performed in [49],[32] and [50]. Other risk metrics include the concept of stochastic dominance and the popular Value-at-Risk (VaR) metric.

In this thesis, the Conditional Value-at-Risk (CVaR) [54] is used because it presents three important advantages: 1) it can be incorporated in the problem (1.7) using a linear formulation, 2) in contrast with VaR it quantifies "fat tails" in the probability distributions and, 3) it is a coherent risk measure that is, it satisfies the properties of translation invariance, subadditivity, positive homogeneity and monotonicity.

Let us assume a stochastic programming problem such as the one described by (1.7). The objective function can be compactly expressed as $\min_{\mathbf{x}} \mathcal{E}_\omega(f(\mathbf{x},\omega))$. For a given $a \in (0,1)$, the VaR is equal

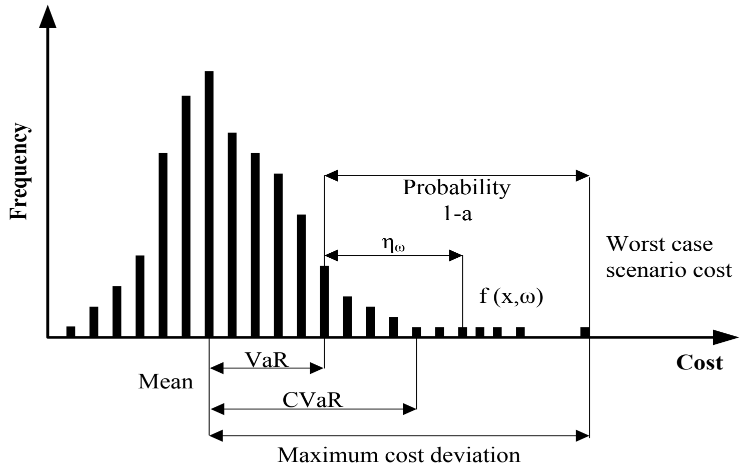

Figure 1.4: Graphical illustration of VaR and CVaR concepts

to the minimum value ζ for which the probability of obtaining a cost higher than ζ is higher than a. It should be noted that ζ is the variable representing the value of the risk measure and not a pre-fixed parameter. Mathematically, VaR is defined in (1.8).

$$VaR(\mathbf{x}, a) = \min \left\{ \zeta : P(\omega | f(\mathbf{x}, \omega) > \zeta) \geq a \right\}, \forall a \in (0, 1) \tag{1.8}$$

For a given $a \in (0, 1)$, CVaR is defined as the expected value of the cost of the scenarios with cost higher than the $(1 - a)$-quantile of the cost distribution (VaR). If all scenarios are equiprobable, CVaR is equivalent to the expected cost of the $a \times 100\%$ worst scenarios. The mathematical definition of CVaR is given in (1.9).

$$CVaR(\mathbf{x}, a) = \min \left\{ \zeta + \frac{1}{1-a} \mathcal{E}_\omega \left\{ \max \left\{ f(\mathbf{x}, \omega) - \zeta, 0 \right\} \right\} \right\}, \forall a \in (0, 1) \tag{1.9}$$

To include the CVaR risk metric in a stochastic optimization problem, the linear constraints (1.10) must be added to the risk neutral problem (1.7). Note that the first constraint in (1.10) is the definition of the CVaR metric, which for a risk-averse DM should be as minimal as possible. Also, it is to be stated that the variable ζ has an optimal value equal to the $VaR(\mathbf{x}, a)$ and η_ω is a continuous nonnegative variable that is equal to the maximum of $f(\mathbf{x}, \omega) - \zeta$ and 0 and stands for the excess of the cost of scenario ω over ζ.

$$\begin{aligned} CVaR(\mathbf{x}, a) &= \zeta + \frac{1}{1-a} \sum_{\omega \in \Omega} \pi_\omega \eta_\omega \\ f(\mathbf{x}, \omega) - \zeta &\leq \eta_\omega, \forall \omega \in \Omega \\ \eta_\omega &\geq 0, \forall \omega \in \Omega \end{aligned} \tag{1.10}$$

The concepts of VaR and CVaR are illustrated in Fig. 1.4 on a distribution of a random variable representing cost.

As it can be presumed by the previous discussion, the inclusion of a risk metric in the stochastic optimization problem turns it into a multi-objective problem that complies with the concepts that were presented in Section 1.5.2. Thus, a multi-objective optimization solution technique must be applied in order to construct the Pareto optimal front that describes the trade-off between the expected cost and the value of the risk metric. In Chapters 4 and 5, the CVaR risk metric is applied in order to consider the risk-averse behavior of an ISO aiming at minimizing the total cost of the system under different wind power generation scenarios.

1.6 Research Questions and Contribution of the Thesis

This thesis aims to investigate the effect of flexible demand side resources on the operations of power systems that are characterized by high levels of wind power generation penetration taking into account that the variable output of this green energy option results in an increased need of procuring reserve services to balance its uncertainty.

In particular, the following research questions will be addressed:

- What is the current status of DR applications in real power systems? Why DR is not yet widely adopted across the world despite its potential benefits?
- Can demand side resources facilitate the system operations when apart from system contingencies and intra-hour load deviations, the ISO must also confront the uncertainty in the production of wind farms?
- What are the qualifications for an industrial consumer to participate in the day-ahead energy and reserve market?
- What is the impact of the load recovery effect on the risk mitigation capability of demand side resources contributing to reserve services?
- Is there a more efficient approach to consider risk management than the weighting method in the day-ahead energy and reserve scheduling problem faced by the ISO?

The contributions of the thesis may be summarized as follows:

- A thorough discussion regarding the main aspects of DR, focusing especially on the mapping of the current status quo based on international experience and on the barriers to the widespread adoption of DR across the world that have lead to contrasting views and asymmetric progress concerning the development of DR programs in different regions.
- The development of day-ahead joint energy and reserve market structures for power systems that are characterized by increased levels of penetration of wind power generation that explicitly incorporate demand side resources capable of providing energy and reserve services.
- The development of a framework for the participation of demand side resources to the provision of load following and contingency reserves.

- The development of a generic load model of an industrial consumer that is capable of participating in the day-ahead market in order to provide energy and reserve services.
- The presentation of a novel approach concerning risk management using a multi-objective optimization approach.
- The investigation of the effect that flexible demand side has on the risk associated with the decisions of the ISO both for the case of industrial consumers and for a conceptual and more general modeling of the load recovery effect.

1.7 Organization of the Thesis

The thesis comprises six chapters and three appendices which are organized as follows:

Chapter 1 is the introductory chapter of the thesis. First, the motivation and the framework of the thesis is presented. Then, the available energy production options from RES are discussed, while the definition of DSM and DR are provided. Subsequently, an overview of the fundamental concepts concerning the electricity market structures and the market participants is given. Furthermore, in this chapter the background on the methodology used throughout the thesis is introduced. The chapter continues by bringing forward the research questions that the work presented in this thesis aspires to answer and lists its contributions. Finally, the chapter concludes by outlining the structure of the thesis.

In Chapter 2 a comprehensive overview of DR is presented. First, a review of the enabling technology and a classification of DR programs according to their type and the consumer response are provided. Then, the benefits of DR for the system and the various market participants are presented, focusing especially on the role of DR in the integration of intermittent generation. Most importantly, an extensive examination of DR programs that are available in different regions around the world is presented and the barriers to the widespread adoption of DR are thoroughly discussed.

In Chapter 3 a two-stage stochastic programming based joint energy and reserve market structure is presented in which both unit outages and transmission line contingencies as well as the wind power generation uncertainty and the intra-hour load demand deviations are considered. Apart from the conventional generating units, demand side resources may be used in order to procure energy and reserve services to compensate the imbalances caused by both system contingencies and wind power generation variations. An illustrative example and a realistic case study are simulated in order to analyze the proposed formulation.

A detailed model that allows the participation of the industrial loads in the market which represents different types of industrial processes is presented in Chapter 4. Also, a two-stage stochastic programming based joint energy and reserve market structure is developed in which the ISO may procure reserves to balance the wind power generation variation both from the generation side and large industrial consumers. Additionally, risk is modeled through the CVaR metric. To test the proposed methodology an illustrative example and a realistic case study are studied both for the case of a risk neutral and a risk averse ISO.

A two-stage stochastic programming based joint energy and reserve market structure that focuses on the modeling of the load recovery effect in order to preserve the internal energy balance of the demand side that participates in reserve procurement is presented in Chapter 5. Another aim of this chapter is to examine the capability of the demand side to mitigate the risk that is associated with the decisions of the ISO due to the wind power generation uncertainty. For this reason, the behavior of a risk averse ISO is modeled as a MOOP that is solved using a novel approach. Moreover, a multi-attribute decision making method is adopted in order to facilitate the ISO in selecting the appropriate solution to implement. The proposed approach is tested by performing simulations both on an illustrative test system and a realistic test case.

In Chapter 6 the main conclusions emerging from this thesis are presented. In addition, possible directions for future research are suggested and the published works of the Author are listed.

In Appendix A the main concepts regarding multi-objective optimization are clarified and the AUGMECON method is demonstrated by presenting a simple arithmetical example.

In Appendix B the historical data used and the wind power scenario generation technique are presented.

Finally, in Appendix C the data used in the simulations performed in the thesis are listed in detail.

Chapter 2

A Critical Overview of Demand Response: Key-Elements and International Experience

2.1 Introduction

The increasing penetration of RES in power systems intensifies the need of enhancing the flexibility in grid operations in order to accommodate the intermittent nature of the leading RES such as wind and solar generation. Utilities have been recently showing increasing interest in developing DR programs in order to more efficiently manage the generation-demand balance. Incentive- and price-based DR programs aim at enabling the demand side in order to achieve a range of operational and economic advantages, towards developing a more sustainable power system structure. Hence, it is crucial to investigate the different aspects of DR and identify its potential benefits as well as the reservations that may hinder its development. For this reason, apart from the technical literature studies, there is also a broad literature of DSM and DR reviews considering different aspects, which can be classified in three main categories: 1) a general DSM/DR overview followed by recommendations for future development, 2) an overview of DSM/DR status focusing on a particular part of the world (a specific country or region), 3) an overview of DSM/DR for a specific implementation (e.g., specific consumer type response).

In the first category, Albadi and El-Saadany presented a concise review of the DR benefits from the participant, market and reliability point of view and performed a market simulation based analysis of a DR scheme [55]. O'Connell et al. analysed the benefits (from the operational, planning and economic points of view) and challenges (from the perspective of market regulation, end-user acceptability and business schemes) related to DR, including a broad literature review on DR modelling assumptions without emphasizing on real world examples [56]. Siano performed a general survey on smart grids and DR; however, without giving specific importance to neither benefits/barriers nor real-world examples of DR programs [57]. Another general review on DSM considering DR, intelligent energy systems and smart loads was performed by Palensky and Dietrich [58]. Kotskova et al. performed a review on load management including DR strategies, providing also a small number of real world examples [59]. Aghaei and Alizadeh performed a general analysis of DR strategies, emphasizing on the application of DR in accommodating the varying nature of RES, presenting also a limited number of DR implementation examples [60]. Gelazanskas and Gamage briefly analysed the benefits and the drivers of DSM and proposed a demand control strategy without a further overview of other DSM and DR relevant topics [61]. Wang et al. presented an overview of real-time markets around the world (especially in North America, Australia and Europe), focusing on the technical analysis of DR integration [62]. Hu et al. analysed the existing dynamic pricing programs in the U.S. and Europe, presenting also real examples, program targets, enabling technologies and policy issues; however, incentive-based programs and the analysis of the benefits and challenges of DR were not considered [63]. Shen et al. reviewed the role of regulatory reforms, market structure changes and technological developments to render DR more viable in the electric power system [64]. In a detailed DR review study, Varkadas et al. examined DR types, requirements and enabling technologies, presenting also many real examples around the world, as well as the optimization methods for DR applications with a broad review of relevant literature studies [65]. However, [65] did not provide a discussion on the drivers that promote DR, available DR programs in different regions, as well as the reasons for which DR is not currently evenly developed around the world.

In the second category, Strbac reviewed the benefits and challenges of DSM specifically for the UK electric power system [66]. Similar to [66], Bradley et al. performed a review-based analysis for the UK in order to evaluate the possible benefits and required costs for wider penetration of DR [67]. Warren considered the UK case from the policy point of view for DSM applications [68]. Ming et al. [69] and Harish and Kumar [70] examined the cases of China and India, respectively, in terms of historical evolvement of DSM applications together with future expectations.

In the third category, Gyamfi et al. examined a specific DR application area concerning residential end-users by reviewing the impacts of behavioural changes of different residential end-user profiles on the success of DR strategies [71]. Soares et al. also analysed the residential end-user behaviour in order to particularly discuss domestic appliance based DR [72]. Muratori et al. considered residential DR from the electricity market point of view [73]. Khan et al. analysed the correlation between the success of DR and the technological advancement in Home EMSs (HEMSs) for residential end-users [74]. Finally, Merkert et al. examined the challenges and opportunities of applying DSM solutions in industrial end-users, supported also by a set of real industrial case studies [75].

This chapter aspires to constitute a reference point regarding 1) the DR enabling control, metering and communication technology, as well as, different DR and consumer response types (Section 2.2), 2) the potential benefits of DR (Section 2.3), 3) the current status of DR development globally (Section 2.4), and 4) the barriers to the development of DR (Section 2.5) in a very comprehensive manner. Furthermore, a remarkable number of real application examples covering several countries and regions are presented in order to thoroughly evaluate the DR status quo around the world and to examine in-depth the key-elements that affect the integration of different kinds of DR solutions in regions with different economic, environmental and political conditions.

2.2 General Overview of Demand Response

2.2.1 Overview of enabling technology

DSM and DR activities have been practically enabled because of the evolution of the technology required to physically implement DR programs. In this section a brief discussion on the required metering, control and communication infrastructure is provided.

2.2.1.1 Metering and control infrastructure

Among the different components of the DR enabling infrastructure, the smart meters and the relevant AMI are the vital enabling technologies for implementing DR strategies. Smart meters are new generation electronic meters that have the capability of bi-directional communication between the end-user and the load serving entity (LSE). For DR activities, smart meters can receive signals from the LSE, such as the maximum allowed level of power procurement in a certain period (e.g., to reduce the loading of a local transformer) or price signals determined in a dynamic way. Besides, AMI is a network of millions of smart meters [76]. Smart meter and AMI penetration across the world is increasing rapidly with many pilot projects implemented in the last decade. A mapping of Smart Metering Projects across the world can be found in [77].

In order to provide automated control for a more effective participation in a DR program, whether it is price or incentive-based, EMS structures in end-user areas (residential, commercial or industrial buildings) are critical components. A common EMS structure receives information signals from the controllable/non-controllable loads of the end-user, including the state of the appliance, its power consumption, etc. Also, the EMS may receive information regarding the available production from RES or conventional self-production units. Besides, all the signals of the LSE including DR event instructions, pricing data, etc., are transferred to the EMS through the AMI. By considering all the input information, the EMS decides the optimal operating strategy for the end-user, aiming at satisfying both the requirements of the LSE that calls for DR and the end-user by not compromising the fulfillment of the service the electricity is used for.

As regards the current state of EMS adoption around the world, major differences can be noticed from region to region. The U.S. is a leader in the adoption of EMS, especially in the HEMS market. European utilities are also supporting relevant pilot projects [78]. Nevertheless, one may argue that since benefits for both the consumers and the utilities have been broadly recognized and due to the fact that numerous major companies (including Siemens, Intel, etc.) have already rendered commercially available EMS products [79], their penetration in the short-term future is likely to increase in residential, commercial and industrial premises.

2.2.1.2 Communication infrastructure

A pivotal requirement for an effective DR implementation is the handling of a significant amount of data transfer. A low-latency, moderate bandwidth communication path between the parties involved (LSEs, end-user EMSs, loads to be controlled, etc.) in a DR action is an essential prerequisite to achieve this. Here, latency corresponds to the delay between the time that a request is sent by the procuring party and the time at which the responding party receives the request and therefore, can accordingly act. Moreover, bandwidth corresponds to the data-transfer rate of each enabling device in the communication path [80]. The aforementioned low-latency and moderate bandwidth specifications are significantly important for the effective transfer of DR commands and the rapid implementation of relevant responses to ensure an improved performance of a DR strategy.

Three domains of data communication are considered in the implementation of a DR program: the smart meter domain, the Internet domain and the home area network (HAN). Note that the HAN domain is a general term that may evenly refer to residential, industrial and commercial end-user premises. The smart meter domain is the AMI structure previously discussed and it consists of a network of a large number of smart meters. The Internet domain (the cloud) that is used as the computing and information management platform by the IT industry is the general public Internet accessed through service providers. The HAN is the gateway to the Internet and smart meter domains for controllable loads, appliances and their interactions with the EMS within the end-user premises [76], [81]. The EMS receives signals from the LSE through the smart meter domain and implements actions through the HAN. The Internet is the interface through which multiple systems having Internet Protocol (IP) can meet to communicate in order to provide a desired task, e.g., direct load control (DLC) over suitable loads in the end-user premises. There are also some other definitions for communication domains, such as Neighbourhood Area Network (NAN) and Wide Area Network (WAN) that represent the range of the communication area for the DR enabling communication infrastructure [82].

Many communication mechanisms are suitable in terms of being able to meet the latency and bandwidth criteria in different data communication domains. In general, the aforementioned communication technologies can be categorized as wireless or wired technologies. Wireless communication technologies have the advantage of lower investment costs due to avoiding additional wiring costs. Besides, it increases the flexibility of the end-points because wireless signals can reach areas where physical connection is problematic. However, these technologies are more prone to signal losses during propagation, a fact that limits their effective range. Furthermore, significantly stronger security mechanisms are necessary for wireless technologies in order to avoid unauthorized access. ZigBee, Z-wave, Wi-Fi, Wi-MAX, cognitive radio and recent cellular technologies can be presented as major wireless communication technologies suitable for many communication areas of a DR enabling smart grid operation [83]. On the other hand, wired communication technologies can use the existing power line or an external wiring for signal transmission. Existing wired technologies include power line communication (PLC), Fiber-optics, Ethernet, etc. Whether wired or wireless technologies are employed, the scalability and replicability, availability, reliability and security of the considered solutions should be further analysed for the specific application area in order to ensure a successful DR implementation [84]. A deeper analysis of communication infrastructure technologies and relevant requirements can be found in [82],[85],[86] and [87].

2.2.1.3 Protocols and standards

There are many efforts to standardise DR related smart grid operational aspects across the world. The U.S. National Institute of Standards and Technology (NIST) is forming a regulatory framework in order to create common smart grid interoperability standards by involving stakeholders and partners from the industry, the government, and the academia. In the short-term, the smart grid standard version 1.0 is planned to be announced aiming to augment it in versions 2.0, 3.0, and beyond [88]. IEEE has also numerous standards relevant to the smart grid operations available, including a significant number of standards having strong relationship to the DR implementation especially from the communications point of view [89].

Apart from the NIST and the IEEE driven standardization approaches for DR related smart grid operations, there are also different standardization studies taking place. For example, OpenADR (Open Automated DR) is a DoE approved standard developed by the DR Research Center focusing on the data communication model for sending and receiving DR signals from a LSE or an ISO to the customers and vice-versa [90]. Australia and New Zealand have the common AS/NZS 4755.3.2 standard named “DR capabilities supporting technologies for electrical products” [91]. There are also many other standardization studies regarding DR, especially in North America [92] and followed by Australia and Europe, including also the evaluation of DR as a business scheme, a fact which indicates that in the near future more standards will be available.

2.2.2 Classification of DR

DR programs may be classified either by their type (motivation method and trigger criteria) or according to the way in which the enrolled consumers respond according to the characterization of their load.

2.2.2.1 Types of DR programs

Based on their type, DR programs may be categorized as incentive-based or price-based DR programs [55]. The main difference between the programs that fall under each of these categories is that in incentive-based programs the customers are offered payments in order to deliver a specific amount of load reduction over a given time period, while in price-based DR programs consumers voluntarily provide load reductions by responding to economic signals.

2.2.2.1.1 *Incentive-based DR*

Direct load control. The target of DLC programs is to engage a large number of small consumers (e.g., residential). Through such programs the utility may directly control a specific type of appliance in the end-user premises. Typical examples are air conditioners (ACs), lighting, water heating, pool pumps, etc. [93]. These programs typically define the number and the duration of interruptions in order not to compromise the end-user comfort level. The participation of the end-user is compensated through discounts or benefits in the electricity bill and potentially by extra payments for being called. These programs are managed by the utility and as a result the end-user is not pre-notified for an interruption. DLC events may be triggered by economic or reliability events.

Curtailable load. Curtailable load programs are addressed to medium and large consumers. Participants in these programs receive incentives in order to turn off specific loads or even to interrupt their energy usage, responding to calls emitted by the utility. Like in the case of DLC programs, contracts should specify the maximum number and the duration of calls. These programs are mandatory, i.e. customers may face penalties in case they fail to respond to a DR event. Utilities may call the consumer to respond to reliability events; however, load curtailments may also be traded in the market [93],[94].

Demand side bidding, capacity and ancillary services. The option of demand side bidding provides the opportunity to consumers to actively participate in the electricity market by submitting load reduction offers. Large customers may participate in the market directly and usually employ sophisticated load management tools and strategies, while relatively small consumers can participate indirectly through third-party aggregators or LSE [95]. The demand side may also participate in capacity and ancillary services markets, providing a variety of system services in different time scales (regulation, spinning reserve, etc.) [96].

A demand side bid may have the form presented in Fig. 2.1. Similar to the bids that are submitted by generators, the bids from the demand may be single or duplex, simple or complex. A single bid pertains the participation only in one market structure, while a duplex bid refers to a bid that pertains the coupled participation in two different markets (e.g., energy and reserve) [97]. Moreover, the bid may consist of only price-quantity pairs, i.e. simple bid, or it may be a complex bid incorporating technical conditions such as minimum energy consumption (D_{min}), maximum energy consumption (D_{max}), total energy over the considered horizon (e.g., daily), load pickup and drop rates, etc. [98]. The only difference between generation side and demand side bids is that the latter are downward. In Fig. 2.1 the negative slope, assuming without loss of generality a linear relationship between price and consumption, indicates that the demand would accept to consume energy (D) as long as its bid is greater or equal to the market clearing price (p). In case the demand side is eligible to submit a duplex bid, then quantity-price offers for upward (R_u,C_u) and downward (R_d,C_d) reserve should be also provided. It should also be noted that voluntarily providing reserves during emergency situations is also referred to as emergency DR [58].

2.2.2.1.2 *Price-based DR*

Time-of-use tariffs. Electricity end-users that are priced with flat prices are not aware of the varying cost of electricity. Flat rates reflect the average electricity supplying cost and may remain constant for years. The basic idea behind time-of-use (TOU) pricing is to better reflect the variations of the electricity provision cost with time, in different periods within a day or a season [94]. TOU pricing is a stepped rate structure which intends to reflect prices under average market

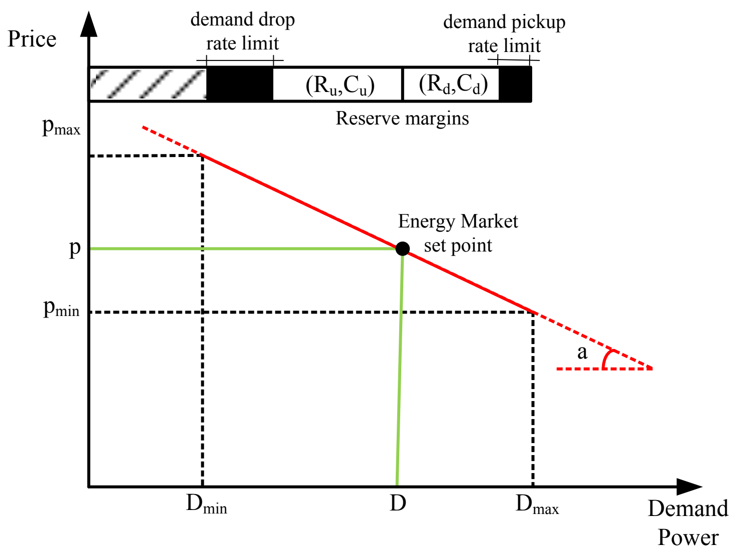

Figure 2.1: Example of demand side bidding

conditions with respect to the time of the day during which electricity is consumed and does not capture the day-to-day volatility of supply costs. A typical TOU structure includes a peak rate, an off-peak rate and potentially a shoulder-peak rate [93], that hold for time periods defined by the utility.

Critical peak pricing. Time-of-use tariffs reflect the longer term electricity supply costs associated with using electricity during a specific period of the day. In order to capture the short-term costs of periods which are considered critical for the power system, critical peak pricing (CPP) may be employed. The CPP tariff stands for the superimposition of a time-independent rate on TOU or flat rates, triggered by system criteria (e.g., unavailability of reserves or extreme weather conditions that cause unexpected variations in demand). The relevant contracts specify the maximum number of days per year that may be considered critical and the number of periods for which the CPP rate applies. However, the utility communicates a CPP event in a very short notice, from several minutes up to several hours before the CPP rate applies. There are also two variants of CPP, namely the Extreme Day pricing (EDP) and the Extreme Day CPP. Extreme day pricing charges higher prices for electricity but, unlike CPP, once EDP rates are called they remain active for all 24 hours of the “extreme day”. Extreme day CPP programs use peak and off-peak rates like in CPP programs, but only on extreme days. For the rest of the days a flat rate applies [55],[93],[99].

Real-time pricing. Real-time pricing (RTP) is a pricing scheme in which the energy price is updated at a very short notice, typically hourly. Through RTP customers are directly exposed to the variability of the cost in the wholesale power market or to the changes in locational or zonal marginal prices. Currently, there are two noticeable RTP programs engaging residential end-users in the U.S., one by Pennsylvania New Jersey Maryland Interconnection (PJM) [100] and one by the Midcontinent ISO (MISO) [101]. Both communicate the day-ahead market prices one day before the actual power delivery; however, the way in which they price the consumers differ. In the first program, end-users are priced according to the real-time prices that are settled in the end of an hour in the actual dispatch day and are the averaged 5-minute prices of that hour, while in the second program consumers are directly priced according to the day-ahead prices.

2.2.2.2 Customer response

2.2.2.2.1 *Industrial customers*

The energy consumption by industrial customers represents a major portion of the total electric energy produced. It has been reported that for many utilities 2-10% of the industrial consumers are responsible for at least 80% of the electricity usage [102]. Paulus and Borggrefe [103] have investigated the potential of DSM in energy-intensive industrial customers in Germany, arguing that the highest economic potential can be found in large-scale processes that rely on a single source to satisfy their energy demand. In Germany the annual electricity demand of the 250 different branches of the industrial sector is 252.6 TWh, while the technical potential of the investigated industrial processes for DR (tertiary positive reserves) is 2660 MW. Similarly, the Swedish Government has provided the energy-intensive companies the opportunity to benefit from reduced taxation on electricity use on the condition that they take energy efficiency measures [104].

The aforementioned facts demonstrate that the industrial sector is suitable for developing DR and DSM programs. However, adopting DR programs may be challenging for the industrial firms. For commercial and residential customers, DR entails potential temporary loss of comfort (e.g., by controlling ACs). On the other hand, industrial customers may reduce their demand by on-site generation, energy storage, consumption shifting, non-critical load curtailment and temporary shut-down of several processes. Temporarily interrupting one or more processes may result in significant load reductions. Nevertheless, several constraints such as the criticality of a process, the number of available production lines, the required production target, inventory restrictions, etc., may have longer term impacts on the process line, rendering DR economically inefficient [102]. Due to their technical requirements several processes such as steel production using electric arc furnaces, cement milling and aluminium electrolysis are only suitable for load shedding, while others such as chloralkali electrolysis and mechanical refining of wood pulp can be shifted [103].

To efficiently provide DR services, industrial consumers must be equipped with an automated decision system that considers the technical constraints of the processes and the alternative energy sources available. In [105] Ding et al. have proposed such a system that performs optimal scheduling of the industrial load considering constraints posed by the processes while considering the possibility of self-generation and energy storage. Furthermore, Paterakis et al. [106] have proposed a stochastic optimization model through which large industrial consumers can provide energy and reserve services in the day-ahead market in order to balance the uncertain wind production.

2.2.2.2.2 *Commercial and other non-residential customers*

Commercial and other types of non-residential premises can also provide DR for load reduction or ancillary services. AC is the most significant load that can be controlled. In [107] the capability of providing spinning reserve from a hotel was demonstrated. The preliminary tests indicated that apart from the quick response, the load could be curtailed up to 37% depending on the outdoors temperature. Furthermore, large commercial heating-ventilation and air conditioning (HVAC) systems provide easier access to a single, significantly larger demand side resource than aggregating large numbers of smaller residential loads, while automation equipment that is already present in most large commercial buildings may be exploited in order reduce the infrastructure costs associated with the implementation of DR programs [108]. Moreover, due to the large space that commercial buildings occupy, they present higher thermal inertia, allowing for longer interruptions. Also, HVAC systems employ variable frequency drives (VFD), the speed and power of which can be quickly and continuously adjusted, following the regulation signal provided by the system operator in order to provide regulation reserve [109].

Recently, the idea of energy intelligent buildings that monitor their energy consumption and manage locally available resources, as well as the energy procurement from the grid has been introduced [110]. In [111] a control and scheduling architecture for offices was proposed in order to take advantage of RTP DR by controlling a range of loads (e.g., lighting).

2.2.2.2.3 *Residential customers*

Residential customers are suitable for DLC and price-based DR programs. Apart from shifting load manually in response to price signals, residential customers may invest on an automated system, namely a HEMS, which monitors and controls the consumption of several appliances [112]. Typical appliances that can be found in most households and are suitable for being scheduled by the HEMS in response to time-varying prices or to be rendered available for direct control by the utility are: electric water heaters, ACs, refrigerators, washing machines, clothes dryers and dishwashers. The first three loads are thermostatically controllable while the other three when equipped with communication modules are called smart appliances.

There is an abundant literature suggesting models and identifying the potential of the residential sector to participate in DR programs in order to provide various system services such as regulation and spinning reserves. For example, [113] investigates the potential of a household equipped with a HEMS to provide frequency response, [114] examines the potential of load flexibility provided by smart appliances in order to participate in reserve services, [115] employs a model of ACs in order to provide reserves by DLC through an aggregator and, finally, [116] performs a similar analysis for electric water heaters.

2.2.2.2.4 *Electric vehicles*

Currently, the market share of electric vehicles (EVs) is relatively low, limited to a few hundreds of registered cars in most industrialized countries. As a result, the impacts of the EVs on the power system, namely the additional energy consumption, are not currently evident [117]; however, as the electrification of the transport sector is expected to be intensified in the future, significant challenges to the integration of large EV fleets may occur [118],[119]. In order to facilitate the integration of EVs in the future, two technical measures that belong to the category of DR have been proposed: 1) controlled unidirectional charging, 2) controlled bi-directional charging, more commonly known as vehicle-to-grid (V2G). The foreseen benefits of implementing such techniques are threefold. First, a fleet of EVs may be employed in order to perform peak shaving and valley filling, improving the economic efficiency of the power system [120]. Second, EVs could increase the price elasticity of residential end-users since the EV charging load would render electricity procurement an important cost for the households [117]. Third, fleets of EVs could be used in order to provide balancing services to facilitate the integration of RES [121].

2.2.2.2.5 *Data centers*

Data centers are an emerging type of consumer that in the recent years has known significant growth both in size and energy consumption. For this reason, a 2007 report from the U.S. Environmental Protection Agency has suggested that data centers should adopt DR strategies in order to reduce the strain on the power system [122]. Irwin et al. [123] have identified three main reasons for which data centers are eligible candidate customer types for DR. First, data centers are major energy consumers and therefore have a significant impact on the power system conditions. Second, their task is tolerant of delays and performance degradations, a fact that makes data centers highly price responsive. Third, servers are already equipped with power management mechanisms that are remotely programmable and therefore, the power may be accurately adjusted according to the provided signals. Masanet et al. [124] found that during 2008 the annual energy consumption of the data centers could have been reduced by 80%, while several other studies address the feasibility of DR provision from data centers [125].

Data centers are also considered capable of providing a range of ancillary services [126]. Regulation services are constantly active and data centers could adjust their consumption according to the signals sent by the grid operator every few seconds. Furthermore, by transitioning a number of active servers to the sleep state, data centers may provide short term operating reserves or emergency DR. After the event, servers are transitioned from sleep mode back to a normal operating state. Data centers typically possess two further assets that increase the value and the flexibility of the provided reserves: backup generators and uninterruptible power sources (UPS). The former may be used in order to provide ancillary services to the grid without interrupting the workload, while the UPS could be used in order to permit longer time response.

2.3 Benefits of DR

DR has the potential to offer a diverse range of benefits depending on the design and the aim of the specific DR implementation. In this section the benefits of DR are presented and discussed, especially focusing on the possible contribution of DR to the integration of high amounts of intermittent renewable generation into the power system. The benefits for the ISO, the electricity market and its participants are also identified.

2.3.1 The role of DR in facilitating the integration of intermittent generation

Large scale integration of RES in power systems plays a central role in ambitious programs initiated by leading countries around the world, such as the regional greenhouse gas emission control schemes in the U.S. and the 20/20/20 targets in the European Union (EU) [127]. Among the different RES, wind and solar capacity is expected to increase significantly in the future [128],[129]. In the U.S. wind is expected to grow from 31 TWh in 2008 to 1160 TWh by 2030, which stands for a target of 20% of the total supply, while solar capacity is anticipated to reach 16 GW by 2020 [130]. Similar tendency is noticed in the EU as well. For example, the target for the electricity generation share of the wind in Ireland is set to 40% by 2020 [131]. Despite the potential environmental benefits that arise from the widespread adoption of wind and solar power generation, their highly uncertain nature may jeopardize the security of the power system and pose new technical and economic challenges to ISOs. These challenges primarily stem from the fact that these resources are highly varying with time, their predictability is limited and they are not controllable, i.e. they cannot be modified by instruction in order to economically match the load [131]. For example, in Fig. 2.2 the total hourly production of wind and solar parks in the island of Crete, Greece, for three consecutive days in April 2012 is presented [132]. As it can be noticed, the wind production ranges between 10 and 125 MW in a time span of less than 24 hours, while it presents significant fluctuations in shorter time frames. On the other hand, despite the fact that the solar production is available only during the day-time, it presents a more stable hourly pattern in this case; however, its intra-hourly behaviour may be significantly variable.

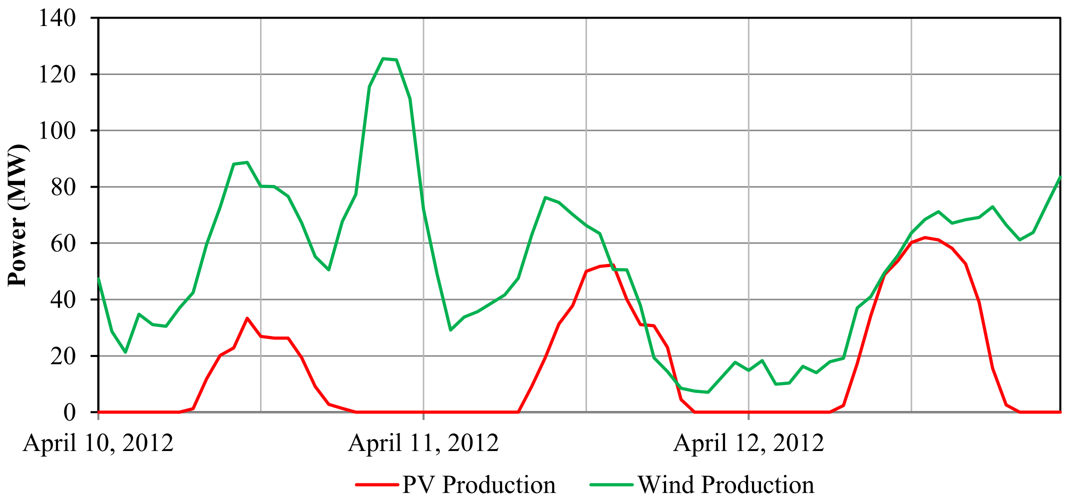

Figure 2.2: Photovoltaic and wind power production in the island of Crete (10/4/2012-12/04/2012)

The majority of existing power systems has been designed considering the fluctuations of the demand. Nevertheless, it is questionable whether the grid can serve both varying loads and high amounts of variable generation such as wind and solar. In order to accommodate the additional uncertainty, an increased amount of reserves should be maintained. Especially regulation and load following needs, both in terms of capacity and ramping capability, are likely to be augmented with the increasing penetration of wind and solar generation.

Generators providing regulation and load following reserves incur significant costs such as efficiency loss because of ramping, environmental costs due to increased emissions, increased wear and tear and, therefore, increased operating and maintenance costs. Furthermore, in order to provide reserve services, a generator must operate partly-loaded, a fact that entails lost opportunity costs in the energy market [133]. As the share of RES increases, peaking and intermediate (cycling) units are likely to be displaced. In addition to that, several base load plants may need to be operated in a cycling manner, a function for which they are not designed because their operation is subject to long start-up, minimum up, down and decommissioning times. These issues can be resolved by the participation of the demand side in the load following reserves through appropriately designed DR programs. Certain types of loads such as ACs and electric space heaters have the ability to adjust their power to changes in demand instantaneously [134], while the ramp rates of conventional generators are limited. Moreover, it is argued that the ancillary services provided by the demand side may prove more reliable since the reliability of the response of an aggregation of a significant number of loads is greater than the one of a small number of large generators [135].

Another important issue that is primarily linked to the wind generation and can be tackled with the utilization of DR activities is the wind "over-generation" [136]. This problem appears when high wind generation is available during off-peak periods, during the night or early in the day. For example, in Fig. 2.2 one may notice high wind generation in the night between April 10 and April 11, 2012. In such cases due to the fact that most markets consider the wind power generators as must-run, either the output of the conventional generation must be reduced in order to accommodate the wind generation, or the excessive wind energy should be curtailed, an option that may bear high penalties, in order to maintain the balance of the system. The situation escalates when the system comprises relatively inflexible base load generators that are committed to operate near their technical minimum power outputs during such periods. In general, operating generating units at lower output or cycling base load units may compromise the environmental benefits of integrating wind power in the system. Typically, the consumption of fuel and the emissions of generators increase when they operate at a low capacity. Evidently, one solution that DR can offer is the increase in the demand in periods in which there is excessive wind power generation. Loads that can be shifted in such a way that allows the otherwise spilled wind energy to be absorbed include water pumping, irrigation, municipal treatment facilities, and thermal storage in large buildings, industrial electrolysis, aluminium smelting, etc. [137].

O' Connel et al. [56] highlight another consequence of increased RES penetration which the coordinated planning and operation of generation and DR could ease, contributing to substantial welfare gains. Power systems with increased wind penetration tend to depend on the interconnections in order to balance the grid. However, the deployment of DR may enable the economically efficient use of interconnections, since the spatial characteristics of wind may adversely affect the prices of the energy exchange depending on the scarcity of wind power generation, because nearby regions are likely to experience high or low wind power generation simultaneously.

Finally, environmental targets will intensify the electrification of the transportation sector in the future in order to displace the use of petroleum, a fact that presents a significant opportunity for DR activities in favour of a better integration of renewable energy in the power system. Fleets of EVs could act as aggregations of distributed energy storage, while their charging could be controlled. Through the V2G option they could act as an energy buffer to improve the grid regulation and other ancillary services. These issues are thoroughly discussed in [138].

2.3.2 Benefits for the system

DR is recognized to have potential system-wide benefits. Many utilities, especially in the U.S., are obliged by regulatory or legislative requirements to consider DR in their resource planning [139], while the Energy Efficiency Directive (EED) [140] of the EU states that the planning process should consider the peak shaving effect of DR. The traditional approach to network upgrading considers that the demand grows gradually and as a result a portion of the added grid capacity will eventually remain unexploited since the longer term forecasting of the load growth is uncertain and, therefore, network reinforcement tends to be economically inefficient in order to be on the safe-side. In general, the network expansion is planned considering a long technical life-span (several decades), e.g., more than 50 years for Norwegian Transmission System Operators (TSOs) [141]. Typically, new investments are triggered because of an anticipated increase in the load. DR can contribute to a reduced forecasted peak demand, since long-term DR programs will be implicitly taken into account in the peak demand forecasts [142]. Thus, network investments may be postponed. Furthermore, the uncertainty in the load evolution can affect the efficiency of a system reinforcement investment. More specifically, it is possible that the demand for electricity may decline, increasing the idle capacity of the system and therefore, the operating cost of the network per unit of output [143]. On the other hand, DR programs may preventively contribute to confront an upward deviation of demand [144].

DR programs that aim to enhance the distribution system operation can also bring a series of benefits. Problems related to the voltage magnitude, distribution substation congestion and losses can be mitigated by DR activities at the distribution level. Electrical equipment is designed for optimum operation at the nominal voltage. Any deviation from this can result in decreased efficiency, damage or severely reduced life of the infrastructure [145]. Furthermore, congestion management can reduce the active power losses and improve the overall system reliability [146]. The distributed nature and the spatial diversity of demand can be exploited in order to eliminate congestions and, therefore, reduced loading of transformers and lines can defer or render redundant the need for costly upgrades and allow an increased penetration of distributed generation [56]. Also, a demonstration on the village of Hartley Bay, British Columbia, Canada, demonstrated how DR can be used in order to enhance the economic and supply efficiency of a remote community [147].

Currently, the total capacity of installed generation must be larger than the system maximum demand in order to guarantee the security of supply under contingencies or severe demand variations. Strbac has demonstrated that the frequency of large energy deficits is very rare [66]. DR can be a preferable choice in order to contemplate relatively small energy deficits. A striking example is the crisis in California in June 2000 in which a shortage of 300 MW (around 0.6% of the total system capacity) caused rolling blackouts [145]. As a result, DR may serve as an alternative to the investment in new power plants that would be underutilized in order to provide capacity reserves [94].

DR has another important side advantage to offer to the system, aiding the ISO to render the power system more environmentally sustainable. Apart from facilitating a better integration of renewable generation in the system, as it was previously discussed, DR may improve the overall energy efficiency and mitigate the reliance on fossil fuels. A recent fact sheet regarding the DR implementation in the MISO [148] has demonstrated that DR programs that cycle residential appliances such as ACs can actually decrease the overall electricity consumption, promoting energy efficiency. Furthermore, the reduced utilization of peaking power plants that are less efficient in order to cover high demand may contribute to the reduction of the carbon footprint of the system. It is characteristically reported that in California the carbon intensity of the power system can be up to 33% higher in peak times in comparison with off-peak times. Finally, considering DR as an equal option when it comes to the system planning, the construction of more conventional power plants may be avoided.

2.3.3 Benefits for the market and its participants

It is widely argued that the active participation of demand side resources could improve the performance of electricity markets and bring significant benefits to the consumers. Regarding the positive effects of DR on electricity markets, three key elements may be identified:

- lower and more stable electricity prices,
- control of market power,
- economic benefits for the consumers.

In order to demonstrate the two first points, without loss of generality the simplified example that is presented in Fig. 2.3 can be employed, which corresponds to markets in which the uniform

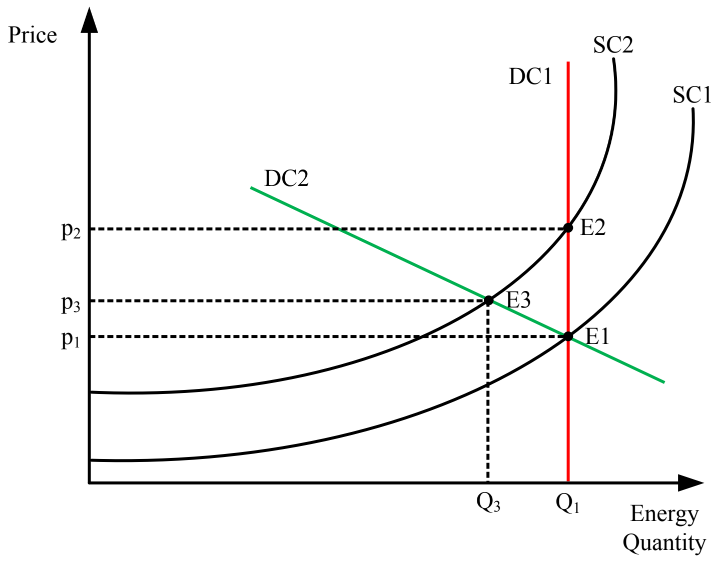

Figure 2.3: An illustration of the effect of responsive demand in electricity markets

spot price of electricity is defined by the intersection of the aggregated supply and demand curves, e.g., Nordpool [149]. The market operator collects the generation and demand side bids and sorts them with respect to their prices. The aggregated supply curve is upward while the aggregated demand curve is downward. Close to the maximum capacity of the system the bids tend to increase exponentially [55]. The fact that the supply curve becomes steeper as the energy quantity increases may be the consequence of the profit maximizing behaviour of the generators or can be attributed to the higher operating costs of peaking units. In such cases, a small reduction in the demand may induce a significant reduction in the market price [142]. The effect of price responsive demand on the market clearing prices was investigated in [150]. A similar analysis is carried out for markets that adopt LMP in [151]. Furthermore, it is interesting to notice that several crises in electricity markets have been linked to the absence of DR programs [152]. For example, it has been reported that a small decrease in the demand of the scale of 5% could have yielded a reduction of 50% in electricity price during the California electricity crisis in 2000 [55]. One of the reasons that lead to the electricity crisis of California is related to the structure of deregulated markets and the fact that generators do not behave like purely competitive firms. As a result, this market design is prone to market manipulation by large generators. Market monitoring is a way to address this issue; however, the economic and technical deficiencies of this approach have led to the enforcement of price caps which in turn is a measure that limits the potential of peaking units to recover their investment costs [153]. DR may prove beneficial in reducing both supplier and locational market power, limiting the ability of large producers to manipulate the price of electricity. The market clearing price p_1 is the value at which the marginal revenue of the supply equals the marginal benefit of the demand, thus constituting an equilibrium point ($E1$). If the demand curve is steep ($DC1$), i.e. the demand is not price-responsive, then the generation side may attempt to manipulate electricity prices by submitting more costly bids. This implies shifting the initial supply curve ($SC1$) upwards ($SC2$) and the new corresponding equilibrium point ($E2$) corresponds to an increased price p_2. However, in case the demand side is price-responsive, then the market leverage is limited, achieving a different equilibrium point ($E3$) that corresponds to a lower price p_3. In addition to this, Siano [57] reports several other relevant benefits: the increase in the number of suppliers in the market through the improvement in the market competition, reduced concentration and restriction of collusion. Appropriate price-based DR programs and a sufficient amount of responsive demand may alleviate the need for price caps and stringent market monitoring.

Allowing consumers to respond to dynamic electricity prices has two anticipated effects that are also commonly referred to as “flattening” of the system load profile: peak shaving during high price periods and load shifting to relatively low price periods. In this way, the magnitude of the wholesale and the retail prices can be reduced while the price spikes and the volatility of the spot market can be mitigated [154]. As a result, in the long-run benefits can also emerge for the consumers that do not participate in DR programs since the lower wholesale market prices due to sustained DR programs, are likely to cause a decrease in the flat retail rates as well [145]. Furthermore, the transition from flat tariffs to time varying prices is thought to increase the consumer and societal welfare [56]. Regarding small customers (e.g., residential), Allcott [155] indicates that the increase in consumer welfare is not significant since the electricity costs represent only a small portion of their overall expenses; however, it results in an increase in the overall social welfare. On the other hand, responding to time varying pricing definitely contributes to the increase in the welfare of larger commercial and industrial consumers [156]. Besides, a study concerning the DR economic welfare analysis in the PJM market has demonstrated a net benefit for the system that exceeds the total annual subsidy payments [157].

2.4 Practical Evidence

2.4.1 North America

As it was reported by the Transparency Market Research, North America was the leading region in the DR capacity market in 2013, accounting for more than 80% of the global market share, followed by Europe and Asia-Pacific [158]. Thus, the analysis of DR examples in North America is significantly notable in order to observe the trends in this leading part of the global smart grid sector.

2.4.1.1 United States

2.4.1.1.1 *Major States of the U.S.*

California. California is the state with the greatest population in the U.S. reaching nearly 40 million people [159] and therefore, has a considerable potential of DR programs to be developed.

Pacific Gas&Electric Company (PG&E) offers the so-called “SmartAC” program to its commercial and residential customers, targeting at controlling ACs by cycling aggregated AC load during occasional summer peaks caused mainly due to the simultaneous operation of hundreds of thousands of ACs. For commercial customers PG&E ensures that the temperature in the working area will not exceed the user’s temperature setting by more than four degrees while in case that the AC cycling event happens in an inconvenient time, the customer can decline to respond without facing a penalty. From a technical perspective, PG&E realizes this program by installing thermostats with communication capability that allows to remotely raise the temperature setting of the enrolled ACs up to four degrees when necessary. A similar program offered to residential end-users provides 50 $ for a 6-month participation period and the SmartAC remotely controllable device that directs the AC to run at a lower capacity during energy shortages for free. The AC settings can also be manually restored if the response to a DR event is inconvenient for the end-user. For larger customers, PG&E offers a range of DR programs such as peak day pricing, base interruptible program, demand bidding program, scheduled load reduction program, optional binding mandatory curtailment plan as business programs, aggregator managed portfolio and capacity bidding program as aggregator programs and automated DR incentive and permanent load shift as incentive-based programs. In the Peak Day Pricing Program (PDPD), a discount on regular summer electricity prices is offered in exchange for higher prices during the 9 to 15 Peak Pricing Event Days per year that normally occur during the hottest days of summer, encouraging energy conservation during these higher demand days. A surcharge is added to the regular time-of-use rate during the event and a pre-alert is sent to the end-user the day before in order to plan the energy conservation or shifting. A risk-free option, named bill protection, is also proposed for the first 12 months providing a credit for the difference if more is paid during the first year on PDPD. The Base Interruptible Program (BIP) offers an incentive to the end-user to reduce the load demand to or below a pre-selected level (firm service level – FIL). By giving an advanced notification of 30 minutes, an incentive of 8 to 9 $/kW per month is provided, while a monthly incentive payment is also given if no DR events occur. However, a charge of 6 $/kW is imposed for the extra demand over the pre-selected level if the end-user fails to reduce its load to or below its FIL during an event. The limit of BIP is 10 events per month or 120 hours per year. The Demand Bidding Program (DBP) is a day-ahead program that allows submitting load reduction bids on an hourly basis without imposing financial penalties if the customer fails to meet its committed reduction. DBP ensures a day-ahead notice by 12:00 pm and offers an incentive payment of 0.50 $/kWh of load reduction, having the minimum requirement of load reduction bids of 10 kW for two consecutive hours. As the PG&E is not obliged to call a DBP event, there is not an incentive given if the end-user enrolled in the DBP is not called within the monthly period and there is no penalty if the end-user fails to reduce the energy during the event periods. The Scheduled Load Reduction Program (SLRP) offers a payment for a load reduction during pre-selected time periods for customers with a minimum average monthly demand of 100 kW by selecting one to three four-hour time periods between 8 am to 8 pm on one or more weekdays with a committed load reduction of at least 15 percent of the average monthly demand. The load reductions are measured considering a baseline that is calculated by averaging the load demand of the selected time periods in the 10 previous normal operating days. The SLRP offers a payment of 0.10 $/kWh per month for the actual energy reductions. The Optional Binding Mandatory Curtailment (OBMC) Plan of PG&E concerns customers that can reduce their electric load within 15 minutes after a call by achieving 15 percent load reduction below their established baseline that is calculated as in the SLRP. The benefit of the customer is not a financial benefit or incentive. PG&E requests rotating outages from all its customers in tight demand periods, while by enrolling in OBMC the customer is excluded from these rotating outages. The customers are notified via e-mail or text messaging for the load reduction ratio (5 to 15 percent) and the beginning and ending times of the event, including holidays and weekends. If the customer fails to reduce the load to the specified level in a call, a 6 $/kWh penalty for each kWh above the power reduction commitment is imposed, while failing to respond to a second call entails exclusion from the participation in the OBMC Plan for five years. Notably, the Automated DR Program (ADRP) provides incentives for customers investing in automatic energy management technologies coupled with DR programs (PDPD, BIP, etc.). Customers participating in the ADRP receive signals from PG&E and are granted with an incentive of 200-400 $/kW of dispatchable load, and therefore can recover their initial investment in the required infrastructure by a pre-payment of 60% of the total project cost initially and 40% after the verification of customer performance in an up-to 12 months period of DR performance evaluation session [160].

San Diego Gas&Electric Company (SDGE) offers a BIP based on monthly bill credits of 12 $/kW or 2 $/kW during certain periods of the year for customers with a minimum reduction of 100 kW or 15% of their monthly average peak demand after a notification lead time of 30 minutes, granting also a flat credit per month even if no DR event is activated. There is a penalty of 7.8 $/kWh or 1.2 $/kWh (related to the period of the year) in the BIP offered by SDGE for excess energy use above the FIL of the customer. SDGE also offers Capacity Bidding, CPP, Permanent Load Shifting and Summer Saver Programs as well as Technology Incentives [161].

