Flexibility Market for Congestion Management in Smart Grids

by

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The work carried out in all publications is partly included in this thesis in Chapters 2, 4 and 5. The material from these publications are not singled out with typographic means and references

ABSTRACT

Current power systems are facing several sustainability challenges to meet the increasing demand of electricity. In addition, there is a global direction to increase the share of renewable energy sources in the power generation mix and energy efficiency. In the face of all such challenges, smart grids were incepted. Smart grids are modernized power systems that integrate state-of-the art communication and information technology to facilitate the bidirectional flow of information and electricity between the supply and demand sides.

The resilience of smart grids can pave the way for having more flexibility at the distribution level of the power systems. Demand response (DR) programs are considered one of the sources of system flexibility and it is one of the main components of smart grids. DR can be defined as the willingness of customers to alter their electricity consumption profile in response to price signals. Transmission system operators have been implementing demand response programs in a straightforward fashion for several years now. For example, by having energy prices that are expensive during on-peak periods and low-priced at off-peak periods. Other type of DR programs introduces price signals when grid reliability is compromised and a reduction in energy consumption is necessary. In this way, customers can plan their activities accordingly in order to save money.

Now, a new era of technology, artificial intelligence and the so-called "internet of things", have provided new ways to explore the full potential of demand response, by allowing to alter loads in a much more dynamic and precise manner, thus optimizing the operation of grid assets. This thesis focuses on one of the main types of DR programs which is demand flexibility. Demand flexibility is the ability of the demand-side customers to adjust their load profiles in response to an external market signal. On the short- and medium-term periods, distribution system operators (DSOs) can take advantage of the flexibility of demand to mitigate network congestions caused by increased peaks or high penetration of renewable energy. On the long-term period, DSOs can include demand flexibility in their network expansion planning process for future demand growth. The optimal usage of demand flexibility can help in postponing needed investments for upgrading the networks' capacity. Demand flexibility can be acquired through market-based solutions which can deliver cost-efficient flexibility services for several market agents by facilitating competition between different flexibility providers. Market mechanisms are considered by policy makers as the optimal solution for flexibility access.

With respect to that, this thesis proposes a comprehensive framework for a distribution-level flexibility market, called "**Flex-DLM**" that enables and facilitates the trading of demand flexibility between the distribution system operator, as the main buyer, and aggregators, as sellers representing flexible consumers. Two types of demand flexibility services were modelled, which are: 1- Up-regulation flexibility (UREG), which corresponds to load decrease volumes, and 2- Down-regulation flexibility (DREG), which corresponds load increase volumes. In addition, the payback effect, which is a common event to the activation of demand flexibility, is considered for both types of flexibility services. Also, the distribution network constraints were modelled, which represents the power flow constraints of the network, which is key to present a realistic model for the flexibility market. In the Flex-DLM, the DSO is considered as the market operator who is responsible of clearing the market, while making sure the network congestions are mitigated. The Flex-DLM operates on two timeframes which are day-ahead and real-time with an objective to provide the DSO with

flexibility products that can help it in the congestion management process. In addition to this, the uncertainty of demand is taken into consideration to prevent the DSO from procuring inaccurate amounts of demand flexibility. A new option is introduced in the day-ahead Flex-DLM, called the right-to-use (RtU) that allows the DSO to reserve the right to activate demand flexibility during the day-ahead period for congestions that have low probability of occurrence on the following operation day. In this way, the DSO can call upon this option in real-time if the congestion takes place. Also, the uncertainty behind the customers' commitment to the flexibility activation requests and amounts is taken into consideration.

In this thesis, the decision-making process of the DSO for optimizing its choice of demand flexibility and minimizing its total cost is modelled. Two methods were carried out for the optimization model proposed in this work. The first method follows a deterministic approach, where the objective is to optimize the DSO's cost and clear the Flex-DLM during the day-ahead period only, without taking into account the uncertainty of demand and the uncertainty of consumers' participation. The second method follows probabilistic approach, which considers the demand uncertainty during the day-ahead and real-time periods and models the uncertainty behind the customers' commitment. Both optimization methods were integrated with an optimal power flow (OPF) solver tool in order to check the technical validity of the activated flexibility services and to make sure that the payback effect does not cause further congestions in the network. The advantage of the proposed framework is that it requires minimum regulatory changes and it does not involve the DSO in any electricity trading. Also, the proposed optimization method can be integrated with any OPF solver tool.

Different distribution feeders obtained from a distribution network located in Spain were used to check the validity of the proposed framework and the decision-making process. The case studies are divided into two parts: 1- The first part applies the proposed flexibility framework from a deterministic perspective and 2- The second part applies the Flex-DLM framework considering all uncertainties, which corresponds to the probabilistic optimization approach. Finally, to help the DSO in the long-term planning process of its local network, a cost & benefit analysis is carried out to value the economic impact of implementing demand flexibility programs as an alternate solution to conventional network upgrades.

RESUMEN

Los sistemas de energía actuales se enfrentan a varios desafíos de sostenibilidad para satisfacer la creciente demanda de electricidad. Además, existe una clara tendencia a aumentar la proporción de fuentes renovables de energía en la generación de energía y así como hacia la eficiencia energética. Como parte de la respuesta a estos desafíos, se iniciaron las redes inteligentes. Las redes inteligentes son sistemas de energía modernizados que integran tecnología de comunicación e información de última generación para facilitar el flujo bidireccional de información y electricidad entre la oferta y la demanda.

La utilización de las redes inteligentes pretende facilitar el empleo de la flexibilidad en la red de distribución de los sistemas eléctricos. Los programas de gestión de la demanda se consideran una de las fuentes de flexibilidad del sistema y es uno de los puntos sobre los que se apoyan las redes inteligentes. La gestión de la demanda se puede definir como la disposición de los clientes a alterar su perfil de consumo de electricidad en respuesta a las señales de precios. Los operadores de sistemas de transporte han estado implementando programas de respuesta a la demanda de manera directa desde hace varios años. Por ejemplo, la diferencia entre precios altos y bajos en el mercado mayorista introduce un incentivo para el consumo en horas de menor precio. Otro tipo de programas de gestión de la demanda introduce señales de precios cuando la fiabilidad de la red se ve comprometida y es necesaria una reducción en el consumo de energía. De esta manera, los consumidores pueden planificar sus actividades en consecuencia para ahorrar costes.

Ahora, una nueva era de la tecnología, la inteligencia artificial y el llamado "internet de las cosas" han proporcionado nuevas formas de explorar el potencial completo de la respuesta de la demanda, al permitir alterar las cargas de una manera mucho más dinámica y precisa, optimizando así la utilización de los activos de red. Esta tesis se centra en uno de los principales tipos de programas de DR que es la flexibilidad de la demanda. La flexibilidad de la demanda es la capacidad de los clientes del lado de la demanda para ajustar sus perfiles de carga en respuesta a una señal del mercado externo. En los períodos a corto y mediano plazo, los operadores de sistemas de distribución pueden aprovechar la flexibilidad de la demanda para mitigar las congestiones en la red causadas por el aumento de los picos de demanda o la alta penetración de energía renovable. En el período a largo plazo, los distribuidores pueden incluir la flexibilidad de la demanda en su proceso de planificación de expansión de la red para el crecimiento futuro de la demanda. El uso óptimo de la flexibilidad de la demanda puede ayudar a posponer las inversiones necesarias para mejorar la capacidad de las redes. La flexibilidad de la demanda se puede conseguir mediante soluciones basadas en el mercado que pueden ofrecer servicios de flexibilidad rentables para varios agentes del mercado al facilitar la competencia entre diferentes proveedores de flexibilidad. Los reguladores suelen considerar que son los mecanismos de mercado los que dan la solución óptima para la gestión de la flexibilidad.

En relación con estos temas, esta tesis propone un marco integral para un mercado de flexibilidad a en la red de distribución, denominado "Flex-DLM" que permite y facilita el comercio de flexibilidad de demanda entre el operador del sistema de distribución, como el principal comprador, y los agregadores, como vendedores que representan a los consumidores flexibles. Se han modelado dos tipos de servicios de flexibilidad de demanda, que son: 1- Flexibilidad a subir (UREG), que corresponde a un requerimiento disminución de carga, y 2- Flexibilidad a bajar (DREG), que corresponde a un requerimiento de aumento de carga. Además, el efecto de rebote, o consumo posterior al uso de la flexibilidad, que es

un fenómeno común tras la activación de la flexibilidad de la demanda, se tiene en cuenta para ambos tipos de servicios de flexibilidad. Además, se han modelado las restricciones de la red de distribución, que representan las restricciones de flujo de potencia de la red, que es clave para presentar un modelo realista para el mercado de flexibilidad. En el mercado Flex-DLM propuesto, se considera al distribuidor como el operador responsable de despejar el mercado, al tiempo que se encarga de mitigar las congestiones de la red. El Flex-DLM opera en dos marcos de tiempo: el diario y el tiempo real con el objetivo de proporcionar al distribuidor productos flexibles que puedan ayudarlo en el proceso de gestión de la congestión. Además de esto, la incertidumbre de la demanda se tiene en cuenta para evitar que el distribuidor adquiera cantidades incorrectas de flexibilidad de la demanda. Se introduce una nueva opción en el Flex-DLM del día siguiente, denominado derecho de uso que le permite al distribuidor reservar el derecho de activar la flexibilidad de la demanda durante el período del día anterior para congestiones que tienen poca probabilidad de ocurrencia en el siguiente día de operación. De esta manera, el distribuidor puede recurrir a esta opción en tiempo real si se produce la congestión. Además, se tiene en cuenta la incertidumbre sobre del compromiso de cumplimiento de los clientes con los requerimientos y las cantidades de energía activadas durante el proceso de gestión de la flexibilidad.

En esta tesis, se modela asimismo el proceso de toma de decisiones del DSO para optimizar su elección de flexibilidad de demanda y minimizar su costo total. Se llevaron a cabo dos métodos para el modelo de optimización propuesto en este trabajo. El primer método sigue un enfoque determinista, donde el objetivo es optimizar el coste de la flexibilidad para el distribuidor y eliminar el Flex-DLM solo durante el mercado diario , sin tener en cuenta la incertidumbre de la demanda y la de la participación de los consumidores. El segundo método sigue un enfoque probabilístico, que considera la incertidumbre de la demanda durante los períodos diarios y en tiempo real y modela la incertidumbre del compromiso de los clientes. Ambos métodos de optimización se integraron con una herramienta de solución de flujo de potencia óptimo (OPF) para verificar la validez técnica de los servicios de flexibilidad activados y asegurar que el efecto de recuperación no cause más congestiones en la red. La ventaja del marco propuesto es que requiere cambios regulatorios mínimos y no involucra al DSO en ningún comercio de electricidad. Además, el método de optimización propuesto se puede integrar con cualquier herramienta de solución OPF.

Se han utiliado diferentes líneas de distribución obtenidos de una red de distribución ubicada en España para verificar la validez del marco propuesto y el proceso de toma de decisiones. Los estudios de caso se dividen en dos partes: 1- La primera parte aplica el marco de flexibilidad propuesto desde una perspectiva determinista y 2- La segunda parte aplica el marco Flex-DLM considerando todas las incertidumbres, que corresponden al enfoque de optimización probabilística. Finalmente, para ayudar al distribuidor en el proceso de planificación a largo plazo de su red local, se lleva a cabo un análisis coste - beneficio para valorar el impacto económico de la implementación de programas de flexibilidad de la demanda como una solución alternativa a las actualizaciones de red convencionales.

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List of Abbreviations and Acronyms

Air conditioning units	AC
Ancillary services	AS
Automatic generation control	AGC
Balance responsible parties	BRPs
Battery storage system	BSS
Bi-directional conditional re-profiling	CRP-2
Business-as-usual	BAU
Capacity to Customers project	C2C
Capital expenses	CAPEX
Clothes driers	DRY
Comisión Nacional de los Mercados y la Competencia	CNMC
Conditional re-profiling	CRP
Cost benefit analysis	CBA
Critical peak pricing	CPP
Day-ahead	DA
Demand flexibility program	DFP
Demand response	DR
Demand side flexibility	DSF
Direct load control	DLC
Dish washers	DW
Distributed energy resources	DERs
Distributed generation	DG
Distribution network operator	DNO
Distribution System Operators	DSOs
Distribution Use of System	DUoS
Distribution-level flexibility market	Flex-DLM
Down-regulation bids	DRB
Down-regulation flexibility	DREG
Electric storage water heater system	EWH
Electric vehicles	EVs
Energy management systems	EMS

Equivalent annual annuity	EAA
European Union	EU
Flexible AC transmission system	FACTS
Freezers	FRZ
Genetic algorithms	GA
German association of Energy Market Innovators	BNE
Heating, ventilation, and air conditioning	HVAC
High voltage	HV
International Council on Large Electric Systems	CIGRE
Interruptible/curtailable load	I/C
Intra-day	ID
Low votlage	LV
Market solution assessment	MSA
Mean absolute percentage error	MAPE
Medium voltage	MV
Mercado Ibérico de la Electricidad	MIBEL
Mixed-integer linear programming	MILP
Net present cost	NPC
Net present value	NPV
Operador del Mercado Ibérico Polo Español, S.A.	OMIE
Operational expenses	OPEX
Optimal Power Flow	OPF
Over-the-Counter	OTC
Payback effect	PB
Plug-in hybrid electric vehicles	PHEVs
Power exchange	PX
Power Flow	PF
Probabilistic forecasting assessment	PFA
Real-time pricing	RTP
Rebate effect	REB
Rebound effect	RB
Red Eléctrica de España	REE
Refrigerators	RFG

Renewable energy sources	RES
Right-to-use option	RtU
Scheduled re-profiling	SRP
Security constrained economic dispatch	SCED
Smart Energy Demand Coalition	SEDC
Supervisory control and data acquisition systems	SCADA
Thermostatically controlled loads	TCLs
Time-of-use	ToU
Traffic light concept	TLC
Transmission system operators	TSOs
Universal Smart Energy Framework	USEF
Up-regulation bids	URB
Up-regulation flexibility	UREG
Vehicle-to-grid	V2G
Washing machines	WM

NOMENCLATURE

Indices

n,m	Indices for nodes
t, i	Indices for time in hours
y	Indices for time in years

Constants

N^n	Number of nodes in the system
$N^b_{n,t}$	Number of flexibility blocks at node n and time t
N_{Sc}	Number of forecasted scenarios generated in the probabilistic analysis

Variables & Parameters

$AggR_n^{UREG}$	Aggregator revenue for selling the required energy to commit to the up-regulation flexibility activation at node n (€)
$AggC_n^{DREG}$	Aggregator revenue for procuring the required energy to commit to the down-regulation flexibility activation at node n (€)
$AggR_n^{REB}$	Aggregator revenue for selling the rebate energy to commit to the down-regulation flexibility activation at node n (€)
$AggC_n^{PB}$	Aggregator cost for procuring the payback power to commit to the up-regulation flexibility activation at node n (€)
Agg_n^{UREG}	Aggregator net profit after all trading processes related to the up-regulation flexibility take place at node n (€)
Agg_n^{DREG}	Aggregator net profit after all trading processes related to the down-regulation flexibility take place at node n (€)
B_y	Income for a specific project at year y (€)
C_n^F	Total cost incurred by the DSO due to flexibility activations at node n during the day-ahead and real-time period (€)
$C_n^{F\_DA}$	Total cost of up/down regulation firm flexibility traded at node n in the DA Flex-DLM in day-ahead time (€)
$\overline{C}_n^{F\_RtU}$	Expected value of up/down regulation flexibility from the right-to-use option (€)
$C_n^{F\_RtU}$	Actual cost of up/down regulation flexibility from the right-to-use option reserved from node n in the DA Flex-DLM and then activated during the real-time (€)
$C_n^{F\_RT}$	Total cost of up/down regulation firm flexibility traded at node n in the RT Flex-DLM in real-time (€)
C_y	Cost of a specific project at year y (€)
$Com_{n,t}$	Commitment probability for every flexibility block k in node n and hour t
d	Discount factor (%)
DSO_C_y	Total cost incurred by the distribution system operator every year y (€)
$EAA_{BAU/DFP}$	Equivalent annual annuity for project BAU or DFP (€)
$F_{n,k,t}^{UREG/DREG}$	Up/down flexibility regulation active power in node n, at block k and hour t (MW)
$F_{n,k,t,MAX}^{UREG/DREG}$	Maximum up/down flexibility regulation active power allowed in node n, at hour t (MW)
$F\_tot_{n,t}^{UREG/DREG}$	Total up/down regulation flexible active power activated from node n, at hour t (MW)

$F_{ind,t}^{UREG}$	Up-regulation flexibility power offered by an industrial customer at time t (MW)
$F_{ind,t}^{DREG}$	Down-regulation flexibility power offered by an industrial customer at time t (MW)
$F_{res,t}^{UREG}$	Up-regulation flexibility power offered by a residential customer at time t (MW)
$F_{res,t}^{DREG}$	Down-regulation flexibility power offered by a residential customer at time t (MW)
$Flex\_Share_{res\_app,t}^{UREG}$	Flexible share of the flexible appliance of residential customer that can be used for up-regulation (%)
$Flex\_Share_{res\_app,t}^{DREG}$	Flexible share of the flexible appliance of residential customer that can be used for down-regulation (%)
$InstCap_{ind}$	Installed Capacity of flexible load of industrial customer (MW)
$InstCap_{res\_app}$	Installed Capacity of flexible appliance of residential customer (MW)
$Load_{ind,t}$	Load of industrial customer at time t (MW)
$Load_{res,t}$	Total load of residential customer at time t (MW)
$Load_{res\_app,t}$	Load of the flexible appliance of residential customer at time t (MW)
Min_Load_{ind}	Minimum load level of industrial customer (MW)
Max_Load_{ind}	Maximum load level of industrial customer (MW)
NPV	Net present value (€)
NPC	Net present cost (€)
$Pnet_{n,t}$	Net injected active power at bus n, at hour t (MW)
$P_{n,t}^{PB}$	Active payback power for bus n at hour t (MW)
$P_{n,t}^{REB}$	Active rebate power for bus n at hour t (MW)
$Qnet_{n,t}$	Net injected reactive power at bus n, at hour t (Mvar)
$Q\_F_{n,k,t}^{UREG/DREG}$	Up/down flexibility regulation reactive power in node n, at block k and hour t (Mvar)
$Q_{n,t}^{PB}$	Reactive payback power for bus n at hour t (Mvar)
$Q_{n,t}^{REB}$	Reactive rebate power for bus n at hour t (Mvar)
$S_{nm,t}$	Apparent power flowing through line nm at hour t (MVA)
Sc_t	Binary variable that corresponds to 1 if a congestion takes place at hour t and 0 otherwise
$S_{nm,MAX}$	Maximum apparent power rating of line n-m (MVA)
S_{base}	Base power (MVA)
$v_{n,t}$, $\delta_{n,t}$	Voltage magnitude and angle in node n at hour t (p.u., rad)
$v_{n,MIN}$, $v_{n,MAX}$	Minimum and maximum value of voltage magnitude in node n (p.u.)
$x_{n,k,t}$	Binary variable that determines the state of activation for flexibility block k in node n, and hour t
y_{nm}, θ_{nm}	Magnitude and angle of the (n,m) element of the bus admittance matrix (p.u.)
$\alpha_{n,k,t}$	Payback coefficient at node n, for block k and hour t (p.u.)
$\beta_{n,k,t}$	Rebate coefficient at node n, for block k and hour t (p.u.)
$\lambda_{n,k,t}^{UREG/DREG}$	Up/down firm flexibility regulation price in the DA Flex-DLM in node n, for block k and hour t (€/MWh)
$\lambda\_RtU_{n,k,t}$	Right-to-use reservation fee in the DA Flex-DLM in node n, for block k and hour t (€)
$\lambda_{n,k,t}^{act}$	Flexibility price for activating the right-to-use option in node n, for block k and hour t (€/MWh)

$\lambda_{n,k,t}^{RT}$	Firm flexibility price in the RT Flex-DLM in node n, for block k and hour t (€/MWh)
λ_{t}^{adj}	Adjustment market price at hour t (€/MWh)
ρ_t	Probability of occurrence for a given congestion at hour t.
ρ^{min}, ρ^{max}	Minimum and maximum probability levels set by the DSO for the probabilistic forecasting assessment
$\varepsilon_{n,k,t}$	Expectation delivery factor for up/down flexibility offered at node n, for block k and time t (p.u.)
Υ_{min}	Threshold set by DSO for thr minimum acceptable probability of commitment for the flexibility blocks

1 INTRODUCTION

This chapter illustrates the motivation for this thesis, defines the objectives and scope, and summarizes the main scientific contributions.

1.1 The energy system transition

The electricity system reform in Europe started in the early 1990's, with an objective to migrate from a vertically integrated to a deregulated liberalized power system structure. Ever since then, regulations and policies are always being updated regularly and new reforms are implemented for better design and operation. The liberalized power system was a necessary move to allow electricity, as a commodity, to be traded in an efficient manner [1]. In this new structure, the generation and supply of energy services take place in competitive markets that allow private owners, investors and retailers to participate.

The electricity markets introduced in the new system had to take a special form in order to deal with the distinctive characteristics of electricity. Unlike other commodities, electricity can be very expensive to be stored in large quantities. As a result, the generation and demand sides must be matched continuously. Also, the physical infrastructure of the electricity system is of a complex nature. Therefore, the design and organization of the electricity markets must take into consideration all the factors that accompany the trading of electricity. The liberalized electricity systems allow electricity trading over long-, medium- and short-term periods, thus increasing the efficiency and versatility of the trading process.

All electricity systems worldwide are now focused on the next energy transition phase, which is to migrate from a fossil-based system to a zero-carbon system, otherwise known as the "*decarbonization of the energy sector*". This decarbonization has been a global demand and the objective is to reduce carbon emissions and integrate more Renewable Energy Resources (RES) and energy efficiency measures. The global directive to address the concerns regarding climate change has encouraged energy systems to become more environmentally friendly with low-carbon emissions. As a result, the penetration of RES has been increasing during the past years in Europe and in the rest of the world. With respect to Europe, the climate and energy framework initiative by the European Council [2], has set a target to increase the share of energy consumption produced from RES in Europe to 27% by 2030 [3] and 97%

by 2050 [4], which will contribute to an estimated emissions reduction of 40% and 60% respectively. Every member country in the EU has set separate targets, for example Spain has set a target of 22.7% increase in the share of energy generated from RES, with 40% increase in the supply of electricity demand, 18.9% increase in the supply of electricity for heating and cooling and 13.6% increase in the supply of electricity needed for transport [5]. Figure 1.1 presents the share percentage of renewable energy to the gross consumption in Spain over the past years [6].

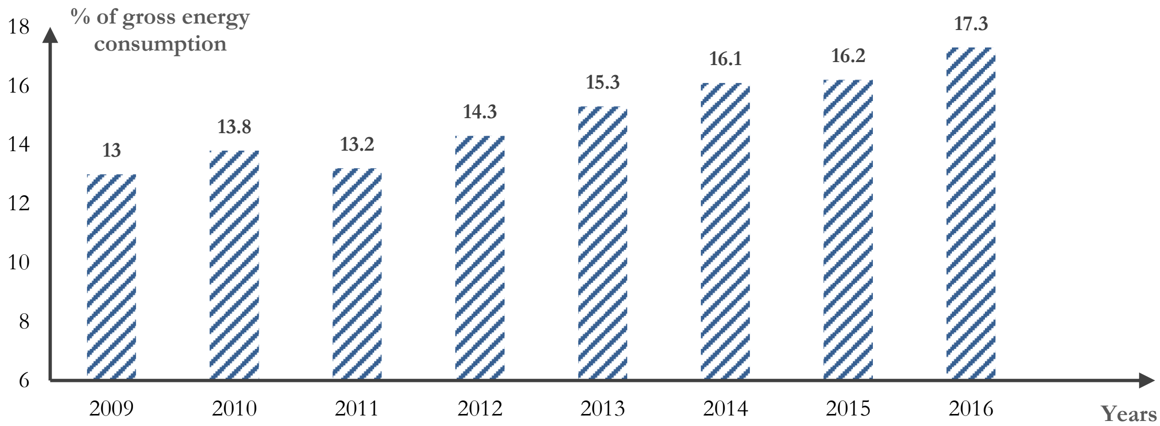


Figure 1.1 Renewable energy percentage share to gross consumption in Spain [6].

The need for a more renewable and sustainable generation system did not stop at the supply side. The ever-increasing level of technological advancements has enabled RES to penetrate the demand-side in the form of Distributed Energy Resources (DERs). DERs are not solely based on RES, such as wind generation and photovoltaic systems, but they can as well incorporate conventional generators and battery storage systems. At the moment, the reliance on self-generation such as DERs is common to many consumers to avoid high electricity prices. Besides having new generation sources at the demand-side, the demand on electricity has been increasing in parallel and is expected to increase even more in the future. Another key driver to the energy decarbonization is the electrification of transportation and heating systems, which include among others electric vehicles (EVs), electric heating systems and electric pumps.

With new information and communication technologies, smart meters and state-of-art control systems, the current structure of the grid can evolve to a smarter, controllable and efficient grid that is called smart grid. Smart girds allow consumers to optimize their consumption behavior based on electricity prices, while allowing bidirectional flow of electricity and information. The challenges of the energy system transition are several when it comes to maintaining a secure, reliable and efficient supply of electricity. Particularly at the distribution grid level, Distribution System Operators (DSOs) are the main actors to face such challenges. The intermittent behavior of RES results in limited controllability levels on their output, which can cause network congestions, voltage problems and reduction in power quality [7], [8]. Thus, balancing the supply and demand becomes a challenging task. Also, local DERs enable bidirectional flows of electricity, which can be sometimes difficult to implement since original designs of power systems did not consider such issue.

The shift to loads electrification has a high impact on the distribution level of electricity systems. DSOs are faced with the challenge to efficiently operate and manage its network to accommodate the new high demand on electricity resulting from new penetrating loads, such as EVs and electric heat pumps. On the short-term, DSOs must provide high quality of supply at minimal costs to cope with the day-to-day demand of electricity, while avoiding potential outages caused by high consumption. On the long-term, DSOs must plan and reinforce their network to be able to meet future peak demand, which require upgrading the network assets and increasing the generation and network capacity.

It is evident that the changes occurring to the current energy system need a more flexible system with modern market frameworks. However, these changes can turn into opportunities. DSOs can take advantage of all of these new resources to efficiently manage its networks, decrease energy losses and power peaks and postpone the need for network reinforcement [9]–[16]. One of the ways that the DSO can benefit from all of these transitions is to implement demand response programs and in particular demand flexibility solutions.

1.2 Flexibility in the power system

Within the new framework of smart grids, new market arrangements are needed to benefit from the flexibility that can be offered by the generation and demand sides. Flexibility can be defined as the ability of adjusting generation and/or consumption profiles in response to external market signals. Flexible resources have been labeled by different policy makers and energy actors as a potential solution to cope with the future challenges of the new and modernized power system. Providing physical flexibility of electricity systems comes with its own burden in establishing efficient policy and market frameworks, which promotes optimal flexible resource investments.

In a general form, flexible resources include flexibility provided from the generation side and the demand side. Generation-side flexibility, the most common type of flexibility, has been used for a long time since the beginning of power systems. Such flexibility may be provided from different types of generation technologies, at different degrees, such as coal, hydro, gas and RES. As for the demand-side flexibility, it has been attracting interest in the past years with its large technical potential. This kind of flexibility can be enabled through the so-called Demand Response (DR) programs. DR are programs established to encourage end-user customers in adjusting their electric usage, in response to changes of electricity prices over time, or incentive payments [17]. They help in reducing electricity consumption at hours of high electricity prices or uphold the reliability of electrical systems when their security is jeopardized [18], [19]. The technical challenges that may face such programs are related to installing new metering equipment and investing in an information and communication infrastructure for the grid [20]. The current structure of the power system lacks the required technology to enable bi-directional exchange of energy and information between the demand and supply sides, especially at the distribution level. Also, smart metering systems are needed in order to encourage the responsiveness of consumers.

Demand response programs can be implemented as a price-based program, which allows consumers to voluntarily adjust their load consumption behavior in response to varying prices of electricity; or they can be implemented as an incentive-based program that provides consumers with financial incentives to provide load adjusting volumes. One of the common incentive-based DR programs is called the demand flexibility program [21]–[23]. Demand flexibility promotes the active participation of consumers in electricity markets to submit increasing or decreasing load consumption offers [24], [25]. Demand flexibility can be used as a source for portfolio optimization for market players who need to meet their energy requirements. Besides, it can provide balancing and congestion management services for system operators such as transmission system operators (TSOs) and DSOs, to maintain system reliability and security [26].

One of the main drivers to exploiting the full potential of demand flexibility is the introduction of aggregation services. In order to have a tangible impact on the large-scaled power system, hundreds of end-users must provide their flexibility at the same time or at different times. This process of coordination and aggregation is out of the customers' scope and interest. A new role was developed to serve such purpose, which is referred to as the aggregator. Handling many customers at the same time, the aggregator has the means to collect, aggregate, manage and trade the aggregated flexibility on behalf of its customers. The aggregator's role has been gaining much attention in the context of demand flexibility programs as a potential facilitator and enabler to unlock the flexibility obtained from the demand side. Aggregators can take over more roles in the current electricity market structure, such as electricity retailing or balancing responsibilities. This issue is covered within this thesis.

Another key driver for achieving maximum efficiency of demand flexibility is to have the right mechanism to facilitate its trading. Demand flexibility can be obtained through contractual connection agreements or through market-based solutions [27]. While both options can be available, regulators and policy markets have favored market mechanisms to deliver cost-efficient and competitive solution to enable flexibility trading between market agents. However, market mechanisms dedicated for flexibility trading are not currently implemented and their absence can have a negative impact on demand flexibility [28] and delay its full deployment [29].

Finally, in the 'Winter Package' published by the European Union (EU) on November 20th 2016 titled "*Clear energy for all Europeans*", several proposals were introduced to facilitate the transition to a clean energy economy and to reform the design and operation of the EU's electricity market [30]. Among these proposals, focus was given on the need for demand flexibility and increase the responsiveness of the consumers. In addition, it was suggested that flexibility, as a commodity, should be efficiently priced and provided through an interlinked market.

1.3 Thesis motivation & objective

1.3.1 Motivation

From the previous sections, several conclusions could be drawn out. The transition of the conventional power system to a more decentralized and smarter system is highly advisable. Also, the integration of RES and DERs will continue to increase which will result in several operational challenges. In addition to this, the shift to a more electrified energy system will increase the electricity consumption in the future. In the face of all such challenges, demand flexibility is emerging to be a promising tool for DSOs to use at the distribution network. This thesis addresses the opportunities that demand flexibility can provide to DSOs in its congestion management process and long-term network planning. As a result, the research questions that this thesis is aiming to answer can be formulated as follows:

"How can demand flexibility be optimally used in the congestion management process at the distribution grid level? What are the market mechanisms that should be implemented to optimize the usage of demand flexibility? What is the best approach for the DSO to face an increasing demand of electricity in a given grid; 1- implementing demand flexibility programs or 2- upgrading the network assets?"

In order to answer these questions, one must first address the impacts of the energy transitions challenges on the DSOs from two perspectives; the operational perspective and the economic value perspective. Both perspectives are the motivation of this thesis. From the operational perspective, the high electricity demand along with high penetration of RES can cause local congestions and network outages. As a result, DSOs are required to handle such congestions using the so-called "congestion management process". Congestion management is a key responsibility of the DSO and introducing demand flexibility as a tool to be used within this process can be highly efficient technically and economically.

Several studies have been addressing new methods for congestion management using demand flexibility or demand response programs. The work in [31] presented a market mechanism for distribution-level congestion alleviation through implementing demand response programs. In [32], authors proposed a market-based environment to solve distribution network congestions using demand response programs implemented at the residential side. A congestion management framework was proposed in [33], where demand response is used as an efficient tool to manage distribution congestions. Also in [34], a model for a day-ahead market is proposed which uses distribution locational marginal pricing (DLMPs) to provide incentive signals to DERs to contribute in the distribution congestion management process and voltage support. The work in [35] takes advantage of flexibility services offered by EVs and heat pumps for real-time congestion management. The authors propose a method called "swap" to maintain the balance between the supply and demand. A more thorough review for what has been carried out in literature can be found in Chapter 2.

From the economic perspective, DSOs are traditionally incentivized to upgrade their local networks with new investments to face the growing demand on electricity and high penetration of RES. With the efficient implementation of demand flexibility programs, these investments costs can be decreased. While demand flexibility can be an interesting and cost-efficient option in comparison to the traditional upgrading method of the DSO, its value and impact can vary from one network to another. Thus, before fully implementing and deploying demand flexibility programs, DSOs are encouraged to carry out cost and benefit analysis to assess the true value of both options and optimize its decision.

1.3.2 Objective

Based on the two motivational perspectives, the answer to the research questions can be written as an objective to the thesis, which can be summarized as:

"The objective is to propose a comprehensive framework for a distribution-level market that enables and facilitates the trading of demand flexibility between the DSO and the aggregator. Within this flexibility market, an optimization algorithm is proposed to optimally solve the distribution network congestions and minimize the DSO's total cost. In addition, a cost & benefit analysis is carried out to value the economic impact of implementing demand flexibility programs as opposed to the alternate solution of conventional network upgrades."

In order to realize the thesis objectives, the current research fields, with respect to demand flexibility implementation and market mechanisms, that are addressed in literature should be assessed first. This issue is discussed in detail in section 2.5 in Chapter 2. Here, a short summary is given regarding this issue. Based on the literature review, it was found that there are seven main topics that are key to model an efficient framework for a flexibility market, which are often addressed separately and not jointly, as will be shown later in Chapter 2. Thus, the objective of the work of this thesis is to consider all of these topics under one flexibility market framework. Figure 1.2 illustrates these research topics and they are explained briefly in the following.

1. **Flexibility products**: In order to have an efficient market for trading flexibility, there has to be a clear definition for the flexibility products. It is important to explore the two possible ways for offering demand flexibility, which can either take an increasing or decreasing form of demand. It is common in literature to consider only one type of flexibility, which is the load decreasing type.

2. **Payback effect**: The payback effect is a subsequent event to flexibility service activation, where the flexible load shifted from one point in time to another may cause another congestion in the grid. The payback effect is one of the often-ignored attributes of demand flexibility in literature and considering it is important to realistically model the impact of demand flexibility on the network.

3. **Grid constraints:** Similar to the current electricity markets, a flexibility market should consider the grid constraints in its clearing process. By not taking into consideration such constraints, inaccurate amounts of flexibility can be cleared, which can be technically infeasible.

4. **Adjusting trading processes:** This issue addresses the trading processes, which should be carried out by the aggregator to ensure the efficient trading of flexibility services. Energy differences will arise between energy bought in wholesale markets and the adjusted new consumption profile after clearing the flexibility market. Thus, further trading is required by the aggregator to adjust such differences.

5. **Uncertainty of demand:** Flexibility markets should consider the uncertainty behind the demand consumption. This issue can be crucial to maximize the efficiency of the trading process. Ignoring demand uncertainty can cause inaccurate procurement of flexibility, which can either be insufficient or unused, thus causing economic losses.

6. **Time period for flexibility trading:** On the short-term, the current structure of the wholesale electricity markets covers several time periods starting from day-ahead and up to the real-time. Thus, flexibility markets should not be only constrained to the day-ahead period and closer to real-time markets should be implemented to allow the market participants to adjust their portfolios. Also, the real-time flexibility market will allow the DSO to mitigate unexpected or sudden congestions that may not be accounted for during the day-ahead period.

7. **Market clearing and optimization:** The DSO, as the main flexibility buyer and the market operator, must carry out an optimization process to minimize its total cost of procurement. In order to realistically and efficiently model this process, the DSO must consider in its optimization process the payback effect, the network constraints and the uncertainty of demand.

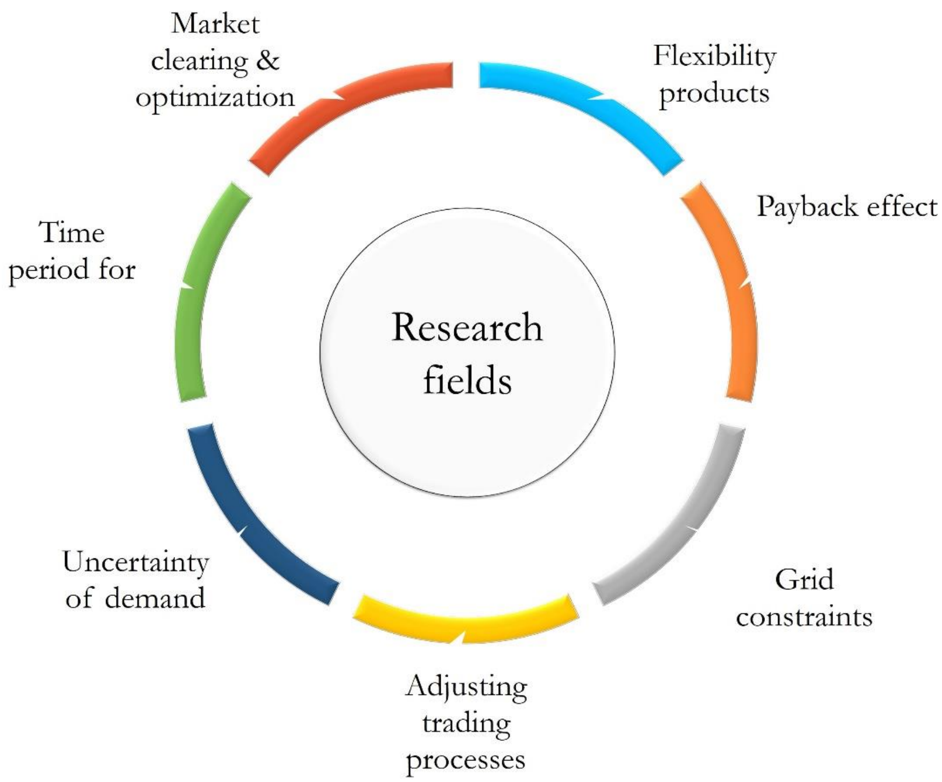


Figure 1.2 Research topics addressed in thesis.

As already mentioned, to fulfill the objective set by the thesis, a framework for a decentralized market platform for demand flexibility trading is proposed, with an objective to provide the DSO with flexibility services to mitigate forecasted network congestions. In addition, the existence of this market will allow the DSO to rethink its long-term network expansion strategy. Based on the before mentioned research fields, the objectives of the thesis can be written in detail as follows:

1. **Exploring the potential of demand flexibility at the distribution network.** Particularly, how DSOs can benefit from flexibility services in the congestion management process. Two types of flexibility products are modelled, which are: 1- Up-regulation flexibility (UREG), which represents load decrease volumes, and 2- Down-regulation flexibility (DREG), which represents load increase volumes.

2. **Proposing a framework for distribution-level flexibility market, called Flex-DLM**. Within this market, a clear definition of the different flexibility products is given. In addition, the payback effect and the network constraints are modelled within the market design and the decision-making process to ensure that the activated demand flexibility will solve the intended congestion and not lead to further network congestions during other hours of the day. Also, the energy variations that will arise as a result of demand flexibility adjustments are addressed from the aggregator's perspective, assuming it is taking the balancing responsible party responsibility. The uncertainty of demand in the day-ahead period is considered within the Flex-DLM framework. This achieved by carrying out a probabilistic assessment that assesses the probability of congestion occurrence during the following day of operation. In this way, the DSO can procure flexibility services for congestions that have high probabilities of taking place and avoid the risk of over- or under-procuring flexibility services. Also, a new option called the right-to-use (RtU) option is introduced in the framework that allows the DSO to reserve amounts of flexibility during the day-ahead period for congestions with medium probabilities of taking place, which can be activated in real-time if needed. Besides operating in the day-ahead period, the Flex-DLM also operates during the real-time period which offers the DSO flexibility services for sudden or unaccounted for network congestions. Finally, the decision-making process of the DSO within the flexibility market framework is modelled using a deterministic and probabilistic approach. The objective of the optimization model is to clear the Flex-DLM, while minimizing the DSO's total cost and considering all the above-mentioned factors.

3. **Checking the validity of the proposed framework using real-life distribution networks**. Several case studies were carried to out to achieve this objective and both optimization approaches, deterministic and probabilistic, where checked against these studies.

4. **Carrying out a cost and benefit analysis study**. The objective is to numerically evaluate the long-term economic impact of deploying demand flexibility programs as opposed to upgrading network assets. This is achieved by proposing a non-complex method that acts as an investment decision tool for the DSO.

1.4 Thesis outline

The structure of the thesis is designed to provide a detailed view of the topics needed to pave the way to achieve the research objective.

- **Chapter 2:** This chapter introduces the concept of demand response and focuses on one important category which is the demand flexibility programs. Furthermore, the potential drivers to implementing such programs are explained, as well as the expected barriers and challenges. The potential flexibility providers and buyers are defined in detail. Finally, a review of the proposed market frameworks and recent pilot projects in literature is carried out which defines the research fields that are covered by the work in this thesis.

- **Chapter 3:** In this chapter, an introduction to electricity markets is given. In addition, the distribution system operator's role, function and business model, which includes its responsibility for the network operation, planning and congestion management, is discussed. Also, the different remuneration schemes that can be applied by DSOs are addressed. The current structure of the Spanish electricity markets with respect to all the previously discussed topics is explained and discussed. Moreover, the chapter addresses the evolution of the power system towards smart grids and the future role of DSOs within such future grids. The future barriers to implementing demand flexibility market mechanisms in the paradigm of smart grids are discussed. Finally, the new market player "aggregator" is introduced and defined in detail.

- **Chapter 4:** In this chapter, a framework for a distribution level market dedicated to demand flexibility trading called "**Flex-DLM**" is proposed. This market operates on two timeframes that is day-ahead and real-time with an objective to provide the DSO with flexibility products that can help it in the congestion management process. In addition to this, the uncertainty of demand is taken into consideration to prevent the DSO from procuring inaccurate amounts of demand flexibility. A new option is introduced in the day-ahead Flex-DLM that allows the DSO to reserve the right to activate demand flexibility during the real-time for congestions that have low probability of occurrence. Also, the consumers' uncertainty to committing to the flexibility activation requests and amounts is taken into consideration. All the trading and optimization processes that are carried out within the framework are explained and discussed in detail. Finally, the Flex-DLM features are compared to other proposed markets in literature.

- **Chapter 5:** This chapter presents different case studies to check the validity of the proposed flexibility framework on different distribution feeders obtained from a distribution network located in Spain. The case studies are divided into two parts: 1- The first part applies the proposed flexibility framework from a deterministic perspective, which does not consider the uncertainty of demand or consumers' commitment. This part represents the first optimization approach that was carried out along the work of this thesis, which is explained in the Appendix section A.2 and; 2- The second part applies the Flex-DLM framework considering the uncertainties, which corresponds to the probabilistic optimization approach explained in detail in the Appendix section A.3.

- **Chapter 6:** This chapter presents a cost and benefit analysis (CBA) case study to compare between deploying demand flexibility programs and the business-as-usual approach (network reinforcements). A non-complex method to carry out the CBA to evaluate the feasibility of demand flexibility programs against conventional network upgrades methods is presented. This case study introduces an easy way to determine the expected flexibility price cap that the DSO can be willing to pay to make the demand flexibility program a feasible option, and a sensitivity analysis is carried out as well to present the variables that can affect the outcome of the cost and benefit analysis.

Finally, **Chapter 7** concludes the thesis and provides final recommendations and discussion regarding areas for future work. The **Appendix** gives a details description to the optimization methods used for the deterministic and probabilistic approaches that are utilized within the Flex-DLM framework.

2 DEMAND FLEXIBILITY

In the recent years, demand response programs became an attractive option to system operators and consumers due to the several technical and economic benefits that it can provide. Under the umbrella of demand response, there are many programs and mechanisms that encourage consumers to reduce their peak consumption and help system operators in efficiently managing their own networks and avoid potential grid problems [17], [36], [37]. One of the potential demand response mechanisms is demand flexibility, which can help system operators to resolve network congestions and serve as a substitute to network investments. Demand flexibility has already been implemented at the transmission level of the electric systems and the need for its penetration at the distribution level has been growing steadily. However, demand flexibility implementation is a challenging task that requires addressing different aspects. For example, in order to enable the trading of demand flexibility at the distribution level, flexibility markets need to be efficiently implemented. In this chapter, an introduction to the general concept of demand response is given, then a review on demand flexibility, its definition, and main drivers and barriers facing its implementation is presented. In addition, the potential demand flexibility providers and buyers are thoroughly explained. Furthermore, a review on recently proposed market models and frameworks for the trading of demand flexibility is presented. In addition, a review for the pilot projects that took place within the past years is discussed. Finally, the research fields that are commonly addressed in literature are highlighted.

2.1 Introduction to demand response

The deployment of new technologies to manage the grid operational levels, starting from the generation and down to the demand level, is set to create a reliable, efficient and economic power system. This is one of the main benefits of the current evolution of conventional electric grids into smarter and more flexible ones. However, the wide penetration of intermitted resources, has imposed many challenges on distribution networks. Consequently, various market players and policy makers have encouraged the idea of flexible resources as a way of coping with such challenges. New technologies such as intelligent smart meters, autonomous load controllers and advanced information and communication automations, are capable of providing sustainable minute-by-minute information to deploy demand response (DR) programs [38], [39]. DR programs are activities that enable end-user customers to alter their load behavior patterns with respect to time, load shape and level of demand, in response to changes of electricity prices over time, or incentive payments [17]. Based on [21], DR can serve three main purposes, which are peak shaving, valley filling and load shifting, as seen in Figure 2.1.

DR can help in reaching mutual profit between system operators and consumers by decreasing load consumption at peak hours and to uphold the reliability of electrical systems [18], [19]. In addition, efficient implementation of DR programs can prevent the need of activating expensive generation plants to meet peak demand. DR can play an important role in promoting off-peak demand consumption by energy storage devices such as batteries or electric vehicles (EVs). As for load shifting, DR can provide consumers with incentives in the form of market signals or price signals to shift their loads from on-peak to off-peak hours, which can efficiently redistribute the load consumption along the day without decreasing the total energy consumption.