Southern California Edison (SCE) Company offers a more targeted program named "Agricultural and Pumping Interruptible Program" to temporarily suspend electricity from pumping equipment of the agricultural sector end-users during critical demand periods. A control device is installed to the pumping equipment or the meter of the end-user that enables SCE to interrupt the electricity supply temporarily, until the critical demand period ends. Eligible customers should have a measured demand of at least 37 kW or an agricultural load of minimum 50 hp. The interruption event is limited to 6 hours per event, while there is a maximum of 25 events or 150 hours of interruption per year. The customer is awarded with 0.01102 $/kWh as a base in the monthly electricity bill in terms of credit if enrolled in the program even if no event is called. The customer is also awarded with additional credits up to 16.27 $/kWh (in summer average on-peak period) during interruption events. SCE also offers ADRP, Permanent Load Shifting, TOU Base Interruptible Program, Capacity Bidding Program, DBP, Aggregator Managed Portfolio Program, CPP, OBMP, RTP, SLRP, Pumping and Agricultural RTP, as well as a Summer Discount Plan [162].

Texas. With a population of nearly 27 million [159], Texas is the second most populated State.

The Electric Reliability Council of Texas (ERCOT) which is managing the flow of electric power for more than 90% of Texas area, enables the engagement of end-users to directly provide offers into ERCOT markets or to rationally reduce their usage of energy by responding to wholesale prices [163]. Currently, Controllable Load Resources are allowed to participate in Non-Spinning Reserve Service Market after an assessment which qualifies them to be dispatched by the Security Constrained Economic Dispatch. Moreover, a recent pilot project named "Fast-Responding Regulation Service" allows specific fast-acting demand side resources to participate in the Regulation Service Market. Moreover, the Four Coincident Peak (4CP) Load Reduction Program that targets the four 15-minute settlement intervals corresponding to the highest load in each of the four summer months (June, July, August and September) is available for Non-Opt-In Entities in the ERCOT jurisdiction area. For demand side resources, Emergency Response Service program that provides a valuable emergency service during grid stress conditions, such as rolling blackouts caused by several reasons including severe weather conditions, is also available. Transmission and Distribution Service Providers (TDSPs) in the region also provide different load management programs. Finally, Price Responsive DR Products including Block&Index, CPP/Rebates, RTP, TOU Pricing, Other Load Control and Other Voluntary DR Product are also employed in the service area of ERCOT [164]. Apart from the DR schemes designed mainly for industrial and commercial end-users, ERCOT is also recommended to provide DR schemes specifically aiming at involving the residential end-users responsible for more than half of the energy usage in ERCOT area during peak summer periods due to AC load [165].

As a TDSP in the State of Texas, CPS Energy operates a voluntary load curtailment program designed for commercial and industrial customers by incentivizing them to shed their loads during extreme system conditions, especially during peak summer days. The program focuses on weekdays between 3 and 6 pm with a two-hour advanced notification. The willing customers should demonstrate at least 50 kW of curtailable electric load in order to be qualified to enroll in the program [166]. CPS Energy has also a Smart Thermostat program for commercial and residential end-users, in which the control equipment is installed free of cost while CPS Energy earns the capability to cycle off AC compressors for short periods of time by sending a radio signal to the smart thermostats during peak demand periods. CPS Energy does not provide the end-users with incentives but ensures a reduction in heating/cooling related costs of at least 10% because of the employment of smart thermostats [167].

American Electric Power (AEP) Texas offers an Irrigation Load Management Program in collaboration with EnerNOC for the agricultural end-users with electric irrigation pumps of 50 hp or greater, willing to allow their irrigation pumps to be remotely shut down during peak demand periods in return for a monetary incentive. This program covers the time span from 1 pm to 7 pm on weekdays with a required duration of 1 to 4 hours per event following an advanced notification interval of 60 minutes. A maximum of 4 events are allowed per month in this program [168]. AEP Texas also provides Load Management Standard Offer Programs (SOPs) for customers with an installed power of 500 kW or higher, supplying them with incentives in exchange for load interruptions on short notice during peak demand periods. There are five different options in this program regarding the maximum number and duration of interruptions [169].

Austin Energy Company introduced the “Rush Hour Rewards” pilot program in the summer of 2013, having enrolled approximately two thousand customers in Austin, Texas. The aforementioned program in collaboration with Nest Company, supplied the participating end-users with the purchase amount of smart thermostats together with additional incentives to avoid operating their ACs during “Rush Hours” of energy usage in summer periods. This was realized with remote control of the installed thermostats by increasing the temperature set point [170]. Reliant Energy Company has also a similar DR program [171]. Moreover, Austin Energy is currently running a program called the “Load Cooperative Program” in which the end-users are offered a payment of 1.25 \$/kWh for their curtailed load with a 60-minute notification interval during summer peak periods [172].

CenterPoint Energy Company offers a Commercial Load Management Program to commercial end-users for mandatory load curtailments in summer periods between June 1 and September 30 of each year from 1 pm to 7 pm on weekdays. Participating customer groups are required to provide an aggregated peak demand of 750 kW. Furthermore, each of the enrolled group members should have at least a normal peak demand of 250 kW plus the capability of curtailing at least 100 kW for a maximum of 5 curtailments per year. The enrolled customers are paid up to 35 \$/kW for the verified curtailed load which is at least the amount of curtailment agreed in the beginning of the contract year [173].

El Paso Electric Company has a Load Management Program for non-residential customers with a minimum of 100 kW of curtailable power capability upon notice between June 1 and September 30 of each year. The curtailment can last up to 5 consecutive hours per event. Nine forced curtailments or a maximum of 50 hours of interruption per year together with scheduled curtailments are requested by the terms of participation in the program. The customers may gain up to 60 $/kW for curtailed power during events in the mentioned program [172],[174]. Furthermore, Oncor Company has a similar program called "Commercial Load Management Program" for commercial end-users who can render 100 kW of load available for curtailment [175].

There are also other load management programs for non-residential end-users offered by different service providers [172]. Another interesting example of DR applications in Texas is the "Free Nights or Weekends" program provided by TXU Energy. This program offers customers willing to participate totally free electricity at night or during the weekends on the condition that they accept significantly higher daytime or weekday rates, which aims to shift more load to normal off-peak hours. The mentioned program has engaged more than 100,000 participants [171].

Florida. With a population of nearly 20 million [159], Florida is also one of the major States. DR programs in Florida are similar to the ones in California and Texas.

Florida Power&Light (FPL) Company has a Commercial Demand Reduction Program which aims to seize direct control of large scale end-users' total load demand by an installed load control device that sheds the pre-determined loads under a pre-notice by the FPL. For each kW of curtailment during events, FPL provides credits to the end-user together with a flat monthly payment for being enrolled in the program [176]. FPL has also an "On Call Program" for business areas that enables FPL to temporarily turn off ACs (15 to 17.5 minutes per 30-minute period for a maximum 6-hour time period) remotely in critical periods. FPL pays a flat monthly credit even if no DR event is called [177].

Tampa Electric Company (TECO) offers a load management program to control the selected equipment (ACs or any specialized equipment) in the end-user premises. TECO installs a remotely controllable device to shut down the equipment selected by the end-user during critical peak power periods in order to operate cyclic or continuous load management programs. As far as cyclic operation is concerned, the end-user earns 3 $/kW, while for continuous operation of the curtailment the end-user earns 3.5 $/kW for the curtailed load during an event [178]. TECO and Progress Energy Company are also offering on-site generation option based programs under two different names: "Standby Generator Program" and "Backup Generator Program", respectively. Both programs aim at enabling the control of available on-site generation by the service provider in order to cover a portion of the end-user's load demand by this generator in order to lower the demand from the grid in peak power periods. Progress Energy also offers a DLC program that enables the service provider to control selected equipment of the customer during critical periods, similar to the program of TECO [179].

New York. New York occupies a smaller geographical area compared to California, Texas and Florida. However, New York is accommodating a population of 20 million and therefore is also a major State in terms of population [159].

The NYISO offers four different DR programs named "Emergency DR Program (EDRP)", "Special Case Resources (SCR)", "Day-Ahead DR Program (DADRP)" and "Demand Side Ancillary Services Program (DSASP)". EDRP and SCR programs offer incentives to industrial and commercial end-users in order to reduce their power in critical periods. DADRP enables end-users to bid their load reductions into day-ahead market which in turn allows NYISO to determine which offers are more economical to pay at the market clearing price. Lastly, DSASP allows retail customers to bid their load curtailment in day-ahead and/or real-time market in terms of operating reserves and regulation service. The market clearing price for reserve and/or regulation is paid for the scheduled load curtailment offers [180].

ConEdison Company offers also several DR programs. Customers enrolled in a 2-hour or less pre-notification program named "Distribution Load Relief Program (DLRP)" receive 6 $/kW or 15 $/kW (considering their status) monthly and 1 $/kWh for the reduced load during an event. As another DR program, the 21-hour pre-notification program "Commercial System Relief Program (CSRP)" offers 10 $/kW per month and 1 $/kWh for the reduced load during event. The customers enrolled in either DLRP or CSRP are required to be involved in an one-hour mandatory test every year and they should supply the load reduction for at least 4 hours during actual events from 6 am to 12 am, any day of the week [181].

2.4.1.1.2 *Other States and territories*

There are also many DR programs with similar structures as the ones in California, Texas, Florida and New York but with different rules and incentives currently available in smaller States of the U.S.. For further information on these programs, readers may refer to [182] and [183].

2.4.1.2 Canada

Apart from the U.S. Canada also demonstrates several applied DR programs and strategies. The Independent Electricity System Operator (IESO) of Ontario allows aggregators to manage demand side flexibility in order to maintain the balance of the grid together with the applied price-based grid balancing strategies. The aggregator pre-notifies its facilities to supply the required load reduction in order to ensure the request of the IESO in terms of total load reduction in critical periods [184]. ENBALA Power Networks Company is a leading aggregator that engages hospitals, wastewater treatment centers, universities, cold storage facilities, etc., to ensure the required load reduction in critical conditions. ENBALA aggregates specific loads of different end-user types such as pumps in water/wastewater treatment plants, compressors, evaporators, etc., in refrigerated warehouses, HVAC units including air handling and chiller equipment in hospitals, universities and colleges and commercial buildings through a platform named "GOFlex" [185]. There are many examples of ENBALA's applied demand side solutions [186]. One of the most remarkable examples is the enrolment of the McMaster University Campus in Ontario in DR aggregation activities through GOFlex. Furthermore, GOFlex uses the flexibility in the temperature settings and therefore the power usage of five chillers with a 16,000 ton cooling capacity within the HVAC system of the McMaster University Campus. Through a communication panel employed in the end-user premises, the Building Management System (BMS) of the campus receives real-time requests and signals from ENBALA GOFlex platform and accordingly adjusts the aggregated settings of the chillers in order to reduce consumption in critical periods without a noticeable deviation from the normal comfort conditions.

Many other LSEs across Canada offer classical DR programs. Toronto Hydro Corporation as a LSE and Rodan Energy Company as a DRP can be given as an example [187].

2.4.1.3 Other North American countries

Another part of North America that demonstrates demand side participation actions is Mexico, especially with the potential smart grid investments (such as the Smart Metering project [188]) in Mexico City directed by Comisión Federal de Electricidad (CFE) of Mexico. Thus, more implementations in terms of DR solutions can be expected from this part of North America in the near future.

2.4.2 South America

2.4.2.1 Brazil

As the leading country in South America in terms of demand side energy solutions, Brazil is considered to have a good potential in this area, presenting also some efforts to implement such solutions. Brazil has demonstrated better progress in terms of energy efficiency improvement efforts; however, there is also some progress in DR applications that can serve as a basis for more advanced implementations. First of all, apart from the energy efficiency solutions, there are other pilot applications concerning the improvement of smart metering infrastructure in the service regions of different LSEs. For the implementation of DR solutions AES Eletropaulo Company, that is the major LSE in terms of consumption and revenues in Latin America, has launched a smart grid pilot implementation plan aiming at implementing DR solutions for different end-user types especially during critical peak periods in order to improve the loading factor of distribution system assets [189]. Furthermore, the Brazilian Electricity Regulatory Agency (ANEEL) has discussed changes in the tariff schemes to motivate price-based DR programs in Brazil [190]. Thus, Brazil could be considered as a good candidate for wider penetration of DR activities in the future within the Latin America region [191].

2.4.2.2 Other South American countries

Apart from Brazil, there are some applications at an initial stage in Colombia and Chile regarding demand side applications and with additional regulations these markets also seem promising for more advanced DR solutions [192].

2.4.3 Europe

The North American DR market is a leader in what regards the development and deployment of DR programs. Nevertheless, Europe holds the second place and the EU countries have recently demonstrated interest in occupying a wider portion of the DR market in the future.

2.4.3.1 United Kingdom

According to an interview published in the Reuters [193], "Longer term, UK's aggressive renewable energy goals, fairly large size, and deregulated market structure make it one of the best potential regions for DR", which clearly indicates the potential of the UK taking a leading role across Europe in DR applications.

KiWi Power Company offers a Demand Reduction Strategy (DRS) that presents similarities to existing programs in the U.S., aiming to temporarily reduce the consumption of certain end-user systems such as HVAC, lighting, etc., through the installation of a remotely controlled equipment in peak energy demand periods. KiWi Power offers different control systems for different end-user types in order to provide reductions when necessary. For example, airport chillers and air handling units (AHUs) in areas such as baggage halls and concourse areas are offered to be turned off while generators serving runway lights or communal retail areas can be also utilized during DR events. Besides, in the case of supermarkets, temporary reductions in the lighting level of retail areas or turning off refrigeration plant compressors in freezers are candidate strategies. Different solutions are also presented for hospitals, steel manufacturing, telecommunications, logistics, etc. [194].

The UK Power Networks Company has developed programs to enable the demand side participation in the UK. In the "Low Carbon London" project, the UK Power Networks Company works with Flexitricity, EDF Energy and EnerNOC companies as aggregator partners to enrol industrial and commercial participants for a DR trial in London aiming at inducing load reductions in the MW level during estimated high demand periods. Moreover, in the "Smarter Network Storage" project, storage systems in the MW/MWh level installed in the distribution system will play an active role in residential or commercial DR. Storage units will compensate the deficiency in production during peak periods in order to cover the demand, while they will absorb excess energy when renewable power plants provide high generation (in sunny or windy days) or in times in which the demand is low. The Smarter Network Storage units are planned to be integrated in the National Grid's ancillary services market for providing Frequency Response and Short-Term Operating Reserve [195].

There are also different demonstration trials of DR solutions in the UK, which are expected to play an important role in the DR market both in Europe and globally in the future.

2.4.3.2 Belgium

Belgium is a country which has also practically involved DR solutions in the daily electricity market operations. ELIA as Belgium's electricity TSO accepts DR capacity to compensate mismatches between production and peak power demand [196], in which industrial customers are given vital importance supported also by the Federation of Belgian Industrial Energy Consumers (FEBELIEC) [197]. DR aggregator companies, such as REstore [198] and Energy Pool [199], provide the required capacities to ELIA under stress conditions, to which hundreds of MWs have already been contracted in order to add flexibility to ELIA operation in the Belgium's power system.

2.4.3.3 Other European countries

Many other countries of the EU are also progressing towards implementing DR actions into their electric power system structures. Apart from the UK and Belgium, France, Finland, Norway, Sweden, the Netherlands and Germany have also improved their progress in the development of DR activities. A recent report on DR in Europe discusses the status of DR in such countries thoroughly and thus readers are addressed to [200] for further information.

2.4.4 Oceania

2.4.4.1 Australia

In Australia many efforts take place in terms of developing different DR schemes. The LSE have announced many short-term targets regarding the application of DR strategies. Following the announcement of new obligations for LSE to publish “Demand Side Engagement Strategies”, enabling the participation of demand side resources in the market by the Australian Energy Market Commission (AEMC) in 2012 [201], the number of DR strategies offered by several LSE has significantly increased. These strategies are firstly implemented in pilot projects. Several successful strategies are already applied on a larger scale while many are still in a trial phase. The Ausgrid Company regularly announces the possible DR strategies and the relevant pilots [202]. One of these possible DR strategies under trial is “Dynamic Peak Rebate Trial” for non-residential medium to large scale customers, that is basically similar to many different existing DR programs around the world, incentivizing customers to reduce their consumption during peak periods, approximately 20-30 hours during the summer (from December to February for Australia). In the first trial in the summer of 2013, 5 demand reduction events were requested from February to March 2013 resulting in an average reduction of 2500 kVA [203]. A similar test was also conducted in the same period by AusNet Services Company for commercial and industrial customers in order to acquire insights into the effectiveness of different DR strategies, through which the company also aims to evaluate and then potentially actualize strategies such as embedded generation, mobile generation, energy storage, tariff and incentive-based DR strategies [204],[205]. The Demand Side Engagement Strategy Report of a joint program by CitiPower Company and Powercor Company considering different DR options was also announced in [206].

Among the currently applied strategies, Endeavour Energy presented the “Energy Savers Program” for large consumers in Arndell Park and Rooty Hill areas. Even more noticeable are the “CoolSaver”, “PeakSaver” and “PoolSaver” DR programs for residential end-users. The “CoolSaver” program is based on mounting the AC of the residential end-user with a remotely controllable device that will automatically adjust the power of the AC during summer periods for a maximum of 6 days, between 2 pm and 7 pm, when there is a critical grid power peak due to very high temperatures. The enrolled customer is promised not to feel discomfort but is not paid per event neither per reduction. On the contrary, the customer is paid a flat 60 $/year and also a 100 $ worth free AC service as a Sign-Up bonus. “PeakSaver” is a DR program in which Endeavour Energy pre-notifies enrolled end-users via SMS, e-mail or recorded voice messages for demand reduction events during the Australian summer period and procures energy reductions through actions such as turning off unnecessary lights and appliances and postponing cloth or dish washing during the event. This program rewards the end-user with 1.50 \$/kWh of saved energy with respect to the customer's baseline. Finally, the "PoolSaver" program requests from the end-users to allow the company to install a new circuit to the power supply of the customer pool pump, which allows it to work in a pre-determined mode during specific off-peak hours. There is no payment for energy curtailment but the company argues that operating the pool pump in off-peak hours will save more than 40% of the pool pump energy consumption cost. Apart from this, the enrolled customers are rewarded with a gift card [207].

Energex Company offers a program named "PeakSmart AC" to end-users who are willing to replace their old ACs with new PeakSmart capable ACs that are remotely controllable via a signal receiver. The implementation of the new PeakSmart program enrols ACs and determines the rewards according to their cooling capacity. Customers possessing ACs with a cooling capacity of less than 4 kW receive 150 \$, between 4-10 kW receive 250 \$, while for more than 10 kW the payment reaches 500 \$. Furthermore, households and businesses can get separate rewards for up to 5 AC unit replacements. The PeakSmart ACs are controlled by the LSE in case of critical summer demand during high temperature days (a few days per year) by slightly changing the AC setting without affecting the end-user comfort significantly. There are also two programs named "Pool Rewards" and "Hot Water Rewards", respectively, for end-users that are willing to enroll their pool pumps and hot water systems to a specific tariff. Energex also offers rewards for business centers willing to install BMS or to increase the efficiency of specific systems [208]. SA Power Networks deploys also pilot projects on direct AC load control for residential areas (involving around 1,000 volunteering households) by switching off AC compressors but not their fans in order to maintain the comfort level [209]. Pre-notification based residential DR programs are also employed by the United Energy Distribution Company for 4,500 households in Melbourne for a maximum of 4 events per summer and a reward of up to 25\$ per 3-hour event [210]. Western Power Company has also performed a trial on direct AC load control, named "Air Conditioned Trial (ACT)", through the Perth Solar City Program of the Australian Government, in which ACT AC compressors were cycled via wireless communication, while AC fans continued running to maintain a sufficient end-user comfort level [211].

Several smaller scale implementations of different DR strategies which are not mentioned here have also taken place in Australia. Relevant information and annual reports by LSEs in Australia can be found in the official website of the Australian Energy Regulator (AER) [212].

2.4.4.2 Other Oceanian countries

Among other countries in the continent, only New Zealand shows a rather remarkable progress regarding DR programs. Transpower Company runs a program for commercial buildings (office buildings, hospitals, data centers, etc.) with standby generators which are requested to be operated in order to reduce the power drawn from the grid in critical peak periods. Besides, Transpower is currently launching new DR programs for the Agricultural sector [213]. EnerNOC, through "DemandSMART" program, enrols interruptible commercial and industrial end-user loads into the Instantaneous Reserves (IR) market. The program limits are 30 min per event for a maximum of 6 events per year in the North Island, while 2 events per year are allowed in the South Island. The targeted loads include refrigeration compressors and fans in cold storage and food facilities, pumps with storage and aerators in water treatment facilities, refiners, chippers and fans in pulp, paper, boar and wood processing facilities, electric furnaces and smelters in manufacturing facilities and, finally, HVAC systems in data centers and large buildings [214]. There are also different solutions presented by LSEs, DRPs and technological companies in New Zealand [215].

2.4.5 Asia

Asian countries do not generally have an active DR market. However, several pilot projects are in preparation or evaluation phase, especially in the Asia-Pacific region.

2.4.5.1 Singapore

Singapore is one of the leading countries in Asia in terms of DR applications. The Energy Market Authority (EMA) of Singapore has already introduced DR programs to enhance the competition in the National Electricity Market of Singapore (NEMS), in which consumers can participate directly or through retailers or DR aggregators. All customers that can offer at least 0.1 MW of reduction for half an hour can participate. The consumers participating in the program share one-third of the savings obtained by the reduction in electricity prices as incentive payments, up to 4,500 $/MWh that is the cap for the wholesale electrical prices. The enrolled consumers can provide temporarily the required reduction by switching off non-critical equipment, reducing HVAC or pumping system power or even using on-site back-up generators for short periods [216].

The Diamond Energy Company has been the pioneering actor in DR applications in the Singapore market having applied load interruption programs to confront abnormal events such as unexpected peak demand or forced outages of power generation [217]. The CPvT Energy Company is also a registered retailer in EMA and participates in the load interruption program [218]. There are also other market participants in the DR market of Singapore, which is currently the most promising for future developments amongst the Asian countries.

2.4.5.2 Japan, South Korea and China

Japan, South Korea and China are also countries that are expected to develop DR programs in order to induce a more active demand side participation in the future. Kyocera, IBM Japan and Tokyu Community have started an Automatic DR Management System pilot project in Japan. In the mentioned project the automatic DR system is planned to send a power-saving request (DR signal) to consumers under system stress conditions, or even to control the end-user Energy Managements Systems (EMSs) if necessary [219]. Comverge, OpenADR Alliance and Fujitsu have also initiated pilot DR projects in Japan [220],[221], that aim at providing a considerable DR sector in Japan that has suffered from intense energy requirements during high emergency conditions, especially after the Fukushima nuclear incident. OpenADR Alliance, being a non-profit corporation created to foster the development, adoption and compliance of the OpenADR smart grid standard, has also taken significant steps towards developing DR applications in South Korea in collaboration with local authorities and associations [221].

In China a collaborative pilot project between the Natural Resources Defence Council, Shanghai Electric Power, NARI Group and the State Grid Corporation of China and Honeywell as an international partner started in Shanghai in 2014 and is the first official DR demonstration project in China. The mentioned pilot project has contracted 33 commercial and public buildings, 31 steel, chemical and automotive industrial customers, which present an aggregated capacity of 100 MW available to be curtailed with a considerable payment per unit of curtailed load. The project is in place, demonstrating the economic and technical sides of DR strategies for different consumer types [222].

2.4.5.3 Other Asian countries

Some other DR activities also take place in the wider Asian continent, being mostly in the pilot stage. CLP Power Company in Hong Kong announced an Automatic DR pilot project in which existing BMS facilities in commercial and industrial customers will be integrated with Automatic DR concept that will also enable CLP to curtail some loads directly in emergency conditions [223].

Noticeably, a small country in the Far East Asia, Bangladesh, currently employs demand side actions mostly by advertisements rather than incentive-based programs. The Bangladesh Power Development Board (BPDB) that is the major regulatory entity in the power system of Bangladesh has established motivational advertisement based programs to enhance the awareness of the end-users. BDBP has started campaigns through electronic and print mass media to request end-users to be more rational and economical in electricity use during peak hours; for example, by switching off unnecessary loads at residential end-user premises or by shifting irrigation loads to off peak hours. It was estimated that with the aid of the campaign around 400 MW of irrigation load was shifted to off-peak hours in the last years. Besides, industries operating with two shifts are requested to interrupt their operation during peak hours. A remarkable piece of evidence from BDBP is that BDBP monitors shop/market closure time and obliges them to close at 8 pm, which contributes to load shifting from peak to off-peak hours by 350 MW and reduces the load shedding necessity [224]. There are also some early-stage studies on DR implementations in some other countries such as India, which could be developed in the future, depending on the policies of the regional governments.

At this point, it should be noted that no remarkable DR activity has been noticed in the Middle-East and thus, no information exists about countries in this region.

2.4.6 Africa

The African continent is hosting different nations that present significant differences in life quality among the population. A very small portion of the population has relatively high income while many others do not even have access to electricity. Thus, DR programs in Africa are limited; yet, there are some remarkable examples. Eskom Company in South Africa offers different DR programs especially to its large customers. The “Standby Generator Program” requests the enrolled customers to supply all their load demand by own on-site generators (minimum 1,000 kW) up to 2 hours during any requested day and for up to 100 events per year. The control of the generator is not in the responsibility of Eskom. Eskom pre-notifies (from 3 pm of the previous day to 30 min prior to an event) the end-user for the DR event period and the end-user is not enabled to use grid power in the mentioned period. The end-user is paid a rate for the self-generated power based on the curtailed grid power. Another program offered by Eskom is "Supplemental Demand Response Compensation Programme" for industrial and commercial customers who can reduce their consumption by 500 kW or 10% of the average of their load demand (whichever is greater) during pre-specified critical periods announced by Eskom. The limits are 1 to 2 hour reduction on a scheduled day for up to 150 events per year with a pre-notification from 3 pm of the previous day to 30 min prior the event with a payment for each kWh of energy curtailed by the customer during the event [225]. Eskom also started pilot projects for residential load management based DR programs. More than 10,000 geyser relays have been installed in residential end-user premises to shed electric appliances remotely during a critical peak power period with a credit based compensation for the customer [226]. There are also many consulting and technical companies in South Africa supporting DR implementations and improvements regionally (e.g., Enerweb Company [227]).

The DR market is growing in Africa with new pilot studies across the continent, especially in the most developed countries. A more complete analysis of the DR status in Africa can be found in [228].

2.5 Barriers to the Development of DR

The potential benefits of DR and the intensive research recently have been the drivers for initiating and developing DR programs around the world. However, one may notice considerably asymmetric progress in enabling the active participation of demand in the power system procedures between different regions. This situation is related to a series of challenges and barriers that limit the active participation of demand in electricity markets. In this section the challenges towards the adoption of DR as well as the barriers that are present in different regions are critically compiled and discussed. The challenges and barriers are classified in six distinct, yet intersecting, categories.

2.5.1 Barriers associated with the regulatory framework

The first obstacle towards the integration of DR resources in the electricity market structures is the absence of rules that implicitly consider their participation in the provision of different services, or the presence of rules that limit their potential. Power system service definitions or security of supply standards refer to the way that an ISO, a reliability organization or a balancing authority define the services that are required in order to maintain the secure operation of the power system. These technical definitions directly define which resources are eligible to provide a given service. These definitions may explicitly exclude or effectively limit the participation of demand side resources in ancillary services markets. In the U.S. the North American Electric Reliability Corporation (NERC) has provided definitions that are functionally based and technology neutral in order to include DR participation. However, several regional reliability organizations in the U.S. such as the Western Electricity Coordinating Council (WECC) do not currently allow the provision of reserves from DR resources [229]. Furthermore, ISO New England does not allow DR resources to participate in the regulation markets [230]. It should be noted that although most regional reliability council definitions comply with NERC's standard, there are several issues that could be viewed as important challenges yet to be overcome, such as issues of fair treatment of DR in comparison with generation when it comes to the qualification of capabilities in resource adequacy planning such as in the case of MISO [231].

Despite the fact that in the U.S. these issues have been long recognized and are being gradually addressed, the situation in Europe is different. The EU policies have generally been more focused on energy efficiency and DSM, rather than DR. Evidently, until recently, the EU was more interested in climate change actions, promoting energy efficiency and renewable energy growth and did not perceive DR as a key solution to address its environmental objectives [232]. With the Third Energy Package and especially with the EED the European Commission has demonstrated strong interest in DR. The main driver seems to be the fact that DR may play an effective role in supporting higher penetration levels of the intermittent renewable generation [233] and therefore has the potential of becoming a catalyst in achieving the EU's 2030 and 2050 energy policy and decarbonisation targets [234]. Article 15.4 of the EED explicitly states that DR participation in balancing and reserve markets and ancillary services procurement should be promoted, while Article 15.8 states that national energy regulatory authorities should encourage DR resources to participate alongside supply in wholesale and retail markets and guarantee that DR is treated in a non-discriminatory manner, on the basis of its technical capabilities [140]. Although the phrasing of the EED could be viewed as progressive and direct, the implementation of DR across Europe is not homogenous. This is due to two reasons: firstly, the directives of the EU have to be adjusted to national level, considering the particularities and the constraints of each system, that is a task that will definitely need time, and secondly, the EU does not have an adequate system in place to monitor the market [232]. Currently fewer than 5 out of the EU 27 Member States have created regulatory and contractual structures that support DR. France and the UK are the only countries with developed DR programs, while Finland, Belgium, Austria, Ireland and Germany are undergoing fundamental regulatory reviews; however, they are still in the formative stage of this process. The rest of the Member States follow national regulations that prohibit consumer participation in balancing, reserve and energy markets, as opposed to the countenance of the EED. The Third Energy Package has also set common rules for the organization of the energy markets in Europe in order to facilitate the completion of the Internal Energy Market [235]. In this context, the absence of homogenous DR products in different European countries could potentially constitute a barrier for DR. For example, capacity mechanisms are considered an attractive market opportunity for DR resources and countries such as France, Italy and the UK are currently developing their own national implementations [236]. Different motivations and priorities could raise conflicts and confusion in contrast with the harmonization targets at European level [237] and as a result the development of DR could be hindered.

2.5.2 Barriers associated with the market entry criteria

Historically, the qualifications regarding the entrance of new market participants into various types of markets (energy, reserve and ancillary services markets) have been developed considering that the sole resources of the system are large centralized generators, which present similar operational characteristics. As a result, the relevant rules are not in position to reflect the diverse technical and qualitative characteristics of other resources such as DR and as a result the market structures cannot integrate such resources without a revision of the existing market entrance criteria. The following issues associated with the requirements that a resource should satisfy in order to participate into several markets, if not addressed, may constitute a direct practical barrier to the development of DR:

- minimum resource bid size,
- possibility of aggregation of multiple small consumers and geographic boundaries of aggregation,
- bid direction,
- number of call events (e.g., on a weekly, yearly basis),
- load recovery period,
- response time,
- duration of response,
- fixed trading charges, membership and entrance fees.

Traditional generators have relatively large capacities (tenths of MWs) and as a result the minimum resource bids that have been set in order to participate in several market structures are high in comparison with the individual consumption of the majority of the loads, explicitly disqualifying DR to participate in these markets. This barrier has been recognized by many ISOs and efforts have been made in order to relax this prerequisite. For example, the ERCOT and PJM have set the minimum bid size to 0.1 MW, while the requirement in MISO is 1 MW [230]. In contrast with the U.S. markets, in Europe this issue is yet to be addressed. Several countries have decreased the minimum size that qualifies the participation of a resource in a variety of services. Finland provides a good example of a DR friendly country. The minimum bid size in order to participate in normal operation reserve program is 0.1 MW while in order to participate in the frequency controlled disturbance program the minimum bid size is 1 MW. Similarly, in Italy the resource must render available at least 1 MW in order to be eligible. In the Netherlands and in the UK the minimum allowed resource capacity is 4 MW (regulation, reserves) and 3 MW (short term operating reserve-STOR), respectively. In order to evaluate whether the minimum resource capacity size constitutes a barrier, the characteristics of the system loads should be taken into account. For example, in the Canary and Baleares Islands the minimum required reduction potential is 0.8 MW; however, the fact that an insular power system structure differs from the mainland grids should be taken into account during the evaluation. In contrast with these relatively positive developments in some countries, in Denmark and Norway, participation in tertiary reserves requires a capacity of at least 10 MW since the instructions are manual (the participants are notified by telephone). One could argue that this particular barrier will not be radically addressed in the near future as regards the majority of European countries since the entry criteria have been only recently revised (2014) [200].

Another important factor to consider together with the high minimum capacity requirements is whether the market rules allow the aggregation of multiple small consumers and to what geographical extent the aggregations are possible. In several markets, aggregation is not legal (e.g., ERCOT, MISO, Austria, Spain) or it is legal but not practically feasible due to other legislation issues (e.g., in Denmark). Furthermore, restricting the geographical extent of the aggregation can further bound the capability of aggregators to participate in markets because of not meeting the minimum capacity requirements. The combination of high capacity requirements and the unavailability of aggregation options exclude residential, commercial and small industrial consumers and limit the DR provision option only to large industrial consumers, such as in Denmark and the UK [238],[239].

Several market structures require that the bids are symmetric. This means that resources should provide equal capacity to change in both directions that in the case of DR would mean that the loads should be equally able to decrease and increase their consumption. This is a requirement that directly restricts the pool of eligible DR resources since only a few types of load would be equally flexible in both directions. Examples of markets that require symmetric regulation capacity offers are MISO, PJM while in Denmark, for this reason DR is not allowed to participate in secondary reserves. In Switzerland tertiary control allows asymmetric bids while secondary reserves require symmetric capacity. The German market allows asymmetric bids but consumers cannot practically participate in reserves because negative deviations (load increase) bear significant penalties.

Other service attributes such as the number of call events, time between two calls, response time and duration of response can potentially hinder the deployment of DR resources. The primary aim of demand is not to provide flexibility to the power system but to serve the specific needs of the end-user. Furthermore, the existing emergency DR programs strictly limit the number and the duration of DR calls per year since the deployment of such resources entails interruption of service for the consumers. In order not to demotivate the consumer participation, utilities have been conservative with the utilization of DR calls. For example, in 2007, CAISO has issued DR calls spanning less than 1% of the year, while only in less than 60% of the highest load periods DR calls were issued. Most markets require the resource to maintain its response from 4 to 12 hours (e.g., Austria and Germany, respectively) during a call. There are also examples of markets that require permanent availability of regulating resources such as the Swiss market, which is a barrier for most consumers to provide DR except for the case of a few large industrial consumers. Nevertheless, it is generally reported that reserves are not typically required for more than 1-2 hours. This is aligned with the requirement of STOR service in the UK in which a call must have duration of 2 hours. However, even in this case commercial consumers are practically excluded [237]. The majority of existing market structures allows the participation of these resources either through direct bidding or through bilateral contracts in the day-ahead market. This fact implies that the planning of the use of such resources should be performed hours ahead of the real-time operation of the system. As a result, the use of such resources is limited to emergency situations that can be predicted by the ISO the day before the actual operation of the power system, while several calls for DR prove to be unnecessary in the real-time. Day-ahead market decisions are connected with high uncertainty and ineffective scheduling of DR calls impairs the forecast error as regards the generation and load response in comparison with dispatch decisions that are made closer to real-time. This situation reduces the competitiveness of demand side resources in comparison with flexible generation resources (such as open cycle gas turbines - OCGT plants) that have the ability of fast start-up and ramping, despite the fact that several load types are capable of adjusting their demand instantaneously, and therefore limits their value for the ISO. Furthermore, the need for advanced notification for DR calls hampers the participation of demand side resources in contingency reserve markets that require short-term response, typically between 10 and 30 minutes, an interval which is shorter than the minimum notification time for DR. The ERCOT is one of the few examples of operators that allow the efficient participation of load in reserves [240], together with the recently revised market rules in Norway that require activation of reserves in 15 minutes.

Finally, the entrance fees for aggregators or DR providers are generally considered to be reasonable, and thus, they do not constitute a direct barrier. For example, in Finland the aggregators have to pay 200 € per month to the TSO, while they have to guarantee a bank deposit in order to reduce the risk of bankruptcy [200].

In order to effectively revise these rules, the ISO should firstly realize a fundamental difference between the impacts of large centralized generation and highly dispersed DR resources on the reliability of the power system, in case that the resource fails to respond to an instruction. Currently, the ISO require stringent monitoring of the response of both generation and demand side resources. However, as it was demonstrated in [241], this last requirement may not be necessary for the case of DR since the aggregation of small-scale consumers (e.g., residential) statistically presents a more reliable response in comparison with a large generator. Furthermore, according to [242] several DR resources may have faster response than generators, be more resilient to rapid changes in consumption than generators are to changes in production (cycling) and do not suffer from increased losses such as generators when operating partially loaded. Given these favourable capabilities of DR, not revising the existing market entry criteria in order to reflect the diverse technical capabilities of loads constitutes a severe underutilization of available system resources.

2.5.3 Barriers associated with market roles and interaction implications

Competition in electricity markets has been promoted in the past decades. Unbundling within electricity markets refers to the separation of electricity generation, transmission, distribution and retail sales that have been vertically integrated structures. The rationale behind unbundling is the promotion of competition by guaranteeing access to the power system for all participants on a non-discriminatory basis. Unbundling can be realized in terms of accounting, legislatory framework and ownership rights [243]. The liberalized environment has enabled several entities in electricity markets that have different roles, responsibilities and objectives.

This situation may impose barriers towards the uptake of DR, especially because of the contrasting views and the absence of an aligned position as regards the use of flexibility between TSOs and DSOs. The majority of DR resources are connected in the distribution system and as a result the collaboration between TSOs and DSOs is important in order to exploit DR. However, issues regarding the purpose of DR deployment may complicate the development of DR programs. For instance, TSOs would view the flexibility provided by DR as a means of balancing the system, while DSOs would use it in order to mitigate local congestion. This implies that coordination between these entities should be developed in order to design different DR products that would transparently and legally allow the utilization of DR in the system and market operations [234].

Another important issue is that despite the unbundling process, in many regions TSOs and DSOs are still regulated entities, responsible for the technical management of the system and as such, the only entities permitted to intervene in investment decisions, excluding the participation of private initiatives. However, the investments of a TSO/DSO are limited by the allowed remuneration that in general limits the expenses on R&D, having a negative effect on the development of new technologies, especially in Europe [244].

The effective business/market scheme under which the demand side would participate in electricity markets is yet debatable and remains in the forefront of the barriers to the uptake of DR. Three main business models can be identified: direct contracts with the TSO, aggregation of small consumptions and real time response of demand to market prices. There are several challenges associated with each of these demand participation options. First, the direct contracts with the TSO allow only the participation of a few capable large industrial consumers that are able to meet the market entry qualifications as it was previously discussed. Second, aggregating demand may compromise the fundamental benefits of dynamic pricing tariff schemes, such as RTP, which is the pricing of the end-user with the market price. The reason for this is that an aggregator has to bid in the market and fulfill its obligations through its portfolio. In order to achieve its targets, this kind of entity could alter the prices in order to reflect not the market prices but the requirements of the market as regards the behaviour of the aggregator [245]. Given that aggregation is an option that would allow the participation of smaller consumers (residential, commercial) in the market, unclear definition of the role and the responsibilities of an aggregator constitutes a barrier to be addressed. Besides, aggregation of consumers is currently illegal or practically infeasible in several markets. Third, the response of demand to real-time market prices [246] raises concerns regarding the demand and price volatility. This is the result of the asymmetry of information, i.e. the time span between the communication of the price and the response of the load and as a result the ISO should perform a prediction. Generally, flexible consumers tend not to contribute to the mitigation of volatility since they can achieve their economic targets, in contrast with relatively inflexible consumers that would have incentive to inform the ISO about their intended consumption pattern. To deal with this issue, appropriate control regulations should be developed in order to define the interaction between demand and the market in order to reduce the volatility of demand and price; however, this would deteriorate the economic efficiency [247].

Finally, it is important to highlight several implications that emerge due to the individual objectives of the different market participants as regards the integration of DR resources into the market [66]. The TSOs and the DSOs will utilize this flexibility in order to facilitate the satisfaction of operational constraints at critical moments. A competitive retailer will use DR in order to reduce the risk of being exposed to high prices in the spot market [248]. On the other hand, commercial aggregators will focus on maximizing their profits, thus expressing their preference to a specific market, a fact that is likely to prohibit the participation of DR resources in other markets such as in France. The absence of a coordinative framework could provoke competitiveness over the utilization of DR. For example, the behaviour of responsive consumers may benefit also consumers that are not flexible by inducing lower electricity rates, implying transfer of wealth from the generation side to the demand side [157]. It is evident that within the liberalized market context, each individual entity would more likely aim at utilizing the flexibility of DR for its own benefit that is not necessarily aligned with the maximization of the social benefit (improved reliability, economic efficiency, no comfort loss for consumers, etc.). The diverse and conflicting views for DR are the source of a series of further challenges such as difficulties in perceiving DR as a crucial system resource, justifying and allocating the requirement investment costs and finally engaging consumers. These issues are covered in the following sub-section.

2.5.4 Barriers associated with DR as a system resource

There is also a category of barriers that is related to the effects of the widespread integration of DR resources in the electricity markets and power systems. These challenges may be compelling since generator shareholders would oppose to the introduction of such resources and the ISOs would perceive DR as a complicating factor for the system operation rather than a beneficial addition to the system.

The most promising application of DR is the balancing of the fluctuations that come from the high penetration levels of intermittent renewable generation. The response characteristics and the availability of several DR resources qualify them for such utilization. However, significant response of the load would probably limit the capacity factors of peaking and intermediate generators that are currently responsible for regulation, load following and ramping. This situation would be favourable for the economic efficiency of the system since the services from these units are expensive and base units operate more efficiently at constant output. However, the revenues of these generators would significantly decrease and therefore it would be harder for their owners to recover their investments, leading to a potential decommissioning of such power plants. This outcome would not be viewed positively by the ISO since several ancillary services (e.g., voltage support, system restoration) cannot be provided by loads [240]. Furthermore, these units would be required in order to meet unsatisfied fluctuations that DR fails to mitigate. The drop in reserve market clearing prices is another potential outcome that would not be viewed positively by the existing stakeholders. Some types of DR have little or no opportunity cost to provide certain types of reserves. Thus, the entry of a large amount of low cost resources would potentially cause a decrease in the clearing price of these services that are an important source of income for flexible generators in several regions [249].

From the ISOs point of view there are three major concerns regarding the introduction of DR in their operational practice. The first is the justification of DR as a valuable system addition in comparison with other technologies. Strbac [66] argues that the value of DR lies both in system operation and system development. The key towards assessing the value of DR is the operational status of the system. In a system that is stressed, i.e. the system's loading is close to its maximum capacity, the value of DR could be high. Another factor that determines the value of the addition of DR resources is the flexibility of the existing generation mix. It is more likely that DR will have greater value in systems with significant penetration of non-dispatchable renewable generation and relatively inflexible base load generation. Furthermore, even in such cases the DR based solutions are not always competitive in comparison with traditional approaches such as the OCGT units that are technically proven and significantly flexible generation side resources.

The economic compensation of DR participation in the energy market is the second issue to be addressed by the ISOs. This discussion is controversial in most markets around the world [240]. One argument is that DR providers should be compensated at the full market price, similarly to the generators, since the two services are identical, which is the case in ISO-NE and NYISO. However, the decision not to purchase energy is not the same as physically supplying energy. The loads participating in wholesale markets would receive dual benefits, being paid at the market price for their service and achieving retail bill savings because of the reduced consumption. In order to promote a more efficient DR compensation from the point of view of the ISO, in MISO and PJM the DR is compensated at the full market price minus the retail rate [231]. On the other hand, DR providers argue that DR creates positive externalities such as economic and environmental benefits and thus, they should be granted payments higher than the market prices. The CAISO [250] identifies the problem of the compensation of DR as one of the main barriers as well. Insufficient compensation of DR may limit its investment recovery capability and thus demotivate its development, while excessive subsides may jeopardize the economic stability of the market.

The third challenge for the ISOs is the lack of suitable and transparent tools in order to evaluate, measure and verify the demand reductions [63]. The European Network of TSOs for Electricity (ENTSO-E) recognizes that inefficient data handling in European electricity markets is a hindrance that may limit the growth of DR [234]. Currently, stakeholders have limited access to data that prohibits them to fulfil their role, while rendering difficult the coordination and the verification of the realization of DR. Furthermore, the existing forecasting and planning methodologies are not adequate to investigate the capability of DR to serve as an alternative to conventional system expansion approaches [251]. The absence of standard methodologies to study the cost-effectiveness of DR hinders the decisions to perform investments. There are also two problems in identifying the size of DR resources. First, it is difficult to evaluate the number of customers that are willing to be involved in a DR program and therefore, its potential capacity [252]. Second, there is not a standard way to determine the customer consumption baselines in order to accurately depict the normal consumption of a customer. A flawed methodology bears the risk of consumers gaming with their baselines in order to get paid without providing real load reductions and would render the deployment of DR resources economically unreliable [231].

2.5.5 Barriers associated with infrastructure and relevant investment costs

The key technologies for the implementation of DR have already been developed. However, the current levels of penetration of control, metering and communication technologies in the power systems should be increased in order to enable widespread DR activities [66].

A range of DR activities may require a small number of limited duration interruptions and could be performed manually (e.g., light dimming, equipment shut down, etc.). Nevertheless, participation of demand in ancillary services would require more frequent and much shorter interruptions. Control and automation technologies must be adopted by the consumers to provide such services, especially regulation. This implies that consumers, with the potential of being subsided by a utility, would have to uptake such investments that bear operating and maintenance costs. Furthermore, metering equipment that allows real-time data transmission should be placed in order to comply with service verification requirements and this constitutes another significant economical burden since telemetry equipment has costs that tend to increase with the required speed of response [229].

Stakeholders in MISO [231] and CAISO [250] have raised concerns regarding the costs, especially to install equipment in order to comply with the telemetry requirements of the available DR programs that have been characterized as unreasonable. For example, Alcoa, a metal industry that participates as a DR resource in MISO has reported a total cost for the telemetry infrastructure, the EMS, the bidding interface and the database system of 750,000 $. It is evident that such costs are bearable only for large industrial consumers, explicitly excluding smaller resources to participate in DR activities. Similarly, the commercial sector perceives the capital costs of manual and automatic DR as prohibitive in order to participate in DR programs [253]. Finally, the increased cost of residential EMSs is a barrier to the development of residential DR [79], while the limited savings from consuming energy in low price periods would not meet the investment costs. Currently, automated residential DR is viable only for longer term home owners who have the income to support such an investment, unlike low income social groups and tenants living in rented residences [254].

2.5.6 Barriers associated with electricity end-users

When it comes to DR the greatest challenge is related to the successful engagement of customers in DR programs. Despite the fact that in the U.S. DR has been developing for more than a decade, only 23% of customers were enrolled in available DR programs in 2012 [255]. Evidently, lack of customer interest and support is a definite factor limiting the development of DR [256]. There is a series of reasons for which the engagement of consumers is an impediment towards the evolution of DR programs.

The first challenge is that unlike the generation side, the electricity consumers do not necessarily follow an economically rational behaviour and, therefore, their response cannot be derived from conventional economic models. The majority of electricity consumers view energy as a service rather than a commodity and as a result minimizing their electricity bill by responding to price signals or raising revenue by participating in other types of DR programs may not be their primary concern. O'Connell et al. [56] have compiled the main results of studies regarding residential customers enrolled in TOU and RTP programs that demonstrate evidence for the lack of economic rationality and the need to develop more advanced economic models in order to predict the response of the consumers considering factors such as the effect of weather on consumption and the asymmetry between information and response. There are also several limitations as regards the non-residential customers. The basic challenge for this sector is that loss of comfort because of consumption limiting or interruption may negatively affect their primary intentions. For example, according to a field test in the UK, hotels are likely to provide a considerable short term response through managing the AC unit load; however, the duration of this response is limited by the thermal comfort of hotel guests. Also, shopping centers theoretically present comparable DR potential, but perceive the loss of comfort linked with DR as a negative factor for the commercial gain [236]. Another factor that renders commercial customers reluctant to enrol in DR programs is the relatively short warning period that does not allow efficient decision making [253]. Finally, in many regions and especially in Europe the majority of end-users are accustomed with a uniform price of electricity and therefore the awareness about the volatile value of electricity is limited. As a result, exposing them to dynamic electricity prices raises concerns about the value of postponing the usage of electricity in comparison with the immediate satisfaction of consuming [248].

The second challenge is related to the design of the contracts. Different consumers should be offered appropriate contracts, tailored to their consumption profile. Without appropriate and transparent information, consumers could be confused with too many unclear offers, complex contract handling and multiple parties involved. The consumer acceptance could be raised in the presence of a single billing scheme in which the retail supplier, network charges and DR payments are all in the single bill [234]. As a result, absence of tools and mechanisms such as price comparison tools and standardization of contract design may pose difficulties to the end-users to deliberately choose the most suitable contract for them [257].

Issues regarding the deployment of smart meters and consumer protection further relate the end-users to the challenges that need to be overcome in order to facilitate the development of DR programs. Currently there exists a broad legal framework on privacy and data security at the EU and international level regarding data processing for billing purposes. However, DR is not specifically covered by this legal framework since it would require a significant increase in processing frequency and data granularity. The EU is currently promoting the active deployment of smart meters because of the perception that it constitutes the core element towards transparency, yet fixed tariff and several varying pricing schemes such as TOU pricing do not require two-way communication [248]. Overall, the low physical security of the meters and control equipment, the prospect of using the internet for communication and services and the increased number of intervening parties should be covered by clear privacy laws. The absence of a common framework fosters an unstable regulatory environment for investors and confines consumer acceptance [235].

2.6 Chapter Conclusions

The current advancement in metering, communication and control infrastructure allows for the development of DR programs targeting at different types of customers through appropriate incentives. Engaging consumers in order to shift or to forgo energy during periods of system stress can prove beneficial in many aspects. Mostly, DR is likely to prove an important resource in order to enhance the flexibility of power systems in order to accommodate increasing amounts of intermittent renewable generation. The thorough and innovative review of existing DR programs around the world demonstrated a highly asymmetrical development between different regions. The U.S. is evidently leading in the adoption of DR, offering diverse programs in order to exploit the response from various types of consumers. Europe and Oceania are also taking important steps towards engaging demand side resources in the system practices. It is interesting to notice that despite the lack of homogeneity, efforts to develop DR programs are pursued globally, clearly indicating that utilities are starting to perceive DR as a useful rather than a complicating factor. Given that the required infrastructure to implement DR programs targeting at any customer type is nowadays available, in order to further promote the activation of the demand side a series of barriers, mainly regulatory and economic, are yet to be addressed.

Chapter 3

Contingency and Load Following Reserve Procurement by Demand Side Resources

3.1 Introduction

The qualification and quantification of the appropriate AS in order to ensure the secure operation of the power system and the provision of uninterrupted and quality service to the consumers plays a primordial role in the short term operations of the ISO. More specifically, it should be guaranteed that sufficient capacity is kept in order to allow for corrective actions in order to face imbalances, that may occur due to different reasons, to be made. Such imbalances may occur due to a generating unit outage or because of the failure of a transmission line. These events that are commonly referred to as system contingencies constitute a severe jeopardy for the operation of the power system and should be tackled through the deployment of reserves from other generation side resources. Apart from these, another source of uncertainty that needs to be confronted is the deviation of the intra-hour load demand from its forecasted value. Different system operators across the world utilize different definitions and procurement procedures as regards reserves [34],[258]. In addition to these sources of uncertainty, the large scale penetration of RES, especially of wind power generation, in the power system has resulted in an increased need of procuring reserves in order to accommodate the volatility in the power output of such resources. As a result, apart from the commonly met AS types, a new type was recently proposed by MISO [259] and CAISO [260], namely the flexible ramping products, designed to increase the robustness of the load following reserves under uncertainty and especially significant solar and wind power ramping events. As it was discussed in Chapter 2 demand side resources may be also deployed in order to provide system services, presenting significant potential technical and economic benefits, especially in the presence of high levels of RES penetration in the generation mix.

Providing AS in a market framework primarily involves the solution of the unit commitment problem that may be solved using various techniques. Among them, meta-heuristic approaches including genetic and evolutionary algorithms [261],[262],[263], particle swarm optimization [264], tabu search and simulated annealing [265], as well as their hybrids [266], have been extensively used for the solution of the unit commitment problem in the literature. Artificial intelligence methods such as fuzzy and expert systems [267] and neural networks [268] have been also used. Furthermore, priority list methods [269] were among the first methods applied for the solution of the unit commitment problem. Another category of techniques utilized for dealing with the unit commitment problem are the mathematical programming based methods. For example, Lagrangian relaxation [270] is applied in [271] for a transient stability-constrained network structure. The Lagrangian relaxation method and its improved versions are also employed in [272] and [273]. The combination of Lagrangian relaxation with mixed-integer nonlinear programming is applied in [274]. Dynamic programming has been also extensively applied for solution of the unit commitment problem in the past [275]. Nowadays, the MILP approach is considered as the state-of-the-art for the unit commitment problem solution. It is almost exclusively employed in modern centralized market clearing engines and has attracted significant attention by the recent related literature [276],[277],[278]. A detailed discussion regarding the solution approaches of the unit commitment problem can be found in [279], while a recent review regarding stochastic unit commitment is presented in [280].

There are also numerous technical studies that propose market designs in order to procure reserve services. In [281] and [282] a stochastic security-constrained market-clearing problem is formulated, in which line and generator outages are considered through a preselected set of random contingencies, determining the reserves by penalizing the expected load not served. In [283] a two-stage stochastic programming model is developed to evaluate the economic impact of reserve provision under high wind power generation penetration. In [284] a two-stage stochastic model is presented, including dispatchable DR providers, used to meet the security constraints of the system. In [285] a day-ahead market structure is presented, in which demand side participates in contingency reserve provision by bidding an offer curve that represents the cost of rendering the loads available for curtailment.

Jafari et al. [286] proposed a stochastic programming based multi-agent market model incorporating day-ahead and several intra-day markets, as well as a spot real-time energy-operating reserve market in order to adjust wind fluctuations. In [286] no demand side resource apart from load-shedding was considered. In [287] a contingency analysis based stochastic security constrained system operation under significant wind power condition was analyzed, while demand side resources were not considered. In [288] a switching operation between two separate energy markets named “conventional energy market” and “green energy market” was proposed where profit maximization of green energy systems was formulated in a stochastic programming framework without considering the contribution of demand side resources. Similar studies neglecting demand side resources for reserve procurement to overcome system uncertainties were also presented in [289], [290] and [291]. It is also worth noting that the aforementioned studies considered the combination of different approaches in order to mainly provide a computationally efficient way to solve the unit commitment problem under uncertainty. The computational efficiency of the unit commitment under uncertainty was also addressed in [292].

Wind and load uncertainties were covered by scheduling optimal hourly reserves using security-constrained unit commitment approach in [293]. A two-stage stochastic programming framework with a set of appropriate scenarios solved using dual decomposition algorithm was provided in [294]. Some further studies focusing mainly on demand and stochastic programming also take place in the literature. Shan et al. [295] considered a DR based load side contribution to reserves under high levels of wind penetration where demand is modeled using a linear price responsive function. Load uncertainty and generation unavailability were covered in [296] without considering RES uncertainty in a two-stage stochastic programming framework. Apart from the stochastic programming based literature studies referred above, many studies considering different modeling frameworks such as probabilistic [297],[298], rolling stochastic [299] and Monte Carlo criteria [300] can also be found.

In this chapter a two-stage stochastic programming based joint energy and reserve market-clearing model within MILP framework is proposed in order to evaluate the required level of reserves in order to tackle with the uncertainty and the imbalances introduced by the increased penetration

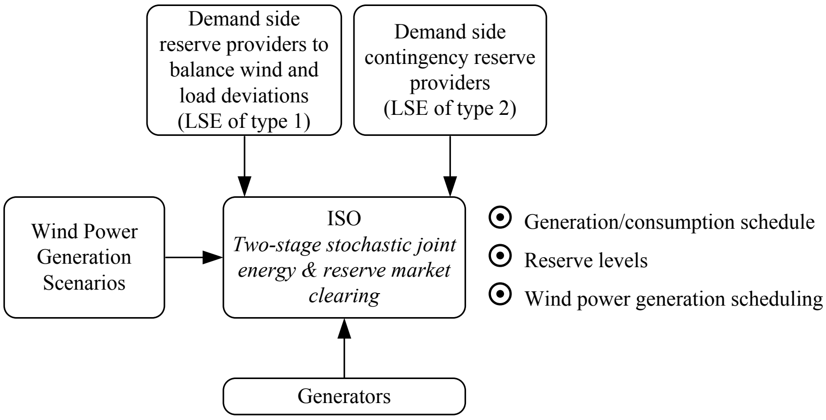

Figure 3.1: Overview of the market clearing model

of wind power generation, intra-hour load variations, line failures and unit outages. The first stage of the model represents the day-ahead market and is cleared for each hour of the next day. The second stage simulates possible instances of the actual operation of the power system and intra-hour intervals are considered. In order to ensure the reliability of the system, several reserve services are employed. Firstly, load-following reserves procured from conventional units and LSE under an appropriate framework deal with the intra-hour load and wind deviations. The power imbalance caused by contingencies related to transmission lines and generators is handled through spinning and non-spinning reserves from on-line and off-line generating units, as well as from LSE that are committed to alter their consumption in order to provide emergency reserves. The explicit novel contribution of this model is the consideration of all the aforementioned resources and operating conditions of a power system in a single joint energy and reserve day-ahead clearing model.

The remainder of this chapter is organized as follows: Section 3.2 presents the assumptions adopted in order to facilitate the formulation of the problem together with the proposed mathematical model. Subsequently, in Section 3.3 the methodology is demonstrated by an illustrative test case and then, a more practical system is analyzed. Finally, relevant conclusions are drawn in Section 3.4.

3.2 Mathematical Model

3.2.1 Overview and modelling assumptions

The overview of the proposed model is portrayed in Fig. 3.1. The model consists of two stages: the first stage represents the day-ahead market and involves variables and constraints that are independent from any specific scenario realization (here-and-now decisions), while the second stage represents the actual operation of the power system and involves variables and constraints dependent on each scenario (wait-and-see decisions) according to their probabilities of occurrence. The first stage of the problem is cleared considering an hourly granularity, while the second stage is cleared considering intra-hour intervals. It is common in the literature for the second stage to have the same time granularity as the first one (e.g., [283]). Nevertheless, the evaluation of the second stage on such an intra-hour basis provides a more realistic insight into the problem. The time granularity of the second stage can be changed to any preferred time interval.

Two types of reserves are considered in this study:

- Load following reserves. This type of reserves is employed by both generators and LSE that are committed to provide this service. It consists of synchronized up and down, and also non-spinning reserves that are provided by units to balance the intra-hour load and wind deviations. LSE can also provide up and down reserves of this type to the system on a continuous basis. The consumption of these flexible entities can be scheduled in the day-ahead market operation. In the second stage, it can be re-scheduled in order to provide load-following reserves. They contribute to the operating cost through their utility value and a cost to schedule the provision of this service.
- Contingency reserves. In case of a unit or a transmission line outage, the deficit of energy is covered by synchronized or non-synchronized units, or LSE that are committed to provide this service. The LSE that provide this service are considered to be compensated at a cost related to the time they are called to provide this service, and are also compensated to be on stand-by.

A load may belong to one of the following three types:

- Inelastic load. The consumption of this type of load cannot be altered. Though, as a last resort and under a very high penalty, the system operator may use involuntary shedding of this type of load in order to satisfy the power balance.
- LSE that provide load following reserves. The consumption of this type of load can alter its scheduled consumption within limits in order to respond to wind power fluctuations and intra-hour load deviations.
- LSE that provide contingency reserves. The scheduled consumption of this load type can be modified in real-time in order to respond to contingencies. Its participation in reserve provision is subject to several constraints. It is also considered that there are limited times of calls during the horizon and that every call has a specific maximum duration. More detailed behavior (e.g., minimum time between two calls) and contract types can be easily integrated within the proposed methodology.

In order to render the rigorous mathematical formulation of the problem practical, several assumptions are adopted:

- The only source of uncertainty is deemed the wind production since it is considered that the transmission line and unit contingencies are perfectly known.
- When a contingency of a unit occurs it is assumed that its power output is instantly set to zero. Because of the short length of the horizon under examination, it is assumed that once a unit trips, it stays in failure condition until the end of the study horizon. When a line failure occurs at some time interval, its power transfer capability is set to zero. Nevertheless, it is consider that a line may be repaired within the study horizon.
- The response of demand side resources is considered instant (practically several minutes [242]) and thus, no ramping constraints are enforced for the LSE.

- Wind power producers are not considered competitive agents and their participation is promoted by the ISO. For the market clearing procedure wind energy is considered free of cost. Practically, it could be paid a regulated tariff out of the day-ahead market scope for the energy actually produced [283].
- The cost for deploying reserves by the units is considered equal to their energy costs. The cost of deploying reserves by the demand side is considered equal to their utility value. However, any pricing scheme may be incorporated within the proposed approach.
- A linear representation of the network is considered, neglecting the active power losses. The losses may be included in a linear formulation as explained in [283].
- Load shedding is only possible for the inelastic loads that are not subject to any resource offering scheme.

3.2.2 Objective function

$$
\begin{aligned}
EC = \sum_{t_1 \in T_1} \Bigg\{ \\
& \sum_{i \in I} \Bigg[\sum_{f \in F^i} (C_{i,f,t_1} \cdot b_{i,f,t_1}) + SUC^1_{i,t_1} + SDC^1_{i,t_1} + C^{R,DN}_{i,t_1} \cdot R^{DN}_{i,t_1} + C^{R,UP}_{i,t_1} \cdot R^{UP}_{i,t_1} + C^{R,NS}_{i,t_1} \cdot R^{NS}_{i,t_1} \Bigg] \\
& + \sum_{j_1 \in J_1} (C^{DN,LSE1}_{j_1,t_1} \cdot LSE1^{DN}_{j_1,t_1} + C^{UP,LSE1}_{j_1,t_1} \cdot LSE1^{UP}_{j_1,t_1}) \\
& + \sum_{j_2 \in J_2} (C^{DN,LSE2}_{j_2,t_1} \cdot LSE2^{DN,con}_{j_2,t_1} + C^{UP,LSE2}_{j_2,t_1} \cdot LSE2^{UP,con}_{j_2,t_1}) \Bigg\} \\
& + \sum_{s \in S} \pi_s \sum_{t_2 \in T_2} \Bigg\{ \sum_{i \in I} \Bigg[\sum_{f \in F^i} (C'_{i,f,t_2} \cdot r^G_{i,f,t_2,s}) + CA_{i,t_2,s} \Bigg] \\
& + \sum_{j_1 \in J_1} \lambda^{LSE1'}_{j_1,t_2} \cdot (LSE1^u_{j_1,t_2,s} - LSE1^d_{j_1,t_2,s}) \\
& + \sum_{j_2 \in J_2} \lambda^{LSE2'}_{j_2,t_2} \cdot \psi^{LSE2}_{j_2,t_2,s} \\
& + \sum_{w \in W} (\frac{V^{spill}_{w,t_2}}{\Delta \mathrm{T}_1} \cdot \Delta \mathrm{T}_2 \cdot S_{w,t_2,s}) + \sum_{r \in R} (\frac{V^{LOL}_{r,t_2}}{\Delta \mathrm{T}_1} \cdot \Delta \mathrm{T}_2 \cdot L^{shed}_{r,t_2,s}) \Bigg\}
\end{aligned}
\tag{3.1}
$$

The objective function (3.1) stands for the minimization of the total expected cost (EC) emerging from the system operation. The first line of the objective function expresses the costs associated with energy provided from the generating units, the start-up and shut-down costs and the commitment of the units to provide reserves. The second and third lines represent the costs of scheduling reserves from the LSE of type 1 and type 2, respectively.

The rest of the objective function is scenario dependent, as indicated by the summation over the scenario index. Furthermore, in the second stage the intra-hour intervals are taken into account since a different set of time intervals is considered. The fourth line of the objective function takes into consideration the cost of changing the status of the generating units and the cost of actually deploying reserves from the generators. Similarly, the fifth line considers the costs of deploying reserves from the LSE of type 1. The sixth line stands for the cost of calling LSE of type 2 to provide contingency reserves. Finally, the last line takes into account the wind spillage cost and the expected cost of the energy not served to the inelastic loads.

$$C^{'}_{i,f,t_2} = \frac{C_{i,f,t_1}}{\Delta \mathrm{T}_1} \cdot \Delta \mathrm{T}_2 \; \forall i, f, t_2 \in T_2^{in}, t_1 \tag{3.2}$$

$$\lambda^{LSE1'}_{j_1,t_2} = \frac{\lambda^{LSE1}_{j_1,t_1}}{\Delta \mathrm{T}_1} \cdot \Delta \mathrm{T}_2 \; \forall i, f, t_2 \in T_2^{in}, t_1 \tag{3.3}$$

$$\lambda^{LSE2'}_{j_2,t_2} = \frac{\lambda^{LSE2}_{j_2,t_1}}{\Delta \mathrm{T}_1} \cdot \Delta \mathrm{T}_2 \; \forall i, f, t_2 \in T_2^{in}, t_1 \tag{3.4}$$

Equations (3.2)-(3.4) are required in order to adjust the units of the marginal cost of the generating units and the utilities of the LSE. The unit is €/MWh which is suitable for the first stage of the problem in which the duration of the time interval is 1 h; however, in the second stage of the problem, intra-hour intervals are considered (minutes) and therefore, the units should be appropriately adjusted.

3.2.3 Constraints

3.2.3.1 First stage constraints

This section presents the first stage constraints of the optimization problem. These constraints involve only decision variables that do not depend on any specific scenario. Furthermore, the time dependence of variables refers to the time interval utilized in the first stage (i.e. hourly in this study) that is denoted by $t_1 \in T_1$.

3.2.3.1.1 ***Generator output limits***

$$P^{sch}_{i,t_1} = \sum_{f \in F^i} b_{i,f,t_1} \; \forall i, t_1 \tag{3.5}$$

$$0 \leq b_{i,f,t_1} \leq B_{i,f,t_1} \; \forall i, f, t_1 \tag{3.6}$$

$$P^{sch}_{i,t_1} - R^{DN}_{i,t_1} \geq P^{min}_i \cdot u^1_{i,t_1} \; \forall i, t_1 \tag{3.7}$$

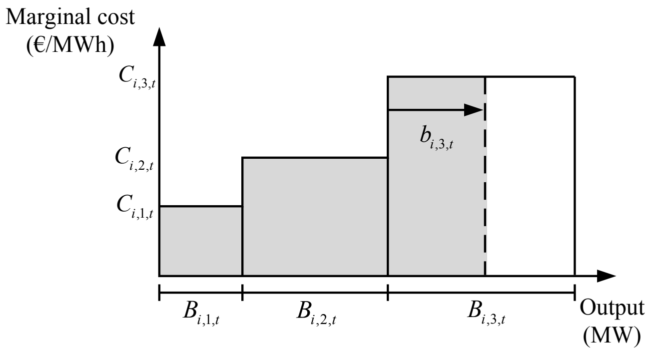

Figure 3.2: Example of a step-wise linear marginal cost function

$$P_{i,t_1}^{sch} + R_{i,t_1}^{UP} \leq P_i^{max} \cdot u_{i,t_1}^1 \ \forall i, t_1 \tag{3.8}$$

The generator cost function is considered convex and is approximated using a step-wise linear marginal cost function as in [301]. This is enforced by (3.5) and (3.6). An example of a marginal cost function for a unit that offers its available energy in three blocks is illustrated in Fig. 3.2. Constraints (3.7) and (3.8) limit the output power of a generating unit, taking also into account the hourly scheduled up and down reserve margins, respectively.

3.2.3.1.2 *Generator minimum up and down time constraints*

$$\sum_{\tau=t_1-UT_i^1+1}^{t_1} y_{i,\tau}^1 \leq u_{i,t_1}^1 \ \forall i, t_1 \tag{3.9}$$

$$\sum_{\tau=t_1-DT_i^1+1}^{t_1} z_{i,\tau}^1 \leq 1 - u_{i,t_1}^1 \ \forall i, t_1 \tag{3.10}$$

Constraint (3.9) forces a unit to remain committed for at least UT_i^1 hours once a startup decision is made ($y_{i,t_1}^1 = 1$), while (3.10) forces a unit to remain decommitted for at least DT_i^1 hours once a shutdown decision is made ($z_{i,t_1}^1 = 1$).

3.2.3.1.3 *Unit commitment logic constraints*

$$y_{i,t_1}^1 - z_{i,t_1}^1 = u_{i,t_1}^1 - u_{i,(t_1-1)}^1 \ \forall i, t_1 \tag{3.11}$$

$$y_{i,t_1}^1 + z_{i,t_1}^1 \leq 1 \ \forall i, t_1 \tag{3.12}$$

Equation (3.11) enforces the startup and shutdown status change logic. The logical requirement that a unit cannot start up and shut down simultaneously during the same period is modelled using (3.12). Note that these constraints indicate only the hour for which a startup or shutdown decision is taken but not the exact sub-hourly interval in which the startup or shutdown decision will actually occur.

3.2.3.1.4 *Startup and shutdown costs*

$$SUC^1_{i,t_1} \geq SUC_i \cdot y^1_{i,t_1} \ \forall i, t_1 \tag{3.13}$$

$$SDC^1_{i,t_1} \geq SDC_i \cdot z^1_{i,t_1} \ \forall i, t_1 \tag{3.14}$$

The cost that occurs when a decommitted unit receives a command by the ISO to start up ($y^1_{i,t_1} = 1$) or when an online unit is commanded to shut down ($z^1_{i,t_1} = 1$) is considered through constraints (3.13) and (3.14).

3.2.3.1.5 *Ramp-up and ramp-down limits*

$$P^{sch}_{i,t_1} - P^{sch}_{i,(t_1-1)} \leq \Delta \mathrm{T}_1 \cdot RU_i \ \forall i, t_1 \tag{3.15}$$

$$P^{sch}_{i,(t_1-1)} - P^{sch}_{i,t_1} \leq \Delta \mathrm{T}_1 \cdot RD_i \ \forall i, t_1 \tag{3.16}$$

In order to consider the effect of the ramp rates that limit the changes in the output of the generating units, constraints (3.15) and (3.16) are enforced. $\Delta \mathrm{T}_1$ is the time length of the optimization interval of the first stage in minutes, e.g., $\Delta \mathrm{T}_1 = 60 \ min$ in the case of hourly granularity.

3.2.3.1.6 *Generation side reserve scheduling*

$$0 \leq R^{UP}_{i,t_1} \leq T^S \cdot RU_i \cdot u^1_{i,t_1} \ \forall i, t_1 \tag{3.17}$$

$$0 \leq R^{DN}_{i,t_1} \leq T^S \cdot RD_i \cdot u^1_{i,t_1} \ \forall i, t_1 \tag{3.18}$$

$$0 \leq R^{NS}_{i,t_1} \leq T^{NS} \cdot RU_i \cdot (1 - u^1_{i,t_1}) \ \forall i, t_1 \tag{3.19}$$

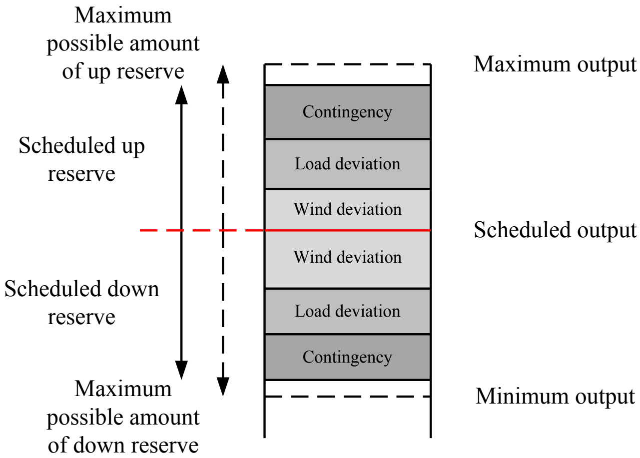

Figure 3.3: Reserve scheduling from generating units

Constraints (3.17)-(3.19) impose limits in the procurement of reserves from the conventional generating units. Up and down spinning reserves and non spinning reserves are defined by (3.17),(3.18) and (3.19), respectively. Note that T^S and T^{NS} is the time in minutes during which the reserves should be fully deployed. The deployment time for each reserve type is defined by the rules that hold for each system. Note that the aforementioned constraints are responsible for scheduling the total amount of reserve that is needed to cover all the imbalances considered in this study, i.e. wind and load fluctuations as well as contingencies.

$$R_{i,t_1}^{UP} = R_{i,t_1}^{UP,load} + R_{i,t_1}^{UP,wind} + R_{i,t_1}^{UP,con} \ \forall i, t_1 \tag{3.20}$$

$$R_{i,t_1}^{DN} = R_{i,t_1}^{DN,load} + R_{i,t_1}^{DN,wind} + R_{i,t_1}^{DN,con} \ \forall i, t_1 \tag{3.21}$$

$$R_{i,t_1}^{NS} = R_{i,t_1}^{NS,load} + R_{i,t_1}^{NS,wind} + R_{i,t_1}^{NS,con} \ \forall i, t_1 \tag{3.22}$$

Up spinning reserves, down spinning reserves and non spinning reserves are scheduled in order to maintain the system balance during the actual operation of the power system that is disturbed due to positive or negative elastic or inelastic load deviations, wind ramp-ups and downs and contingency events. Up spinning reserves imply the increase of a synchronized unit's power output, while down spinning reserves stand for the opposite. Non-spinning reserves are provided by non synchronized units as stated by (3.19). Equations (3.20)-(3.22) decompose the unit's total scheduled up, down or non spinning reserves to different services that correspond to the different factors that can trigger the need of such reserves. The decomposition of reserves from the generation side is displayed in Fig. 3.3.

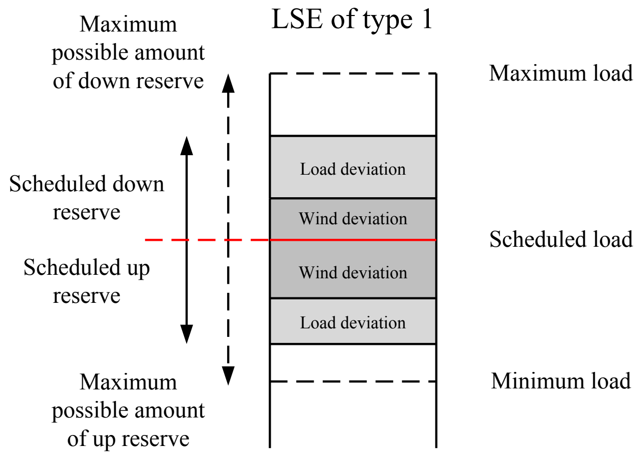

Figure 3.4: Load and reserve scheduling from LSE of type 1

3.2.3.1.7 *Wind power scheduling*

$$0 \leq P_{w,t_1}^{WP,S} \leq P_w^{WP,max} \ \forall w, t_1 \tag{3.23}$$

Typically the wind power generation scheduled in the day-ahead market is considered equal to its forecast value. However, in this study it is considered that the ISO schedules the optimal amount of wind at each period t_1 according to the technicoeconomic optimization within the limits imposed by (3.23). Several studies consider that the upper bound of wind power scheduling in the day-ahead market is ∞. However, in this study the upper limit is consider equal to the installed capacity of each wind farm.

3.2.3.1.8 *Load serving entities*

It was stated before that the demand side can also contribute in reserves. In this study, two types of LSEs that are able to provide different reserve services are considered. First, the LSE of type 1 can provide up and down load following reserves in order to balance the wind fluctuations and the intra-hour load deviations. Second, the LSE of type 2 may provide up and down reserve in order to confront contingencies. The two types of LSE are graphically illustrated in Figs. 3.4 and 3.5 in which the basic parameters of these loads are identified.

$$LSE1_{j_1,t_1}^{min} \leq LSE1_{j_1,t_1}^{sch} \leq LSE1_{j_1,t_1}^{max} \ \forall j_1, t_1 \tag{3.24}$$

$$0 \leq LSE1_{j_1,t_1}^{UP} \leq LSE1_{j_1,t_1}^{sch} - LSE1_{j_1,t_1}^{min} \ \forall j_1, t_1 \tag{3.25}$$

$$LSE1_{j_1,t_1}^{UP} = LSE1_{j_1,t_1}^{UP,load} + LSE1_{j_1,t_1}^{UP,wind} \ \forall j_1, t_1 \tag{3.26}$$

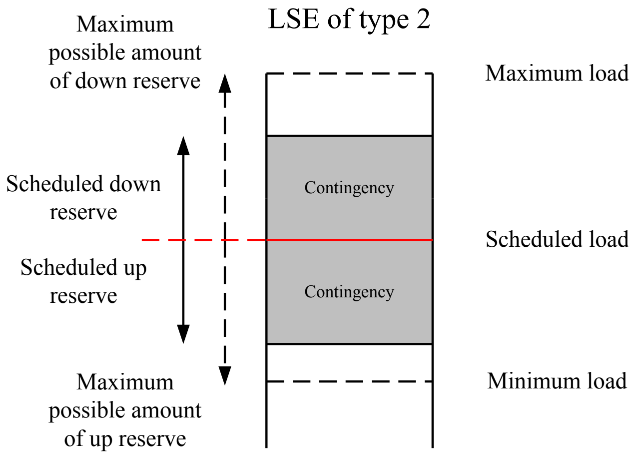

Figure 3.5: Load and reserve scheduling from LSE of type 2

$$0 \leq LSE1^{DN}_{j_1,t_1} \leq LSE1^{max}_{j_1,t_1} - LSE1^{sch}_{j_1,t_1} \ \forall j_1, t_1 \tag{3.27}$$

$$LSE1^{DN}_{j_1,t_1} = LSE1^{DN,load}_{j_1,t_1} + LSE1^{DN,wind}_{j_1,t_1} \ \forall j_1, t_1 \tag{3.28}$$

$$\sum_{t_1 \in T_1} LSE1^{sch}_{j_1,t_1} \geq E^{req}_{j_1} \ \forall j_1 \tag{3.29}$$

According to (3.24) the load may be scheduled within an upper and lower limit around its nominal value that define its flexibility. The amount of up reserves that may be scheduled during a period t_1 are between zero and the margin that is defined by the difference between the scheduled and the minimum allowed load as stated in (3.25). These reserves are further decomposed into a component related to a reduction in order to balance wind fluctuations and a component that is related to balancing an intra-hour deviation of the load as stated by (3.26). Similarly, the amount of down reserve that may be scheduled in each period is between zero and the capacity that is defined by the difference between the maximum allowed and the scheduled load, a fact that is stated by (3.27). The decomposition of down reserves in its components is realized by (3.28). Finally, in order to ensure that the LSE of type 1 energy needs are fulfilled during the horizon, despite the fact that it may be scheduled for partial curtailment in several periods, the energy requirement constraint (3.29) is enforced.

$$LSE2^{min}_{j_2,t_1} \leq LSE2^{sch}_{j_2,t_1} \leq LSE2^{max}_{j_2,t_1} \ \forall j_2, t_1 \tag{3.30}$$

$$0 \leq LSE2^{UP,con}_{j_2,t_1} \leq LSE2^{sch}_{j_2,t_1} - LSE2^{min}_{j_2,t_1} \ \forall j_2, t_1 \tag{3.31}$$

$$0 \leq LSE2^{DN,con}_{j_2,t_1} \leq LSE2^{max}_{j_2,t_1} - LSE2^{sch}_{j_2,t_1} \ \forall j_2, t_1 \tag{3.32}$$

Similar to LSEs of type 1 the load of LSEs of type 2 may be scheduled within an upper and lower limit around its nominal value. This is enforced by (3.30). The up and down reserves that are scheduled by the LSEs of type 2 in order to confront system contingencies are defined by (3.31) and (3.32), respectively. This type of load is not subject to an energy requirement constraint due to the fact that it is paid to be curtailed for a pre-specified number of periods.

3.2.3.1.9 *Day-ahead market power balance*

$$\sum_{i \in I} P^{S}_{i,t_1} + \sum_{w \in W} P^{WP,S}_{w,t_1} = \sum_{r \in R} D^{1}_{r,t_1} + \sum_{j_1 \in J_1} LSE1^{sch}_{j_1,t_1} + \sum_{j_2 \in J_2} LSE2^{sch}_{j_2,t_1} \ \forall t_1 \tag{3.33}$$

Equation (3.33) enforces the market power balance. In other words, it states that the total generation of the conventional units and the total production of the wind farms must be equal to the demand of the inelastic load and the demand of the LSE of the two types at any given time interval t_1. It is common in the literature [283] and also in real systems, not to enforce the network constraints in the day-ahead formulation. Nonetheless, any market scheme may be implemented within the proposed formulation.

3.2.3.2 Second stage constraints

This section presents the second stage constraints of the optimization problem. These constraints involve only decision variables that do depend on a specific scenario. Furthermore, the time dependence of variables refers to the time interval utilized in the second stage (i.e. sub-hourly intervals, e.g., 15 minutes) that is denoted by $t_2 \in T_2$.

3.2.3.2.1 *Generating units*

Constraints (3.34)-(3.43) are related to the operation of the generation side in the light of each individual scenario outcome.

$$P^{G}_{i,t_2,s} \geq P^{min}_{i} \cdot u^{2}_{i,t_2,s} \ \forall i, t_2, s \tag{3.34}$$

$$P^{G}_{i,t_2,s} \leq P^{max}_{i} \cdot u^{2}_{i,t_2,s} \ \forall i, t_2, s \tag{3.35}$$

The minimum and maximum generation limits are also enforced in the second stage of the problem through (3.34) and (3.35).

$$P^G_{i,t_2,s} - P^G_{i,(t_2-1),s} \leq \Delta \mathrm{T}_2 \cdot RU_i \ \forall i, t_2, s \tag{3.36}$$

$$P^G_{i,(t_2-1),s} - P^G_{i,t_2,s} \leq \Delta \mathrm{T}_2 \cdot RD_i + N_1 \cdot (1 - UC_{i,t_2}) \ \forall i, t_2, s \tag{3.37}$$

As stated before, a $\Delta\mathrm{T}_2$-minute time interval is adopted in the second stage of the model constraints (3.36) and (3.37) hold to limit the ramp-up and down of the units. As the ramp-up and down rates of the generators are given in MW/min, the power output of a unit can change by its ramp-up or down rate multiplied by $\Delta\mathrm{T}_2$ in each scenario. Note that constraint (3.37) is relaxed when the unit i fails by using a sufficiently large value for the constant N_1.

$$\sum_{\tau=t_2-\frac{UT_i^2}{\Delta \mathrm{T}_2}+1}^{t_2} y^2_{i,\tau,s} \leq u^2_{i,t_2,s} \ \forall i, t_2, s \tag{3.38}$$

$$\sum_{\tau=t_2-\frac{DT_i^2}{\Delta \mathrm{T}_2}+1}^{t_2} z^2_{i,\tau,s} \leq 1 - u^2_{i,t_2,s} \ \forall i, t_2, s \tag{3.39}$$

In the second stage of the problem the minimum up and down times of the generating units are given in minutes. Thus, in (3.38) and (3.39) these times are divided by the duration of each interval $\Delta\mathrm{T}_2$ in order to express the minimum up and down times in a number of intervals. Evidently, UT_i^2 and DT_i^2 must be integer multiples of $\Delta\mathrm{T}_2$.

$$y^2_{i,t_2,s} + z^2_{i,t_2,s} \leq 1 \ \forall i, t_2, s \tag{3.40}$$

$$y^2_{i,t_2,s} - z^2_{i,t_2,s} = u^2_{i,t_2,s} - y^2_{i,(t_2-1),s} \ \forall i, t_2, s \tag{3.41}$$

Similarly to (3.11) and (3.12), constraints (3.40) and (3.41) ensure that the logic of unit commitment is preserved.

$$SUC^2_{i,t_2,s} \geq SUC_i \cdot y^2_{i,t_2,s} \ \forall i, t_2, s \tag{3.42}$$

$$SDC^2_{i,t_2,s} \geq SDC_i \cdot z^2_{i,t_2,s} \ \forall i, t_2, s \tag{3.43}$$

The startup and shutdown costs of the generators are enforced in the second stage through (3.42) and (3.43).

3.2.3.2.2 *Wind spillage limits*

$$0 \leq S_{w,t_2,s} \leq P^{WP}_{w,t_2,s} \ \forall w, t_2, s \tag{3.44}$$

A portion of available wind production may be spilled if it is necessary to facilitate the operation of the power system. This is enforced by (3.44).

3.2.3.2.3 *Involuntary load shedding limits*

$$0 \leq L^{shed}_{r,t_2,s} \leq D^2_{r,t_2} \ \forall w, t_2, s \tag{3.45}$$

As a last resort the ISO can decide to shed a part of the inelastic demand in order to maintain the consistency of the system. This requirement is enforced by constraint (3.45).

3.2.3.2.4 *Energy requirement constraint for LSE of type 1*

$$\sum_{t_2 \in T_2} \frac{LSE1^{ac}_{j_1,t_2,s}}{\Delta\mathrm{T}_2} \geq E^{req}_{j_1} \ \forall j_1, s \tag{3.46}$$

Constraint (3.46) enforces the energy requirement constraint for the LSE of type 1 in each scenario. The division with the duration of the time interval $\Delta\mathrm{T}_2$ is required in order to appropriately match the units of energy and power.

3.2.3.2.5 *Reserve deployment from LSE of type 2*

Equations (3.47)-(3.55) enforce several constraints related to the deployment of reserves from the LSE of type 2.

$$LSE2^{u,con}_{j_2,t_2,s} \leq N_2 \cdot \upsilon^{u}_{j_2,t_2,s} \ \forall j_2, t_2, s \tag{3.47}$$

$$LSE2^{d,con}_{j_2,t_2,s} \leq N_2 \cdot \upsilon^{dn}_{j_2,t_2,s} \ \forall j_2, t_2, s \tag{3.48}$$

$$\upsilon^{LSE2}_{j_2,t_2,s} = \upsilon^{u}_{j_2,t_2,s} + \upsilon^{dn}_{j_2,t_2,s} \ \forall j_2, t_2, s \tag{3.49}$$

$$\upsilon^{u}_{j_2,t_2,s} + \upsilon^{dn}_{j_2,t_2,s} \leq 1 \ \forall j_2, t_2, s \tag{3.50}$$

Constraints (3.47)-(3.50) are used in order force the LSE of type 2, once called, to provide only up or down contingency reserves. More specifically, (3.47) and (3.48) determine the amount of up and down reserve that may be deployed. The right hand side of these inequalities involves the multiplication of a sufficiently large constant N_2 with a binary variable that indicates whether an LSE of type 2 provides up or down reserve. If the LSE of type 2 is called in period t_2 then $\upsilon^{LSE2}_{j_2,t_2,s} = 1$. The call implies that either up or down reserves are provided ($\upsilon^{u}_{j_2,t_2,s} = 1$ or $\upsilon^{dn}_{j_2,t_2,s} = 1$). These states are mutually exclusive, a fact that is expressed by (3.49) and (3.50).

$$\psi^{LSE2}_{j_2,t_2,s} - \zeta^{LSE2}_{j_2,t_2,s} = \upsilon^{LSE2}_{j_2,t_2,s} - \upsilon^{LSE2}_{j_2,(t_2-1),s} \ \forall j_2, t_2, s \tag{3.51}$$

$$\upsilon^{LSE2}_{j_2,t_2,s} \geq \psi^{LSE2}_{j_2,t_2,s} \ \forall j_2, t_2, s \tag{3.52}$$

$$\upsilon^{LSE2}_{j_2,t_2,s} \geq \zeta^{LSE2}_{j_2,(t_2+1),s} \ \forall j_2, t_2, s \tag{3.53}$$

Constraints (3.51)-(3.53) enforce the deployment logic of this type of resource.

$$\sum_{t_2 \in T_2} \psi^{LSE2}_{j_2,t_2,s} \leq N^{call}_{j_2} \ \forall j_2, t_2, s \tag{3.54}$$

$$\sum_{\tau = t_2 - \frac{T^{dur}_{j_2}}{\Delta \mathrm{T}_2} + 1}^{t_2} \psi^{LSE2}_{j_2,\tau,s} \geq \upsilon_{j_2,t_2,s} \ \forall j_2, t_2, s \tag{3.55}$$

The deployment of demand side resources to provide reserve services may be subject to several rules, e.g., maximum number of calls, duration of a call, etc. Equation (3.54) limits the maximum number of times each LSE of type 2 can be utilized to procure contingency reserves during the scheduling horizon. Finally, (3.55) constrains the maximum duration of each call to last at most $T^{dur}_{j_2}$ periods.

3.2.3.2.6 *Network constraints*

$$
\begin{aligned}
\sum_{i \in N_n^i} P^G_{i,t_2,s} + \sum_{w \in N_n^w} (P^{WP}_{i,t_2,s} - S_{w,t_2,s}) + \sum_{n \in B_b^{nn}} f_{b,t_2,s} \\
= \sum_{n \in B_b^n} f_{b,t_2,s} + \sum_{r \in N_n^r} (D^2_{r,t_2} - L^{shed}_{r,t_2,s}) \\
+ \sum_{j_1 \in N_n^{j_1}} LSE1^{ac}_{j_1,t_2,s} + \sum_{j_2 \in N_n^{j_2}} LSE2^{ac}_{j_2,t_2,s} \\
\forall b, (n, nn) \in B(n, nn), t_2, s
\end{aligned}
\tag{3.56}
$$

$$
f_{b,t_2,s} = B_{b,n} \cdot (\delta_{n,t_2,s} - \delta_{nn,t_2,s}) \cdot LC_{b,t_2} \; \forall b, (n, nn) \in B(n, nn), t_2, s \tag{3.57}
$$

$$
-f_b^{max} \cdot LC_{b,t_2} \leq f_{b,t_2,s} \leq f_b^{max} \cdot LC_{b,t_2} \; \forall b, t_2, s \tag{3.58}
$$

$$
-\pi \leq \delta_{n,t_2,s} \leq \pi \; \forall n, t_2, s \tag{3.59}
$$

$$
\delta_{n,t_2,s} = 0 \; \forall t_2, s, if n \equiv ref \tag{3.60}
$$

In the second stage of the problem, the network constraints are taken into account using a lossless DC power flow formulation. More specifically, equation (3.56) stands for the power balance at each node of the system which states that the total power generated at each node by conventional units, the net production of wind farms plus the power injection from incoming transmission lines must equal the total net consumption of inelastic and elastic loads as well as the power that is injected to outgoing transmission lines. The flow over a transmission line is defined by (3.57), while a power flow limit is set according to the maximum capacity of a transmission line by (3.58). In case of a transmission line failure, the active power flow through a transmission line is forced to zero. Finally, (3.59) and (3.60) state that the voltage angles must be bounded between $-\pi$ and π and that at the slack bus the voltage angle must be specified, respectively.

3.2.3.3 Linking constraints

The set of linking constraints bridges the day-ahead market decisions and the decisions made based on the outcome of each plausible scenario. As a result, the constraints pertaining this stage involve both scenario independent and scenario dependent decision variables. Linking constraints enforce the fact that reserves in the actual operation of the power system are no longer a stand-by capacity, but are materialized as energy. To simplify the mathematical formulation presented below the following should be noted: the equations that refer to reserve deployment by generating units hold only for units that are not under contingency. Furthermore, as long as there are no contingencies or wind/load deviations, the reserves provided by the demand side are also zero and the relevant equations do not hold. It should be also noted that the notation $t_2 \in T_2^{in}$ means that t_2 is a sub-hourly interval of the hour t_1 that appears in the same equation.

3.2.3.3.1 *Additional cost due to change of commitment status of units*

$$CA_{i,t_2,s} = \sum_{t_2 \in T_2} SUC^2_{i,t_2,s} - SUC^1_{i,t_1} + \sum_{t_2 \in T_2} SDC^2_{i,t_2,s} - SDC^1_{i,t_1} \;\forall i, t_2 \in T_2^{in}, t_1, s \tag{3.61}$$

In case of a difference occurring in the commitment status, a commitment scheduling change cost is charged through (3.61).

3.2.3.3.2 *Generation side reserve deployment*

$$P^G_{i,t_2,s} = P^{sch}_{i,t_1} + r^{up}_{i,t_2,s} + r^{ns}_{i,t_2,s} - r^{dn}_{i,t_2,s} \;\forall i, t_2 \in T_2^{in}, t_1, s \tag{3.62}$$

$$r^{up}_{i,t_2,s} = r^{up,load}_{i,t_2,s} + r^{up,wind}_{i,t_2,s} + r^{up,con}_{i,t_2,s} \;\forall i, t_2, s \tag{3.63}$$

$$r^{dn}_{i,t_2,s} = r^{dn,load}_{i,t_2,s} + r^{dn,wind}_{i,t_2,s} + r^{dn,con}_{i,t_2,s} \;\forall i, t_2, s \tag{3.64}$$

$$r^{ns}_{i,t_2,s} = r^{ns,load}_{i,t_2,s} + r^{ns,wind}_{i,t_2,s} + r^{ns,con}_{i,t_2,s} \;\forall i, t_2, s \tag{3.65}$$

$$0 \le r^{up}_{i,t_2,s} \le R^{UP}_{i,t_1} \;\forall i, t_2 \in T_2^{in}, t_1, s \tag{3.66}$$

$$0 \le r^{dn}_{i,t_2,s} \le R^{DN}_{i,t_1} \;\forall i, t_2 \in T_2^{in}, t_1, s \tag{3.67}$$

$$0 \le r^{ns}_{i,t_2,s} \le R^{NS}_{i,t_1} \;\forall i, t_2 \in T_2^{in}, t_1, s \tag{3.68}$$

The power output of a unit i in a scenario s in period t_2 that is a sub-hourly interval of t_1 is equal to the scheduled generation output during period t_1 augmented by the deployment of up spinning and non spinning reserves, minus the deployment of down spinning reserve as stated by (3.62). Furthermore, the deployed reserves are further decomposed into several components related to the factor that triggered their deployment. This is enforced by (3.63)-(3.65). Constraints (3.66)-(3.68) limit the deployment of the different types of reserves in period t_2 by their scheduled amount in the corresponding hourly interval t_1. Therefore, the scheduled reserves of each type in each interval of the day-ahead market coincide with the maximum reserve deployment within that interval in the second stage of the problem. Finally, it should be noted that similarly to (3.66)-(3.68) that impose restrictions to the total amount of deployed reserves, each reserve component should be also constrained by its corresponding scheduled amount.

$$r^{up}_{i,t_2,s} + r^{ns}_{i,t_2,s} - r^{dn}_{i,t_2,s} = \sum_{f \in F^i} r^{G}_{i,f,t_2,s} \ \forall i, t_2 \in T_2^{in}, t_1, s \tag{3.69}$$

$$r^{G}_{i,f,t_2,s} \leq B_{i,f} - b_{i,f,t_1} \ \forall i, f, t_2 \in T_2^{in}, t_1, s \tag{3.70}$$

$$r^{G}_{i,f,t_2,s} \geq -b_{i,f,t_1} \ \forall i, f, t_2 \in T_2^{in}, t_1, s \tag{3.71}$$

In the second stage of the problem, generation side reserves are materialized as an energy alteration and therefore the cost increase or decrease that occurs is priced according to the marginal cost function of each generation. Constraints (3.69)-(3.71) are used in order to decompose the deployed reserves into the power blocks of the generation cost function.

3.2.3.3.3 ***Demand side reserve deployment***

$$LSE1^{ac}_{j_1,t_2,s} = LSE1^{sch}_{j_1,t_1} - LSE1^{u}_{j_1,t_2,s} + LSE1^{d}_{j_1,t_2,s} \ \forall j_1, t_2 \in T_2^{in}, t_1, s \tag{3.72}$$

$$LSE1^{u}_{j_1,t_2,s} = LSE1^{u,load}_{j_1,t_2,s} + LSE1^{u,wind}_{j_1,t_2,s} \ \forall j_1, t_2, s \tag{3.73}$$

$$LSE1^{d}_{j_1,t_2,s} = LSE1^{d,load}_{j_1,t_2,s} + LSE1^{d,wind}_{j_1,t_2,s} \ \forall j_1, t_2, s \tag{3.74}$$

$$0 \leq LSE1^{u}_{j_1,t_2,s} \leq LSE1^{UP}_{j_1,t_1} \ \forall j_1, t_2 \in T_2^{in}, t_1, s \tag{3.75}$$

$$0 \leq LSE1^{d}_{j_1,t_2,s} \leq LSE1^{DN}_{j_1,t_1} \ \forall j_1, t_2 \in T_2^{in}, t_1, s \tag{3.76}$$

Constraint (3.72) adjusts the actual consumption of the LSE of type 1 according to the deployed reserves, while (3.73) and (3.74) decompose the up and down deployed reserves into their components. Constraints (3.75)-(3.76) limit the deployment of the different types of reserves in period t_2 by their scheduled amount in the corresponding hourly interval t_1. Note that constraints that limit the deployment of the individual reserve components should be also enforced.

$$LSE2^{ac}_{j_2,t_2,s} = LSE2^{sch}_{j_2,t_1} - LSE2^{u,con}_{j_2,t_2,s} + LSE2^{d,con}_{j_2,t_2,s} \ \forall j_2, t_2 \in T^{in}_2, t_1, s \tag{3.77}$$

$$0 \leq LSE2^{u,con}_{j_2,t_2,s} \leq LSE2^{UP,con}_{j_2,t_1} \ \forall j_2, t_2 \in T^{in}_2, t_1, s \tag{3.78}$$

$$0 \leq LSE2^{d,con}_{j_2,t_2,s} \leq LSE2^{DN,con}_{j_2,t_1} \ \forall j_2, t_2 \in T^{in}_2, t_1, s \tag{3.79}$$

As in the case of the LSE of type 1, constraints (3.77)-(3.79) hold for the case of the LSE of type 2.

3.2.3.3.4 *Load following reserves determination*

$$\begin{aligned} \sum_{w \in W} (P^{WP}_{i,t_2,s} - S_{w,t_2,s} - P^{WP,S}_{w,t_1}) &= \sum_{i \in I} (r^{dn,wind}_{i,t_2,s} - r^{up,wind}_{i,t_2,s} - r^{ns,wind}_{i,t_2,s}) \\ &+ \sum_{j_1 \in J_1} (LSE1^{d,wind}_{j_1,t_2,s} - LSE1^{u,wind}_{j_1,t_2,s}) \\ &\forall i, j_1, t_2 \in T^{in}_2, t_1, s \end{aligned} \tag{3.80}$$

$$\begin{aligned} \sum_{r \in R} (D^2_{r,t_2} - L^{shed}_{r,t_2,s} - D^1_{r,t_1}) &= \sum_{i \in I} (r^{up,load}_{i,t_2,s} + r^{ns,load}_{i,t_2,s} - r^{dn,load}_{i,t_2,s}) \\ &+ \sum_{j_1 \in J_1} (LSE1^{u,load}_{j_1,t_2,s} - LSE1^{d,load}_{j_1,t_2,s}) \\ &\forall i, j_1, t_2 \in T^{in}_2, t_1, s \end{aligned} \tag{3.81}$$

Equations (3.80)-(3.81) enforce the logic of deploying load following reserves. Constraint (3.80) states that if the net accepted wind in a sub-hourly interval t_2 in a specific scenario is greater than the scheduled wind power during the corresponding hourly interval t_1 in the day-ahead market, then down reserves should be deployed. This may be accomplished either by decreasing the power output of the generating units or by increasing the consumption of the LSE of type 1. The opposite holds when the wind deviation is negative. In order to procure reserves to balance the intra-hour deviations of the load (3.81) must be enforced. According to (3.81) when the load deviation is positive, then either the units should increase their production or the LSE of type 1 should decrease their consumption. The opposite holds if there is a negative load deviation. Note that in both cases, a combination of up and down reserves from the different resources is also possible, as long as the imbalances are covered.

3.2.3.4 Compact formulation

The optimization problem that must be solved is compactly represented by (3.82).

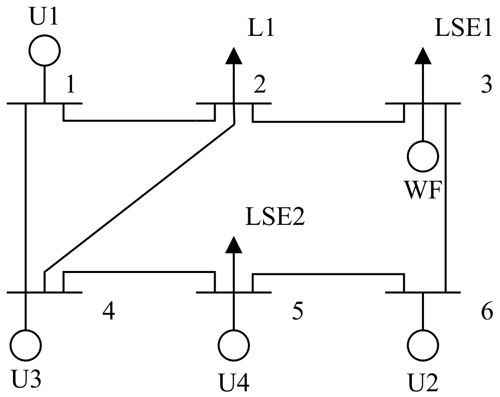

Figure 3.6: Topology of the 6-bus system

$$\begin{aligned} &\min\ (3.1) \\ &s.t.\ (3.2) - (3.81) \end{aligned} \tag{3.82}$$

3.3 Case Studies

3.3.1 Illustrative example

To demonstrate the proposed methodology, the sample 6-bus system comprising four conventional generators, a wind farm with installed capacity 100 MW, one inelastic load, a LSE of type 1 and a LSE of type 2 shown in Fig. 3.6 is analyzed over a six-hour horizon, considering that the intra-hour granularity is 10 min. The characteristics of the transmission system are presented in Table 3.1. The technical and economic data of the generators are presented in Tables 3.2 and 3.3, respectively. Spinning reserves must be fully available in 15 minutes, while the non spinning reserves in 30 minutes. The cost of providing spinning and non spinning reserves from the generating units is equal to 20% and 10% of the most expensive power block, respectively. Three wind power generation scenarios (Low, Moderate and High), are considered with probabilities of occurrence 54.29%, 30% and 15.71%. The three wind power generation scenarios are presented in Fig. 3.7. Note that in order to construct these scenarios, the methodology of Appendix B can be directly applied given that historical data with 10-min granularity are available. However, since the historical data utilized in this thesis are given for hourly intervals, the scenario generation methodology must be slightly altered for the purposes of this chapter. More specifically, firstly, three hourly scenarios are constructed (the periods 10 am to 3 pm of the selected day are utilized in this case study) and subsequently, it is considered that in each intra-hour interval the wind power production may randomly (a uniform distribution is used) deviate 5% up or down from the corresponding hourly value. Note that the wind spillage cost and the involuntary load shedding cost are considered equal to 1000 €/MWh.

Regarding the demand side resources, the LSE of type 1 offers continuous up and down load following reserves at a cost of 5 €/MWh. The LSE of type 2 may contribute to contingency reserves at a cost of 10 €/MWh. Additionally, it is paid 40 € when called to provide reserve.

Table 3.1: Characteristics of the transmission lines (6-bus system)

Line No.	From Bus	To Bus	X (pu)	Flow limit (MW)
1	1	2	0.170	410
2	1	4	0.258	200
3	2	3	0.037	500
4	2	4	0.197	250
5	3	6	0.018	500
6	4	5	0.037	250
7	5	6	0.140	230

Table 3.2: Technical characteristics of the generating units (6-bus system)

Unit	U1	U2	U3	U4
Minimum capacity (MW)	150	120	40	20
Maximum capacity (MW)	500	450	400	150
Minimum up time (h)	3	12	0	0
Minimum down time (h)	3	12	0	0
Minimum up time (min)	180	720	20	10
Minimum down time (min)	180	720	10	10
Ramp up rate (MW/min)	5	15	40	40
Ramp down rate (MW/min)	5	15	40	40
Initial output (MW)	300	450	0	0
Time committed/decommitted at the beginning of the scheduling horizon (h)	5	5	-5	-5
Time committed/decommitted at the beginning of the scheduling horizon (min)	300	300	-300	-300

Table 3.3: Economic characteristics of the generating units (6-bus system)

Unit	Power blocks (MW)					Marginal costs (€/MWh)					Startup cost (€)	Shutdown cost (€)
	B1	B2	B3	B4	B5	C1	C2	C3	C4	C5		
U1	250	120	60	50	20	5	5.5	6	6.5	7	30000	5000
U2	150	110	90	60	40	9	10	10.5	11	12	25000	2000
U3	200	80	60	40	20	20	20.5	21	22	23	2000	1000
U4	50	50	30	10	10	22	24	25	26	28	1000	500

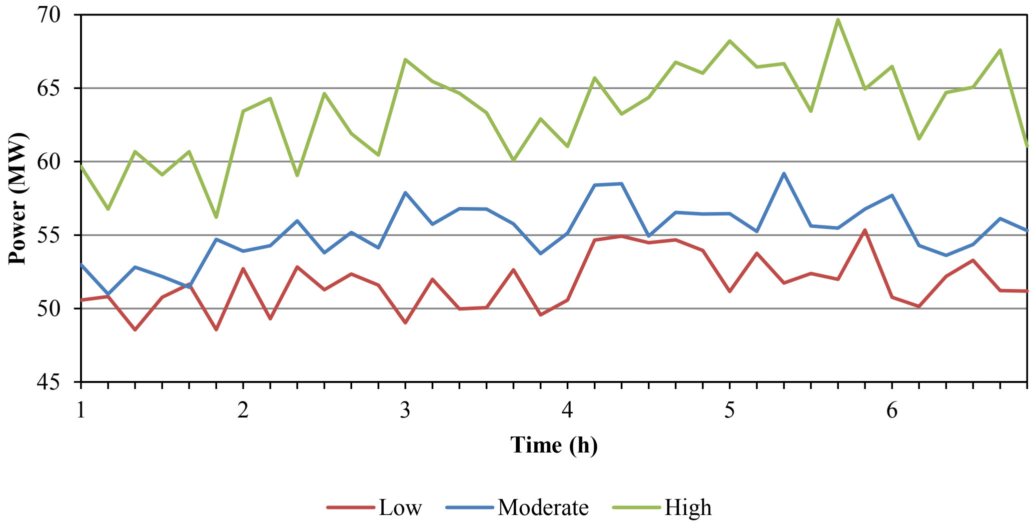

Figure 3.7: Wind power generation scenarios (6-bus system)

Table 3.4: System load (6-bus system)

Time	Inelastic load (MW)	Nominal LSE1 load (MW)	Nominal LSE2 load (MW)
1	900	80	90
2	800	90	120
3	550	100	110
4	750	80	80
5	600	70	70
6	450	60	50

Contingency reserves from the LSE of type 2 may be procured two times within the scheduling horizon and the service should last for a maximum of 30 min.

The nominal system load is presented in Table 3.4. The intra-hour inelastic load profile is provided in Table 3.5. Note that it is considered that the demand of the LSE of both types is equal to their nominal load. The LSE of type 1 may provide up and down reserves altering its load in both directions by 20%. The LSE of type 2 may provide only up contingency reserves by reducing its consumption up to 50%.

In order to elaborate the reserve scheduling methodology, the following tests are performed: first the loads of LSE are considered inflexible and therefore, cannot participate in reserve provision. Firstly, the system is considered to be free of contingencies (case C1-A). Subsequently, two contingency scenarios are investigated: 1) the must-run unit 2 is considered to fail at 4:10 (case C1-B) and, 2) the transmission line 2 (that connects buses 1 and 4) is considered to fail at 4:10 (case C1-C). It should be noted that owing to the small size of the test system, concurrent contingencies would lead to an infeasible optimization problem. Then the same cases are studied considering also the participation of LSE (cases C2-A, C2-B and C2-C). Results concerning period 4 of the day-ahead market and the intra-hour interval 4:10 in which the contingencies are considered to occur are analyzed in detailed.