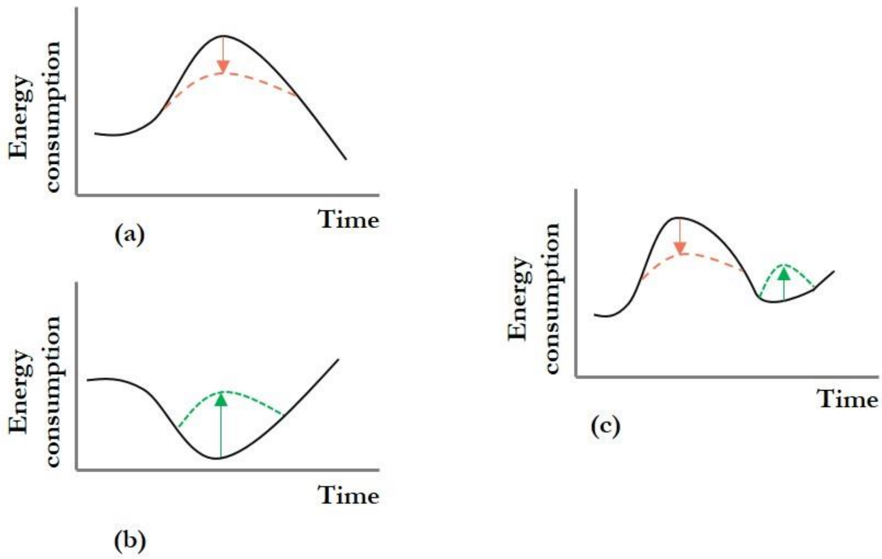


Figure 2.1 Demand response functions: (a) peak shaving; (b) valley filling; and (c) load shifting.

DR programs can be divided into two main types [21]–[23], price-based and incentive-based programs. Figure 2.2 illustrates the different categories of demand response programs. In price-based programs, customers are provided with variable electricity prices during the day. Consequently, customers will be encouraged to voluntarily adjust their loads in response to such prices by consuming less at peak hours and consuming more at less expensive hours. Price-based programs encompass the following options:

- **Time-of-use (ToU):** In this program, energy prices are designed to be different at various time intervals of the day, or different seasons of the year. An example for ToU program is to divide the pricing pattern of the day into three periods; on-peak, medium-peak, off-peak, where every period has a constant value of electricity price. Based on these periods, customers are encouraged to shift their loads from on-peak periods (high prices) to medium-peak and off-peak periods (lower prices). Examples of countries that utilize such pricing method are France, Germany and Italy [40], [41].
- **Critical peak pricing (CPP):** This program is similar to time-of-use pricing when it comes to having fixed prices during the day. The difference is that higher prices are introduced only when grid reliability is compromised and a reduction in energy consumption is necessary. CPP is usually implemented for a limited number of hours or days, based on the condition of the network, which is usually found in the Nordic countries [42].

- **Real-time pricing (RTP):** Also referred to as dynamic pricing, RTP presents variable electricity prices during different intervals of the day, e.g. every 15 min or every single hour or on day-ahead basis. With a varying pricing program such as RTP, the customers' participation plays a very important role. Current European countries implementing such program are such as Spain and Netherlands [43].

The second DR program type is incentive-based programs, where customers are offered incentives, in addition to or separate from electricity prices, in order to deliver specific amounts of load adjustment at a given time. These load adjustments can be in both directions, i.e. increasing or decreasing consumption. Incentive-based programs are usually implemented when there are frequent system contingencies. The different types of incentive-based programs can be classified as follows:

- **Direct load control (DLC):** This program allows power utilities to have direct access to the electrical appliances of the customers, in which it can switch-off or cycle such loads. This is achieved through communication switches installed at the customers' side, which are then controlled by the power utility. DLC is offered to residential and small commercial customers.
- **Interruptible/curtailable load (I/C):** This program provides economic incentives to customers who can decrease, some or the total amount, of their energy consumption. This program is applicable for medium to large customers. Also, penalties are applied for customers who fail to respond to their activation call.
- **Capacity programs:** For customers who are able to provide load reductions capacities with day-ahead notifications. Similar to other programs, penalties are applied for those who fail to commit to their activation call.
- **Demand side bidding:** Also referred to as demand flexibility or demand-side flexibility (DSF), this program allows the customers to submit load reduction or increase bids in electricity markets. These bids can be of value to power utilities in peak hours when the network reliability is jeopardized. This program is usually offered to large customers. Small customers may be able to participate, but they will require third parties, e.g. aggregators, to collect their bids and represent them in the market.

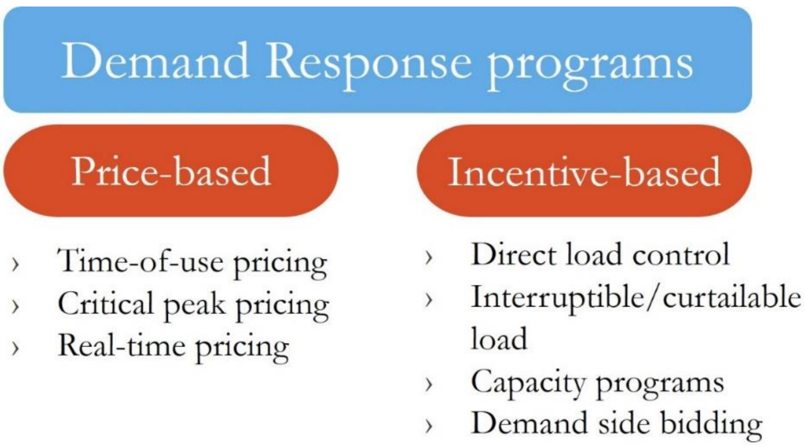


Figure 2.2 Categories of demand response programs.

The potential of demand response in Europe is significant and it can reach an hourly values ranging between 61 GW and 172 GW [44]. Further details about the energy amounts with respect to every DR program type can be found in the assessment carried out in [45]. According to the report published by the Smart Energy Demand Coalition (SEDC) in 2017 [46], demand response has been gaining much interest in many countries in the EU. The research showed that several countries are currently highly involved in the framework of demand flexibility development such as Switzerland, France, Belgium and Great Britain [47]. Table 2.1 illustrates the European countries with respect to different degrees of demand response potential. Even with several EU countries having almost fully developed DR programs and frameworks, the challenges that are faced are plenty. Several fundamental barriers exist concerning market regulations and policies [48]. To maintain an efficient market environment, free access to perfect information must be granted to all involved agents. The failure to achieve this can result in some market agents having better information than others, which can result in imperfect competition. Consequently, market agents with full information access can exercise market power.

Table 2.1 Demand Response development in Europe.

Commercially active	Partial opening	Preliminary development	Closed
Ireland	Netherlands	Poland	Portugal
Great Britain	Germany	Slovenia	Spain
France	Denmark		Italy
Belgium	Sweden		Estonia
Switzerland	Norway		
	Austria		

2.2 Demand Flexibility

A new era of technology, artificial intelligence and the so-called "internet of things", have provided new ways to explore the full potential of demand response, by allowing to alter loads in a much more dynamic and precise manner, thus optimizing the operation of grid assets. The work in this thesis focuses on the incentive-based DR program called demand flexibility. Demand flexibility can be defined as the ability of adjusting generation and/or consumption profiles in response to external market signals, to assist the system operator in efficiently managing its network [49]. As in Figure 2.3, there are several attributes that can describe demand flexibility: its location, which describes the level at which flexibility is traded, e.g. transmission or distribution; its purpose, which can vary from congestion management to portfolio optimization or balancing services; and its direction, which describes how the demand is changed, either increasing or decreasing. The concept of flexibility has been in practice in some countries for many years at the transmission level, to provide energy balancing services for TSOs and balance responsible parties (BRPs). With the growing demand on electricity and the high integration of RES in power systems, there has been an increasing need for deploying the mechanism of flexibility at the distribution level.

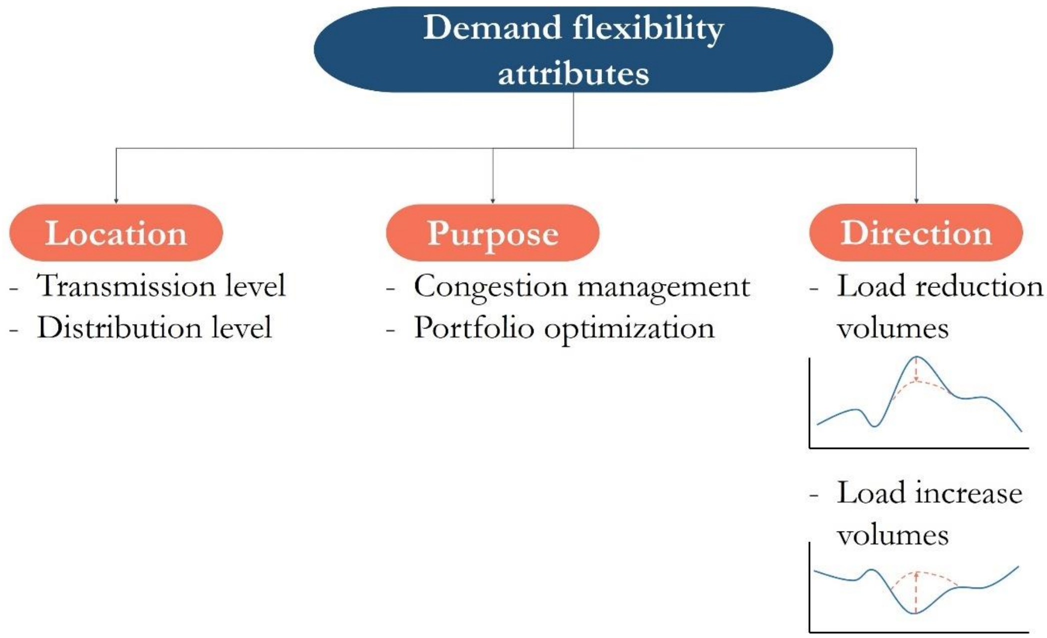


Figure 2.3 Demand flexibility attributes.

2.2.1 Timeline for flexibility

Demand flexibility services have direct impact on the performance of grids on the short-, medium- and long-term periods [49], as seen in Figure 2.4. On the short-term, demand flexibility can be traded within short time windows (from minutes up to hours) with the objective of mitigating imminent danger on electricity networks, which can be sudden voltage fluctuations or overloaded lines. Short-term flexibility can be of great value to avoid problems caused by forecasting errors for RES and demand, generators outages and emergencies. Medium-term flexibility can be traded from one day- to several days-ahead and can offer energy adjustment services focused on shifting loads from on-peak to off-peak hours. During day-ahead periods, forecasts for demand consumption enable system operators, such as the DSO, to predict potential network congestions, which can be mitigated by using demand flexibility. On the long-term, typically between months and years, flexibility services can be useful in the matching between supply and demand, which is needed in systems with high penetration of renewables [50]. Also, planning long-term flexibility services can be help system operators in postponing, and sometimes avoiding, the need for reinforcing and upgrading the networks to accommodate new demand consumptions.

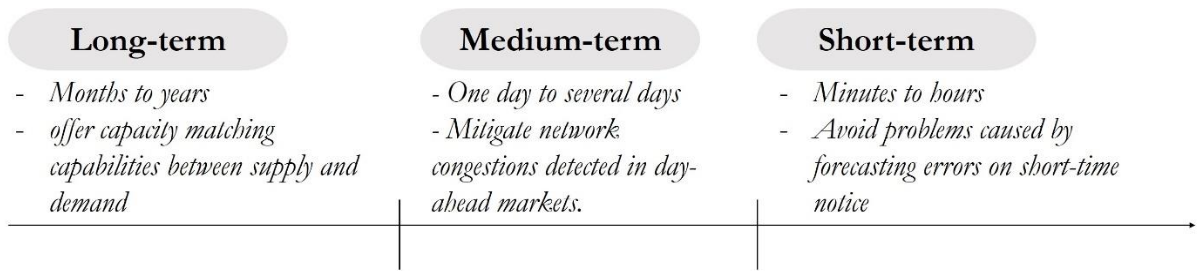


Figure 2.4 Timeline of possible flexibility tradings.

2.2.2 The need for demand flexibility

At the moment, flexibility services are already being used by TSOs as a balancing tool in fully developed markets at the transmission-level. In a similar way, in the day-to-day operation, demand flexibility can be a valuable tool to help DSOs enhance the operation at the distribution level and provide assistance in its congestion management. For example, demand flexibility in the form of load reduction volumes, can offer distribution system operators a fast and efficient way to overcome common network constraints such as overloaded lines [51], [52]. In addition, on the long-term planning period, demand flexibility can postpone or eliminate the need for upgrading the assets of the network. In the common practice of long-term network planning, system operators consider the demand growth over the time period being assessed and overestimation of such growth is sometimes included to secure a safe capacity margin for unexpected demand peaks. As a result, the full network capacity can sometimes be unused, which reduces the economic efficiency of this approach. It has been advised by several regulators [53]–[55], that considering demand flexibility in the network planning process can be very beneficial, as it decreases the forecasted peaks, which reduces the capital expenditure needed for network upgrading [56].

In distribution networks with the large-scale penetration of RES, several operational challenges are faced by system operators due to their intermittent behavior. The nature-dependency of RES affect their prediction accuracy and consequently affect their production rates. All of such factors may affect the voltage levels of the system and cause network outages. Demand flexibility services can offer load reduction or load increase volumes to system operators in order to manage the variability of the renewables and to avoid the need of curtailing their production. Figure 2.5 summarizes the main drivers for the implementation of demand flexibility at the distribution level. Demand flexibility allows the DSO to manage grid congestions by avoiding demand peaks. This can possibly lead to deferring the need for network reinforcements [57], decreasing the total capital and operation expenditures of distribution networks [58]. In addition, demand flexibility provides more resources to manage the requirements of the increasingly high penetration of DERs based on RES.

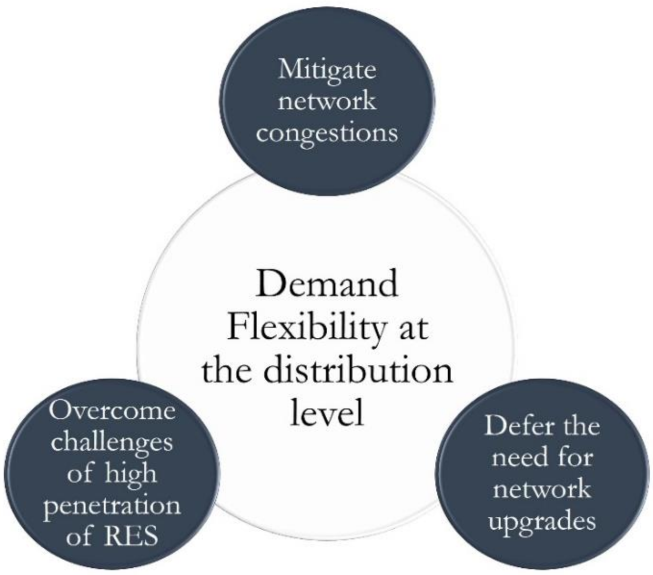


Figure 2.5 Drivers for implementing demand flexibility at the distribution level.

2.2.3 Demand flexibility barriers

Even though the potential benefits of demand flexibility are undeniable and it has been the focal point of many recent studies, there are some challenges and barriers to their deployment [59]. One of the main obstacles are those related to the absence of regulations and policies that govern their penetration and participation as a service in electricity markets [46]. According to the IEA Demand Side Management Energy Efficiency Technology Collaboration Program [60], regulatory policies are needed to promote demand flexibility in different electricity markets. The EU policies are currently working on promoting the use of demand flexibility services in balancing and reserve markets, as well as providing ancillary services. In addition, the policies are expected to allow these services to participate in wholesale and retail markets. Unfortunately, the recognition of demand flexibility in the EU is not enough for a full implementation across all countries. Moreover, the heterogeneity of demand flexibility services in several European countries can handicap their potential development [20], [49]. Other discouraging regulations in the EU are those related to the TSOs and DSOs. Such regulations do not encourage system operators to invest in alternative approaches other than network reinforcement [61]. By disallowing any benefits for DSOs and TSOs if they are capable of postponing cost associated with network expansion, system operators are not fully engaged in programs promoting for demand flexibility [62].

A key factor that is also delaying the use of the full potential of demand flexibility is the lack of efficient market design that promotes and optimizes its usage. Modern market designs are required to have appropriate price signals that can benefit all market participants, and to have shorter trading intervals closer to real time with enhanced bidding mechanisms [63]. In addition, the current market entry regulations must be able to accommodate the diverse characteristics of demand flexibility. Issues regarding the minimum amount of MW that are required to be eligible for market participation can easily hinder the deployment of demand flexibility services, as the flexibility that can be provided from it is certainly less than the bid sizes provided by generation sources. As a result, many countries across Europe are inclining towards relaxing such requirements for participation [64]. Finally, the economic compensations to be received by flexibility providers are still under debate and yet to be established and agreed upon [22]. One side of the argument says that flexibility services should be remunerated in regular energy market prices. However, this means besides being remunerated for their flexibility services, flexibility providers will also achieve further bill savings for reducing their consumption. The other side of the argument says that higher payments for flexibility services than the energy market prices should be applied, as a form of compensation to the economic and environmental benefits that their flexibility services provide to the systems. Figure 2.6 summarizes the barriers to implementing demand flexibility programs in the current market structures.

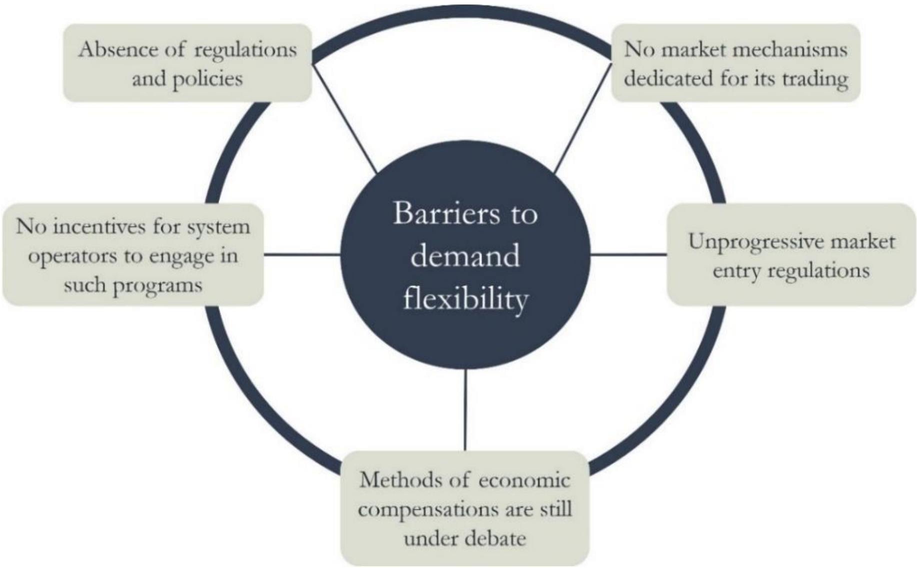


Figure 2.6 Barriers to implementing demand flexibility.

2.3 Demand flexibility providers

Demand flexibility can be considered as a source of revenue for consumers willing to participate in such programs. Due to their limited resources, their participation in flexibility programs becomes considerably challenging and complex. As a result, a new market player emerged, called the aggregator, with an objective to facilitate their participation in demand flexibility programs. Aggregators are defined as an intermediary business entity between their affiliated customers on the one hand, and the grid company, or their energy retailer, on the other hand [65]–[68]. Their main task is to collect and aggregate the flexibility from their affiliated customers and trade this flexibility in electricity markets considering their and the customers' best interest. One of the several benefits of aggregation is that it can increase the reliability of demand flexibility services and facilitate their penetration [43], [69]. In addition, aggregation services encourage consumers to participate in such flexibility programs as they remove from them the complexities associated with electricity market participation. Aggregators, being the responsible parties of collecting and presenting the flexibility of the consumers, can be thought of as flexibility providers. However, the main source of demand flexibility are the consumers, or prosumers in case they are DER owners. A detailed description to the definition and functions of the aggregator will be provided in Chapter 3.

According to [70], the potential of demand flexibility in Europe can be estimated to be an amount of 52.35 GW, with 31% coming from the industrial sector, 27% from the tertiary sector and 42% from the residential sector. The ability of customers to participate in the demand flexibility programs depends on the sector they belong to and the type of loads involved. Flexibility sources have been characterized by European Committee for Electro-technical Standardization (CENELEC) [71], from the least to the most flexible, as illustrated in Figure 2.7; uncontrollable, curtailable, shiftable, buffered and freely controllable. Uncontrollable loads are not capable of providing flexibility [72]. Curtailable loads can offer demand flexibility without the need of supplying back the curtailed energy as they are unshiftable. Shiftable loads can be moved at any time during the day, either before or after the activation of flexibility which depends on the nature of the load and type of consumer. In this section, only curtailable and shiftable loads with respect to flexibility provided from the industrial, tertiary and residential sectors and DERS will be discussed.

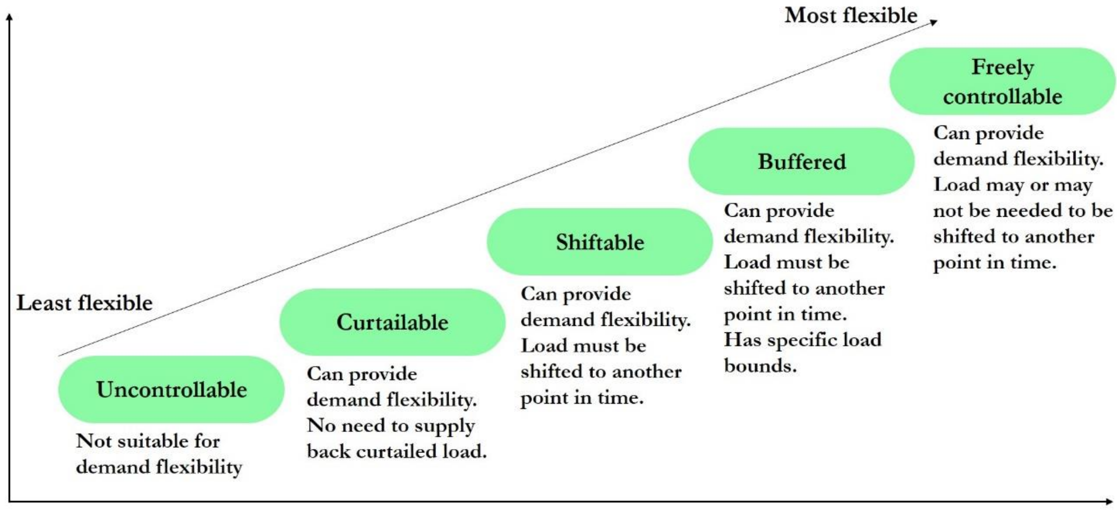


Figure 2.7 Types of loads accrdoing to CENELEC [71].

2.3.1 Industrial Sector

According to [73], industrial customers contribute, on average, to an 80% of the electricity consumption, which makes the large-scale and energy-intensive sector of great potential as a demand flexibility provider. The level of flexibility offered by the industrial sector is largely affected by several factors, such as process criticality, available production lines and production targets. The potential of demand flexibility in Europe with respect to several consumer sectors is presented in [44]. The nature of the industry involved in the flexibility program affects the type of flexibility that can be obtained. For example, several energy intensive factories are only suitable for load shedding, i.e. curtailable loads. Common energy intensive industries are such as aluminum production, copper refinement, zinc production [74], steelmaking in electric arc furnaces and chloralkali process [75], [76]. Other types of industrial factories, such as mechanical wood pulp production and paper machines are considered shiftable loads, which means they require their loads to be shifted to either earlier or later times. For the shiftable loads, [44] presents certain measures that defines their flexibility potential such as the shifting time, which is the maximum duration until the flexible load must be balanced, and the maximum allowed number of interventions per year. Table 2.2 presents some examples for industrial factories with their load nature and preference for load shifting. It should be noted that some of these factories are located in the highest voltage levels of the distribution system or the transmission level.

Table 2.2 Example of industrial factories according to their load nature and shifting preference.

Factory	Load nature	Shifting preference
Aluminum production	*Curtailable*	*N/A*
Chloralkali process	*Curtailable*	*N/A*
Steelmaking in arc furnaces	*Curtailable*	*N/A*
Mechanical wood production	*Shiftable*	*Before or after flexibility activation*
Paper machines	*Shiftable*	*Before or after flexibility activation*
Cement mills	*Shiftable*	*Before or after flexibility activation*

In literature, the potential of the industrial sector as a source of demand flexibility has been addressed several times. In [75], the technical and economic potential of demand side management provided by energy intensive industries is investigated. With the high integration of renewables, a high demand on ancillary services is expected to take place. The work suggests that significant economic benefits can be achieved by implementing demand response programs coming from large-scale industries. The work also studies different industrial processes and their technical and economic properties. The flexibility potential of various process in the food industry, such as refrigerated warehouses and cooling production and distribution are investigated in [77]–[81]. The common steel production processes such as steel mills and electric arc furnaces are studied in [82], [83]. Chloralkali process and electrolytic process which are commonly used in the production of chloride can be found in [84], [85].

2.3.2 Tertiary Sector

The tertiary sector concerns the production of services instead of manufacturing of raw materials [86]. The potential of demand flexibility in this sector comes from large-scale commercial loads relying on cooling and heating of water and ventilation [87], [88]. A comprehensive study on the potential of demand flexibility from the tertiary sector is found in [44]. Different commercial loads were considered, where they have diverse shifting times and maximum number of yearly interventions. One of the common commercial loads is the heating, ventilating, and air conditioning (HVAC) system, which is a high potential source for demand flexibility. The advantages of such loads is that they constitute a large portion of the total load of the commercial site and they are mostly controlled with energy management systems (EMS), which makes it easier to implement flexibility control actions [89]. Also, these loads can be considered shiftable and curtailable at the same time. The reason is due to their thermal characteristics, which can maintain adequate temperature levels for periods of time without affecting the nominal room temperature. In that case they can be considered as curtailable loads. However, for long periods of time, temperatures at room level decrease, which means they will require part, or the full amount of the demand flexibility activated. In addition, some of these loads have constraints when it comes to having back their rebound power. Table 2.3 provides an example of different tertiary loads with respect to their load nature and shifting preference.

Table 2.3 Example of tertiary loads according to their load nature and shifting preference.

Load	Load nature	Shifting preference
Food retailing cooling	*Shiftable*	*After flexibility activation*
Commercial ventilation	*Shiftable*	*After flexibility activation*
Commercial air conditioning	*Shiftable*	*After flexibility activation*
Commercial storage water heater	*Shiftable*	*Before flexibility activation*
Commercial storage heater	*Shiftable*	*Before flexibility activation*
Hotels & restaurants cooling	*Shiftable*	*Before or after flexibility activation*
Water supply pumps	*Shiftable*	*Before or after flexibility activation*

2.3.3 Domestic Sector

The evolution of residential customers' behavior from passive to active, can have a large impact on the implementation of demand flexibility. With the ongoing technological advancements, the typical households' loads now are of various types, with a wide range of flexibility to be controlled [90], [91]. Typical uncontrollable loads in households are such as microwaves and ovens, which are not capable of providing flexibility [72]. Other loads such as lightings, TVs and computers are as well not suitable for flexibility, as they are frequently used during the day and disrupting their usage might cause discomfort to customers. Table 2.4 presents some examples of residential loads with respect to their load nature and shifting preference. Some examples of controllable loads that can offer flexibility without affecting the comfort level of the customers are illustrated in the following groups:

- **Refrigeration Appliances**: These appliances are usually in a continuous mode of operation almost every hour during the year with rare occasions of turning them off. Loads such as refrigerators (RFG) and freezers (FRZ) can offer load shifting and load curtailment flexibility with their full load without the need of pre-cooling. Also, these loads have thermal storage properties which provides the benefit of controlling their temperatures while they are in the on-state of operation. Moreover, they can keep good levels of internal temperature for short periods of time. However, they cannot be turned off for long periods of time since they are critical for the customers' comfort [92].

- **Cooling & Heating Appliances**: The operation mode of such appliances is dependent on the season during the year. For example, air conditioning units (AC) usually work in the summer period and electric storage water heater systems (EWH) work during the winter period. Even though, these loads can contribute to a considerable amount of flexibility, they cannot be used at any time during the year. Same as the refrigeration appliances, their thermal storage properties facilitate temperature control during their operation hours [93]. Cooling and heating appliances, as well as refrigeration appliances, can be considered as curtailable and shiftable at the same time. The thermal storage property of such appliances can prevent temperatures from fast declining if loads are curtailed for short periods of times. However, for longer periods, customers' comfort may be affected and the reduced load must be shifted to either later or earlier times [94], [95].

- **Washing Appliances**: Washing appliances include washing machines (WM), clothes driers (DRY) and dish washers (DW). As important as they are, these loads usually are not in a continuous operation mode every day. However, they are more frequently used than the cooling and heating appliances. Their level of flexibility does not depend on the customer's comfort since they can be shifted at any time during the day [44]. However, the nature of these loads is different from the other types, their mode of operation is only based on on/off status, meaning that these loads cannot increase or decrease while it is in on status [96].

Table 2.4 Example of residential flexible appliances according to their load nature and shifting preference.

Load	Load nature	Shifting preference
Washing appliances	*Shiftable*	*Before or after flexibility activation*
Refrigeration Appliances	*Shiftable*	*After flexibility activation*
Residential air conditioning	*Shiftable*	*After flexibility activation*
Residential electric storage water	*Shiftable*	*Before flexibility activation*
Residential electric storage heater	*Shiftable*	*Before flexibility activation*

The residential side is said to be the future potential for flexibility services. Lately, more studies have been focusing on investigating the different types of household loads that can be used as source of flexibility [97]. In [98], the flexibility of heating, ventilation, and air conditioning (HVAC) appliances in the building sector is quantified. The work suggests that considerable financial savings can be achieved by flexibility providers if robust optimization methods aimed at enhancing the decision-making process are implemented. The coordination of thermostatically controlled loads (TCLs) and air conditioning loads in response to pricing incentives through a proposed mechanism of bidding is proposed in [99], [100]. In [101], the benefits of flexibility obtained from of electric space heating loads in detached houses are addressed. The work proposes a framework based on a set-point controller which shows a significant increase in the yearly savings for a single household when participating in demand flexibility programs. In a similar study, the work in [102] assesses the impact of demand flexibility obtained from electric heating loads to mitigate unforeseen wind power ramp effects. The results showed that efficient management of such loads can have a positive impact on system with high wind penetration by reducing the curtailment and operation costs. The potential of heat pumps and thermal storage systems as a flexibility source in Austria is investigated in [103], where a thermal model for the thermal and electrical systems is proposed.

Loads such as refrigerators and freezers have the ability to offer different types of flexibility services from load shifting to load curtailment. Such loads are almost in continuous mode of operation every day. The thermal storage property of such appliances can facilitate their control strategy without the need of pre-cooling [92]. The work in [104], [105] explores the potential of demand flexibility obtained from refrigerating systems found in supermarkets. The work in [106] presents a general analysis on the demand flexibility that can be obtained from the residential side in Bogota, Columbia. It is suggested that with the increase availability of demand flexibility, considerable amount of energy savings can be reached by the consumers, which can reach up to 30%. The work in [107] assesses the optimal DR programs that can secure more benefits to the residential customers at low voltage feeders. Two DR programs are assessed and analysed, one is studied from the perspective of the energy supplier aiming to decrease the cost of electricity, and the second is studied from the perspective of the Distribution network operator (DNO) with the objective of deferring the needs of grid investments.

2.3.4 Distributed energy resources

The penetration of Distributed Energy Resources (DERs) has a significant effect on distribution grids in enabling the bidirectional flow of electricity between the supply and the demand side. Common types of DERs are such as distributed generation (DG), which can be either conventional-based or renewable-based, electric vehicles (EVs) and battery storage systems (BSS) [108]. While the introduction of DERs can be beneficial to the electric system in decreasing the carbon emissions, reducing demand peaks and promoting the active role of consumers, the impact of DERs can be challenging on the network reliability and stability because of potential voltage fluctuations and congestions [109]. As suggested in [110], the efficient use of flexibility obtained from DER can be beneficial to system operators in grid management and in deferring network reinforcements.

Renewable-based DGs such as Photovoltaics (PVs) have low predictability levels due to their dependence on the weather conditions. However, with the introduction of smart inverters, PV generation can be offer flexibility services in the form of capacity injection or withdrawal [109], [111]. On the other hand, the storage capabilities of BSS and EVs make them a potential and efficient candidate for providing demand flexibility in the form of capacity injection and withdrawal. In addition, they do not require any forecasting processes, as opposed to RES, since their behaviour is easily controlled. Depending on the battery technology, for example Li-ion, Ni-MH and Ni-Cd, and the specific characteristics of the battery, such as battery size and power density, BSS can be used for several application to serve different flexibility needs. As suggested in [112], integrating BSS with other potential flexibility providers, such as commercial and industrial customers, can provide an efficient flexibility portfolio. In addition, BSS can help market agents in avoiding penalties caused by deviations from consumption or generation due to errors in forecasting.

EVs participation in the framework of distribution level flexibility is inevitable, that is due to their electric storage properties and versatilities [113]. EVs can be considered as shiftable loads [114], [115], as the energy required for flexibility, whether its increasing or decreasing, must be moved to another time during the day. EV flexibility could be attained through two approaches; injection into the network by discharging the EVs batteries during network high load consumption and consumption from the network, by charging the battery during high RES injection into the grid. During charging periods, EVs acts as a normal load. Whereas during discharging periods, the EV acts as a generator, and it can be economically compensated for the power injected into the network. A relative new concept in the framework of EVs is called the vehicle-to-grid (V2G) interactions [116], [117]. Under the V2G concept, EVs can become active players in network operations by becoming a DER. In this way, optimal management and scheduling of EVs can assist in maximizing the potential of flexibility in distribution network [118].

An overview assessment of the different charging systems of EVs in Spain is addressed in [119]. The work analyzes the current structure of charging systems from the point of view of charging types, charging modes and alternative charging methods. In addition, the agents involved in the process of supplying charging power to the EVs are described, as well as the different types of EVs that exists in Spain. An overview description of the flexibility services that can be obtained from EVs at the distribution level is investigated in [120]. The work considers EVs location, activation time and duration while providing recommendations for the efficient provision of distribution system operator (DSO) flexibility services. The impact of demand response on the charging schedule of EVs is addressed in [121]. A scheduling algorithm for EVs is proposed, which can be integrated with demand response programs. Furthermore, the efficient use of EVs as flexibility sources and the corresponding V2G benefits is discussed in [122]. The work discusses the impact of different power schedules along with EV participation as flexibility sources on the locational marginal prices. In literature, several factors that can affect the levels of flexibility offered by EVs have been investigated, some of which are described as follows:

- **Driving patterns:** While the potential is high for EVs in the paradigm of demand flexibility, forecasting realistic scenarios for the driving patterns of EV drivers is one important challenge. The unpredictability of human behavior adds a very high level of uncertainty to the whole process. Also, it is difficult to categorize all possible trip purposes that could exist for different drivers since the possibilities are endless. For example, common car drivers usually have one single trip in the morning to work and another one back to home in the evening. Other car drivers can have one or more trips during the day, with different purposes other than work such as going to shopping malls or personal visits [123], [124].
- **EV battery size:** The aggregator plays a key role in the penetration of EVs' demand flexibility. One of the challenges facing the aggregators in that matter is the battery sizes of the EVs. EVs consumptions (kWh) per every km driven differ from one car type to another. These consumption levels are highly affected by many factors concerning the EV such as the types of roads (city or highways), weather conditions which can influence the operation of car heating and systems consumption and the driving speed. All these factors must be considered by the aggregator when collecting and aggregating their flexibility. Table 2.5 presents some examples of EV cars and their corresponding kWh consumption per km and battery capacities [119].

Table 2.5 Examples of EVs with respect to their consumption per km and battery size.

Car type	EVs consumptions	EVs capacity
	kWh/km	*kWh*
BMW i3	0.125	19
BYD E6	0.160	45
Renault Zoe	0.146	22
VW UP	0.117	18.7

- **Charging & discharging rates:** Another important factor that needs to be mentioned is the rate of charge and discharge of the EV batteries. The speed of EV charging power depends on the voltage and the maximum value of current that can be supplied. There are wide ranges of charging which depend on the type and location of the charging pole [119], [125]. Charging poles at households can vary depending on whether the poles are connected to single or 3-phase voltage supply. A single-phase AC supply can provide 230 V up to 16 A which can supply an average of 3.3 kW of power per hour and can fully charge an EV in 6 to 8 hours. Three phase supplies can provide current up to 63 A with average power per hour of 10 kW and can charge EV batteries between 2 to 3 hours. As for public charging poles, they offer higher levels of current which can reach to 550 A offering full vehicles charge between 10 to 30 minutes.

2.4 Demand flexibility buyers

Demand flexibility can be a valuable commodity to several market agents. The main beneficiaries of demand flexibility are usually system operators such as TSOs and DSOs. Also, other market actors such as RES-based generator owners, retailers and BRPs can benefit from demand flexibility. The task of distribution network operation and electricity delivery to end-user customers is assigned to distribution system operators. In addition, DSOs are responsible for the future planning of their own networks, which may need maintaining or upgrading depending on the demand growth. The current challenge facing the distribution system operators is how to confront the future changes in electricity demand. Such changes are credited to the growing technological advancements of all sorts of devices, which are dependent on electricity. In addition to this, the wide penetration of decentralized electricity production, which is usually based on RES, is also contributing to changing the consumers' behavior. Furthermore, the rise of electric vehicles is exerting pressure on distribution networks to accommodate their charging requirements. As opposed to network reinforcements, demand flexibility can relief the pressure of recurring demand peaks in the grid. Distribution system operators can use the flexibility of the demand-side in shifting the demand from peak to valley hours. In addition, demand flexibility can be used as a solution tool in the DSOs' congestion management process.

At the transmission level of electricity, transmission system operators are responsible for managing the balance between production and consumption every hour. At the moment, transmission level flexibility is being traded in electricity markets to manage voltage and frequency fluctuations. In such markets, TSOs act as the market operator and flexibility can be used for balancing and ancillary services, as well as avoiding demand peaks, which increases the overall reliability of the system operation and decrease the losses in the grid. Similar to DSOs, transmission system operators can defer the need for grid investments by considering demand flexibility in their future planning [68], [126]. One of the key factors to ensure the success of flexibility is having efficient coordination between the DSO and TSO.

Such coordination and information exchange between both parties regarding flexibility activations is essential to avoid unnecessary flexibility requirements, which can lead to further grid problems. As suggested in [49], this coordination can be done by communicating the flexibility offers to the DSO in advance order to discard those offers that can create local congestions in the distribution network, or through assigning the task of demand flexibility management to the DSO like a technical virtual power plant. In the work carried out in this thesis, the demand flexibility is addressed and modelled at the distribution grid level and the communication channel between the DSO and the TSO is not explored, as it is out of the research objective.

Other agents which can benefit from procuring demand flexibility are retailers or balance responsible parties (BRPs). The process of energy purchase usually takes place before the actual operation, e.g. day-ahead energy markets, deviations between the bid amount and the actual real-time consumption amount are bound to happen, which may result in high penalty costs. In order to avoid such costs, retailers and BRPs can benefit from demand flexibility to balance their consumption profiles. The current trend for local generator owners is to depend on electricity produced from intermitted resources, e.g. solar and wind energy, due to its considerably low operation and maintenance cost. However, the unpredictable behavior of such sources can be challenging when participating in electricity markets. The day-ahead generation forecasting of such sources is subject to inaccuracy, which yields as well to imbalance costs for their owners. In such cases, demand flexibility can be utilized to balance these deviations of consumption by either increasing the demand at times of high generation or reducing the demand at times of low generation. A summary for the potential flexibility buyers their purposes for obtaining flexibility are given in Figure 2.8 and the details for every buyer and the type of service they can use are explained in this section [27].

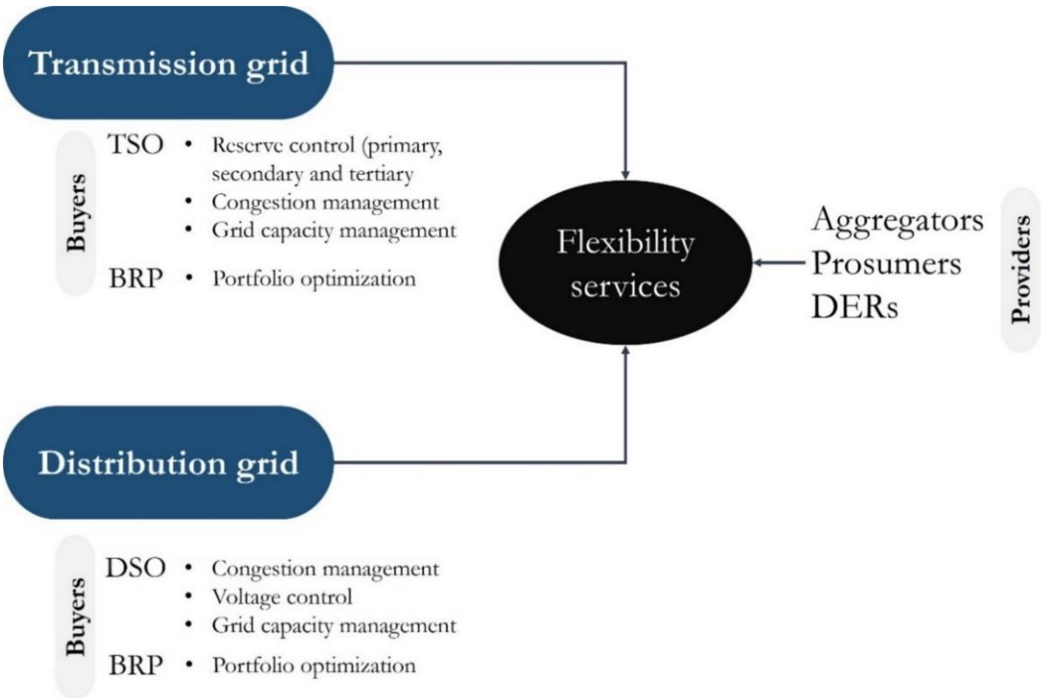


Figure 2.8 Potential demand flexibility buyers and their purpose of acquiring demand flexibility.

2.5 Literature Survey

According to [27], several distribution system operator associations are demanding from policymakers and regulators to promote the role of DSO as a neutral market facilitator that is able to supervise and integrate flexibility services in their networks. In addition to this, it is advised to incentivize distribution system operators for their usage of demand flexibility services for congestion management, given it is cost effective. DSOs should be able to optimize the operation planning of their own network by either deploying demand flexibility programs or by network upgrading. The distribution system operator associations also call for a transparent exchange of information and data between DSOs, TSOs and aggregators.

There are many forms the DSO can use to acquire demand flexibility [27]. One of such is through connection agreements. Also called variable network access or flexible network connection agreements, this type of contracts provides limited access to the involved parties, such as generators or consumers, when the network is suffering from a contingency. Thus, the distribution system operators' need for network investments can decrease. Another way for flexibility access can be through market-based solutions. Considered by policy makers as the optimal solution for demand flexibility access, market mechanisms can deliver cost-efficient flexibility services for several market agents by facilitating competition between different flexibility providers. To reach the potential of flexibility services, market-based solutions require clear product definition and more participants, in order to increase the competition level, thus achieving lower prices. Another key factor that can increase the value of flexibility markets is to ensure a coordinated co-existence with other electricity markets. This means that flexibility service activations should not have negative impacts on other markets or players. Also, the penetration of aggregation services, as well as relaxing the barriers for market entry and exit, can encourage more end-user customers to participate in the flexibility services. In this section, a survey is carried out to study the different proposals and techniques considered in literature for market mechanisms. In addition, another survey is presented that focuses on the recent pilot projects promoting demand flexibility.

2.5.1 Market mechanisms for demand flexibility

There have been many proposals and diverse approaches for market structures in literature regarding demand flexibility management and procurement. One of the concepts that questions how demand flexibility can be managed between market participants and network operators, is introduced in [127] and called the traffic light concept (TLC). The TLC system describes the network status at a specific time with the colors of the traffic lights (green, amber and red), as seen in Figure 2.9. Given a normal operation, the network status can be assigned to the green light. When the system security is jeopardized, the network status is given a red light. The amber light resembles an alert state, which is activated when a congestion is expected to take place and flexibility markets are called upon to provide flexibility services to the DSO to mitigate such congestions [128], [129]. Based on the TLC system, the German association of Energy Market Innovators (BNE) has developed a decentralized market-based instrument for flexibility management called De-Flex-Market [130], [131]. The proposed market focuses on providing flexibility services to the DSO to resolve local capacity constraints as an alternative approach for network reinforcement. The De-Flex-Market has a contracting time frame of one year, and a time frame for flexibility need notification and activation of a quarter of an hour. The contracted customers or flexibility providers should oblige to the flexibility requirements of the DSO for an entire calendar year, and they are remunerated with economic incentives for their compliance.

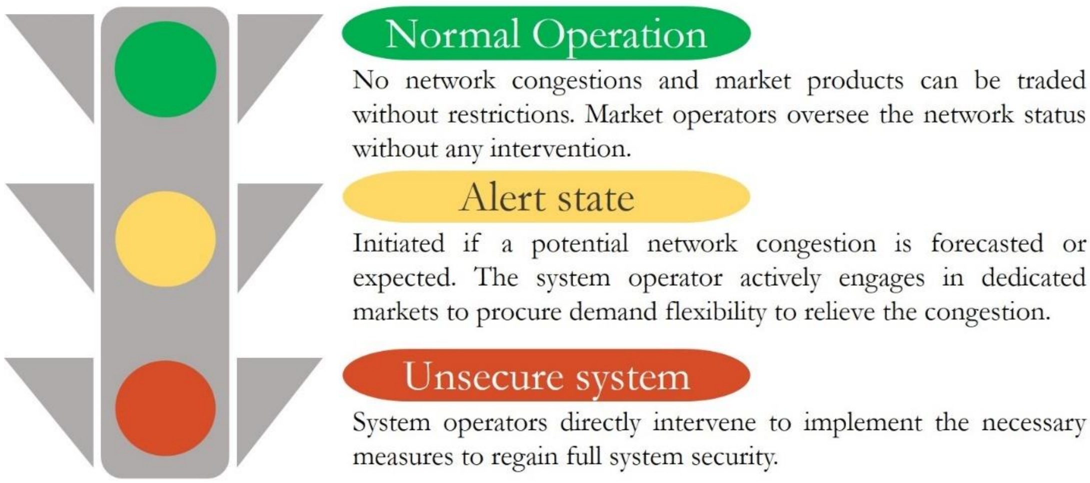


Figure 2.9 Traffic light concept.

In another approach, a Danish Flexibility Clearing House named FLECH is proposed in [132], [133]. The market aims to promote for the integration of small scale DERs as flexibility sources in order to provide flexibility services for the DSO. The FLECH works in parallel to the existing electricity markets (day-ahead, intra-day, etc.), as seen in Figure 2.10. On the distribution level, the FLECH's purpose is to provide assistance to the DSO in mitigating grid congestions which can vary between feeders overloading or voltage fluctuations. Moreover, the market relies heavily on the services of the aggregator, in order to aggregate and present different flexibility services in the market. The DSO determines the amount of flexibility services needed during its year-ahead planning, and accordingly the aggregators are able to submit flexibility offers to match these needs. Here, the aggregators are the responsible party for the scheduling and optimization of the activated DERs in the flexibility services. Figure 2.11 illustrates the trading processes in the proposed FLECH.