Table 3.5: Intra-hour system load (6-bus system)

Time	Inelastic load (MW)	Time	Inelastic load (MW)	Time	Inelastic load (MW)
1	822	3	503	5	564
1:10	851	3:10	561	5:10	601
1:20	965	3:20	502	5:20	648
1:30	918	3:30	532	5:30	627
1:40	952	3:40	497	5:40	562
1:50	901	3:50	580	5:50	575
2	847	4	821	6	450
2:10	858	4:10	615	6:10	450
2:20	698	4:20	790	6:20	430
2:30	840	4:30	704	6:30	450
2:40	875	4:40	780	6:40	440
2:50	640	4:50	785	6:50	450

Table 3.6 presents the scheduled power output of the generating units and the scheduled reserve levels from generation and demand side resources for period 4 of the day-ahead market. In all the cases during period 4, the wind power scheduled coincides with the installed capacity of the wind farm (100 MW). In C1-A, the total upward reserves scheduled are 121.848 MW while the total downward reserves are 140.701 MW. These reserves are exclusively used in order to balance intra-hour deviations in the load demand and the wind power generation uncertainty and should be sufficient to cover the highest intra-hour deviations. The highest load increase is 71 MW and occurs in interval 4, while the maximum load decrease is 135 MW and occurs at period 4:10. Thus, the total up reserve scheduled to balance the load increase is 71 MW, while the down reserve scheduled for this purpose is 140.701 MW which exceeds the maximum load decrease. This implies that in order to cover this negative deviation in the consumption both up and down reserves should be deployed. The maximum energy deficit that has to be balanced because of wind deviations is 49.431 MW in period 4 and 50.848 MW upward reserves are scheduled. In C2-A the same amount of upward and downward reserves as in the case C1-A are scheduled. In addition to these reserves, 3.333 MW of upward reserves are scheduled to balance wind deviations and 10 MW of down reserves are scheduled in order to accommodate changes in the inelastic load.

In C1-B during period 4 the scheduled output power of unit 2 is 355.795 MW and therefore, once the contingency occurs, this energy deficit has to be balanced by the other generating units and especially the off-line units 3 and 4 that provide non spinning reserve. Furthermore, the load following reserves that would be normally provided by unit 2 must be replaced by other units. In C2-B in which LSE of type 2 are eligible resources to provide contingency reserve 40 MW are called by the ISO and are active for 50 minutes. Furthermore, the maximum available of load following reserves that may be deployed from LSE of type 1 are scheduled (16 MW) in order to increase the ramping capability of the system.

In C1-C and C2-C the unit commitment status of the generating units is the same as in cases C1-A and C2-A. However, the power generated by unit 1 can be provided only through transmission line 1 that connects buses 1 and 2. As a result, the output of unit 1 which is scheduled to operate at its maximum capacity should be reduced and therefore 300 MW of down spinning reserve are

Table 3.6: Scheduled generator output, generation and demand side reserves (MW)

		C1-A	C1-B	C1-C	C2-A	C2-B	C2-C
Unit 1	Scheduled output	**500**	**454.205**	**500**	**500**	**407.428**	**500**
	Spinning up reserve	0	0	0	0	0	0
	Spinning up reserve (load)	0	0	0	0	0	0
	Spinning up reserve (wind)	0	0	0	0	0	0
	Spinning up reserve (contingency)	0	0	0	0	0	0
	Spinning down reserve	50	135	300	50	119	300
	Spinning down reserve (load)	50	135	45.666	50	119	40.899
	Spinning down reserve (wind)	0	0	0.467	0	0	0.467
	Spinning down reserve (contingency)	0	0	253.866	0	0	258.634
Unit 2	Scheduled output	**310**	**355.795**	**310**	**310**	**402.572**	**310**
	Spinning up reserve	43.435	32.440	8.697	43.435	26.822	4.017
	Spinning up reserve (load)	38.105	29.034	0	38.105	26.092	0
	Spinning up reserve (wind)	5.330	3.376	8.697	5.330	0.730	4.017
	Spinning up reserve (contingency)	0	-	0	0	0	0
	Spinning down reserve	90.701	0	151.877	90.701	0	156.558
	Spinning down reserve (load)	90.701	0	140.658	90.701	0	145.339
	Spinning down reserve (wind)	0	0	11.219	0	0	11.219
	Spinning down reserve (contingency)	0	0	0	0	0	
Unit 3	Scheduled output	**0**	**0**	**0**	**0**	**0**	**0**
	Non spinning reserve	78.413	378.786	370.852	78.413	367.176	366.518
	Non spinning reserve (load)	32.895	31.583	71	32.895	13	101.899
	Non spinning reserve (wind)	45.518	41.502	45.985	45.518	41.604	45.985
	Non spinning reserve (contingency)	0	305.701	253.866	0	312.572	218.634
Unit 4	Scheduled output	**0**	**0**	**0**	**0**	**0**	**0**
	Non spinning reserve	0	150	0	0	142.005	0
	Non spinning reserve (load)	0	95.353	0	0	84.908	0
	Non spinning reserve (wind)	0	4.553	0	0	7.097	0
	Non spinning reserve (contingency)	0	50.094	0	0	50	0
LSE 1	Up reserve (load)	0	0	0	0	16	0.557
	Up reserve (wind)	0	0	0	3.333	0	0
	Down reserve (load)	0	0	0	10	16	3.341
	Down reserve (wind)	0	0	0	0	0	0
LSE 2	Up reserve (contingency)	0	0	0	0	40	40
	Down reserve (contingency)	0	0	0	0	0	0
	Total upward reserve	121.848	561.226	379.549	125.181	592.003	411.092
	Total downward reserve	140.701	135	451.877	150.701	135	459.899

scheduled. Moreover, LSE of type 2 are also employed in C2-A to provide contingency up demand side reserve and a small amount of load following reserve is scheduled by LSE of type 1 in C2-C. The reserve needs increase in comparison with the contingency free cases, however are less than in the case of unit failures. This implies that the impact of the considered transmission line contingency is less severe than the unit outage.

Figures 3.8 and 3.9 illustrate a specific instance of the actual operation of the system in period 4:10 in the Moderate wind power generation scenario neglecting and considering the contribution of the two different types of LSE, respectively. It may be noticed that when contingency is anticipated, the operation of the system is the same in this instance since the cost of scheduling load following reserves from the LSE of type 1 is higher than procuring reserves from the generation side. The difference between the scheduled wind power generation and the Moderate scenario is 41.604 MW, while the inelastic load deviation is negative and equal to 135 MW. Thus, the required net demand change that must be balanced by the generation side is a decrease of 93.396 MW which is implemented by deploying 44.299 MW down spinning reserve from unit 1, 90.701 MW down spinning reserve from unit 2 and 41.604 MW of non spinning reserves from unit 3. In the case of the contingency of unit 2, in addition to the load following requirements, the deficit of 355.795 MW has to be covered. As a result, unit 4 is also contributing to non spinning reserves. If the contribution of LSE of types 1 and 2 is considered, the consumption of the LSE of type 1 is increased by 16 MW, while the LSE of type 2 is curtailed by 40 MW. Finally, in the case of the transmission line 2 contingency, the LSE of type 2 may also be curtailed by half in order to procure less reserves from the generation side.

3.3.2 Application on a 24-bus system

3.3.2.1 Case study description

In this section the proposed methodology is tested on a modified version of the IEEE Reliability Test System for a 12-hour horizon, using 15-minute intervals in the second stage of the problem. Complete data regarding the technical and economic characteristics of the system may be found in Appendix C, Section C.2. The nuclear units at buses 18 and 21 and the hydro units at bus 22 are considered must-run units. A wind farm is added to the generation mix and is located at bus 10. To account for the wind power generation stochasticity, 10 non equiprobable scenarios are generated for the total wind production according to the methodology described in Appendix B. Note that in order to construct these scenarios the methodology of Appendix B can be directly applied provided that historical data with 15-min granularity are available. However, since the historical data utilized in this thesis are given for hourly intervals, the scenario generation methodology must be slightly altered for the purposes of this chapter. More specifically, firstly, 10 hourly scenarios are constructed (the periods 1 am to 12 pm of the investigated day are utilized in this case study) and subsequently, it is considered that in each intra-hour interval the wind power production may randomly (a uniform distribution is used) deviate 5% up or down from the corresponding hourly value. For the sake of simplicity no intra-hour load deviations are considered in this section. Note that the wind spillage cost and the involuntary load shedding cost are considered equal to 1000 €/MWh.

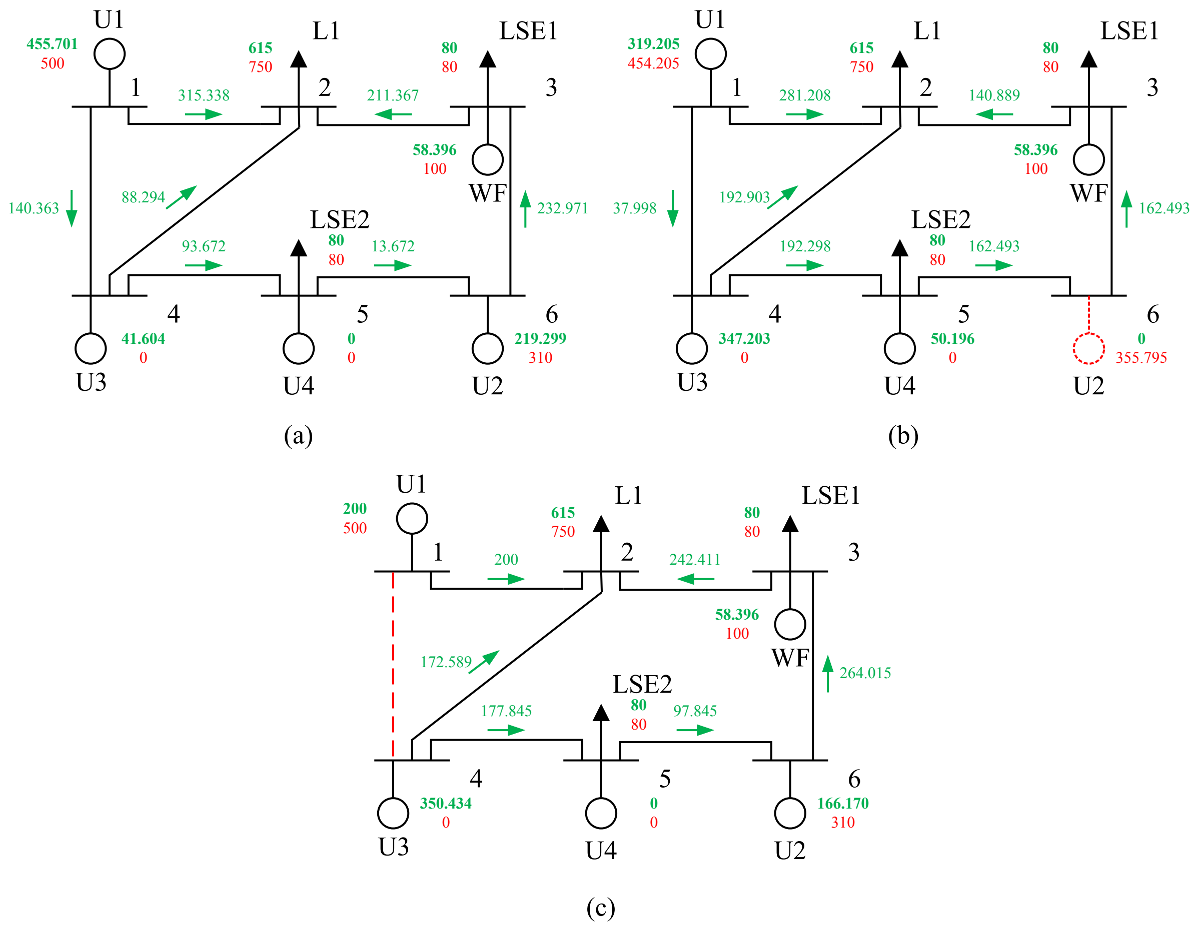

Figure 3.8: Analysis of period 4:10 in moderate scenario when contribution of LSEs is neglected.
a) without contingencies, b) U2 fails at 4:10, c) transmission line 2 fails at 4:10.
Red color: generation and consumption scheduled in the day-ahead market.
Green color: generation, consumption and active power flows in moderate scenario.
All values are in MW.

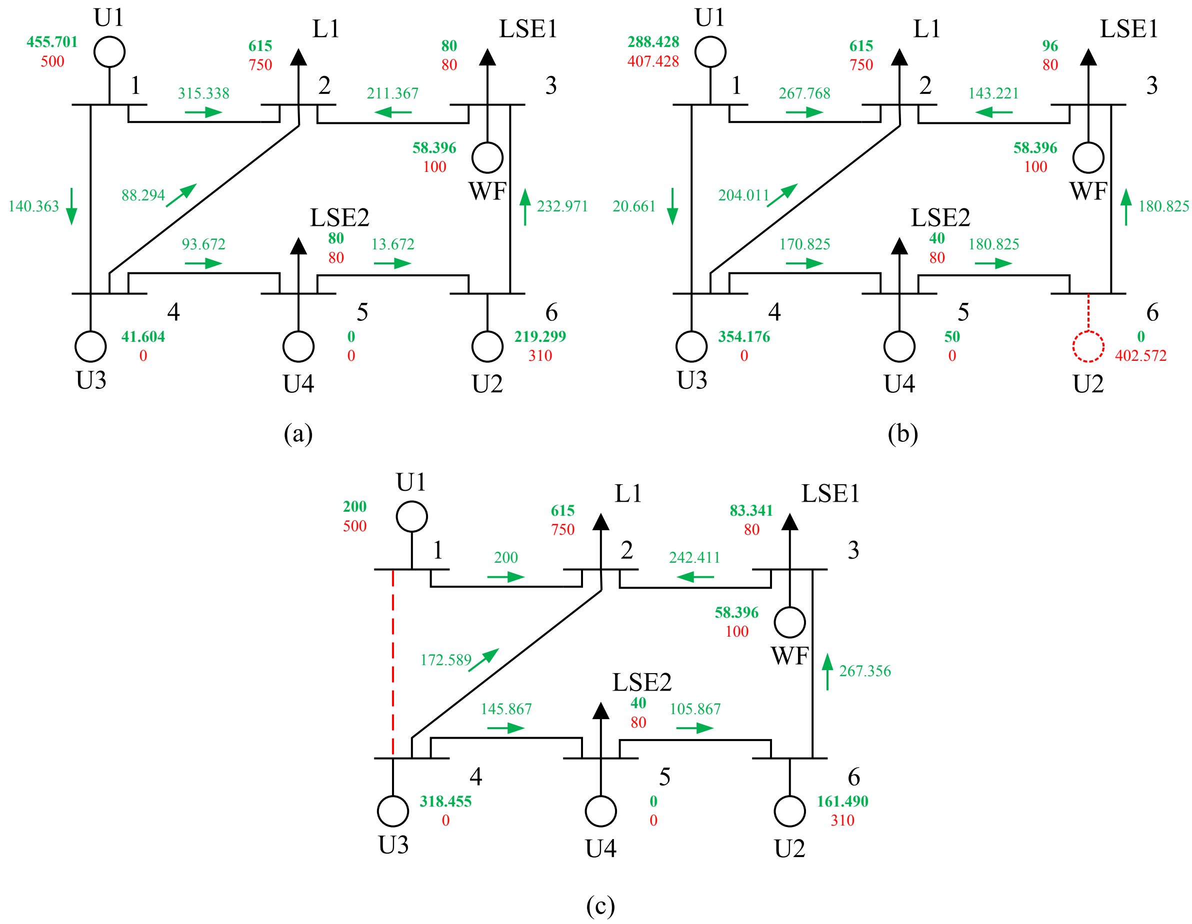

Figure 3.9: Analysis of period 4:10 in moderate scenario when contribution of LSEs is considered.
a) without contingencies, b) U2 fails at 4:10, c) transmission line 2 fails at 4:10.
Red color: generation and consumption scheduled in the day-ahead market.
Green color: generation, consumption and active power flows in moderate scenario.
All values are in MW.

All the generators except for the units at bus 22 (must-run at constant output) can participate in spinning up and down reserves that must be fully available in 15 minutes. The proposed formulation explicitly allows units that are off-line to be committed in the day-ahead to alter their status and provide non spinning reserves. Non spinning reserves must be fully deployed within 30 minutes and the units 3, 4, 5, 6 and 7 are considered eligible for the provision of this service.

The following cases are investigated:

- **C1-A.** The loads connected at buses 18 and 20 which stand for approximately 11.7% and 4.5% of the total system load, respectively, are considered to represent LSE of type 1. The only source of imbalances is the uncertain wind power generation of the 200 MW wind farm. The cost of scheduling reserves from the LSE of type 1 is equal to 5 €/MWh, while the cost of deploying reserves is 50 €/MWh.
- **C1-B.** The cost of scheduling reserves from the LSE varies from 1 to 5 €/MWh, while the cost of deploying reserves receives a value equal to ten times the reserve scheduling cost. The LSE of type 1 located at bus 20 is considered available only for reserve provision (cannot be rescheduled) with a flexibility of 20%.
- **C2-A.** Apart from the wind power output uncertainty, a unit outage and a transmission line failure are considered. More specifically, the must-run unit 10 fails at 7:30 causing a deficit of 300 MW, while the transmission line 33 that connects buses 20 and 23 fails at 7:30, is repaired at period 9:15 and fails again at 11:30. The LSE of type 1 located at bus 20 is considered capable of providing load following reserve.
- **C2-B.** The LSE of type 2 located at bus 19 (6.4% of total system load) may provide up contingency reserve. The cost of scheduling contingency reserves from LSE of type 2 is 0.25 €/MWh, while the price paid by the ISO in order to deploy reserve is 40 €/MWh. This type of reserve may be called at most 2 times and each call may last maximum 30 minutes.
- **C2-C.** The LSE of type 1 at bus 20 may provide load following reserve with an upward and downward flexibility of 30%, while the LSE of type 2 at bus 19 may provide upward contingency reserves with a upward flexibility of 50%.
- **C3.** The capacity of the wind farm at bus 10 is considered to have different installed capacities while the LSE of type 1 and 2 have the same characteristics as in the C2-C.

3.3.2.2 Results & discussion

Prior to delving into the analysis of the results concerning the aforementioned cases, it should be noted that due to the high wind spillage cost, no available wind energy spillage is noticed in any of the studied cases.

Figures 3.10 and 3.11 present the nominal load of the LSE of type 1 connected to buses 18 and 20, respectively. It may be noticed that in both cases, when a certain amount of flexibility is available for the LSE of type 1, its demand is rescheduled so that load is shifted from the relatively higher system loading periods (8-12) to the relatively low system loading periods (1-7). As a result, the day-ahead energy cost is expected to reduce with the increase of the available flexible demand, a

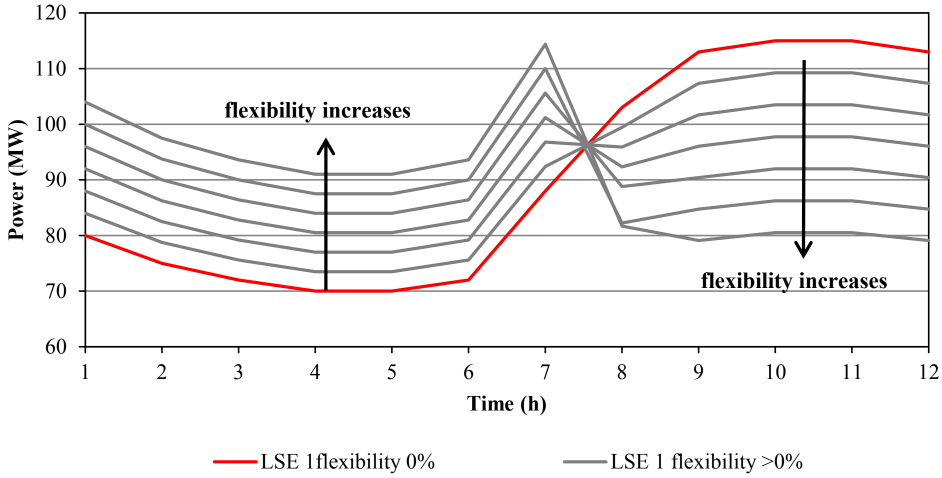

Figure 3.10: Scheduled load of LSE of type 1 connected at bus 18

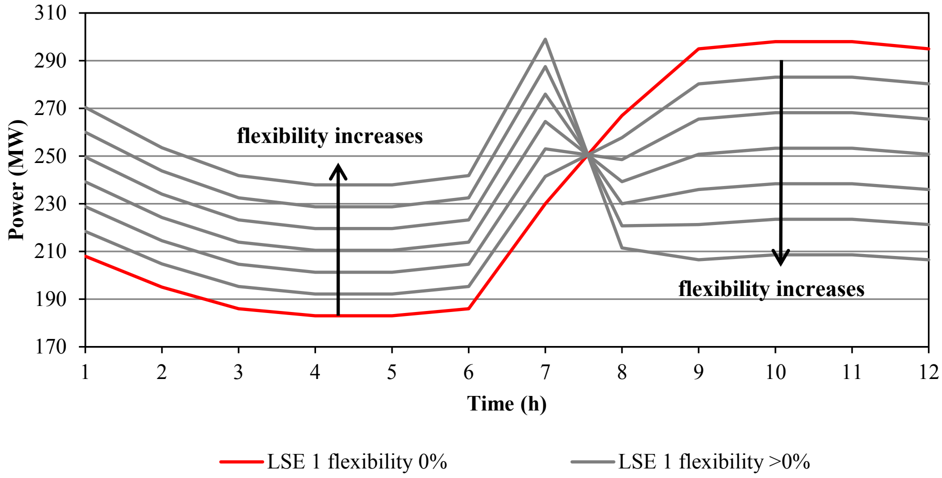

Figure 3.11: Scheduled load of LSE of type 1 connected at bus 20

fact that is confirmed by the results portrayed in Fig. 3.12. It is interesting to notice that when the LSE of type 1 that is connected to bus 18 is considered, the decrease in the energy cost is more significant because of the larger amount of load reallocation.

It is also important to investigate the effect of the contribution of the LSE of type 1 to reserves in order to balance the wind power generation deviations on the cost of scheduled reserves from the generation side in the day-ahead market. The cost of scheduled day-ahead generation side reserves with respect to different levels of flexibility regarding the LSE of type 1 is illustrated in Fig. 3.13. The LSE of type 1 connected to bus 20 leads in a reduction in cost of generation side reserves as the flexibility increases from 0 to 20%. Note that for all the degrees of flexibility, the amount of reserves scheduled by LSE of type 1 is the same. The energy and reserve reduction costs are a consequence of the flexible demand rescheduling. Increasing the flexibility to 25% and 30% does not cause any further reduction in the generation side reserve cost. Considering that the load of bus 18 represents a LSE of type 1, the generation side reserve cost is reduced more because the amount of load that is rendered available to be re-scheduled is larger. Although the amount of reserves scheduled by the LSE is the same as in the previous case, the load re-allocation facilitates the wind power integration and therefore, reduces the cost of reserve procurement by

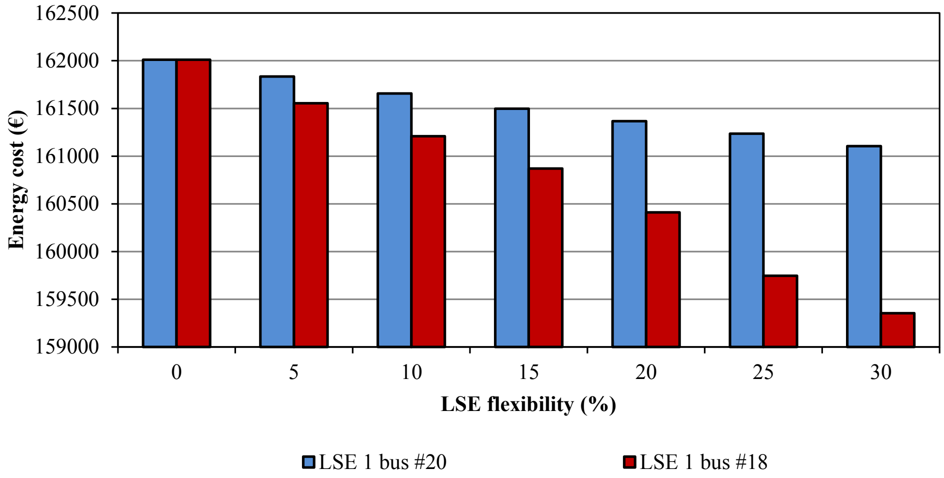

Figure 3.12: Energy cost for different values of LSE of type 1 flexibility (C1-A)

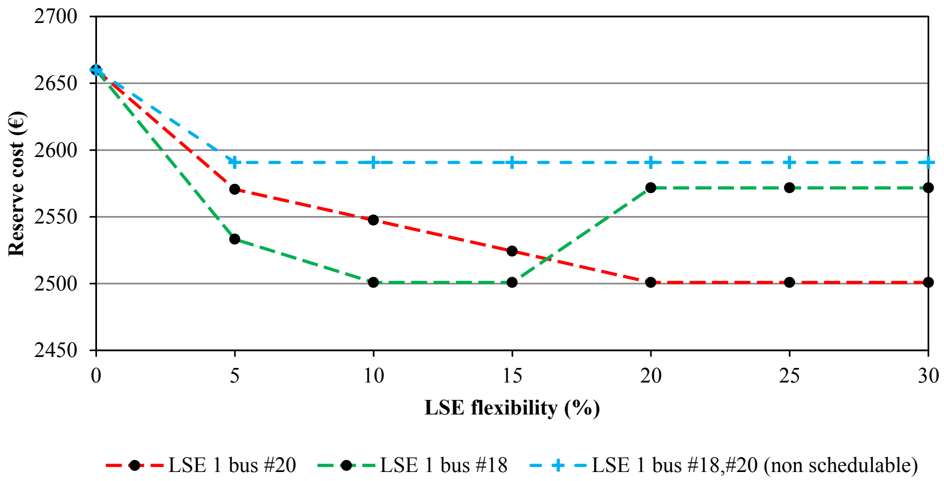

Figure 3.13: Reserve cost for different values of LSE of type 1 flexibility (C1-A)

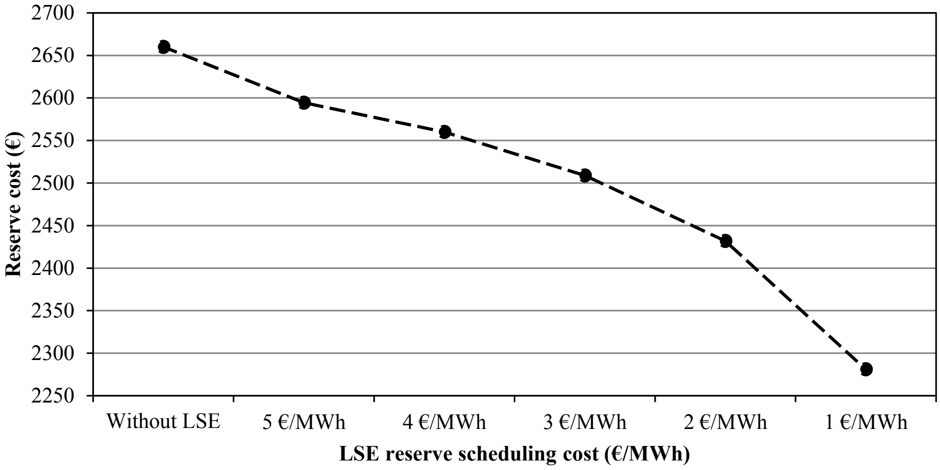

Figure 3.14: Generation scheduled reserve cost for different costs of LSE of type 1 reserve cost

the generation side. It is noticeable that the cost of generation side reserves for 10% and 15% is the same, while it increases for 20%, 25% and 30%. This increase is linked to the fact that the load re-allocation leads to significant reduction in the conventional generation energy production cost on the expense of slightly increasing the generation side reserve cost.

Another case that is examined is related to enforcing the requirement of the LSE of type 1 not being able to be re-scheduled in the day-ahead market. Nevertheless, it may be scheduled to provide up and down reserves. This results in a constant day-ahead energy cost of 162011 € regardless of the LSE of type 1 flexibility. Evidently, for the LSE of type 1 located at either bus 18 or 20 the minimum required flexibility of 5% yields the maximum possible reduction in the reserve cost.

One determining factor for the utilization of LSE of type 1 as reserve providers is the cost at which their service is provided. In order to be an appealing alternative to the deployment of generation side resources, the cost of demand side reserves should be less than the cheapest reserve service offered by the generators, that is 5 €/MWh from units 8 and 9. To demonstrate the importance of the demand side reserve offering cost, in C1-B a parametric analysis is performed. Firstly, in Fig. 3.14 the generation side reserve cost versus the cost of LSE of type 1 reserve scheduling cost is depicted. Due to the fact that the load cannot be rescheduled with respect to its nominal value, the reserve cost reduction is purely the effect of scheduling more reserves from the LSE of type 1 with the reduction in the LSE of type 1 reserve scheduling cost. For instance, the nominal load and the deployed load in scenario 10 is displayed in Fig. 3.15. It may be noticed that for a LSE of type 1 scheduling cost of 1 €/MWh the changes in the load pattern are substantial, while for a slight increase of the cost by 1€/MWh the reserves are significantly reduced. For higher costs, no reserves are deployed by the LSE of type 1 in scenario 10. Thus, it may be concluded that the sensitivity of scheduling reserves from the demand side is highly sensitive to the cost of this service.

In cases C2-A, C2-B and C2-C a unit outage and a transmission line failure are considered. This implies that contingency reserves should be also scheduled in order to balance the energy production deficit and the network disturbances. In case C2-A, only the generation side may alter its production to provide contingency reserves. However, in cases C2-B and C2-C, in addition to the generation side, LSE of type 2 may also contribute to contingency reserves. In Fig. 3.16 the

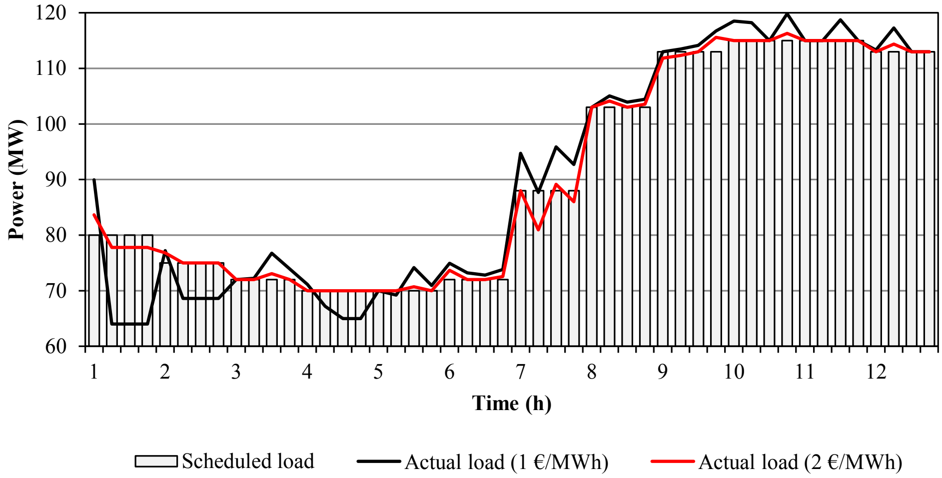

Figure 3.15: Scheduled load of LSE of type 1 and actual consumption in scenario 10

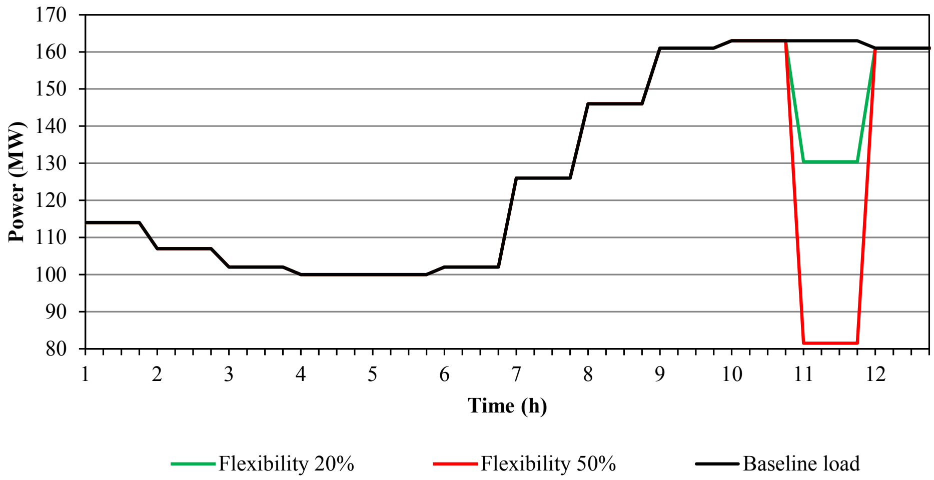

Figure 3.16: Baseline load of LSE of type 2 and deployed contingency reserve

baseline consumption of the load connected to bus 19 that serves as an LSE of type 2 is illustrated together with the deployment of up contingency reserve considering two different degrees of flexibility. The maximum amount of load that may be curtailed is scheduled for deployment of contingency reserve in all scenarios. The ISO calls two times the LSE of type 2 to provide contingency reserve for the maximum allowed duration (1 hour). The first call is activated in period 11 and the second in period 11:30. These calls not only coincide with the second failure of the transmission line 33 but also with the highest system load periods that implies that the demand side provision of contingency reserves is an alternative to providing contingency reserves from the already highly loaded units (generation side reserves would have a higher deployment cost).

The day-ahead energy and reserve cost for the cases C2-A, C2-B and C2-C are presented in Table 3.7. When the participation of the demand side resources is not considered, the contingencies cause an increase of 8110 € in the scheduled generation side reserves while maintaining the scheduled day-ahead energy cost. In C2-A as the flexibility of the LSE of type 1 increases, the day-ahead energy and reserve cost decrease as a result of optimally re-scheduling its load demand. In C2-B in which the LSE of type 2 renders available its load to provide contingency reserve, higher cost reductions occur since its reserves address the source of imbalances that is responsible

Table 3.7: Energy and reserve costs for cases C2-A, C2-B and C2-C

Case	Flexibility (%)	Energy cost (€)	Reserve cost (€)	LSE of type 1 reserve cost (€)	LSE of type 2 reserve cost (€)
C2-A	0	162011	10770	-	-
	10	161657	10682	8.185	-
	20	161366	10647	8.185	-
	30	161105	10629	8.185	-
C2-B	20	162011	10627	-	8.150
	50	162011	10434	-	20.375
C2-C	(30% and 50%)	161105	10271	8.185	20.375

Table 3.8: Energy and reserve costs for different installed capacity of wind farm (C3)

Wind-farm capacity (MW)	Case	Energy cost (€)	Reserve cost (€)	LSE of type 1 reserve cost (€)	LSE of type 2 reserve cost (€)
200	Without LSE	162011	10770	-	-
	Non schedulable LSE 1 load	162011	10368	8.185	20.375
	Schedulable LSE 1 load	161105	10271	18.785	20.375
500	Without LSE	143766	14580	-	-
	Non schedulable LSE 1 load	143766	14129	92.083	20.375
	Schedulable LSE 1 load	142818	14069	213.125	20.375
800	Without LSE	128147	19020	-	-
	Non schedulable LSE 1 load	128147	18575	171.333	20.375
	Schedulable LSE 1 load	127574	18390	333.333	20.375

for the high day-ahead scheduled reserves. Finally, the greatest energy and reserve reduction costs are noticed in C2-C. The energy cost in this case coincides with the energy cost of C2-A with a flexibility of 30%, while the reserve cost is the lowest among the different cases.

In the previous cases the capacity of the wind farm was considered to be 200 MW. In order to investigate the effect that the demand side resources have on the energy and reserve costs with the increase in the installed capacity of the wind farm, case C3 is investigated. In this case, the wind farm is considered to have a capacity of 200 MW, 500 MW and 800 MW, while the aforementioned contingencies are also taken into account. The relevant results are listed in Table 3.8. It may be noted that on the one hand, the energy cost when no flexible demand side resources are considered drops from 162011 € to 143766 € and 128147 € for increasing the wind farm capacity to 500 MW and 800 MW, respectively, due to integrating more free of cost wind energy in the day-ahead market. On the other hand, the generation side reserve scheduling cost increases by 26.13% and 43.37%. When the LSE of type 1 is considered able only to provide reserves (non schedulable load) the energy cost does not change, while the generation side reserve cost is reduced. If the LSE of type 1 is considered schedulable, the energy cost is reduced together with the reserve cost. It is important to notice that with the increasing penetration of wind power generation, the LSE of type 1 offers more reserves, especially in the case in which the load may be optimally scheduled, while the total amount of power curtailment available from the LSE of type 2 is utilized in all the cases.

Table 3.9: Computational statistics (6-bus system)

	Without contingency/ without LSE	Unit contingency/ without LSE	Line contingency/ without LSE	Without contingency/ with LSE	Unit contingency/ with LSE	Line contingency/ with LSE
Equations	36304	34252	36292	36304	34252	36292
Continuous variables	288200	287741	288200	288200	287741	288200
Discrete variables	2890	2788	2890	2890	2788	2890
Time (s)	12.62	4.59	3.24	23.81	7.80	4.77

Table 3.10: Computational statistics (24-bus system)

	C2-C
Equations	566648
Continuous variables	2364079
Discrete variables	32028
Time (s)	562

3.3.3 Computational statistics

All the simulations are performed on a workstation with 256 GB of RAM memory, employing two 16-core Intel Xeon processors clocking at 3.10 GHz running on a 64-bit windows distribution. The maximum allowed relative optimality gap is set to $10^{-4}\%$.

Indicative results from the simulations presented in this chapter are presented in Tables 3.9 and 3.10. It may be noticed that the simulations on the 6-bus system are trivial from the perspective of the computational burden. On the other hand, the 24-bus system is characterized by an increased number of constraints and variables, especially discrete. As a result, the computational time required to solve these cases increases. Nevertheless, the computational time in all the cases is deemed acceptable.

3.4 Chapter Conclusions

In this chapter a two-stage stochastic joint energy and reserve market structure that incorporates two different types of demand side resources capable of providing reserve in order to confront imbalances caused by load demand and wind power generation deviations, as well as system contingencies was presented. The proposed formulatation was applied both on an example test system in order to explain its functionality and on a modified version of the IEEE Reliability Test System in order to obtain more scalable results. Through the investigated test cases it was rendered evident that the contribution of the two types of LSE to reserves bears economic benefits for the ISO. Given that the services offered by the demand side may be procured at lower prices in comparison with the generation side reserves, they constitute an appealing alternative resource to confront power imbalances and transmission system disturbances. Especially, the contribution of the demand side resources was demonstrated to be more significant when higher levels of wind power generation penetration are considered.

Chapter 4

Load Following Reserve Provision by Industrial Consumer Demand Response

4.1 Introduction

It was discussed in Section 2.2.2.2.1 that several types of industrial processes and loads are eligible to participate to the electricity market structures through appropriately designed DR programs and exploit their potential as a system resource. The main reason for which industrial loads have attracted such an attention for the development of DR programs are: 1) their inherently large loads, 2) the existence of sensor and metering technologies used already for other purposes may reduce the overall investment costs and, 3) industries often employ personnel trained on energy management related issues since electricity constitutes a significant cost for industrial customers. It is also noticeable that many programs have been developed in practice in order to engage industrial and other types of large consumers. The most significant examples were presented in Section 2.4. It is also interesting to notice that despite the fact that there is an abundant literature regarding the participation of demand side resources in power system operations and a well documented discussion on the DR potential of the industrial sector, only a few studies have focused on the development of analytical models of industrial consumer processes.

In this chapter a day-ahead joint energy and reserve market structure is developed. The ISO may utilize generation side and demand side reserves that are offered by industrial loads. In order to account for the technical restrictions related to the participation of industrial consumers in the market, a novel comprehensive load model for the industrial consumers is proposed. The market clearing problem is formulated both for a risk neutral and a risk averse ISO. The remainder of this chapter is organized as follows: Section 4.2 presents the assumptions adopted in order to facilitate the formulation of the problem together with the proposed mathematical model. Subsequently, in Section 4.3 the methodology is demonstrated by an illustrative test case and then, a more practical system is analyzed both for the cases of a risk neutral and risk averse ISO. Finally, relevant conclusions are drawn in Section 4.4.

4.2 Mathematical Model

4.2.1 Overview and modelling assumptions

To accommodate the uncertain nature of wind power production, a network-constrained day-ahead market clearing model is proposed under a two-stage stochastic programming framework. The first stage of the model represents the day-ahead market where energy and reserves are jointly

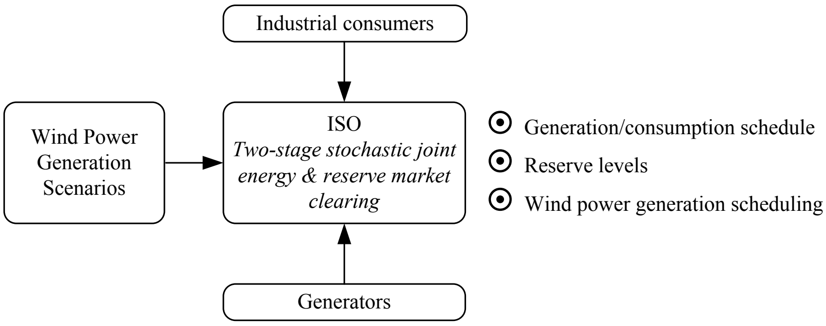

Figure 4.1: Overview of the market clearing model

scheduled to balance wind volatility. The variables of this stage do not depend on any specific scenario realization and constitute here-and-now decisions. The second stage of the model stands for several actual system operation possibilities. The variables of this stage are scenario-dependent and have different values for every single wind scenario. The second stage variables constitute wait-and-see decisions. The proposed market structure is illustrated in Fig. 4.1

Reserves can be procured by resources located both in the generation and the demand side:

- Generating units: They can provide up spinning, down spinning and non-spinning reserves.
- Industrial consumers: these market participants can increase (down spinning reserve) or decrease (up spinning reserve) the power consumption of ongoing processes by a discrete amount or even to reschedule the operation of their processes (non spinning reserves). It should be noted that the spinning and non spinning reserves terminology in the case of demand side reserves is adopted in accordance with the unit procured reserves. Spinning tends to mean "alteration of an existing consumption", while non spinning reserve provision in the case of the industrial consumers stands for a time-shift of a process.

In order to render the rigorous mathematical formulation of the problem practical, several assumptions are adopted:

- The only source of uncertainty is deemed the wind production. Thus, no contingencies are taken into account, while the load forecasting as well as the response of the demand side resources are considered perfectly reliable.
- The response of demand side resources is considered instant (practically several minutes [242]) and thus, no ramping constraints are enforced for the industrial consumption.
- Wind power producers are not considered competitive agents and their participation is promoted by the ISO. For the market clearing procedure wind energy is considered free of cost. Practically, it could be paid a regulated tariff out of the day-ahead market scope for the energy actually produced [283].
- The cost for deploying reserves by the units is considered equal to their energy costs. The cost of deploying reserves by the demand side is considered equal to their utility value. However, any pricing scheme may be incorporated within the proposed approach.

- A linear representation of the network is considered, neglecting the active power losses. The losses may be included in a linear formulation as explained in [283].
- Load shedding is only possible for the inelastic loads that are not subject to any resource offering scheme.
- The scheduling horizon is one day with hourly granularity.

4.2.2 Objective function

4.2.2.1 Risk neutral ISO

$$
\begin{aligned}
EC = \sum_{t \in T} \Bigg\{ & \\
\sum_{i \in I} \Bigg[& \sum_{f \in F^i} (C_{i,f,t} \cdot b_{i,f,t}) + SUC_i \cdot y^1_{i,t} + SDC_i \cdot z^1_{i,t} + C^{R,D}_{i,t} \cdot R^D_{i,t} + C^{R,U}_{i,t} \cdot R^U_{i,t} + C^{R,NS}_{i,t} \cdot R^{NS}_{i,t} \Bigg] \\
& + \sum_{d \in D} (C^{R,D,In}_{d,t} \cdot R^{D,ind}_{d,t} + C^{R,U,In}_{d,t} \cdot R^{U,ind}_{d,t} + C^{R,NS,In}_{d,t} \cdot R^{NS,ind}_{d,t}) \Bigg\} \\
& + \sum_{s \in S} \pi_s \sum_{t \in T} \Bigg\{ \sum_{i \in I} \Bigg[SUC_i \cdot (y^2_{i,t,s} - y^1_{i,t}) + SDC_i \cdot (z^2_{i,t,s} - z^1_{i,t}) + \sum_{f \in F^i} (C_{i,f,t} \cdot r^G_{i,f,t,s}) \Bigg] \\
& + \sum_{d \in D} \lambda^D_{d,t} \sum_{g \in G} \sum_{p \in P} (r^{U,pro}_{d,g,p,t,s} - r^{D,pro}_{d,g,p,t,s} - r^{NS,pro}_{d,g,p,t,s}) \\
& + \sum_{w \in W} (V^S \cdot S_{w,t,s}) + \sum_{j \in J} (V^{LOL} \cdot L^{shed}_{j,t,s}) \Bigg\}
\end{aligned} \tag{4.1}
$$

The objective function (4.1) stands for the minimization of the total expected cost (EC) emerging from the system operation. The first line of the objective function expresses the costs associated with energy provided from the generating units, the startup and shutdown costs and the commitment of the units to provide reserves. The second line represents the costs of scheduling reserves from the industrial consumers.

The rest of the objective function is scenario dependent, as indicated by the summation over the scenario index. The third line takes into consideration the cost of changing the status of the generating units and the cost of actually deploying reserves from the generators. Similarly, the fourth line considers the costs of deploying reserves from the industrial loads. Finally, the last line takes into account the wind spillage cost and the expected cost of the energy not served to the inelastic loads. Since wind power production is assumed to be free of cost, the optimization would potentially avoid to accommodate all the available wind production because of the costs that emerge due to reserves that should be scheduled and deployed by other resources and therefore, curtailment of wind production may be noticed. The minimization of wind spillage cost indicates that it is required to integrate as much wind as possible into the power system (i.e., due to the policy of the ISO).

4.2.2.2 Risk averse ISO

The objective function (4.1) minimizes the total expected cost EC, while neglecting other characteristics of the distribution of costs in different scenarios. Thus, it may be said that the ISO that makes decisions according to this objective neglects the risk of experiencing high costs in several scenarios and therefore, is a risk neutral ISO. The importance of risk management through the consideration of an appropriate risk measure was discussed in Section 1.5.4. In this study, it is considered that the ISO is willing to take into account the risk pertaining its decisions utilizing the CVaR metric. The risk averse decision making objective function is described by (4.2).

$$C = EC + \beta \cdot CVaR \tag{4.2}$$

The objective function (4.2) states that the ISO minimizes the total expected cost (EC) of the system taking into account the effect of different levels of risk aversion that are expressed through the positive weighting factor β, aiming also at minimizing the CVaR metric. Note that a risk averse ISO must also consider three additional constraints ((4.3)-(4.5)) into the optimization problem, apart from the ones that are presented in Section 4.2.3.

$$CVaR = \xi + \frac{1}{1-a} \sum_{s \in S} \pi_s \cdot \eta_s \tag{4.3}$$

$$\begin{aligned}
&\sum_{t \in T} \Bigg\{ \sum_{i \in I} \Bigg[\sum_{f \in F^i} (C_{i,f,t} \cdot b_{i,f,t}) + SUC_i \cdot y^1_{i,t} + SDC_i \cdot z^1_{i,t} + C^{R,D}_{i,t} \cdot R^D_{i,t} + C^{R,U}_{i,t} \cdot R^U_{i,t} + C^{R,NS}_{i,t} \cdot R^{NS}_{i,t} \Bigg] \\
&+ \sum_{d \in D} (C^{R,D,In}_{d,t} \cdot R^{D,ind}_{d,t} + C^{R,U,In}_{d,t} \cdot R^{U,ind}_{d,t} + C^{R,NS,In}_{d,t} \cdot R^{NS,ind}_{d,t}) \Bigg\} \\
&+ \sum_{t \in T} \Bigg\{ \sum_{i \in I} \Bigg[SUC_i \cdot (y^2_{i,t,s} - y^1_{i,t}) + SDC_i \cdot (z^2_{i,t,s} - z^1_{i,t}) + \sum_{f \in F^i} (C_{i,f,t} \cdot r^G_{i,f,t,s}) \Bigg] \\
&+ \sum_{d \in D} \lambda^D_{d,t} \sum_{g \in G} \sum_{p \in P} (r^{U,pro}_{d,g,p,t,s} - r^{D,pro}_{d,g,p,t,s} - r^{NS,pro}_{d,g,p,t,s}) \\
&+ \sum_{w \in W} (V^S \cdot S_{w,t,s}) + \sum_{j \in J} (V^{LOL} \cdot L^{shed}_{j,t,s}) \Bigg\} \\
&- \xi \leq \eta_s \;\; \forall s
\end{aligned} \tag{4.4}$$

$$\eta_s \geq 0 \;\; \forall s \tag{4.5}$$

Constraint (4.3) stands for the definition of $CVaR$, the inequality (4.4) states that the $CVaR$ is considered with respected to the cost of each individual scenario and finally, (4.5) forces the auxiliary variable η_s to be positive.

4.2.3 Constraints

4.2.3.1 First stage constraints

This section presents the first stage constraints of the optimization problem. These constraints involve only decision variables that do not depend on any specific scenario.

4.2.3.1.1 *Generator output limits*

$$P_{i,t}^{S} = \sum_{f \in F^{i}} b_{i,f,t} \ \forall i, t \tag{4.6}$$

$$0 \leq b_{i,f,t} \leq B_{i,f,t} \ \forall i, f, t \tag{4.7}$$

$$P_{i,t}^{S} - R_{i,t}^{D} \geq P_{i}^{min} \cdot u_{i,t}^{1} \ \forall i, t \tag{4.8}$$

$$P_{i,t}^{S} + R_{i,t}^{U} \leq P_{i}^{max} \cdot u_{i,t}^{1} \ \forall i, t \tag{4.9}$$

The generator cost function is considered convex and is approximated using a step-wise linear marginal cost function as in [301]. This is enforced by (4.6) and (4.7). Constraints (4.8) and (4.9) limit the output power of a generating unit, taking also into account the scheduled up and down reserve margins, respectively.

4.2.3.1.2 *Generator minimum up and down time constraints*

$$\sum_{\tau=t-UT_i+1}^{t} y_{i,\tau}^{1} \leq u_{i,t}^{1} \ \forall i, t \tag{4.10}$$

$$\sum_{\tau=t-DT_i+1}^{t} z_{i,\tau}^{1} \leq 1 - u_{i,t}^{1} \ \forall i, t \tag{4.11}$$

Constraint (4.10) forces a unit to remain committed for at least UT_i periods once a start-up decision is made ($y_{i,t}^{1} = 1$), while (4.11) forces a unit to remain decommitted for at least DT_i periods once a shut-down decision is made ($z_{i,t}^{1} = 1$).

4.2.3.1.3 *Unit commitment logic constraints*

$$y^1_{i,t} - z^1_{i,t} = u^1_{i,t} - u^1_{i,(t-1)} \ \forall i, t \tag{4.12}$$

$$y^1_{i,t} + z^1_{i,t} \leq 1 \ \forall i, t \tag{4.13}$$

Equation (4.12) enforces the startup and shutdown status change logic. The logical requirement that a unit cannot start up and shut down simultaneously during the same period is modelled using (4.13).

4.2.3.1.4 *Ramp-up and ramp-down limits*

$$P^S_{i,t} - P^S_{i,(t-1)} \leq \Delta\mathrm{T} \cdot RU_i \ \forall i, t \tag{4.14}$$

$$P^S_{i,(t-1)} - P^S_{i,t} \leq \Delta\mathrm{T} \cdot RD_i \ \forall i, t \tag{4.15}$$

In order to consider the effect of the ramp rates that limit the changes in the output of the generating units, constraints (4.14) and (4.15) are enforced. $\Delta\mathrm{T}$ is the time length of the optimization interval in minutes, e.g., $\Delta\mathrm{T} = 60\ min$ in the case of hourly granularity.

4.2.3.1.5 *Generation side reserve limits*

$$0 \leq R^D_{i,t} \leq T^S \cdot RD_i \cdot u^1_{i,t} \ \forall i, t \tag{4.16}$$

$$0 \leq R^U_{i,t} \leq T^S \cdot RU_i \cdot u^1_{i,t} \ \forall i, t \tag{4.17}$$

$$0 \leq R^{NS}_{i,t} \leq T^{NS} \cdot RU_i \cdot (1 - u^1_{i,t}) \ \forall i, t \tag{4.18}$$

Constraints (4.16)-(4.18) impose limits in the procurement of reserves from the conventional generating units. Up and down spinning reserves and non spinning reserves are defined by (4.16),(4.17) and (4.18), respectively. Note that T^S and T^{NS} is the time in minutes during which the reserves should be fully deployed. The deployment time for each reserve type is defined by the rules that hold for each system.

4.2.3.1.6 *Wind power scheduling*

$$0 \leq P_{w,t}^{WP,S} \leq P_{w,t}^{WP,max} \; \forall w, t \tag{4.19}$$

Typically the wind power generation scheduled in the day-ahead market is considered equal to its forecast value. However, in this study it is considered that the ISO schedules the optimal amount of wind according to the technicoeconomic optimization within the limits imposed by (4.19). The upper limit may stand for the installed capacity of a wind farm (i.e. $P_{w,t}^{WP,max}$ is time independent) or for the maximum value of the wind scenarios during a period t. It may also coincide with a maximum value that represents the bid of a wind power producer (if wind power producers are considered competitive participants).

4.2.3.1.7 *Industrial consumer model*

In this study, the industrial load is considered to comprise different task groups that may work in parallel and include several individual processes, similar to real-life practice [106]. Generally, we can refer to three categories of processes, namely, totally flexible, flexible and inflexible:

- Totally flexible processes can be considered as the ones that are not physically constrained to maintain power for consecutive time intervals, for example, due to thermal dynamics (e.g., a set of production facilities that work as long as there is input material).
- Flexible processes are the ones that should be completed at most within a certain time span, but with the flexibility of allocating energy consumption. Within their completion time, they can be continuous (type 1) or interruptible (type 2).
- The most rigid processes are the inflexible ones that have to be completed in a strictly specified time and with a predefined energy allocation (e.g., a sensitive metallurgy process). However, it is assumed that such processes can be shifted in time.

For the sake of simplicity, in the formulation proposed, the hourly energy limit is considered to be uniform for each process. There are specific cases that this assumption does not cover, but this restriction is easy to overcome by defining a time varying hourly energy limit.

A process is characterized by several parameters that define the different types of flexibility in terms of energy treatment. To better illustrate the operation of the model, examples of different types of processes are presented in Fig. 4.2. The totally flexible process consumes energy that can be allocated in four discrete blocks during the day. The only restriction is that no more than two blocks of energy may be allocated in a single period. The flexible process has to consume energy that can be allocated in four discrete blocks. The restrictions are that the process has to be completed in maximum three hours after it starts (no restriction in which period to start) and that no more than two energy blocks can be allocated in a single period. Also, there has to be at least one power block allocated per period for the case of the flexible process of continuous type (type 1). This type of process offers two degrees of freedom. First, the optimal starting period is selected, and then some parts of the consumption may be shifted in adjacent time periods. Finally,

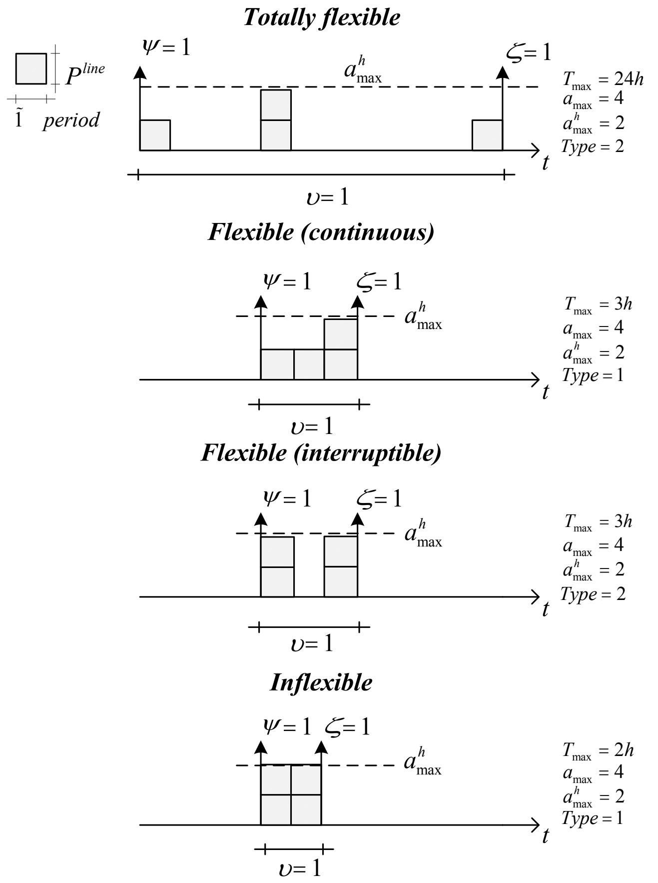

Figure 4.2: The types of industrial processes

the inflexible process has to be completed in exactly two periods after it begins (no restriction in which period to start), allocating energy blocks in a predefined manner. The only flexibility of this type of process is that the starting time can be optimally selected.

Operation of the industry. Before describing the way in which load following reserves are procured by industrial consumers, the model of the processes described above should be mathematically expressed.

$$\sum_{t \in T} a_{p,g,d,t} = a_{p,g,d}^{max} \; \forall p, g, d, t \tag{4.20}$$

$$P_{p,g,d,t}^{pro,S} = a_{p,g,d,t} \cdot P_{p,g,d}^{line} \; \forall p, g, d, t \tag{4.21}$$

$$P_{d,t}^{ind,S} = D_{d,t}^{min} + \sum_{g \in G} \sum_{p \in P} P_{p,g,d,t}^{pro,S} \; \forall d, t \tag{4.22}$$

Equation (4.20) is an energy requirement constraint. It states that all the processes should be completed throughout the scheduling horizon. Equations (4.21) and (4.22) define the power that a process as well as the whole industry consumes during a given period, respectively. Especially, (4.22) states that the total power $P_{d,t}^{ind,S}$ consumed by the industry in a given period t consists of the time-flexible controllable process load and an inelastic part $D_{d,t}^{min}$ that is characterized as minimum or mandatory (e.g., must-run equipment or uncontrollable processes of the industry).

$$\upsilon_{p,g,d,t}^{1} \leq a_{p,g,d,t} \leq a_{p,g,d}^{max,h} \cdot \upsilon_{p,g,d,t}^{1} \ \forall p \in P_{type}^{1}, g, d, t \tag{4.23}$$

$$0 \leq a_{p,g,d,t} \leq a_{p,g,d}^{max,h} \cdot \upsilon_{p,g,d,t}^{1} \ \forall p \in P_{type}^{2}, g, d, t \tag{4.24}$$

The constraints expressed by (4.23) and (4.24) impose limits on the number of processes that could be scheduled in every hour by the industry. These constraints cover both interruptible and continuous processes and they can be used in order to guarantee that limitations such as the installed power of the industry are not violated. It should be noted that the term production line is a general term adopted here in order to express discrete amounts of power that can be consumed by an individual process, not necessarily referring to physical production lines.

$$\sum_{\tau=t-T_{p,g,d}^{c,max}+1}^{t} a_{p,g,d,\tau} \geq a_{p,g,d}^{max} \cdot \zeta_{p,g,d,(t+1)}^{1} \ \forall p, g, d, t \tag{4.25}$$

$$a_{p,g,d,t} \geq \zeta_{p,g,d,(t+1)}^{1} \ \forall p, g, d, t \tag{4.26}$$

$$\psi_{p,g,d,t}^{1} \leq a_{p,g,d,t} \ \forall p, g, d, t \tag{4.27}$$

$$\psi_{p,g,d,t}^{1} + \zeta_{p,g,d,t}^{1} \leq 1 \ \forall p, g, d, t \tag{4.28}$$

$$\psi_{p,g,d,t}^{1} - \zeta_{p,g,d,t}^{1} = \upsilon_{p,g,d,t}^{1} - \upsilon_{p,g,d,(t-1)}^{1} \ \forall p, g, d, t \tag{4.29}$$

$$\sum_{t \in T} \zeta_{p,g,d,t}^{1} = 1 \ \forall p, g, d \tag{4.30}$$

$$\sum_{t \in T} \psi_{p,g,d,t}^{1} = 1 \ \forall p, g, d \tag{4.31}$$

Constraints (4.25)-(4.29) describe the logic of the commitment of a process. Specifically, (4.25) guarantees that a process is finished within the required completion time, while constraints (4.26)-(4.29) define the logic of operating, starting and ending a processes. Finally, constraints (4.30) and

(4.31) stipulate that a process can be run only once within the scheduling horizon. It is important to notice that omitting constraints (4.30) and (4.31) will lead to the violation of constraint (4.25). Thus, special care should be taken when dealing with processes that may be initiated more than once during the scheduling horizon.

$$\psi^{1}_{p,g,d,t} \leq \sum_{\tau=t-T^{g,max}_{(p-1),g,d}}^{t-T^{g,min}_{(p-1),g,d}} \zeta^{1}_{(p-1),g,d,\tau} \ \forall p \in \{P|p>1\}, g, d, t \tag{4.32}$$

In case that several processes must be executed in a predefined order, (4.32) guarantees that the next process will begin after a number of periods that may be within a minimum and a maximum time limit, as required by the nature of the processes. Naturally, this is a generic formulation and can cover any possible sequencing preferences.

Reserve scheduling from the industrial consumer. As it was discussed in Section 4.2.1, industrial consumers may offer up spinning, down spinning and a type of non spinning reserves, terms that respectively stand for load reduction, load increase and load reallocation. Reserve procurement from this consumer type is described by constraints (4.33)-(4.41).

$$R^{U,ind}_{d,t} = \sum_{p \in P} \sum_{g \in G} R^{U,pro}_{p,g,d,t} \ \forall d, t \tag{4.33}$$

$$R^{U,pro}_{p,g,d,t} = a^{up}_{p,g,d,t} \cdot P^{line}_{p,g,d} \ \forall p, g, d, t \tag{4.34}$$

$$0 \leq a^{up}_{p,g,d,t} \leq a_{p,g,d,t} \ \forall p, g, d, t \tag{4.35}$$

Constraint (4.33) stands for the total up reserve scheduled by the industrial load during a period, while (4.34) and (4.35) define each specific process participation in up spinning reserve. More specifically, (4.35) states that no more than the number of scheduled production lines can be scheduled for up reserve in a given time interval.

$$R^{D,ind}_{d,t} = \sum_{p \in P} \sum_{g \in G} R^{D,pro}_{p,g,d,t} \ \forall d, t \tag{4.36}$$

$$R^{D,pro}_{p,g,d,t} = a^{down}_{p,g,d,t} \cdot P^{line}_{p,g,d} \ \forall p, g, d, t \tag{4.37}$$

$$0 \leq a^{down}_{p,g,d,t} \leq a^{max,h}_{p,g,d} \cdot \upsilon^{1}_{p,g,d,t} - a_{p,g,d,t} \ \forall p, g, d, t \tag{4.38}$$

Similarly to (4.33)-(4.35), constraints (4.36)-(4.38) stand for the down spinning reserve scheduling. Especially, (4.38) states that the increase of consumption cannot surpass the hourly limit.

$$R_{d,t}^{NS,ind} = \sum_{p \in P} \sum_{g \in G} R_{p,g,d,t}^{NS,pro} \ \forall d,t \tag{4.39}$$

$$R_{p,g,d,t}^{NS,pro} = a_{p,g,d,t}^{ns} \cdot P_{p,g,d}^{line} \ \forall p,g,d,t \tag{4.40}$$

$$0 \leq a_{p,g,d,t}^{ns} \leq a_{p,g,d}^{max,h} \cdot (1 - \upsilon_{p,g,d,t}^{1}) \ \forall p,g,d,t \tag{4.41}$$

Finally, non spinning reserves are defined by (4.39)-(4.41). Note that (4.41) states that no more than the maximum discrete amount of energy can be used in a given time interval.

4.2.3.1.8 *Day-ahead market power balance*

$$\sum_{i \in I} P_{i,t}^{S} + \sum_{w \in W} P_{w,t}^{WP,S} = \sum_{j \in J} L_{j,t} + \sum_{d \in D} P_{d,t}^{ind,S} \ \forall t \tag{4.42}$$

Equation (4.42) enforces the market power balance. In other words, it states that the total generation of the conventional units and the total production of the wind farms must be equal to the demand of the inelastic load and the industrial consumers at any given time interval t. It is common in the literature and also in real systems, not to enforce the network constraints in the day-ahead formulation. Nonetheless, any market scheme may be implemented within the proposed formulation.

4.2.3.2 Second stage constraints

This section presents the second stage constraints of the optimization problem. These constraints involve only decision variables that do depend on a specific scenario.

4.2.3.2.1 *Generating units*

Constraints (4.43)-(4.50) are related to the operation of the generation side in the light of each individual scenario outcome.

$$P_{i,t,s}^{G} \geq P_{i}^{min} \cdot u_{i,t,s}^{2} \ \forall i,t,s \tag{4.43}$$

$$P_{i,t,s}^{G} \leq P_i^{max} \cdot u_{i,t,s}^{2} \ \forall i, t, s \tag{4.44}$$

$$\sum_{\tau=t-UT_i+1}^{t} y_{i,\tau,s}^{2} \leq u_{i,t,s}^{2} \ \forall i, t, s \tag{4.45}$$

$$\sum_{\tau=t-DT_i+1}^{t} z_{i,\tau,s}^{2} \leq 1 - u_{i,t,s}^{2} \ \forall i, t, s \tag{4.46}$$

$$P_{i,t,s}^{G} - P_{i,(t-1),s}^{G} \leq \Delta T \cdot RU_i \ \forall i, t, s \tag{4.47}$$

$$P_{i,(t-1),s}^{G} - P_{i,t,s}^{G} \leq \Delta T \cdot RD_i \ \forall i, t, s \tag{4.48}$$

$$y_{i,t,s}^{2} - z_{i,t,s}^{2} = u_{i,t,s}^{2} - u_{i,(t-1),s}^{2} \ \forall i, t, s \tag{4.49}$$

$$y_{i,t,s}^{2} + z_{i,t,s}^{2} \leq 1 \ \forall i, t, s \tag{4.50}$$

Minimum and maximum unit output constraints are also enforced in the second stage of the problem by (4.43) and (4.44). The minimum up and down times are imposed by (4.45) and (4.46), respectively. Similarly, (4.47) and (4.48) enforce the ramp rate limits of the generators in each individual scenario. Finally, (4.49) and (4.50) enforce the unit commitment logic in the second stage of the problem.

4.2.3.2.2 *Wind spillage limits*

$$0 \leq S_{w,t,s} \leq P_{w,t,s}^{WP} \ \forall w, t, s \tag{4.51}$$

A portion of available wind production may be spilled if it is necessary to facilitate the operation of the power system. This is enforced by (4.51).

4.2.3.2.3 *Involuntary load shedding limits*

$$0 \leq L_{j,t,s}^{shed} \leq L_{j,t} \ \forall j, t, s \tag{4.52}$$

As a last resort the ISO can decide to shed a part of the inelastic demand in order to maintain the consistency of the system. This requirement is enforced by constraint (4.52).

4.2.3.2.4 ***Industrial load constraints***

$$\sum_{t\in T} a^2_{p,g,d,t,s} = a^{max}_{p,g,d} \ \forall p, g, d, t, s \tag{4.53}$$

$$\upsilon^2_{p,g,d,t,s} \le a^2_{p,g,d,t,s} \le a^{max,h}_{p,g,d} \cdot \upsilon^2_{p,g,d,t,s} \ \forall p \in P^1_{type}, g, d, t, s \tag{4.54}$$

$$0 \le a^2_{p,g,d,t,s} \le a^{max,h}_{p,g,d} \cdot \upsilon^2_{p,g,d,t,s} \ \forall p \in P^2_{type}, g, d, t, s \tag{4.55}$$

$$\sum_{\tau=t-T^{c,max}_{p,g,d}+1}^{t} a^2_{p,g,d,\tau,s} \ge a^{max}_{p,g,d} \cdot \zeta^2_{p,g,d,(t+1),s} \ \forall p, g, d, t, s \tag{4.56}$$

$$a^2_{p,g,d,\tau,s} \ge \zeta^2_{p,g,d,(t+1),s} \ \forall p, g, d, t, s \tag{4.57}$$

$$\psi^2_{p,g,d,t,s} \le a^2_{p,g,d,t,s} \ \forall p, g, d, t, s \tag{4.58}$$

$$\sum_{t\in T} \zeta^2_{p,g,d,t,s} = 1 \ \forall p, g, d, s \tag{4.59}$$

$$\sum_{t\in T} \psi^2_{p,g,d,t,s} = 1 \ \forall p, g, d, s \tag{4.60}$$

$$\psi^2_{p,g,d,t,s} + \zeta^2_{p,g,d,t,s} \le 1 \ \forall p, g, d, t, s \tag{4.61}$$

$$\psi^2_{p,g,d,t,s} - \zeta^2_{p,g,d,t,s} = \upsilon^2_{p,g,d,t,s} - \upsilon^2_{p,g,d,(t-1),s} \ \forall p, g, d, t, s \tag{4.62}$$

$$\psi^2_{p,g,d,t,s} \le \sum_{\tau=t-T^{g,max}_{(p-1),g,d}}^{t-T^{g,min}_{(p-1),g,d}} \zeta^2_{(p-1),g,d,\tau,s} \ \forall p \in \{P|p>1\}, g, d, t \tag{4.63}$$

Constraints (4.53)-(4.63) are the stochastic counterparts of the relevant industrial load constraints presented and explained in the first stage of the problem.

4.2.3.2.5 ***Network constraints***

$$\begin{aligned} &\sum_{i\in N_n^i} P_{i,t,s}^{G} + \sum_{w\in N_n^w} (P_{i,t,s}^{WP} - S_{w,t,s}) + \sum_{n\in B_b^{nn}} f_{b,t,s} \\ &= \sum_{n\in B_b^n} f_{b,t,s} + \sum_{j\in N_n^j} (L_{j,t} - L_{j,t,s}^{shed}) + \sum_{d\in D_n^d} P_{d,t,s}^{ind,C} \\ &\qquad\qquad\qquad\qquad \forall b,(n,nn)\in B(n,nn),t,s \end{aligned} \tag{4.64}$$

$$f_{b,t,s} = B_{b,n}\cdot(\delta_{n,t,s} - \delta_{nn,t,s})\ \forall b,(n,nn)\in B(n,nn),t,s \tag{4.65}$$

$$-f_b^{max} \le f_{b,t,s} \le f_b^{max}\ \forall b,t,s \tag{4.66}$$

$$-\pi \le \delta_{n,t,s} \le \pi\ \forall n,t,s \tag{4.67}$$

$$\delta_{n,t,s} = 0\ \forall t,s,if n \equiv ref \tag{4.68}$$

In the second stage of the problem, the network constraints are taken into account using a lossless DC power flow formulation. More specifically, equation (4.64) stands for the power balance at each node of the system which states that the total power generated at each node by conventional units, the net production of wind farms plus the power injection from incoming transmission lines must equal the total net consumption of inelastic and industrial loads as well as the power that is injected to outgoing transmission lines. The flow over a transmission line is defined by (4.65), while a power flow limit is set according to the maximum capacity of a transmission line by (4.66). Finally, (4.67) and (4.68) state that the voltage angles must be bounded between $-\pi$ and π and that at the slack bus the voltage angle must be specified, respectively.

4.2.3.3 Linking constraints

The set of linking constraints bridges the day-ahead market decisions and the decisions made based on the outcome of each plausible scenario. As a result, the constraints pertaining this stage involve both scenario independent and scenario dependent decision variables. Linking constraints enforce the fact that reserves in the actual operation of the power system are no longer a stand-by capacity, but are materialized as energy.

4.2.3.3.1 *Generation side reserve deployment*

$$P^G_{i,t,s} = P^S_{i,t} + r^U_{i,t,s} + r^{NS}_{i,t,s} - r^D_{i,t,s} \ \forall i,t,s \tag{4.69}$$

Constraint (4.69) involves the scheduled day-ahead unit outputs with the scenario-dependent deployed power.

$$0 \leq r^U_{i,t,s} \leq R^U_{i,t} \ \forall i,t,s \tag{4.70}$$

$$0 \leq r^{NS}_{i,t,s} \leq R^{NS}_{i,t} \ \forall i,t,s \tag{4.71}$$

$$0 \leq r^D_{i,t,s} \leq R^D_{i,t} \ \forall i,t,s \tag{4.72}$$

$$r^U_{i,t,s} + r^{NS}_{i,t,s} - r^D_{i,t,s} = \sum_{f \in F^i} r^G_{i,t,s,f} \ \forall i,t,s \tag{4.73}$$

$$r^G_{i,t,s,f} \leq B_{i,f,t} - b_{i,f,t} \ \forall i,f,t,s \tag{4.74}$$

$$r^G_{i,t,s,f} \geq -b_{i,f,t} \ \forall i,f,t,s \tag{4.75}$$

Constraints (4.70)-(4.72) stipulate that the deployed reserves cannot be greater than their respective scheduled values. Constraints (4.73)-(4.75) decompose the deployed reserves into energy blocks.

4.2.3.3.2 *Industrial load reserve deployment*

$$P^{ind,C}_{d,t,s} = D^{min}_{d,t} + \sum_{g \in G} \sum_{p \in P} P^{pro,C}_{p,g,d,t,s} \ \forall d,t,s \tag{4.76}$$

$$P^{pro,C}_{p,g,d,t,s} = P^{pro,S}_{p,g,d,t} + r^{D,pro}_{p,g,d,t,s} - r^{U,pro}_{p,g,d,t,s} + r^{NS,pro}_{p,g,d,t,s} \ \forall p,g,d,t,s \tag{4.77}$$

Constraints (4.76) and (4.77) determine the actual consumption of the industrial load. Especially, (4.76) sums all the consumptions of the individual processes up to the actual consumption of the industry. The power of each process is reallocated through the determination of reserves by (4.77).

$$r^{U,pro}_{p,g,d,t,s} = a^{up,rt}_{p,g,d,t,s} \cdot P^{line}_{p,g,d} \; \forall p, g, d, t, s \tag{4.78}$$

$$0 \leq r^{U,pro}_{p,g,d,t,s} \leq R^{U,pro}_{p,g,d,t} \; \forall p, g, d, t, s \tag{4.79}$$

$$0 \leq a^{up,rt}_{p,g,d,t,s} \leq a^{up}_{p,g,d,t} \; \forall p, g, d, t, s \tag{4.80}$$

$$r^{D,pro}_{p,g,d,t,s} = a^{down,rt}_{p,g,d,t,s} \cdot P^{line}_{p,g,d} \; \forall p, g, d, t, s \tag{4.81}$$

$$0 \leq r^{D,pro}_{p,g,d,t,s} \leq R^{D,pro}_{p,g,d,t} \; \forall p, g, d, t, s \tag{4.82}$$

$$0 \leq a^{down,rt}_{p,g,d,t,s} \leq a^{down}_{p,g,d,t} \; \forall p, g, d, t, s \tag{4.83}$$

$$r^{NS,pro}_{p,g,d,t,s} = a^{ns,rt}_{p,g,d,t,s} \cdot P^{line}_{p,g,d} \; \forall p, g, d, t, s \tag{4.84}$$

$$0 \leq r^{NS,pro}_{p,g,d,t,s} \leq R^{NS,pro}_{p,g,d,t} \; \forall p, g, d, t, s \tag{4.85}$$

$$0 \leq a^{ns,rt}_{p,g,d,t,s} \leq a^{ns}_{p,g,d,t} \; \forall p, g, d, t, s \tag{4.86}$$

The determination of the reserves provided by the reallocation of the energy needs of the processes is given by constraints (4.78)-(4.86). The rationale followed is similar to the reserve determination for generating units.

4.2.4 Compact formulation

In this Section, the optimization problems that have to be solved are compactly presented. Depending on whether the ISO is willing to adopt a risk averse behavior or not, the optimization problems that have to be solved are slightly different. The risk neutral optimization problem is expressed by (4.87) while the risk averse optimization problem is formulated by (4.88).

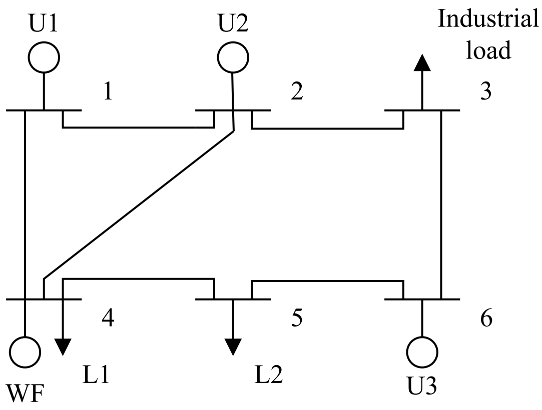

Figure 4.3: Topology of the 6-bus system

$$\begin{aligned} &\min \ (4.1) \\ &s.t. \ (4.6) - (4.86) \end{aligned} \tag{4.87}$$

$$\begin{aligned} &\min \ (4.2) \\ &s.t. \ (4.3) - (4.86) \end{aligned} \tag{4.88}$$

4.3 Case Studies

4.3.1 Illustrative example

The proposed methodology is firstly applied on an illustrative 6-bus system that is displayed in Fig. 4.3. The characteristics of the transmission system are provided in Table 4.1. The sample system consists of three conventional generators, a wind farm with installed capacity of 100 MW, two inelastic loads and an industrial customer. The technical and economic characteristics of the generators are presented in Tables 4.2 and 4.3, respectively. Spinning reserves must be fully available in 15 minutes, while the non spinning reserves in 30 minutes. The cost of providing spinning and non spinning reserves from the generating units is equal to 20% and 10% of the most expensive power block, respectively. Three wind power generation scenarios (Low, Moderate and High) that are generated according to the methodology presented in Appendix B are considered with probabilities of occurrence 54.29%, 30% and 15.71%. Note that the wind spillage cost and the involuntary load shedding cost are considered equal to 1000 €/MWh. The three wind power generation scenarios are presented in Fig. 4.4. The total inelastic load is presented in Table 4.4 and is equally divided between the loads located at buses 4 and 5.

The industrial load consists of a minimum non dispatchable portion and dispatchable processes that are originally scheduled as in Table 4.4. The dispatchable processes are rendered available to be scheduled by the ISO according to their technical characteristics that are collected in Table 4.5. As it can be seen, there are three groups of processes. The first groups contains an inflexible processes (GR1|PRO1) and a continuous flexible process (GR1|PRO2). Furthermore, the second process of this group should start as soon as the first one finishes. The second group comprises a

Table 4.1: Characteristics of the transmission lines (6-bus system)

Line No.	From Bus	To Bus	X (pu)	Flow limit (MW)
1	1	2	0.170	140
2	1	4	0.258	110
3	2	3	0.037	150
4	2	4	0.197	140
5	3	6	0.018	130
6	4	5	0.037	50
7	5	6	0.140	140

totally flexible process (GR2|PRO1). The third group contains two continuous flexible processes (GR3|PRO1 and GR3|PRO2) and the time interval between the end of the first and the beginning of the second can vary from two to five hours.

Note that the industrial load provides all types of services at zero cost. This implies that it makes no difference when the industry receives the energy to accomplish its deferrable processes as long as the total energy required is provided and also serves for the illustrative purposes of this test case.

Two cases are investigated in order to demonstrate the operation of the proposed model. In the first case (base case), the industrial load does not participate in the ISO scheduling. The following operation of the dispatchable processes is considered as a baseline:

- (GR1|PRO1) consumes 4 MWh during periods 16 and 17,
- (GR1|PRO2) consumes 4 MWh during periods 16 and 17, 2 MWh during periods 18 and 19,
- (GR2|PRO1) consumes 2 MWh between periods 9 and 18,
- (GR3|PRO1) consumes 2 MWh during periods 8 and 10, 4 MWh during period 9,
- (GR3|PRO2) consumes 6 MWh during periods 13 and 14.

In the second case (C2) the processes are rendered available to the ISO for optimal scheduling and reserve procurement.

Allowing the industrial load to contribute to reserve procurement has a profound effect on the total loading of the system. Relevant results are displayed in Fig. 4.5. It can be noticed that the load peak that normally occurs during period 17 is clipped by 2.17%, while valley filling is noticed during the relatively low load periods 3-5.

In Figs. 4.6-4.9 the processes scheduling of the industrial consumer in the day-ahead market, as well as the re-scheduling in order to provide reserves in each one of the scenarios are presented.

Process (GR1|PRO1) is scheduled during periods 13 and 14 while it is committed to be rescheduled (8 MW) in order to provide non spinning reserve during periods 2 and 3 in the Low wind power generation scenario and during periods 3 and 4 in the other two scenarios. Similarly, process (GR1|PRO2) that must be initiated directly after the end of process (GR1|PRO1) provides 2 MW

Table 4.2: Technical characteristics of the generating units (6-bus system)

Unit	**U1**	**U2**	**U3**
Minimum capacity (MW)	100	10	10
Maximum capacity (MW)	220	200	50
Minimum up time (h)	4	3	1
Minimum down time (h)	4	2	1
Ramp up rate (MW/min)	0.7	0.5	0.4
Ramp down rate (MW/min)	0.8	0.6	0.4
Initial output (MW)	140	20	10
Time committed/decommitted at the beginning of the scheduling horizon (h)	+4	+3	+1

Table 4.3: Economic characteristics of the generating units (6-bus system)

Unit	**Power blocks (MW)**					**Marginal costs (€/MWh)**					**Startup cost (€)**	**Shutdown cost (€)**
	B1	**B2**	**B3**	**B4**	**B5**	**C1**	**C2**	**C3**	**C4**	**C5**		
U1	80	50	40	30	20	22.200	23.600	24.720	25.560	26.120	100	50
U2	20	25	45	50	60	23.800	24.800	26.600	28.600	31	200	40
U3	5	8	10	12	15	30	31.376	35.160	35.160	37.740	80	10

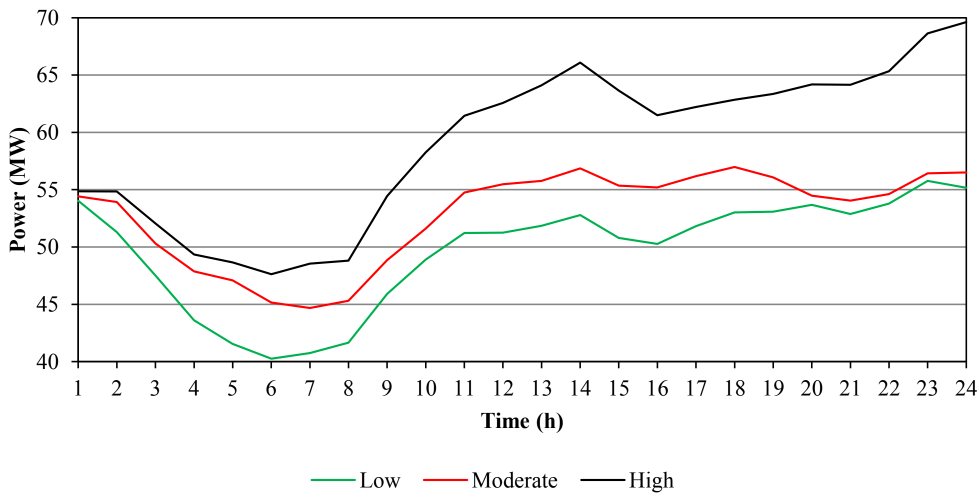

Figure 4.4: Wind power generation scenarios (6-bus system)

Table 4.4: System load (6-bus system)

Time	Inelastic load (MW)	Non dispatchable industrial load (MW)	Dispatchable industrial load (MW)
1	175.190	18	0
2	165.150	17	0
3	158.670	16	0
4	154.730	15	0
5	155.060	16	0
6	160.480	16	0
7	173.390	17	0
8	177.600	16	2
9	186.810	13	6
10	206.960	17	4
11	228.610	21	2
12	236.100	22	2
13	242.180	16	8
14	243.600	16	8
15	248.860	23	2
16	255.790	16	10
17	256	16	10
18	246.740	21	4
19	245.970	23	2
20	237.350	24	0
21	237.310	24	0
22	232.670	23	0
23	195.930	20	0
24	195.600	20	0

Table 4.5: Technical data of industrial processes (6-bus system)

		Type	Block size (MW)	Number of blocks	Maximum no. of blocks per hour	Completion time (h)	Minimum time between processes (h)	Maximum time between processes (h)
GR1	PRO1	1	2	4	2	2	0	0
	PRO2	1	2	6	2	4		
GR2	PRO1	2	2	10	10	24	-	-
GR3	PRO1	1	2	4	2	3	2	5
	PRO2	1	2	6	6	10		

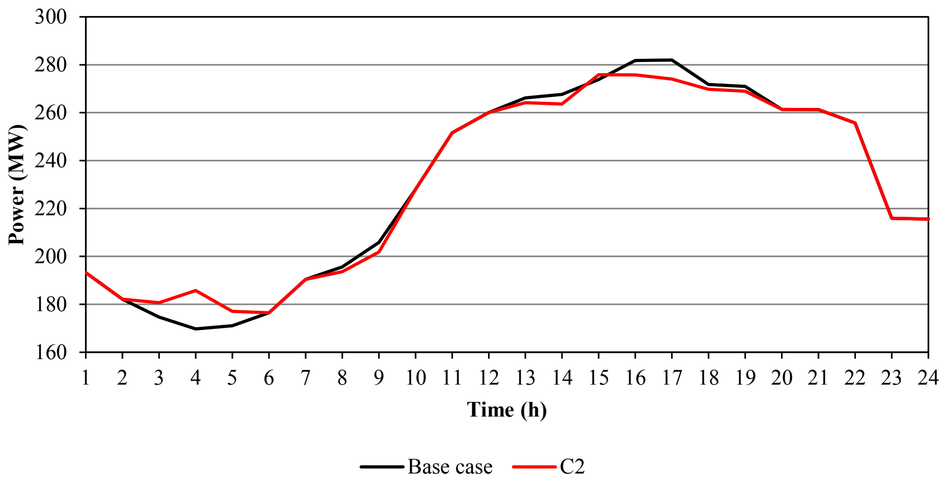

Figure 4.5: Total system load in the base case and C2

and 4 MW of non spinning reserve during periods 4, 7 and 5, 6, respectively, in the Low wind power generation scenario. Also, in the Moderate and High wind power generation scenarios this process is re-scheduled according its technical characteristics to provide the required levels of non spinning reserves.

Since the duration of (GR2|PRO1) is 24 h, it is considered that any power re-allocation constitutes up or down spinning reserve. In the day-ahead market, this process is scheduled during the low consumption periods 3-5 during which energy is scheduled from the cheapest energy blocks of the generators. This behavior is also observed for the different scenarios of wind production, noticing only negligible reserve deployment.

The third group of processes must also satisfy a sequencing requirement. Process (GR3|PRO1) must be completed within 3 hours. It is scheduled to be satisfied during periods 3-5. Thus, the re-allocation of power blocks during periods 6 and 7 is equivalent to the deployment of non spinning reserve of 8 MW. On the other hand, the load increase of 4 MW during period 2 corresponds to down spinning reserve since the load of period 3 is maintained. Finally, it is interesting to notice that the ISO is also able to exploit the freedom provided by the quite flexible time interval requirement between the two processes (between 2 h and 5 h). In the day-ahead market, (GR3|PRO2) is scheduled to begin 3 h after the (GR3|PRO1) is accomplished. In the Low wind power generation scenario this time interval is extended to 4 h. In the Moderate and High wind power generation scenarios this time interval is reduced to 2 h.

Finally, in order to demonstrate how the industrial load may contribute towards accommodating more wind power generation, the power of the dispatchable industrial processes is plotted against the wind power scheduled in the day-ahead market and the outcome of the Moderate scenario. The relevant results are portrayed in Fig. 4.10. It is evident that the load increase occurs during periods during which the actual wind power generation would be higher than the wind power generation that was considered in the day-ahead market. As a result, more available wind power may be exploited while avoiding ramping down conventional generators.

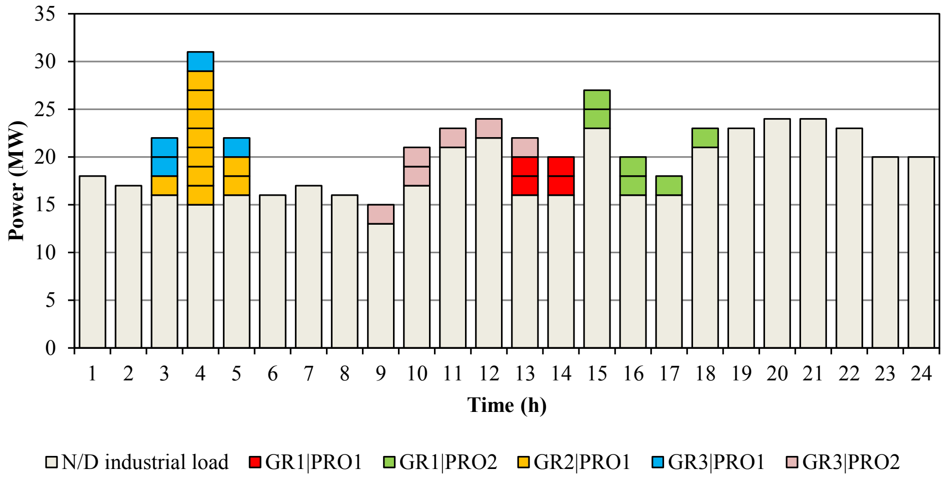

Figure 4.6: Scheduled industrial load

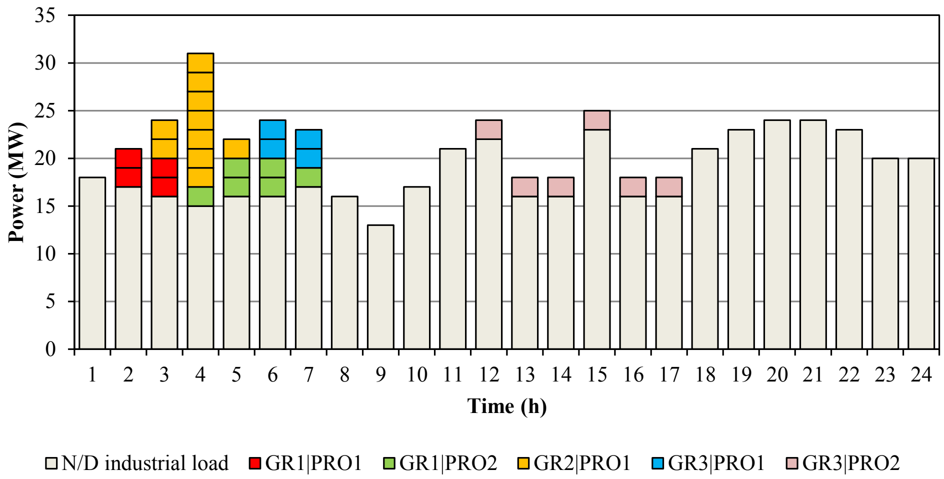

Figure 4.7: Industrial load in Low wind production scenario

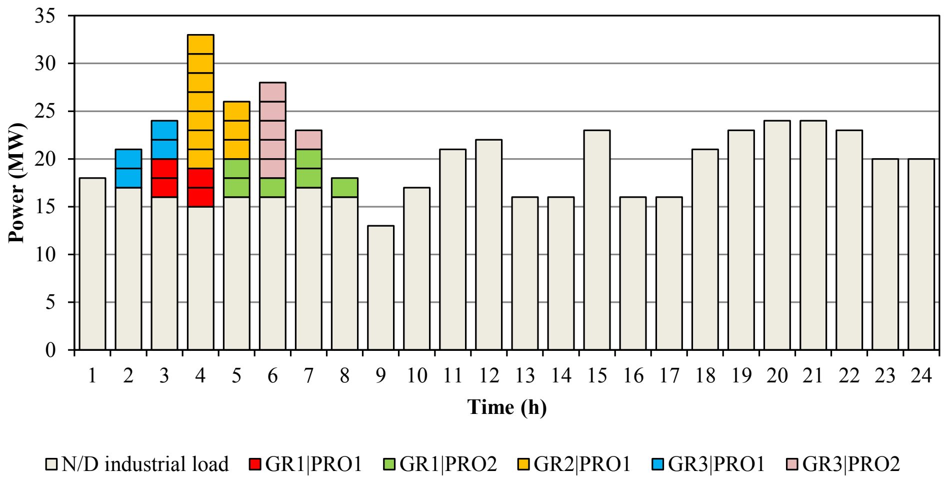

Figure 4.8: Industrial load in Moderate wind production scenario

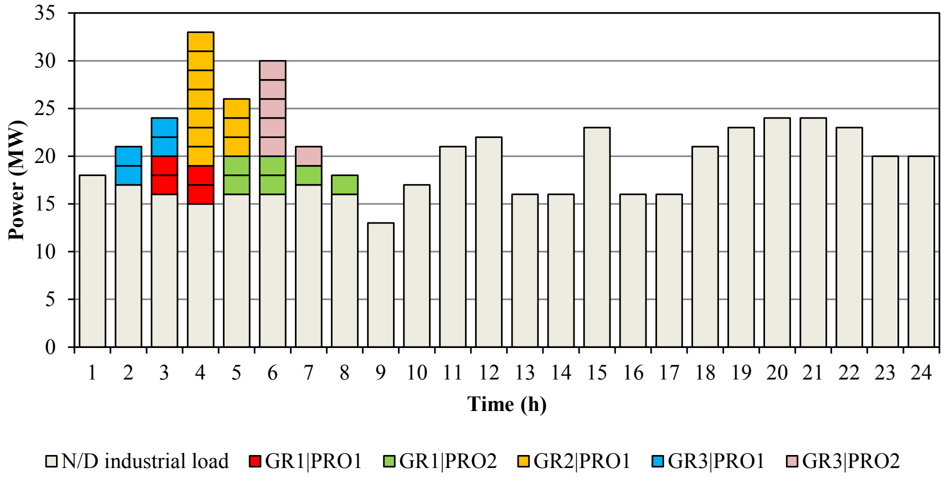

Figure 4.9: Industrial load in High wind production scenario

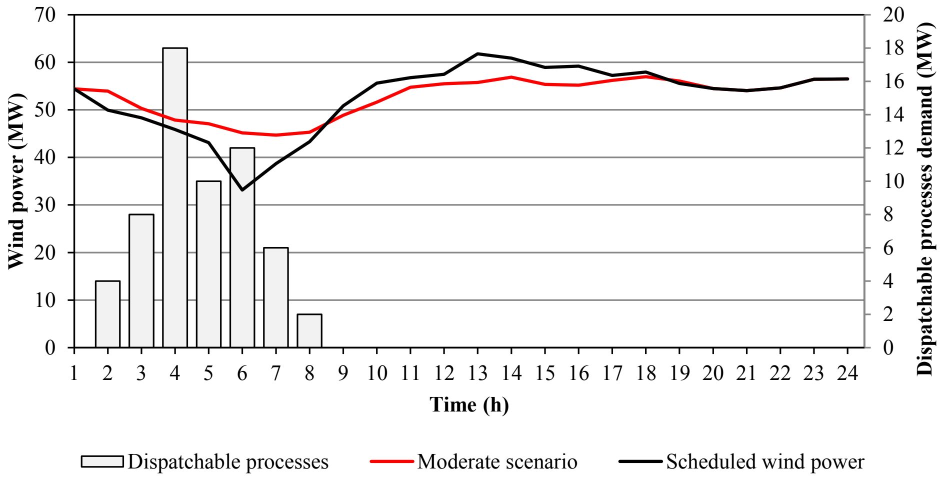

Figure 4.10: Industrial load reallocation and wind power generation in Moderate scenario

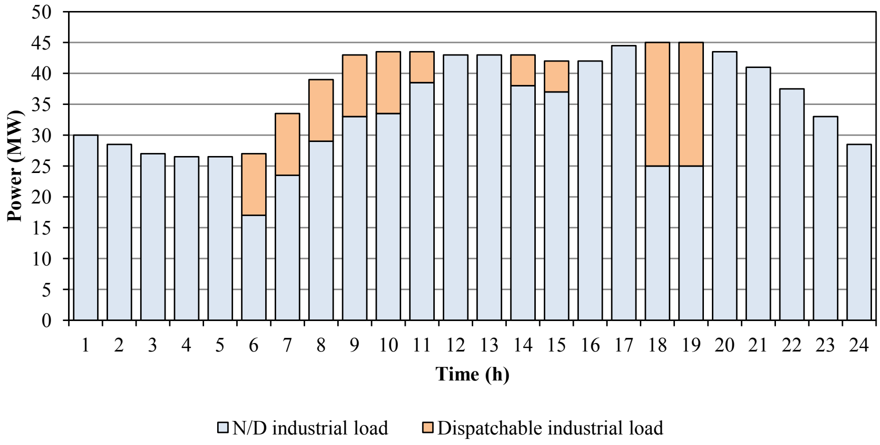

Figure 4.11: Baseline industrial load consumption (bus 2)

4.3.2 Application on a 24-bus system - Risk neutral problem

4.3.2.1 Case study description

In this section, the risk neutral mathematical programming model expressed by (4.87) is tested on a modified version of the IEEE Reliability Test System. Complete data regarding the technical and economic characteristics of the system may be found in Appendix C, Section C.3. Six wind farms are added to the system located at buses 3,5,6,16,21 and 23 with installed capacity 20 MW, 15 MW, 35 MW, 45 MW, 10 MW and 25 MW, respectively. To account for the wind power generation stochasticity, 15 non equiprobable scenarios are generated for the total wind production according to the methodology described in Appendix B which are divided to the wind farms according to their installed capacity.

Furthermore, the half of the load connected at bus 2 which stands for approximately 3.4% of the total system demand is considered to correspond to industrial consumers. In total, the daily energy requirement of the industrial consumption is 899 MWh, while 11.68% of this load is assumed to represent dispatchable processes. The baseline consumption of the industrial consumer at bus 2 is portrayed in Fig. 4.11, in which the non dispatchable (N/D) and the dispatchable consumption are distinguished. Also, the half of the load located at bus 19 which represents 6.74% of the total system loading is associated with industrial consumption. The daily energy requirement of the industrial consumption at bus 19 is 1690 MWh of which 400 MW are considered dispatchable. The baseline consumption of the consumer at bus 19 is displayed in Fig. 4.12

Regarding the economic compensation of the industrial consumers for providing flexibility as regards the scheduling of their energy production as well as reserve services, the following simplifications are adopted: since the total energy required by the industrial customers to accomplish their purposes is guaranteed to be provided during the day, the utility of this type of load may be considered equal to zero, since theoretically, no economic loss occurs. Following the same rationale, the economic compensation of the industrial consumer for providing reserve services is considered to be also zero. Besides, according to the relevant discussion in Chapter 2 it is common practice to compensate the demand side resources based on their real-time performance with respect to their baseline consumption, motivating them to enroll to different programs through attractive

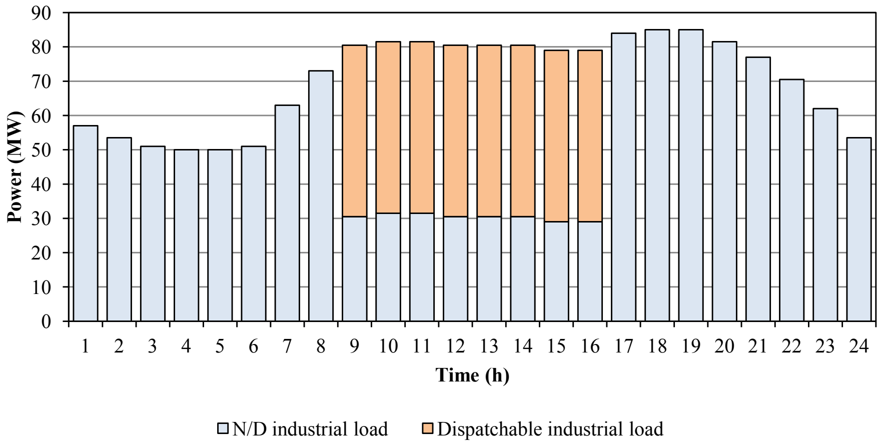

Figure 4.12: Baseline industrial load consumption (bus 19)

billing plans, fixed payments and other incentives, e.g., exclusion from involuntary load shedding (avoidance of production loss). On the other hand, as a last resort, the ISO may curtail a part of the inelastic load under a high penalty (1000 €/MWh).

Finally, all the generators except for the units at bus 22 (must-run at constant output) can participate in spinning up and down reserves that must be fully available in 15 minutes. Note also that in order to reduce the number of binary variables that are related to controlling the commitment status of the generators, units of the same type that are connected to the same bus are grouped together and are controlled as a single unit. The proposed formulation explicitly allows units that are off-line to be committed in the day-ahead to alter their status and provide non spinning reserves. However, given the fact that the equivalent grouped units are characterized by relatively high maximum output levels and therefore, there is adequate spinning reserve capacity and that contingencies and significant wind ramping events are out of the scope of the study, non-spinning reserves are not deemed an option for the purposes of this case study [1].

4.3.2.2 Results & discussion

4.3.2.2.1 *Base case*

In the base case only the generation side may provide reserves in order to balance the plausible fluctuations of wind power generation. Wind power generation is considered a free source of energy; however, it comes with the cost of having to balance its volatility through reserves that may represent an important economic burden for the ISO. This implies that the ISO would integrate wind generation as long as the cost of reserves and the cost of altering the commitment status of conventional units do not overshadow the reduction in energy cost. This would be the case for an ISO that strictly considers the operation of the power system from the economical point of view. Nevertheless, environmental targets such as the reduction in carbon emissions or political reasons (e.g., promoting RES) may force an ISO to accept as much wind power generation as possible. As it has been stated before, the wind spillage cost is an artificial cost that represents the willingness of an ISO to promote the integration of wind power generation and has a profound impact on the economic operation of the power system. In order to obtain unbiased results, the wind spillage cost

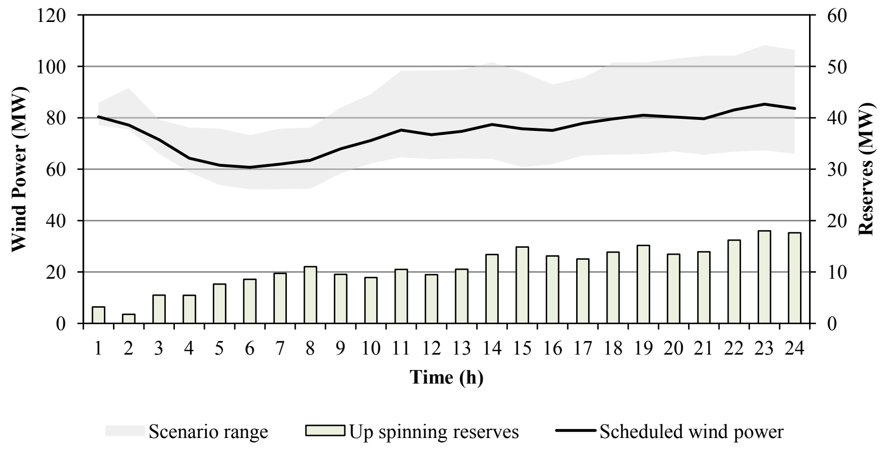

Figure 4.13: Scheduled wind power and generation side reserves

is initially considered equal to 0 €/MWh and the ISO schedules the economically optimal amount of wind generation.

Neglecting the wind spillage cost, the scheduled energy production from the wind farms stands for 3.37% of the total energy requirements of the system load during the day. The scheduled hourly wind power generation together with the scheduled generation side reserves are depicted in Fig. 4.13. It is interesting to notice that only up spinning reserves are scheduled, exclusively from units 8 and 9 connected at buses 18 and 21, respectively. This is due to the fact that these units offer the least cost energy and reserve services and therefore, it is more economical to operate these units close to their maximum output both in the scenario independent day-ahead scheduling and in each individual scenario. Another point that needs to be denoted is the fact that the amount of up spinning reserves scheduled in each period is exactly equal to the amount required to balance the production deficit that results from the occurrence of the scenario with the minimum wind generation during that period.

It may be noticed that relatively little wind power energy is scheduled to be integrated in the day-ahead scheduling when wind power generation is not promoted by the policy of the ISO. Furthermore, the fact that only up spinning reserves are scheduled implies that significant amounts of available wind power generation will be curtailed in case that a scenario with high wind generation occurs in practice. For this reason and in order to examine the effect of the wind spillage cost, further simulations in which the wind spillage cost is considered equal to 10 €/MWh and 100 €/MWh are performed.

The effect on the day-ahead energy and reserve cost is displayed in Fig. 4.14. Evidently, as the wind spillage cost increases, a decrease in the energy cost is noticed since more wind power generation is scheduled (Fig. 4.15) and thus, less production is requested by the conventional units. In the same time, more reserves must be procured in order to balance plausible shortages in wind power generation. Unlike in the case of facing more wind than scheduled in which reserves are not necessary in order to maintain the balance of the system (since curtailment of excessive wind is possible), shortages must be faced through deploying upward reserves (or involuntary load shedding), irrespective of the probability of occurrence of such scenarios. The wind energy integrated in the day-ahead scheduling increases to 3.57% and 4.17% for a wind spillage cost equal

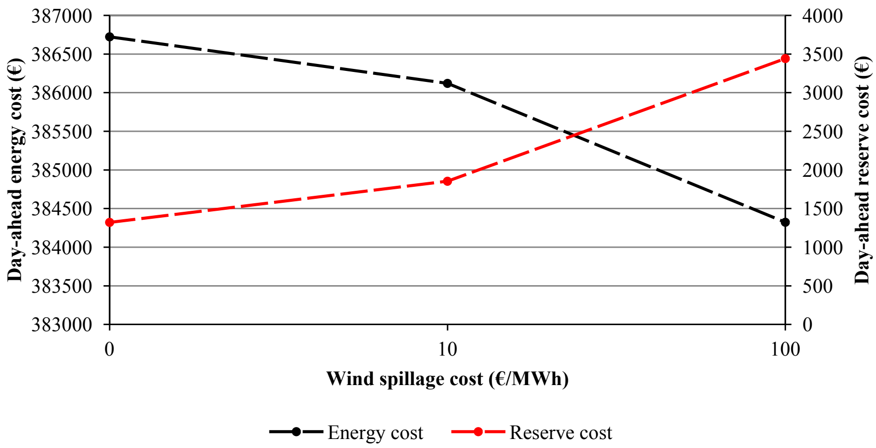

Figure 4.14: Day-ahead energy and reserve cost for different values of wind spillage cost

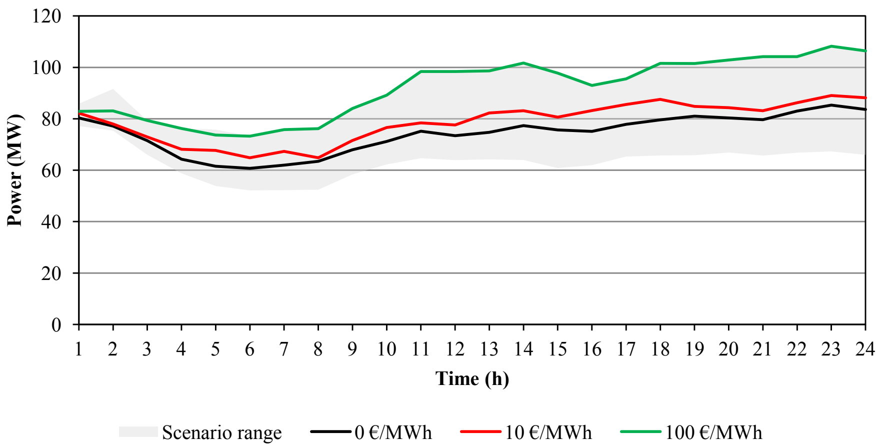

Figure 4.15: Day-ahead wind power scheduling for different values of wind spillage cost

to 10 €/MWh and 100 €/MWh respectively, while the total up spinning reserves scheduled for these cases balance exactly the scenario with the minimum wind generation.