In the study of the effect of the increased penetration of DERs based on RES and the impact it has the DSO's network operation, a regional flexibility market was proposed called RegioFlex [134]. In order to solve the increased need of high investments at the distribution level to adapt to the DERs penetration, the proposed market takes advantage of the services of demand flexibility. Based on the of the TLC system, the RegioFlex aims to switch the system status from the yellow phase to a green phase. This is achieved by enabling a platform for the DSOs to facilitate the call for demand flexibility services, and for the aggregators to offer their flexibility services. The work in [135] studied the optimal market design criteria for deploying flexibility markets. In order to solve common grid congestion problems, the work assesses the problem of market design from a temporal, spatial, contractual, and price clearing dimensions. Furthermore, it analyzes three different approaches for flexibility contracting; flexibility contracted an existing wholesale markets, creating separate flexibility market, and implementing a reserve market type approach. The theoretical and mathematical approaches for enabling flexible demand participation are discussed in [136]. The work proposes a novel day-ahead market pool mechanism which focuses on the common non-convexities characteristics that are often present when rescheduling demand's price response. The lack of coordination between the DSO and other market players such as the aggregators, which can limit the potential of demand flexibility, is discussed in [137]. Also, the work proposes a market architecture based on a blockchain transactive platform that enables autonomous energy exchange between residential households to locally balance the production of RES, while providing them with financial incentives.

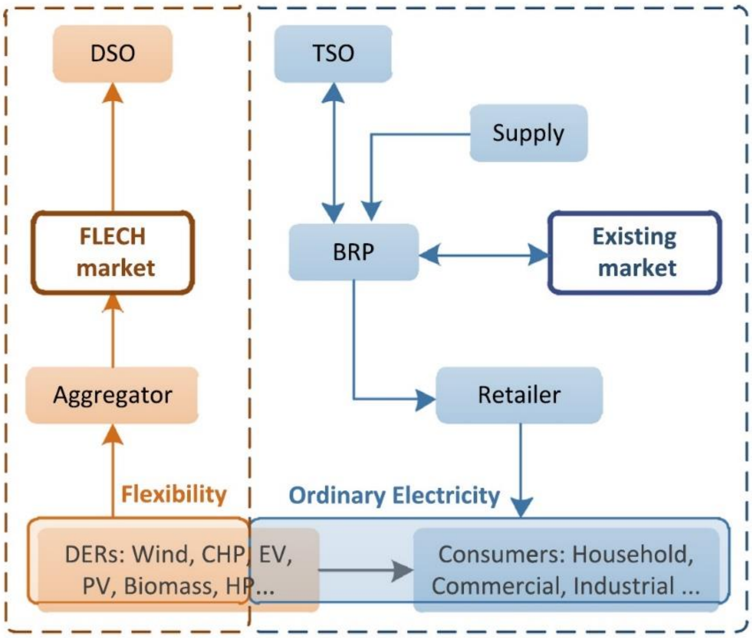


Figure 2.10 Architecture of FLECH [132], [133].

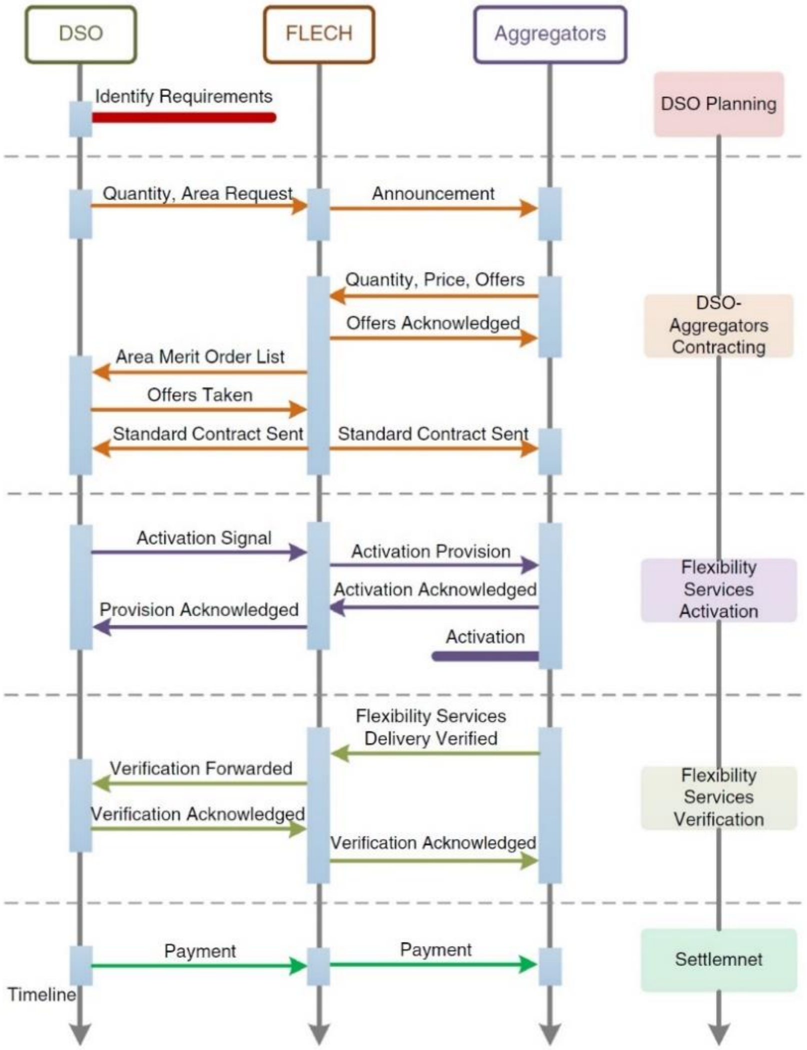


Figure 2.11 Trading processes in FLECH [132], [133].

The foreseen high penetration levels of intermittent RES in the future is expected to impact the volatility of market prices and impose certain challenges on load forecasting, thus highly affecting the short-time trading timeframe. This can lead to high imbalance costs incurred by market players due to deviations between purchased volumes on day-ahead markets and real-time consumptions. This issue has been addressed in [138], where a short-term planning framework for flexible demand bidding strategies is introduced. In a day-ahead framework, the proposed model forecasts the aggregated load demand of customers and construct flexibility bidding offers. The objective of the model is to maximize the profit for the flexibility providers. The model takes advantage of stochastic programming to manage uncertainties concerning market prices, load demand behaviors and customers' response to dynamic tariffs. In a similar study, the work in [139] presents a short-term planning model for optimal bidding curves for flexibility aggregator in the day-ahead market. The work investigates the effect of price elasticity on the flexibility aggregator, in which it can benefit from in some cases. Moreover, it carries out a numerical case study using the Nordic electricity market model to assess the impact of risk factors on the aggregator's profit as well as the risk levels, average market prices and total load consumptions. It also indicates that demand flexibility can lead to lower market prices and eventually lower electricity bills. The work in [140] investigates the effects of short-term demand flexibility in the day-ahead framework on the market value as well as on the consumers' cost. The work in [141] addressed the need for additional incentive mechanisms for demand flexibility in electric systems with high RES shares. Similarly in [142], the appropriate framework conditions for promoting variable RES flexibility in the Nordic and Baltic area are identified. The work explores the different sets of framework conditions from a market-based and regulatory-based perspective, which can influence the flexibility investment decisions for market agents.

Other literature prefers a wider scope when assessing the issue of demand flexibility markets design and proposal. In [66], a promising framework for building smart energy products and services is suggested by the Universal Smart Energy Framework (USEF). The proposed framework aims to maximize the value of demand flexibility by presenting it as a tradable commodity in an efficient market structure. USEF follows a market-based coordination mechanism and it highlights the different roles for active stakeholders. The architecture of the proposed framework is presented in Figure 2.12. The work in [143] takes advantage of the USEF framework by presenting a multi-agent negotiation mechanism to optimally divide the flexibility services among different time periods.

In [144], a framework for flexibility trading is introduced that works on two-time frame levels. First, using day-ahead and intra-day markets operated by a local flexibility operator, the model optimizes their energy portfolios for the coming day. In return, portfolios are only accepted if no congestions are created in the grid. Secondly, on a real-time basis, the model integrates a set of control actions that are determined by the DSO to resolve a network congestion if one occurs at real-time. Finally, the work presented addresses the problem faced by the DSO to operate in the proposed framework. Accordingly, the paper proposes a bi-level optimization problem that optimizes the bidding strategy for the DSO to minimize the total cost of procuring flexibility and at the same time clears the day-ahead and intra-day markets. A joint market framework for flexibility services procurement at the transmission and distribution level is suggested in [145]. The work uses the tertiary Danish market for reserves control as an illustrative example of a market that can be integrated with a proposed distribution level market for congestion management services. The novelty of the paper lies in the proposal of a single pool for flexibility services where the TSO and the DSO can procure ancillary services simultaneously. The proposed framework encompasses a flexibility reservation market which spans from a year-ahead to a day-ahead time period. In this way, it provides long term certainty planning for the TSO and DSO while increasing the competitiveness of the market environment on the short period. The reservation market is followed by a real time activation market where flexibility bids are arranged, and the market is cleared accordingly.

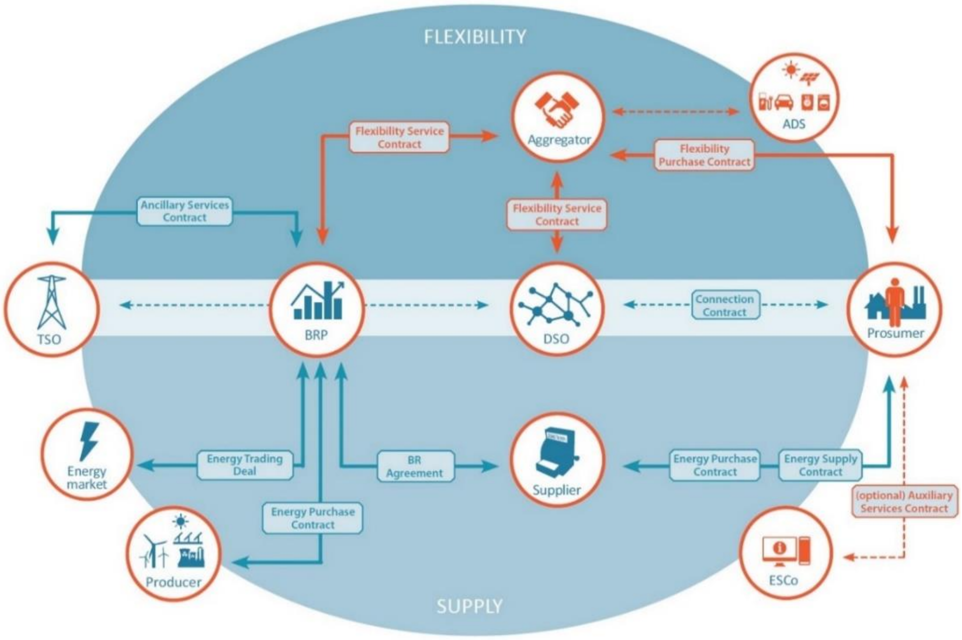


Figure 2.12 Architecture of USEF [66].

Finally, more general literature regarding different aspects of demand flexibility can be found in [146]–[148]. In [146], a novel distributed control strategy for high flexible demand penetration is proposed. In order to reach market equilibrium and minimum energy cost for flexibility providers, a Nash equilibrium concept and Lyapunov-based techniques in a game theoretical framework are used. The novelty of the proposed strategy lies in guaranteeing equilibrium regardless of the flexible demand penetration level and for any type of flexible load. In [147], an economic model of incentive DR programs is proposed based on the elasticity of prices of load demand and customers' benefit function. The work investigates the impact of such programs on price responsive loads. An optimal method for using DR in ancillary services is proposed in [148]. The method minimizes the total cost of demand response used as a contingency reserve while maximizing the social welfare and maintain a stable operation of the grid.

2.5.2 Pilot Projects

In order to cope with the objectives set by the European Council, which has a target to increase the share of energy consumption produced from renewable energy sources in Europe to 27% by 2030 [3] and 97% by 2050 [4], road maps and investment plans are being established at the moment to develop smart grids. It is believed that active integration of demand flexibility programs is an important pillar to support the potential of smart grids. Within Europe and globally, countries are trying to reform their markets into a more liberalized structure. There are several global and European smart grid pilot projects that are promoting for the flexibility of demand. These projects are studying the impact of deploying demand flexibility services on electricity systems, some of these projects are explained here [149], [150].

- **E-DeMa Project**

This German based project was founded by the German Federal Ministry of Economics and Technology. E-DeMa is one of many E-Energy projects that are being carried out to investigate the level of customers' acceptance of advanced smart grid technologies. The project's objective is to investigate smart load management and the provision of consumption data. Specifically focusing on the residential sector of the Western area of Germany (Rhine-Ruhr-area). The project was able to fund the installation of smart grid equipment and communication systems for almost 700 customers [151].

- **Your Energy Moment (YEM) Project**

As a part of the Dutch Innovation Program for Smart grids, Your Energy Moment (YME) project was deployed in 2012 for a duration of 3 years [152]. The project's objective was to investigate the real-life impact of high penetration of flexibility services on the technological, economic and social sides in two residential areas in Zwolle and Breda in Netherlands. This was achieved through installing smart grid equipment, PV solar panels, and smart washing machines and dryers at the residential side. The project results showed that with appropriate management and with access to smart grid products, residential customers were able to adjust their daily behavior. Load flexibility levels reached to 10% of daily energy consumptions [153]. Further analysis were carried in coordination with YEM project in [154], where the depth of the flexibility of demand of the residential customer in the area of Zwolle over the period of one year is investigated. The study highlights the impact of having smart appliances at the residential level as well as smart energy management systems, on the behavior of the customers. The results showed significant and positive response from the customers in adjusting their usage of load in response to dynamic price signals.

- **LINEAR Project**

Another EU project that was developed in 2009, the LINEAR (large-scale implementation of smart grid technologies in distribution grids) project focuses on the direct impact of active demand strategies in smart grids at the residential area of Flanders, Belgium. The project's main focus is the implementation of an autonomous active demand management system on the distribution level [155]. An extensive study that aims to quantify the flexibility of demand response for the residential customers of that area based on input from the LINEAR project can be found in [90]. The study focuses on five types of flexible residential appliances which are; washing machines, tumble dryers, dishwashers, domestic hot water buffers and electric vehicles. The study shows the high value of demand flexibility in maximizing the grid's reliability and economic sides.

- **DR-BOB Project**

DR-BOB is an EU project developed between France, Italy, the UK and Romania, which is a part of the European Horizon 2020 framework program for research and innovation [156]. The project focuses on the techniques and tools of harnessing load flexibility from building blocks. The project promotes the efficient use of electric equipment, efficient load shifting strategies and the promotion of energy storage devices for RES [157], [158].

- **China Pilot Projects**

While unbranded by a commercial name, many pilot projects were carried out in China [159]. These pilot projects are aiming to study the impact of demand response in deferring the need of grid investment on the transmission and distribution levels. Other Chinese pilot projects can be found in [160]–[162]. Several cities in China have implemented short DR programs to better formulate incentive policies and to establish well-structured DR platforms. For example, the pilot project in Shanghai has indicated that during 2014, the total consumed energy was almost equal to the maximum capacity of the local power plants. Thus, reliability levels are heavily threatened in the case of power plants malfunctions. The project's objective was to develop DR strategies for local enterprises and in commercial buildings. Results shows a significant decrease of peak loads by 10% with an approximate capacity of DR of 50 MW. Another pilot project took place in the city of Foshan, aiming to deploy DR strategies to shift 60 MW of load demand.

- **IESO Demand Response Project**

In the liberalized and unbundled energy sector of Ontario, Canada, the Independent Electricity System Operator (IESO) has launched a DR pilot project in 2015 [163]. This project's objective was to test the DR capabilities in providing flexibility services in response to hour-ahead and real-time market signals. Moreover, the project is assessing the commitment of customers' load curtailment in day-ahead and four-hours ahead in response to economic incentives.

- **Power Off & Save Project**

The transmission system operator (EirGrid) in Ireland has piloted a residential focused DR project in 2015 called Power Off and Save. The project involved 15000 residential customers with the aim to secure a range of 2 to 5 MW of DR flexibility in the residential sector. The flexibility involved in this project included load flexibility and on-site generation systems. The DR was managed through remote controlled loads of typical residential appliances, as well as activating on-site generation systems which can vary between RES or heat pumps [164].

- **FlexNett Project**

Based in Norway, the pilot project FlexNett (Flexibility in the future smart distribution grid) focuses on maximizing the potential of demand flexibility in future smart grid networks. The project's objective is to verify the technical feasibility of flexibility market solutions of DR programs in a cost-effective and reliable manner [165].

- **ADVANCED Project**

This project's goal is to widen the understanding of active demand programs between different types of customers to encourage their participation. Many national pilot projects were launched under the umbrella of the ADVANCED project [166]. One of these projects is ADDRESS which encourages the active participation of domestic and small commercial consumers in the electricity markets [12]. The ADDRESS project proposed three main flexibility products, named scheduled re-profiling (SRP), conditional re-profiling (CRP) and bi-directional conditional re-profiling (CRP-2) [168]. The SRP products are obligatory products where flexibility is provided by their providers to the flexibility buyer at a specific time. CRP products are conditional where flexibility providers must have the capacity to provide a specified amount of flexibility during a specific time period, which is delivered upon request from the buyer. Finally, CRP-2 products are similar to CRP but with the providers being able to provide bi-directional flexibility services, i.e. load increase or decrease. Figure 2.13 shows an example for the delivery of the product CRP. It should be noted that the energy payback in the figure refers to the amount of energy presented by the flexibility provider that needs to be moved to another hour during the operation period.

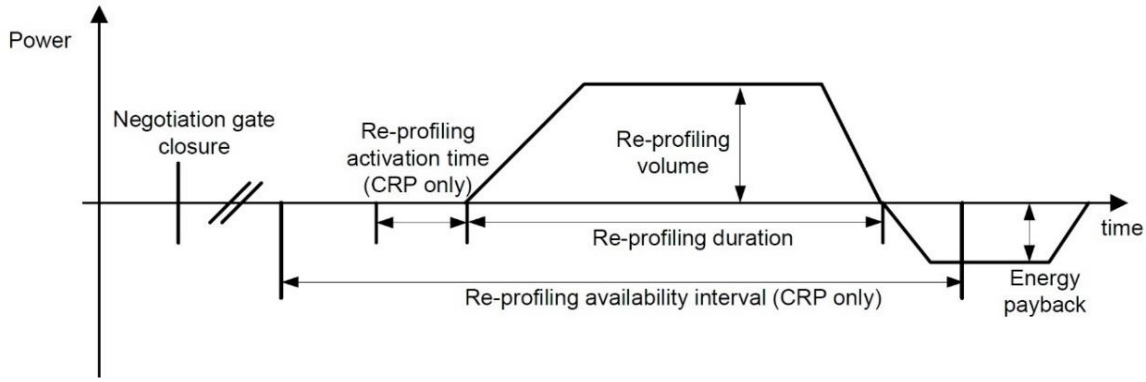


Figure 2.13 Example for CRP product delivery in the ADDRESS project [168].

- **IDE4L Project**

This European project was funded by the European commission between 2013 to 2016 [169], [170]. The IDE4L project addressed the topic of active distribution networks that are targeted to provide high levels of operation sustainability and efficiency. Its objective was to develop new distribution automation systems, which enables real-time monitoring and control of the medium voltage and low voltage grids and the trading of flexibility services obtained from aggregators and DERs. One of the main findings of this project is that a flexibility market is essential to exist to enable the trading of flexibility services. Within this project, the flexibility services modelled are based on what was proposed in the ADVANCED project, which are the scheduled re-profiling (SRP) and conditional re-profiling (CRP). The project also made clear that the role of the aggregator is essential to gather and optimize the trading for flexibility for their affiliated customers. Figure 2.14 shows the interactions setup between the aggregator, TSO, DSO and other market participants. In the proposed framework, a flexibility market is presented that receives flexibility bids from the aggregator and allow the TSO and DSO to procure flexibility services to solve network congestion.

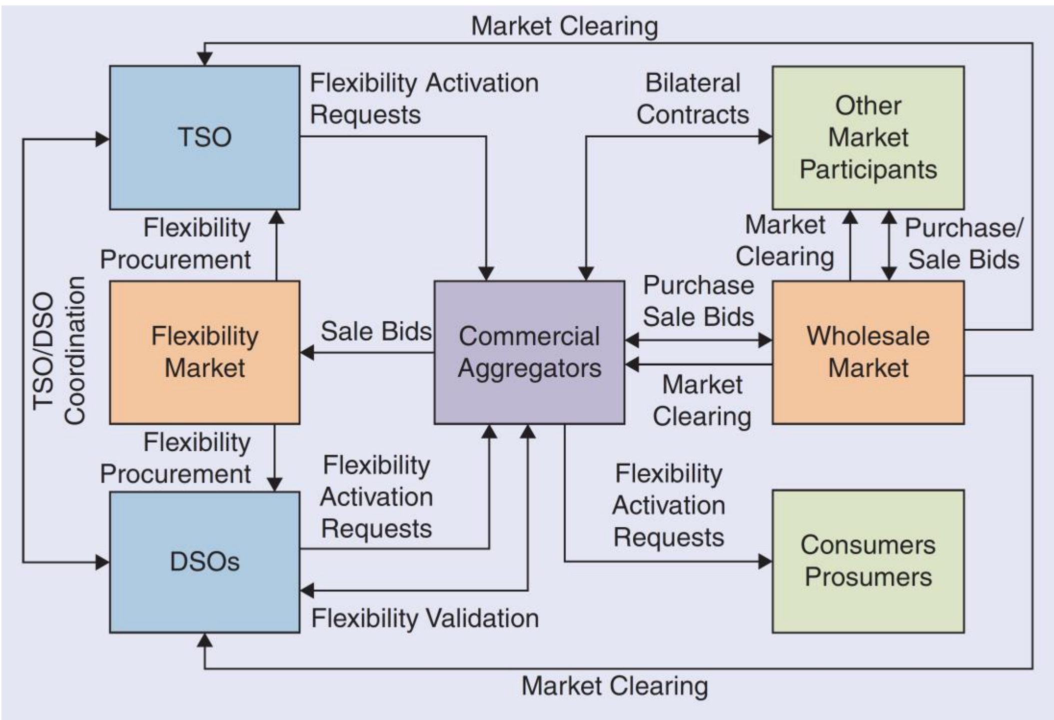


Figure 2.14 IDE4L Project interactions between different market agents [169].

- **iPower Project**

iPower "Strategic Platform for Innovation and Research in Intelligent Power" is a Danish platform that focuses its research in the field of aggregated flexibility services in smart grids. The FLECH market was proposed by the iPower project [132]. The iPower platform proposed some contractual setups for the flexibility services between the DSO and the aggregator that can help to mitigate common grid congestions. Such services are like the Power Cut Planned, where the contract setup stipulates that flexibility providers must decrease a certain amount of pre-specified power at a pre-specified time during the contract period without any kind of a triggering signal. This pre-specified power is based on accurate prediction and forecasting for daily load patterns. Another proposed service is called Power Cut Urgent where flexibility providers will decrease a certain amount of power based on a triggering signal from the DSO. This triggering signal represents the occurrence of certain congestion in the grid [171].

2.6 Current research fields

One can notice that there are several market proposals mechanisms in literature and multiple pilot projects that were deployed in the past years. The common objective of all these proposals and projects is to study how demand flexibility can be efficiently utilized, how it can assist system operators in their day-to-day operations and how to encourage consumers to participate in such programs. Even though several barriers and challenges are facing the full deployment of demand flexibility programs, the expected benefits are numerous and valuable. Based on the available and collected information from the aforementioned pilot projects, it was be observed that the ADDRESS project [12], the IDE4L project [169] and the iPower project [132] have the most interesting and realistic approaches to the issue of demand flexibility implementation and deployment. Such projects were developed within the past decade and were able to realize better proposals and clear definitions on how demand flexibility can be utilized, traded and managed. As a result, such projects inspired the work presented in this thesis.

Based on the surveyed studies in literature, it was found that there are several research fields that are important to the full realization of a flexibility market framework, but such fields are not addressed jointly. While some previous studies addressed one or two of these topics under the same proposal, it was hard to find a single framework that considers all these topics. It is the aim of the work in this thesis is to propose a framework that encompass all of such key topics to achieve an efficient framework for demand flexibility trading in distribution systems. Table 2.6 presents a summary for previous research studies with respect to the seven research topics, and in the following these topics are discussed in detail.

- **Flexibility products**

Demand flexibility, as already discussed, can be used for several purposes by several market agents. Thus, with many possible services, the proposed flexibility market must have a clear definition to address the available flexibility products. The common interpretation of demand flexibility services in many studies is an activity of decreasing the load. While this is a frequent use to flexibility services, and in demand response programs in general, one should not overlook the possibility of using the opposite direction of demand flexibility, which is increasing the load. With the wide penetration of renewables in distribution systems, there are several occasions when the load fails to meet the generation, since RES output cannot be accurately predicted. As a result, voltage levels can surpass the permissible limits causing possible outages. Therefore, one way to use demand flexibility is to take advantage of consumers willing to increase the load. Thus, demand flexibility in both directions are two mutually important products that can be of value to DSOs. In literature, many studies choose to consider only one type of flexibility product, which is load decrease. For a more efficient utilization of existing flexibility, both demand reduction and increase should be considered.

- **The payback effect**

Demand flexibility is often accompanied by what is called the rebound or payback effect [172]. The payback in general describes the amount of energy shifted from one point in time (due to activation of flexibility) to another point in time (the consumers likely to need to consume the energy they provided as flexibility). The payback can have a negative effect on the network if not considered properly, since the energy moved from one hour to solve a congestion, can cause another congestion at another hour. As a potential buyer, the DSO must know beforehand the conditions of the payback effect, such as the time when the consumers need the energy back. Based on such conditions, the DSO can be inclined to choose flexibility from other consumers with payback conditions more suitable and aligned to the network needs. The inter-temporal characteristic of the payback effect may be complex to model and it was neglected in several studies. However, it is essential to be considered in order to present a realistic model to a flexibility trading process.

- **The grid constraints**

In general, the optimal operation of transmission and distribution networks is controlled by close monitoring of the power flow within the grid and the voltage levels at every node. Modelling the grid constraints can be problematic due to its complexity, especially for large networks. However, an efficient market design should consider the grid constraints to model the real behavior of energy flows and voltage levels in distribution networks. DSOs, being the primary flexibility buyer, must make sure that the activated demand flexibility will solve the intended congestion and will not cause further network congestions. The grid constraints were absent from several studies and they should be considered.

- **Adjusting trading processes**

Another issue that is not covered in literature is the adjusting trading processes that should take place to ensure the efficient trading of demand flexibility. It should be noted that demand flexibility trading is not a single process of buying and selling between the DSO and the consumers. For example, if the DSO procures demand flexibility in the day-ahead period, there will be energy differences arising between the energy already bought by the aggregator in the wholesale electricity market and the adjusted new load profile after clearing the flexibility market. In addition, the payback power that is needed by the consumers must be procured by the aggregator. All these processes are rarely mentioned in literature and should be addressed.

- **Uncertainty of demand**

Common proposals in literature develop flexibility markets that are operating during the day-ahead period. Similar to the wholesale electricity markets, day-ahead flexibility markets will be subject to forecasting errors which can result in inaccurate procurement of demand flexibility during the day-ahead period. The uncertainty of demand is a very important issue which can jeopardize the validity of demand flexibility trading, the effect of such uncertainty should be taken into consideration to increase the efficiency of the demand flexibility trading process and decreases the DSO's potential financial losses that may be incurred as a result of purchasing either more or less than the actual required flexibility.

- **Time periods for flexibility trading**

The wholesale day-ahead electricity market is usually followed by intra-day markets that help market agents in adjusting their portfolios, since forecasting accuracy increases as the real-time operation approaches. Intra-day markets as well help system operators to better monitor their networks and with better accuracy they can mitigate network congestions. Similarly, flexibility markets should not be operating solely in the day-ahead period and closer to real-time markets should exist. Real-time flexibility markets can allow system operators to mitigate sudden congestions and to avoid the drawbacks of forecasting errors. Thus, considering both time frames: day-ahead and real-time will be more efficient. The day-ahead flexibility market allows the DSO to procure flexibility based on the day-ahead forecasts to mitigate congestions which are considered almost sure to take place. Also, the new option previously explained in section 2.7.5 can be traded in this market, which allows the DSO to reserve an amount of flexibility to be used upon request in case the DSO is not sure about the probability of congestions taking place. The real-time flexibility market allows the DSO to procure on short-time notice during the real-time to avoid unplanned or sudden network outages.

- **Market clearing & optimization**

The flexibility market operator (which may be the DSO) has the responsibility of managing the trading process of demand flexibility and clearing the market. There have been many proposals in literature regarding different techniques and approaches to clearing flexibility markets. The flexibility market operator has to optimize the procurement of demand flexibility, while considering several factors, such as the payback effect, grid constraints and the uncertainty of demand. It was noticed that all proposals found in literature do not necessary consider all of the mentioned aspects within the optimization process. Taking in account all the necessary aspects of demand flexibility during the optimization process will more likely lead to more realistic simulation and results.

2.6.1 A comprehensive approach

The objective of this work is to propose an efficient framework for a flexibility trading market that considers all the aforementioned topics, which are often addressed separately in literature. This objective is achieved by carrying out the following:

1. Providing a clear definition to the flexibility products offered in the flexibility market and considering two possible flexibility products which are demand reduction or demand increase.
2. Taking into account the payback effect that is accompanied with demand flexibility activation within the market design. In this way, the activated demand flexibility is ensured to solve the intended congestion and do not lead to further network congestions during other hours of the day.
3. Considering the network constraints, which model the permissible limits of the power flow and voltage limits, within the decision-making process of flexibility procurement in order to compute accurate amounts of demand flexibility in a realistic manner.
4. Addressing the adjusting trading processes that should be carried out by the aggregator to ensure the efficient trading of flexibility.
5. Taking into account the uncertainty of demand to eliminate the DSOs' risk of over- or under-procuring flexibility services. Also, the uncertainty behind the consumers' commitment to the flexibility activation request and amount of flexibility needed is considered.

6. Enabling flexibility trading during both the day-ahead and real-time periods, thus allowing the DSO to optimize its purchase accordingly.
7. Proposing an optimization algorithm that clears the flexibility market, ensures the optimal trading of flexibility between the market agents and minimize the DSO's total cost. This optimization algorithm takes into account all the above-mentioned factors in the optimization process.

Table 2.6 Summary for literature with respect to research fields.

Ref	1. Flexibility products	2. The payback effect	3. The grid constraints	4. Adjusting trading processes	5. Uncertainty of demand	6. Time periods for flexibility trading	7. Market clearing & optimization
[66]	Load reduction	×	×	×	×	Day-ahead	×
[130], [131]	Load reduction	×	×	×	×	Day-ahead	×
[132], [133]	Load reduction	×	×	×	×	Day-ahead	√
[134]	Load reduction	×	×	×	×	Day-ahead	×
[137]	Load reduction	×	×	×	×	Day-ahead	×
[138], [139]	Load reduction	×	×	×	×	Day-ahead	×
[144]	Load reduction	×	×	×	×	Day-ahead & real-time	√
[167], [173], [illegible]	Load reduction	√	×	×	×	Day-ahead	×
[175]	Load reduction	×	√	×	×	Day-ahead	√
[176]	Load reduction	×	×	×	×	Not mentioned	√
[177]	Load reduction	×	×	×	×	Not mentioned	×
[178]	Load reduction	×	×	×	×	Day-ahead & real-time	√
[179]	Load reduction	×	×	√	√	Day-ahead & intra-day	√
[180]	Load reduction	×	×	×	√	Day-ahead	√
[181], [182]	Load reduction	×	×	×	×	Real-time	√

2.7 Summary

This chapter gave an overview about demand response programs and a detailed view of demand flexibility, with respect to its attributes, the need for deploying such programs and the potential barriers to their implementation. Also, the potential providers and buyers of the demand flexibility services was addressed. Sources of the described demand flexibility were from the industrial sector, tertiary sector, domestic sector and DERs. The potential buyers of flexibility services are DSOs and TSOs. However, flexibility services at the distribution level is the focus of this thesis, thus DSOs are considered as the main buyer. A thorough survey for the proposed flexibility market mechanisms in literature was carried out. In addition to this, a review of the recent pilot projects promoting the deployment of demand flexibility was made. Finally, the current research fields, which are key to fully realize an efficient flexibility market framework, were addressed. Thus, with respect to such research fields, a brief description of the thesis's objective was given which aims to consider all the research fields. Before introducing the proposed flexibility market framework, it is important to define properly the architecture of electricity markets and the key role of the DSOs in distribution networks and its future role in the paradigm of smart grids. This is given in the following chapter.

3 Electricity Markets & Distribution networks

During the past decades, the electricity sector transformed remarkably, mainly due to liberalization and deregulation of the system [183], [184]. The generation and retail sectors were liberalized fostering a playing field for producers and suppliers to compete. However, natural monopolies associated with network's activities i.e. distribution and transmission sectors, were not affected by deregulation. These activities are still operated as monopolies and, therefore, regulatory intervention is needed to prevent potential monopolistic behaviors by network operators, such as charging grid users with unnecessarily high prices or not ensuring an adequate level of quality of supply [185]. Regulations can be defined as instruments implemented to establish rules to control an activity. In the power industry business, there are several aspects that concerns regulators, i.e. entities responsible for implementing the rules. One of which is designing rules to steer market agents towards general welfare, which is the collective benefit gained by customers and operators. In addition to this, regulators must oversee and supervise the implementation of its rules. Even though market mechanisms can have proper business structures, regulators must monitor and take the necessary actions for rules violations. Other concerns to the regulator include prices, tariffs and quality of service [186].

This chapter reviews the unbundling of the electricity system, as well as the different electricity market structures. In addition, it defines the distribution system operator main responsibilities, business model, congestion management tasks, regulatory remuneration schemes and distribution network tariffs. Also, it presents a review on the electricity markets structure and operation in Spain. Moreover, the chapter addresses the topic of smart grids and how it represents the nature evolution to the current conventional distribution networks. This evolution requires DSOs to reshape their roles and goals, and future responsibilities are added to their scopes. One of the DSOs' key responsibilities that will evolve is related to the future planning and development process. With the wide penetration of DERs and new loads such as EVs, and the continuous demand on electricity, demand flexibility has been called by regulators and policy makers as a potential tool to mitigate any future challenges. Nowadays, DSOs are only incentivized for these conventional upgrades, with many regulatory barriers to the deployment of demand flexibility. Thus, current regulations need to be reformed to provide innovative remuneration schemes to DSOs for using smart solutions.

3.1 Basics of electricity markets

In the past decades, the power industry along with several electric utilities world-wide were forced to migrate from a centralized vertically integrated utility structures to an unbundled and open market systems, which put an end to the idea of "utility monopolies". A vertically integrated structure allowed the power sector to have a single entity in the power system to own and operate the activities of generation, transmission and distribution. This encouraged utilities to act in a monopolistic way, locally or regionally, depending on the geographical area. One of the disadvantages of such structure is that it did not provide the utilities with incentives to enhance their operation, and thus competition was needed to raise the bar for the quality of service. Hence, the unbundled market was conceived. The drivers to such change were different among countries. For developed countries, the reason was to provide lower prices of electricity and promote competition between new players. However, this change was the only way for developing countries to overcome the challenges of the demand growth and inefficient tariff policies, which lead to the unavailability of financial resources to provide investments to improve the capacity of the system. In the following, the concepts of a centralized and liberalized structures will be explained in detail.

3.1.1 Centralized vs. liberalized system

In a general sense, regulations are laws and rules set by the government to allow efficient operation of the power system keeping in mind the interest of all participants, in which case are the utility and the customers. In the centralized structure, there is a single utility that owns and operates the flow of electricity from generation to transmission and finally distribution and retailing to the consumers. Therefore, such customers are not allowed to choose their generation or retailing supplier and are bound by the utility in their own area and in addition they pay a set price. The lack of private players, i.e. competitors, in vertically integrated systems can enable utilities to have full control in system prices. However, this issue is controlled by the government regulation.

The transition to a liberalized system, sometimes referred to as a deregulated system, does not mean removing the regulations and control systems that govern the power system. A deregulated system is the same as a centralized power system but with different rules applied, thus the term "deregulated" can be thought of as "re-regulating" or "liberating" the power system. The objective of liberalized power system is to promote competition between new players, provide customers with several utility options and to introduce a competitive market for electricity trading. The process of liberalizing the power system is called unbundling. The unbundling process disaggregates the single utility structure to several utilities, each one assigned to a single activity in the power system, i.e. generation, transmission and distribution, thus allowing new players to get involved. Unbundled systems entail two main activities:

- **Liberalized activities**: Includes the liberalization of the activities of electricity generation and retailing. This allows private players to own generation plants and compete with the generation utility in selling their generated energy. Also, consumers will have the option to choose their electricity supplier or retailer according to their financial capabilities.

- **Natural monopolies**: Includes the transmission and distribution systems, which were found necessary to be a natural monopoly, due to the economies of scale. However, the operation of transmission and distribution are bound by regulations from the government. It should be noted that it is common that for most EU countries to have only one transmission utility, while in other countries like Germany to have more than one transmission system operators, four to be precise, which is due to their history. Similarly, at the distribution level, distribution utilities are natural monopolies in their own geographical area

It is evident that opening the market for new players will increase the competition for market share, which can decrease the electricity prices. Also, distribution utilities will not have monopolies over selling electricity to the consumers. One of the main enablers to such shift in power structure is the advancements in technology that increased the efficiency of conventional generation sources and allowed the introduction of new data communication infrastructures. In addition to this, there are no more risk factors in investing in new power plants or infrastructure since electricity became an essential commodity in the society and the revenues expected from it are guaranteed. With new competitions in the market, there were incentives for utilities to enhance their services and provide new technologies to optimize their operation and increase the customer level of satisfaction. Figure 3.1 compares between the vertically integrated system and the unbundled deregulated system.

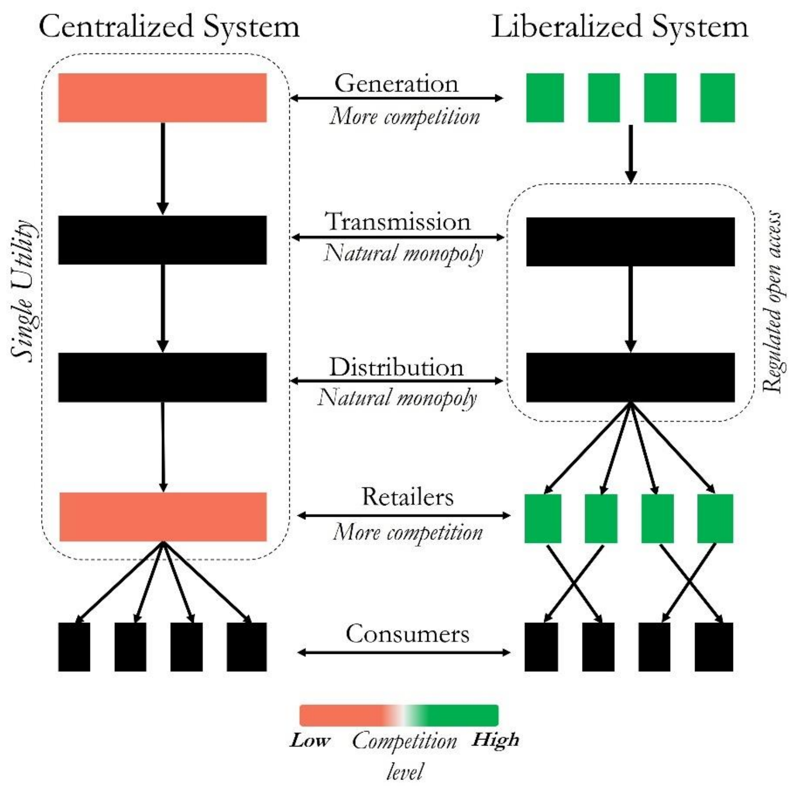


Figure 3.1 Centralized power system vs. liberalized power system.

3.1.2 Market stakeholders

In the wake of the new liberalized market era, it is important to redefine the market entities and introduce new ones. These entities are referred to as market agents, players or stakeholders and are explained as follows [187].

- **Consumers**: Consumers are the main users of electricity and they represent all different sectors such as industrial, commercial and domestic sectors. They can buy electricity in a traditional way from either the pool or future markets, or they may obtain their electricity through bilateral contracts from other market agents, such as producers or retailers. Bilateral contracts are energy arrangements between suppliers and consumers, which takes place outside the limits of energy markets. In such contracts, consumers can buy their energy directly from the producer, or through an energy retailer. Also, consumers have the option to participate in reserve markets, and they may need to participate in balancing markets if their consumption.

- **Producers**: Producers are the market agents who have electricity generation units. They can sell energy in energy markets or directly to consumers or retailers, through bilateral contracts.

- **Non-dispatchable producers**: Non-dispatchable generation refers to electricity generation units based on RES, such as wind or solar power.

- **Retailers**: Entities which buy electricity from the wholesale market and sell to consumers, who are not interested or allowed to participate in such markets. Retailers do not have to own power generation, transmission or distribution assets.

- **Market operator**: A nonprofit entity that provides a platform that enables the trading of electricity. In the day-ahead and intra-day markets, the market operator receives the sale and purchase offers from the sellers and buyers respectively through an online platform. Also, it is responsible for setting the market rules, receiving the energy bids from all market agents and then clearing the energy market.

- **System operator**: A nonprofit entity which is responsible for the technical management of parts of the network. For example, the distribution system operator (**DSO**) is responsible for the operation and maintenance of a distribution network at a given area. Similarly, the transmission system operator (**TSO**), owns and operates the transmission network and ensure the secure transmission of electricity from the generation to the distribution sides of the network.

- **Market regulator**: A governmental entity that ensures the fair competitiveness and trading of the energy markets.

- **Balance responsible party (BRP)**: An entity that is responsible for maintaining a continuous power balance between production and consumption. Also, a BRP can provide ancillary services to the system to maintain the system reliability and efficiency level.

3.1.3 The cost of electricity

Electricity tariff received by customers are composed of two main components, which are the energy cost and the access tariff. The energy cost corresponds to the cost of purchasing energy in the market, directly or through a retailer. The access tariff includes the distribution network costs, transmission network costs, along with taxes and policy costs. The distribution network tariffs are also known as Distribution Use of System (DUoS) charges and are computed independently of other components of the electricity tariff, and its share in the electricity tariff varies between 10% and 30% in European Member States according to [188]. DUoS charges are meant to cover recurrent operating and capital costs for network maintenance and expansion [189]. Different methods may be used to design and compute DUoS, which is composed of two consequent stages [190]: (i) determining the total allowed revenue for distribution companies, and (ii) allocating it to the users of the distribution network, i.e. deciding tariff structures. The allocation of costs and tariff procedure should follow the fundamental principles of tariff design, which are grouped into three main groups [189], [191], as shown in Table 3.1.

There are three general tariff structure elements: fixed, volumetric and demand charges [192]. A fixed charge (€/period) is independent of the customer's profile or consumption. It does not incentivize customers to modify their consumption, it only aims to recover part of the network costs (usually the metering and administrative part). A volumetric charge (€/kWh) is dependent on the customer's energy consumption. It aims to recover the variable cost associated with energy transport. Since it is function in the energy consumed, it incentivizes customers to reduce their energy consumption. Finally, a demand charge (€/kW) is dependent on the maximum power contracted or consumed within a specific period of time, regardless of its duration or frequency. It aims to cover costs related to the network assets and infrastructure. It incentivizes customers to reduce their maximum power rather than their energy consumption.

Table 3.1 Principles of tariff design.

System sustainability principles	Economic efficiency principles	Consumer protection principles
Universal access to electricity to be guaranteed to all network users.	**Productive efficiency**, i.e. network services being provided to the network users at the lowest cost possible.	**Transparency**, i.e. the adopted methodology and the results of the tariff allocation being available to all network users.
Cost recovery of the accredited costs for the distribution companies.	**Allocative efficiency**, i.e. customers being charged according to how much they value the service they receive.	**Simplicity**, i.e. the adopted methodology and the results of the tariff allocation being as easy as possible to understand.
Additivity of components, the sum of which has to add up to the total revenue requirement.	**Cost causality** i.e. tariffs accurately reflecting each network user's contribution to network costs. **Equity**, i.e. charging, through tariffs, each consumer the same amount for using the same good or service, independently of electricity usage and customer's characteristics.	**Stability**, i.e. tariffs being stable in the short-term and gradually changing in the long-term, so to reduce regulatory uncertainty.

3.2 The architecture of electricity markets

The liberation of the electricity sector has enabled the emergence of electricity markets worldwide. This evolution facilitated the transformation of the centralized operational framework of the energy industry to a more competitive framework. The objective of this new framework is to increase the overall efficiency of the power system while ensuring the quality of supply and minimizing the cost of electricity. An energy market can be seen as a platform where market participants can trade electricity based on the prices that they are willing to pay or receive, and according to the capacity of the electrical network. The trading of electricity is organized across a sequence of successive markets, which can cover periods from years to months to days and up to the real operation time. The delivery of electricity can be either physical or financial [186]. Physical trading means that electricity must be delivered and paid for at the time of contract expiry, while financial trading means that only the cost of electricity traded is paid for at the time of contract expiry. In this section, the structure, the sequence and the market players will be explained.

3.2.1 Electricity trading

The trading in wholesale markets can be divided into two main architectures [186], [193]; the bilateral trading and the organized trading. Bilateral trading, as it the name suggests, allow sellers and buyers (supply and demand) to enter a bilateral contract, where they negotiate its terms and conditions which includes: its length, amount and price of electricity to be traded, when the trade will take place, and penalties for non-compliance [194]. Brokers or market mediators can as well be involved between the seller and buyer in such contracts. Bilateral trading can be customized for long-term periods, typically several months to years ahead. Such contracts help avoid the volatile prices of short-term trading of electricity, which can be an issue for some market participants. Also, they can as well cover shorter periods of time, typically weeks to days, which can be referred to as Over-the-Counter (OTC) [186]. In the bilateral trading structure, there are no official prices to the market, but rather several prices between the contracted parties, which are usually remain anonymous. In bilateral markets, electricity can be traded by means of physical delivery or financial instruments.

In the organized trading structure, two market models exist that can be considered the core of short-term electricity trading in wholesale markets. These two models are pool markets and power exchange (PX) markets. It should be noted that short-term trading is otherwise known as “spot markets”. Spot markets are subject to high prices volatility, which can be affected by a sudden increase or decrease in demand or in production [194]. Their short-term coverage ranges between days to hours and up to real-time operation. In power pool markets, the trading of electricity is carried out in a mandatory and centralized manner. Suppliers and buyers submit price and quantity energy offers and bids into a centralized pool market that cover every hour during the market horizon. The structure of the pool market requires that the offers submitted by the supply side to be of a complex nature, which means that besides the normal selling prices, other factor can be included in the offer such as ramping constraints, start-up costs and minimum and maximum on and off times. In some cases when the demand is highly inelastic, the market relies on forecasted profiles for the demand and no demand bids are submitted. After all the offers and bids are submitted from the market participants, they are aggregated to form the supply and demand final curves. Then, the pool market operator clears the market by means of a market-clearing procedure and the activated bids are those who come before the point of equilibrium between the supply and demand curves. The intersection point represents the market clearing price, or the system marginal price, which is the price of one additional megawatt-hour of energy, as seen in Figure 3.2. The market clearing process incorporates a security constrained economic dispatch (SCED) process which considers the bidding curves and the network constraints and has an objective of maximizing the social welfare. The pool market enables optimal coordination between the generation and the transmission sides and electricity prices for every node can be evaluated, also called locational marginal prices or nodal prices [135]. Pool markets are common in several countries outside Europe, such as the USA [195].

The power exchange model is a common market that is followed and implemented in most of the European countries, such as in Spain, Netherlands, Italy and Germany [193]. The PX model is characterized by a decentralized market organization that allows energy exchange between participants in a non- mandatory approach and as well allows for direct bilateral trading between sellers and buyers. The PX receives the supply and demand offers and bids across various subsequent markets and they are all cleared by finding the equilibrium point between the two curves [196], [197], similar to what is shown in Figure 3.2. However, the offers presented from the supply demand are free of the complexities and non-convexities that is existent in the pool model, which means they only consist of price and quantity per bid [135]. Therefore, the market clearing procedure does not take into consideration the network operation constraints. It is then the task of the system operator to check the technical feasibility of the market solution. The decentralized characteristic of the PX model enables the generator side to optimize its power plant dispatch independently and it ensures that market prices become a market-driver [198], [199].

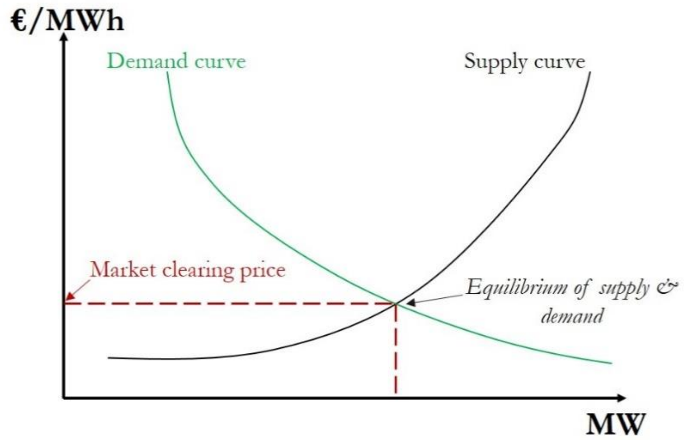


Figure 3.2 Supply & demand curve.

Finally, it should be noted that there are two market clearing methods to evaluate the market marginal price which are the uniform pricing and the pay-as-bid structures. In the uniform pricing structure, all market agents obtain the same price of electricity, regardless of their original bidding price. This price is obtained from the intersection point between the supply and demand curves. This approach is simple, and it provides a reference price for other markets. An example for a uniform pricing method can be shown in Figure 3.2. In the pay-as-bid structure, the agents receive payments based on their bidding prices and not on the market marginal price, as opposed to the uniform pricing [200]. This approach is inefficient to be used in wholesale markets for several reasons. The incentive for market agents to bid their marginal opportunity cost, which is existent in the uniform pricing, is absent in the pay-as-bid system. In a uniform pricing system, agents may not be inclined to present bids above their own marginal costs, as it will decrease their opportunity of being activated. Similarly, bidding below their marginal costs can yield economic loss. In the pay-as-bid system, the agents' strategic reasoning will be to bid above their own marginal costs, but lower than their estimated intersection point between the supply and demand curve, so they ensure they get activated and maximize their profits.

3.2.2 Market sequences

The business model of the power system is considered as capital intensive, since it requires large capital investments and has long project lifetime spanning from years to decades. In addition to this, electricity cannot be stored on a large scale, which means the process of matching the supply and demand can be challenging and necessary. Therefore, power system management decisions can be made over several time periods. With respect to the types of electricity markets explained in 3.2.1, the market sequences can be divided to three periods, as seen in Figure 3.3.

The long-term scheduling period covers a period spanning from years to months ahead. During such period, the scheduling of electricity generation sources to meet future demand is allowed, which can be through long-term markets [201]. There are several markets and contracts that are available, one of which are forward markets. In forward markets, all parties are able to negotiate their terms and conditions for their desired prices for a fixed amount of electricity to be delivered in the future. Forwards contracts are physical contracts and they can be traded through a bilateral or organized market structure. Another type of long-term markets are future markets, which are based on pure financial trading. In such markets, future contracts allow risk-adverse participants to either buy or sell contracts aiming to gain profit in the future, where the delivery date and quantity are standardized [186]. Future contracts can be traded in either a bilateral or in a power exchange setup. Besides the future contracts, there is also the option contracts, which gives the buyer the right to call for the commodity by paying premium charges to the seller [202].

In the short-term scheduling period, spot markets take place, which usually operate a day-ahead. During the day-ahead market, the operation schedule for the coming day is determined where generators are dispatched according to the market clearing procedures. Day-ahead markets are either designed as a market pool or a power exchange, which varies from one country to another. Adjustment to the day-ahead schedule are enabled by following markets such as the intraday and balancing markets. However, before the adjustment markets take place, the system operator carries out a congestion management process with respect to the day-ahead market solution, which can result in adjusting the market solution. Next step, adjustment markets commence their operation and continue until right before the actual time of delivery [1]. Adjustment markets allow buyers and sellers to submit purchase and sale bids to adjust their portfolios. In the close-to-real-time period, several markets take place that provide ancillary services to the system operator. The reserve markets start their operation from day *d-1* and until right before delivery time. Reserve markets help the system operator by providing upward and downward generation regulation services, voltage control capabilities and frequency regulation [203].

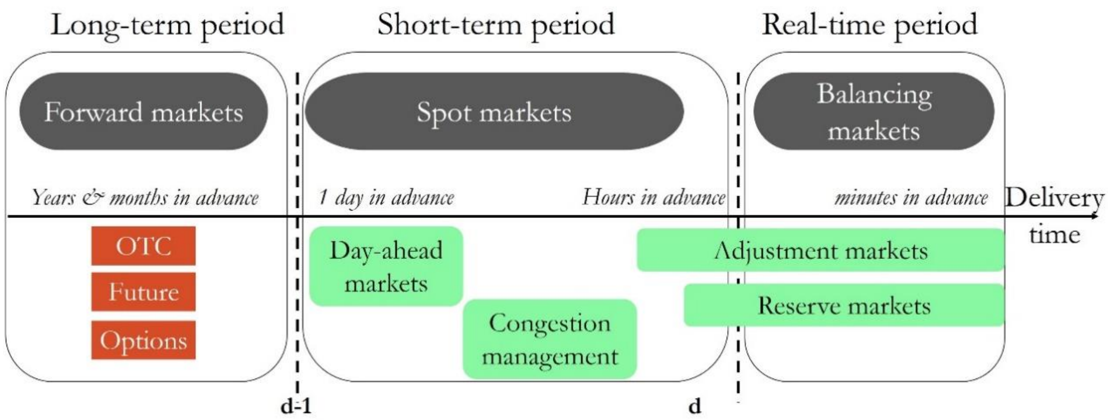


Figure 3.3 Market sequences.

3.2.3 Congestion management

Power systems in general are restricted with various constraints that ensure the safe flow of electricity from one point in the system to another. These constraints may require the re-dispatch of certain generators in the system to keep the flow of electricity within the limits. In vertically integrated systems, the activities of generation, transmission and distribution are all assigned to a single entity, which means potential system outage can be managed efficiently and quickly. In liberalized power system with open markets, vast changes in the generation and consumption flows are enabled in small periods of time, which can cause a problem to the system operator. In such market mechanisms, suppliers and buyers are inclined towards maximizing their profits and minimizing their cost respectively, and such agents do not account for the network constraints when making their own bids. As a result, network congestions become a frequent incident. Congestion management is critical and a key tool at both the transmission and distribution levels. TSOs manage the transmission network and set boundaries to the system that governs the maximum amount of power to be transmitted between any given two points in the grid, the allowable voltage limits at every connection point and the permissible frequency variation levels. Here, the strategies of transmission congestion management are divided into two main types, shown in Figure 3.4, which are:

- **Non-market-based methods**

Non-market-based methods are economically inefficient due to the lack of a strict mechanisms to allocate scarce capacity, not to mention their arbitrariness. Basically, these methods focus on optimal allocation of transmission capacity. Such methods are like first-come-first-serve, long-before-short and pro rata [204].

- **Market-based methods**

Market-based methods offer an efficient way of allocating available capacity. There are several strategies to market-based methods [205]. In nodal and zonal pricing and market splitting, market participants are required to pay for the usage of capacity. These strategies are dedicated for optimally allocating available capacity for market participants, while ensuring grid constraints are not violated. Other strategies such re-dispatching and counter trading, are approaches to solve existing or coming congestions. While re-dispatching is not a market-based solution, it the default process for managing congestions. Finally, flexibility services at the transmission level is one of the main tools that can be used by the TSO in the congestion management process and balancing needs as well [49], [206], [207]. Flexibility services can be considered also a process of re-dispatching.

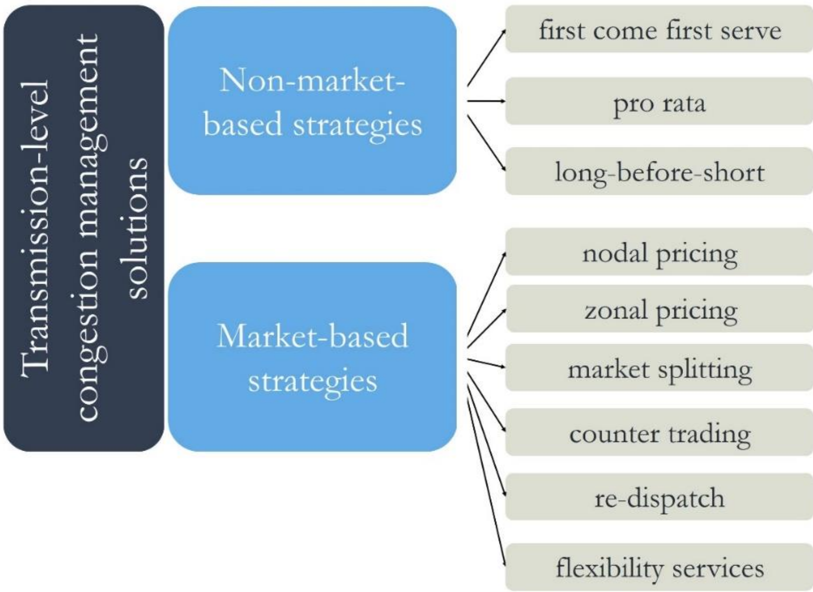


Figure 3.4 Congestion managemet solutions at the transmission-level.

3.3 Distribution systems

According to the European legislation (Directive 2009/72/EC) [210] article 25, Distribution system operators (DSOs) are responsible for ensuring the long-term ability of the system to meet reasonable demand for the distribution of electricity, for operating, maintaining and developing a secure, reliable and efficient electricity distribution system. DSOs are legally obliged to be unbundled from other actors in the power system supply chain [58]. However, the DSO remains as a part of the vertically integrated undertaking, but it will be independent when it comes to its organization and decision-making processes [209]. DSOs are subject to strict regulation that monitor their activities in order to ensure they do not act as a monopoly and to maintain fair competition. DSOs have the task to provide fair distribution network access and facilitate competition in wholesale markets. They should ensure that all demand is met during all times and offer connection to new customers, while providing an adequate level of reliability and security of supply. Moreover, they also handle metering and administrative customers' issues. In this section, the responsibilities of the DSO with respect to the network operation and planning, the congestion management task and the business model of the DSO will be explained in detail.

3.3.1 The role of the DSO

DSOs carry out a series network-related technical functions that can be divided into network operation and planning [203]. The process of operation and control carried out by the DSO usually takes place in dispatch centers using distribution management systems and supervisory control and data acquisition systems (SCADA) [186]. The DSO controls, monitors and supervises its own network to ensure system security and quality of service. With respect to the technical requirements for service quality and power flow conditions, the DSO must maintain a balance between supply and demand according to grid codes and standards. Thus, the DSO must apply the necessary measures to remedy its network in the case of outages or voltage fluctuations. Another important task carried out by the DSO is the maintenance planning and activates, where the DSO ensures the safe operation of its assets through preventive and predictive maintenance. While the TSO is in charge of the overall system security, the DSO focuses only on the operation of its own network.

Distribution networks are designed to maintain long-term reliability and security to serve electricity to its consumers. Therefore, networks require extensive investment for its declining infrastructure to sustain an affordable and reliable supply of electricity. As the network planner, the DSO is responsible for the short- and long-termed planning of the network development, which means demand growth estimation studies are carried out for the future [210]. The process of network planning is a crucial function to the DSO. Its objective is to develop strategic decisions for future network needs by considering the demand growth of the network, urban development plans and the wide penetration of DERs. Network planning involves reinforcing existing assets by installing lines, transformers and building substations to meet the growing need of electricity [211]. With the new direction towards energy efficiency programs, integrating large-scale renewable energy sources and distributed generation, and demand response programs; all of which require network investments, the DSO needs to rethink its network planning strategy. Also, the paradigm shift that the energy industry is witnessing is forcing utilities to substitute their current business models with modernized and progressive ones.

It is evident that the common practice of distribution planning has shifted from being standard-oriented and focusing on a providing a good service, to being target-oriented as new challenges are arising every day which must be overcome. In addition, service reliability has become an integral part of the distribution operation, which is a difficult technical challenge to maintain. On the economic side, the evolution of modern business models in the utilities has a high impact on the process of distribution planning. Not to mention, the aging distribution infrastructure is slowly becoming a problem to grid operators. Assets approaching their nominal lifetime limits are prone to operation failure and outage, and need more maintenance, which affect the operation reliability and add extra cost [212].

3.3.2 Congestion management at the distribution level

At the distribution level, DSOs are responsible for taking the necessary measures to mitigate network congestions. In literature [49], congestion management at the distribution level was classified into two main categories: 1- feeder overload management, which ensures that the network feeders do not reach its capacity limits that can be caused by electricity demand growth; and 2- feeder voltage/var management, which ensures that voltage levels and reactive power at feeders are within acceptable limits. These limits can be violated due to high penetration of RES production as well as local variations of generation and demand. Common ways to mitigate network congestions is by upgrading the existing assets of the network or building new lines or substations. Such approaches can be beneficial for the network on the long-term. However, on short-term basis they can be inapplicable as they may require large capitals and investments to be implemented. From a short-term perspective, there are several approaches to mitigate network congestions. These approaches can be divided to two categories, named indirect and direct strategies, as seen in Figure 3.5.

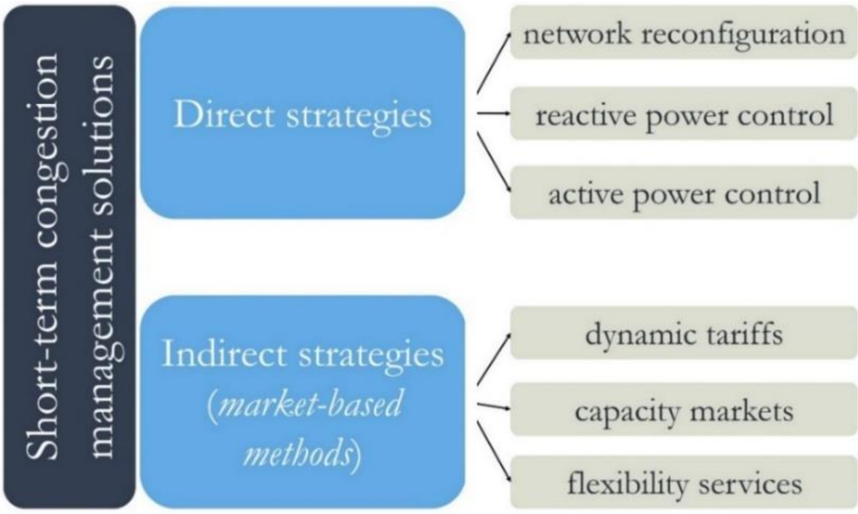


Figure 3.5 Short-term congestion managemet solutions at the distribution-level.

- **Direct strategies**

Under such strategies, there are three common ways introduced in literature [213], [214], which are: 1- Network reconfiguration, this method refers to changing the grid structure through changing the status of normal-open switches and some normal-close switches in order to share the demand consumption between different lines or networks. This strategy is mostly suitable with thermal congestion problems, such as overloading lines capacity; 2- Reactive power control, this method is for other types of congestions, such as over- or under-voltage, typically in networks with long feeders, reactive power control through flexible AC transmission system (FACTS) is a common strategy [191]; and 3- Active power control, this strategy is associated with load shedding or generation curtailment for efficient congestion management.

- **Indirect strategies**

Also called market-based methods, indirect strategies use price signals to influence the behavior of customers [213]. Market-based methods include several sub-strategies for congestion management. One of the common methods is dynamic tariff strategies, which refers to electricity prices that vary across time, and in sometimes location as well. Based on the status of the network, this type of strategy can affect retailers' and consumers' decisions towards the system operator needs [215]. Similar to the concept of dynamic tariffs, there is also distributed locational marginal prices, which can have different tariffs at different nodes in the same network grid.

Another congestion management is using capacity markets. In distribution capacity markets, the capacity of the distribution grid is allocated to aggregators with an optimized price [213]. These markets can either take an explicit auctioning or an implicit auctioning approach. In explicit auctioning, capacity and wholesale electricity markets are separated and the grid capacity is allocated to market participants based on their willingness to pay. The explicit auctioning approach can be a complicated process for large network with several congested lines, which can be a main disadvantage. The implicit auctioning method aims to avoid the complexities of the explicit approach by integrating the grid constraints in the wholesale electricity market clearing algorithm. Therefore, the cleared prices reflect the cost of generating, transmitting and distributing electricity to customers. Such prices are usually called locational marginal prices [216].

The final method for congestion management is influenced by what is carried out at the transmission level. Flexibility services at the transmission level is one of the main tools that can be used by the TSO in the congestion management process and balancing needs [49], [206], [207]. Flexibility services can be considered as well as a process of re-dispatching. In a similar way, flexibility services can be utilized at the distribution level for congestion management [217]. DSOs can use flexibility services to manage local congestions, as opposed to buying new assets. Also, different market agents, such as BRPs and suppliers, can use flexibility services to efficiently balance their portfolios. Using flexible demand as a congestion management tool has been addressed several times in literature [31], [34], [218]

3.3.3 Business model & revenues

In the liberalized market structure, DSOs remain natural monopolies but under heavy regulation. When it comes to revenues and distribution grid tariffs, the national regulatory authority is responsible for overseeing the DSO activities in their local networks. The purpose of this subsection is to explain the possible remuneration schemes for DSOs, which show how DSOs are mainly remunerated for investing in new assets. Such schemes should be modernized to value smart grid solutions to encourage DSOs to invest in demand response programs, such as demand flexibility. This subsection aims to describe the different existing remuneration mechanisms to show the effect of the current revenue system on the DSO's decision to invest in smart congestion solutions. There are three main different regulatory approaches that may be followed to remunerate DSOs: Rate-of-return (ROR), Incentive-based, and Yardstick, as discussed in the literature [219], [220].

- **The ROR method**

This method is based on the costs the DSO reports to the regulator, where the regulator defines a reasonable rate of return for the distribution company [221]. The main drawback of ROR regulation is that does not incentivize DSOs to reduce their costs and/or improve their efficiency. Instead, it incentivizes DSOs to overinvest due to the guarantee of higher returns. Equation (3.1) describes the formula of the ROR method with respect to time *t*, where $\mathrm{RR_t}$ is the required revenue, $\mathrm{OE_t}$ represents the operating expenses, $\mathrm{D_t}$ is the depreciation expense, $\mathrm{T_t}$ is the tax expense, RB is the rate base and ROR is the rate of return.

$$\mathrm{RR_t} = \mathrm{OE_t} + \mathrm{D_t} + \mathrm{T_t} + (\mathrm{RB} - \mathrm{ROR_t}) \tag{3.1}$$

- **Incentive-based regulation**

This method was implemented to encourage DSOs to be more efficient. In the incentive-based approach, Price/revenue caps are set ex-ante the regulatory period and are used to incentive DSO to minimize their costs [222]. The cap is usually defined by the so-called CPI-X formula [186], [221]. Price and revenue caps are calculated as shown in (3.2) and (3.3) respectively. $\mathrm{P_t}$ and $\mathrm{P_{t-1}}$ are the price ceilings for period *t* and *t-1* respectively and CPI is the Consumer Price Index. X is the productivity factor, which is adjusted over time and depends on the productivity gains of the whole industry. If correctly set, the X factor provides a high incentive for DSOs to achieve a higher productivity, since it allows the company to make more profits. X is only applied to DSOs' controllable costs. The factor Z represents adjustments occurring due to unforeseen events beyond the management control, such as natural catastrophes or tax hikes. $\mathrm{R_t}$ and $\mathrm{R_{t-1}}$ are the allowed revenues for period *t* and *t-1* respectively; $\Delta\mathrm{Cust}$ is the change in the number of customers; CGA is the customer growth adjustment factor.

$$P_t = P_{t-1} \times (1 + CPI - X) \pm Z \quad (3.2)$$

$$R_t = [R_{t-1} + CGA \times \Delta Cust] \times [(1 + CPI - X) \pm Z] \quad (3.3)$$

The main drawback of incentive-based regulation is linked to correctly setting the productivity factor X. The incentive-based approach is a performance-based regulation; thus, it is possible that DSOs can underinvest in the short term, leading to deterioration of continuity of supply. This may be solved through quality regulation that can be applied in addition to a performance based regulation scheme [221].

- **Yardstick approach**

This approach is regarded as a way of benchmarking DSOs rather than a regulatory scheme itself, therefore adopted as a tool in incentive-based models. The price cap formula is calculated as in (3.4) [220], with respect to time *t* and utility company *i*, where: $P_{i,t}$ is the authorized price cap, α_i is the share of company's cost information, $C_{i,t}$ is the unit cost of the company and finally for a group of companies *n*, f_j is the revenues and $C_{j,t}$ is the unit cost for every company.

$$P_{i,t} = \alpha_i \, C_{i,t} + (1 - \alpha_i) \sum_{j=1}^{N} f_j \, C_{j,t} \quad (3.4)$$

According to [221], the high variability characterizing DSOs' demand and cost functions is the main problem of yardstick regulation. However, asymmetric information between the regulator and DSOs can be reduced through yardstick regulation instead of using other regulatory schemes. This is because DSOs would not benefit by falsely reporting their costs, since the assessment of their performance depends on the performances of all the other utilities in the sector as well [223].

Different remuneration schemes are used around Europe as presented in [191]. In Germany, DSO's revenues are set based on revenue caps. These caps are set according to benchmarking process that compares different DSOs to each other [224]. Whereas in the Netherlands, price caps are set based on the average efficiency of the sector [225]. In Italy, different regulatory schemes are implemented for each of the capital and operational expenditures. Operational expenditures are regulated on a price cap basis, while capital expenditures on a rate-of-return one [226].

Beside the regular costs of the DSO previously explained, there is another factor worth mentioning that may affect the distribution network's operation and costs. This factor is the high integration of DER. The DERs benefits are well recognized in the literature [109], and are mainly related to energy, which includes to peak load reduction, balancing, energy losses reduction, reserve and security of supply. However, their impacts may cause an increase in network costs as network upgrades may be needed to accommodate power injections from DERs [227]. This particularly the case when network power injections exceed local network's demand. This represent a capital cost, consisting of the upgrade of circuits and substations in rural networks, and switchboards replacement in urban networks [228]. Also, DERs have certain operational challenges that need more sophisticated voltage control schemes and more complex protection devices [227]. On the other hand, DERs may potentially reduce network costs by replacing network investments and reducing losses and voltage variation. In [229], it is defined as a capacity replacement value that is due to smaller electricity flows from higher to lower voltage levels led by DER integration. Thus, it may resolve network congestions or accommodate load growths while postponing the need of network investments. Article 14/7 of the EU electricity directive specifically requires DSOs to consider DERs as an alternative to network expansion [230]. However, adequate frameworks are needed to encourage DSOs to integrate DERs within network planning, thus avoiding potential inefficiencies in electricity supply infrastructure [231]

3.4 The Spanish case

Currently, the Spanish regulatory framework is a highly strategic system which is able to ensure optimal levels of operation with minimum costs [232]. However, this was not always the case for the Spanish energy sector as it has undergone significant changes in the past decades. In the following, a brief history regarding Spain electricity markets will be given, as well as the current scheme operation and remuneration. Moreover, the construction of the Spanish electricity bill will be given.

3.4.1 Brief history & current status

In Europe, there are several existent wholesale markets such as the electricity pool in the UK [233], the Nordpool in the Scandinavian area [234] and the *Mercado Ibérico de la Electricidad* (MIBEL) in the Iberian Peninsula [235]. The Iberian Peninsula is located in the southwest corner of Europe, which is occupied mainly by Spain and Portugal and small territories such as Andorra. The market characteristics of the Iberian Peninsula are the basis on which the work of this thesis is based upon. Between 1996 and 1997, a change in the EU legislation resulted in the Electric Power Law (Law 54/1997), which liberalized the power sector in the Iberian Peninsula and opened all sectors to competition and unbundling. In July 2007, the MIBEL commenced its operations as a common wholesale market for the Spanish and the Portuguese operators [236]. Some challenges were faced in the integration process due to regulatory and technological concerns. However, high-level coordination between different regulators and system operators have contributed to an efficient adaption process.

The Spanish market operator is called the *Operador del Mercado Ibérico Polo Español, S.A.* (OMIE) [237], which manages all markets involved in the Iberian Peninsula and it is responsible for their settlement. Along the past years, the market size in Spain has been growing gradually to cope with the increasing demand of electricity. Figure 3.6 illustrates the annual electricity demand in Spain over the past decade [238]. The change in percentage values of the demand across all the Spanish areas from 2016 to 2017 is shown in Figure 3.7. The analysis carried out by the International Council on Large Electric Systems (CIGRE) [239], reported that there are over 28 million customers in Spain.

In the Spanish market, there are several generation companies with variable percentage shares in the market. While the data provided by [240] are not the latest, it can give an indication for the largest companies that dominates the market, as seen in Figure 3.8, such as Endesa and Iberdrola. The transmission system operator (TSO), and the system operator as well, in Spain is called *Red Eléctrica de España* (REE), which is the company dedicated to operating and maintaining the activity of electricity transmission in the national grid. Their responsibility is to ensure the grid security, managing the flow of energy without outages and coordinating with the supply side (generation) to match the demand of electricity. Distribution system operators (DSOs) are the responsible entities for the operation, maintenance and expansion of the distribution networks. As already mentioned, DSOs are natural monopolies in their respective areas, which is similar to the TSOs as well except they are mainly natural monopolies on the country level. According to [239], [241], there are more than 300 DSOs currently in operation in Spain, with only 5 large DSOs with more than 100,000 customers. The jurisdiction map which defines their geographical territories for the largest five DSOs in Spain [242], is shown in Figure 3.9.

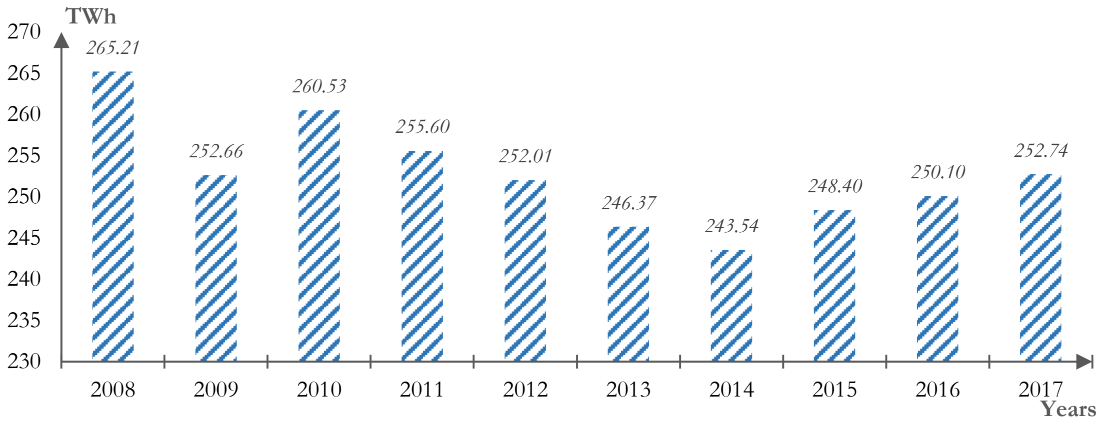


Figure 3.6 Electricity demand growth in Spain over the past decade.

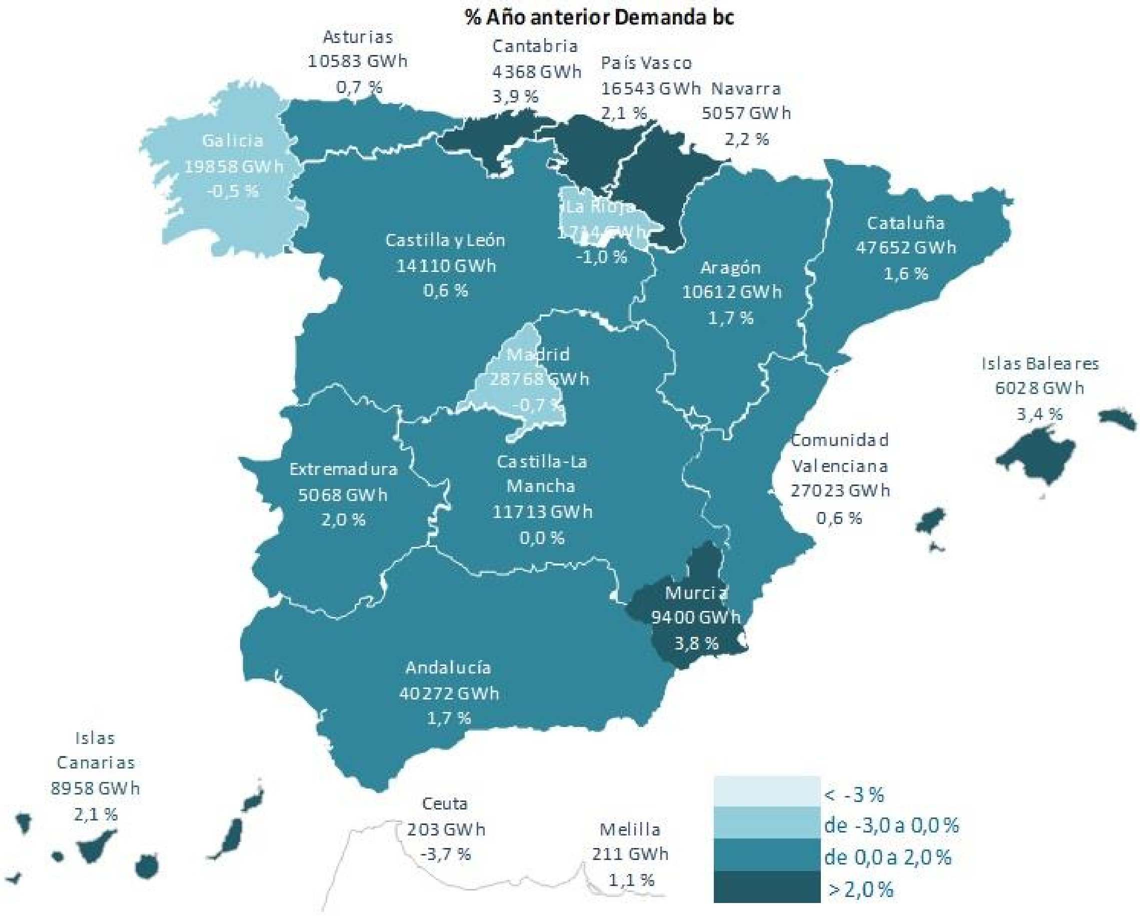


Figure 3.7 Percentage change in demand from 2016 to 2017 across Spain [238].

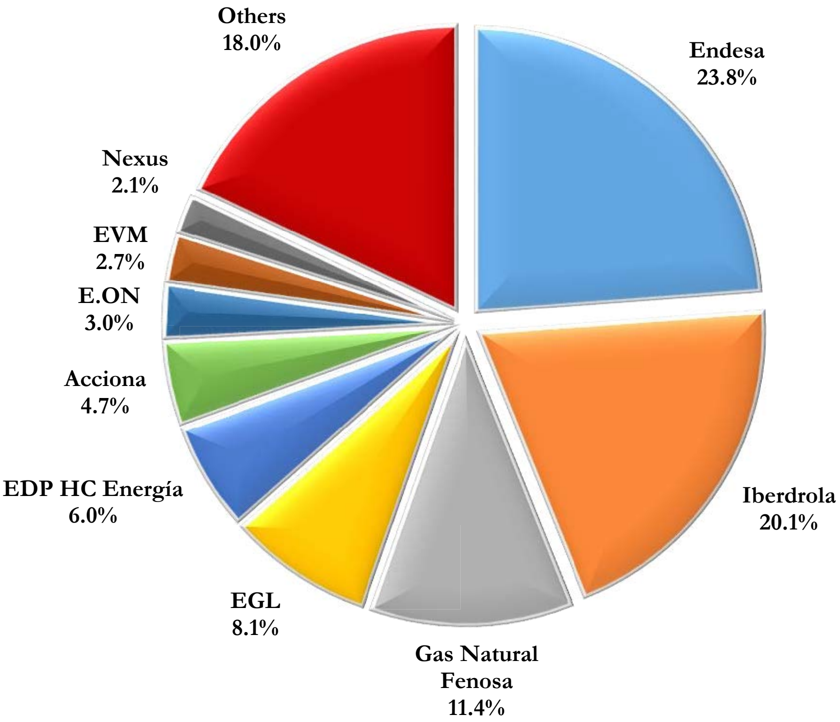


Figure 3.8 Percentage market share of electricity generation companies in Spain.

Figure 3.9 Jurisdiction map of DSOs in Spain [242].

3.4.2 Wholesale markets

The Spanish spot market follows a power exchange model which consist of day-ahead markets, intra-day markets and balancing markets, which represents the organized part of the market. The remaining market part is an unorganized structure which consists of physical bilateral contracts [243]. It should be noted that the Spanish market also accepts complex bids for sales offers only, which follows the same rules of simple bids but with additional constraints on the hourly bids [193], [244]. The trading of the bulk of energy for every day operation takes place in the day-ahead (DA) market, which is in continuous operation during 365 days of the year. In the day-ahead market, also referred to as the wholesale market, the supply and demand sides send their selling offers and purchase bids respectively before to 12 noon in day *d-1*, which is when the market gates are closed. The supply side consists of the generator owners which are obliged to submit their sale offers for their available capacity that has not been previously committed through bilateral trades from their generating units [245]. The demand side in the market consists of distributors, retailers and customers (formerly known as qualified customers [245]). Retailers buy electricity to sell it to other retailers or customers. The customers are able to procure their needed electricity totally or partially in the market.

For every hour, OMIE sorts the supply offers with respect to their marginal cost from the least to the highest and the demand bids are arranged from the highest to the lowest bidding price. After the market gates are closed, the matching process is carried out and the marginal price is obtained by the point of intersection between the supply and demand curves. This price will be allocated to all producer offers under the intersection and all the purchase bids above the intersection. An example of a typical supply and demand curve submitted in the wholesale market for a single hour [237], is illustrated in Figure 3.10. The figure shows the simple aggregated sale and purchase offers, the thin orange and blue lines respectively. It also shows the cleared sale offers, in the thick red line, which takes into consideration the complex bids of the generation side. This process is carried out on day-ahead basis for every single hour by the OMIE, which results in a 24-hour daily prices and traded energy as shown in Figure 3.11.

Figure 3.10 Aggregated supply and demand curves in the Spanish wholesale market for a sample day [237].

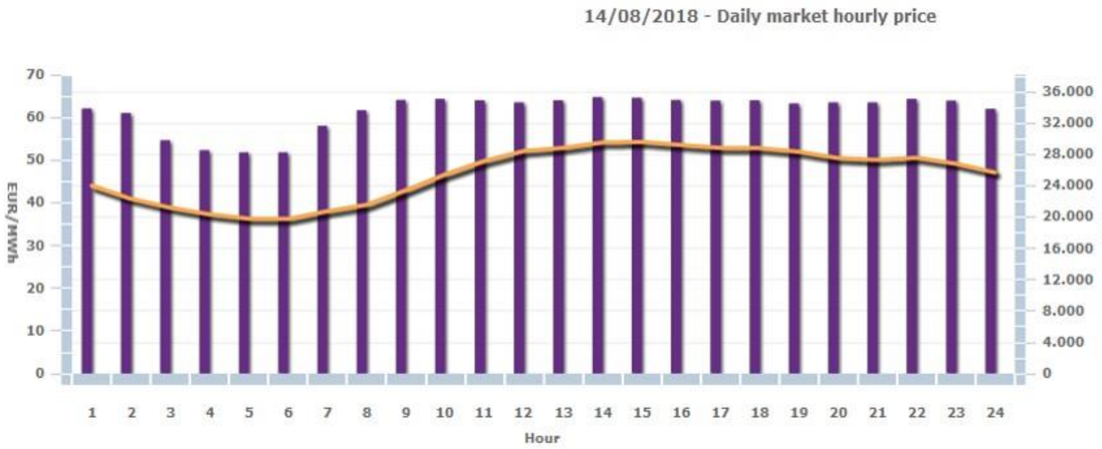


Figure 3.11 The marignal prices (€/MWh) and amount of traded energy (MWh) for a sample day [237].

Intra-day (ID) markets are operated and cleared using the same concept in day-ahead market but at different time periods. They can be considered as complementary markets to the day-ahead markets, working until four hours ahead of real time and can be extended to the coming up operation day. Intra-day markets allow participants to readjust their commitment for the selling and buying of energy, which may change from their original plan due to better forecasts or changes in consumption plans. In the Iberian Peninsula, there are six intra-day market sessions which comprise different adjustment markets serving the purpose for adjusting the energy cleared from the day-ahead market [246]. It should be noted that there is another intra-day market that is called the continuous market, which targets the continuous trading of energy between market zones and continuous implicit allocation of capacity for the cross-border trading [247], [248].

In order to ensure the equilibrium between supply and demand and to increase the reliability level, other markets also exist providing ancillary services (AS) [249]. The objective of ancillary services is to maintain a high level of security to the power system [250], [251]. In Spain, the ancillary services are provided through three stages [252], the first one is called primary control, which is a mandatory AS [251]. It provides standby spinning and non-spinning power to cover unplanned failures in generating units and large fluctuations in load demand [253]. The second AS stage is referred to as the regulation market or secondary reserve market that stabilizes the frequency level to the permissible level, through automatic generation control (AGC). In this market, the trading of up and down load-following capability is facilitated to ensure the continuous balance between production and consumption. This market receives its offers at hour 16:00 and gets cleared at hour 17:45 of day *d-1,* for ancillary services for the following day *d*. In real time, deviations are expected to occur for either the generation or the consumption, which may cause system imbalances. Adjusting these imbalances may require an increase or decrease in the production of electricity. Tertiary AS markets also exist to manage unforeseen deviations on short term-basis [249]. This market starts at hour 21:00 of day *d-1* and continue operation during day *d*. Figure 3.12 shows the electricity market sequence in Spain.

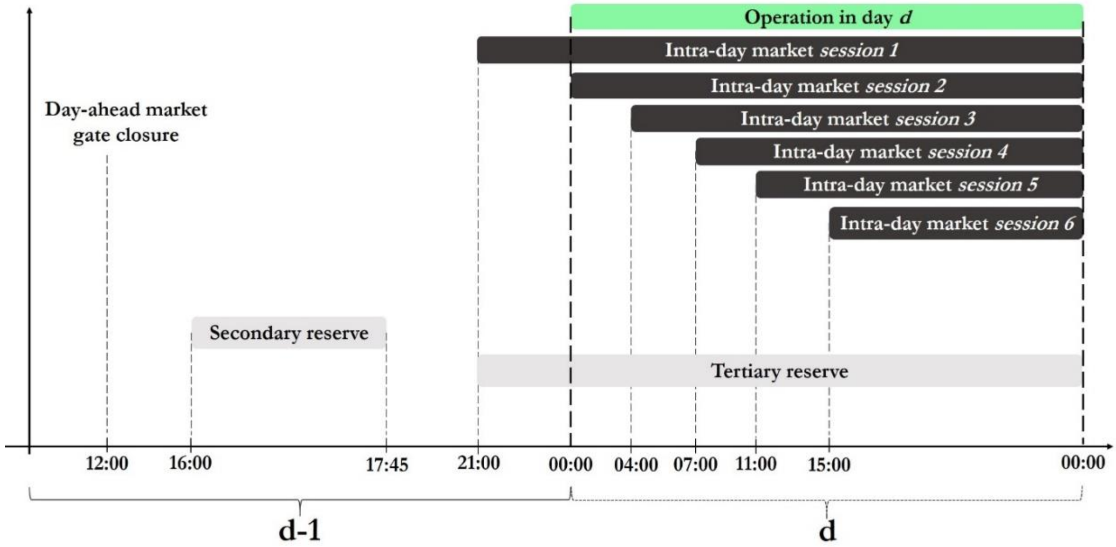


Figure 3.12 Electricity markets sequence in Spain.

3.4.3 Congestion management in Spain

In Spain, the congestion management mechanism takes place after the resolution of the day-ahead market. The system operator, i.e. REE, evaluates the dispatch schedule in a sequential manner [245]. In the beginning, the operator checks if the international capacity is exceeded. Accordingly, it can withdraw sale or purchase offers with respect to international interconnections. In the following step, the system operator checks the security and reliability constraints at the transmission level of the Spanish network. At the transmission level, only the generation side is involved in the procedure of relieving transmission constraints, this is achieved by allowing productions units to increase or decrease their production as per needed [254]. An asymmetric reward scheme is applied to remunerate these production units. The units that are selected for decreasing their production are paid at the day-ahead market price only for the actual amount of generation and they are not remunerated for the amount decreased. For the units that are selected to increase their production, the extra amount of generation is paid at their bidding price in the daily market. Finally, a security-constrained dispatch process takes place which results in changes to the first resolution of the day-ahead market. This new schedule is obtained before 2:00 pm of day d-1, i.e. day before actual operation. A similar process is carried out after the intra-day market resolution

3.4.4 DSO Remuneration scheme

Along the decade between 1997 and 2007, the DSO remuneration scheme consisted of aggregating revenue caps (common revenue cap formulas for all distribution operators), which is allocated through sharing coefficients [255]. These sharing coefficients are evaluated as weighted average values between pre-liberalization shares and results of a reference network model. However, this scheme failed to reflect the individual status of DSOs since electricity demand was different across the different Spanish regions. Also, the governmental demands for higher electricity service quality was not met with any economic compensations. In 2008, the Spanish regulation introduced individualized remuneration schemes for every DSO, which remained in operation until 2013. During this period, the Spanish electricity system suffered from a tariff deficit caused by the high costs of regulated and operation activities of the electricity industry compared to the regulated revenues set by the government [252].

As a result, a regulatory reform was carried out to correct these deficits, introduced by the royal-decree-law 9/2013, of July 12, 2013 [256]. The objective of this reform was to provide the energy sector with economic and financial stability through a uniform, transparent and stable regulatory framework that will resolve the issue of tariff deficit. Another act was issued on 27th of December 2013 under electricity sector act 24/2013, which contained the main principals regarding the remuneration of RES [232]. According to these new reforms, the remuneration schemes for distribution operators has been updated. Equation (3.5) calculates the total remuneration $\mathrm{R_n^i}$ for DSO *i* in year *n* [255], [257], where $\mathrm{R_{base\_n}^i}$ is the remuneration base of capital and operation expenses which corresponds to installations in service up to 2 years before the regulatory period, which is 6 years; $\mathrm{R_{NI\_n}^i}$ is the remuneration for all capital and operation expenses installed after the base year and in service up to 2 years before year *n*; $\mathrm{ROI_n^i}$ is the cost of other regulated tasks, such as metering, billing and taxes; $\mathrm{Q_n^i}$ is incentives for cost of supply; $\mathrm{P_n^i}$ is incentives for technical losses reduction, and $\mathrm{F_n^i}$ is incentives to fraud reduction. The remuneration base of the DSO can be calculated as in (3.6), where $\mathrm{RI_{base}^i}$ is the remuneration base for investment in the year *n* and $\mathrm{ROM_{base}^i}$ is the remuneration base for O&M in the year *n*. The remuneration to the new installations is calculated as in (3.7), where $\mathrm{RI_n^j}$ and $\mathrm{ROM_n^j}$ are the remuneration for investment and O&M of asset *j* respectively.

$$\mathrm{R_n^i = R_{base\_n}^i + R_{NI\_n}^i + ROI_n^i + Q_n^i + P_n^i + F_n^i} \tag{3.5}$$

$$\mathrm{R_{base\_n}^i = RI_{base}^i + ROM_{base}^i} \tag{3.6}$$

$$\mathrm{R_{NI\_n}^i = \textstyle\sum_{\forall j} RI_n^j + ROM_n^j} \tag{3.7}$$

It can be noticed from the current scheme implemented in Spain that a significant portion of the total DSOs' revenues comes from new installed assets. As a result of such system, DSOs do not have the incentives to invest in new solutions that can better manage their networks, such as demand flexibility programs. As already mentioned in Chapter 2, section 2.2.3, such issue is one of the key barriers which are delaying the implementation of demand flexibility programs.

3.4.5 The electricity bill

According to the Comisión Nacional de los Mercados y la Competencia (CNMC) [258] and to [259], customers in Spain receive a three-component electricity bill [260], that reflects network, energy and policy costs, as illustrated in Figure 3.13. Their contribution in the bill amounts to 18%, 33% and 48% respectively. The regulated costs of the tariff cover both the network and policy costs, which is recovered through demand and volumetric (energy) charges. Demand charges mainly target the network costs and are based on the end-user's contracted peak capacity. As for policy costs, they are partially recovered through demand charges, and the rest are recovered through volumetric charges [261]. This tariff incentivizes customers to reduce their peaks rather than their energy consumption. However, depending on the portion of policy costs within the electricity bill, which is currently approximately a third of the electricity bill on average, customers may be encouraged to more economically meet their energy needs. The policy & taxes cost include also the subsidies to renewables.