To compare the amount of available wind production spilled in each scenario, the metric (4.89) is introduced that stands for the ratio of the amount of the wind energy spilled over the total wind energy available in each individual scenario from all the wind farms.

$$\%\ available\ wind\ spilled(s) = \sum_{w \in W} \sum_{t \in T} \frac{S_{w,t,s}}{P^{WP}_{w,t,s}} \cdot 100\%\ \forall s \tag{4.89}$$

The relevant results for the different values of wind spillage cost are illustrated in Fig. 4.16 from which it may be noticed that strictly less available wind is spilled in each individual scenario. It is also worth pointing out that for a wind spillage cost of 100 €/MWh small amounts of wind generation are spilled in scenarios 7 and 8. Scenario 7 has a very low probability of occurrence (1.428%) and presents the maximum wind power values in periods 1-3. On the other other hand, scenario 8 has the highest probability of occurrence among the scenarios (15.714%); however, only a small amount of the available (and relatively high) wind generation in this scenario is curtailed

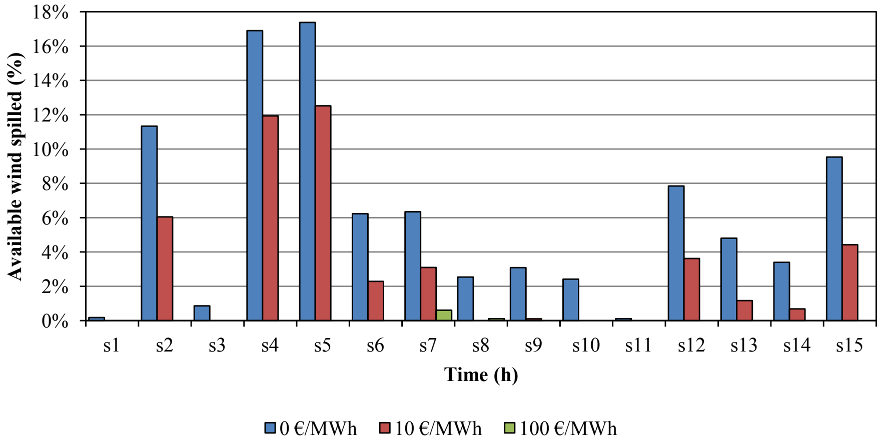

Figure 4.16: Wind spillage in individual scenarios for different values of wind spillage cost

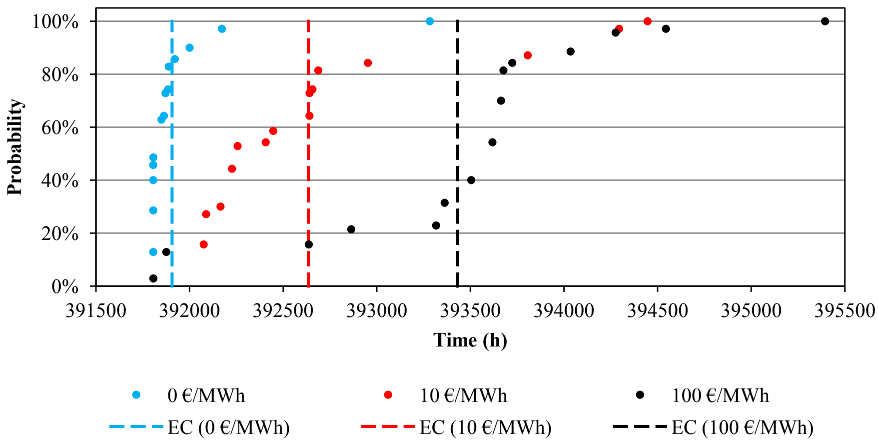

Figure 4.17: Cumulative distribution function of cost in different scenarios

during period 1. Thus, these curtailments are linked to a negligible wind spillage cost (either due to small probability of occurrence, or because of small amount of curtailment).

Furthermore, the effect of the different values of wind spillage cost on the individual scenario cost distribution are demonstrated through the cumulative distribution functions that are comparatively displayed in Fig. 4.17, while the relevant characteristics are presented in Table 4.6. Apart from the evident increase in the expected cost of the system, one may notice that other characteristics of the cost distribution deteriorate by forcing the ISO to accept more wind than the economically optimal levels. The standard deviation of the cost has increased by 150% while the probability of incurring costs higher than the expected cost has raised from 14.285% when wind curtailment is not penalized, to 60% when the wind spillage cost is set to 100 €/MWh. Also, the value of the worst case cost with respect to the expected cost increases with the increase of the wind spillage cost. As a result, the penalization of wind power generation curtailments as a measure alone may not only lead to suboptimal decisions for the ISO, but also riskier.

Table 4.6: Characteristics of the scenario cost distribution

Wind spillage cost (€/MWh)	**0**	**10**	**100**
Expected cost (€)	391907.132	392634.276	393430.665
Standard deviation (€)	376.051	774.482	940.869
Probability of incurring cost greater than expected (%)	14.285	35.714	60
Worst case cost (% higher than expected)	0.349	0.461	0.500

4.3.2.2.2 *Flexible industrial load*

In order to demonstrate the potential benefits that flexible industrial consumers may offer to the operation of the power system, a base case was firstly analyzed in which the industrial consumption was considered inelastic. In this section different cases are examined in which a portion of industrial load is dispatchable. Note that the proposed model may cover a range of different industrial processes. However, for illustrative purposes only several characteristic types of processes and their parameters are examined. The characteristics of the flexible processes in each of the cases are listed in Table 4.7. In cases C1-A to C1-C the dispatchable portion of the industrial load is considered to be of the totally flexible type and allocated in discrete blocks of different sizes, while in cases C2-A to C2-C the maximum amount of dispatchable consumption that may be scheduled during a period is limited to 25 MW and in cases C3-A to C3-C the this limit is further reduced to 20 MW. Finally, in C4 the dispatchable portion of the industrial load is rendered available into a number of flexible and inflexible processes with different characteristics. Note that the processes in C4 are temporarily independent. Furthermore, in the aforementioned test cases, the wind spillage cost is considered equal to 10 €/MWh.

Economic results concerning the different test cases are presented in Table 4.8. It may be noticed that in all the cases the day-ahead energy production cost is reduced in comparison with the base case (Table 4.6). The relatively lowest costs are noticed for the cases C1-A to C1-C which present the most flexible characteristics (the maximum allowed load allocation is 50 MW). Furthermore, in all the cases that consider the flexible industrial load the cost of scheduling reserves by the generation side is reduced since cheaper reserves may be procured by the demand side. It is important to notice that minimum energy cost is noticed in C1-C in which the maximum amount of reserves among the test cases is procured from both the generation and the demand side. This implies that the cost reduction is achieved because of optimally re-scheduling the load and integrating more wind power generation (higher level of reserves). Finally, C4 presents the minimum expected cost. This is due to the fact that this case is linked to higher levels of wind curtailments since it also contains the most rigid process types that cannot be easily deployed to accommodate the continuous nature of wind power uncertainty.

Furthermore, regarding the scheduling of the industrial loads, in all the cases the dispatchable load is shifted from the peak periods to the relatively low consumption periods. For instance, the scheduled load and reserves of the industrial loads located at buses 2 and 19 in C1-C are illustrated in Figs. 4.18 and 4.19.

Table 4.7: Technical characteristics of dispatchable processes

Case	Industrial load	Group	Process	Type	Block size (MW)	Number of blocks	Maximum no. of blocks per hour	Completion time (h)	Initial period allocation
C1-A	bus 2	1	1	2	0.5	210	100	24	baseline
	bus 19	1	1	2	0.5	800	100	24	baseline
C1-B	bus 2	1	1	2	1	105	50	24	baseline
	bus 19	1	1	2	1	400	50	24	baseline
C1-C	bus 2	1	1	2	5	21	10	24	baseline
	bus 19	1	1	2	5	80	10	24	baseline
C2-A	bus 2	1	1	2	0.5	210	50	24	baseline
	bus 19	1	1	2	0.5	800	50	24	baseline
C2-B	bus 2	1	1	2	1	105	25	24	baseline
	bus 19	1	1	2	1	400	25	24	baseline
C2-C	bus 2	1	1	2	5	21	5	24	baseline
	bus 19	1	1	2	5	80	5	24	baseline
C3-A	bus 2	1	1	2	0.1	210	40	24	baseline
	bus 19	1	1	2	0.1	800	40	24	baseline
C3-B	bus 2	1	1	2	1	105	20	24	baseline
	bus 19	1	1	2	1	400	20	24	baseline
C3-C	bus 2	1	1	2	5	21	4	24	baseline
	bus 19	1	1	2	5	80	4	24	baseline
C4	bus 2	1	1	1	10	2	1	2	6-7
		2	1	1	10	2	1	2	8-9
		3	1	1	5	3	3	3	10-11
		4	1	1	5	2	3	2	14-15
		5	1	1	5	8	4	2	18-19
	bus 19	1	1	2	50	8	1	10	9-16

Table 4.8: Costs for the different cases

Case	Energy cost (€)	Reserve cost (€)	Load reserve cost (€)	Expected cost (€)
C1-A	383017.030	1683.590	11.700	392634.276
C1-B	383013.111	1687.052	11.600	389308.648
C1-C	382907.239	1780.578	15.500	389320.194
C2-A	383849.605	1687.259	11.300	389328.792
C2-B	383833.103	1684.031	11.800	390132.345
C2-C	383706.106	1816.385	14.500	390145.432
C3-A	384109.569	1760.566	11.300	390141.470
C3-B	384096.582	1773.934	10.300	390485.162
C3-C	384045.952	1816.513	11	390485.572
C4	383642.395	1258.275	5.500	390496.059

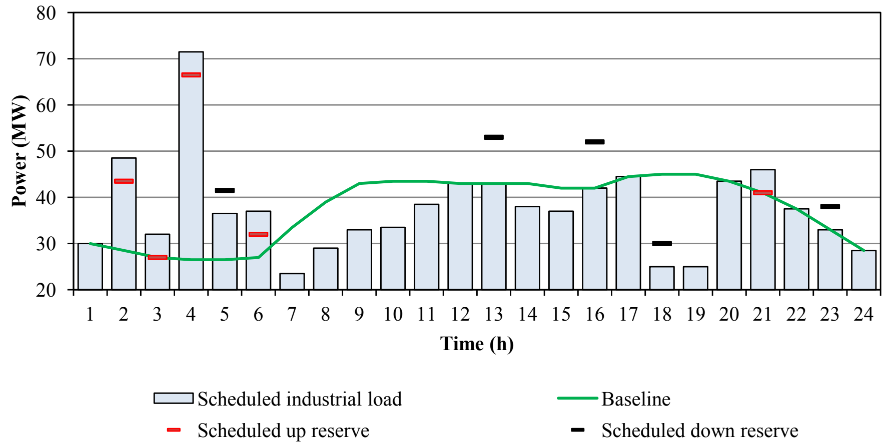

Figure 4.18: Scheduled industrial load and reserves for industrial load at bus 2 (C1-C)

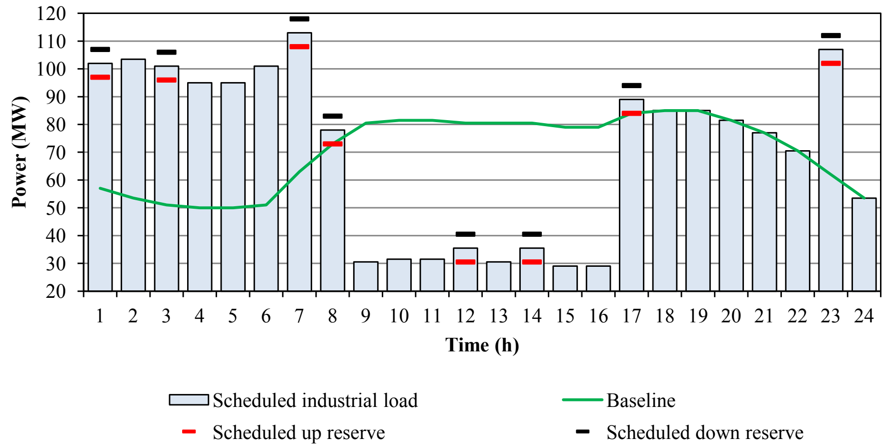

Figure 4.19: Scheduled industrial load and reserves for industrial load at bus 19 (C1-C)

Finally, to clarify the way in which reserves are scheduled when the dispatchable industrial load is considered, a numerical example is presented. For the case C1-A in period 23 the scheduled production of the conventional units is 1899.475 MW while 19.226 MW of up spinning reserve are scheduled. The wind power generation scheduled is 84.525 MW. Moreover, the scheduled industrial load is 143 MW and 4.5 MW of down reserve (load increase) and 3 MW of up reserve (load decrease) are scheduled by the two industrial consumers for the same period. The scheduled reserves represent the maximum amount of reserves (consumption and generation alterations) that may be deployed in any of the considered scenarios. For instance, in scenario 11 in period 23 the available wind power generation is 67.298 MW. Since it is less than the scheduled production from the wind farms, naturally no wind curtailment occurs. The wind power difference that must be satisfied is 17.227 MW. As a result, the generation is increased by 19.227 MW, while the industrial load is increased by 2 MW so that the generation-consumption balance is maintained.

4.3.2.2.3 *The role of industrial load in accommodating higher wind generation penetration levels*

As it was previously discussed, by enforcing a penalty for the curtailment of available wind power generation the ISO is forced to integrate more wind power in the system. This results into lower day-ahead energy production cost on the expense of increasing the cost of scheduled reserves in order to balance the plausible changes in wind power production. The cost of procuring reserves is expected to increase as the level of wind power generation penetration in the system increases. In this section the benefit of integrating flexible demand side resources when it comes to accommodating higher levels of uncertain wind power generation is demonstrated.

The total installed capacity in the previous cases was 150 MW which stands for 4.31% of the installed generation capacity. This represents a relatively low wind power generation penetration. In order to demonstrate the effect of the flexible industrial load in systems with higher percentages of wind penetration additional tests are performed in which the installed wind farm capacity is considered to increase to 300 MW, 600 MW and 1500 MW which represent 8.27%, 15.28%, and 31.08% of the total installed generation capacity of the system, respectively. For each level of wind power penetration the industrial load is considered both to be inflexible and flexible according to the characteristics of the load in C1-A. Also, for all the cases, the wind spillage cost is considered equal to 100 €/MWh.

The relevant results are presented in Table 4.9. Evidently, as the penetration of wind power generation increases, the day-ahead energy cost decreases since more wind power is scheduled, reaching a rate of 50% for a penetration of 31.08%. On the other hand, the cost of procuring reserves increases by more than 11 times. It may be also noticed that by incorporating demand side resources the day-ahead energy cost decreases further for two reasons: first, more free wind energy is scheduled in the day ahead and additionally, due to the peak clipping and valley filling effect that the responsive industrial consumption scheduling entails. Furthermore, the reserve cost is slightly decreased because generation side reserves are exchanged for reserve scheduling from the industrial consumers. The cost reduction is more evident as the penetration of wind power generation increases.

Table 4.9: Results for different sizes of installed wind farm capacity

Installed wind-farm capacity		Energy cost (€)	Reserve cost (€)	Load reserve cost (€)	Expected cost (€)	Standard deviation (€)
150 MW	Inflexible load	384322.523	3441.673	0	393430.666	940.869
	Flexible load	381327.205	3176.766	11.850	389873.485	896.493
300 MW	Inflexible load	358689.175	6883.346	0	373143.461	1881.739
	Flexible load	356813.897	6346.966	23.750	368403.803	1793.795
600 MW	Inflexible load	310450.586	13766.693	0	333637.211	3760.907
	Flexible load	308788.872	12689.045	47.500	328211.922	3580.214
1500 MW	Inflexible load	191980.045	39117.988	0	252339.802	14483.543
	Flexible load	190246.958	37736.922	118.200	247760.445	7931.002

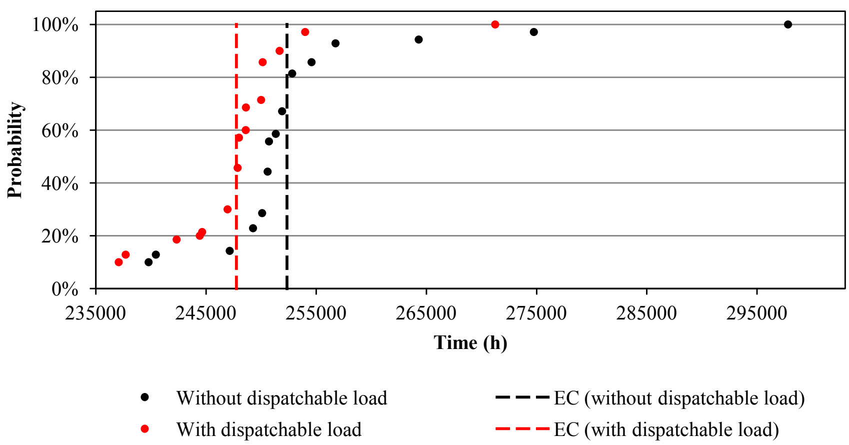

Figure 4.20: Cumulative distribution function of cost in different scenarios (1500 MW installed wind generation capacity)

It is also interesting to investigate the impact of the flexible industrial load on the cost distribution. The expected cost of the system decreases with the introduction of more wind power generation, while the standard deviation of the costs that the ISO may face in different scenarios increases. This is mainly caused because of the cost of scheduling more reserves which are the means of tackling the uncertainty of wind. The fact that the industrial load may provide reserves at lower cost in comparison with the conventional generators leads to limiting the standard deviation of the cost. For instance, the cumulative distribution functions for the case of 1500 MW installed wind generation capacity, both considering that the system load is totally inelastic and that the industrial load may offer energy and reserve services, are comparatively presented in Fig. 4.20. Note that apart from the fact that the expected cost is reduced by 4579.35 € the standard deviation of the cost is also reduced by 45.24%. From the results presented in this section, one may conclude that demand side resources may potentially constitute both a means of more economically accommodating wind power generation and limiting the risk associated with the decisions of the ISO. This will be the subject of the next section.

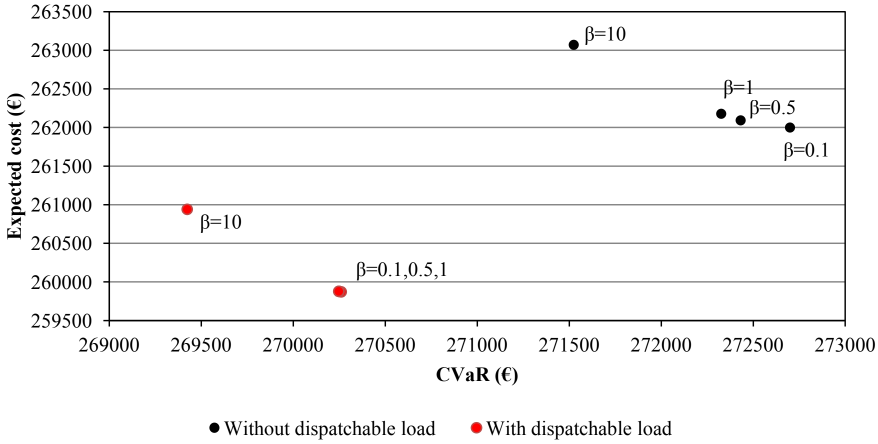

Figure 4.21: Efficienty frontiers of the examined cases

4.3.3 Application on a 24-bus system - Risk averse problem

In this section the risk-averse problem (4.88) is studied. The parameters of the test system are the same with the ones used in the previous tests. As it has been stated in Section 4.3.2.2.3 the industrial load may have an effect on the risk associated with the decisions of the ISO. Two parameters have been found to affect the distribution of the cost: the cost of reserves and the willingness of the ISO to incorporate as much wind as possible in the system, as expressed by a non-zero value of the wind spillage cost. Thus, two different tests are performed in this section, considering the total load of the system to be inelastic as well as the effect of the flexible industrial consumption which without loss of generality is considered to have the characteristics of C3-B, considering that the cost of providing reserves is 1 €/MWh. It is considered that the wind spillage cost receives a value equal to 100 €/MWh. Note that for the sake of clarity of the presented results, the installed wind capacity in the system is considered to be 1500 MW. For all the examined cases the confidence level is $\alpha = 0.9$, while the set of weights that defines the different levels of risk-aversion of the ISO is $\beta = [0.1, 0.5, 1, 10]$.

Figure 4.21 displays the efficient solutions returned for different values of β regarding the two examined cases. It may be noticed that for a higher risk-aversion level, the CVaR metric decreases while the expected cost increases. Furthermore, the impact of considering the dispatchable industrial load is straightforward: the Pareto front has shifted downwards and leftwards which implies that for the same level of risk aversion, lower values of the risk metric may be reached while achieving lower values of expected cost in the same time. Note that for $\beta = 0.1$, $\beta = 0.5$ and $\beta = 1$, the corresponding non dominated solutions present very similar values.

In order to reveal the mechanism of controlling the efficient trade-offs between the expected cost and the CVaR metric, Figs. 4.22 and 4.23 that illustrate the cost of scheduling reserves from the generation side and the average available wind spilled, respectively, are presented.

In the case in which the total load of the system is considered inflexible, the day-ahead energy cost as well as the total amount of wind energy scheduled remain constant for all the levels of risk aversion at 211375 € and 18613 MWh, respectively. However, the cost of scheduling reserves from the generation side in the day-ahead market varies. For $\beta = 0.1$ and $\beta = 0.5$ the cost of reserves increases in order to avoid the curtailment of available wind generation in the scenarios (and the

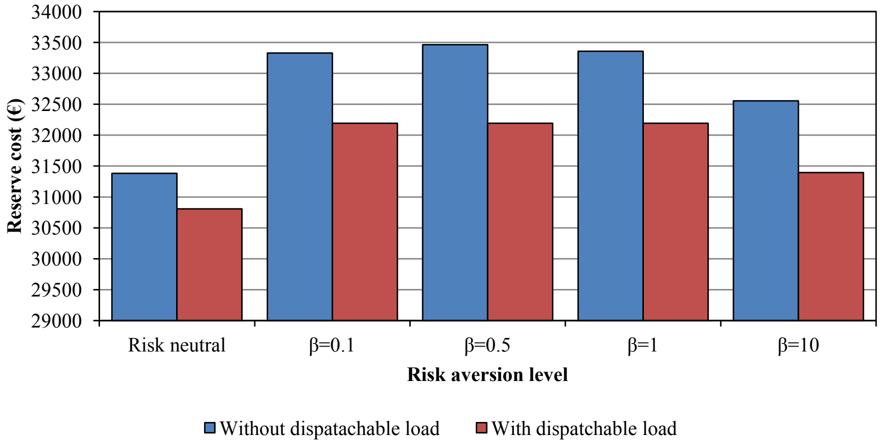

Figure 4.22: Generation side reserve cost for different levels of risk aversion

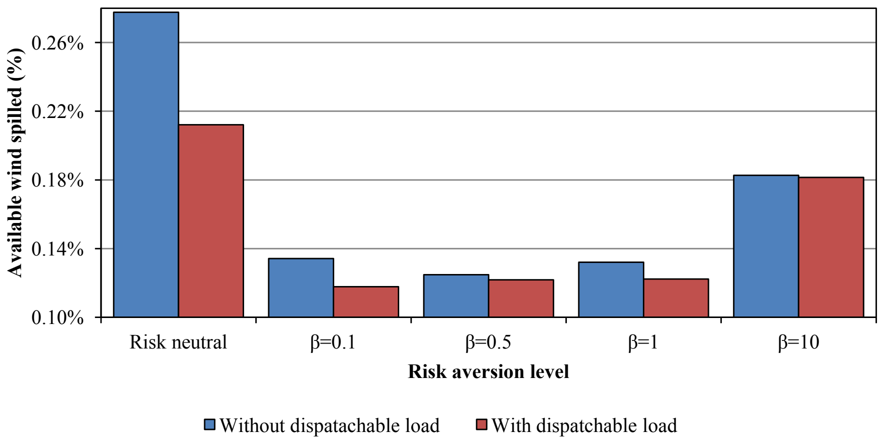

Figure 4.23: Average available wind spillage for different levels of risk aversion

Table 4.10: Computational statistics (6-bus system)

	Base case	With dispatchable industrial load
Equations	14173	28909
Continuous variables	29845	42253
Discrete variables	903	4863
Time (s)	1.46	13.9

Table 4.11: Computational statistics - risk neutral problem (24-bus system)

	C1-C
Equations	272433
Continuous variables	435490
Discrete variables	24057
Time (s)	236

corresponding penalty). Indeed, the average wind spillage is significantly less in comparison with the respective risk-neutral case. For $\beta = 1$ and $\beta = 10$ the cost of scheduling reserves in the day-ahead market slightly decreases, since it is more economical to curtail wind instead of scheduling reserves in order to accommodate the wind generation uncertainty.

In the case in which a portion of the industrial load is dispatchable, for $\beta = 0.1$ to $\beta = 1$ the day-ahead energy cost is constant at 210279 €, while for $\beta = 10$ the energy cost is reduced by 102 €. Also, in the risk neutral case the cost of scheduling reserves from the generation side from the generation side is 30806 €, while the total cost of scheduling reserves from the industrial loads is 399 €. This leads to a scheduled wind production in the day-ahead market equal to 18575.5 MWh. For higher levels of risk aversion the cost of scheduling reserves from the generation side is increased to 32192 €. Nevertheless, less demand side reserves are scheduled which leads to increased average wind curtailment. For the highest level of risk aversion ($\beta = 10$) the maximum wind spillage is noticed. This is due to reducing the total reserve scheduling cost by 824.5 €. Finally, it is important to notice that for all the levels of risk aversion, the average available wind spilled is less when the dispatchable industrial load is considered.

4.3.4 Computational statistics

All the simulations are performed on a workstation with 256 GB of RAM memory, employing two 16-core Intel Xeon processors clocking at 3.10 GHz running on a 64-bit windows distribution. The maximum allowed relative optimality gap is set to $10^{-4}\%$.

Indicative results from the simulations presented in this chapter are presented in Tables 4.10-4.12. It may be noticed that the simulations on the 6-bus system are trivial from the perspective of the computational burden. On the other hand, the 24-bus system is characterized by an increased number of constraints and variables, especially discrete. As a result, the computational time required to solve these cases increases. The highest computational times are noticed in the case of the risk averse problems. Nevertheless, the computational time in all the cases is deemed acceptable.

Table 4.12: Computational statistics - risk averse problem (24-bus system)

	With dispatchable industrial load
Equations	272449
Continuous variables	488072
Discrete variables	26352
Time (s)	423

4.4 Chapter Conclusions

In this chapter a two-stage stochastic joint energy and reserve market structure that incorporates a responsive industrial load capable of rendering a portion of its demand to be optimally scheduled by the ISO as well as to provide reserves by re-allocating its consumption was presented. The proposed structure has been expressed both for the cases of a risk neutral and a risk averse ISO. The proposed formulation was firstly applied on an illustrative test system in order to explain its functionality. Subsequently, in order to acquire more scalable results several simulations were performed on a modified version of the IEEE Reliability Test System. First, a base case was analyzed considering that the total system demand is inflexible and the effect of policies that lead the ISO to accept higher amounts of wind power generation in the system was examined. Afterwards, the effect of different degrees of flexibility of the industrial load parameters on the operation of the system was analyzed considering that there exist two industrial consumers that may render available a significant portion of their consumption to be managed by the ISO. Also, the benefit of having an active demand side was further clarified for increasing levels of wind power generation penetration in the generation mix. Finally, the risk averse behavior of the ISO was studied, rendering evident that relatively lower cost demand side resources may not only be beneficial for the system as regards the reduction of the operational cost but also by reducing the risk embedded in the decision of the ISO in the presence of wind power generation uncertainty.

Chapter 5

Demand Side Reserve Procurement Considering the Load Recovery Effect

5.1 Introduction

Practical and economic reasons suggest that the provision of reserves by the demand side should not be viewed as a mere increase or decrease in the load. Electrical energy is used in order to facilitate the activities of a certain sector (i.e. residential, commercial, or industrial) the primary activity of which is not the participation in the electricity market. Thus, technical and social constraints imply that the curtailed energy will have to be provided to the consumers before or after the interruption. Alternatively, in economic terms, if the internal load energy balance is not conserved, then the value that the demand side resources assign to electrical energy is not consistent [150]. In certain cases, depending on the dynamics of a load that incurs an interruption, more energy than the interrupted has to be provided [285]. The aforementioned facts suggest that the demand side reserve provision should be viewed as a redistribution of the demand over time and therefore the energy recovery should be appropriately modeled. Thus, the intertemporal effects of the load recovery are important since they reflect the fact that after a load curtailment the cost of supplying electricity would increase during the recovery periods in which the ISO must consider the delivery of additional electricity. Lack of the recovery effect consideration when utilizing demand side resources may lead to the underestimation of the electricity cost or to overestimating the benefits of DR along the scheduling horizon [302] and therefore, any market clearing scheme involving the utilization of demand side resources cannot realistically be optimal [303].

This chapter aims at contributing to the understanding of the impacts of the load recovery effect related to the deployment of reserve services by demand side resources both on the market clearing and the risk associated with the decisions of the ISO in the presence of significant wind penetration. In this study, a joint energy and reserve day-ahead market structure based on two-stage stochastic programming is developed. The ISO that is responsible for the clearing of the market may utilize generation and demand side resources in order to procure load following reserves in order to accommodate the uncertain wind production. Furthermore, special attention is given to the load recovery effect modeling in order to preserve the internal energy balance of the demand side resources participating in reserve provision. Finally, in this study a novel approach to risk-management from the point of view of the ISO is employed.

The remainder of this chapter is organized as follows: Section 5.2 presents the assumptions adopted in order to facilitate the formulation of the problem together with the proposed mathematical model. Also, the proposed multi-objective optimization approach together with the multi-attribute decision method used in order to facilitate the selection of the ISO are explained. Then, in Section 5.3 the methodology is demonstrated by presenting its application on an illustrative test case and a practical test system. Finally, the chapter concludes in Section 5.4.

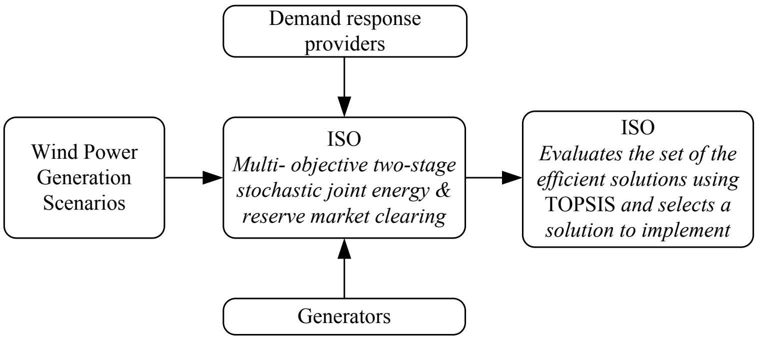

Figure 5.1: Overview of the market clearing model

5.2 Mathematical Model

5.2.1 Overview and modelling assumptions

To accommodate the uncertain nature of wind power production, a network-constrained day-ahead joint energy and reserve market clearing model is proposed under a two-stage stochastic programming framework. The market clearing procedure is depicted in Fig. 5.1.

Reserves can be procured by resources located both in the generation and the demand side:

- Generating units: They can provide up spinning, down spinning and non-spinning reserves.
- Demand response providers: these market participants can increase (down reserve) or decrease (up reserve) their consumption in order to provide reserves. Two types of DRPs are considered, distinguished by their energy recovery requirements. The first type of DRP represents loads that may increase and decrease their consumption as long as the energy requirements throughout the day are satisfied. The second type of DRP may offer a load reduction, however the energy must be paid back within a limited number of periods following a load curtailment and therefore represents a more rigid resource from the perspective of the ISO.

In order to render the rigorous mathematical formulation of the problem practical, several assumptions are adopted:

- The only source of uncertainty is deemed the wind production. Thus, no contingencies are taken into account, while the load forecasting as well as the response of the demand side resources are considered perfectly reliable.
- The load response is subject to load reduction and increase rates similar to the generating units, namely the load drop rate and and the load pickup rate according to the particular characteristics of the demand represented by a DRP.
- Wind power producers are not considered competitive agents and their participation is promoted by the ISO. For the market clearing procedure wind energy is considered free of cost. Practically, it could be paid a regulated tariff out of the day-ahead market scope for the energy actually produced [283].

- The cost for deploying reserves by the units is considered equal to their energy costs. The DRPs also offer their services at a scheduling and a deployment cost, respectively. However, any pricing scheme may be incorporated within the proposed approach.
- A linear representation of the network is considered, neglecting the active power losses. The losses may be included in a linear formulation as explained in [283].
- Load shedding is only possible for the inelastic loads that are not subject to any resource offering scheme.
- The scheduling horizon is one day with hourly granularity.

5.2.2 Objective functions

In this formulation two conflicting objective functions are considered: the expected cost (EC) of the system operation and the CVaR risk metric that both need to be minimized.

5.2.2.1 Expected cost

$$
\begin{aligned}
EC = \sum_{t \in T} \Bigg\{ & \\
& \sum_{i \in I} \left[\sum_{f \in F^i} (C^G_{i,f,t} \cdot b_{i,f,t}) + SUC_i \cdot y^1_{i,t} + SDC_i \cdot z^1_{i,t} + C^{G,U}_{i,t} \cdot R^{G,U}_{i,t} + C^{G,D}_{i,t} \cdot R^{G,D}_{i,t} + C^{G,NS}_{i,t} \cdot R^{G,NS}_{i,t} \right] \\
& + \sum_{j \in (J^1 \cup J^2)} (C^{DRP,U}_{j,t} \cdot R^{DRP,U}_{j,t}) \Bigg\} \\
& + \sum_{s \in S} \pi_s \left\langle \sum_{t \in T} \left\{ \sum_{i \in I} \left[SUC_i \cdot (y^2_{i,t,s} - y^1_{i,t}) + SDC_i \cdot (z^2_{i,t,s} - z^1_{i,t}) + \sum_{i \in F^i} (C^G_{i,f,t} \cdot r^G_{i,f,t,s}) \right] \right. \right. \\
& \left. + \sum_{j \in (J^0 \cup J^1 \cup J^2)} (c^{DRP,U}_{j,t} \cdot r^{DRP,u}_{j,t,s} + V^{ENS}_j \cdot L^{shed}_{j,t,s}) + \sum_{w \in W} (V^S \cdot S_{w,t,s}) \right\} \\
& \left. + \sum_{j \in (J^1 \cup J^2)} (V^{ENS}_j \cdot ENR_{j,s}) \right\rangle
\end{aligned} \tag{5.1}
$$

The objective function (5.1) stands for the minimization of the total expected cost emerging from the system operation. The first line of the objective function expresses the costs associated with energy provided from the generating units, the startup and shudown costs as well as the cost of scheduling reserves from the generation side. The cost of scheduling demand reduction by the DRPs is taken into account by the second line.

The rest of the objective function is scenario dependent. The third line considers the cost that emerges from altering the commitment status of a generating unit and the cost of materializing the generation side reserves. The fourth line of the objective function stands for the cost of deploying reserves from the DRPs as well as the penalty for shedding load from the inelastic demand. Also, the wind spillage cost is taken into account. Finally, the last line of the objective function considers the cost of the energy not recovered after the deployment of a DRP load reduction.

5.2.2.2 Conditional value-at-risk

$$CVaR = \xi + \frac{1}{1-a}\sum_{s\in S}\pi_s \cdot \eta_s \tag{5.2}$$

Similar to Chapter 4 the CVaR metric is defined by (5.2). Nevertheless, unlike the formulation presented in Chapter 4, the risk measure is considered a separate objective function that is treated as explained in Section 5.2.4.

$$\begin{aligned}
&\sum_{t\in T}\Bigg\{\sum_{i\in I}\Bigg[\sum_{f\in F^i}(C^G_{i,f}\cdot b_{i,f,t} + C^G_{i,f}\cdot r^G_{i,f,t,s}) + SUC_i\cdot y^1_{i,t} + SDC_i\cdot z^1_{i,t}\\
&+C^{G,U}_{i,t}\cdot R^{G,U}_{i,t} + C^{G,D}_{i,t}\cdot R^{G,D}_{i,t} + C^{G,NS}_{i,t}\cdot R^{G,NS}_{i,t} + SUC_i\cdot(y^2_{i,t,s} - y^1_{i,t}) + SDC_i\cdot(z^2_{i,t,s} - z^1_{i,t})\Bigg]\\
&+\sum_{j\in(J^1\cup J^2)}(C^{DRP,U}_{j,t}\cdot R^{DRP,U}_{j,t} + c^{DRP,u}_{j,t}\cdot r^{DRP,u}_{j,t,s} + V^{ENS}_j\cdot L^{shed}_{j,t,s})\\
&+\sum_{w\in W}(V^S\cdot S_{w,t,s})\Bigg\} + \sum_{j\in(J^1\cup J^2)}(V^{ENS}_j\cdot ENR_{j,s}) - \xi \le \eta_s \ \forall s
\end{aligned} \tag{5.3}$$

$$\eta_s \ge 0 \ \forall s \tag{5.4}$$

Constraint (5.3) is enforced in order to define the CVaR that is associated with the cost of each individual scenario while (5.4) states that the auxiliary variable η_s is non negative.

5.2.3 Constraints

5.2.3.1 First stage constraints

5.2.3.1.1 *Generating units*

$$P^{sch}_{i,t} = \sum_{f\in F^i} b_{i,f,t} \ \forall i,t \tag{5.5}$$

$$0 \le b_{i,f,t} \le B_{i,f,t} \ \forall i,f,t \tag{5.6}$$

$$P_{i,t}^{sch} - R_{i,t}^{G,D} \geq P_i^{min} \cdot u_{i,t}^1 \; \forall i, t \tag{5.7}$$

$$P_{i,t}^{sch} + R_{i,t}^{G,D} \leq P_i^{max} \cdot u_{i,t}^1 \; \forall i, t \tag{5.8}$$

$$P_{i,t}^{sch} - P_{i,t-1}^{sch} \leq RU_i \cdot \Delta\mathrm{T} \; \forall i, t \tag{5.9}$$

$$P_{i,t-1}^{sch} - P_{i,t}^{sch} \leq RD_i \cdot \Delta\mathrm{T} \; \forall i, t \tag{5.10}$$

$$0 \leq R_{i,t}^{G,D} \leq RD_i \cdot T^S \cdot u_{i,t}^1 \; \forall i, t \tag{5.11}$$

$$0 \leq R_{i,t}^{G,U} \leq RU_i \cdot T^S \cdot u_{i,t}^1 \; \forall i, t \tag{5.12}$$

$$0 \leq R_{i,t}^{G,NS} \leq RU_i \cdot T^{NS} \cdot (1 - u_{i,t}^1) \; \forall i \in I^{NS}, t \tag{5.13}$$

$$\sum_{\tau=t-UT_i+1}^{t} y_{i,\tau}^1 = u_{i,t}^1 \; \forall i, t \tag{5.14}$$

$$\sum_{\tau=t-DT_i+1}^{t} z_{i,\tau}^1 = 1 - u_{i,t}^1 \; \forall i, t \tag{5.15}$$

$$y_{i,t}^1 - z_{i,t}^1 = u_{i,t}^1 - u_{i,t-1}^1 \; \forall i, t \tag{5.16}$$

$$y_{i,t}^1 + z_{i,t}^1 \leq 1 \; \forall i, t \tag{5.17}$$

The cost functions of the generators are considered convex and are approximated using a monotonically ascending step-wise linear marginal cost functions as it is enforced by (5.5) and (5.6). The output of a generating unit is constrained between a minimum and a maximum value considering also the scheduled down and up spinning reserves using (5.7) and (5.8), respectively. The ramping constraints are taken into account by (5.9) and (5.10). Furthermore, the scheduled up and down spinning, as well as the non-spinning reserves are limited by (5.11)-(5.13). Note that non spinning reserves may be scheduled only by units that are technically capable of providing this service.

Equations (5.14) and (5.15) enforce the minimum up and down time constraints of a generating unit. Finally, (5.16) and (5.17) implement the unit commitment logic. More details regarding these constraints may be found in Chapters 3 and 4.

5.2.3.1.2 *Wind power scheduling*

$$0 \leq P_{w,t}^{W,sch} \leq P_{w}^{W,max} \ \forall w, t \tag{5.18}$$

Constraint (5.18) limits the wind power production that may be scheduled. In this study, it is considered that the minimum scheduled wind production is zero and the maximum limit coincides with the installed capacity of the wind farm and therefore, it is practically time-independent.

5.2.3.1.3 *Demand response providers*

In this study, it is considered that DRPs may participate in upward reserve scheduling by rendering a portion of their demand available to be curtailed under suitable incentives. Furthermore, the fact that the demand that is curtailed during a given interval may have to be recovered in other periods allows the DRPs to contribute to downward reserves through appropriate coordination of the curtailment and the recovery periods. In order to participate in the reserve market, the ISO may require several parameters to be submitted by the DRPs together with the demand reduction and recovery costs such as: maximum demand modification rate, rate of energy recovery, load pickup/drop rate, minimum demand curtailment, load recovery duration and maximum number of curtailments per day. Constraints (5.19)-(5.21) enforce the reserve scheduling from the DRPs.

$$0 \leq R_{j,t}^{DRP,U} \leq \min(\xi_{j,t}^{U} \cdot D_{j,t}, RU_{j}^{DRP} \cdot T^{S}) \ \forall j \notin J^{0}, t \tag{5.19}$$

$$0 \leq R_{j,t}^{DRP,D} \leq \min(\xi_{j,t}^{D} \cdot D_{j,t}, RD_{j}^{DRP} \cdot T^{S}) \ \forall j \notin J^{0}, t \tag{5.20}$$

$$\sum_{j \notin J^{0}} R_{j,t}^{DRP,U} \leq \frac{p}{1-p} \cdot \sum_{i \in I} (R_{i,t}^{G,U} + R_{i,t}^{G,NS}) \ \forall t \tag{5.21}$$

Specifically, (5.19) states that the upward reserve scheduled by a DRP is constrained either by the maximum upward demand modification rate or by the load drop rate. Similarly, the downward reserve as a result of scheduled load recovery is constrained either by the maximum downward demand modification rate or by the load pick-up rate (5.20).

Despite the fact that the utilization of demand side resources is promoted, many ISOs impose limits on the share of demand side resources contribution to reserves. Such rules may be imposed in order to avoid extensive reserve deficits that may occur if the DRPs do not honor their commitment to provide reserve services. This market rule is taken into account by (5.21) that states that the contribution of DRPs to upward reserves during a given period cannot exceed $p\%$ of the total scheduled upward reserves during that period.

5.2.3.1.4 *Day-ahead market power balance*

$$\sum_{i \in I} P_{i,t}^{sch} + \sum_{w} P_{w,t}^{W,sch} = \sum_{j \in (J^0 \cup J^1 \cup J^2)} D_{j,t} \; \forall t \tag{5.22}$$

Equation (5.22) states that the production from the generating units plus the scheduled production from the wind farms must be equal to the total consumption of all the types of loads.

5.2.3.2 Second stage constraints

5.2.3.2.1 *Generating units*

$$P_i^{min} \cdot u_{i,t,s}^2 \leq P_{i,t,s}^G \leq P_i^{max} \cdot u_{i,t,s}^2 \; \forall i,t,s \tag{5.23}$$

$$P_{i,t,s}^G - P_{i,t-1,s}^G \leq RU_i \cdot \Delta\mathrm{T} \; \forall i,t,s \tag{5.24}$$

$$P_{i,t-1,s}^G - P_{i,t,s}^G \leq RD_i \cdot \Delta\mathrm{T} \; \forall i,t,s \tag{5.25}$$

Constraints (5.23)-(5.25) enforce the minimum and maximum power output as well as the ramping limits of the generating units in each of the considered scenarios. Additional constraints must be enforced for generating units that may provide non-spinning reserves. More specifically, constraints (5.14)-(5.17) must be enforced in the second stage, replacing the first-stage variables $u_{i,t}^1$, $y_{i,t}^1$, $z_{i,t}^1$ with the second stage variables $u_{i,t,s}^2$, $y_{i,t,s}^2$, $z_{i,t,s}^2$, respectively.

5.2.3.2.2 *Wind spillage limits*

$$0 \leq S_{w,t,s} \leq P_{w,t,s}^{WP} \; \forall w,t,s \tag{5.26}$$

A portion of available wind production may be spilled if it is necessary to facilitate the operation of the power system. This is enforced by (5.26).

5.2.3.2.3 *Involuntary load shedding limits*

$$0 \leq L^{shed}_{j,t,s} \leq D_{j,t} \; \forall j \in J^0, t, s \tag{5.27}$$

As a last resort the ISO can decide to shed a part of the inelastic demand in order to maintain the consistency of the system. This requirement is enforced by constraint (5.27).

5.2.3.2.4 *Demand response providers*

Reserve deployment. The deployment of reserves by the DRPs is defined by (5.28)-(5.31).

$$u^{DRP,u}_{j,t,s} \cdot R^{DRP,U,m}_{j} \leq r^{DRP,u}_{j,t,s} \leq RU^{DRP}_{j} \cdot T^S \cdot u^{DRP,u}_{j,t,s} \; \forall j \in (J^1 \cup J^2), t, s \tag{5.28}$$

$$0 \leq r^{DRP,d}_{j,t,s} \leq RD^{DRP}_{j} \cdot T^S \cdot u^{DRP,d}_{j,t,s} \; \forall j \in (J^1 \cup J^2), t, s \tag{5.29}$$

$$u^{DRP,u}_{j,t,s} + u^{DRP,d}_{j,t,s} \leq 1 \; \forall j \in (J^1 \cup J^2), t, s \tag{5.30}$$

$$\sum_{t \in T} u^{DRP,u}_{j,t,s} \leq N^{in}_{j} \; \forall j \in (J^1 \cup J^2), s \tag{5.31}$$

Constraint (5.28) defines the deployment of up reserve from the DRP, stating that a load curtailment must be greater than a minimum limit and less than an amount that depends on the load drop rate. Also, through (5.29) the deployed down reserves are constrained by the load pick-up rate. Furthermore, the logical constraint (5.30) states that a DRP cannot reduce and increase its consumption simultaneously. Finally, (5.31) imposes a maximum limit to the load reductions that may be procured by a DRP during the scheduling horizon.

Energy recovery. Two different types of load recovery are modeled. The first type refers to a DRP that represents a load that is capable of storing (e.g., using batteries, air compressors, products [303], etc.) or foregoing energy and therefore, the energy recovery is rather flexible. The load recovery of this type is modeled by (5.32).

$$\sum_{t \in T} r^{DRP,d}_{j,t,s} + ENR_{j,s} = \gamma_j \cdot \sum_{t \in T} r^{DRP,u}_{j,t,s} \; \forall j \in J^1, s \tag{5.32}$$

The system operator may procure a load reduction from a DRP of type 1, while the only constraint is that the energy has to be recovered before or after a reduction occurs. Note that if $0 \leq \gamma_j < 1$

the energy that is required to be recovered is less than the initial load reduction. Also, it is possible that an amount of the energy that is to be paid back to the DRP is not recovered, given that the DRP receives a financial incentive.

The second type of load recovery corresponds to a DRP with the strict requirement of recovering the reduced energy within T_j^{req} intervals, starting directly after a reduction occurs, while another interruption cannot be sustained during this period. The former requirement is imposed by (5.33) and the latter by (5.34). In the special case in which $T_j^{req} = 1$ constraint (5.33) may be substituted by the simpler constraint (5.35). Finally, (5.36) states that during the first scheduling interval, load recovery is not possible.

$$u_{j,t,s}^{DRP,u} \cdot \sum_{\tau=t+1}^{t+T_j^{rec}} r_{j,\tau,s}^{DRP,d} = \gamma_j \cdot r_{j,t,s}^{DRP,u} \ \forall j \in J^2, t, s \tag{5.33}$$

$$u_{j,t,s}^{DRP,d} = \sum_{\tau=t-T_j^{rec}}^{t-1} u_{j,\tau,s}^{DRP,u} \ \forall j \in J^2, t, s \tag{5.34}$$

$$r_{j,t+1,s}^{DRP,d} = \gamma_j \cdot r_{j,t,s}^{DRP,u} \ \forall j \in J^2, t, s, \ ifT_j^{req} = 1 \tag{5.35}$$

$$u_{j,t,s}^{DRP,d} = 0 \ \forall j \in J^2, s, \ if \ t = 1 \tag{5.36}$$

Constraint (5.33) is not linear since it involves the multiplication of a binary and a sum of continuous variables on the left-hand side. In order to preserve the MILP formulation, the linearization of this constraint is required. In [285] the load recovery effect is modeled using a constraint that is essentially equivalent to (5.33), yet omitting the multiplication of the left-hand side with the binary variable. Although such a constraint seems straightforward, in fact it is not a general constraint and is valid only for the case in which $T_j^{rec} = 1$. For instance, let us assume that in period 1 of scenario s an amount of up reserve is deployed from a DRP j ($r_{j,1,s}^{DRP,u} > 0$) and that the curtailed energy must be recovered in the next two periods, 2 and 3. Also, for the sake of simplicity it is considered that $\gamma_j = 1$. If the multiplication with the binary variable is neglected in (5.33), then for $t = 1$, $r_{j,1,s}^{DRP,u} = r_{j,2,s}^{DRP,d} + r_{j,3,s}^{DRP,d}$ holds. If $r_{j,3,s}^{DRP,d} > 0$, then in period $t = 2$, $r_{j,2,s}^{DRP,u} = r_{j,3,s}^{DRP,d} + r_{j,4,s}^{DRP,d}$ must hold. However, the previous constraint would be infeasible since $r_{j,2,s}^{DRP,u} = 0$ and $r_{j,3,s}^{DRP,u} = 0$ must also hold since in the recovery period another load reduction may not occur. The only occasion on which this constraint could be feasible would be if $r_{j,3,s}^{DRP,d} = 0$ which corresponds either to the case that feasibility is achieved by recovering all the load immediately in the first period after the load reduction or to a load recovery period of $T_j^{rec} = 1$. To generalize the load recovery constraint, the multiplication with the binary variable is essential. Let us now consider constraint (5.33) as is. From constraints (5.30) and (5.34) it may be easily verified that if $u_{j,1,s}^{DRP,u} = 1$, then $u_{j,2,s}^{DRP,u} = 0$ and $u_{j,3,s}^{DRP,u} = 0$. In periods 1,2 and 3 constraint (5.33) becomes $1 \cdot (r_{j,2,s}^{DRP,d} + r_{j,3,s}^{DRP,d}) = r_{j,1,s}^{DRP,u}$, $0 \cdot (r_{j,3,s}^{DRP,d} + r_{j,4,s}^{DRP,d}) = r_{j,2,s}^{DRP,u}$, $0 \cdot (r_{j,4,s}^{DRP,d} + r_{j,5,s}^{DRP,d}) = r_{j,3,s}^{DRP,u}$ which evidently alleviates the previous infeasibility.

The set of linear constraints (5.37)-(5.40) may substitute (5.33). The main idea is to substitute the term $u_{j,t,s}^{DRP,u} \cdot \sum_{\tau=t+1}^{t+T_j^{rec}} r_{j,\tau,s}^{DRP,d}$ with the non negative auxiliary variable $\kappa_{j,t,s}$ as in (5.37), which receives values according to (5.38)-(5.40).

$$\kappa_{j,t,s} = \gamma_j \cdot r_{j,t,s}^{DRP,u} \ \forall j \in J^2, t, s, if\ T_j^{req} > 1 \tag{5.37}$$

$$0 \leq \kappa_{j,t,s} \leq RD_j^{DRP} \cdot T^S \cdot T_j^{rec} \cdot u_{j,t,s}^{DRP,u} \ \forall j \in J^2, t, s, if\ T_j^{req} > 1 \tag{5.38}$$

$$\kappa_{j,t,s} \geq \sum_{\tau=t+1}^{t+T_j^{rec}} r_{j,\tau,s}^{DRP,d} - (1 - u_{j,t,s}^{DRP,u}) \cdot RD_j^{DRP} \cdot T^S \cdot T_j^{rec} \ \forall j \in J^2, t, s, if\ T_j^{req} > 1 \tag{5.39}$$

$$\kappa_{j,t,s} \leq \sum_{\tau=t+1}^{t+T_j^{req}} r_{j,\tau,s}^{DRP,d} \ \forall j \in J^2, t, s, if\ T_j^{req} > 1 \tag{5.40}$$

To achieve the linearization of constraint (5.33) the auxiliary variable $\kappa_{j,t,s}$ must be bounded. The lower bound of $\kappa_{j,t,s}$ is zero since the amount of down reserves is positive. An upper bound of $\kappa_{j,t,s}$ is the maximum technically achievable amount of energy that may be recovered during the recovery period that is constrained by the load pickup rate $RD_j^{DRP} \cdot T^S \cdot T_j^{rec}$. If during period t a load curtailment occurs, then $u_{j,t,s}^{DRP,u} = 1$ and subsequently, according to (5.39) and (5.40) the auxiliary variable receives the value $\kappa_{j,t,s} = \sum_{\tau=t+1}^{t+T_j^{rec}} r_{j,\tau,s}^{DRP,d}$. In case that no load curtailment occurs, then $u_{j,t,s}^{DRP,u} = 0$ and because of constraint (5.38) $\kappa_{j,t,s} = 0$, while (5.39) and (5.40) become redundant.