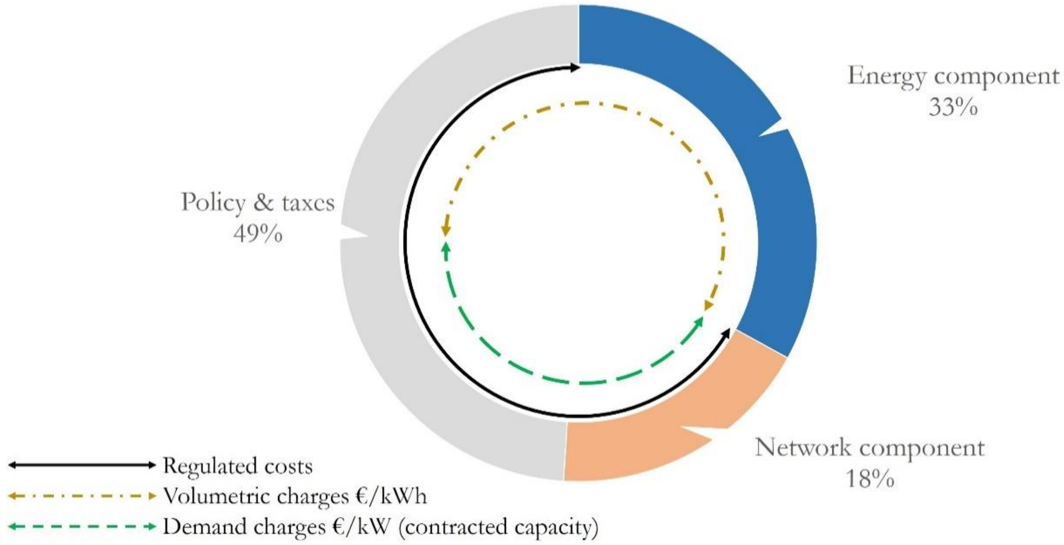


Figure 3.13 Spanish electricity bill components.

3.5 Towards Smart Grids

The continuous and growing need of electricity is getting more complicated than ever, as it requires monitoring systems that allows electricity system operators to efficiently manage their grids and to avoid outages. In response to all these new challenges and taking advantages of new technologies, the concept of Smart Grids was realized. According to the European commission and the EC Directorate-General for Energy 2011 [262], this definition of smart grids was agreed upon as: *"A Smart Grid is an electricity network that can cost efficiently integrate the behavior and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety"*. Furthermore, they categorized the main application of the smart grids to: 1- grid monitoring and control optimization; 2- consumers contributing in grid management and 3- improving physical capacity and flexibility of the grid.

There have been several definitions to smart grids in literature, such as in [263], [264], which are similar to some extent. Here, we describe smart grids as the intelligent integration between all the involved parties in electric systems, with the objective of achieving a more secure and reliable power system. It involves a state-of-the-art upgrade of the current conventional electric grid. The core of smart grids relies on the implementation of a smart digital layer in the network infrastructure, which improves the IT and data communication capabilities and facilitates the interaction between producers and consumers [265]. New technologies that are enabled in these grids are such as smart meters, smart sensors and smart control systems in its daily operations [266]. There are four major layers that are key to describe and visualize the upgrade that is smart grids [267]. First layer has to do with the physical infrastructure of the grid, which are the generation, transmission and distribution assets. The second layer is the telecommunication infrastructure, which enables the monitoring and control of the grid through technologies such as fiber optics, wireless communications and WiFi. The third layer concerns the data and information availability. Smart grids will allow an abundant amount of data collection across all network levels, which requires state-of-the-art data-processing tools. All of this data can largely improve the performance of the electricity system. Finally, the fourth layer is the software application technologies. These applications facilitate the information process of the data collected from the grid levels. These tools increase the efficiency of grid monitoring and control while optimizing the gird performance. All of these layers are combined to enable better grid automation and monitoring and to decrease network outages. In addition, they can incentivize customers to enhance their energy usage and introduce demand response programs, which can only be enabled by smart meters. The work of this thesis falls in the fourth layer of the smart grid, where demand response programs are enabled.

The smart grid vision is to evolve in parallel with the current level of technology, allowing a bi-directional flow of electricity and information. This two-way communication will facilitate the grid monitoring process from both ends, i.e. generation and consumption, on the system operators. Also, it will enable access to new information at a deeper grid level, such as the consumers' loads, appliances and preferences, which is usually difficult in conventional grids. Smart grids encourage the large-scale integration of new generations sources based on RES, such wind and solar energy. Also, it enables the connection of electric vehicles and new storage devices. In addition, they promote the deployment of demand response programs, which has been named by regulators and policy makers as a promising solution to the issue of demand growth and RES penetration in the distribution grid.

In reality, the current conventional grid already has highly efficient monitoring systems such as supervisory control and data acquisition systems (SCADA) and energy management systems (EMS). However, these systems are mainly located and focusing on the upper grid level, transmission network. As for the distribution grid, it currently lacks these kinds of smart control systems and smart sensors. Therefore, it is wise to say the smart grids focus on, but not limited to, upgrading the distribution grid to a higher level of sophistication. The objective of the distribution grid to increase the reliability and efficiency of the network operation and maximize the asset utilization levels. Traditional distribution systems are characterized by their unidirectional flow of power and information [267], which can be clearly shown the in Figure 3.14. Over the past decades, a significant progress was achieved in the distribution network towards evolving into a smarter network. According to [267], the automation level of substations and feeders has increased significantly. Enhanced distribution systems and monitoring tools and advancement metering systems allowed the availability of near real time data from substations and feeders. There is a new direction towards decreasing the dependency on centralized generation and promoting DER as a form of decentralized generation. There has been as well a noticeable grow in the usage of advanced distribution management systems. Finally, there is a rapid growth in investing in advanced metering infrastructures that enables two-way communications and facilitate the implementation of demand response programs. The future look of the more enhanced and smarter distribution network is illustrated in Figure 3.15.

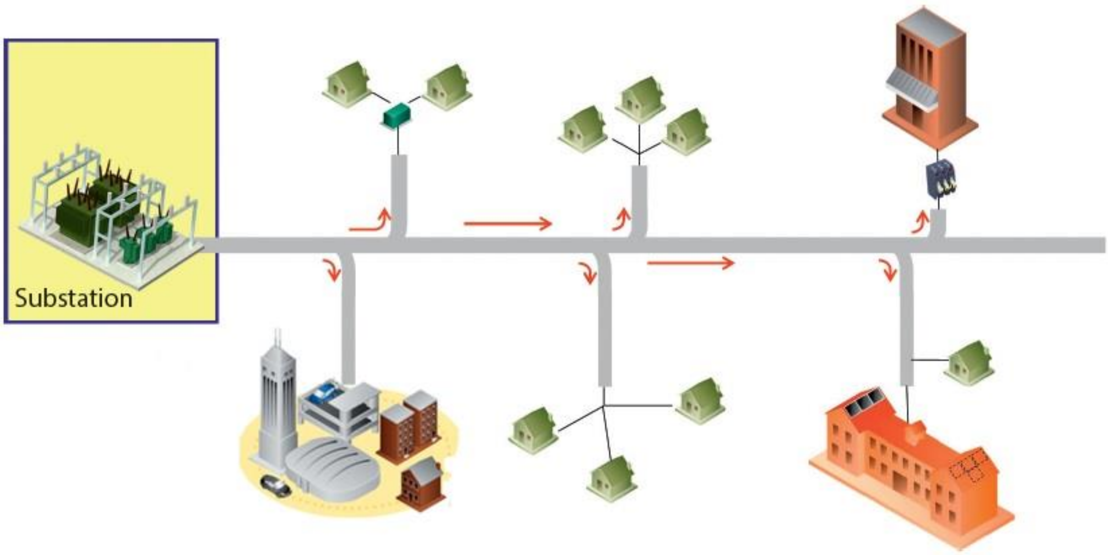


Figure 3.14 Traditional distribution system structure [267].

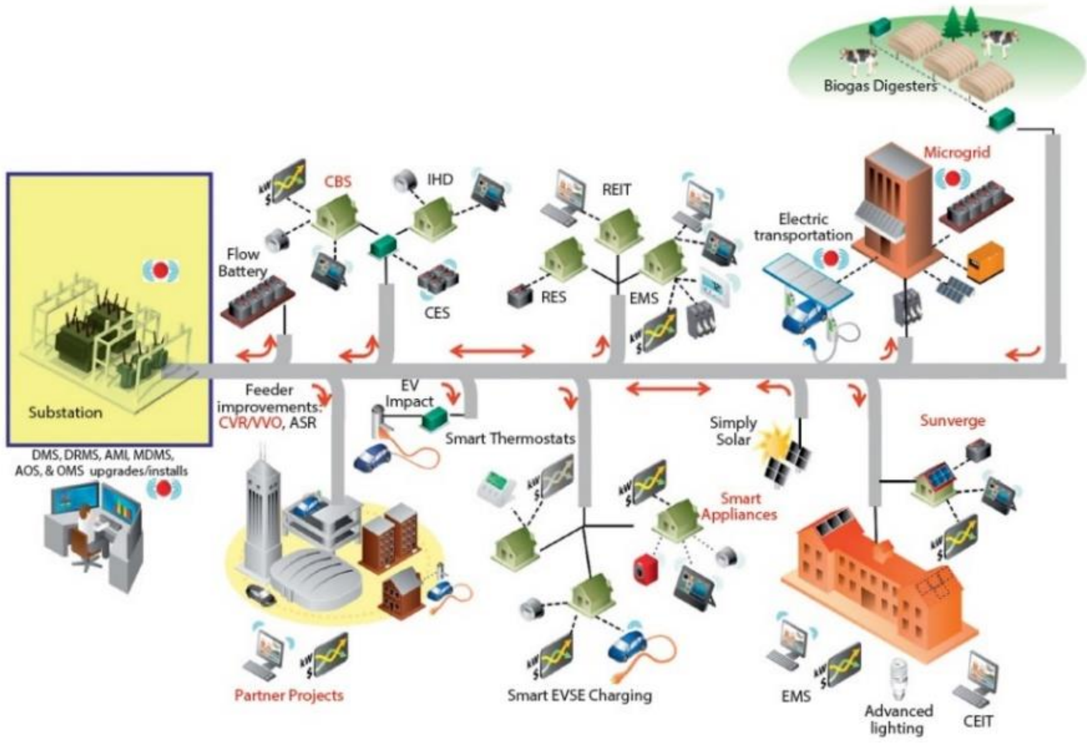


Figure 3.15 Future smart distribution system structure [267].

3.5.1 The future role of the DSO

In the paradigm of smart grids, renewables and demand flexibility programs, DSOs are encouraged to be more active grid managers [268]. As a result, new responsibilities are emerging to account for this future role. The key drivers that are encouraging this future role are illustrated in Figure 3.16. A new role for the DSO concerns encouraging the deployment of demand flexibility programs and supporting market-based services. Since it has been advised in several studies [269] that the transaction of flexibility should take place in an organized and well-structured market. DSOs can potentially take the responsibility of a flexibility market operator [270], which can procure flexibility services from aggregators and/or other customers with the objective of using it in its congestion management process. There are some existing DSO roles that should evolve due to the change in environment and new opportunities. To begin with, more coordination between DSOs and TSOs must be present and an exchange in operational data is important. Also, according to [271], DSOs are encouraged to be involved in the infrastructures of EVs. As a result, the EU states may allow DSOs to own, develop, manage and operate recharging stations, in order to ensure an efficient and reliable operation of the distribution system. Another evolving DSO role is being a smart meter and data manager, that collects, validates and analysis all acquired information [272]. Now, several DSOs in Europe own and manage the smart metering infrastructure [273]. In addition to this, more than 13 European countries are planning a large-scale rollout out of smart meters by 2020.

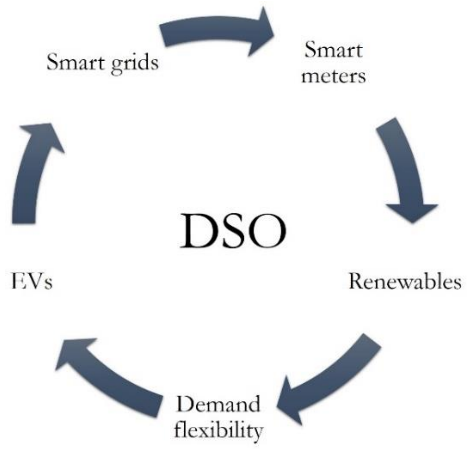


Figure 3.16 DSO key drivers to becoming an active grid manager.

3.5.2 The future barriers to demand flexibility

Demand flexibility services is one of the rising instruments in the area of congestion management [274]. Like any other commodity, flexibility services need a medium to facilitate its trading. However, there are several barriers to the implementation of local markets for demand flexibility within the distribution level, as illustrated in Figure 3.17 and discussed below. Barriers could be in the form of reformations required to existing policies and regulations, lack of enabling policies and regulations, missing technical requirements, or allowing new identities into the market.

- **Technical barriers**

    1. **Smart meters and ICT infrastructure**. Smart meter rollout is essential to crucial for the accurate measurement of consumption patterns and to communicate economic signals to customers. The EU's Smart Meter Rollout Directive (2009/72/EC) mandates that all member states should achieve at least an 80% rollout of smart metering by [275]. Moreover, enhanced communication will engage more customers to participate in the market.

    2. **Distribution-level monitoring** is required to transmit information regarding network operation in order to allow distribution level auctions to be established efficiently.

3. **Distributed System Platform**. DSOs need to invest in integrated system platforms that enables network participants to participate in a networked and responsive grid while allowing a local energy market / Peer to peer (P2P) trading / local balancing

- **Regulatory barriers**

1. **Regulatory incentives for DSOs** to encourage the deployment of necessary digital technologies that enable advanced monitoring and communication. Thus, regulations should be reformed to incentivize DSOs to be more innovative and fully integrate DERs in their network planning and operation phases.

2. **New regulatory arrangements for DSOs** to develop new activities are required to allow DSOs to procure services through market-based mechanisms. Hence, terms and conditions for local market arrangements need to be well defined and authorized by energy regulators [276].

3. **Data visibility and exchange**. According to [277], a large obstacle to achieving a resilient, DER-integrated energy grid is how little data can be gathered and shared regarding the operation of the grid. Ownership, access and sharing of the data between network agents (DSO, TSO, intermediates) needs to be well-defined to ensure a fair, efficient, transparent and non-discriminatory environment [278]. It is essential to share relevant information with all parties and create an adequate playing field level for flexibility services to be traded on a competitive basis considering data privacy [278].

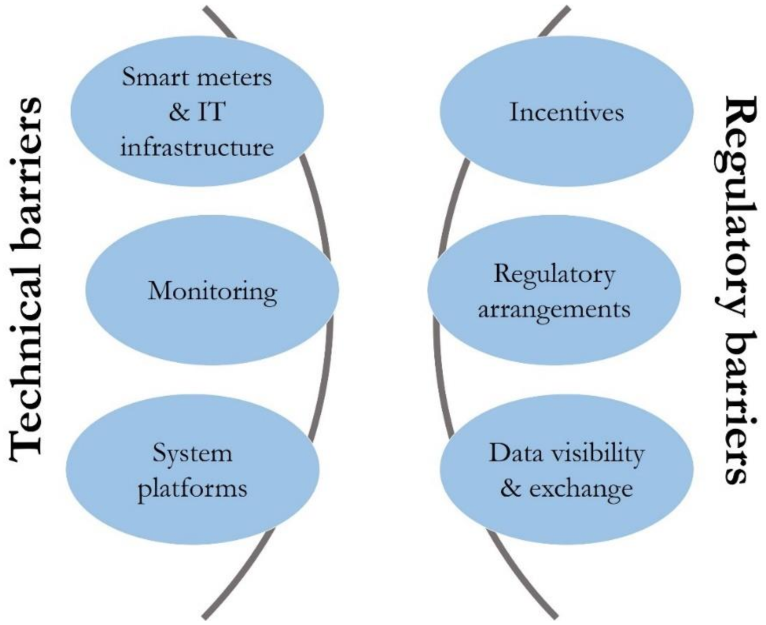


Figure 3.17 Potential barriers to the implementation of flexibility market mechansims at the distribution level.

3.6 Aggregators – The new players

Generally, demand flexibility is not fully exploited with respect to all its potential providers. Compared to medium to large customers, small customers such as households have difficulties to be engaged in the activities of demand flexibility. The reason for this can be due to their unwillingness because there are no real incentives or their lack of knowledge to how to be involved in the first place. As a result, new roles and responsibilities are created in electricity markets to cope with such challenges. The most frequent role that is referenced in almost all recent literature is the role of the aggregator. Associating the term "services" with "demand flexibility" means that demand flexibility, as a product, needs to be served or transferred from their providers to their potential buyers, in an efficient and economic manner certainly. This is where the aggregator comes in. The aggregator has been defined in a general way as "*a company which acts as an intermediary between electricity end-users and DER owners and the power system participants who wish to serve these end-user or exploit the services provided by these DERs*" [67].

To limit the broad scope of that definition, here an aggregator is considered as a company which helps electricity consumers to take part in demand flexibility programs [68]. Its main responsibility is to collect and aggregate demand flexibility from their providers and trade such flexibility in markets aiming to maximize theirs and the providers profits [65], [66]. Aggregators are aware of the magnitude and cost of demand response that different appliances can provide. Besides, they consider other parameters such as response time span, storage characteristics, appliance usage constraint, and the kind of compensation customers require [279]. They possess the technology required for performing demand response services, as well as they are responsible for the installation of the communication and control devices at customer premises [280].

Aggregators can be considered as the missing link to exploiting the flexibility of the small-sized consumers. However, some challenges may be laying ahead before the aggregators. The domestic-level research carried out in [281] aimed to explore the preconditions that must be provided by the aggregator to the consumers or prosumers, in order to encourage them to participate in flexibility programs. The research indicates that the majority of consumers are not familiar with the problems arising from peak loads and its potential effect on the network. Therefore, the main elements that need to be covered by the aggregator when selling the proposal of flexibility to consumers is explaining in a simple form the problem of peak load in the system, and how their contribution will have a positive impact on the operation. In addition, the information access must be provided to consumers who are willing to get involved in such programs regarding the flexible appliances. Another key finding of such research is that the financial investments required by the consumers, such as smart appliances and smart control systems, should be minimal. From a general view, aggregators must be technologically advanced to provide full automation for flexibility sources at the consumers' households without bothering them with instructions and actions to be carried out. Sustaining a constant level of comfort level will make the consumers satisfied.

In Great Britain, aggregators can only access some markets directly, whilst other markets can only be accessed through the supplier (i.e. the Wholesale Market and the Balancing Market) [282]. The ability of aggregators to access markets varies across Europe. For example, in Germany, aggregators require agreement with the supplier before they can access the flexibility of the consumer, though this may be changing. In France, on the other hand, pre-determined arrangements allow aggregators to access all markets without negotiating first with a supplier. There are various responsibilities that the aggregator can take, other than aggregation [144], [283], [284]. Aggregators may take the roles of energy retailers or BRPs. Such many tasks assigned to the aggregator can have advantages and disadvantages. One of the main disadvantages is that assigning the role of retailing to the aggregator could allow him to exercise market power. Aggregators can deliberately create bids in the day-ahead market that would result in network congestions, which then force the DSO to activate their aggregated flexibility [68]. However, avoiding the issue of market power is rather difficult even if the aggregator is not a retailer (for example, congestion that may be alleviated only by one aggregator).

Possible measures to mitigate such issue might be long term contracts, flexibility price caps [285], and efficient monitoring of irregular market bids. Also, the DSOs' need for flexibility is subject to it being more economical than reinforcing its own network. Therefore, aggregators will always be inclined to present flexibility prices in the allowed price range of DSOs. On the other hand, aggregators remove the complex burden of market participation from the customers by enabling them to deal with only a single entity. As for the system, it is expected that the aggregator would be responsible for the imbalances resulting between the actual and the forecasted demand and generation, due to the flexibility activation. Thus, a more effective balancing operation will be achieved if the aggregator acts as a BRP. Also, according to the economies of scale [67], aggregating the flexibility of many customers can result in better flexibility prices, than a single customer acting on his own [62]. Moreover, the overall efficiency of this arrangement will be higher because of the economies of scope involved. Some proposals consider this merging of activities (flexibility manager, retailer and BRP) as a possibility, such as in [71] and [68].

Throughout the work of this thesis, the aggregator is assumed to take the part of the retailer and the BRP besides the responsibility of collecting and aggregating the flexibility from the customers. In Figure 3.18, it can be seen that the aggregator is in the center between the customers and all other markets and players. As a retailer, the aggregator procures energy from the day-ahead market for its customers and carries out balancing responsibilities in intra-day markets. Furthermore, flexibility is collected from the customers by the aggregator and it is supplied to several possible buyers, such as the DSO or other market players, which can be other BRPS or aggregators looking to optimize their portfolios. As previously mentioned, market-based solutions hold the most benefits when it comes to promoting the use of demand flexibility services. Therefore, a market mechanism must exist between the aggregator and the potential beneficiaries that can facilitate the trading of such services.

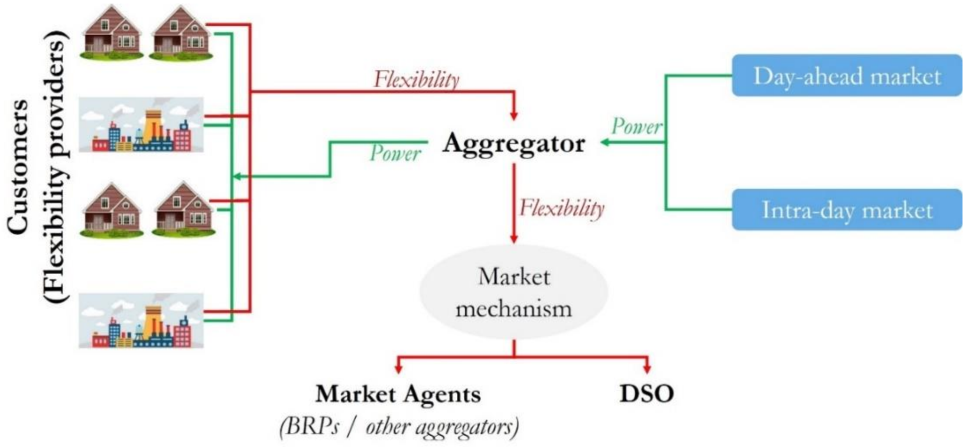


Figure 3.18 Aggregator responsbilities.

3.7 Summary

In the midst of the power system shift to become smarter, more environmentally friendly and less-centralized, demand flexibility presents itself as a key enabler to overcome any potential challenges that may be present. One of the conclusions drawn from this chapter is that distribution systems should be more versatile to adapt itself to these challenges by promoting demand flexibility programs. In addition to be being able to defer the capital investments that may be needed for capacity upgrade on the long-term, demand flexibility can be a valuable tool to the day-to-day congestion management operation to DSOs. However, the current regulations and remuneration schemes are only incentivizing DSOs for conventional network upgrades. Therefore, DSOs are not encouraged to invest in new smart grid solution such demand flexibility programs. Such regulations and policies must be modernized to cope with the future challenges. Another conclusion to mention is that the full potential of demand flexibility can only be exploited if modern market mechanisms are implemented that provide optimal incentives to the participants and ensure the safe trading of flexibility services.

This chapter overviewed the current structure of the liberalized power systems, as well as the structure of wholesale electricity markets, the market sequences and players. In addition, the chapter discusses the various roles of the DSO when it comes to network operation, planning and congestion management. Moreover, the DSO's business model, remuneration scheme and network tariff structure are explained. Taking the Spanish electricity market as the reference case for the work in this thesis, a review on its structure, wholesale markets, and implemented remuneration scheme and congestion management process is given. Also, the shift towards smart grids is addressed, which in return evolve the current role of the DSO and adds new responsibilities as well. In the paradigm of smart grids, the future barriers to the implementation of demand flexibility markets are addressed. Finally, the new role of the aggregators as a demand flexibility enabler is discussed. The following chapter presents the proposed framework for the flexibility trading market at the distribution level.

4 DISTRIBUTION LEVEL FLEXIBILITY MARKET

In order to exploit the full potential of demand flexibility, a modern market platform dedicated to demand flexibility trading is needed. A market in general describes an environment that permits buyers, sellers and retailers to trade a specific product [135]. Since DSOs manage and monitor all operations in their own local networks, proposing a market for flexibility trading at the distribution level can be referred to as a 'local flexibility market'. An efficient local flexibility market must have clear product definition, appropriate price signals that can benefit all market participants, more participants to increase the competition level and to have shorter trading intervals closer to real time with appropriate bidding mechanisms [63]. Moreover, the market mechanism must coordinate with other electricity markets to avoid negative impacts on other markets or players [27]. The importance of having a local market for flexible resources that can work in coordination between the DSO and the aggregators for the provision of demand flexibility, was addressed in the SmartNet project [270]. The European-based project (Italy, Denmark and Spain) focuses on the acquisition of ancillary services such as reserve and balancing, voltage control and congestion management.

In this Chapter, a comprehensive framework for a decentralized local market dedicated for flexibility transactions at the distribution-level grid called (**Flex-DLM**), is proposed. Most of the work in this chapter was previously published in [286]–[288]. Following the decentralization trend in energy markets, the Flex-DLM follows a decentralized approach, which means several markets can exist for different areas in the distribution network. The decentralized architecture is necessary since the distribution network congestions are local. Based on the literature review carried out in Chapter 2, the framework proposed in this thesis aims to consider all the research fields that were addressed separately in literature. The objective of the proposed framework is to define all the necessary aspects concerning the trading of flexibility services to ensure an efficient process between all involved parties. The aspects covered by the proposed framework are illustrated in Figure 4.1. The targets to be realized by the Flex-DLM can be summarized as follows:

- Optimally manage the flexibility procurement process between the involved parties, i.e. DSO and aggregators.
- Provide an efficient service to the DSO that allows it to mitigate network congestion at the distribution level.
- Consider the uncertainty of congestion occurrence and prevent the DSO from procuring unneeded flexibility in the day-ahead timeframe.
- Introduce a new option for reserving demand flexibility for network congestions that have low probabilities of occurring.
- Implement a flexibility market operating in real-time to reduce the negative effect of forecast errors and load and generation deviations in the real-time operation.
- Consider the uncertainties of customer of participation and commitment to the flexibility activation requests.

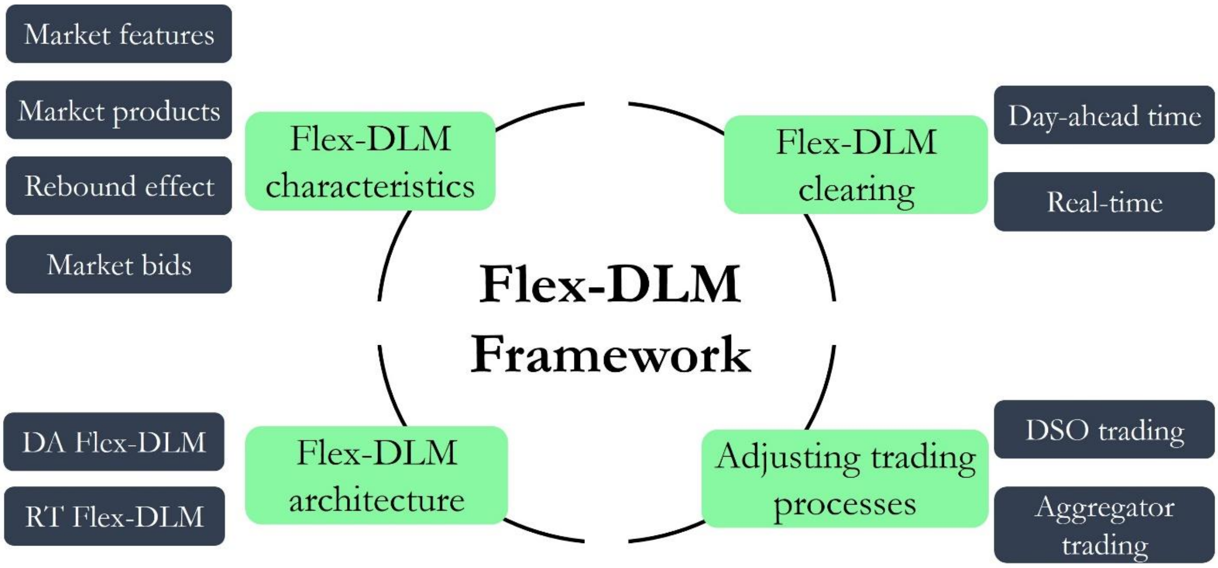


Figure 4.1 Aspects covered by the proposed framework.

4.1 Flex-DLM characteristics

4.1.1 Market Features

The general criteria for classifying flexibility markets, as proposed in [135], are those related to the temporal, spatial, contractual, and price-clearing dimensions of trading.

- **The temporal dimension** is related to the time when the market takes place. The proposed Flex-DLM operates in the day-ahead (DA) and real-time (RT) timeframe.

- **The spatial dimension** refers to the geographical area for which electricity is contracted and prices are settled. The different categories that the market can follow can be found in [135]. One of the main objectives in Flex-DLM is to promote efficient management of distribution network. Therefore, location is a critical aspect that must be taken in consideration in this design. Thus, Flex-DLM can be considered as re-dispatch economic process, which is a market-based optimization considering technical and locational constraints.

- **The contractual dimension** introduces the basis upon which buyers and sellers trade. Contracts may take the form of bilateral trading, pool market trading or power exchange trading. Bilateral trading demand from the buyers and sellers to reach an agreement regarding price and terms and obligations of purchase and delivery of electricity without the interference of a third party, such as in long-term contracts. Pool market trading requires from the suppliers and consumers to bid for electricity, then demand and supply curves are matched, and the market is cleared. Pool market trading is suitable for the wholesale day-ahead market. Power exchange trading is an organized platform that allow buyers and sellers to interact, with no obligations to be committed to one single buyer or seller, which makes it optimal for flexibility markets in general and Flex-DLM particularly.

- **The price-clearing dimension** refers to the price setting mechanisms used by each market. There are two main approaches have been identified in literature: uniform pricing and pay-as-bid pricing [289]. In uniform pricing, activated market participants receive the same marginal price cleared by the market operator. However, in pay-as-bid pricing, activated market participants receive payments which are equal to their nominated price in the bids. Similar to congestions markets, the Flex-DLM uses the pay-as-bid approach.

4.1.2 Market Products

As already mentioned, the services that can be offered to the DSO as a form of demand flexibility are several. The shape, quantity and direction of the available flexibility may vary depending on the type of the customer. Such features determine the way flexibility is integrated into electricity markets. One of which is their market orientation, where the flexibility may be traded in either one or multiple markets [290]. Also, the flexibility can be constrained to minimum or maximum energy consumption and total energy over the time frame considered [291]. The work in this thesis focuses on one key aspect of demand flexibility which is its direction.

The flexibility offered by the demand side can take the form of either increasing or decreasing the load. Thus, two kinds of flexibility are defined here, named up-regulation (UREG) and down-regulation (DREG) flexibility. UREG flexibility represents load reduction volumes provided by the customers. This type of flexibility can be of use to the distribution system operators to mitigate network constraint concerning overloaded lines. For example, in Figure 4.2, it can be noticed that during the second half of the day, the load profile is expected to surpass the network maximum capacity limit. In this case, to ensure optimal operation, the DSO will require that this amount of energy to be moved to another period with less network loading. With proper mechanisms and given the right incentives, customers can be able to provide UREG flexibility (load decrease) during these hours and assist the DSO in avoiding this congestion. The amount of UREG flexibility power will be referred to as F^{UREG}.

The other type of flexibility is DREG flexibility corresponds to load increase volumes offered by the consumers. This type of flexibility can be of value for networks with high penetration of RES. A common practice in most countries, is to provide priority access to the generation based on RES to be served before conventional generation and to avoid curtailing RES [292]. However, due to the intermittent behavior of such resources, sometimes it can be difficult to accurately predict their generation profile. In such case, the excess RES generation can cause voltage problems to the network (voltage levels rising above the permissible limits). An illustrative example is given in Figure 4.3, where it can be seen that excess RES generation occurs during the middle of the day, which causes the voltage levels to surpass the nominal limits to the network (1± 0.05 p.u). In this case, the DSO can benefit from the availability of DREG flexibility (load increase) to manage these voltage levels. The amount of DREG flexibility power will be referred to as F^{DREG}.

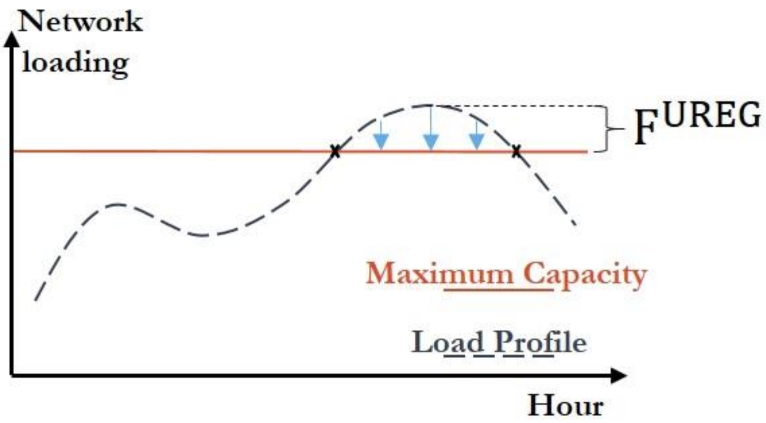


Figure 4.2 Network congestion occuring due to high load demand.

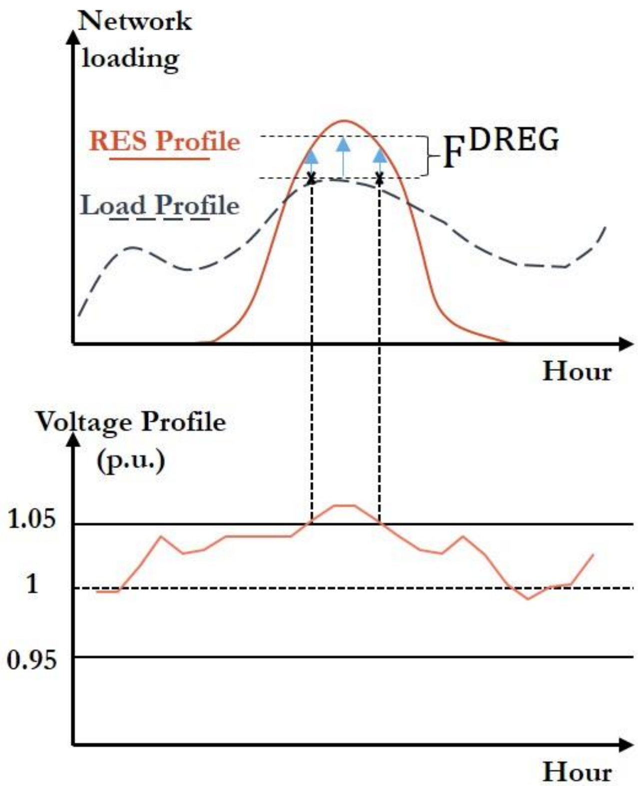


Figure 4.3 Network congestion occuring due to high RES generation.

In a market-oriented approach of flexibility management, the flexibility obtained from UREG and DREG can be expressed by up-regulation bids (URB) and down-regulation bids (DRB) respectively and can be offered for sale. It can be noticed that the names of the two flexibility types, UREG and DREG, conversely corresponds to the opposite direction of load behavior, i.e. load decrease and increase respectively. However, these names are inspired by the way regulation volumes are defined in balancing markets, where up-regulation corresponds to less consumption or more generation, and down-regulation corresponds to more consumption or less generation [234], [293].

4.1.3 Rebound Effect

As explained, the two types of demand flexibility considered here consists of either increasing or decreasing the load. Based on the type of customers involved in the flexibility services, these flexibility amounts may require to be shifted to another hour during the day. This shifting of energy can produce further problems in the grid if not considered properly; for example, in Figure 4.4, the reduced energy due to UREG flexibility is recovered by the customer at a load peak hour, producing further congestion. This can be referred to as the energy **rebound effect (RB)** [294]. Considering the rebound effect of demand flexibility is important for the DSO to avoid possible subsequent problems in the network. However, it adds further complexities to the task of the DSO.

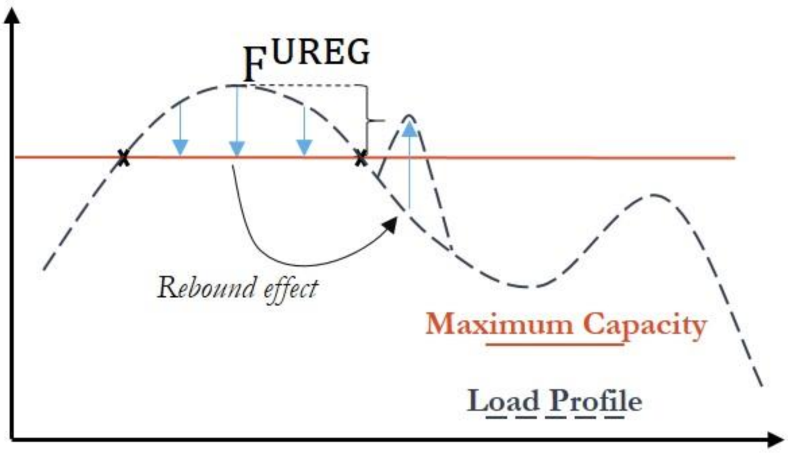


Figure 4.4 Payback Effect causing another peak in the load profile.

Recent literature has been referring to the rebound effect when addressing the potential of demand flexibility. However, certain aspects of the rebound effect are yet to be explored and investigated. For example, a common simplification for modelling the rebound effect is to consider it as a load that is being shifted with a time lag of one hour only [295]. In reality, there can be many possibilities to shift this load, which is dependent on the type and nature of the load being shifted, as well as the preference of the customer. Another aspect that is not considered in recent literature, concerns the impact of this rebound effect on the choice of demand flexibility. In real distribution networks with potentially several numbers of customers offering demand flexibility, the complications arising from every rebound effect for every customer can be difficult to handle. The problem that the DSO must consider is the possible demand peaks that this rebound effect can cause if the flexibility is used. In this thesis, these two issues are addressed and will be explained in this subsection.

In order to clearly model the impact of the rebound effect to the process of acquiring demand flexibility, a proposal for the conditions which can define the rebound effect is given here. The rebound conditions are those concerning the rebound hour and the rebound power [288]. The rebound hour is the hour at which the flexibility power is shifted to, while the rebound power is the amount of flexibility power that will be shifted. The rebound conditions are dependent on the type of customers and the nature of the load providing the flexibility. Consequently, the rebound power can either be equal to the activated flexibility, or just a percentage of it. Similarly, for the rebound hour, customers have the possibility of deciding the most convenient hour to have the rebound power. The customers' preferences on receiving their rebound energy have been mentioned briefly in other papers [44], [93], [172]. Here, the possible customers' preferences with respect to the rebound conditions considered in this work are illustrated and defined in Table 4.1. These preferences may be provided by the customers. The objective behind these assumptions is to model the possible options and scenarios that the rebound conditions can take. Also, to show the effect these conditions have on the process of demand flexibility transaction.

Table 4.1 Rebound Conditions.

Rebound Conditions	Type	Description
Rebound Hour	$\boldsymbol{Cond_{H1}}$	Rebound power must be on following hour of flexibility activation.
	$\boldsymbol{Cond_{H2}}$	Rebound power is in between a predefined time interval (before or after flexibility activation).
	$\boldsymbol{Cond_{H3}}$	Rebound power can be at any hour during the day.
	$\boldsymbol{Cond_{H4}}$	Rebound power is not needed.
Rebound Power	$\boldsymbol{Cond_{P1}}$	Rebound power is equal to the flexibility activated.
	$\boldsymbol{Cond_{P2}}$	Rebound power is a fraction of the flexibility activated.
	$\boldsymbol{Cond_{P3}}$	Rebound power is not needed.

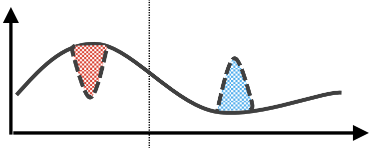
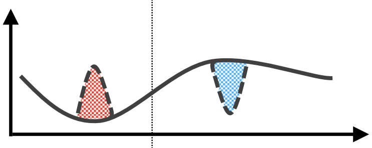
In order to differentiate between the rebound power of both UREG and DREG flexibilities, two different names will be assigned to each one of them. Since UREG requires supplying back the regulation power at the rebound hour, the rebound effect will be referred to as the **payback effect (PB)** [296], [297], with payback power at the payback hour [95], [298]. On the other hand, as the DREG requires a decrease of the load at the rebound hour, it will be referred to as the **rebate effect (REB)**, with rebate power at the rebate hour. As already mentioned, in certain cases the rebound effect may create new network congestions. Such cases may occur if the PB creates unexpected new peaks, or when the REB decreases the load leading to overvoltages. The rebound conditions concerning the rebound power can be formulated as in (4.1) and (4.2), where α and β correspond to the payback and rebate coefficients respectively. These coefficients determine the share of demand flexibility power needed back by the customers, i.e. rebound power, and their limits can be given in (4.3). Table 4.2 summarizes the types of demand flexibility with their corresponding type of rebound effect. It should be noted that, while previous work has discussed the payback effect from the perspective of UREG flexibility [172], up to the knowledge of the author, there are no current studies that address the rebound effect in case of DREG flexibility.

$$\mathrm{P}^{\mathrm{PB}} = \alpha\, \mathrm{P}^{\mathrm{UREG}} \tag{4.1}$$

$$\mathrm{P}^{\mathrm{REB}} = \beta\, \mathrm{P}^{\mathrm{DREG}} \tag{4.2}$$

$$0 \leq \alpha, \beta \leq 1 \tag{4.3}$$

Table 4.2 Summary of demand flexibility types and their corresponding rebound effect.

<table>
<tr><th>Types of flexibility</th><th>Types of rebound effect</th></tr>
<tr><td>Up-regulation (UREG): Load reduction volume</td><td>Payback (PB): Supplying back power</td></tr>
<tr><td colspan="2"></td></tr>
<tr><td>Down-regulation (DREG): Load increase volume</td><td>Rebate (REB): Reducing power</td></tr>
<tr><td colspan="2"></td></tr>
</table>

4.1.4 Market Bids

The products offered in the Flex-DLM (DA or RT) are based on load reduction or load increase volumes, UREG and DREG flexibility, which are collected and aggregated by the aggregator to take the form of flexibility bids. The flexibility services can be sold by two means, it can either be effectively bought (firm flexibility), which means payment is transacted upon market clearing, or it can be reserved by a new option introduced in the market called the Right-to-Use (RtU) option. The RtU option allows the DSO to pay a reservation fee to hold a specific amount of flexibility that can be activated upon request from the DSO at a later time. If such option is called upon later and the reserved amount is activated, the cost of the service can be transacted. This option can be useful when the DSO is not certain about the amount of flexibility it may need for a specific congestion or if the probability of the congestion taking place is low, for example due to uncertainty in demand consumption. In the flexibility framework proposed and the case studies carried out later, the flexibility bids modeled (whether UREG or DREG), are an aggregation of several customers connected to a single node in the feeder. For a particular node *n* and a trading period time *t*, a typical flexibility bid must consist of four main aspects: First, a number of flexibility blocks N_t^b, where every block *k* has an individual amount of available flexibility $F_{n,t,MAX}^{UREG/DREG}$, second are the corresponding flexibility prices $\lambda_{n,k,t}^{UREG/DREG}$ for every flexibility block, which are then ordered in a non-decreasing manner, third is RtU reservation fee $\lambda\_Rtu_{n,k,t}$; and, finally the rebound conditions for every block *k*, which must define the rebound hour and rebound power, according to Table 4.1. Table 4.3 illustrates an example for an aggregated flexibility bid which consist of three blocks with the flexibility quantities, prices and the rebound conditions. We recall that the Flex-DLM follows a pay-as-bid structure, which means cleared bids receive their bidding prices and not the market marginal price. Therefore, the cost of flexibility activation, denoted $C_{n,t}^F$, at node *n* and time *t*, can be calculated as in (4.4), which is equal to the sum of the activated flexibility $F_{n,k,t}^{UREG/DREG}$ at every block in the bid, multiplied by every block's corresponding price $\lambda_{n,k,t}^{UREG/DREG}$. The activated flexibility is constrained as in (4.5) between a minimum and maximum values of $F_{n,t,MIN}^{UREG/DREG}$ and $F_{n,t,MAX}^{UREG/DREG}$. Finally, the total activated flexibility per bid $F\_tot_{n,t}^{UREG/DREG}$, can be easily computed by (4.6).

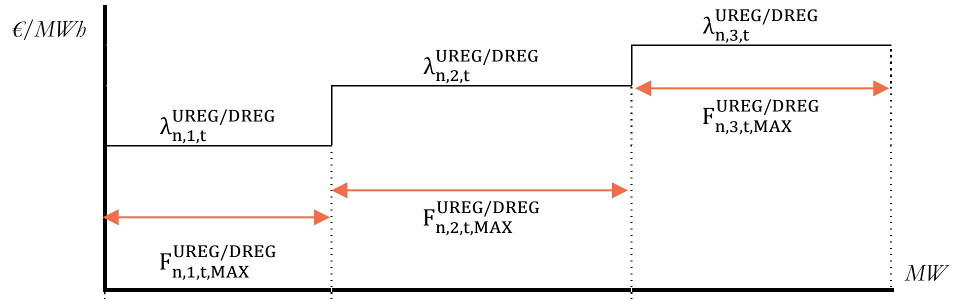
$$C^{F}_{n,t} = \sum_{k=1}^{N^b_t} F^{UREG/DREG}_{n,k,t} \; \lambda^{UREG/DREG}_{n,k,t} \qquad \forall t, n \qquad (4.4)$$

$$F^{UREG/DREG}_{n,k,t,MIN} \leq F^{UREG/DREG}_{n,k,t} \leq F^{UREG/DREG}_{n,k,t,MAX} \qquad \forall t, n \qquad (4.5)$$

$$F\_tot^{UREG/DREG}_{n,t} = \sum_{k=1}^{N^b_t} F^{UREG/DREG}_{n,k,t} \qquad \forall t, n \qquad (4.6)$$

Table 4.3 Example of a flexibiltiy bid with its rebound conditions

Flexibility Quantities & Prices



RtU reservation fee		$\lambda\_Rtu_{n,1,t}$	$\lambda\_Rtu_{n,2,t}$	$\lambda\_Rtu_{n,3,t}$
Possibilities of Rebound Conditions				
Rebound Hour	$Cond_{H1}$		*Define the rebound intervals per block*	
	$Cond_{H2}$			
	$Cond_{H3}$			
	$Cond_{H4}$			
Rebound Power	$Cond_{P1}$		*Define the rebound coefficient per block*	
	$Cond_{P2}$			
	$Cond_{P3}$			

4.2 Flex-DLM architecture

The general scheme for the proposed operations, as well as the actors and the time sequence for the two timeframes are illustrated in Figure 4.5. The actors involved in the proposed scheme are: the customers; the aggregator; the energy market operator, who is responsible for clearing the day-ahead market; then there is the flexibility market operator responsible for clearing the Flex-DLM, which is assumed to be the DSO; finally, the DSO who is the operator of the grid's distribution level. In the day-to-day operation, energy is scheduled in the wholesale day-ahead markets based on the bids provided by the generation and demand sides. In the proposed framework, it is assumed that the aggregator takes the role of the energy retailer and the BRP. As an energy retailer, the aggregator participates in the day-ahead market to purchase the required energy for its customers. After the wholesale market is cleared, the provisional schedule is sent to the DSO for technical validation and possible grid contingencies are detected, which can be solved by modifying the initial market solution. After the DSO has identified the network violations in the upcoming day, a flexibility call is activated, and the DSO calls for the DA Flex-DLM. The DA Flex-DLM is proposed to be operating after the day-ahead market is cleared. In response, aggregators present their aggregated flexibility bids and the flexibility market operator clears the market to solve the network constraints. As suggested in the SmartNet project [270], the role of the Flex-DLM operator can be assigned to the DSO, where it can clear the market considering all the technical constraints and flexible bid prices to obtain the most economic outcome. The flexibility obtained from the DA Flex-DLM must ensure a safe mode of operation in the day-ahead timeframe. The market solution should consist of the accepted flexibility bids and the time when the rebound energy can take place, thus allowing the aggregator to adjust the flexible loads accordingly.

In the real-time operation, unexpected deviations in the load and/or generation profiles are bound to occur, due to errors in forecast or changes in the consumption behavior of customers. Such unforeseen congestions can jeopardize the operation of the network. Thus, the RT Flex-DLM is proposed to be available in the real-time operation to allow the DSO to mitigate such congestions. In this market, the DSO may need more flexibility than what was already purchased in the DA timeframe, or it may require flexibility for congestions that were not considered in the first place. The existence of a RT Flex-DLM reduces the problems arising from the forecast errors of load and generation, and it decreases the effect of sudden network contingencies.

The validation processes (black blocks) in Figure 4.5 are the responsibility of the DSO and they are a key process in any electricity market. It consists of running a Power Flow (PF) analysis to ensure a secure operation in the grid, with respect to the system and resources constraints [299]. In the proposed flexibility framework, the DSO, as the flexibility market operator, must optimally clear the market and minimize its total cost of flexibility purchase. This is achieved by running Optimal Power Flow (OPF) in order to minimize the total cost of procuring flexibility and making sure system constraints are not violated. The basic power flow equations can be described as in (4.7)-(4.10). For a given network, with $\mathrm{N_n}$ number of nodes, the net injected active and reactive power at node *n,* denoted $\mathrm{Pnet_{n,t}}$ and $\mathrm{Qnet_{n,t}}$ respectively, follow equations (4.7) and (4.8). The maximum bounds for the line capacities for every line *nm* in the system and voltage levels for every node *n*, follows the constraints (4.9) and (4.10). All the power flow equations are valid for every time *t* during the timeframe considered in this problem. For example, in a day-ahead time frame, as the framework proposed here, the time $t \in \{1{,}24\}$.

$$\mathrm{Pnet_{n,t}} = \mathrm{S_{base}} \sum_{m=1}^{N_n} \mathrm{v_{n,t}}\, \mathrm{v_{m,t}}\, \mathrm{y_{nm}} \cos(\delta_{n,t} - \delta_{m,t} - \theta_{nm}) \qquad \forall t, n \tag{4.7}$$

$$\mathrm{Qnet_{n,t}} = \mathrm{S_{base}} \sum_{m=1}^{N_n} \mathrm{v_{n,t}}\, \mathrm{v_{m,t}}\, \mathrm{y_{nm}} \sin(\delta_{n,t} - \delta_{m,t} - \theta_{nm}) \qquad \forall t, n \tag{4.8}$$

$$\mathrm{S_{nm,t}} \leq \mathrm{S_{nm,MAX}},\ \mathrm{S_{nm,t}} = \left| \mathrm{v_{n,t}^2}\, \mathrm{y_{nm}}\, e^{-j\theta_{nm}} - \mathrm{v_{n,t}}\, \mathrm{v_{m,t}}\, \mathrm{y_{nm}}\, e^{j(\delta_{n,t}-\delta_{m,t}-\theta_{nm})} \right| \cdot \mathrm{S_{base}} \quad \forall t, m, n \tag{4.9}$$

$$\mathrm{v_{n,MIN}} \leq \mathrm{v_{n,t}} \leq \mathrm{v_{n,MAX}} \qquad \forall t, n \tag{4.10}$$

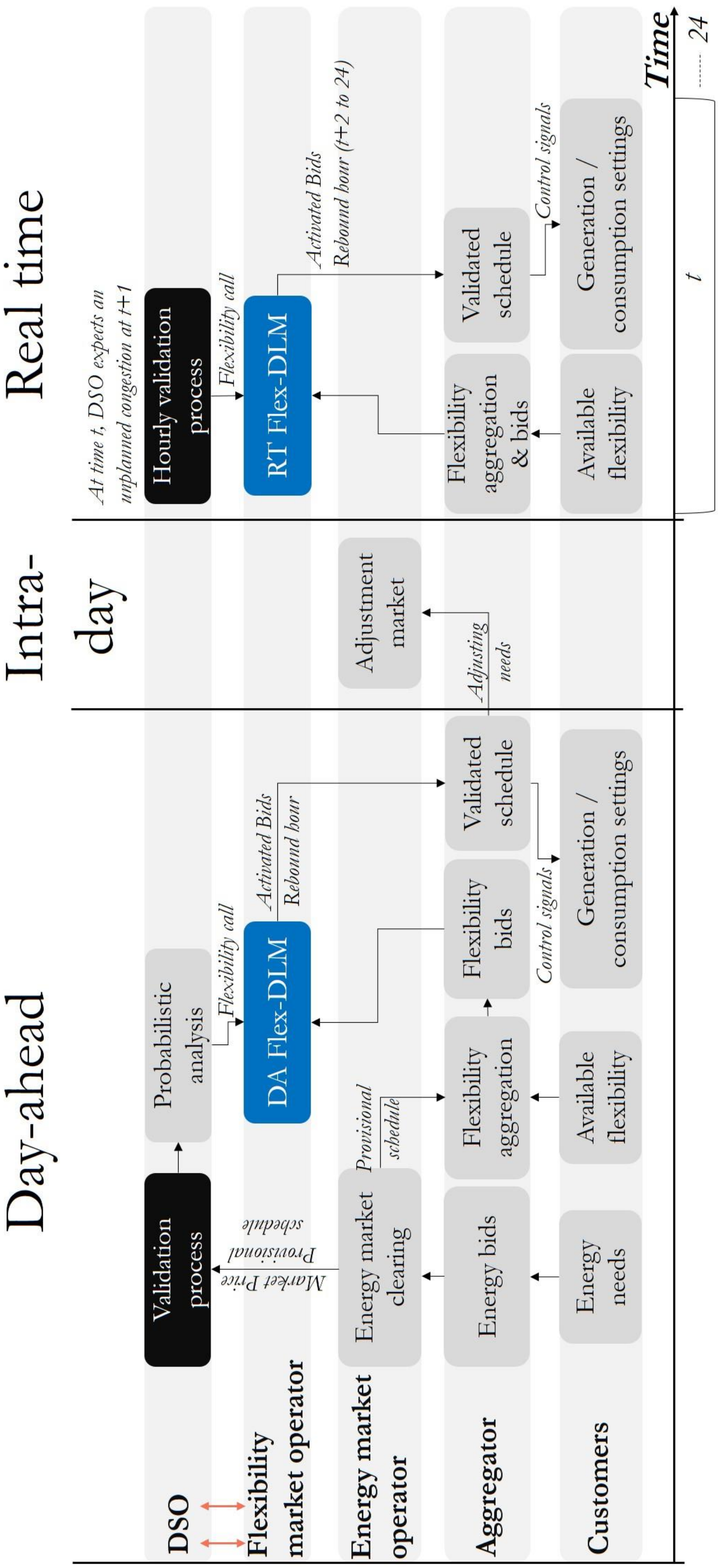


Figure 4.5 Architecture of Flex-DLM along the DA and RT.

4.2.1 Day-ahead Flex-DLM

The DA Flex-DLM is a market dedicated for prior purchase of flexibility services for congestions occurring in the following day of operation. Usually, the next day network congestions are determined after the energy market operator sends the provisional market solution to the DSO for technical assessment. In this validation process, the DSO carries out a Power Flow (PF) analysis to ensure that the wholesale market solution is technically feasible. In the DA Flex-DLM, the validation process (black blocks in Figure 4.5) carries out a congestion probability assessment after the PF analysis. Here, it is assumed that the DSO carries out short-term forecasts for load and generation to assess the possible congestions that can take place in the following hours in its network. Short-term forecasts are available from a variety of sources, and there is a well-established state of the art about these techniques, which give rather accurate results when aggregated values are determined for the whole system. In distribution grids, however, this accuracy is not as high because the aggregation level of consumers is smaller and hence the so-called portfolio effect (the cancellation of random prediction errors produced when a large number of consumers are considered) does not take place. Thus, the level of uncertainty that any DSO must face is larger than, for instance, the TSO of a power system. Load forecasting in the distribution systems is an evolving research area [300] and there are several contributions in literature regarding this matter with variable error values. For example, according to [74], the average Mean Absolute Percentage Error (MAPE) achieved across all medium voltage (MV) and low voltage (LV) substations in the network for 24 hour-ahead forecasting was 8.27%. In [302], the MAPE was found to be 3.30% for the aggregated load, but 8.70% and 27.79% in average for individual residential loads and industrial loads, respectively.

Implementing a probabilistic analysis at the distribution level can help to determine congestions with a high probability, discard those of low probability and be aware of those with medium probability of occurrence. But even though forecasting may be available at this aggregation level, predictions are usually deterministic (i.e. a single value is determined). Probabilistic forecasting gives not just a single value, but the confidence intervals of such predictions. By using historical data and forecasting tools, or through forecasting agencies, we would assume that the DSO has access to the results of probabilistic forecasts for the coming day. The proposed analysis method and the market model are based on this assumption. Then, the DSO can calculate the probability of congestion occurrence for every hour in the following day. The main advantage of this probabilistic assessment is that it makes sure there is a valid need for calling for the DA Flex-DLM. Due to forecasting errors, the resulting market solution may have certain inaccuracies, which can make the DSO overestimate the congestions of the coming day, thus buying unnecessary amounts of demand flexibility.

In the probabilistic assessment, the overall probability of congestion occurrence for every hour *t* during the next day can be calculated as in (4.11), where Sc_t is a binary variable that corresponds to 1 if a congestion takes place at hour t and 0 otherwise, and N_{Sc} is the total number of scenarios generated. Based on the output of the probabilistic assessment, the DSO divides the space of probabilities into three groups using two levels of probabilities ρ^{max} and ρ^{min}, as seen in Figure 4.6. The congestion groups are: 1- congestions with very high probabilities of happening (above the maximum level) are considered almost certain to take place, 2- congestions that have medium probabilities (between both levels) are considered unsure to take place, and 3- congestions that are less likely to happen (probability below the minimum level) and can be neglected. The maximum and minimum probabilities levels are set by the DSO and they correspond to the level of the risk the DSO will be willing to take. Different probability levels have a direct effect on the amount of flexibility traded in the DA Flex-DLM. For the high probable congestions, the DSO participates in the DA Flex-DLM to procure flexibility to mitigate the congestions which are considered very sure to happen. Beside the congestions resulting from line overloading or voltage fluctuations, there are other types of congestions that can take place because of maintenance activities, for instance transformers maintenance. The less probable congestions, below the minimum bound, can be ignored by the DSO. However, for the medium probability congestions, the DSO can pay a fee to reserve the right to activate a specific amount of demand flexibility if necessary in the following day. The RtU option can eliminate the problems arising from the uncertainty of congestion occurrence in the day-ahead timeframe.

$$\rho_t = \frac{\sum_{x=1}^{N_{Sc}} Sc_{t,x}}{N_{Sc}} \tag{4.11}$$

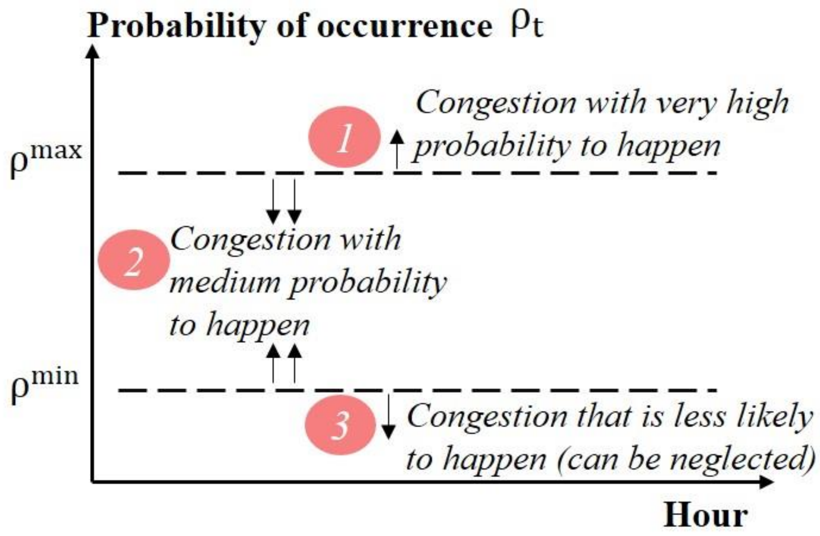


Figure 4.6 Classification of congestions according to their probability of occurrence.

With respect to the network congestions expected to take place in the following day, the DSO has two sets of information. The first set is based on the findings of the wholesale market solution, which will be referred to as the market solution assessment (MSA). The second set comes from the findings of the probabilistic forecasting assessment (PFA). Before calling for the DA Flex-DLM, the DSO must analyze both sets of information to choose the best strategy in order to buy the necessary flexibility services. One of these strategies is given, as an example, in Table 4.4, for a specific hour *t*. If the MSA and PFA indicate that a congestion can be expected at this hour with a high probability of occurrence, then the DSO can procure firm flexibility services in the DA Flex-DLM. Other possibilities may as well exist, for example if the MSA does not indicate a congestion, while the PFA shows a high probability of congestion occurrence, then the DSO can take advantage of the RtU option. In a similar way, the DSO can also use the RtU option if the PFA shows a congestion with a medium probability, even if the MSA indicates a congestion at that hour. The RtU option is also used if the congestion has a low probability of occurrence according to the PFA. If neither of MSA and PFA show a congestion at hour t, the DSO can follow the approach of "wait-and-see" and may call for the real-time Flex-DLM if an unplanned or unexpected congestion takes place later. It should be remarked that the DSO's strategy is not restricted to what is given in Table 4.4; more scenarios may exist, and different actions can be taken according to the level of risk the DSO is willing to take.

Table 4.4 Possible DSO's strategy for buying flexibility services in the DA Flex-DLM.

Indicator		MSA	
		Congestion	*No congestion*
PFA	*Sure congestion* ($\rho_t > \rho^{max}$)	Firm flexibility	RtU option
	Unsure congestion ($\rho^{min} \leq \rho_t \leq \rho^{max}$)	RtU option	RtU option
	No congestion ($\rho_t < \rho^{min}$)	RtU option	"wait-and-see"

After the DSO identifies the hours with the highest probabilities for congestion occurrence, it can call for the DA Flex-DLM to purchase the required flexibility. After the flexibility call is initiated, aggregators prepare their flexibility bids, and the flexibility market operator, which is the DSO, clears the market. The DSO's objective when clearing the DA Flex-DLM is twofold: first, it must optimize the cost of procuring the flexibility, while making sure that the network congestion is avoided; second, it must ensure that the payback effect of the activated flexibility will not cause further network constraints. Both objectives are achieved by running multiple Optimal Power Flow (OPF) based analysis, considering the intertemporal constraints derived from the payback effect, to ensure an overall safe operation for the network. Since the operation is day-ahead, the payback power can take place at any given hour during the day according to the payback conditions of the selected bids. The market solution of the flexibility market should consist of the accepted flexibility bids and the time when the payback power can take place, thus allowing the aggregator to adjust the flexible loads accordingly. During the intra-day period, the aggregator is responsible for adjusting the original schedule of the wholesale market to accommodate the flexibility activation needs.

4.2.2 Real-time Flex-DLM

In the real-life experiment carried out by the flexibility management framework proposed by the Universal Smart Energy Framework (USEF) [281], it was concluded that one of the common reasons for failing to mitigate network congestions are the unforeseen congestions during the day-ahead trading. Such congestions fall below the minimum risk bound of the DSO, which cannot be forecasted or estimated. The USEF framework highlighted that more markets should exist with up-to-date information in order to accommodate better forecasting profiles. In light of this, the proposed flexibility framework here implements a real-time flexibility market (RT Flex-DLM).

During the real-time operation, the DSO is continuously checking the technical feasibility of the network for every following hour. If a network constraint is identified to be happening in the following hour, three possible scenarios could take place: first, if the DSO procured the RtU option for the forthcoming congestion, then the DSO can activate that option and avoid this constraint without entering the RT Flex-DLM. Second, if the DSO needs more flexibility than what was already reserved by the RtU option, then the DSO will call for the RT Flex-DLM to procure the remaining required flexibility. And third, if an unforeseen or unplanned network congestion is taking place, the DSO also calls for the RT Flex-DLM to purchase the needed flexibility. This last scenario cannot be considered as a rare event, since unplanned deviations from forecasted values of generation and demand are common. The existence of a real-time market for flexibility trading increases the reliability of the total system, eliminates the complications arising from the forecasting errors and decreases the effect of sudden network contingencies. In the RT Flex-DLM, aggregators must be ready to supply flexibility on short notice to the DSO. The market solution here must also consist of the accepted flexibility bids and the time when the payback power can take place, which must be on the following hours to the activation request. For example, as in Figure 4.5, if the DSO validation process at time t detects a congestion for the following hour $t+1$, thus the rebound power can only take place from hour $t+2$ and till the end of the day.

4.3 Flex-DLM Clearing

The problem facing the DSO when participating in the Flex-DLM (DA or RT) is choosing the optimal flexibility bids, while considering the grid constraints and the rebound effect. During the work of this thesis, two methods were developed to solve the optimization problem facing the DSO in clearing the Flex-DLM, which are explained as follows:

- **Deterministic approach:** In this approach, the objective is to optimize the DSO's cost and clear the Flex-DLM without taking into account the probabilistic assessment of congestion occurrence and the uncertainty of consumers' participation were discarded. The DSO calls for the DA Flex-DLM and procure firm flexibility for the following day of operation based on the submitted generation and load profiles from the wholesale electricity market. Here, the RtU option is not considered either. Also, the RT Flex-DLM is not implemented, thus the DSO cannot procure flexibility services on short-time basis.

- **Probabilistic approach:** In this approach, the whole Flex-DLM framework is modelled, that is the probabilistic assessment (PFA), the RtU option, the customers' uncertainty and the RT Flex-DLM.

The optimization algorithms for both approaches are explained in detail in the appendix. The two approaches represent the work progress done along this thesis. While the deterministic approach may be easier to model, the probabilistic approach represents a much closer model to reality, since the demand uncertainty and forecasting errors are common problems in electricity markets. However, it should be noted that the choice between both approaches is a decision made by the DSO. It can be expected that this decision will depend on the amount of information available for the DSO regarding the demand uncertainty and forecasting errors, and also the level of risk it is willing to take when it comes to the congestion probabilities. Finally, it should be noted that in accordance with Spanish electricity markets criteria, the trading periods for all objective functions in the Flex-DLM are considered for one hour. In the following, all optimization processes taking place in the DA and RT Flex-DLM periods will be explained thoroughly.

4.3.1 Trading in the day-ahead period

During this period, two kinds of flexibility transactions can take place, which means that two optimization processes are as well carried out by the DSO. The first one is for the high probable/almost certain congestions, where the DSO buys firm flexibility in the DA Flex-DLM. The second transaction is for the medium probability congestions, where the DSO enters the DA Flex-DLM to buy the RtU option in order to reserve a certain amount of flexibility to be used if needed in the real-time operation. The main difference between the two transactions is in the rebound power scheduling. For firm flexibility (highly probable congestions), the DSO is able to schedule the rebound power to take place at the optimal hour along the following day of operation, but as the flexibility for the medium probability congestion is not guaranteed to be requested, the DSO cannot schedule the rebound day-ahead and can only schedule it if it is activated in real-time.

Take for example the two possible scenarios in Figure 4.7. In the first scenario (top figures), in the day-ahead period, we assume that congestions at hour 9 and 15 have very high probabilities. With one flexibility bid presented at both hours, the DSO procures firm flexibility. Therefore, the DSO can schedule ahead the rebound power for the activated blocks, which will take place at hours 3, 6 and 14 for the blocks at hour 9, and at 18 and 23 for the blocks at hour 15. In the second scenario (bottom figures), congestions at hours 10 and 17 have probabilities between the DSO's probability levels. Thus, the DSO reserves only the flexibility blocks by paying the fee for the RtU option. In this case, the DSO can activate this option if these congestions actually take place in real-time. However, the rebound cannot be planned ahead. Therefore, in real-time, if the flexibility is required at hour 10 and 17, the DSO is can schedule the payback power to take place after the activation of the flexibility. In this case, the rebound power for the activated blocks from the bid at hour 10 will take place in hours 16, 19 and 20 and the rebound hours for the two blocks activated at hour 17 will be shifted to hours 23 and 24 respectively, considering that no new congestion occur at these hours.

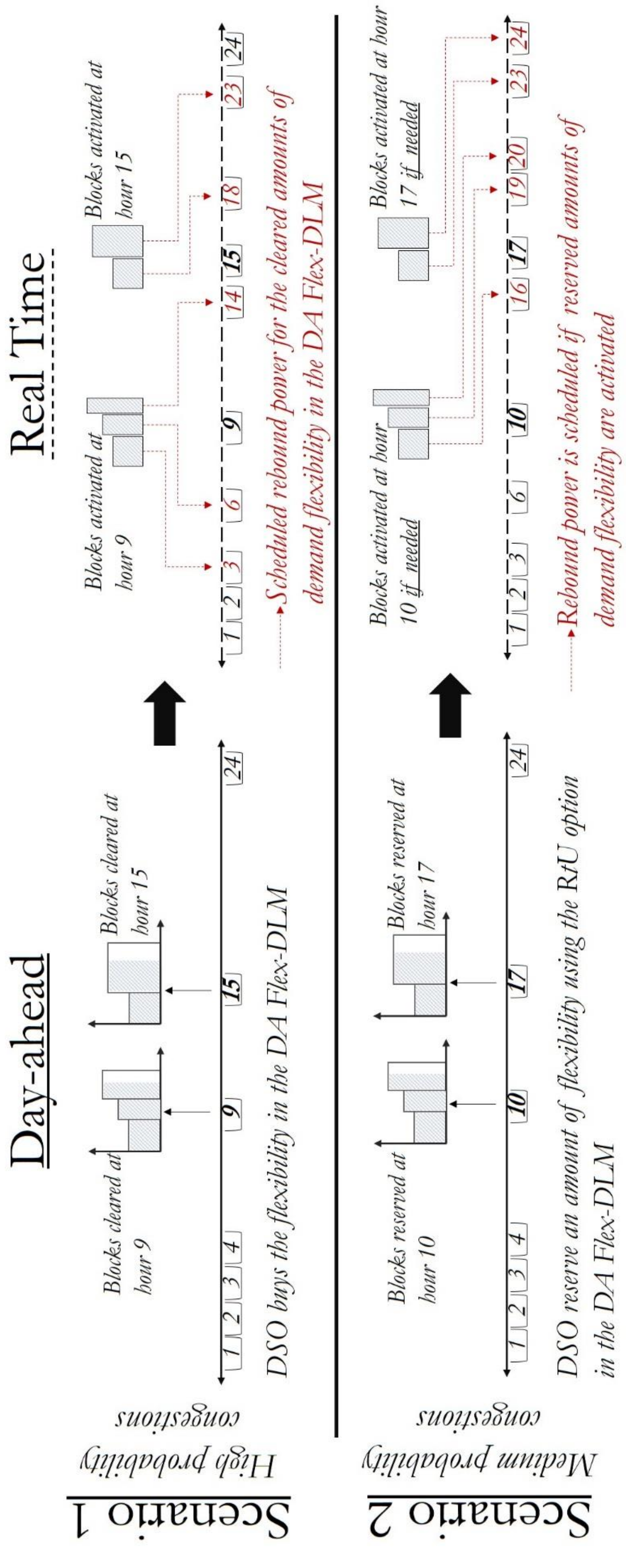


Figure 4.7 Difference between the two flexibility transactions in the DA Flex-DLM (top figure: Flexibility trading for highly probable congestion, Bottom figure: Flexibility trading for medium probability congestion.

- **Optimization process for the high probability congestions**

In the DA Flex-DLM, firm flexibility is scheduled for all the congested hours with probabilities above the maximum limit. The objective function in (4.12) represents the DSO's cost of activating firm flexibility, denoted C^{F_DA} , at block *k* at node *n* at time *t*, with price $\lambda_{n,k,t}^{UREG/DREG}$ and activated flexibility power $F_{n,k,t}^{UREG/DREG}$. The superscripts UREG and DREG means that the formulation is applicable for both types of flexibility trading. The optimization constraints are described in (4.13)-(4.19).

$$\underset{F_{n,k,t}^{UREG/DREG}}{\mathrm{Min}} C^{F\_DA} = \sum_{t=1}^{24} \sum_{n=1}^{N^n} \left[\sum_{k=1}^{N_{n,t}^b} F_{n,k,t}^{UREG/DREG} \quad \lambda_{n,k,t}^{UREG/DREG}\right] \tag{4.12}$$

$$F_{n,k,t,MIN}^{UREG/DREG} \leq F_{n,k,t}^{UREG/DREG} \leq F_{n,k,t,MAX}^{UREG/DREG} \qquad \forall t, n \tag{4.13}$$

$$P_{n,t}^{PB} = \sum_{i \in \Psi_t} \sum_{k=1}^{N_{n,i}^b} \alpha_{n,k} F_{n,k,i}^{UREG} \qquad \forall t, n \tag{4.14}$$

$$P_{n,t}^{REB} = \sum_{i \in \Omega_t} \sum_{k=1}^{N_{n,i}^b} \beta_{n,k} F_{n,k,i}^{DREG} \qquad \forall t, n \tag{4.15}$$

$$Pnet_{n,t} + \sum_{k=1}^{N_{n,t}^b} F_{n,k,t}^{UREG} - \sum_{k=1}^{N_{n,t}^b} F_{n,k,t}^{DREG} - P_{n,t}^{PB} + P_{n,t}^{REB} = S_{base} \sum_{n=1}^{N_n} v_{n,t}\, v_{j,t}\, y_{nm} \cos(\delta_{n,t} - \delta_{m,t} - \theta_{nm}) \qquad \forall t, n \tag{4.16}$$

$$Qnet_{n,t} + \sum_{k=1}^{N_{n,t}^b} Q\_F_{n,k,t}^{UREG} - \sum_{k=1}^{N_{n,t}^b} Q_{F_{n,k,t}}^{DREG} - Q_{n,t}^{PB} + Q_{n,t}^{REB} = S_{base} \sum_{n=1}^{N_n} v_{n,t}\, v_{m,t}\, y_{nm} \sin(\delta_{n,t} - \delta_{m,t} - \theta_{nm}) \qquad \forall t, n \tag{4.17}$$

$$S_{nm,t} \leq S_{nm,MAX}, S_{nm,t} = \left|v_{n,t}^2\, y_{nm}\, e^{-j\theta_{nm}} - v_{n,t}\, v_{m,t}\, y_{nm}\, e^{j(\delta_{n,t} - \delta_{m,t} - \theta_{nm})}\right| \cdot S_{base} \quad \forall t, l \tag{4.18}$$

$$v_{n,MIN} \leq v_{n,t} \leq v_{n,MAX} \qquad \forall t, n \tag{4.19}$$

The maximum and minimum limits to the flexibility amounts, UREG or DREG, which can be activated are defined in (4.13). Equations (4.14) and (4.15) calculate the payback and rebate powers respectively as functions of the UREG and DREG power and subject to the payback and rebate coefficients $\alpha_{n,k}$ and $\beta_{n,k}$ respectively. These coefficients represent the amount of UREG or DREG power needed at the payback and rebate hours for every block *k*. Also, the payback and rebate powers are calculated for every flexibility bid activated having rebound power at time *t*. Sets Ψ_t and Ω_t correspond to the activated bids for the payback and the rebate at time *t*, respectively. The grid constraints are represented in (4.16)-(4.19). In (4.16) and (4.17), the active and reactive load flow equations at any node *n* in the system are modeled, where $Pnet_{n,t}$ and $Qnet_{n,t}$ are the net injected active and reactive power at every node. In the proposed formulation, only the active power is considered as an optimization variable in the flexibility bids, while the reactive power is modeled to adapt accordingly to maintain a constant power factor for each customer. Equations (4.18) and (4.19) reflect the network's line capacities and the voltage magnitude bounds at any given node respectively.

- **Optimization process for the medium probability congestions**

The second optimization process is also carried out during the DA timeframe and it concerns the RtU option for the congestions with medium probability of occurrence. The RtU option gives the DSO the rights to reserve a certain amount of flexibility to be used when needed in the real-time operation. In this case, the total cost of activating the flexibility will consist of two components: the actual cost of flexibility activated in the real-time and the price for the RtU option offered by the aggregator in the DA Flex-DLM. The rebound effect equations are not considered at this point since the activation of flexibility is not a certain case. However, the grid constraints equations described in (4.13) and (4.16)-(4.19) are taken into consideration. Even though the RtU option can be considered as a safe measure for the DSO to avoid the likely to happen congestions, a certain level of risk is still present with respect to buying this option. The two main factors affecting the DSO's decision are the flexibility prices and the RtU fee. The problem is which of those terms has more influence on the optimal solution.

Take for example Figure 4.8, where a congestion is considered to have medium probability and the DSO needs an amount of 0.2 MW to relieve it. If two flexibility bids are presented at node *n* and time *t*, with a single block each, flexibility prices of 70 and 85 €/MWh and RtU fee of 2.2 and 1.2 € respectively, then the expected total cost for reserving and activating the first and the second bid are 16.2 € and 18.2 €. The RtU fees here ranges from 5% to 20% of the total cost of the offered flexibility [171]. At first glance, it can be noticed that the first bid has a cheaper flexibility price than the second bid. However, the situation is reversed when considering the RtU fee, as it is more expensive to reserve the first bid than the second one. Therefore, from the stand point of the DSO, if this congestion takes place in the real-time, the optimal bid would be the first one, i.e. minimum total cost. But, if the congestion does not take place, then reserving the second bid for 1.2 € would be a better option to the DSO, since no extra cost for actual flexibility activation will be paid.

In order to enhance the DSO's decision in such cases, we propose to include the probability of congestion occurrence in the DSO's objective function, which can be written as in (4.20). The first term corresponds to the activation cost of flexibility multiplied by the probability of congestion occurrence, and the second term corresponds to the reservation cost, where $\lambda\_\mathrm{Rtu}_{n,t}^{\mathrm{UREG/DREG}}$ is the RtU fee for every activated block *k* at node *n* multiplied by a binary variable $x_{n,t}$, which represents the state of flexibility activation for every flexibility block. The function of this binary variable is to eliminate the RtU reservation fee from the objective function if a given flexibility block is not reserved. The binary variable status is evaluated by equation (4.21). It should be noted that the left-hand side term $\bar{C}^{\mathrm{F\text{-}RtU}}$ represents an expected value for the DSO for reserving and activating the flexibility, and it does not correspond to the actual cost that the DSO will pay. The objective of the probability value is to be a weighting factor and to identify the optimal flexibility blocks to be reserved by the DSO, taking into consideration the probability of congestion occurrence. In other words, the probability value helps to determine if the congestion is worth the risk to reserve the cheaper bid with the high RtU fee (has a relative high probability of occurrence), or the congestion is not worth the risk (has a relative low probability), which means that the expensive bid with low RtU fee is a better option. Therefore, the actual cost of reserving and activating the flexibility, denoted $C^{\mathrm{F\text{-}RtU}}$, will follow (4.22), which is determined after solving (4.20).

$$\underset{F_{n,k,t}^{UREG/DREG}}{\mathrm{Min}} \bar{C}^{F\_RtU} = \sum_{t=1}^{24} \sum_{n=1}^{N^n} \left[\sum_{k=1}^{N_{n,t}^b} \rho_t \, F_{n,k,t}^{UREG/DREG} \, \lambda_{n,k,t}^{UREG/DREG} + x_{n,t} \, \lambda\_Rtu_{n,t}^{UREG/DREG} \right] \quad (4.20)$$

$$x_{n,k,t} \, F_{n,k,t,MIN}^{UREG/DREG} \leq F_{n,k,t}^{UREG/DREG} \leq x_{n,k,t} \, F_{n,k,t,MAX}^{UREG/DREG} \quad (4.21)$$

$$C^{F\_RtU} = \sum_{t=1}^{24} \sum_{n=1}^{N^n} \left[\sum_{k=1}^{N_{n,t}^b} F_{n,k,t}^{UREG/DREG} \, \lambda_{n,k,t}^{UREG/DREG} + \lambda\_Rtu_{n,t}^{UREG/DREG} \right] \quad (4.22)$$

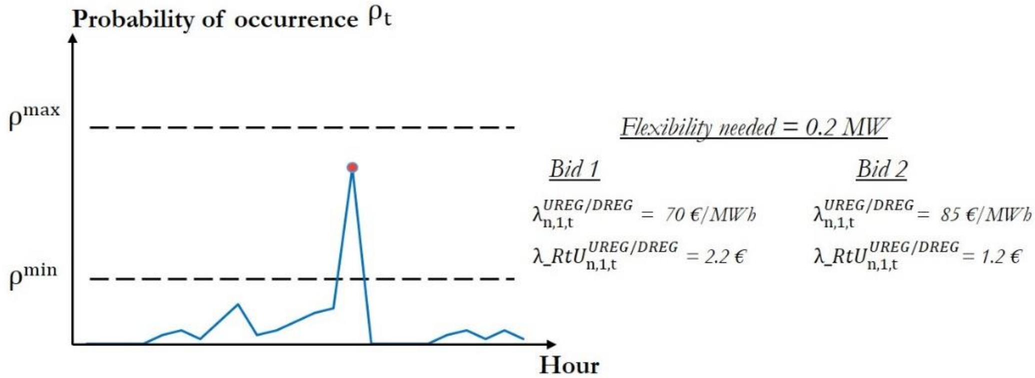


Figure 4.8 Example for a congestion with medium probability of occurring.

In order to clarify the before mentioned approach, we take the same example of the two bids, where we assume three different values of probabilities (0.3, 0.5, and 0.8) and another case where no probability is considered, for a single hour congestion. Table 4.5 gives the total DSO cost to reserve and activate the flexibility for the four cases. For a low probability of occurrence of 0.3, considering objective function (4.20), the DSO's best outcome is to reserve the Bid 2, since it has the cheapest RtU fee and the probability of congestion occurrence is relatively low. For higher probabilities such as 0.5 and 0.8, more weight is given to the first term in (4.20). In this case, the DSO's best decision will be to reserve the Bid 1. In the three cases of different probability values, the actual cost that the DSO pays follows equation (4.22). As already mentioned, the probability value included does not decrease the cost of flexibility activation. Its sole purpose is to help the DSO optimize its decision with minimum financial cost and losses. Thus, regardless of the value of congestion probability, if the DSO reserves the first bid for a probability of occurrence of 0.3, the aggregator should receive a total amount of 16.2 € if the flexibility is finally activated in real-time. It should be noted that in some cases the reserved flexibility using the RtU option may not be activated in real-time because the congestion may not take place. In such case, the DSO will only incur the fee of flexibility reservation, i.e. first term of (4.22) will be equal to zero. Thus, the DSO will only pay 1.2 € for a congestion of probability 0.3 that does not take place in real-time. The proposed method of including the probability of congestion occurrence in the objective function can help the DSO to avoid procuring demand flexibility that has a low probability of being activated. However, a congestion with low probability of 0.3 has still a chance of taking place in real-time. In such case, the DSO would have reserved and activated the overall higher bid cost for flexibility, which is 18.2 € of Bid 2, as opposed to the 16.2 € of Bid 1. Therefore, the maximum and minimum levels of probability set by the DSO play a key role in determining which congestions to consider having high, medium or low probability of occurrence.

Figure 4.9 shows the flowchart for the processes carried out by the DSO during the DA period. In the DSO's validation process, after the MSA and PFA are evaluated, the DSO assesses all congested hours in the following day and decides which kind of flexibility (firm flexibility or RtU option) should be bought for every hour. After all hours are assessed, the DSO calls for the DA Flex-DLM and two optimization processes are carried out, one for the highly probable congestions, where firm flexibility will be procured, and the other one for the medium probability congestions, where the RtU option will be procured.

Table 4.5 Example for the cost of reserving and activating 0.2 MW from two bids considering different probabilities of congestion occurrence.

Bids	Bid 1	Bid 2	Bid 1	Bid 2	Bid 1	Bid 2	Bid 1	Bid 2
ρ_t	*0.3*		*0.5*		*0.8*		*No probability considered*	
$\lambda_{n,k,t}^{UREG/DREG}$ (€/MWh)	*70*	*85*	*70*	*85*	*70*	*85*	*70*	*85*
$\lambda\_Rtu_{n,t}^{UREG/DREG}$ (€)	*2.2*	*1.2*	*2.2*	*1.2*	*2.2*	*1.2*	*2.2*	*1.2*
Expected value $\bar{C}^{F\_RtU}$ (€)	*6.4*	***6.3***	***9.2***	*9.7*	***13.4***	*14.8*	***16.2***	*18.2*
Actual Cost C^{F_RtU} (€)	*16.2*	***18.2***	***16.2***	*18.2*	***16.2***	*18.2*	***16.2***	*18.2*

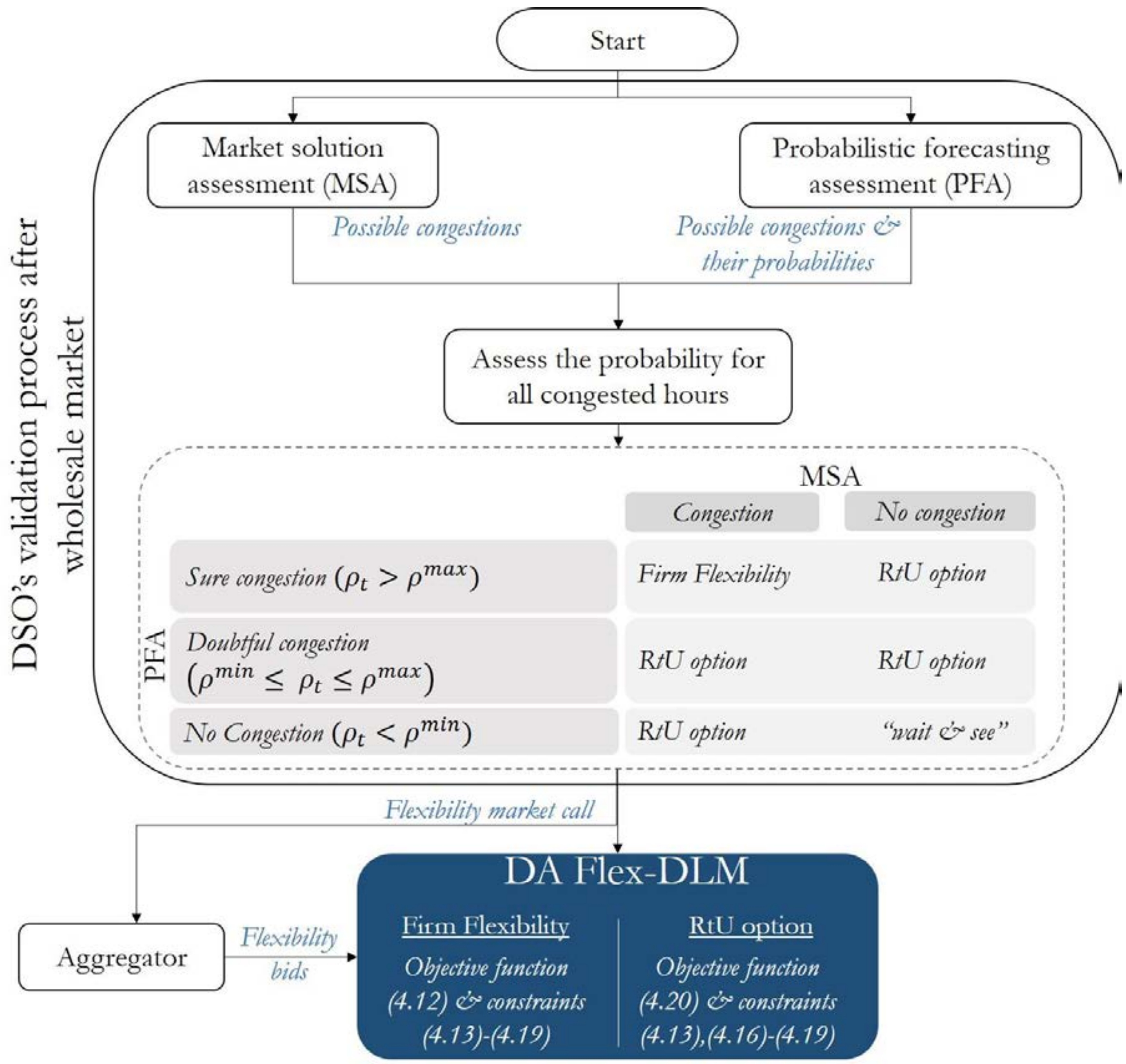


Figure 4.9 Flowchart for trading processes during the DA period.

4.3.2 Trading in the real-time period

During the real-time operation, the DSO checks the technical feasibility of the network continuously, which is assumed here to be on an hourly basis. Figure 4.10 shows the flowchart for the processes carried out during the RT period. If a congestion is detected at any following hour, the DSO checks if this congestion was already considered when procuring the RtU option during the DA timeframe and the amount reserved is sufficient to mitigate the congestion. In such case there is no need to call for the RT Flex-DLM and the amount of flexibility reserved by the DSO can be activated. Then the rebound power can be scheduled according to (4.14)-(4.15), which can only take place in forthcoming hours. However, if this congestion was not considered in the DA period, or the DSO needs more flexibility than what was reserved in the RtU option, it must call for the RT Flex-DLM to procure what is needed, and the rebound is scheduled accordingly as well. In the RT period, the flexibility prices are expected to be higher than in the DA Flex-DLM, due to the short notice. In this case, the same optimization process described in the DA Flex-DLM will be carried out with the same constraints, but with a different timeframe. Therefore, the DSO's total cost for activating flexibility during the real-time, denoted C^{F_RT}, can be written as the optimization function in (4.23). If the DSO's feasibility check is carried out at time *t* and the congestion is expected at time *t+1*, then (4.23) is valid from *t+1* till the end of the day.

$$\underset{F_{n,k,t}^{UREG/DREG}}{\text{Min}} C^{F\_RT} = \sum_{i=t+1}^{24} \sum_{n=1}^{N^n} \left[\sum_{k=1}^{N_{n,i}^b} F_{n,k,i}^{UREG/DREG} \quad \lambda_{n,k,i}^{UREG/DREG} \right] \tag{4.23}$$

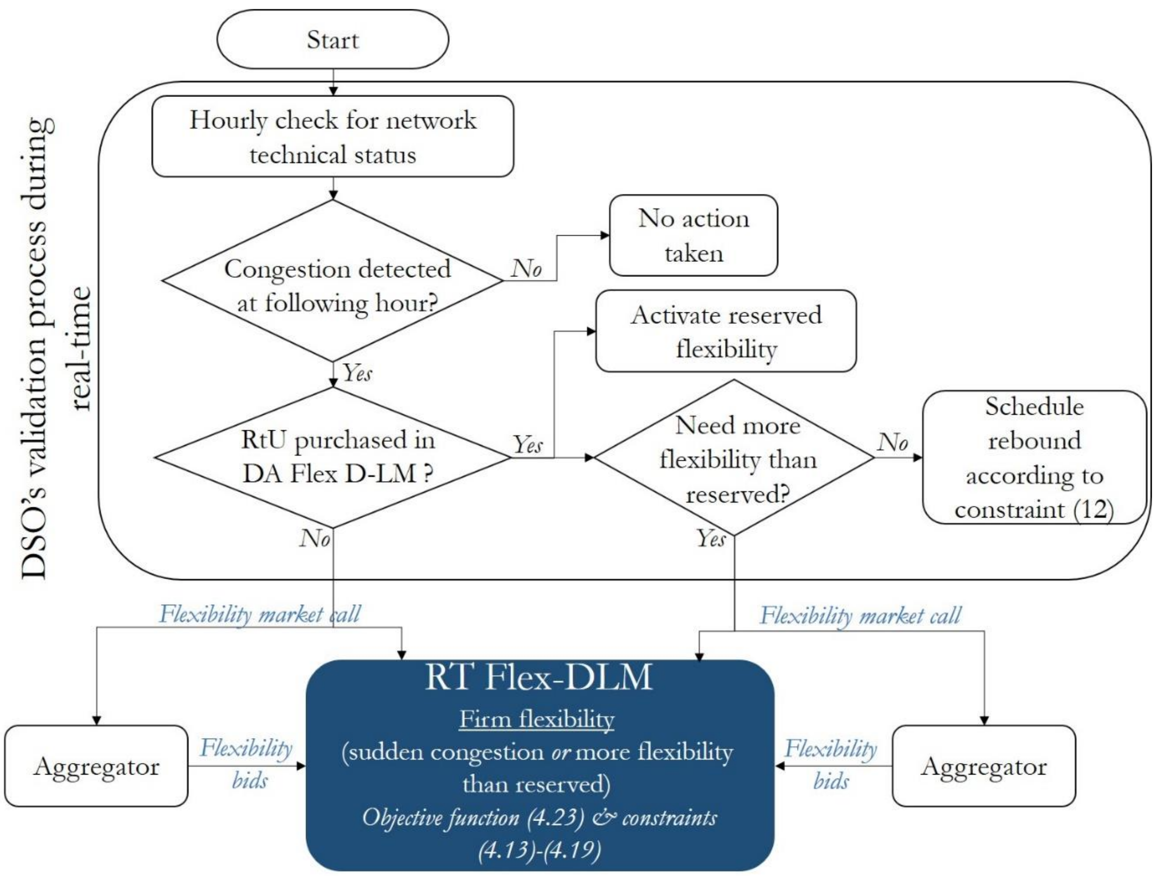


Figure 4.10 Flowchart for processes during the RT period.