The constraints that are used to model reserve deployment and load recovery in this chapter are generic. Other constraints such as minimum and maximum duration of an interruption, load recovery sequence, etc., are out of the scope of this chapter, since they depend on the nature of the specific load type that is represented by a DRP. For example, in Chapter 4 a detailed model regarding the participation of an industrial consumer into the day-ahead energy and reserve market was presented.

5.2.3.2.5 *Network constraints*

$$\begin{aligned}\sum_{i \in N_n^i} P_{i,t,s}^G + \sum_{w \in N_n^w} (P_{i,t,s}^{WP} - S_{w,t,s}) + \sum_{n \in B_b^{nn}} f_{b,t,s} \\ = \sum_{n \in B_b^n} f_{b,t,s} + \sum_{j \in N_n^j} (D_{j,t,s}^A - L_{j,t,s}^{shed}) \\ \forall b, (n, nn) \in B(n, nn), t, s\end{aligned} \tag{5.41}$$

$$f_{b,t,s} = B_{b,n} \cdot (\delta_{n,t,s} - \delta_{nn,t,s}) \ \forall b, (n, nn) \in B(n, nn), t, s \tag{5.42}$$

$$-f_b^{max} \leq f_{b,t,s} \leq f_b^{max} \; \forall b, t, s \tag{5.43}$$

$$-\pi \leq \delta_{n,t,s} \leq \pi \; \forall n, t, s \tag{5.44}$$

$$\delta_{n,t,s} = 0 \; \forall t, s, if n \equiv ref \tag{5.45}$$

In the second stage of the problem, the network constraints are taken into account using a lossless DC power flow formulation. More specifically, equation (5.41) stands for the power balance at each node of the system which states that the total power generated at each node by conventional units, the net production of wind farms plus the power injection from incoming transmission lines must equal the total net consumption of the loads as well as the power that is injected to outgoing transmission lines. The flow over a transmission line is defined by (5.42), while a power flow limit is set according to the maximum capacity of a transmission line by (5.43). Finally, (5.44) and (5.45) state that the voltage angles must be bounded between $-\pi$ and π and that at the slack bus the voltage angle must be specified, respectively.

5.2.3.3 Linking constraints

5.2.3.3.1 *Generation side reserve deployment*

$$P_{i,t,s}^{G} = P_{i,t}^{S} + r_{i,t,s}^{G,u} + r_{i,t,s}^{G,ns} - r_{i,t,s}^{G,d} \; \forall i, t, s \tag{5.46}$$

$$0 \leq r_{i,t,s}^{G,u} \leq R_{i,t}^{G,U} \; \forall i, t, s \tag{5.47}$$

$$0 \leq r_{i,t,s}^{G,d} \leq R_{i,t}^{G,D} \; \forall i, t, s \tag{5.48}$$

$$0 \leq r_{i,t,s}^{G,ns} \leq R_{i,t}^{G,NS} \; \forall i \in I^{NS}, t, s \tag{5.49}$$

$$r_{i,t,s}^{G,u} + r_{i,t,s}^{G,ns} - r_{i,t,s}^{G,d} = \sum_{f \in F^i} r_{i,f,t,s}^{G} \; \forall i, t, s \tag{5.50}$$

$$r_{i,f,t,s}^{G} \leq B_{i,f,t} - bi, f, t \; \forall i, f, t, s \tag{5.51}$$

$$r^G_{i,f,t,s} \geq -B_{i,f,t} \ \forall i,f,t,s \tag{5.52}$$

$$y^2_{i,t,s} = y^1_{i,t} \ \forall i \notin I^{NS}, t, s \tag{5.53}$$

Constraints (5.46) and (5.47)-(5.49) link the scheduled power output with the actual power generation and the scheduled reserve capacity with the deployed reserves, respectively. Moreover, constraints (5.50)-(5.52) decompose the deployed reserves into the blocks of energy. Finally, (5.53) is used to fix the startup status of units that are not capable of providing non spinning reserves (such constraints are called non anticipativity constraints).

5.2.3.3.2 ***Demand side reserve deployment***

$$D^A_{j,t,s} = D_{j,t} - r^{DRP,u}_{j,t,s} + r^{DRP,d}_{j,t,s} \ \forall j,t,s \tag{5.54}$$

$$0 \leq r^{DRP,u}_{j,t,s} \leq R^{DRP,U}_{j,t} \ \forall j,t,s \tag{5.55}$$

$$0 \leq r^{DRP,d}_{j,t,s} \leq R^{DRP,D}_{j,t} \ \forall j,t,s \tag{5.56}$$

Constraints (5.54)-(5.56) hold for the deployment of reserves from the demand side and are similar to the ones that hold for the generating units.

5.2.4 Multi-objective optimization approach

A compact stochastic programming optimization problem formulation incorporating a risk measure function is presented in (5.57).

$$\begin{aligned} &\min \ (1-\beta)\cdot EC + \beta \cdot CVaR \\ &s.t. \ (5.3)-(5.32) \ and \ (5.34)-(5.56) \end{aligned} \tag{5.57}$$

The parameter $\beta \in [0,1]$ is a weighting factor that implements the trade-off between the expected cost and risk aversion. By varying the parameter different optimal solutions are obtained and the efficient frontier of expected cost versus risk is constructed. Note that the efficient frontier is not necessarily convex or concave [32].

Essentially, the problem presented in (5.57) is a MOOP with conflicting objectives that is treated as a single objective problem by weighting the different objectives into a composite objective function. This approach is straightforward and easy to implement and therefore has been widely adopted in the technical literature in different power systems problems that risk needs to be considered. However, it presents several technical disadvantages [304]: 1) this method is only usable for convex efficient sets, 2) a uniformly distributed set of weights does not guarantee a uniformly distributed set of efficient solutions and as a result, the mapping of the efficient set may be insufficient, and 3) the weighted sum method suffers from the fact that there may be different combinations of weights that result into the same efficient solution. In practical terms, many more iterations would be needed in order to discover a given number of unique efficient optimal solutions.

The aforementioned problems of the weighted sum method may be addressed by another well-known MOOP solution method, namely the epsilon-constraint method [304] which comprises the optimization of one objective function while using the rest of the objective functions as inequality constraints of the optimization problem the bounds of which are parametrically varied in order to return efficient solutions. Nevertheless, it also presents several pitfalls. The most important are that the parameter vector used to search the efficient set must lie in the range of the objective functions, else the efficiency of the returned solutions is not guaranteed and the method may return weakly efficient solutions, instead. A variant of the epsilon-constraint method, namely the AUGMECON method retains the advantages of the epsilon constraint method and addresses its disadvantages. Specifically, 1) the ranges of the objective functions are calculated using lexicographic optimization, 2) the efficiency of the returned solutions is proven and 3) the use of acceleration techniques enhances the computational efficiency of the method. These conceptual advantages may qualify AUGMECON as an acceptable exact technique to incorporate risk management into a stochastic optimization problem, which is the focus of this study. A detailed presentation of the method can be found in [304].

The calculation of the range of the objective functions is not trivial. The common approach is to calculate the ranges using the pay-off table that contains the results of the individual optimization of the objective functions. Without loss of generality, considering two objective functions to be minimized, although the minimum value of the objective functions is easily obtained, the maximum value is not easily identified. In case the maximum value is approximated by the maximum value of the corresponding column, these values may not represent efficient points. This problem is confronted with the use of lexicographic optimization that defines reservation values, i.e. upper limits for the objective functions. In this case, the values of the pay-off table (5.58) are calculated by solving the optimization problems (5.59)-(5.62).

$$Lex = \begin{bmatrix} Lex_{1,1} & Lex_{1,2} \\ Lex_{2,1} & Lex_{2,2} \end{bmatrix} \tag{5.58}$$

$$\begin{aligned} &Lex_{1,1} = \min \;\; (5.1) \\ &s.t. \; (5.3) - (5.32) \; and \; (5.34) - (5.56) \end{aligned} \tag{5.59}$$

$$\begin{aligned}
&Lex_{1,2} = \min \ (5.2)\\
&s.t.\ (5.3) - (5.32)\ and\ (5.34) - (5.56)\\
&Lex_{1,1} = (5.1)
\end{aligned} \tag{5.60}$$

$$\begin{aligned}
&Lex_{2,2} = \min \ (5.2)\\
&s.t.\ (5.3) - (5.32)\ and\ (5.34) - (5.56)
\end{aligned} \tag{5.61}$$

$$\begin{aligned}
&Lex_{2,1} = \min \ (5.1)\\
&s.t.\ (5.3) - (5.32)\ and\ (5.34) - (5.56)\\
&Lex_{2,2} = (5.2)
\end{aligned} \tag{5.62}$$

More specifically (5.59) involves the individual optimization of the expected cost. Then, in (5.60) CVaR is minimized while maintaining the optimal value of the expected cost resulting from (5.59) as a constraint. The individual optimization of CVaR is performed in (5.61) and the minimum value of CVaR is enforced as a constraint in (5.62). In this way, the pay-off table contains only efficient solutions.

The DM (in this case the ISO) needs to specify a number P of grid points e_p for which the efficient frontier is evaluated. Then, the values of the p-th point are calculated using (5.63). The number of grid points defines the density with which the Pareto optimal front is evaluated. However, an increased number of grid points may result in an increase in the computational burden since the number of optimization problems that needs to be solved increases. Thus, an appropriate trade-off between the accuracy of the representation of the efficient front and the computational burden must be considered.

$$\begin{aligned}
&e_p = e_{p-1} + \frac{Lex_{1,2} - Lex2,2}{P},\ p > 1\\
&e_p = Lex_{2,2},\ p = 1
\end{aligned} \tag{5.63}$$

To guarantee that the produced solutions are indeed efficient, the inequalities constraining the second objective in the original epsilon-constraint method must be binding. Thus, a transformation of the original method constraint to equality is used to force the method produce only efficient solutions. The equivalent optimization problem is presented in (5.64) in which $\varepsilon \in \left[10^{-6}, 10^{-3}\right]$ and σ is a non negative slack variable. By parametrically varying e_p in the set defined by (5.63), the efficient frontier of expected cost-risk metric is constructed.

$$\begin{aligned}
&\min\ EC + \varepsilon \cdot \sigma\\
&s.t.\ CVaR + \sigma = e_p,\ (5.3) - (5.32)\ and\ (5.34) - (5.56)\\
&\sigma > 0
\end{aligned} \tag{5.64}$$

Note that for $e_1 = Lex_{1,2}$ and $e_p = Lex_{2,2}$, (5.64) yields a solution that has the same expected cost with the solution obtained from the problem formulation presented in (5.57) for $\beta = 0$ (risk neutral problem) and the same risk measure value with the solution obtained with (5.57) for $\beta = 1$ (extremely risk averse problem), respectively. However, due to the use of lexicographic optimization, the solutions obtained using the proposed approach may dominate the corresponding solutions obtained using (5.57), in case the latter are weakly efficient solutions.

5.2.5 Multi-attribute decision making method

As stated before, the solution of the MOOP comprises a set of efficient solutions. Therefore, after the set of efficient solutions is known, a DM should intervene and decide one single solution to be implemented, according to his/her preferences. The DM may decide without a systematic method, based on experience instead. However, when dealing with a very large set of relatively optimal solutions, a method to rank and present a narrower subset would be very useful, facilitating the selection of the solution to be implemented. This falls under the umbrella of multi-attribute decision making problems, for which several methods have been proposed in the literature. In this study, the technique for order preference by similarity to ideal solution (TOPSIS) [305] has been implemented.

Let the solution of the aforementioned p-objective multi-objective problem comprise m Pareto optimal alternative solutions. The TOPSIS method evaluates the $m \times p$ decision matrix (5.65).

$$DM = \begin{bmatrix} x_{1,1} & \dots & x_{1,j} & \dots & x_{1,p} \\ \vdots & \ddots & & & \vdots \\ x_{i,1} & & x_{i,j} & & x_{p,j} \\ \vdots & & & \ddots & \vdots \\ x_{m,1} & \dots & x_{m,j} & \dots & x_{m,p} \end{bmatrix} \tag{5.65}$$

Each row of the decision matrix represents an alternative solution, while each column is associated with an objective (to be minimized or maximized). In the general case, each objective is expressed in different units. Thus, the next step of the TOPSIS method is to transform the decision matrix into a non-dimensional attribute matrix in order to enable a comparison among the different attributes. The normalization process is performed through the division of each element by the norm of the vector (column) of each criterion. An element $r_{i,j}$ of the normalized matrix is given by (5.66).

$$r_{i,j} = \frac{x_{i,j}}{\sqrt{\sum_{i=1}^{m} x_{i,j}^2}} \tag{5.66}$$

A set of weights $w = \{w_1, \dots, w_j, \dots, w_p\}$, $\sum_{j=1}^{n} w_j = 1$ that express the relative importance of each objective (criterion) is provided by the DM at this point. The weighted normalized matrix with elements $v_{i,j}$ is created by multiplying each column of the matrix with elements $r_{i,j}$ by the corresponding weight w_j.

Next, the ideal (A^+) and the negative ideal (A^-) solution vectors must be specified. In (5.67) and (5.68) J is the set of objectives (criteria) to be maximized and $J^{'}$ is the set of objectives to be minimized. These artificial alternatives indicate the most preferable (ideal) solution and the least preferable (negative-ideal) solutions.

$$A^+ = \{(\max_i(\upsilon_{i,j})|j \in J), (\min_i(\upsilon_{i,j})|j \in J^{'})\} \; \forall i = 1, \ldots, m \tag{5.67}$$

$$A^- = \{(\min_i(\upsilon_{i,j})|j \in J), (\max_i(\upsilon_{i,j})|j \in J^{'})\} \; \forall i = 1, \ldots, m \tag{5.68}$$

Then, the separation measure of each alternative from the ideal (S_i^+) and the negative ideal (S_i^-) solution is measured by the n-dimensional Euclidean distance as in (5.69) and (5.70).

$$S_i^+ = \sqrt{\sum_{j=1}^{n}(\upsilon_{i,j} - \upsilon_j^+)^2} \; \forall i = 1, \ldots, m \tag{5.69}$$

$$S_i^- = \sqrt{\sum_{j=1}^{n}(\upsilon_{i,j} - \upsilon_j^-)^2} \; \forall i = 1, \ldots, m \tag{5.70}$$

The final step in the application of the TOPSIS method is the calculation of the relative closeness to the ideal solution. According to the descending order of C_i^+, $0 < C_i^+ < 1$, the ranking of the alternatives is performed with respect to the similarity index that is calculated by (5.71).

$$C_i^+ = \frac{S_i^-}{S_i^+ + S_i^-} \; \forall i = 1, \ldots, m \tag{5.71}$$

5.2.6 Compact formulation

The proposed methodology is concisely compiled in Algorithm 1. It consists of four procedures that are consecutively executed: firstly, the pay-off table which defines the ranges over which the objective functions are evaluated is constructed. Subsequently, the grid points used in the MOOP are calculated. Then, the MOOP is solved resulting in a number of efficient solutions. Finally, the TOPSIS method is applied in order to rank the solutions that constitute the efficient frontier according to the preferences set by the ISO regarding the two objective functions. The ISO may at this stage select and implement the preferred solution.

Algorithm 1 The proposed approach

procedure CALCULATE THE PAY-OFF TABLE
    solve optimization problem (5.59)
    solve optimization problem (5.60)
    solve optimization problem (5.61)
    solve optimization problem (5.62)
    return pay-off table Lex
end procedure
procedure DEFINE GRID POINTS(P)
    for $p = 1 : P$ **do**
        if $p = 1$ **then**
            $e_p = Lex_{2,2}$
        else
            $e_p = e_{p-1} + \frac{Lex_{1,2} - Lex_{2,2}}{P}$
        end if
    end for
    return grid points e_p
end procedure
procedure MULTI-OBJECTIVE OPTIMIZATION(e_p,P)
    for $p = 1 : P$ **do**
        solve optimization problem (5.64)
    end for
    return set of efficient solutions (SES)
end procedure
procedure MULTI-ATTRIBUTE DECISION MAKING(SES,w)
    apply TOPSIS according to (5.65)-(5.71)
    return ranked set of efficient solutions
end procedure
select a solution to implement
print values of the decision variables for the solution to be implemented

5.3 Case Studies

5.3.1 Illustrative example

The proposed methodology is firstly applied on the illustrative 6-bus system with the characteristics presented in Section 4.3.1. A wind farm with installed capacity 150 MW is considered to be connected to bus 5. The total system load is divided to the load of buses 3, 4 and 5 by 20%, 40% and 40%, respectively. Fifteen wind power generation scenarios that are generated according to the methodology presented in Appendix B and are presented in Appendix C are considered. The load of bus 5 is considered to be managed by a DRP that may provide reserve services at a scheduling cost equal to 1 €/MWh while the reserve exercise cost is 10 €/MWh. The cost of energy not served/recovered is set to 1000 €/MWh. For the sake of simplicity, the wind spillage cost is neglected.

First, the operation of the two different types of load recovery is demonstrated without considering risk management. The DRP is considered to render available up to 15% of the scheduled load for reserve procurement. For the first type of load recovery, the number of interruptions is not limited, while the load recovery rate is considered 100%. For the load recovery of type 2 the minimum amount of reserve that must be deployed is 5 MW, the service is limited to one interruption during the scheduling horizon, while 30% of the curtailed load must be fully recovered within 3 hours after the interruption. The load drop and pickup rates are considered 5 MW/min.

The nominal demand of the DRP of type 1 that manages the load of bus 5 as well as its actual consumption in scenario 12 is portrayed in Fig. 5.2. It can be noticed that the reimbursement of the curtailed energy occurs before the deployment of up reserves in periods 1-9 and especially during the 6 first periods in which the available wind power generation is higher than the wind energy scheduled in the day-ahead market. For instance, in period 1 the excess of wind power production is 6.98 MW which matches the load increase. The load curtailment occurs in periods 10-24 and the largest amount of reserves occurs in periods 18-20 in which the scheduled wind energy is higher than the available wind energy and the load decrease facilitates the ISO in balancing the energy deficit. For the case in which the load recovery is of type 2 the nominal demand and the actual consumption of the load of bus 5 in scenario 1 is displayed in Fig. 5.3. The load reduction occurs in period 21 and the load recovery takes place in the next three periods. In period 21 the deficit in wind power generation in scenario 1 is 17.24 MW which is covered by 14.23 MW by the load curtailment which coincides with the maximum reserve deployment capability of the DRP (15% of nominal load). The load increase in periods 23 and 24 is equal to 0.78 MW and 3.48 MW which exactly balances the increase in the wind power generation in scenario 1. The fact that the DRP of type 1 are more flexible in terms of load recovery in comparison with the DRP of type 2 results in 26.25 MWh more wind power integration in the day-ahead market in the first case.

To demonstrate the technical advantages of the proposed approach as regards the consideration of risk-management, the efficient frontier for the case of DRP of type 1 with 15% upward and downward demand modification capability and load recovery rate of 100%. For the application of the classic approach that is expressed by optimization problem (5.57) a set of 21 evenly spaced values of $\beta \in [0, 1]$ is used, while 20 grid points are used for the application of the proposed

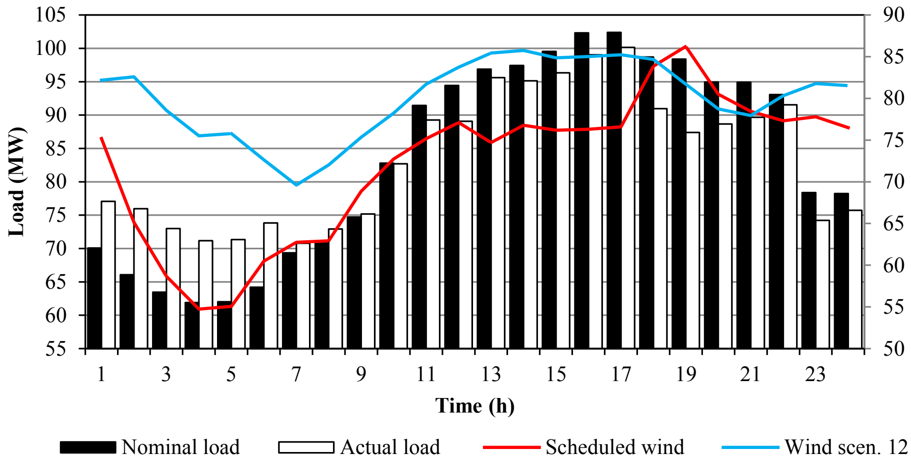

Figure 5.2: Load of DRP of type 1 in scenario 12

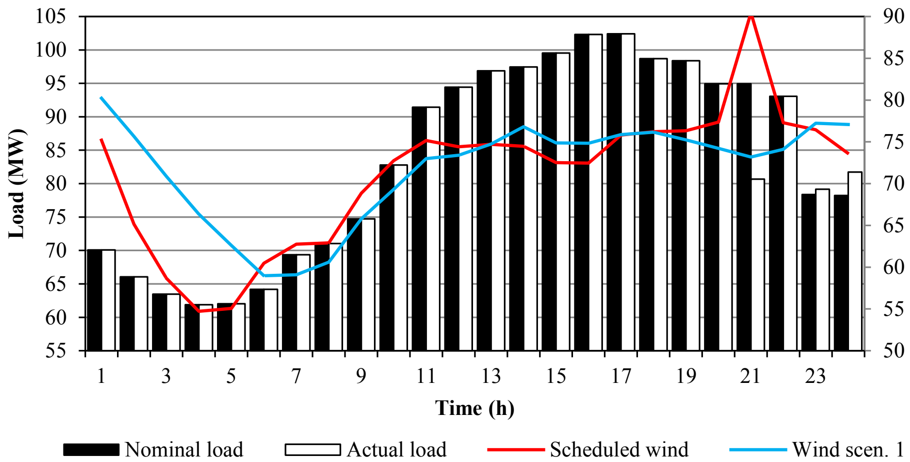

Figure 5.3: Load of DRP of type 2 in scenario 1

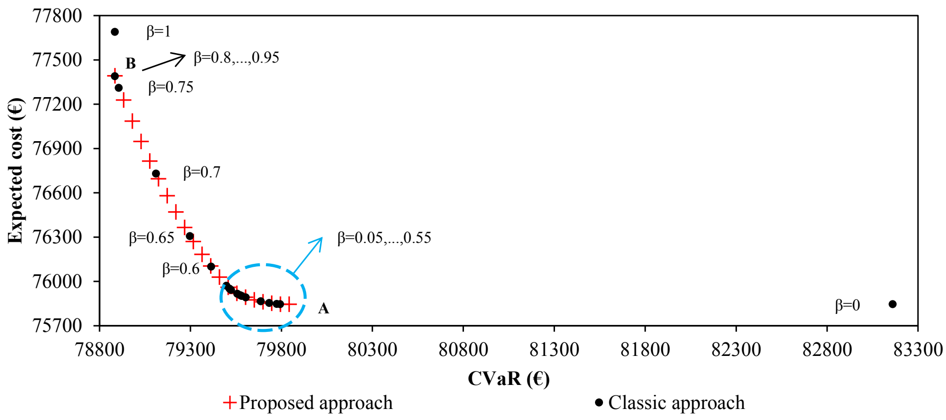

Figure 5.4: Comparison of efficient frontiers: classic vs. the proposed approach

approach in order to generate the same number of solutions. The obtained efficient frontiers are displayed in Fig. 5.4. The confidence level for the calculation of CVaR is 0.9.

It may be noticed that solution A obtained with the proposed approach dominates the solution for $\beta = 0$ because for the same expected cost, A presents a lower value of CVaR. In other words, the solution for $\beta = 0$ (risk neutral problem) of the classic approach is weakly efficient. Furthermore, solution B resulting from the application of the proposed approach dominates the solution obtained using the classic approach for $\beta = 1$ (extremely risk averse problem) since for the same value of CVaR, B presents a smaller value for the expected cost. As a result, the proposed approach eliminates the weakly efficient solutions that occur for the extreme values of weight interval due to the use of lexicographic optimization. Moreover, it is evident that the proposed approach discovers more efficient solutions in comparison with the classic approach for the same number of optimization problems that need to be solved, resulting in a more dense and therefore, more effective mapping of the Pareto front. For weights between 0.05 and 0.55 only a narrow segment of the efficient front is discovered through the employment of the classic approach. Also, for weights between 0.8 and 0.95, the same efficient solution is discovered, while the proposed approach returns only unique efficient solutions. Finally, it is to be stated that for $\beta \in (0, 1)$ the efficient fronts that are obtained by the two different approaches do not dominate each other since both methods return non dominated solutions that belong to the same efficient front.

In order to reveal the mechanism that controls the trade-off between expected cost and CVaR Figs. 5.5 and 5.6 that illustrate the wind energy scheduled and the expected wind energy spillage and the day-ahead energy and reserve cost, respectively, are presented. Note that the expected wind energy spillage is the weighted sum of available wind energy spillage in all scenarios during the scheduling horizon. As the values of CVaR decrease, more wind spillage is expected and as a result, less wind energy is integrated in the day-ahead market. As a result, the day-ahead energy cost increases since more generation must be scheduled by the conventional generating units. The expected wind spillage increases since less reserves are scheduled in order to balance the wind deviations.

The effect of the market rule presented in (5.21) is investigated for the same case. It is considered that during each period the upward demand side reserves may not exceed 5%, 10% and 15% of the total upward reserves scheduled during that period. The relevant results are presented in Fig. 5.7.

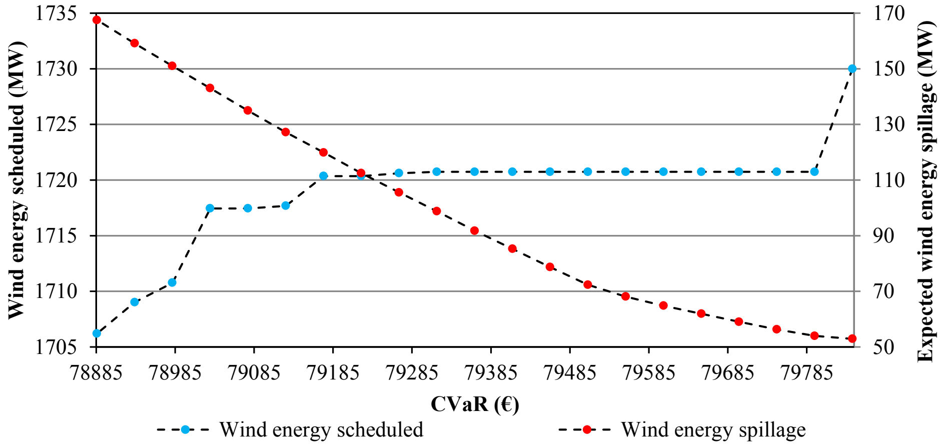

Figure 5.5: Wind energy scheduled and expected wind energy spillage

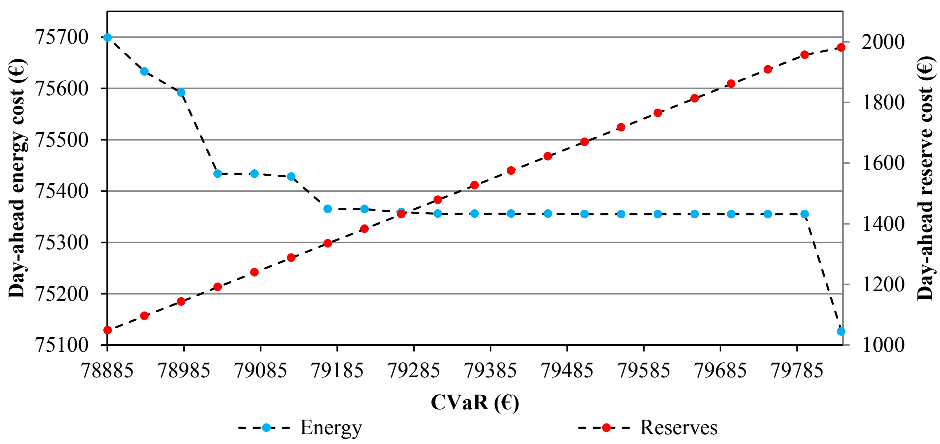

Figure 5.6: Day-ahead energy and reserve cost

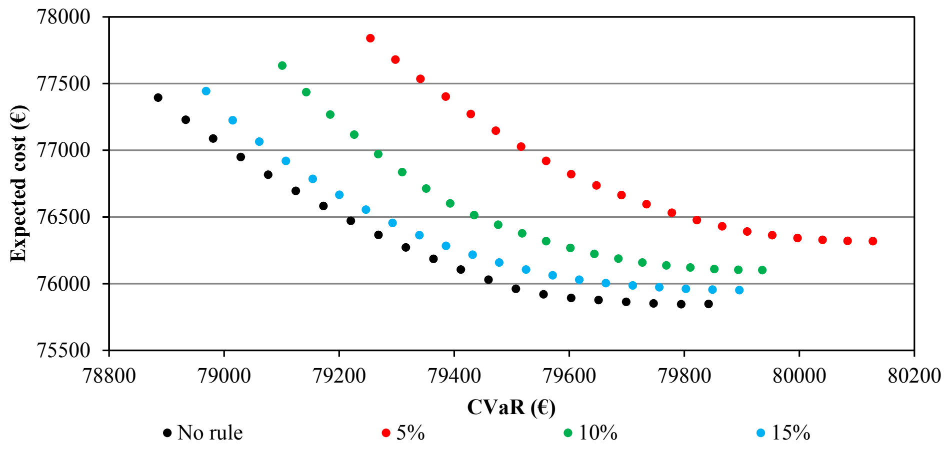

Figure 5.7: Efficient frontiers for different percentages of participation of DRP in reserves

As it can be seen, as the allowed participation of demand side resources increases, the efficient frontiers shift downwards and leftwards, implying both reduction in the expected cost and the value of CVaR. Despite the fact that the wind energy is considered free, the volatility of wind increases the cost of reserves. As a result, the reduction of the reserve cost is the means of reducing the risk associated with the ISO decisions. Since the demand side reserves are economically competitive, the relaxation of the participation limit allows a more significant generation-side reserve cost reduction in exchange of procuring larger amounts of demand side reserves.

The effect of the load recovery rate parameter is also examined for the case in which the load modification rate is 15% and the load recovery rate receives the values 0%, 20%, 50%, 70%, 100%, 120% and 150%. Values less than 100% imply that the energy that needs to be recovered is less than the energy that is curtailed. Relevant results regarding the impact on the efficient frontiers are illustrated in Fig. 5.8. Note that the efficient frontiers comprise a discrete number of solutions and are not continuous. It may be noticed that as the amount of energy which must be recovered increases, the efficient frontiers shift upwards and rightwards. It is demonstrated that both the expected cost and the CVaR increase when the curtailed load has to be recovered during the horizon. When the load recovery rate is less than 100%, the expected cost decreases since the costs of energy generation are limited. As a result, the positive impact of demand side resources on the risk-management may be overshadowed by the load recovery effect.

The set of efficient solutions resulting from the application of the proposed methodology and that was displayed in Fig. 5.4 is presented in detail in Table 5.1. After having obtained a set of efficient solutions, the ISO must intervene through a decision making process in order to select the solution to be implemented. In fact, the DM chooses the weights of the objectives according to a given goal. The application of the TOPSIS method results in a ranking of the solutions with respect to the value of the similarity index. Relevant results for different combinations of weights are reported in Table 5.2. As expected, the rankings of the solutions with a weight for the expected cost equal to 1 and 0, respectively, are opposite: this fact further shows that in effect expected cost and CVaR objectives are conflicting. Also, it is to be noticed that for these extreme values of weights, the first-ranked solutions (1 and 21, respectively) coincide with the ideal solutions. When the weight of the expected cost decreases from 1 to 0, there is a gradual transition of the initially top-ranked solutions towards the end of the ranking. Intermediate values of the weight of the expected cost

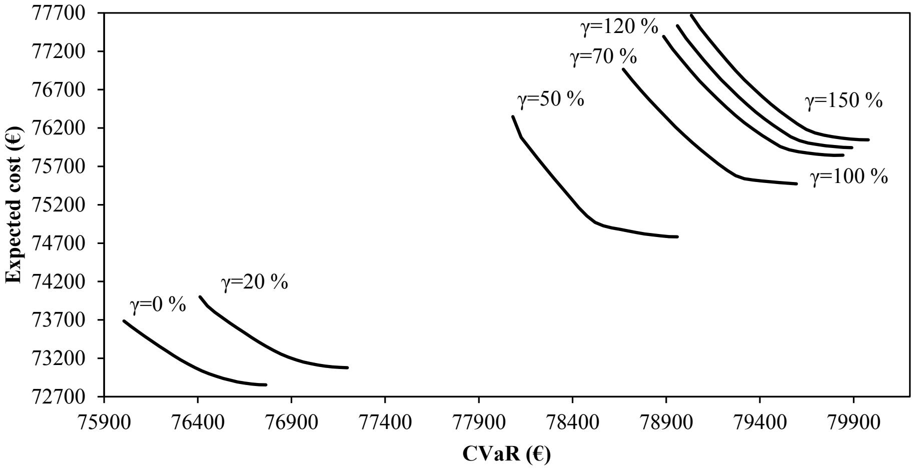

Figure 5.8: Efficient frontiers for different values of the load recovery rate

lead to highlight some prevailing top- and low-ranked solutions. For example, for values of the weight of the expected cost between 0.5 and 1 the solutions 12 to 21 remain in the last 8 positions and only the first part of the ranking is different. Also, for values between 0 and 0.3 the solutions 1 to 10 remain in the last 10 positions.

For example, in Fig. 5.9 the similarity index of the solution 10 is depicted. The highest values of the similarity index are noticed for the relatively higher values of the weight of the expected cost. For values of the weight associated with the expected cost between 0.7 and 1 remains in the tenth position, for values between 0.4 and 0.6 it is found within the first 5 solutions, while for weights less than 0.3 it is always in the twelfth position. Evidently, the value of the similarity index by itself is not very indicative regarding the performance of a solution when considering different weights for the different objectives. To obtain a better indicator, the number of weight combination N^W is introduced, representing all the weight combinations available for the problem under analysis. Furthermore, the average similarity index $\bar{C_i^+}$ is introduced, representing the average value of the similarity index referring to the solution i and obtained for all the N^W weight combinations, i.e., by indicating with C_i^+ the value of similarity index C_i^+ at the weight combination j, according to (5.72).

$$\bar{C_i^+} = \frac{1}{N^W} \sum_{j=1}^{N^W} C_{i,j}^+ \tag{5.72}$$

In Fig. 5.10 the average similarity index of all the efficient solutions obtained is presented. It may be noticed that the solutions 18, 19, 20 and 21 that present relatively low values of similarity index remain in the four last positions for 7 combinations of weights, while solution 9 receives relatively better positions for all the combinations of weights.

Table 5.1: Numbering of efficient solutions

Solution #	Expected cost (€)	CVaR (€)
1	75845.640	79842.910
2	75844.380	79795.060
3	75850.680	79747.210
4	75861.450	79699.360
5	75875.020	79651.510
6	75891.610	79603.660
7	75917.910	79555.810
8	75958.90	79507.960
9	76028.710	79460.110
10	76103.390	79412.260
11	76183.230	79364.410
12	76269.680	79316.550
13	76364.410	79268.700
14	76469.610	79220.850
15	76580.420	79173
16	76694.580	79125.150
17	76814.260	79077.300
18	76947.640	79029.450
19	77085.560	78981.600
20	77227.500	78933.750
21	77392.310	78885.900

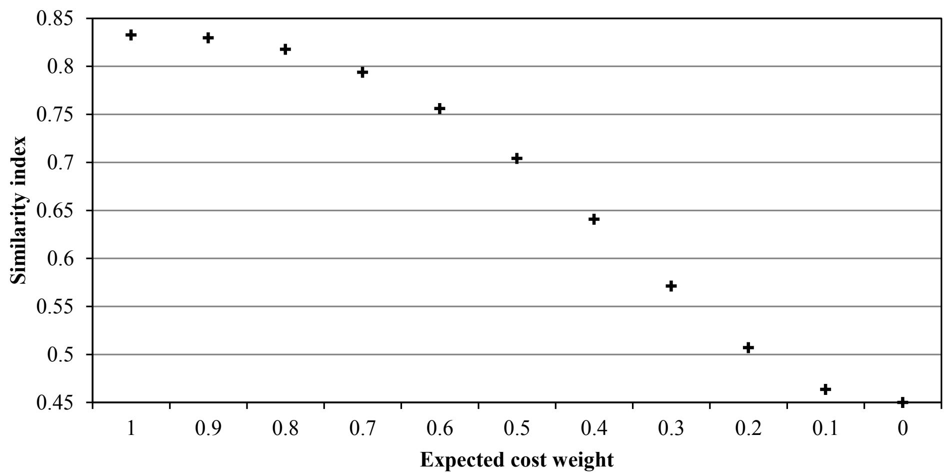

Figure 5.9: Similarity index of solution #10 for different values of weight over the expected cost

Table 5.2: Raking of efficient solutions for different values of weights over the objectives

Expected cost (1), CVaR (0)																				
1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
1	.999	.996	.989	.980	.969	.952	.926	.881	.833	.781	.725	.664	.596	.524	.451	.373	.287	.198	.106	0

Expected cost (0.9), CVaR (0.1)																				
5	**4**	**3**	**6**	**2**	**1**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
.946	.945	.944	.943	.941	.938	.935	.915	.875	.830	.779	.724	.664	.596	.525	.452	.376	.291	.205	.122	.062

Expected cost (0.8), CVaR (0.2)																				
6	**7**	**5**	**4**	**8**	**3**	**2**	**1**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
.894	.893	.891	.886	.884	.882	.876	.870	.856	.818	.772	.721	.663	.597	.528	.458	.385	.306	.230	.165	.129

Expected cost (0.7), CVaR (0.3)																				
7	**8**	**6**	**5**	**9**	**4**	**3**	**2**	**1**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
.838	.837	.834	.827	.821	.820	.813	.805	.797	.794	.758	.713	.660	.599	.535	.470	.404	.335	.274	.228	.203

Expected cost (0.6), CVaR (0.4)																				
8	**7**	**9**	**6**	**10**	**5**	**4**	**3**	**11**	**2**	**1**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
.777	.773	.771	.765	.756	.756	.746	.736	.732	.726	.716	.698	.655	.603	.548	.492	.437	.382	.337	.305	.284

Expected cost (0.5), CVaR (0.5)																				
9	**8**	**10**	**7**	**11**	**6**	**12**	**5**	**4**	**3**	**13**	**2**	**1**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
.708	.707	.704	.698	.694	.687	.675	.675	.663	.651	.647	.639	.627	.610	.569	.527	.487	.447	.415	.391	.373

Expected cost (0.4), CVaR (0.6)																				
11	**12**	**10**	**13**	**9**	**8**	**14**	**7**	**15**	**6**	**5**	**16**	**4**	**3**	**17**	**2**	**1**	**18**	**19**	**20**	**21**
.644	.643	.641	.635	.634	.626	.620	.612	.599	.598	.583	.576	.568	.555	.553	.542	.528	.528	.506	.488	.471

Expected cost (0.3), CVaR (0.7)																				
15	**16**	**14**	**17**	**13**	**18**	**19**	**12**	**20**	**11**	**21**	**10**	**9**	**8**	**7**	**6**	**5**	**4**	**3**	**2**	**1**
.636	.636	.631	.631	.621	.620	.608	.607	.596	.589	.581	.571	.553	.536	.517	.497	.478	.461	.446	.432	.419

Expected cost (0.2), CVaR (0.8)																				
19	**18**	**20**	**17**	**21**	**16**	**15**	**14**	**13**	**12**	**11**	**10**	**9**	**8**	**7**	**6**	**5**	**4**	**3**	**2**	**1**
.720	.719	.715	.711	.704	.694	.671	.642	.609	.575	.541	.507	.475	.446	.417	.389	.364	.342	.324	.308	.296

Expected cost (0.1), CVaR (0.9)																				
20	**21**	**19**	**18**	**17**	**16**	**15**	**14**	**13**	**12**	**11**	**10**	**9**	**8**	**7**	**6**	**5**	**4**	**3**	**2**	**1**
.845	.843	.833	.809	.776	.736	.693	.648	.602	.556	.509	.464	.419	.375	.333	.292	.253	.219	.190	.169	.157

Expected cost (0), CVaR (1)																				
21	**20**	**19**	**18**	**17**	**16**	**15**	**14**	**13**	**12**	**11**	**10**	**9**	**8**	**7**	**6**	**5**	**4**	**3**	**2**	**1**
1	.950	.900	.850	.800	.750	.700	.650	.600	.550	.500	.450	.400	.350	.300	.250	.200	.150	.100	.050	0

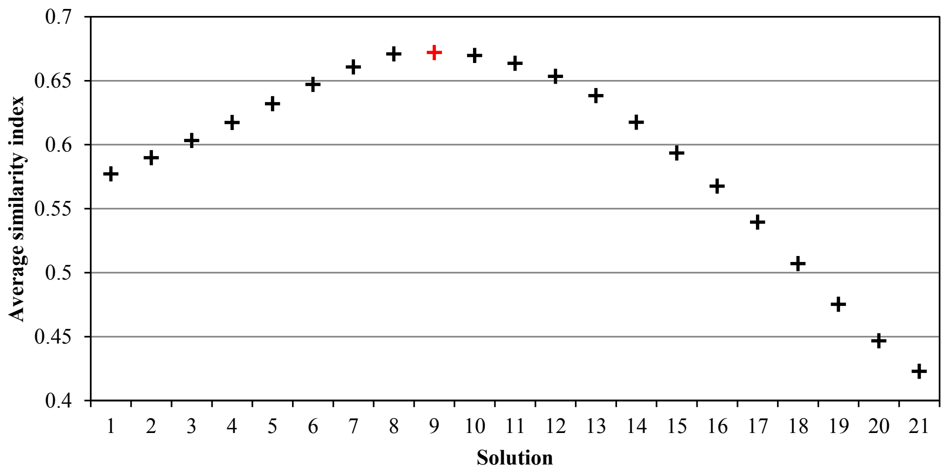

Figure 5.10: Average similarity index of different solutions

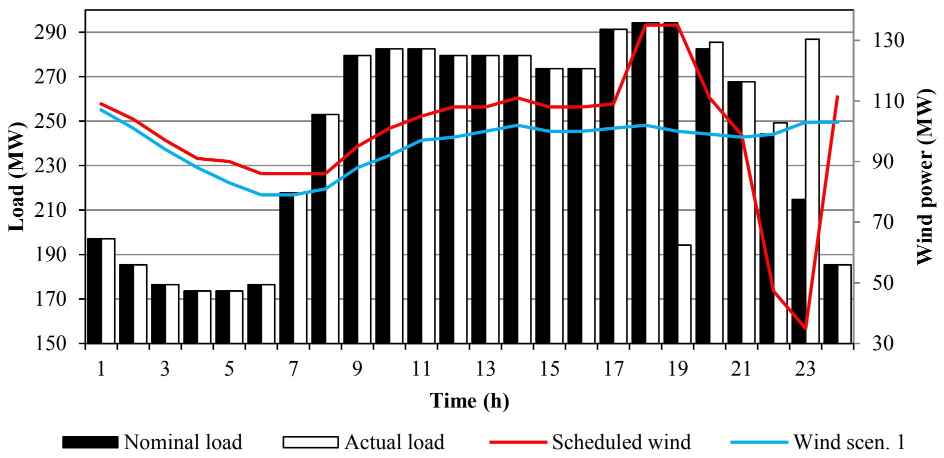

Figure 5.11: Load of DRP of type 2 at bus 15 in scenario 1

5.3.2 Application on a 24-bus system

In this section the proposed model is applied on a modified version of the IEEE Reliability Test System. The nuclear units connected to buses 18 and 21 as well as the hydro unit connected to bus 22 are considered must-run units. Furthermore, six wind farms with a total installed capacity of 20, 50, 30, 25, 25 and 50 MW (a total of 200 MW) are considered to be connected to buses 3, 5, 7, 16, 21, 23, respectively. The wind power uncertainty is taken into account through 15 non equiprobable scenarios (the same used in the case of the illustrative test system). All the units except for the must-run units may offer up and down spinning reserve at a cost equal to 20% of the most expensive power block of their offer. For the sake of simplicity non spinning reserves are not considered in this study. The wind spillage cost for all the cases is neglected in all the cases that follow while involuntary load shedding is not allowed. For all the cases the confidence level for the calculation of CVaR is 0.9 and 5 grid points are used to map the efficient frontier. Several cases are investigated in order to resolve the technical and economic aspects of the load recovery effect.

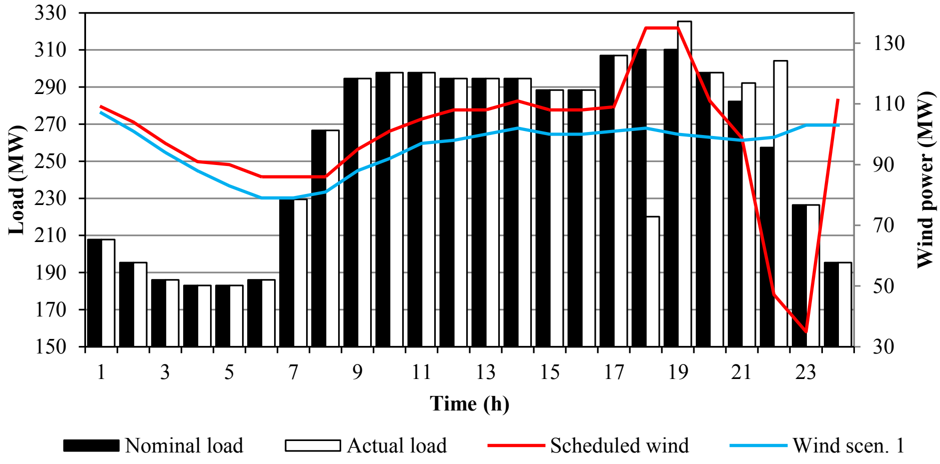

Figure 5.12: Load of DRP of type 2 at bus 18 in scenario 1

In the first case the loads connected to bus 15 (11.664% of total system load) and bus 18 (12.315% of total system load) are considered DRPs with a load recovery of type 2 capable of rendering available one time during the scheduling horizon for reserve procurement 100% of their demand. The load recovery rate is 80% and the curtailed load should be recovered within 4 hours after the load curtailment occurs. The load pickup and drop rates are considered equal to 10 MW/min. The cost of scheduling reserves from the DRPs is 1 €/MWh, while the reserve exercise cost is 2 €/MWh. The cost for energy not recovered is set to 10 €/MWh.

Figures 5.11 and 5.12 portray the nominal and actual load consumption in scenario 1 for the DRPs of bus 15 and 18 respectively. It may be noticed that in the case of DRP at bus 15 a curtailment of 100.05 MW occurs during period 19 of which 3 MW are recovered in period 20, 5 MW in period 22 and 72.04 MW during period 23. Similarly the demand of 90 MW of the load of the DRP at bus 18 that are curtailed in period 18 is recovered in periods 19 (15.2 MW), 21 (10 MW) and 22 (46.8 MW).

In periods 18 and 19 the scheduled wind power generation is 33 MW and 35 MW higher than the actual generation available in scenario 1. As a result, the load reductions are procured during these periods in order to balance the the energy deficit. Also, in these periods the highest load is noticed and therefore the load curtailment contributes to the reduction in the energy cost. It is interesting to notice that 21.11% of the load recovery of the DRP at bus 18 occurs in period 19 in which the load of bus 18 is reduced resulting in a total 84.85 MW load reduction. Furthermore, in periods 22 and 23 the scheduled wind power in the day-ahead market is less than the available generation in scenario 1 which implies that downward reserves should be procured. However, the load that is being recovered from the DRPs during these periods matches exactly the imbalance. Evidently, the ISO coordinates a curtailment not only with respect to the intertemporal constraints of its recovery but also by taking into account the operation of other DRPs.

In the second case all the loads are considered to be represented by a DRP with a demand modification rate of 1% of their nominal demand and a load recovery of type 1 with a nominal load recovery rate of 100%. The load pickup and drop rates are considered equal to 10 MW/min. Like in the first case the cost of scheduling reserves from the DRPs is 1 €/MWh, while the reserve deployment cost is 2 €/MWh. The cost of energy not recovered varies between 0 and 100 €/MWh.

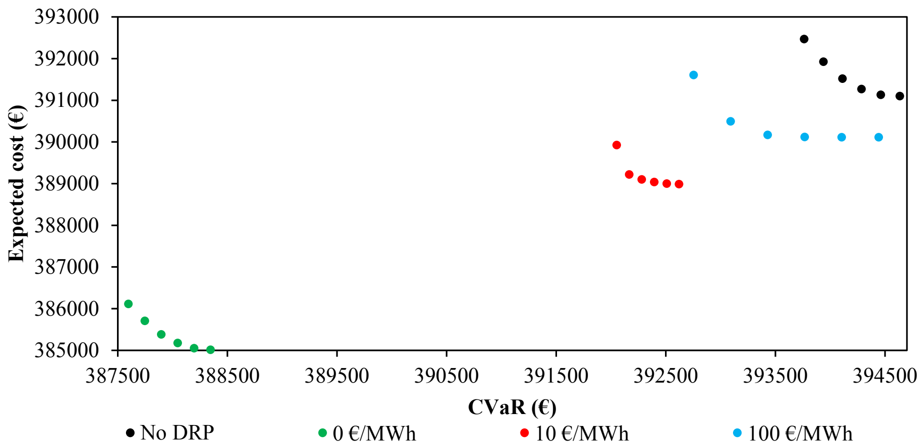

Figure 5.13: Efficient frontiers for different values of the cost of the energy not recovered

In Fig. 5.13 the efficient frontiers for different values of the cost of energy not recovered are comparatively presented. It may be noticed that as the cost of the energy that is not recovered following a load curtailment increases the efficient frontiers shift upwards and rightwards. This implies that both the expected cost and the CVaR values increase. This behavior can be justified by examining the results that are listed in Table 5.3. Note that solution number 1 corresponds to the solution with the maximum CVaR value. It may be noticed that for all the cases, as the CVaR decreases, the day-ahead energy cost increases as a result of scheduling less wind energy. Note that the least cost increase is noticed for a cost of energy not recovered equal to 0 €/MWh. The scheduling of wind energy in the day-ahead market is promoted when a higher amount of up DRP reserves are scheduled due to the absence of the load recovery constraint, as indicated by the increased cost of DRP scheduled reserve, since the mechanism of controlling risk is the reduction in reserve costs, as mentioned before. The aforementioned facts indicate that the ability of the demand side to contribute to reducing the risk associated with the decisions of the ISO is limited by the load recovery constraint.

In the third case all the loads are considered to be represented by a DRP with a demand modification rate of 100% of their nominal demand and a load recovery of type 1 and a load recovery rate equal to 100%. The load pickup and drop rates are considered equal to 10 MW/min. The cost for energy not recovered is set to 100 €/MWh and the effect of the reserve scheduling and deployment cost is examined assuming that the DRP deployment cost is double than the cost of scheduling demand side reserves. The efficient frontiers for different DRP reserve scheduling and deployment cost are illustrated in Fig. 5.14. It is shown that as the cost of DRP reserves decreases the efficient frontiers shift downwards and leftwards which means that both the CVaR and the expected cost decrease. Evidently, the results are very sensitive to the cost of the DRP reserve cost.