4.4 Adjusting trading processes

The approach carried out here emphasizes that demand flexibility trading is different from the normal electricity trading in wholesale markets. In order to comply with the Flex-DLM solution, aggregators must carry out further energy trading processes in forthcoming adjustment markets to balance the energy differences arising between the energy already bought by the aggregator in the day-ahead market and the adjusted new load profile after the DA Flex-DLM clearing. The aggregator is responsible for acquiring the rebound power (payback or rebate) for its customers. Therefore, as a BRP, the aggregator takes the responsibility of adjusting these differences in adjustment markets. With much trading being carried out to deliver the flexibility required by the DSO, demand flexibility can be regarded as a trading of service and not a trading of energy. In this way, the prices of flexibility services can be independent of the day-ahead market marginal prices. However, the flexibility prices can be affected by the level of competition between different aggregators in flexibility markets. Also, they can be limited by the maximum prices that the DSO will be willing to pay in order to avoid investing in network reinforcement. Table 4.6 illustrates the energy trading by the DSO and the aggregator across the markets involved in the proposed scheme. The processes carried out by every participant are explained as follows.

Table 4.6 Trading of energy for makret particpants across markets.

Participants	Markets		
	Day-ahead market	*DA/RT Flex-DLM*	*Adjustment markets*
DSO	-	Buys flexibility	-
Aggregator	Buys energy for customers	Sells flexibility	Buys/sells energy to adjust differences and supply rebound power for customers

4.4.1 DSO trading

In accordance with the current regulatory policies, the DSO should not be involved in any other trading processes. For a single node *n*, the DSO's total cost for flexibility activations, denoted C_n^{F}, is calculated as in (4.23). This total cost is composed of the cost of firm flexibility $C_n^{F\_DA}$ activated during the DA period for the high probable congestions, cost of reserving flexibility with medium probabilities during the DA period and activating it during the RT period, denoted $C_n^{F\_RtU}$, and finally the cost of activating flexibility for sudden and unplanned congestions during the RT period, which is denoted $C_n^{F\_RT}$. The components of the total DSO cost are evaluated from the previously described equations (4.12), (4.22) and (4.23).

$$C_n^{F} = C_n^{F\_DA} + C_n^{F\_RtU} + C_n^{F\_RT} \tag{4.24}$$

4.4.2 Aggregator trading

The aggregator, being the BRP, will be in charge of the needed energy trading to ensure the delivery of the requested flexibility, which can be firm flexibility during DA or reserved amount due to RtU option or firm flexibility during the RT. The total flexibility (UREG or DREG) required by the DSO, which is calculated in (4.6), is in fact an amount of energy already purchased by the aggregator in the wholesale market. Therefore, to secure the delivery of the required flexibility, the aggregator must sell that energy consumption (activated flexibility) to other market players in coming adjustment markets, which run after the day-ahead market. If the flexibility traded is UREG, then the aggregator needs to sell an amount of energy (equivalent to the activated flexibility), and if the flexibility traded is

DREG, the aggregator buys an amount of energy (equivalent to the amount of load increase) required by the DSO. Therefore, with respect to node *n*, the aggregator will receive a revenue for selling the UREG energy amount, denoted $\mathrm{AggR_n^{UREG}}$, and to pay a cost, denoted $\mathrm{AggC_n^{DREG}}$, for procuring the energy needed. Equations (4.25) and (4.26) calculates both revenue and cost for the aggregator, which consists of the total activated flexibility per bid $\mathrm{F\_tot_{n,t}^{UREG/DREG}}$, multiplied by the adjustment market price λ_t^{adj}.

$$\mathrm{AggR_n^{UREG}} = \sum_{t=1}^{24}\left[\mathrm{F\_tot_{n,t}^{UREG}}\ \lambda_t^{adj}\right] \qquad \forall n \qquad (4.25)$$

$$\mathrm{AggC_n^{DREG}} = \sum_{t=1}^{24}\left[\mathrm{F\_tot_{n,t}^{DREG}}\ \lambda_t^{adj}\right] \qquad \forall n \qquad (4.26)$$

Beside the energy balancing responsibility, the aggregator must also obtain the needed rebound power corresponding to the flexibility service activated. This can be obtained also in adjustment markets. Equations (4.27) and (4.28) calculate the cost of procuring the payback power and revenue of selling the rebate power, by multiplying the individual amount of activated flexibility per block by the payback and rebate coefficients, and then multiplying it by the price of the adjustment market.

$$\mathrm{AggC_n^{PB}} = \sum_{t=1}^{24}\left[\sum_{k=1}^{N_{n,t}^{b}} \alpha_{n,k,t} F_{n,k,t}^{UREG}\right]\lambda_t^{adj} \qquad \forall t, n \qquad (4.27)$$

$$\mathrm{AggR_n^{REB}} = \sum_{t=1}^{24}\left[\sum_{k=1}^{N_{n,t}^{b}} \alpha_{n,k,t} F_{n,k,t}^{DREG}\right]\lambda_t^{adj} \qquad \forall t, n \qquad (4.28)$$

Finally, after all the processes take place, the aggregator's net profit for a single node *n* can be calculated as in (4.29) and (4.30). For UREG trading, the profit is computed in (4.29) by subtracting the cost of procuring the payback power from the revenue acquired from selling the flexibility to the DSO and selling the energy in the adjustment market. For DREG, the aggregator's revenue in (4.30) will come from the DSO's cost of activation and the amount of rebate power sold, while the cost will come from procuring the generation amount at the adjustment market. It can be easily concluded that flexibility transactions involve other trading processes for the aggregator. Thus, flexibility should be regarded as trading of service and not a trading of energy. In addition to that, the flexibility prices attached to the bids must secure an acceptable profit margin for the aggregator and its affiliated customers. Figure 4.11 shows a schematic diagram for all the trading processes carried out within the proposed framework between the DSO, the aggregator and other market agents. It should be noted that the adjusting trading processes carried out by the aggregator can take place in either one or several adjustment markets based on the aggregator's strategy to maximize its profits and minimize its costs.

$$\mathrm{Agg_n^{UREG}} = \mathrm{C_n^F} + \mathrm{AggR_n^{UREG}} - \mathrm{AggC_n^{PB}} \qquad \forall t, n \qquad (4.29)$$

$$\mathrm{Agg_n^{DREG}} = \mathrm{C_n^F} + \mathrm{AggR_n^{REB}} - \mathrm{AggC_n^{DREG}} \qquad \forall t, n \qquad (4.30)$$

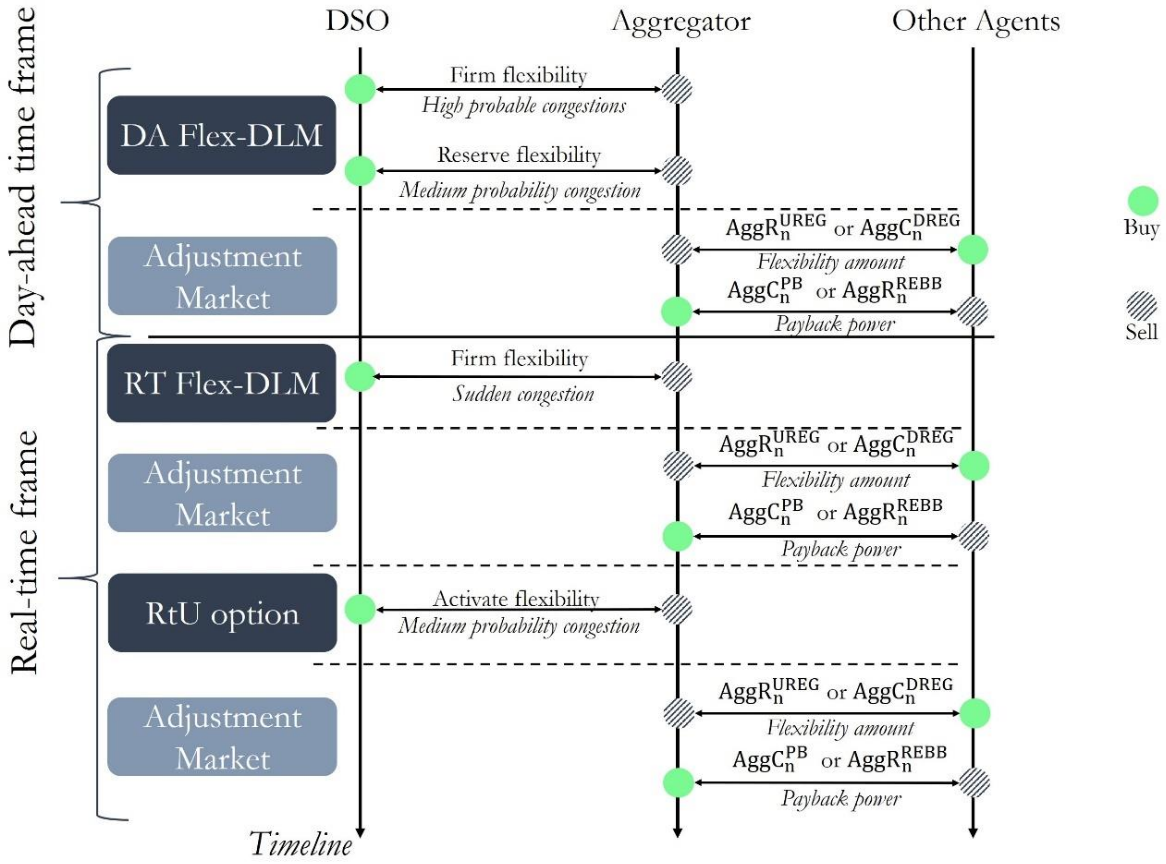


Figure 4.11 Trading processes within the Flex-DLM.

4.5 Uncertainty of customers' behaviour

One of the common disadvantages of demand flexibility is the amount of uncertainty involved in its activation. As already discussed, deviations in actual load consumption and generation profiles from their forecasted counterparts are common, and one way to solve it is through the proposed probabilistic assessment carried out by the DSO. While such approach helps the DSO to increase its accuracy of predicting forthcoming congestion, there are still certain levels of uncertainty that are yet to be explored and addressed, which concerns the responsiveness of the consumers to the flexibility activation requests [303]. This type of uncertainty is particularly found in small consumers, typically households. The behavior of such consumers can be affected by several factors such as their economic needs and level of commitment. These issues can cause delays in the flexibility requests issued by the DSO or even cause delivery failure. Contracts between DSOs and aggregator should have conditions that penalizes consumers or aggregators who fail to commit to the flexibility request [304]. However, there are certain safety measures that can be taken by the DSO to minimize the effect of such situations. A variety of approaches can be found in literature that quantifies the level of response in demand flexibility programs [305], [306]. In order to sustain such safety measures for the DSO, the work in this thesis assumes that the DSO can use historical data to predict and model the customers' uncertainties of commitment and delivery of flexibility power. Two approaches were carried out to serve this purpose, which are explained as follows.

- **Uncertainty of activation commitment**

In practice, the DSO cannot guarantee the compliance of the customers to the activation request of flexibility, which can decrease the reliability of the flexibility services. In order to overcome this issue, based on historical data, the DSO can assign a probability for every flexibility bid that represents the expected compliance to the flexibility activation request. Then, a minimum threshold is set by the DSO which corresponds to the minimum probability of commitment that the DSO can consider for the bids in order to ensure that the flexibility requested is activated.

This can be shown in Figure 4.12, where there are 10 aggregated flexibility bids and the DSO has assigned a probability value for every bid corresponding to their expected commitment to the activation request. Two possibilities are illustrated for the DSO's minimum threshold at 0.9 and 0.95. Bids such as 3 and 6 have the highest probabilities, thus they can be considered by the DSO in the activation process. However, bids 2 and 5 are dependent on the level of risk the DSO is willing to take. For a minimum threshold of 0.9, bids 2 and 5 will be considered by the DSO, while for a threshold of 0.95 only bid 2 will be considered and 5 will be neglected.

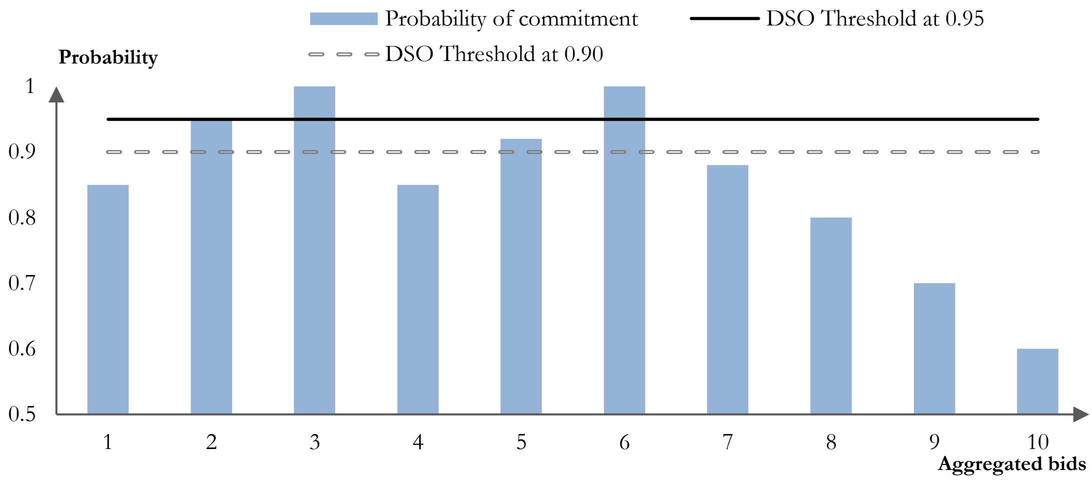


Figure 4.12 Probability of commtiment against DSO's threshold.

- **Uncertainty of amount delivery**

Another type of uncertainty can be considered which concerns committing to the delivery of flexibility requested. If the response to the flexibility activation is guaranteed, i.e. no uncertainty of commitment, delivering the total required flexibility might not be fully secured. Therefore, the DSO must take in his consideration the minimum amount of flexible power expected from every bid. Based as well on historical data, the DSO can assign minimum percentages of delivery for every block in every flexibility bid. These percentages indicate the minimum amount of flexibility guaranteed to be dispatched per block. Therefore, the flexibility amount $F_{n,k,t}^{UREG/DREG}$, whether it is UREG or DREG, of every block *k* at every node *n* at time *t*, will lie between maximum and minimum limits, $F_{n,k,t,MAX}^{UREG/DREG}$ and $F_{n,k,t,MIN}^{UREG/DREG}$ respectively, multiplied by the expectation of delivery factor $\varepsilon_{n,k,t}$, as shown in (4.31). An example is illustrated in Figure 4.13, where there is a bid consisting of 3 blocks with total amount of flexibility of 3 MW. By assigning different percentages to every block, the DSO can expect less available flexibility from this bid. However, this can increase the reliability of the flexibility transaction process.

$$\varepsilon_{n,k,t}\ F^{UREG/DREG}_{n,k,t,MIN} \leq F^{UREG/DREG}_{n,k,t} \leq \varepsilon_{n,k,t}\ F^{UREG/DREG}_{n,k,t,MAX} \qquad \forall t, n \qquad (4.31)$$

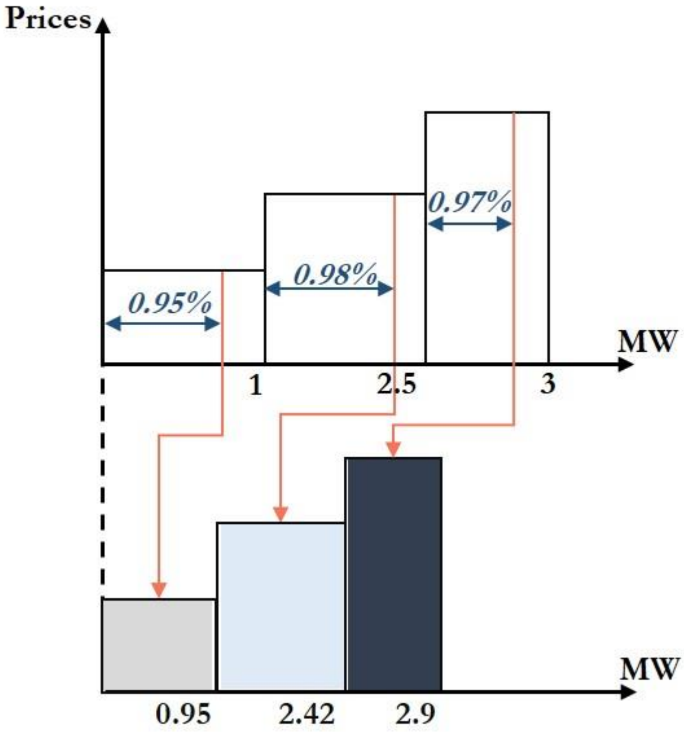


Figure 4.13 An example for a flexibility bid before and after applying the expectation percentage of delivery.

4.6 Illustrative example

In order to show the processes taking place in the proposed flexibility markets, an illustrative example is given and explained in this section. In Figure 4.14, an example for a distribution feeder with 5 buses is presented. Bus 1 is connected to the main grid, bus 3 is connected to a solar power generation plant and bus 5 is connected to the grid load. After the wholesale electricity market clearance, the DSO's MSA identifies an expected congestion to occur between buses 1 and 2, i.e. line 1-2, at hours 8, 13, 14, 19, 20 and 21 caused by overloading. The MSA for line 1-2 is shown in Figure 4.15. As already explained, before calling for the DA Flex-DLM, first the DSO reproduces potential scenarios for the load consumption and the solar plant generation profile, which is the PFA. The objective here is to ensure there is a true need for acquiring demand flexibility. A sample of these generated scenarios can be visible in Figure 4.14 next to buses 3 and 5. In this example, the number of generated scenarios for the demand and RES profile is 1000, which is a high enough number to calculate acceptable values of congestions probabilities.

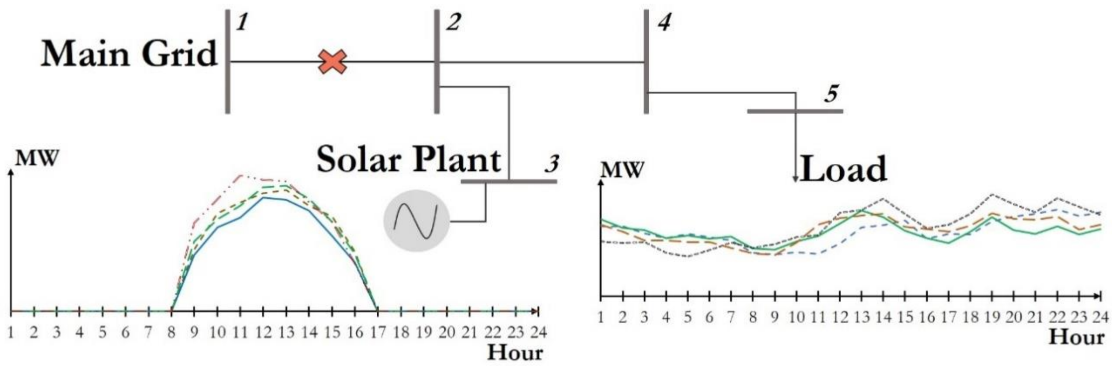


Figure 4.14 Example for Distribution Network with generated scenarios for load and solar power.

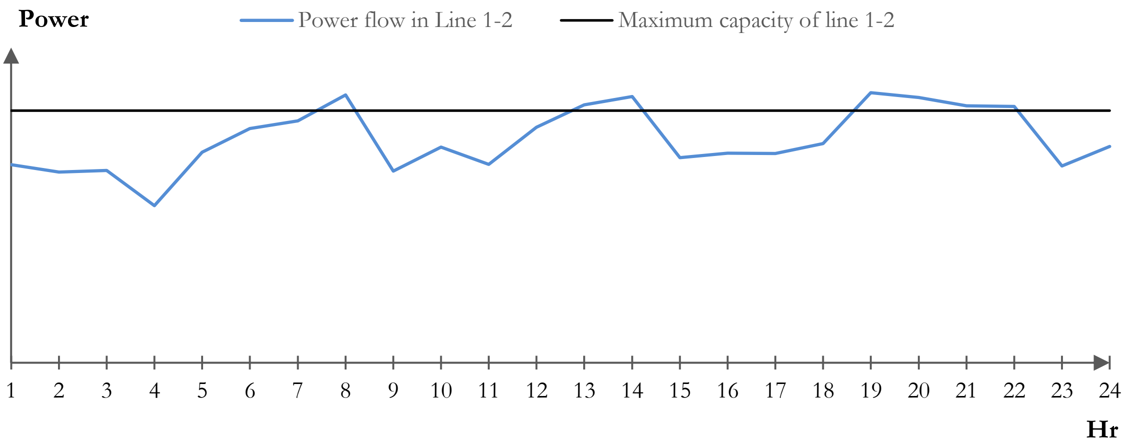


Figure 4.15 Expected power flow in line 1-2 based on the initial day-ahead market solution.

With respect to every generated scenario, the DSO carries out a technical validation analysis to determine the probability of network congestions occurrence on the following day. Due to the large size of the generated scenarios of demand and RES generation, the power flow at line 1-2 illustrated in Figure 4.16 represents only a sample of these scenarios. It can be noticed that there is a small number of scenarios where the maximum capacity of line 1-2 is surpassed, such as in hours like 12 and 13. However, there are several scenarios where the load flow at line 1-2 surpasses the maximum capacity, such as in hours 19, 20 and 21. Based on the all generated scenarios, the probability of congestion occurrence at every hour can be calculated. Other types of network constraint can also be present, such as voltage levels surpassing the permissible voltage limits of the network. However, only one type of network constraint was considered in this example to facilitate the explanation.

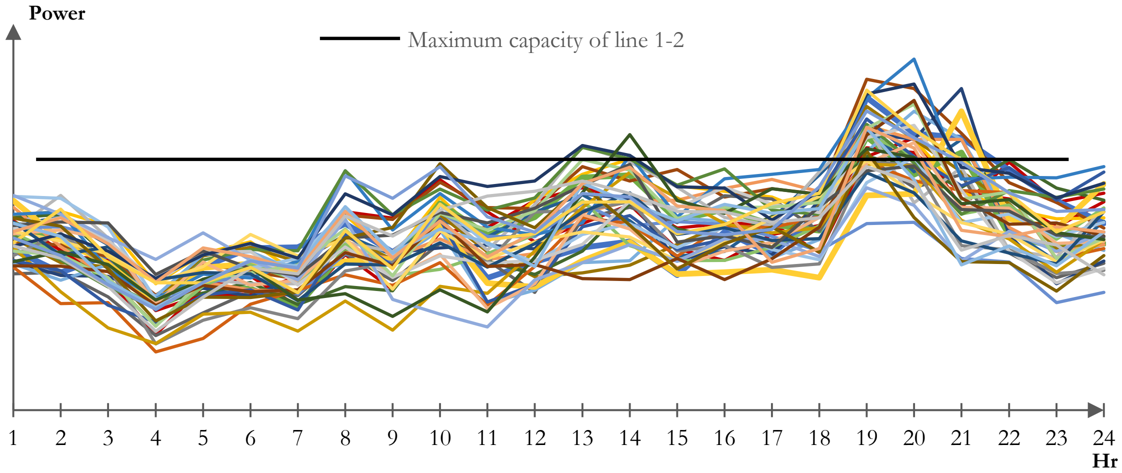


Figure 4.16 Load Flow at line 1-2 for a sample of generated scenarios.

After the PFA takes place, the DSO is able to calculate the probability of congestion occurrence at every hour across the next day of operation, as shown in Figure 4.17. In this example, it is assumed that the distribution system operator's probability levels have maximum and minimum values of 90% and 40% respectively. This means, that congestions having probabilities of occurrence higher than 90% are considered as almost sure to happen, such those at hours 19, 20 and 21. Congestions with probabilities between 40% and 90% are considered as likely to happen, such as hours 13 and 14. Lower probabilities than 40% indicate congestions are less likely to happen and can be neglected by the DSO.

It can be noticed that according to the MSA, line 1-2 is expected to suffer from a network constraint at hour 8, as shown in Figure 4.17. However, after the DSO's PFA, it was found that this congestion has very low probability of happening, below 40%, as in Figure 4.17. The main advantage of the proposed assessment is that it prevents the DSO from procuring demand flexibility that may be not needed. Another key advantage of the proposed scheme is that it allows the DSO to purchase the RtU of demand flexibility for the hours with congestions that are most likely to happen, falling between the probability levels, such as hours 13 and 14. In this way, if these expected congestions do not occur, the economic losses of the DSO are not as high compared to procuring the whole needed flexibility. Finally, the assessment carried out makes it clear that the congestions occurring at hours 19, 20 and 21 have a probability of occurrence higher than the maximum bound, which means demand flexibility must be procured at these hours.

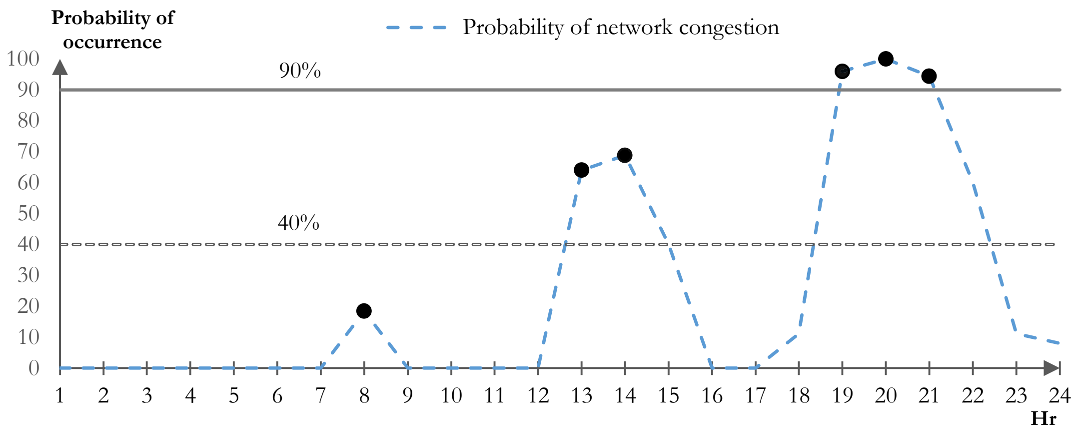


Figure 4.17 Probability of congestion occurrence and the DSO's risk level bounds.

In the real-time operation and during the hourly monitoring activity, the DSO's validation process at hour 9 indicates that a network congestion is going to take place at the following hour 10. The probability of occurrence of this congestion was below the minimum probability level, which means it was not considered by the DSO in the DA Flex-DLM. In this case, the DSO must call for the RT Flex-DLM at hour 9 to procure the needed flexibility. In addition, since the flexibility will be activated for hour 10, the rebound power can only take place from hour 11 to the end of the operation period, which in this example takes place at hour 11. Moreover, the congestions that are most likely to occur, hours 13 and 14, are found to be actually taking place. However, there is no need for the DSO to enter the RT Flex-DLM, as it already purchased the RtU option. In this case also the rebound power can only take place after the activation. In this example flexibility is shifted to hours 16 and 17. It should be noted that the rebound power could be pushed to the following day of operation if it is more feasible to the DSO and convenient to the flexibility provider.

As already mentioned, there are several trading processes carried out by the aggregator to adjust the imbalances caused by the flexibility activation. Considering the same example and to simplify the explanation, only one hour of congestion is considered here which is hour 19. In the day-ahead wholesale market, the aggregator, as a retailer, was able to procure an amount of 12 MW for the customers to consume on the following day. It should be reminded that the network is suffering from an overload in line 1-2, which can be solved by a decrease in the load consumption, i.e. UREG flexibility. After the flexibility call is activated, the aggregator prepares the flexibility bids to be submitted in the DA Flex-DLM. The aggregated bid presented in the market is illustrated in Figure 4.18, where it has three blocks, every block has a given quantity, a flexibility price and rebound conditions. The individual amounts of flexibility per every block are be 2, 2 and 3 MW respectively. The rebound preferences follow the conditions previously explained in Table 4.1. For example, in the first block, the rebound hour must be provided back between a specified time period, in this case it is between hours 15 and 20. Also, the payback coefficient is assigned the value 0.85, which means that the amount of rebound power needed to be provided to the customers of this block correspond to 0.85 from the amount of flexibility activated. The trading processes carried out by the DSO and the aggregator are explained as follows.

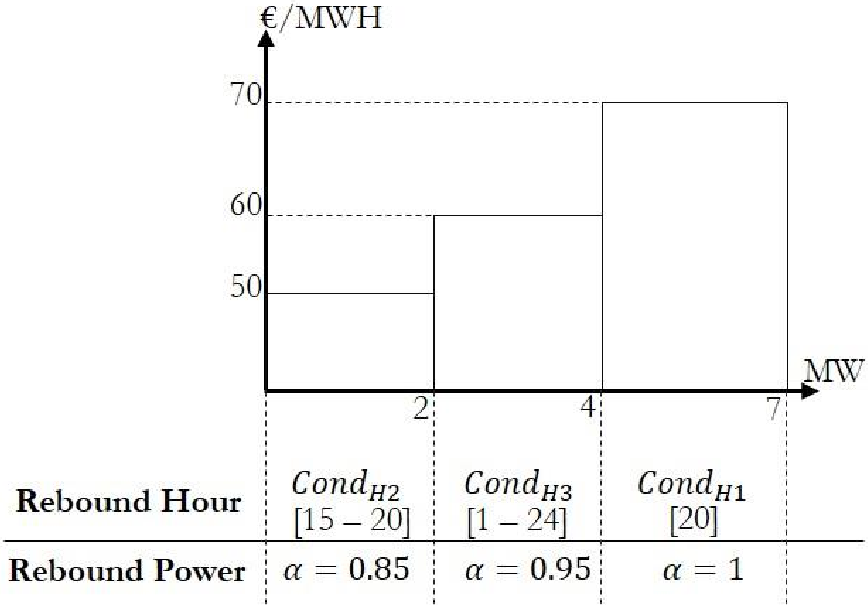


Figure 4.18 Aggregated flexibility bid for the illustrative example case.

4.6.1 DSO trading – illustrative example

As the Flex-DLM operator, the DSO clears the market and asks the aggregator for an amount of 2.5 MW of flexibility, which is the amount needed by the DSO to mitigate the coming-day congestion at hour 19. Thus, the individual flexibility activated from the first block is 2 MW and from the second block is 0.5 MW. Therefore, the DSO's cost of flexibility activation at node *n=5* at hour *t=19* follows equation (4.32), where the number of nodes $\mathrm{N^n}$ offering flexibility in the feeder is only one and the number of blocks $\mathrm{N^b_{n,t}}$ in the bid is three.

$$\mathrm{C^{F\_DA}_{5,19}} = \left[\sum_{k=1}^{3} \mathrm{F^{UREG/DREG}_{n,k,t}}\ \lambda^{\mathrm{UREG/DREG}}_{\mathrm{n,k,t}}\right] = [(2 \times 50) + (0.5 \times 60)] = 130\ € \tag{4.32}$$

4.6.2 Aggregator trading – illustrative example

As already explained, the aggregator needs to sell an amount of 2.5 MW (UREG flexibility), which is already included in the 12 MW bought in day-ahead market. In this case, the aggregator participates in intraday markets, to sell this amount at the corresponding prices of such markets, which is in this case 60 €/MWh. Thus, the balancing income is computed as in (4.33).

$$\mathrm{AggR^{UREG}_5} = \mathrm{F\_tot^{UREG}_{5,19}}\ \lambda^{\mathrm{adj}}_{19} = 2.5\ \times 60 = 150\ € \tag{4.33}$$

The final trading process carried by the aggregator is acquiring the rebound power for the activated consumers. The rebound power is also acquired from the adjustment market at its corresponding prices, which is assumed to be 70 €/MWh. It should be reminded that the rebound power in this case is constrained by the payback coefficients for the activated blocks. The cost for acquiring the payback power is calculated as in (4.34).

$$\mathrm{AggC^{PB}_5} = \left[\sum_{k=1}^{3} \alpha_{\mathrm{n,k}} \mathrm{F^{UREG}_{n,k,5}}\ \right]\lambda^{\mathrm{adj}}_{\mathrm{t}} = \ [(2 \times 0.85) + (0.5 \times 0.95)] \times 70 = \ 152.25\ € \tag{4.34}$$

The aggregator's final profit can be calculated as in (4.35), which should be transferred partly to the activated flexible customers. Based on the contractual agreement between the customers and the aggregator, it is necessary to incentivize customers to encourage their participation. It should be reminded that the detailed method of revenue sharing between the aggregator and the customers falls out of this thesis's scope. Besides being able to control the flexibility prices, thus gaining more profit, the aggregator can as well trade the consumption reduction and the payback power in the adjustment markets that will produce the maximum revenue and minimum cost. Therefore, it is of the aggregator's best interest, and the consumers also, to present the flexibility bids at competitive prices to maximize the final profit, considering the possibility that multiple aggregators can participate in the market.

$$\mathrm{Agg}_5^{\mathrm{UREG}} = \sum_{t=1}^{24}\left[\mathrm{C}_5^{\mathrm{F}} + \mathrm{AggR}_5^{\mathrm{UREG}} - \mathrm{AggC}_5^{\mathrm{PB}}\right] = [(130 + 150) - 152.25] = 127.75\ € \quad (4.35)$$

Equation (4.32) is used to calculate the DSO's total cost for procuring flexibility for the congestions that falls above the maximum probability level set by the DSO. However, for medium probability congestions, the RtU option is enabled for the DSO. In this case, the DSO reserves the option to use the flexibility bid by paying a reservation fee to the aggregator. For the congestion expected to occur at hour 13, with a probability of almost 64% according to Figure 4.17, we consider the same flexibility bid in Figure 4.18 and an RtU fee of 50 €. The RtU fees here ranges from 5% to 20% of the total cost of the offered flexibility [171]. If the DSO requires an amount of 1.5 MW to alleviate this congestion, then the total cost of flexibility reservation and activation can be calculated as in (4.36). It should be clarified that the DSO reserves an amount of 1.5 MW of flexibility in the DA Flex-DLM. In the real-time, when the DSO needs to activate this option, it does not need to enter the RT Flex-DLM to procure this amount again. However, it may enter the RT Flex-DLM to acquire more flexibility if the amount already reserved by the RtU option is not enough to mitigate the network congestion.

$$\mathrm{C}_5^{\mathrm{F\_RtU}} = \left[\sum_{k=1}^{3} \mathrm{F}_{n,k,t}^{\mathrm{UREG}}\ \lambda_{n,k,t}^{\mathrm{UREG}} + \lambda\_\mathrm{Rtu}_{n,t}^{\mathrm{UREG}}\right] = [(1.5 \times 50) + 50] = 125\ € \quad (4.36)$$

4.7 Assessment of the Flex-DLM

As explained in Chapter 2, several studies have presented market mechanisms for trading demand flexibility. While such studies are significant contributions, some important key factors were absent in the proposed models. The first factor has to do with grid power flow constraints. In general, the optimal operation of transmission and distribution networks is controlled by close monitoring of the power flow within the grid and the voltage levels at every node. Modelling the power flow constraints can be problematic due to its complexity. However, considering them is essential to realistically model the impact of demand flexibility activations at the distribution level.

One of the recent significant contributions is the work presented in [175], where a framework for demand response utilization that follows a decentralized approach was proposed. While the proposed framework considers the grid operation constraints, the payback effect and the uncertainty of generation and load profiles were left out of the model. Another decentralized approach for managing demand flexibility services in the distribution network was proposed in [176], where the DSO takes advantage of the flexibility services in the congestion management process. However, the work lacked the introduction of the payback effect, grid constraints and uncertainty. A local flexibility market dedicated to solve low voltage grid contingencies was proposed in [177]. In this market, the DSO receives flexibility bids (amounts and prices) based on the future grid problems forecasts. However, the market is cleared based on the offered prices only, without considering the technical impact of the bids cleared or the payback effect. A detailed flexibility market framework was introduced in [178], which operates in the day-ahead and real-time periods, without taking into account the grid operation constraints and the payback effect. In [179], an algorithm that optimizes the scheduling of flexible devices in the day-ahead and intra-day timeframes was proposed. The flexibility services modeled are aimed to serve other market agents such as BRPs or DSOs. Despite the valuable contribution of considering the uncertainty of flexible loads, the work does not consider the payback effect nor the grid constraints in the optimization process.

A detailed framework for demand flexibility modelling is introduced in [180], which as well does not consider the payback effect. Other real-time electricity markets dedicated to flexibility services transactions in the distribution level can be found in [181], [182]. Also, the rebound effect was absent in the proposals in [130], [132]. Another key factor that must be considered is that the forecasting capabilities in the day-ahead timeframe has its own limits. Thus, deviations in real-time operation are bound to happen. Such errors can affect the DSO in real-time as it may result in requiring more or less flexibility. This unpredictability must be taken in consideration. Also, the uncertainties behind the behavior of the consumers towards their commitment to the flexibility activation is an important issue that must not be discarded. Table 4.7 presents a comparison between the proposed Flex-DLM and the FLECH [132], [133] and DE-Flex-Market [130], [131] with respect to certain attributes.

Table 4.7 Comparing the features of Flex-DLM & other flexibility markets.

Attributes	FLECH	De-Flex-Market	Flex-DLM
Rebound Effect	*No*	*No*	*Yes*
Grid Constraints in market clearing	*No*	*No*	*Yes*
Operation periods	*Month or day*	*Month or shorter*	*Day-ahead & real-time*
Flexibility services offered	*Overload and overvoltage management*	*Not mentioned*	*Overload and overvoltage management*
Forecast errors consideration	*No*	*No*	*Yes*
Customers uncertainties	*No*	*No*	*Yes*

4.8 Summary

This chapter explained in detail the proposed Flex-DLM framework. The framework consists of two flexibility markets operating in the DA and RT periods, which allow the DSO to interact with the aggregators to procure demand flexibility according to its need. The DSO, as the Flex-DLM operator, is responsible for clearing the market and optimizing its cost of purchase, while considering the grid constraints and the rebound effect. While the Flex-DLM maybe simple in its format, it can be considered a mature and realistic consideration for what flexibility markets should be in the future. Moreover, it values the aggregator role in optimizing the usage of demand flexibility, and it does not require complex regulatory changes. Also, the Flex-DLM can fit into the TLC concept [127], specifically in the yellow stage, which corresponds to an alert state for the network that gives the system operator a chance to mitigate forthcoming network congestions using demand flexibility. In the following Chapter, case studies are carried out to ensure the validity of the proposed Flex-DLM and to show the value of flexibility services in the congestion management process.

5 CASE STUDIES

Based on what was explained in the previous chapters, demand flexibility services can become a valuable commodity to the DSO in its congestion management process. Moreover, it can present an alternative option to the need of network upgrades that is the common approach to facing potential demand growth in the network. In order to prove the worth of demand flexibility and to showcase the Flex-DLM framework proposed in the previous chapter, the framework is checked against several medium voltage distribution feeders obtained from a real distribution network located in the north center of Spain, specifically in the city of Cuéllar, as seen in Figure 5.1. These feeders are subjected to frequent congestions caused by various reasons, such as overloaded lines and overvoltages. The case studies carried out in this chapter are divided into two main parts:

- **Section 5.1:** The deterministic approach for modelling and solving the optimization process in the Flex-DLM will be the base for two distribution network feeders (details about algorithm explained in appendix) [286].
- **Section 5.2:** The probabilistic approach, where the uncertainty of demand, real-time frame and consumer's commitment will be considered for the last case study (details about algorithm explained in appendix) [287].

As already mentioned in Chapter 4, both approaches can be used in the framework of Flex-DLM. However, the decision of the best approach depends on the DSO's level of risk aversion, and also depends on the information that the DSO can acquire regarding the demand uncertainty and forecasting errors. The expected outcomes of the case studies chapter are as follows:

- Show how the flexibility products (UREG and DREG) can help the DSO in managing different types of distribution network congestions.
- Discuss the difference between using the probabilistic approach and the deterministic approach.
- Address the adjusting trading processes that are required to be carried out by the aggregator to ensure the delivery of the activated flexibility by the DSO.

- Illustrate the importance of considering the uncertainty of the customers' behavior when it comes to the commitment to the activation request and amount of flexibility needed.
- Discuss the impact of demand flexibility penetration level on the DSO's decision and final cost.

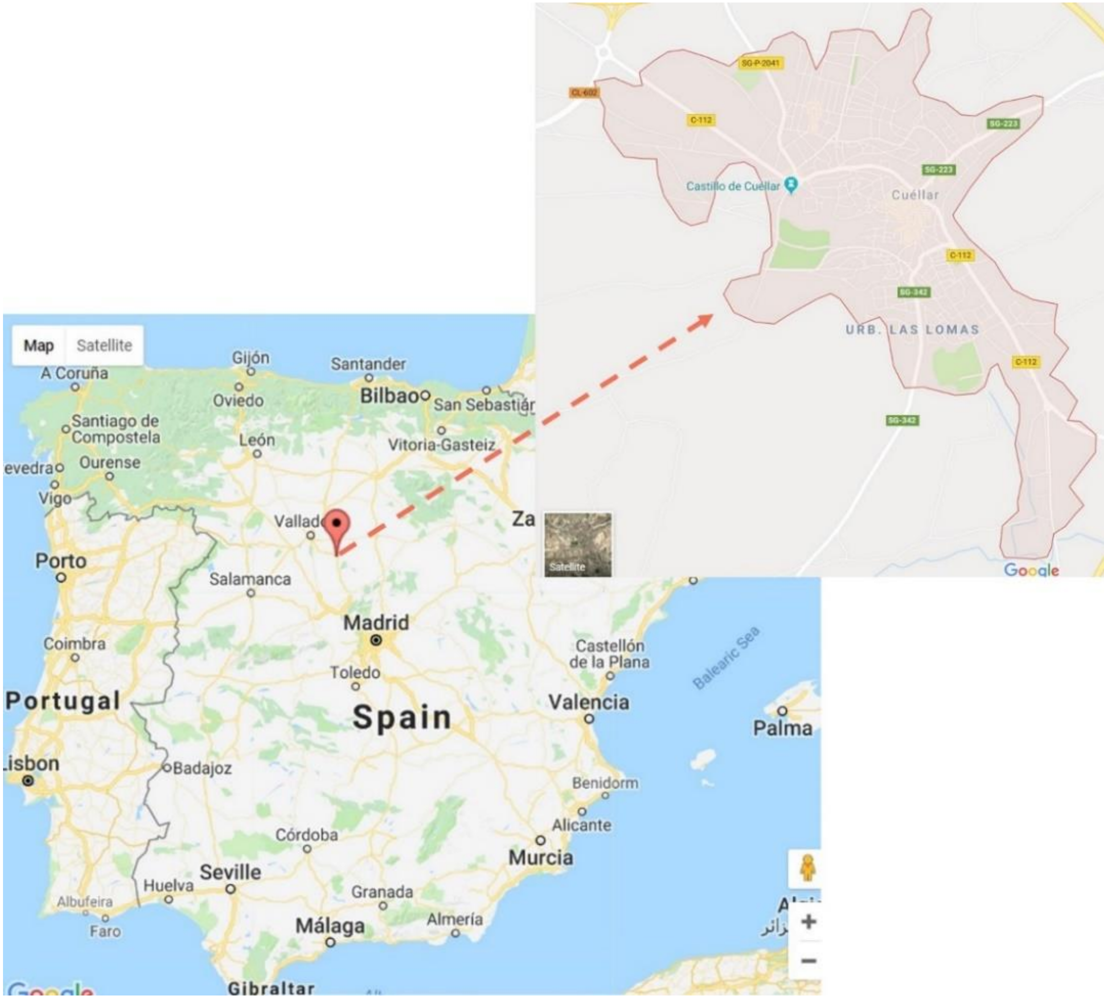


Figure 5.1 Location of the city Cuéllar in the map of Spain.

5.1 Deterministic approach

In this approach, the probabilistic assessment process proposed in Chapter 4 is not considered. The DSO calls for the Flex-DLM to solve potential congestion in the following day only relying on the MSA, which is the market solution assessment process. Here, two case studies are implemented to illustrate how UREG and DREG services can be of value to the DSO in two different scenarios. The first scenario is for a distribution feeder with high penetration of solar photovoltaic (PV) power, which can cause voltages in the network to exceed their limitations. The second scenario is for a feeder suffering from thermal congestions caused by network lines surpassing their nominal capacity. There are several other scenarios that can cause congestions at distribution networks that are not covered in this Chapter since the objective is to show how different types of flexibility services can be of value to the DSO. The real-life data obtained in the case studies here are only related to the overall capacities of the network lines, line parameters and the load consumptions of network. However, the detailed information regarding the types of customers at every node and their corresponding consumption are hard to acquire, as they require an already established communication infrastructure and data repositories, which was not available. Thus, some assumptions were made related to the types of customers, their corresponding loads at every node and the rebound conditions for every flexibility bid based on previous studies done in [44], [93], [307].

5.1.1 Case I: Feeder voltage management by DREG flexibility

Here, a small feeder of a distribution network in Spain operating at a 15-kV level is used. The feeder has 6 main buses: bus 1 is connected to the main grid while the load buses are 2, 3, 4 and 6. The grid's overall capacity is 6 MW and its topology is illustrated in Figure 5.2. The line parameters r and x, corresponding to the per-unit resistance and reactance considering a 100 MVA, 15 kV base are given in Table 5.1. Moreover, there is a solar PV plant connected at bus 6 with an installed capacity of 3.3 MW. The forecasted load demand and the solar PV production are illustrated in Figure 5.3. It should be noted that the forecasted solar PV production represents a typical sunny and cloudless day in the area of Cuéllar where the network exists. Also, the values presented in the graph correspond to the hourly average production and not to the instantaneous ones.