Finally, in the fourth case all the loads are considered to be represented by a DRP with a demand modification rate of 1% of their nominal demand and a load recovery rate equal to 100%, while the load recovery is of type 1. The load pickup and drop rates are considered equal to 10 MW/min. The cost of scheduling reserves from the DRPs is 1 €/MWh and the reserve exercise cost is 2 €/MWh, while the cost for the energy not recovered is 100 €/MWh. For the application of the classic approach the set of weights $\beta = [0, 0.2, 0.4, 0.6, 0.8, 1]$ is used. The relevant results are displayed in Fig. 5.15. It may be noticed that solutions A and B dominate the solutions obtained for $\beta = 0$

Table 5.3: Decomposition of cost and energy components for different values of cost of energy not recovered

Solution number	Energy cost (€)	Wind energy scheduled (MWh)	Generation side reserve cost (€)	DRP reserve cost (€)	DRP reserve deployment cost (€)	Expected wind spillage (MWh)	Expected energy not recovered (MWh)
			Without DRP				
1	373543.918	2483	1797.940	0	0	40.252	0
2	373574.278	2483	1623.288	0	0	54.152	0
3	373720.458	2473	1448.616	0	0	78.395	0
4	374285.792	2436.167	1273.944	0	0	105.295	0
5	375113.992	2381.873	1099.272	0	0	142.330	0
6	375972.462	2318.654	924.600	0	0	195.865	0
			100 €/MWh				
1	372369.421	2472.630	1615.690	219.990	358.520	33.077	1.007
2	372345.036	2474.744	1670.027	207.986	353.710	33.077	0.566
3	372320.062	2477.740	1723.551	197.990	337.860	33.101	0.122
4	372272.510	2488.640	1493.288	195.990	315.090	53.929	0
5	373195.980	2435.760	1156.414	195.990	228.150	91.969	0
6	374929.106	2293.760	796.292	188.200	188.020	215.694	0
			10 €/MWh				
1	369446.528	2713.470	896.009	465.150	550.850	16.529	232.552
2	370023.949	2671.080	757.071	459.150	485	22.752	196.815
3	370369.686	2645.017	658.511	448.740	441.450	28.456	170.309
4	370833.466	2613.898	552.003	442.740	392.780	34.887	144.310
5	371390.204	2576.956	450.056	428.376	346.180	43.585	116.056
6	373551.048	2416.510	181.760	350.750	200.430	108.922	22.640
			0 €/MWh				
1	367216.484	2919.860	1613.164	527.740	942.310	1.477	471.155
2	367242.112	2919.860	1463.534	527.740	913.940	1.286	456.649
3	367290.205	2917.670	1312.358	527.740	871.870	2.662	435.616
4	367661.022	2890.778	1162.729	527.740	820.050	4.617	409.636
5	368137.452	2854.080	1013.099	527.740	743.410	7.870	371.243
6	368759.888	2809.030	863.470	527.740	660.740	12.220	330.024

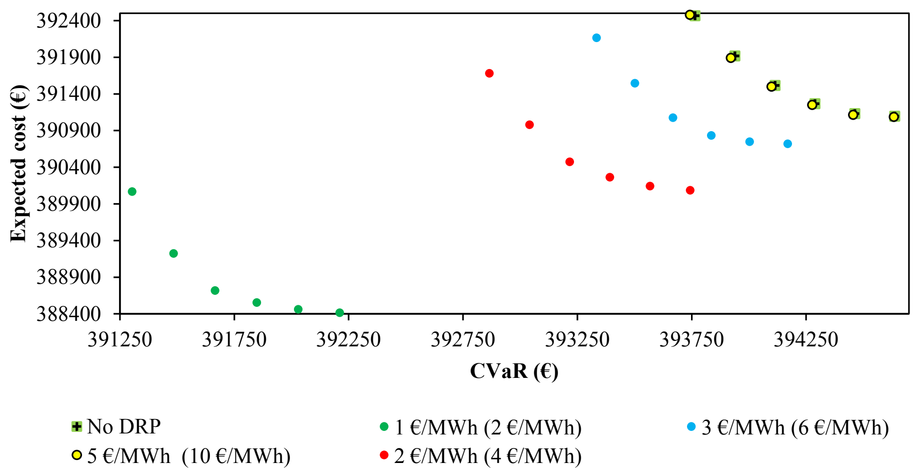

Figure 5.14: Efficient frontiers for different scheduling and deployment costs of DRP reserve

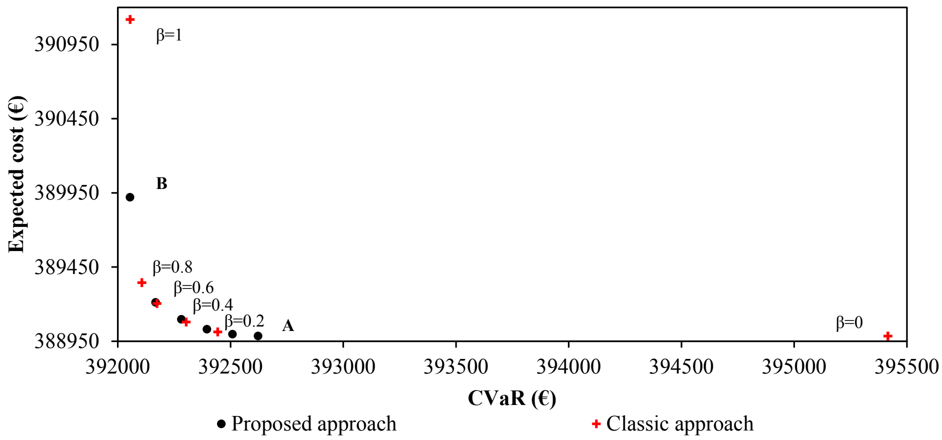

Figure 5.15: Comparison of efficient frontiers: classic vs. the proposed approach (24 bus system)

and $\beta = 1$ respectively. Furthermore, in this case that only a few points are used to evaluate the efficient frontier, the proposed approach returns a more meaningful mapping. Also, the ranking of the solutions for different values of the expected cost weight are presented in Table 5.4 while the average similarity index for the different solutions is listed in Table 5.5. It may be noticed that the solutions with the highest average similarity index are solutions 4 and 5. These solutions have a relatively good position in the ranking for all the values of the expected cost weight.

5.3.3 Computational statistics

All the simulations are performed on a workstation with 256 GB of RAM memory, employing two 16-core Intel Xeon processors clocking at 3.10 GHz running on a 64-bit windows distribution. The maximum allowed relative optimality gap is set to 0%.

Indicative results from the simulations presented in this chapter are presented in Tables 5.6 and 5.7. It may be noticed that the simulations on the 6-bus system are trivial from the perspective of the computational burden. However, when the load recovery is of type 2 the computational time increases by thirteen times. This is the effect of the stricter intertemporal constraints that must be satisfied. The 24-bus system is characterized by an increased number of constraints and variables, especially discrete. As a result, 264 sec are required for the solution of each optimization subproblem for the last case examined.

5.4 Chapter Conclusions

In this chapter a two-stage stochastic joint energy and reserve market structure in which generation and demand side resources may be deployed in order to balance the wind power generation deviations was presented. Demand side resources are thought to be a useful tool in mitigating the risk that is embedded in the decisions of the ISO and are a result of the uncertainty of the wind power generation. However, the deployment of demand side reserves should not be viewed as a mere reduction in the load; the internal energy balance of the load must be maintained and

Table 5.4: Ranking of efficient solutions for different values of expected cost weight

Expected cost weight						
1	**1** 1.000	**2** 0.988	**3** 0.951	**4** 0.880	**5** 0.757	**6** 0.000
0.9	**2** 0.947	**3** 0.937	**1** 0.937	**4** 0.877	**5** 0.757	**6** 0.063
0.8	**3** 0.902	**2** 0.891	**1** 0.869	**4** 0.868	**5** 0.758	**6** 0.131
0.7	**3** 0.855	**4** 0.849	**2** 0.827	**1** 0.795	**5** 0.760	**6** 0.205
0.6	**4** 0.820	**3** 0.797	**5** 0.763	**2** 0.755	**1** 0.713	**6** 0.287
0.5	**4** 0.779	**5** 0.768	**3** 0.729	**2** 0.673	**1** 0.624	**6** 0.376
0.4	**5** 0.776	**4** 0.731	**3** 0.651	**2** 0.581	**1** 0.525	**6** 0.475
0.3	**5** 0.785	**4** 0.679	**6** 0.585	**3** 0.566	**2** 0.477	**1** 0.415
0.2	**5** 0.793	**6** 0.707	**4** 0.635	**3** 0.483	**2** 0.363	**1** 0.293
0.1	**6** 0.844	**5** 0.798	**4** 0.608	**3** 0.421	**2** 0.253	**1** 0.156
0	**6** 1.000	**5** 0.800	**4** 0.600	**3** 0.400	**2** 0.200	**1** 0.000

Table 5.5: Average similarity index of different solutions (24 bus system)

Solution	Average similarity index
1	0.575
2	0.632
3	0.699
4	0.756
5	0.774
6	0.424

Table 5.6: Computational statistics (6-bus system)

	Load recovery of type 1	Load recovery of type 2
Equations	37454	39254
Continuous variables	140121	138636
Discrete variables	2172	2172
Time (s)	6.51	85

Table 5.7: Computational statistics (24-bus system)

Equations	174589
Continuous variables	545984
Discrete variables	16743
Time (s)	264

therefore, the response of the demand side should be viewed as a redistribution of energy instead. Furthermore, the weighting method in order to model the risk averse behavior of the ISO has several drawbacks which in this chapter are addressed by introducing the AUGMECON method in order to solve the corresponding MOOP. Another issue that needs to be addressed is that the solution of the MOOP consists of a set of efficient solutions that express the trade-off between the expected cost and the value of the risk metric. The set of efficient solutions may comprise a large number of solutions, while the ISO must only select and implement one solution. For this purpose, a multi-attribute decision making approach, namely the TOPSIS method is employed. The proposed methodology is verified by performing numerical experiments both on an illustrative test system an on the IEEE Reliability Test System. Through these test cases the superiority of the proposed approach as regards the mapping of the efficient frontier is demonstrated. Also, these simulations have indicated that the capability of the demand side resources to mitigate the risk associated with the decisions of the ISO may be limited by the load recovery effect, especially when the load recovery must be materialized in a rigid manner.

Chapter 6

Conclusions

In this chapter the main conclusions of the thesis are highlighted on the basis of answering the research questions that constituted the main motivation of this research. Then, several points to guide future research are proposed. Finally, the publications of the Author are listed.

6.1 Main Conclusions

The results presented in this thesis allow for answers to be given to the research questions that were initially posed in Section 1.6.

- *What is the current status of DR applications in real power systems? Why DR is not yet widely adopted across the world despite its potential benefits?*

  In the past years a wide range of DR programs have been developed in different power systems accross the world. These programs aim at engaging all the types of consumers: from large industrial customers to residential end-users with relatively small electricity consumption, considering also special types of consumers such as the EV and data centers. Evidently, the North American markets are leading in the integration of demand side resources in the market operations. It is interesting to notice that apart from the programs that are addressed to large industrial consumers, suitably designed programs aim at aggregating the potential of a specific appliance that is located in the residential end-user premises such as the ACs. Also, there exist programs based on electricity pricing that aim at shifting load that in several cases have managed to engage even hundreds of thousands of participants. Apart from the North American countries, the EU countries have also demonstrated noticeable interest in developing DR programs with the UK and Belgium leading in this effort, while the EED is deemed to set off the maturation of the European DR market. Significant recent developments may be also noticed in Oceania whilst, less pronounced evolution can be noticed in Asian and African countries; however, several projects related to the deployment of DR programs are currently in the demonstration phase in many countries. Based on these facts it may be concluded that the development of DR across the world is characterized primarily by asymmetric forwarding and secondarily by attempts to activate the available demand side resources in the majority of regions through the funding of demonstration projects.

  The primary motive for developing DR programs is that by enabling the participation of the demand side in electricity markets significant benefits are anticipated: more efficient and sustainable system planning, enhancement of the operation of the distribution system, lower and more stable electricity prices in the long run, mitigation of the market power of several participants and promotion of competition, economic benefits for the consumers and increased operational flexibility. Increased operational flexibility is directly linked to accommodating the handicaps of the trend that indicates that significant amount of variable RES generation will be introduced in power systems in the future. The question therefore remains: why even if the benefits of DR have been recognized, the current status of DR fails to respond to what one would expect?

The answer to this question may be given by delving into the factors that limit the DR potential. The primary obstacle to the integration of DR resources in electricity markets comes from the applicable regulatory framework that define whether DR is an eligible system resource or not. In the U.S. NERC has provided technology neutral definitions that allow the direct participation of DR, while through the EED the European Commission has demonstrated interest in DR. However, unlike in the U.S. the progress in DR participation in the EU is hampered by the fact that the directives must be adjusted to a national level a process that may be opposed to the completion of the Internal Energy Market. A second important reason for constraining DR is that the market rules effectively exclude the participation of demand side resources because of technical requirements that are formulated based on a perception of the power system only with centralized generation. Although in the North American markets this problem has been long recognized and it has been addressed, in other regions the market entry criteria are not likely to change in the near future, a fact that will effectively limit the participation of DR in the market. Another important barrier is the confusion over the utilization and the verification of DR as a system resource, the lack of coordination and the conflicting interests of different market actors. Finally, activating demand side resources implies relatively costly investments which could exclude a wide range of consumer types for which the incentives in exchange for the uptake of such costs are not sufficient. All in all, these barriers not only do not allow the initiation of major DR programs in several regions but also procrastinate the accumulation of experience over utilizing the demand side in market operations which would allow the exploitation of the demand side resources to their full extent in the future.

- *Can demand side resources facilitate the system operations when apart from system contingencies and intra-hour load deviations, the ISO must also confront the uncertainty in the production of wind farms?*

  Contingencies are major events that cause energy deficits or disturbances in the active power flow through the transmission lines. On the other hand, the variations of the wind power generation and the intra-hour load demand require reserves to be procured in order to maintain the balance between the generation and the demand. In Chapter 3 a two-stage stochastic programming based joint energy and reserve market structure was developed in which apart from the generation side, the ISO may rely on two types of demand side resources in order to procure contingency and load following reserves. Based on the numerical studies that were presented the following conclusions may be reached:

  1. The need in reserves increases when contingencies are anticipated, leading in scheduling non spinning reserves from units that are scheduled to be off-line.
  2. The flexibility of the demand side is an important parameter; the higher the flexibility the more the day-ahead energy cost decreases due to shifting the load from the relatively high loading periods to relatively low demand periods.
  3. Apart from the energy cost, the cost of scheduling reserves from the generation side decreases when the demand side resources are considered, especially when the LSE renders its demand available to be optimally scheduled by the ISO. It should be noted

that the decrease in the reserve cost depends on the cost of utilizing demand side resources.

4. The ISO utilizes the contingency reserves offered by the demand side to their full extent.
5. The effect of the flexible demand side becomes more significant when increasing capacity of the wind farm is considered.

- *What are the qualifications for an industrial consumer to participate in the day-ahead energy and reserve market?*

  The review of existing DR programs that was presented in Chapter 2 suggests that a great number of them are addressed to industrial loads. Naturally, it is of interest to investigate how an industrial consumer can participate in the day-ahead energy and reserve market in order to provide services aiming at accommodating the uncertain wind power generation. Thus, in Chapter 4 a two-stage stochastic programming based joint energy and reserve market structure was developed in which the explicit participation of industrial loads is considered. In order to render available the flexibility that may be offered by industrial consumers appropriate modeling of the processes that are run by the industry is required. Thus, a novel load model in order to describe different types of processes as well as their behavior and constraints while providing system services was developed. The most important constraint that was considered refers to the fact that the total energy that is required by the industry must be provided during the scheduling horizon by respecting the operating characteristics of each process in order to prevent profit loss due to not providing energy in order to complete the necessary processes to fulfill the production goals of the industrial customer. Furthermore, the effect of the industrial load on the risk averse behavior of the ISO was investigated. The numerical results presented in Chapter 4 allow to conclude the following:

  1. The wind spillage cost that is an artificial penalty used in order to force the ISO to accept as much available wind as possible increases both the operational cost of the system as well as the associated risk.
  2. The day-ahead energy production cost as well as the total expected cost of the system is reduced when the industrial consumer participates in the market, while the cost reduction is greater for the case of processes with more flexible operational characteristics.
  3. The cost reduction resulting from the operation of the flexible industrial consumption is more evident as the levels of wind power generation penetration increase.
  4. The operation of the industrial consumer has an inherent capability of not only reducing the expected operational cost of the system but also the standard deviation of the cost in the considered scenarios.
  5. When the risk averse behavior of the ISO is considered the existence of a flexible industrial consumption leads to better trade-offs between the expected cost and CVaR.
  6. The means of controlling risk when only uncertain wind power generation is considered is the cost of scheduling reserves in order to cover imbalances between the scheduled wind energy in the day-ahead market and the realizations of the different scenarios.

- *What is the impact of the load recovery effect on the risk mitigation capability of demand side resources contributing to reserve services?*

  It is widely argued that demand side resources may contribute to the mitigation of the risk linked to the decisions of an ISO when high levels of wind power generation are considered since the cost of their participation in the market is deemed less than the cost of procuring reserves from the generation side. However, apart from the cost at which the demand side offers to provide system services, the fact that DR implies that the load curtailed during a specific period should be potentially recovered in other periods, in other words the intertemporal characteristics of the load must be also considered. The load recovery effect may constitute a factor that limits the usableness of demand side resources and therefore, their risk mitigation potential. For this purpose, in Chapter 5 the problem faced by a risk averse ISO that must procure reserves in order to balance the uncertain wind production in the day-ahead market is formulated as a multi-objective two-stage stochastic programming based problem with the objectives of minimizing both the expected cost of the system and the CVaR metric considering two different types of load recovery. Based on the numerical studies conducted in Chapter 5 the following remarks should be considered:

1. The load curtailment and recovery periods may be optimally coordinated so that the load recovery effect serves as a source of downward reserve. Also, the load curtailment and recovery of different DRPs may be coordinated in order to procure appropriate amounts of up and down reserve.
2. The mechanism of controlling risk is the reduction of the cost of scheduling reserves in order to balance the wind power generation imbalances.
3. The technical parameters of the load have a major effect on the obtained efficient frontiers that express the trade-offs between expected cost and risk. Higher flexibility of the load provides a superior set of efficient solutions while market rules such as constraints regarding the percentage of the reserves that may come from the demand side lead to worse sets of efficient solutions. It is important to notice that the load recovery rate is a parameter to which the obtained sets of efficient solutions are very sensitive. The best results are associated with a mere load curtailment without having to reimburse it, while the sets of the efficient solutions are comparatively worse for higher values of this parameter. Furthermore, the cost at which the services of the DRPs are offered have a direct effect on the amount of demand side reserves scheduled and therefore, on the obtained efficient frontiers.

- *Is there a more efficient approach to consider risk management than the weighting method in the day-ahead energy and reserve scheduling problem faced by the ISO?*

  In Chapter 5 instead of utilizing the approach that is commonly used in the relevant literature (the weighting method) an improved version of the ε-constraint method, the AUGMECON method, was proposed in order to solve the multi-objective problem and construct the efficient frontier that expresses the trade-off between the expected cost and the value of the CVaR metric. The numerical studies have demonstrated the superiority of AUGMECON as opposed to the weighting method in mapping the set of efficient solutions. First of all, the AUGMECON method due to the use of lexicographic optimization returns two solutions that dominate the weakly efficient solutions from the application of the classic approach for the extremely risk averse and the risk neutral problems, achieving a lower value of expected cost and CVaR for the same value of CVaR and expected cost, respectively. The AUGMECON method presents two additional advantages: it is guaranteed that each point at which the efficient set is evaluated returns a unique efficient solution, while a more even mapping of the efficient frontier is obtained, rendering vague the selection of the appropriate set of weights for the two objectives. Overall, it may be said that in the general case more unique efficient solutions are obtained for the same number of optimization problems that are solved. Furthermore, if it is required, the AUGMECON method might be iteratively used in order to map in more detail a specific region of the efficient frontier.

6.2 Recommendations for Future Work

The following points may be further studied in order to broaden the understanding of the topics treated in this thesis:

- The main source of uncertainty which is characterized using scenarios is the wind power generation. Nevertheless, uncertainty resides in a series of other parameters such as the load demand, production cost of conventional generators and the response of the demand side resources to the calls of the ISO. Thus, an important research topic is the development of a methodology to evaluate and generate appropriate scenarios for all the uncertain parameters.
- The joint energy and reserve day-ahead pool-based market structures presented in this thesis may be extended by including shorter-term markets such as intra-day markets.
- The increasing penetration of wind power generation may have an impact on the planning of the power systems. Thus, the consideration of demand side resources in system expansion studies is an important topic that needs to be investigated.
- The participation of demand side resources in electricity markets may be viewed from the perspective of a consumer. Thus, bidding strategies for the consumers may be developed on the basis of the models presented in this thesis.
- As it has been highlighted stochastic models may bear a significant computational burden which may hamper their applicability. Several measures can be applied in order to reduce the computational time required to solve such models. First, modern computing techniques such as grid and cloud computing may be used. Since there are already companies that provide computational power at affordable prices, this proposal promises tractability even for large-scale mathematical programming problems. Also, commercially available software has evolved to support such techniques, recently. Although the technological advances are of unquestionable importance, special attention should be given to the efficient modeling of a problem. Decomposition techniques, such as Benders' Decomposition, allow exploiting efficiently the developments in the informatics field.

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Appendices

Appendix A

Multi-Objective Optimization Using the AUGMECON Method

A.1 An Illustrative Multi-Objective Optimization Problem

To clarify the concepts that were discussed in Section 1.5.2, a simple arithmetical example is employed. For the sake of simplicity, let us consider the multi-objective LP problem described in (A.1) which has 2 decision variables and 2 objective functions, both to be maximized. The decision variable space, the direction of the objective functions and the objective function space are portrayed in Fig. A.1.

$$
\begin{aligned}
&\max\ f_1 = x_2 \\
&\max\ f_2 = 3x_1 + 4x_2 \\
&\textit{subject to} \\
&x_1 + x_2 \leq 2 \\
&x_1 \leq 1.5 \\
&x_1 + \frac{8}{3}x_2 \leq 4 \\
&x_1, x_2 \geq 0
\end{aligned}
\tag{A.1}
$$

The feasible region of the optimization problem (A.1) is enclosed by the polytope (O, A, B, C, D). It can be easily verified that objective function f_1 has an individual optimum value of 1.5 at point D at which $f_2 = 6$, while objective function f_2 has an individual optimum value of 7.2 at point C at which $f_1 = 1.2$. Evidently the two objectives are conflicting and it is interesting to notice an infeasible point in the objective function space that is named *ideal objective vector* and is denoted by I. This is the solution that would simultaneously optimize both objective functions and would strongly dominate all the other solutions. By applying the concepts of dominance that were described in Section 1.5.2.1 one may easily verify that the solutions on the segment $(C'D')$ are incomparable with each other and in the same time dominate all the other solutions. Thus, the segment $(C'D')$ is the Pareto optimal set of the problem (A.1). Note that the Pareto optimal set is infinite. The aim of a multi-objective optimization solution technique is to discover a set of solutions that would provide the DM with an adequate picture of the possible trade-offs in the objective function.

In this appendix, the AUGMECON technique is demonstrated by applying it to solve the LP problem (A.1). It should be noted that the application of this technique to other types of mathematical programming problems is straightforward.

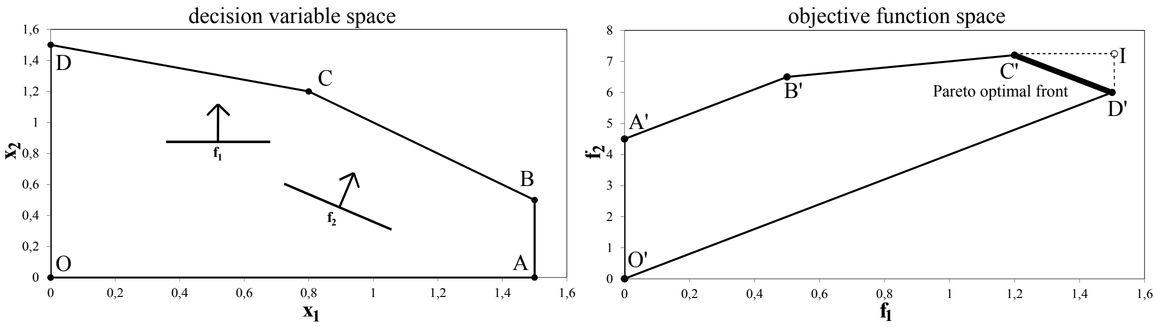

Figure A.1: Decision variable space and objective function space of the example multi-objective optimization problem

A.2 Solution Procedure Using the AUGMECON Method

The first step in the application of AUGMECON is to transform the problem as in the classical ε-constraint method, that is to to optimize one of the objective functions using the other as an inequality constraint. By parametrically varying the RHS of the constraint objective function (e) in (A.2) the efficient solutions of the problem are obtained.

$$
\begin{aligned}
&\max \;\; f_1 = x_2 \\
&\textit{subject to} \\
&3x_1 + 4x_2 \geq e \\
&x_1 + x_2 \leq 2 \\
&x_1 \leq 1.5 \\
&x_1 + \frac{8}{3}x_2 \leq 4 \\
&x_1, x_2 \geq 0
\end{aligned}
\tag{A.2}
$$

The second step is to calculate the range in which the parameter e should vary. In order to properly apply the ε-constraint method the range of the objective function that is transformed to an inequality constraint over the Pareto optimal set must be calculated. The best value is the value that corresponds to the individual optimization of each objective function which is an extreme Pareto optimal solution. The worst value over the Pareto optimal set must be also a Pareto optimal solution. To guarantee this, the AUGMECON method employs lexicographic optimization in order to calculate the pay-off table, that in the case of (A.2) means firstly to individually optimize f_1 and then to individually optimize f_2 by adding the previous optimal solution as an equality constraint. One can easily verify that this would yield the range $[6, 7.2]$ for e.

The third step consists of selecting the number of grid points that will be used in order to approximate the Pareto optimal front. Increasing the number of grid points leads to a more dense representation of the Pareto optimal frontier; however, it increases the number of iterations that in turn may lead to increased computational time for more complex problems or for problems for more than two objectives. For this illustrative example, let us consider that 6 evenly-spaced grid points are used. This implies that $e = \{6, 6.24, 6.48, 6.72, 6.96, 7.2\}$.

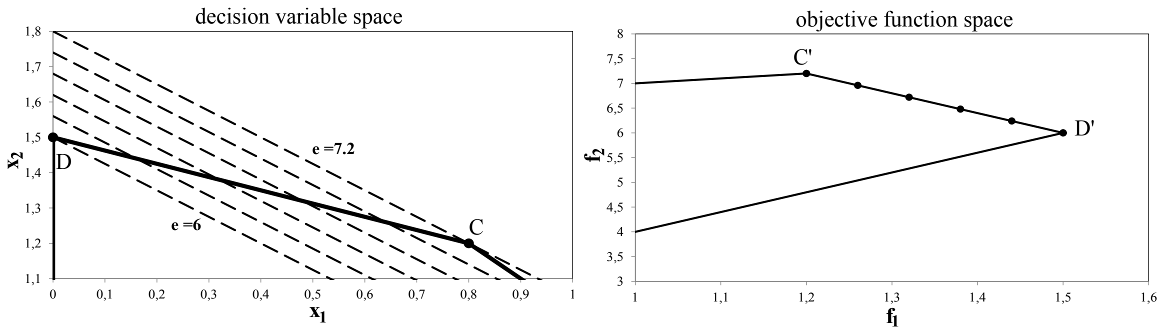

Figure A.2: Solution of the multi-objective optimization problem using AUGMECON

The application of the AUGMECON method to solve the optimization problem is illustrated in Fig. A.2. Given that AUGMECON is an improved variant of the ε-constraint method, the working principle is the same: the efficient solutions discovered are given by the intersection of the segment (DC) and the dashed lines that correspond to different values of the parameter e.

AUGMECON has a series of advantages that qualify it as an effective excact multi-objective optimization solution technique:

- Unlike the weighting method, that is to transform the multi-objective problem to a single objective one through weighting the diferrent objective functions and combining them into a composite scalar objective function, AUGMECON can discover solutions when the Pareto optimal front is non-convex. Furthermore, the objective functions do not need to be expressed in the same physical units. Additionally, a more even approximation of the Pareto optimal front is achievable since in the weighting method, an even set of weights does not guarantee an even distribution of the solutions. Finally, the weighting method suffers from the fact that the same solution may be discovered for different combinations of the weights. For example, in the example presented in this appendix, the application of the weighting method would only discover one of the two extreme optimal solutions C' and D' for any combination of (positive valued) weights.
- It addresses the pitfalls of the classical ε-constraint method since: 1) the solutions are proven to be on the Pareto optimal front, 2) the ranges of the objective functions are in the Pareto optimal set and, 3) the computational efficiency may be enhanced by the application of several acceleration techniques.

A more detailed treatment of the AUGMECON method together with the necessary proofs can be found in [304] while suggestions to enhance its computational performance have been presented in [306].

Appendix B

Wind Power Production Scenarios

In this appendix the wind power generation scenario technique adopted throughout this thesis is presented. The scenario generation technique is based on forecasting using time series models [307] utilizing the ECOTOOL MATLAB toolbox [308]. Historical data regarding the total production of the wind farms located in the island of Crete are collected from the database of the SiNGULAR project [132] for the years 2011 and 2012. The wind farms have an installed capacity of 176.5 MW. Scenarios are created for the randomly selected day 4/9/2012.

The normalized (with respect to the total installed capacity) historical time series spanning from 20/6/2012 to 3/9/2012 is displayed in Fig. B.1. Firstly, in order to stabilize the variance of the time series, the logarithmic transformation is applied to the original data. Subsequently, the logarithmically transformed time series is applied to an ARIMA model.

The generic form of the ARIMA model is represented by Eq. (B.1).

$$\psi_t = c + \frac{1}{(1-B)^{d_0}(1-B^{s_1})^{d_1}\dots(1-B^{s_k})^{d_k}} \frac{\theta_{q_0}(B)}{\phi_{p_0}(B)} \frac{\theta_{q_1}(B^{s_1})}{\phi_{p_1}(B^{s_1})} \cdots \frac{\theta_{q_k}(B^{s_k})}{\phi_{p_k}(B^{s_k})} \varepsilon_t \tag{B.1}$$

where ψ_t stands for the observed time series; ε_t is Gaussian white noise with zero mean and constant variance; $s_j, (j = 0, 1, \dots, k)$ are a set of seasonal periods, with $s_0 = 1$; $(1 - B^{s_j})^{d_j}, (j = 0, 1, \dots, k)$ are the $k + 1$ differencing operators necessary to reduce the time series to mean stationarity; $\theta_{q_j}(B^{s_j})$ and $\phi_{q_j}(B^{s_j}), (j = 0, 1, \dots, k)$ are invertible and stationary polynomials in the backshift operator $B : B^l = y_{t-l}$ of the type $\theta_{q_j}(B^{s_j}) = (1 + \theta_1 B^{s_j} + \theta_2 B^{2s_j} + \dots + \theta_{q_j} B^{q_j s_j})$; c is a constant.

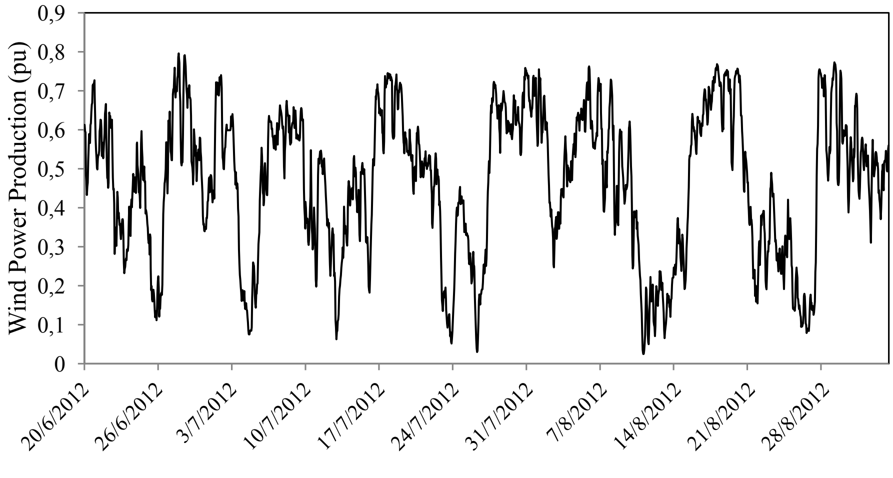

Figure B.1: Normalized historical wind farm production

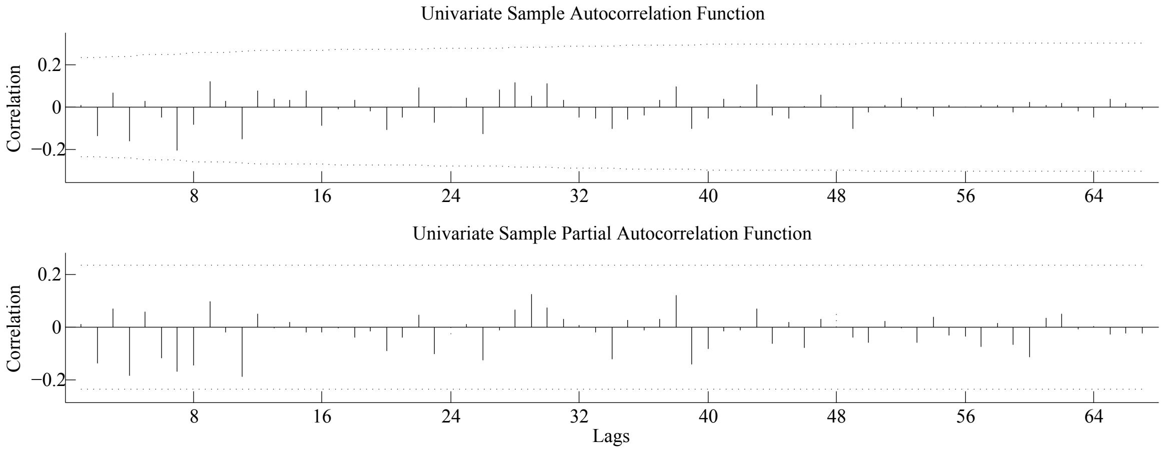

Figure B.2: ACF and PACF of the residuals

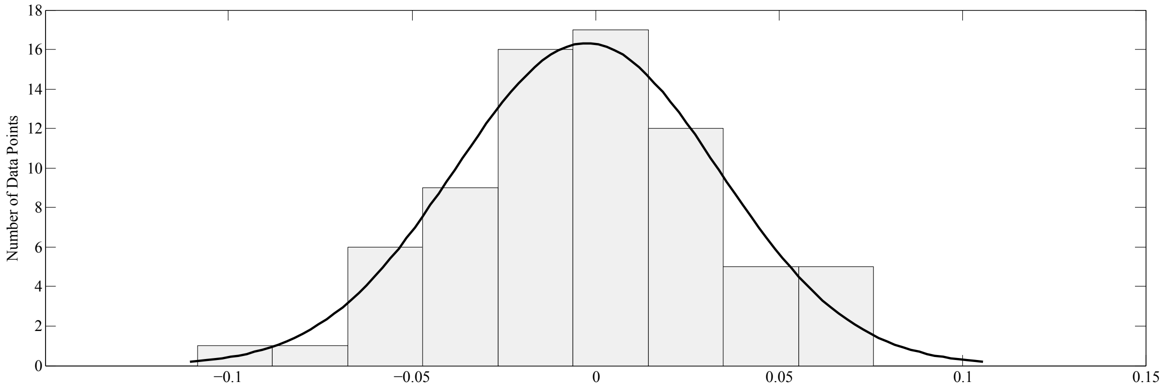

Figure B.3: Histogram of the residuals

For example, the particular ARIMA fit to the time series spanning from 28/8/2012-3/9/2012 is presented in (B.2).

$$
\begin{aligned}
\log y_t = c + & \frac{1}{(1-B)(1-B^{24})} \\
& \frac{(1-\theta_1 B^1 - \theta_2 B^2 - \theta_3 B^3 - \theta_4 B^4 - \theta_5 B^5 - \theta_9 B^9 - \theta_{13} B^{13} - \theta_{14} B^{14})}{(1-\phi_1 B^1 - \phi_2 B^2 - \phi_3 B^3 - \phi_4 B^4 - \phi_5 B^5 - \phi_6 B^6)} \\
& \frac{(1-\theta_{17} B^{17} - \theta_{18} B^{18} - \theta_{24} B^{24} - \theta_{31} B^{31} - \theta_{48} B^{48})}{(1-\phi_{12} B^{12} - \phi_{13} B^{13} - \phi_{14} B^{14} - \phi_{17} B^{17})} \\
& \frac{1}{(1-\phi_{24} B^{24})} \varepsilon_t
\end{aligned}
\tag{B.2}
$$

Statistical models have two components: the fitted model and the residuals. Residuals are thought of as error incurred from using the estimated model in order to describe the response variable. For a credible forecast it is important to assure that the residuals do not contain any information that could be captured by a better fit. Ideally, the residuals should follow a Normal distribution. In order to test the normality assumption regarding the residuals resulting from the fit of (B.2), two graphical tools are used: the autocorrelation function (ACF) and the partial autocorrelation function (PACF), as well as the historgram of the residuals as opposed to a theoretical Normal distribution. The results are displayed in Figs. B.2 and B.3, respectively.

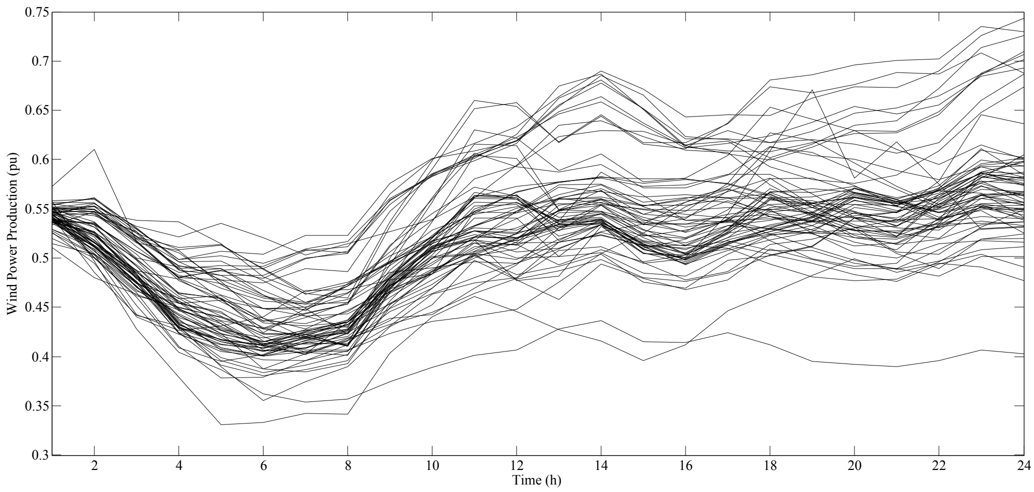

Figure B.4: Initial set of scenarios

To generate wind power generation scenarios, several ARIMA models are fit to the observed time series. The rationale followed in this thesis is that forecasting is performed for the 24 h of a specific day by considering different ranges of historical data. More specifically, starting from the first past week, a day is added to the time series and the forecasting is repeated, while a new ARIMA model is fit when adding a whole new week to the data range. For example, a particular ARIMA model is estimated both when performing a forecast based on the 7 previous days and the 14 previous days; however, the forecasts that are also considering the 8 to 13 previous days are performed using the ARIMA model that was fit for the 7-day forecast. Following this procedure and by considering historical data spanning from 20/6/2012 to 3/9/2012 the initial pool of 70 equiprobable scenarios portrayed in Fig. B.4 is constructed.

The computational performance of the stochastic programming models strongly depends on the size of the scenario set. In this respect, a scenario reduction technique based on the k-means clustering algorithm [309] is applied in order to reduce the number of scenarios by substituting the initial scenario set by an approximate representative set of non-equiprobable scenarios. The outcome of the scenario reduction for each of the case studies examined in this thesis is presented in Appendix C.

Appendix C

Test Systems

In this appendix the data of the test systems used in this thesis are presented. The simulations are performed on a suitably modified version of the IEEE Reliability Test System [310]. The topology of the system is presented in Section C.1. The data that are used in the simulations performed in this thesis are based on the data presented in [32] and [311]. The specific data used in each chapter are listed in Sections C.2 and C.3.

C.1 System Data

The system comprises 24 buses and 34 transmission lines which are arranged as illustrated in Fig. C.1. The data of the transmission system are presented in Table C.1. The original system comprises 32 generating units of different technologies. In order to reduce the number of binary variables related to controlling the commitment status of the generating units, a technique that is commonly used in the relevant literature is used (e.g., in [32] and [283]). The units are grouped by type and bus. The idea behind this simplification is that units of the same technology (e.g., hydro, nuclear, etc.) that are connected at the same bus are controlled using the same set of binary variables. The maximum power output of the grouped units is the sum of maximum power output of each single unit and the minimum power output is the sum of the minimum power output of each generating unit. The reduction of the computational burden is related to the number of units that are grouped and their location and not on the number of buses. The application of this technique results in 12 generating units. The bus to which these units are connected is presented in Table C.2.

C.2 Data for the Simulations Performed in Chapter 3

The technical and economic data of the conventional generators that are used in Chapter 3 are presented in Tables C.3 and C.4, respectively. Data concerning the system loading are presented in Table C.5. Finally, the 10 wind power generation scenarios that are used are displayed in Fig. C.2 while their probability of occurrence are listed in Table C.6.

C.3 Data for the Simulations Performed in Chapters 4 and 5

The technical and economic data of the conventional generators that are used in Chapters 4 and 5 are presented in Tables C.7 and C.4, respectively. Data concerning the system loading are presented

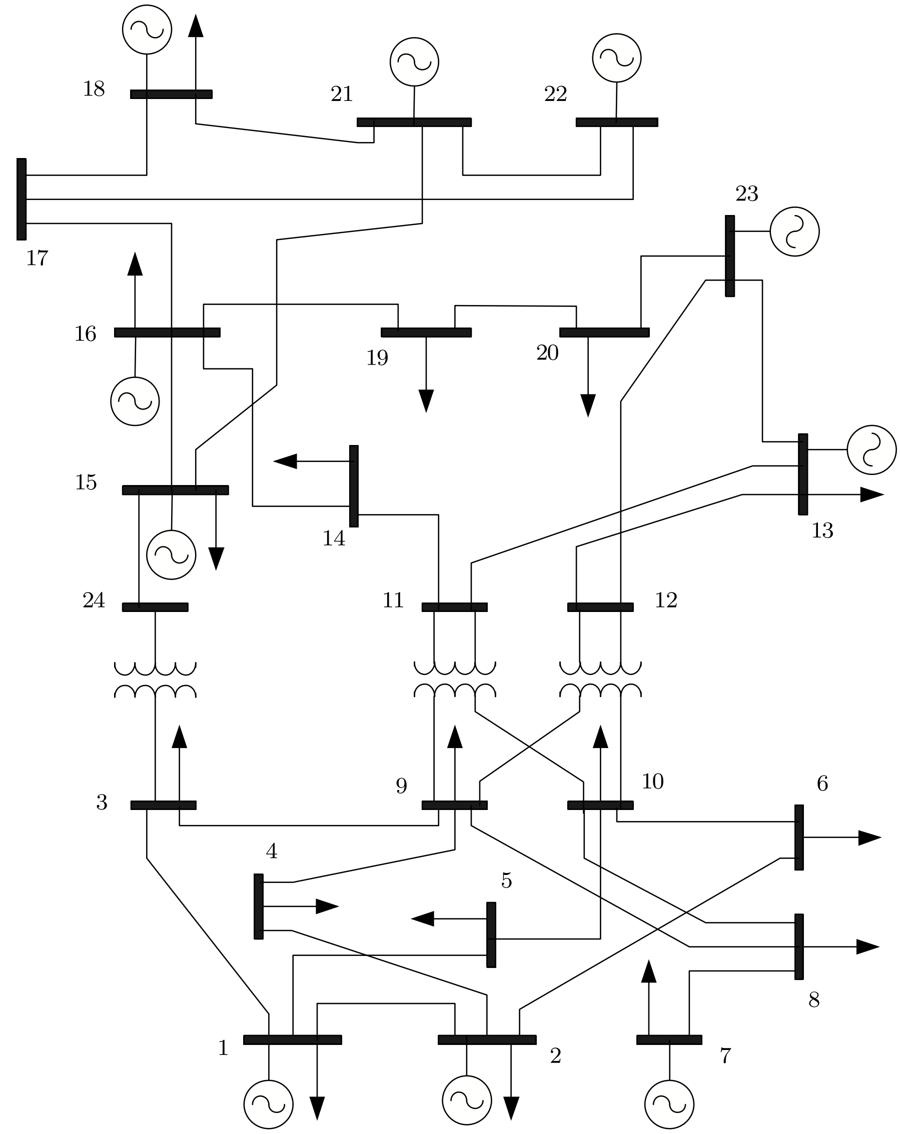

Figure C.1: The 24-bus system

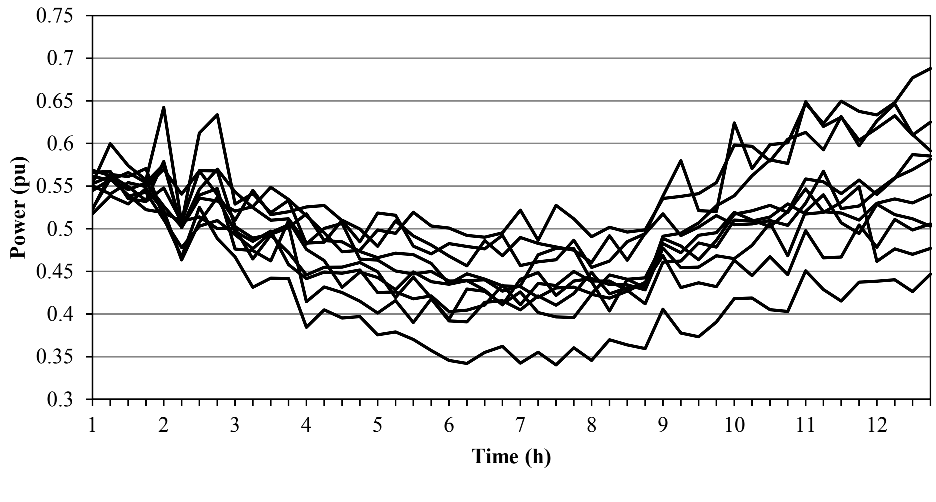

Figure C.2: 10 wind power generation scenarios (Chapter 3)

Table C.1: Characteristics of the transmission system

Line No.	From Bus	To Bus	X (pu)	Flow limit (MW)
1	1	2	0.0146	175
2	1	3	0.2253	175
3	1	5	0.0907	175
4	2	4	0.1356	175
5	2	6	0.2050	175
6	3	9	0.1271	175
7	3	24	0.0840	400
8	4	9	0.1110	175
9	5	10	0.0940	175
10	6	10	0.0642	175
11	7	8	0.0652	175
12	8	9	0.1762	175
13	8	10	0.1762	175
14	9	11	0.0840	400
15	9	12	0.0840	400
16	10	11	0.0840	400
17	10	12	0.0840	400
18	11	13	0.0488	500
19	11	14	0.0426	500
20	12	13	0.0488	500
21	12	23	0.0985	500
22	13	23	0.0884	500
23	14	16	0.0594	500
24	15	16	0.0172	500
25	15	21	0.0249	1000
26	15	24	0.0529	500
27	16	17	0.0263	500
28	16	19	0.0234	500
29	17	18	0.0143	500
30	17	22	0.1069	500
31	18	21	0.0132	1000
32	19	20	0.0203	1000
33	20	23	0.0112	1000
34	21	22	0.0692	500

Table C.2: Location of generating units

Unit	Bus
1	1
2	2
3	7
4	13
5	15
6	15
7	16
8	18
9	21
10	22
11	23
12	23

Table C.3: Technical data of conventional generators (Chapter 3)

Unit	Maximum output (MW)	Minimum output (MW)	Minimum up time (h/min)		Minimum down time (h/min)		Ramp up rate (MW/min)	Ramp down rate (MW/min)	Initial output (MW)	Periods committed (h/min)	
U1	152	30.4	8	480	4	240	5	5	35	22	1320
U2	152	30.4	8	480	4	240	5	5	35	22	1320
U3	300	75	8	480	8	480	10	10	0	-20	-1200
U4	591	206.85	12	720	10	600	18	18	0	-10	-600
U5	60	12	4	240	2	120	2	2	60	10	600
U6	155	54.25	8	480	8	480	5.2	5.2	0	-20	-1200
U7	155	54.25	8	480	8	480	5.2	5.2	55	10	60
U8	400	100	1	0	1	60	13.4	13.4	400	769	76140
U9	400	100	1	60	1	60	13.4	13.4	400	16	960
U10	300	300	0	0	0	0	10	10	300	24	1440
U11	310	108.5	8	480	8	480	10.4	10.4	140	10	600
U12	350	140	24	1440	48	2880	8	8	140	30	1800

Table C.4: Economic data of conventional generators (Chapters 3, 4 and 5)

Unit	Power blocks (MW)				Marginal costs (€/MWh)				Reserve cost (€)	Startup cost (€)	Shutdown cost (€)
	B1	B2	B3	B4	C1	C2	C3	C4			
U1	30.4	45.6	45.6	30.4	11.46	11.96	13.89	15.97	16	1430.4	1430.4
U2	30.4	45.6	45.6	30.4	11.46	11.96	13.89	15.97	16	1430.4	1430.4
U3	75	75	90	60	18.6	20.03	21.67	22.72	23	1725	1725
U4	206.85	147.75	118.2	118.2	19.2	20.32	21.22	22.13	23	3056.7	3056.7
U5	12	18	18	12	23.41	23.78	26.84	30.4	30	437	437
U6	54.25	38.75	31	31	9.92	10.25	10.68	11.26	11	312	312
U7	54.25	38.75	31	31	9.92	10.25	10.68	11.26	11	312	312
U8	100	100	120	80	5.31	5.38	5.53	5.66	5	0	0
U9	100	100	120	80	5.31	5.38	5.53	5.66	5	0	0
U10	300	0	0	0	0	0	0	0	0	0	0
U11	108.5	77.5	62	62	9.92	10.25	10.68	11.26	12	624	624
U12	140	87.5	52.5	70	10.08	10.66	11.09	11.72	12	2298	2298

Table C.5: System load (Chapter 3)

Period	Inelastic system load (MW)	Load bus	Percentage of system load (%)
1	1776	1	3.802
2	1670	2	3.404
3	1590	3	6.304
4	1563	4	2.597
5	1563	5	2.503
6	1590	6	4.790
7	1963	7	4.402
8	2281	8	6
9	2520	9	6.095
10	2546	10	6.793
11	2546	13	9.291
12	2520	14	6.793
		15	11.105
		16	3.503
		18	11.703
		19	6.404
		20	4.500

Table C.6: Probabilities of scenarios (Chapter 3)

Scenario	Probability (%)
s1	10
s2	4.28
s3	14.28
s4	2.85
s5	20
s6	5.71
s7	17.14
s8	1.42
s9	14.28
s10	10

Table C.7: Technical data of conventional generators (Chapters 4 and 5)

Unit	Maximum output (MW)	Minimum output (MW)	Minimum up time (h)	Minimum down time (h)	Ramp up rate (MW/min)	Ramp down rate (MW/min)	Initial output (MW)	Periods committed (h)
U1	152	30.4	8	4	2.5	2.5	35	22
U2	152	30.4	8	4	2.5	2.5	35	22
U3	300	75	8	8	5	5	0	-20
U4	591	206.85	12	10	9	9	0	-10
U5	60	12	4	2	1	1	0	-10
U6	155	54.25	8	8	2.6	2.6	0	-20
U7	155	54.25	8	8	2.6	2.6	55	10
U8	400	100	1	1	6.7	6.7	400	769
U9	400	100	1	1	6.7	6.7	400	16
U10	300	300	0	0	5	5	300	24
U11	310	108.5	8	8	5.2	5.2	140	10
U12	350	140	24	48	4	4	140	30

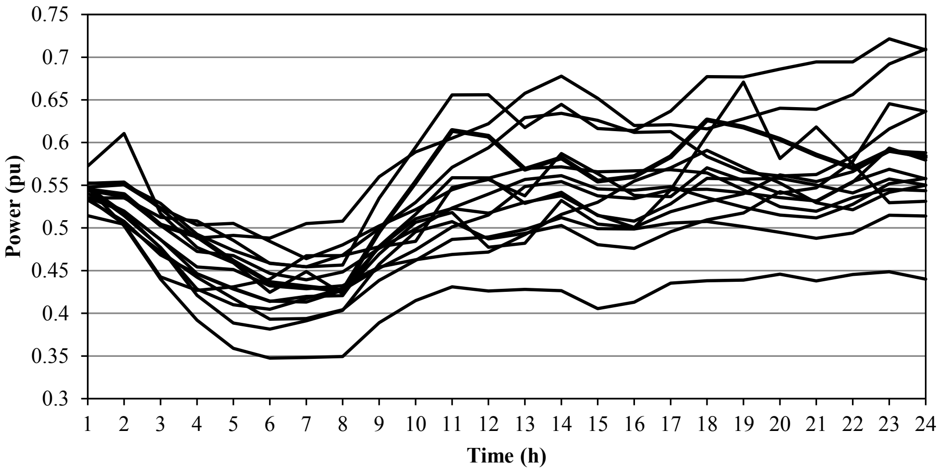

Figure C.3: 15 wind power generation scenarios (Chapters 4 and 5)

in Table C.8. Finally, the 15 wind power generation scenarios that are considered are displayed in Fig. C.3 while their probabilities of occurrence are listed in Table C.9.

Table C.8: System load (Chapters 4 and 5)

Period	Inelastic system load (MW)	Load bus	Percentage of system load (%)
1	1689	1	4.026
2	1588	2	1.776
3	1512	3	6.631
4	1486.5	4	2.724
5	1486.5	5	2.605
6	1512	6	5.033
7	1866.5	7	4.618
8	2169	8	6.335
9	2396.5	9	6.394
10	2421	10	7.164
11	2421	13	9.769
12	2396.5	14	7.164
13	2396.5	15	11.664
14	2396.5	16	3.671
15	2345	18	12.315
16	2345	19	3.375
17	2494.5	20	4.737
18	2521		
19	2521		
20	2421		
21	2294		
22	2094		
23	1841		
24	1588		

Table C.9: Probabilities of scenarios (Chapters 4 and 5)

Scenario	Probability (%)
s1	7.143
s2	2.857
s3	4.286
s4	10
s5	2.857
s6	1.429
s7	1.429
s8	15.714
s9	2.857
s10	11.429
s11	2.857
s12	8.571
s13	8.571
s14	14.286
s15	5.714

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