Based on the wholesale market solution assessment, the DSO identifies that in times of low load and high solar production, overvoltages are going to take place in the feeder. Generally, this overvoltage might force the system operators to install rather expensive equipment to control the voltage levels to avoid PV generation curtailment or promote the use of smart PV inverters [111]. Another solution could be the curtailment of PV, which is not a preferred approach in Spain, since renewable based generation are always given priority access in serving its output power. The solution proposed here is to use DREG flexibility (load increase volumes), which can decrease the difference between the high generation of PV and the load consumption and keep the voltage levels in the permissible limits. In this feeder, two buses are assumed to be connected to customers providing flexibility: bus 3 is feeding an industrial park and bus 4 is feeding a residential area of households. The voltage limits for the system are 1 ± 0.05 p.u. The expected hours according to the MSA to violate the voltage limits are hours 10, 11 and 12 with voltage levels reaching 1.051 p.u. Here hour 10 will be used to demonstrate the flexibility bids construction and evaluation.

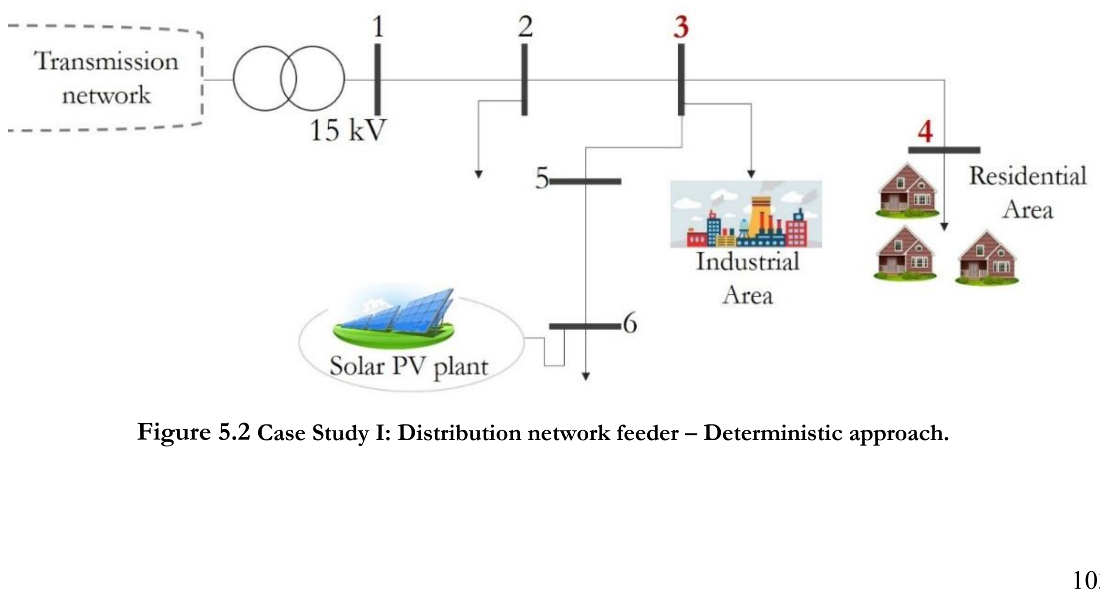


Figure 5.2 **Case Study I: Distribution network feeder – Deterministic approach.**

Table 5.1 Network line parameters.

Branch		r	x	Capacity
		p.u	p.u	MVA
5	3	0.02	0.210	8.31
4	3	0.02	0.193	8.30
5	6	0.02	0.295	8.30
2	3	0.02	0.270	8.60
1	2	0.03	0.968	8.60

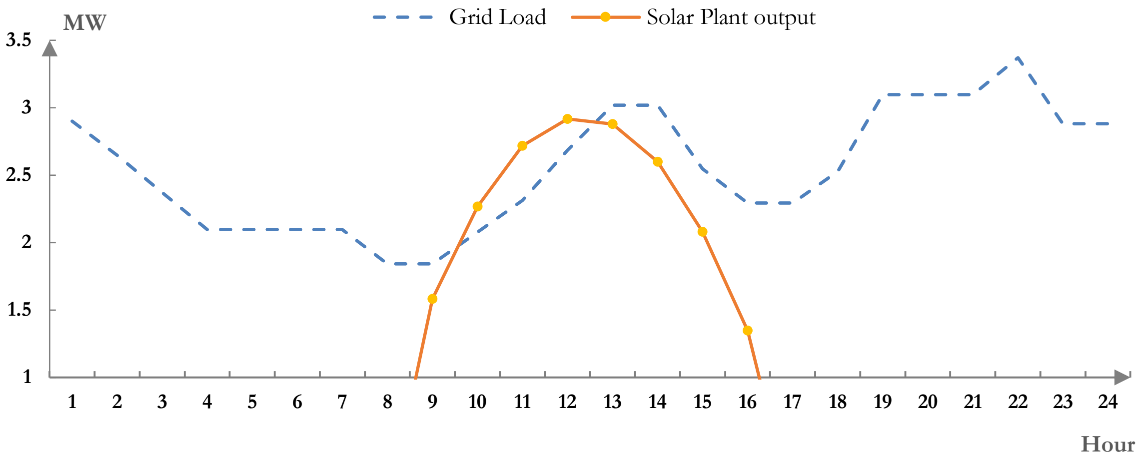


Figure 5.3 Forecasted load profile (MW) and PV solar production (MW).

The different nature of industrial and residential loads has a direct effect on the evaluation of the amount of DREG flexibility. In order to highlight these differences, every type of customer will be addressed separately to deliver a clear explanation of their effect.

- **Industrial customers**

Industrial customers are constrained by the characteristics of their loads such as productions rate and economic targets. The industrial park in the given network consists of several factories, which flexibility can be aggregated into four flexibility blocks. The factories have the capacity to deliver DREG flexibility because their normal operation is beneath their full capacity. The installed capacities of these factories were obtained from [44] and fit in the load profiles of the network feeder. The amount of DREG power offered by every process in the industrial park are calculated using equation (A.2) described in the appendix.

Table 5.2 presents the installed capacity for the factories considered and their loads at hour 10. Moreover, it illustrates the amount of DREG power, their corresponding prices and the rebound conditions which consists of the rebate factor and the time intervals for the rebate hour. The aggregated bids at that node contains 4 blocks of flexibility ordered in a non-decreasing manner according to their accompanied prices. The difference in prices between the factories, as seen in Table 5.2, can be justified as a measure of sensitivity to the changes in the operating plan. This means that blocks offered at low prices reflect less sensitive operation to the activation of DREG flexibility. For example, the flexibility offered by Fact_1 is less sensitive than that of Fact_2. This justifies that the rebound factor of Fact_2 is higher than that of Fact_1. In addition, it can be noticed that every factory is assigned to a single price. In reality, factories can be assigned to multiple prices according to the available flexibility they can offer and the sensitivity of their operation. However, assigning a single price per factory here does not affect the optimization problem nor the results.

Table 5.2 Industrial area flexibility at hour 10.

Aggregated bid	Block	$\mathbf{InstCap_{ind}}$	$\mathbf{Load_{ind,10}}$	$\mathbf{F^{DREG}_{n,10,MAX}}$	$\boldsymbol{\lambda^{DREG}_{n,10}}$	Rebound Conditions	
		MW	MW	MW	€/MWh	$\beta_{n,k,t}$	Rebate hour
$\mathbf{DRB_1}$	$\mathbf{Fact_1}$	0.314	0.104	0.210	67.26	0.8	7-16
	$\mathbf{Fact_2}$	0.353	0.160	0.193	71.65	0.90	9-15
	$\mathbf{Fact_3}$	0.712	0.417	0.295	72.79	0.95	12-20
	$\mathbf{Fact_4}$	0.390	0.120	0.270	73.05	1	16-21
Total	**Total**	**1.769**	**0.801**	**0.968**	-		

- **Residential customers**

The residential area connected to bus 4 is assumed to have direct load control systems installed at their side that allows the aggregators to directly control the flexible loads. Aggregators are capable of bundling all the different flexible loads and accordingly constructs flexible bids. The residential flexible loads used here are washing machines (WM), dryers (DRY), dishwashers (DW), refrigerators (RFG) and freezers (FRZ). Here, the aggregator bundles the flexibility of the residential customers into five groups, which are translated into five flexibility blocks, where every group or block consists of different number of appliances. The number of appliances per group and their installed capacities are given in Table 5.3. More appliances can exist in every flexibility block, but since the issue of aggregating and evaluating the specific flexibility that can be obtained from every single appliance is not the focus of this work, the given data in Table 5.3 are sufficient to carry out the case study.

The DREG power was calculated as explained in the appendix and the specific data used concerning the flexible appliances were obtained from [44], [307]. Moreover, it is expected that not all customers have the same standard of comfort level. While some are easily affected by flexibility activations, others can be less sensitive when their appliances are activated for flexibility. Therefore, the prices that the aggregators assign to the flexibility reflect the level of customers' sensitivity to change their consumption pattern. Group 1 is the least sensitive with the lowest rebound factor and group 5 is the highest sensitive with a unity rebound factor. Table 5.4 presents the total load of bus 4 at hour 10, the DREG power and prices for every flexible group.

The Flex-DLM is cleared by the DSO once the aggregated bids are offered. The activated bids should decrease the voltage magnitude levels of all buses to the allowable ranges, thus alleviating any voltage constraint. In addition, the rebound conditions of these bids must not cause further network constraints during the day-ahead operation. According to Figure 5.3, the amount of flexibility needed to match the forecasted solar PV output at hour 10 is 0.19 MW. The activated bids for hour 10 are illustrated in Figure 5.4. The DSO's optimal benefit will be activating an amount of 0.14 MW from the aggregated bid of the industrial area, which is only a part of the first block as shown in Figure 5.4 (a), and an amount of 0.06 MW from the aggregated residential bid, by full activation of the first 2 groups as seen in Figure 5.4 (b). The difference between the activated DREG power and the amount of flexibility originally needed accounts for the line losses that are taken into consideration within the formulation and the optimization procedure.

Table 5.3 Flexible residential appliances at every group in the bid.

Blocks	Flexible appliance	$InstCap_{res_{app}}$	Number of Units
		kW	#
1	WM	0.5	7
	DRY	3	5
	DW	1.5	4
	RFG	0.35	55
	FRZ	0.4	25
2	WM	0.5	6
	DRY	3	5
	DW	1.5	5
	RFG	0.35	45
	FRZ	0.4	20
3	WM	0.5	7
	DRY	3	5
	DW	1.5	4
	RFG	0.35	50
	WM	0.4	25
4	WM	0.5	9
	DRY	3	5
	DW	1.5	4
	RFG	0.35	60
	WM	0.4	40
5	WM	0.5	8
	DRY	3	4
	DW	1.5	5
	RFG	0.35	55
	WM	0.4	40

Table 5.4 Residential area flexibility at hour 10.

Aggregated bid	Block	$Load_{res,10}$	$F_{n,10,MAX}^{DREG}$	$\lambda_{n,10}^{DREG}$	Rebound Conditions	
		MW	MW	€/MWh	$\beta_{n,k,t}$	Rebate hour
DRB_2	Group 1	0.238	0.032	70.20	0.85	15-24
	Group 2		0.028	71.25	0.85	18-20
	Group 3		0.043	72.52	0.90	9-15
	Group 4		0.038	73.19	0.95	10-13
	Group 5		0.034	74.63	1	12-18
Total		-	**0.175**	-		

Table 5.5 summarizes the results of the Flex-DLM for the day-ahead operation for the 3 expected hours to suffer from overvoltage in the day-ahead operation and it provides the optimal hours for the rebate to take place. The number of the buses providing flexibility in this network is not large, therefore the complexity level here is not high and the computation time is short. However, this case study shows that DREG flexibility service can be a very useful tool for the DSO to counteract the rise of voltage levels due to the penetration of intermittent resources. Also, since the rebate power means a decrease in the load, the DSO prefers to shift it to hours when the peak is high. For example, the first block of DRB_1 is activated at hour 10, given that the rebate power can take place any time over the interval from 7 to 16, the DSO decides to move it to hour 16, which is one of the peak hours along this interval.

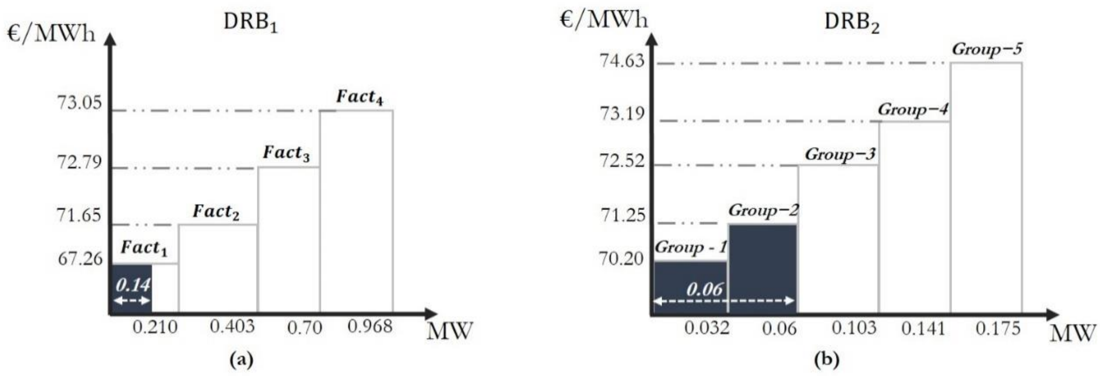


Figure 5.4 (a) Activated blocks in the aggregated industrial bid at hour 10; (b) Activated blocks in the aggregated residential bid at hour 10.

Table 5.5 DA Flex-DLM results for the day-ahead operation.

Aggregated bids	Blocks	Hour 10			Hour 11			Hour 12		
		$F_{n,10}^{DREG}$	C^{F_DA}	rebate	$F_{n,11}^{DREG}$	C^{F_DA}	rebate	$F_{n,12}^{DREG}$	C^{F_DA}	rebate
		MW	€	Hr	MW	€	Hr	MW	€	Hr
DRB_1	**$Fact_1$**	0.14	9.41	16	0.37	24.43	15	0.21	13.59	14
DRB_2	**Group 1**	0.032	2.24	20	0.022	1.56	21	0.013	0.94	22
	Group 2	0.028	2.00	19	0.028	1.83	20	0.017	1.33	18
Total		**0.20**	**13.65**	**-**	**0.42**	**27.82**	**-**	**0.24**	**15.86**	**-**

5.1.2 Case II: Feeder overload management by UREG flexibility

In the second case study, another distribution feeder is used which consists of 79 buses with an annual demand of 109.25 GWh operating at 15 kV voltage level. This part of the grid is rather large to include its topology here. Therefore, only the part needed for this case study is illustrated in Figure 5.5. Based on the MSA, the DSO expects an overload congestion at between nodes 14 and 10, i.e. line 14-10, during hours 19 and 20. The apparent power S, in MVA, expected at this line during the next day is given in Figure 5.6. Instead of upgrading the grid to accommodate this increase in the load, UREG flexibility can assist the DSO in managing the grid during the hours when the load is expected to surpass the grid's capacity. Hour 19 will be used to demonstrate the evaluation of UREG flexibility.

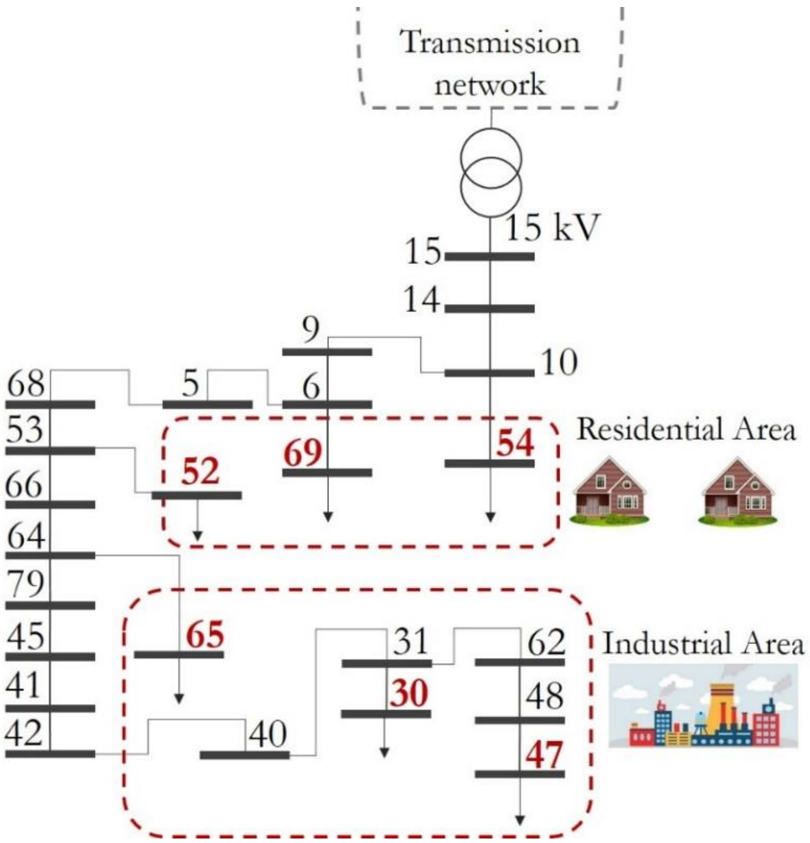


Figure 5.5 Case Study II: Distribution network feeder – Deterministic approach.

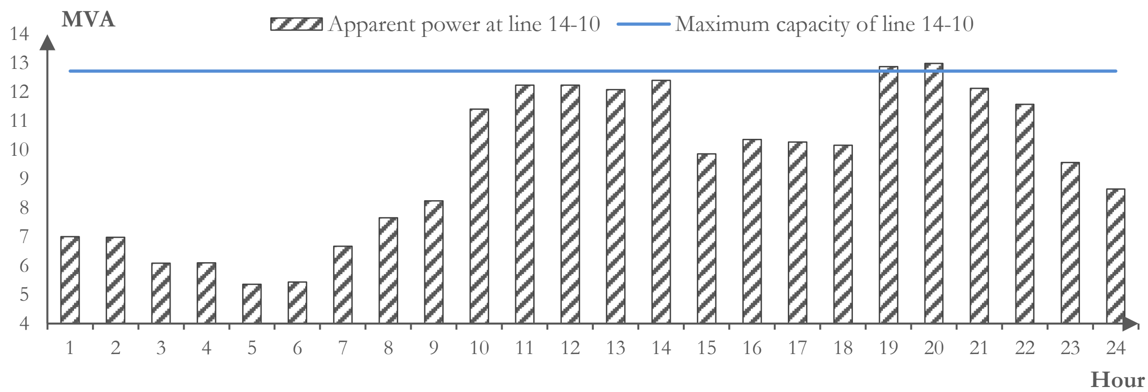


Figure 5.6 Apparent power at line 14-10 and the line maximum capacity (MVA).

There are two main areas in the feeder that can provide UREG flexibility, an industrial area and a residential area. The flexibility bids from each area can be obtained as follows.

- **Industrial customers**

The industrial area consists of 3 buses (30, 47 and 65), where every bus is feeding several industrial factories. The data regarding the factories used here were obtained from [44]. Table 5.6 presents the installed capacities for the factories, the loads at every bus at hour 19, and the UREG power and prices. Based on [44], industrial factories can have different preferences when it comes to the rebound conditions. Since the specific data concerning the industrial factories at this network are unavailable, the rebound conditions are assumed values.

Table 5.6 Industrial area flexibility at hour 19.

Aggregated bids	Bus	Block	$\mathbf{MaxLoad_{ind}}$	$\mathbf{Load_{ind,19}}$	$\mathbf{F^{UREG}_{n,19,MAX}}$	$\boldsymbol{\lambda^{UREG}_{n,19}}$	Rebound Conditions	
			MW	MW	MW	€/MWh	$\alpha_{n,k,t}$	Payback hour
$\mathbf{URB_1}$	30	$\mathbf{Fact_1}$	2.541	1.983	1.220	88.63	0.90	9-12
$\mathbf{URB_2}$	47	$\mathbf{Fact_2}$	0.628	0.477	0.080	86.71	0.90	15-20
		$\mathbf{Fact_3}$	0.781	0.497	0.120	90.54	0.95	12-18
		$\mathbf{Fact_4}$	1.425	1.014	0.089	98.19	0.95	17-20
$\mathbf{URB_3}$	65	$\mathbf{Fact_5}$	1.151	0.879	0.016	83.65	0.80	18-24
		$\mathbf{Fact_6}$	1.242	0.953	0.021	94.36	0.85	12-20
Total			**7.768**	**5.803**	**1.546**	-		

- **Residential customers**

The residential area is situated at buses 52, 54 and 69, where every bus has an aggregated flexibility bid with different number of blocks. Every block contains a number of aggregated flexible appliances from consumers sharing the same standard of comfort level and aggregated based on their sensitivity to the activation of flexibility. The aggregated flexibility bid from the residential customers consists of multiple load types from different households. The flexible appliances' installed capacity, number of units and flexible share percentage are given in Table 5.7 based on data obtained from [44], [307]. The UREG flexibility bids are illustrated in Table 5.8. Households with low comfort levels have their flexibility offered at lower prices than households with higher comfort levels. Similar to the industrial area, the rebound conditions for the flexibility bids are assumed in order to reflect the diversity that may arise from different flexibility appliances and to show its impact on the DSO's final decision. As already mentioned, the assumed rebound conditions do not undermine the case study, as they can be changed according to data availability.

Table 5.7 Flexible residential appliances at every group per bid.

Aggregated bids	Block	Flexible appliance	$\mathbf{InstCap_{res_{app}}}$	Number of Units	$\mathbf{Flex\_Share^{UREG}_{res\_unit,t}}$
			kW	#	%
$\mathbf{URB_4}$	1	**WM**	0.5	50	20
		FRZ	0.4	40	85
		RFG	0.35	50	85
	2	**RFG**	0.35	30	85
		FRZ	0.4	40	85
$\mathbf{URB_5}$	1	**WM**	0.5	150	20
		DRY	3	60	40
		DW	1.5	70	40
	2	**WM**	0.5	50	20
		EWH	2	10	100
		RFG	0.35	50	85
	3	**RFG**	0.35	40	85
		FRZ	0.4	30	85
$\mathbf{URB_6}$	1	**WM**	0.5	50	20
		DRY	3	50	40
		DW	1.5	50	40
	2	**RFG**	0.35	40	85
		FRZ	0.4	20	85

Table 5.8 Residential area flexibility at hour 19.

Aggregated bids	Bus	Block	$\mathbf{Load_{res,19}}$	$\mathbf{F^{UREG}_{n,19,MAX}}$	$\boldsymbol{\lambda^{UREG}_{n,19}}$	**Rebound Conditions**	
			MW	MW	€/MWh	$\alpha_{n,k,t}$	Payback hour
URB_4	**52**	**1**	1.943	0.135	85.18	1	12-16
		2		0.157	92.45	0.95	13-17
URB_5	**54**	**3**	1.619	0.111	88.63	0.90	10-15
		4		0.027	97.43	0.95	12-24
		5		0.129	98.19	1	9-16
URB_6	**69**	**6**	1.608	0.107	80.98	0.95	19-24
		7		0.026	81.20	1	18-22
Total			**5.17**	**0.692**	**-**		

It can be noticed that the UREG flexibility prices are higher than the DREG flexibility prices illustrated in the previous case, which emphasizes that the flexibility services prices are not related to the actual prices of the electricity markets. The difference in prices can be due to different contracting agreements, or the high level of competition between the aggregators at both networks. In reference to the deterministic approach described in the appendix, there are four feasible combinations of bids resulting from the first stage of the optimization process where their rebound conditions have not been checked. An example for two of these combinations of bids is shown in Figure 5.7. Even though the total amount of flexibility activated for all the possible combinations from stage 1 are almost equal, their rebound conditions are what determine the final result. The constraint of having specific time intervals for the payback power can limit the options on the DSO. Thus, after assessing the feasibility of the rebound conditions for all the combinations in the preliminary group, including the ones presented in Figure 5.7, it was found that the rebound conditions of some of them were causing further network congestions at hours 11 to 14.

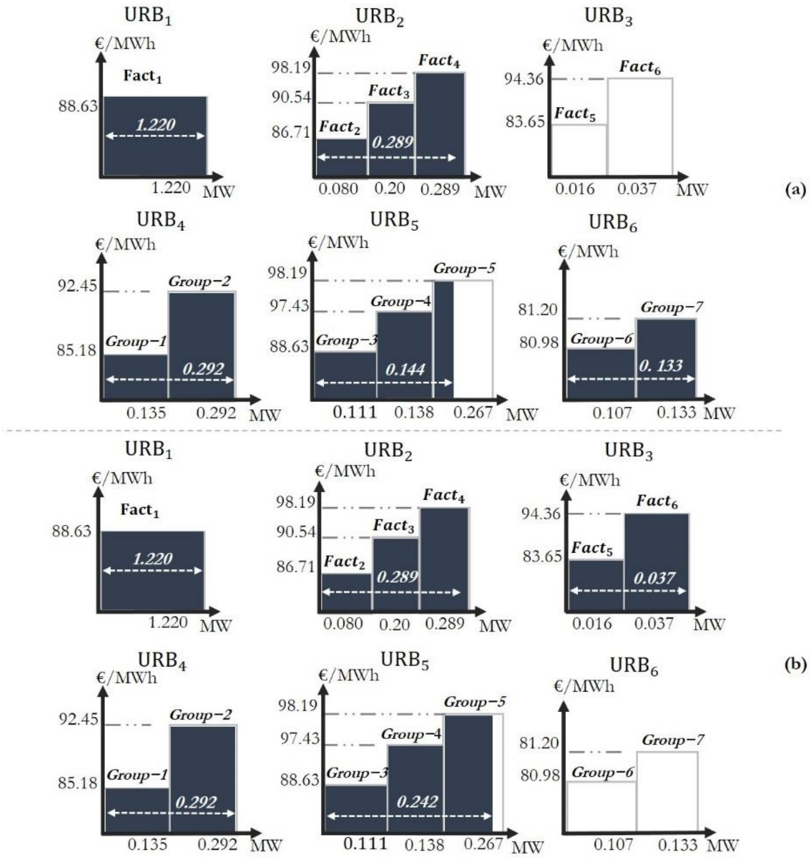


Figure 5.7 Possible feasible combination of bids resulting from stage 1 of optimization at hour 19.

The optimal combination of bids whose rebound conditions were found feasible is illustrated in Figure 5.8. In such combination, the whole flexibility offered in the first bid of the industrial area is activated, thus reducing the load by an amount of 1.220 MW, as seen in Figure 5.8 (a). Moreover, the flexibility from the second and third bids was activated with amounts corresponding to 0.284 MW and 0.037 MW respectively, as seen in Figure 5.8 (b) and (c). The first and third bids from the residential area were activated in full, with amounts corresponding to 0.292 MW and 0.133 MW, as illustrated in Figure 5.8 (d) and (f). Only the first block from the second residential bid was activated with an amount of 0.111 MW as shown in Figure 5.8 (e). The total amount of flexibility traded at this hour corresponds to 2.07 MW, which accounts to the amount of load reduction needed by the DSO to relieve the congestion of the overloaded lines within the grid, while considering the line losses. Table 5.9 sums up the market results at hour 19 and 20 respectively. It presents the amount of UREG flexibility traded from every bid with its corresponding cost and the optimal hour of payback for the activated bids.

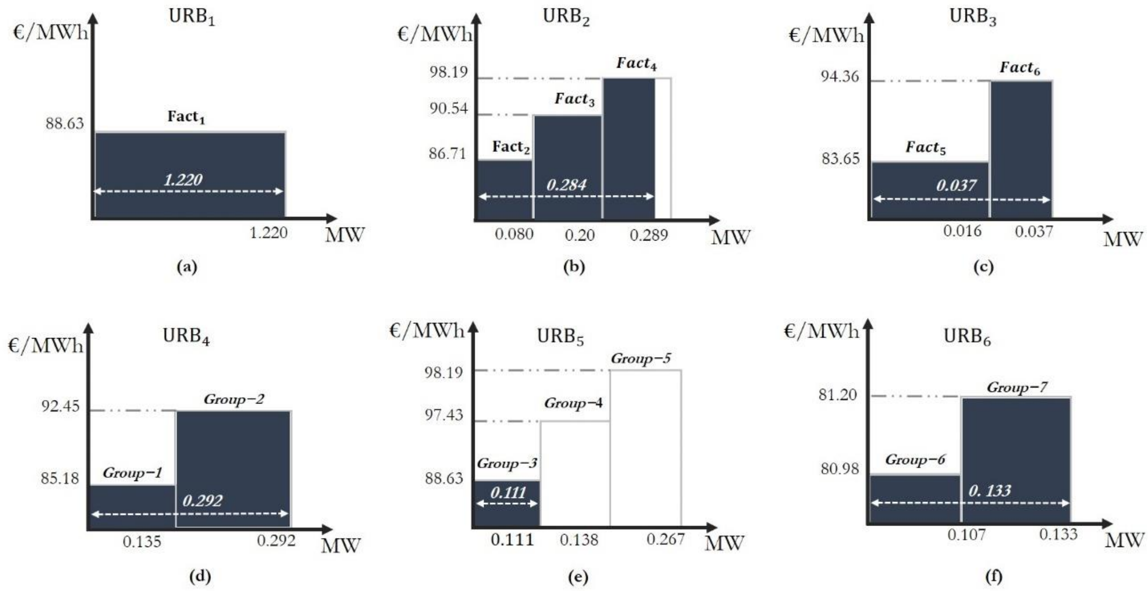


Figure 5.8 Activated blocks from the industrial (a,b,c) and residential aggregated bids (d,e,f) at hour 19.

Table 5.9 Flex-DLM results for day-ahead operation.

Aggregated bids	Block	Hour 19			Hour 20		
		$F_{n,19}^{UREG}$	C^{F_DA}	payback	$F_{n,20}^{UREG}$	C^{F_DA}	payback
		MW	€	Hr	MW	€	Hr
$\mathbf{URB_1}$	$\mathbf{Fact_1}$	1.220	108.21	9	1.326	119.87	9
$\mathbf{URB_2}$	$\mathbf{Fact_2}$	0.080	6.98	16	0.123	11.24	15
	$\mathbf{Fact_3}$	0.120	10.85	17	0.211	20.82	17
	$\mathbf{Fact_4}$	0.084	8.24	18	0.016	1.75	17
$\mathbf{URB_3}$	$\mathbf{Fact_5}$	0.016	1.34	18	0.099	8.52	18
	$\mathbf{Fact_6}$	0.021	1.99	16	0.111	11.13	17
$\mathbf{URB_4}$	**Group 1**	0.135	11.49	15	0.126	11.58	15
	Group 2	0.157	14.54	15	0.147	14.38	16
$\mathbf{URB_5}$	**Group 3**	0.111	9.84	16	0.104	9.64	15
$\mathbf{URB_6}$	**Group 6**	0.107	8.70	24	0.101	8.65	24
	Group 7	0.026	2.11	24	0.024	2.14	23
Total		**2.077**	**184.29**	**-**	**2.39**	**219.72**	**-**

As already explained in the appendix, an enumerative approach can be used for the first stage of the optimization problem, taking approximately 16 seconds to solve. However, the computation time decreases by 30% when the proposed GA searching tool is used, which takes 12 seconds to solve. Even though the given network has only 6 buses as sources of flexibility, the proposed optimization methodology is flexible to handle more buses offering flexibility, as explained in [288]. In reality, the DSO is expected to manage several feeders at the same time, where every feeder consists of hundreds of buses, which can increase the size of the optimization problem. Thus, an effective and time efficient optimization tool must be used to handle such complexity.

5.2 Probabilistic approach

In this approach, the PFA is taken into consideration by the DSO. This means that before calling for the Flex-DLM, the DSO carries out a probabilistic assessment to calculate the probabilities of congestion occurrence. The distribution feeder used in this case consists of 70 buses with an annual demand of 87 GWh operating at 15 kV level. Due to the large size of the feeder, only a part of it is illustrated as in Figure 5.9. This feeder suffers from frequent thermal congestions related to overloading on certain lines. Thus, the optimal type of flexibility that can be offered here is the UREG flexibility. It is considered that customers who can offer demand flexibility are connected to 6 different buses. As already described, the unavailability of the customers' information regarding their individual consumptions and types of flexible appliances makes it difficult to accurately quantify the specific demand flexibility that can be used at every node. In this approach, a different way was used to quantify the available flexibility from the consumers. Here we consider a 10% flexibility penetration level at the buses offering flexibility, which means that consumers can offer 10% of their load as flexibility to the DSO [286].

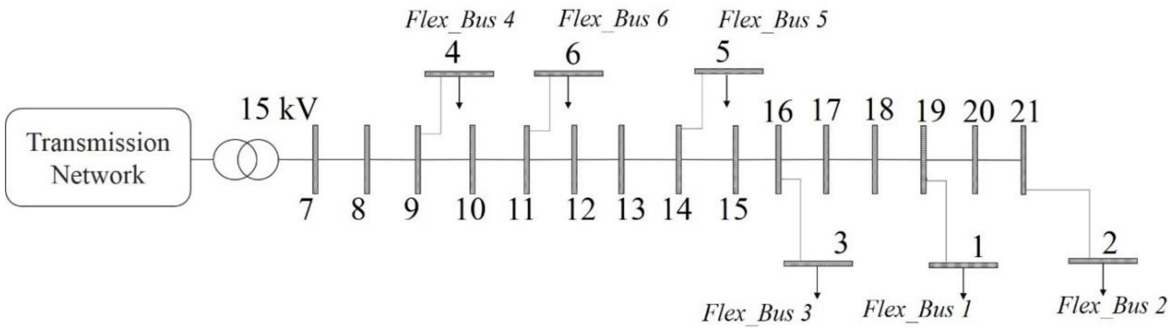


Figure 5.9 Case Study III: Distribution network feeder – Probabilistic approach.

5.2.1 Probabilistic assessment (Scenarios-generating tool)

In order to avoid entering the DA Flex-DLM and procuring unneeded flexibility, the DSO carries out a probabilistic analysis that considers historical data and forecasting tools with the purpose of valuing the probability of occurrence of such congestions. As already mentioned, probabilistic forecasting is still rarely available, especially at distribution level, and therefore it is difficult to have access to it. Hence, a method to produce the equivalent of the output of a probabilistic forecast has been devised. Instead of modelling a complicated forecasting algorithm, a scenario-generating method is implemented here, which generates possible scenarios for the demand. From a base trajectory (in our case the measured consumption in the feeder), a number of scenarios can be obtained for each time period t adding an error series with an accuracy similar to demand forecasting programs. In this case, a MAPE ranging between 5% and 10% has been considered. The error series was modelled using an autoregressive time series AR(1), as given in equation (5.1). The number of generated scenarios in this case study is 1000, which is sufficient to calculate the probability of congestion occurrence.

$$y_t = \phi\, y_{t-1} + \varepsilon r_t \tag{5.1}$$

In this equation, y is the error value added to the original trajectory and εr is the innovation (or white noise). The values of the parameter ϕ must be fit to get the wished properties of the series to be produced. This normalized error series must be scaled to the actual value of the consumption taking into account that the absolute error value depends on the consumption level along the day, i.e., larger when the consumption is higher and smaller when it is lower. This method can be used to produce as many synthesized forecasts as wished, and therefore, equiprobable trajectories around the basic production series can be obtained, having thus a multi-scenario prediction trajectory that can be used in probabilistic operational tools as the congestion management assessment. The median of all these scenarios will be taken as the point prediction if this is needed for a comparison study.

5.2.2 Day-ahead operation

In the wholesale electricity market, the generation and demand bids are submitted based on their respective forecasts for the following day. After the wholesale market is cleared, the DSO assess the technical feasibility of the market solution, i.e. MSA. In this assessment, the DSO finds that the network line between buses 7 and 8, i.e. line 7-8, is expected to be overloaded at hours 19, 20, 21 and 22. The apparent power S, in MVA, at this line during the whole day, based on the market solution, is given in Figure 5.10. It can be noticed that the apparent power at these hours surpasses the maximum allowable limit of the line. In order to ensure the need of obtaining flexibility services to solve the congestion at these hours, the DSO carries out the probabilistic forecasting assessment (PFA) by generating 1000 scenarios for the load consumption. Figure 5.11 shows the apparent power flow at line 7-8 for a sample of the generated scenarios.

Next, the DSO checks the technical feasibility of every scenario and calculates the probability of congestion occurrence at every hour during the coming day. Based on the probability levels, 90% and 40% respectively, set by the DSO, the congestions' probabilities are divided to high probability (almost certain to take place), medium probability (uncertain to take place) and congestions that can be ignored. The probabilities calculated at every hour across the day are illustrated in Figure 5.12. The PFA indicates that congestions at hours 19, 20, 21 and 22 have high probabilities of occurring, while congestions at hours 13 and 14 have medium probabilities. Based on the above analysis, two transaction processes take place, which are explained as follows.

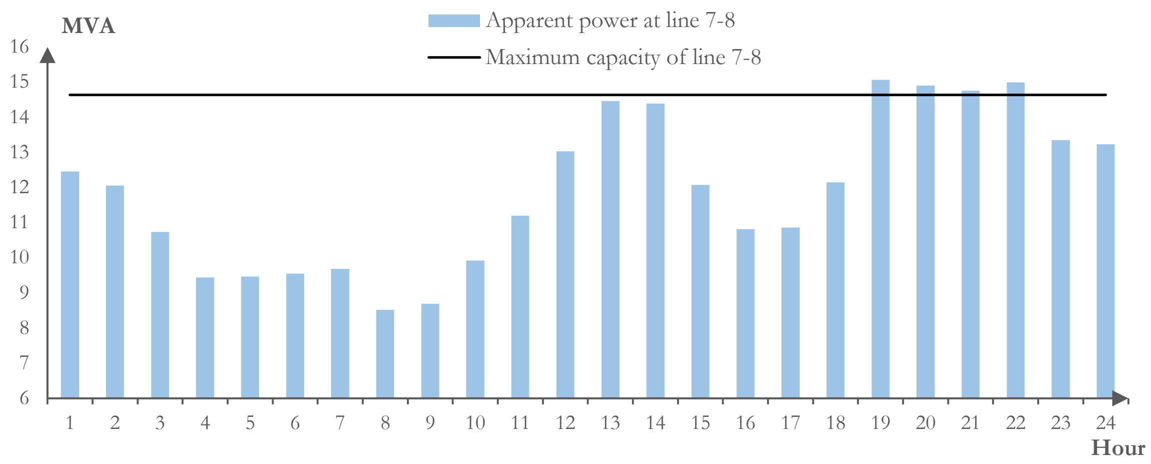


Figure 5.10 Apparent power at line 7-8 and the line maximum capacity (MVA).

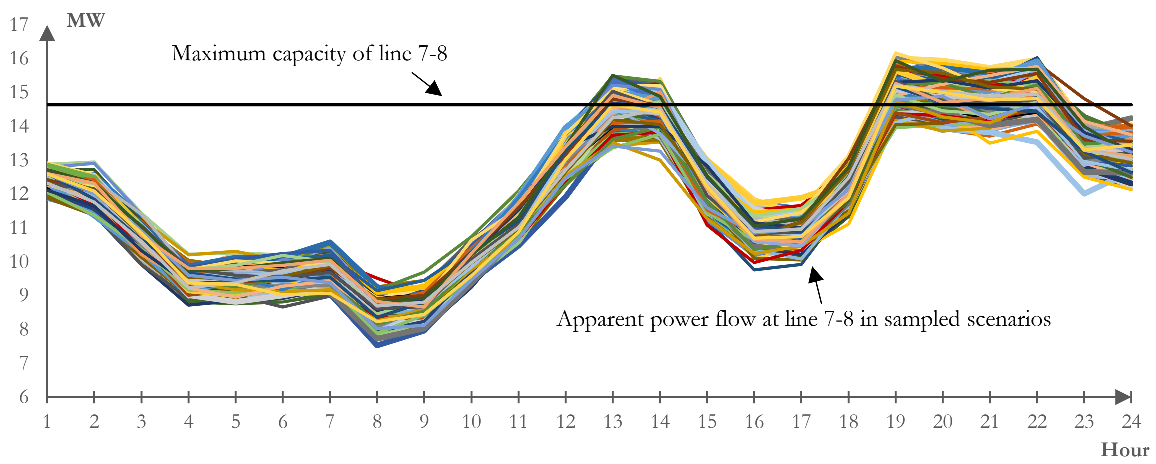


Figure 5.11 Apparent power at line 7-8 for a sample of generated scenarios and the line maximum capacity (MVA).

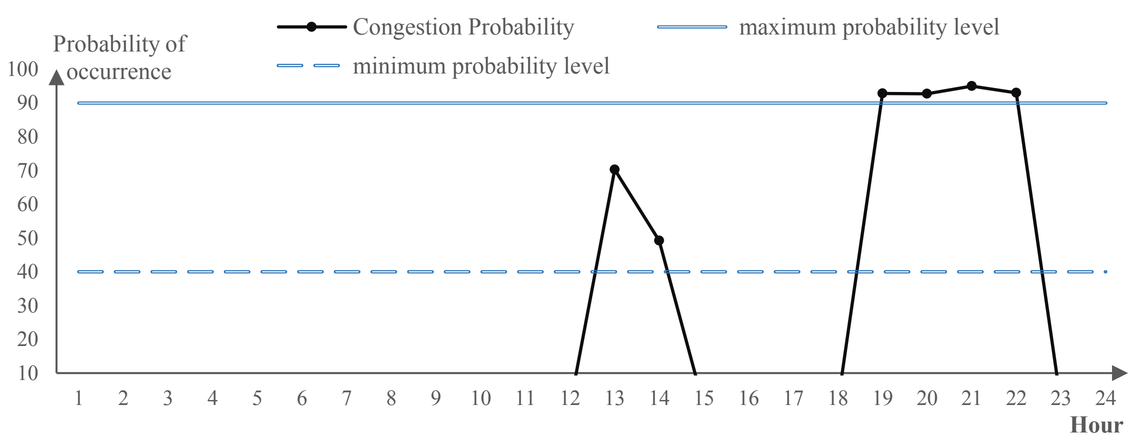


Figure 5.12 Probability of congestion occurrence and the DSO's risk level bounds.

- **Optimization process for the high probability congestions**

Both the MSA and PFA indicate that a congestion is expected to take place at hours 19, 20, 21 and 22, with high probability of occurrences, due to an overload in line 7-8 as seen in Figure 5.12. With such high certainty, the DSO calls for the DA Flex-DLM to procure the flexibility needed. As a result, all aggregators submit their flexibility bids, which can have several blocks depending on the number of consumers and types of flexible loads. The presented flexibility bids from the aggregators and the rebound conditions for the payback effect are shown in Tables 5.10, 5.11 and 5.12. It should be noted again that there could more complex conditions for the rebound conditions. The DSO, as the flexibility market operator, clears the DA Flex-DLM and the activated bids and the optimal payback hours are notified to the aggregator. Table 5.13 illustrates the activated bids during these hours, the optimal payback power and hour for every activated block per bid. Also, the total cost incurred by the DSO for firm flexibilities in the market, from all nodes, is computed to be 124 €. The total traded power for these transactions is 1.59 MW and the total payback power required by the customers is 1.46 MW. Figure 5.13 illustrates the original total load of the network, in MW, based on the wholesale market solution before any flexibility activation, and the new load schedule after the firm flexibility and payback scheduling for the high probable congestions take place in the DA Flex-DLM.

Table 5.10 URBs at buses 1 & 2 in the DA-Flex-DLM.

Hour	Flex_Bus 1		Flex_Bus 2					
	$F^{UREG}_{1,1,MAX}$ MW	$\lambda^{UREG}_{1,1,t}$ €/MWh	$F^{UREG}_{2,1,MAX}$ MW	$F^{UREG}_{2,2,MAX}$ MW	$F^{UREG}_{2,3,MAX}$ MW	$\lambda^{UREG}_{2,1,t}$ €/MWh	$\lambda^{UREG}_{2,2,t}$ €/MWh	$\lambda^{UREG}_{2,3,t}$ €/MWh
19	0.123	76.82	0.036	0.051	0.015	73.80	76.06	77.57
20	0.125	80.78	0.038	0.054	0.016	77.60	79.98	81.57
21	0.120	83.00	0.036	0.052	0.016	79.74	82.19	83.82
22	0.125	79.98	0.039	0.056	0.017	76.84	79.20	80.77
$\alpha_{n,k,t}$	0.85	-	0.80	0.95	0.70		-	
Payback hour	1-24	-	13-24	1-16	17-24		-	

Table 5.11 URBs at buses 3 & 4 in the DA-Flex-DLM.

Hour	Flex_Bus 3				Flex_Bus 4					
	$F^{UREG}_{3,1,MAX}$ MW	$F^{UREG}_{3,2,MAX}$ MW	$\lambda^{UREG}_{3,1,t}$ €/MWh	$\lambda^{UREG}_{3,2,t}$ €/MWh	$F^{UREG}_{4,1,MAX}$ MW	$F^{UREG}_{4,2,MAX}$ MW	$F^{UREG}_{4,3,MAX}$ MW	$\lambda^{UREG}_{4,1,t}$ €/MWh	$\lambda^{UREG}_{4,2,t}$ €/MWh	$\lambda^{UREG}_{4,3,t}$ €/MWh
19	0.022	0.065	72.29	76.06	0.030	0.050	0.020	72.29	73.80	78.33
20	0.023	0.069	76.02	79.98	0.027	0.045	0.018	76.02	77.60	82.36
21	0.022	0.067	78.11	82.19	0.026	0.044	0.018	78.11	79.74	84.63
22	0.024	0.072	75.27	79.20	0.027	0.045	0.018	75.27	76.84	81.55
$\alpha_{n,k,t}$	0.82	0.95	-		0.90	0.95	0.80	-	0.90	0.95
Payback hour	12-20	6-16	-		8-13	9-18	1-24	-	8-13	9-18

Table 5.12 URBs at buses 5 & 6 in the DA-Flex-DLM.

Hour	Flex_Bus 5				Flex_Bus 6			
	$F^{UREG}_{5,1,MAX}$ MW	$F^{UREG}_{5,2,MAX}$ MW	$\lambda^{UREG}_{5,1,t}$ €/MWh	$\lambda^{UREG}_{5,2,t}$ €/MWh	$F^{UREG}_{6,1,MAX}$ MW	$F^{UREG}_{6,2,MAX}$ MW	$\lambda^{UREG}_{6,1,t}$ €/MWh	$\lambda^{UREG}_{6,2,t}$ €/MWh
19	0.066	0.054	76.82	77.57	0.035	0.065	76.06	76.82
20	0.060	0.049	80.78	81.57	0.032	0.059	79.98	80.78
21	0.058	0.047	83.00	83.82	0.031	0.057	82.19	83.00
22	0.059	0.049	79.98	80.77	0.032	0.059	79.20	79.98
$\alpha_{n,k,t}$	0.88	0.92	-		0.94	1.00	-	
Payback hour	1-24	12-16	-		1-24	1-24	-	

Table 5.13 Market solution for DA-Flex-DLM for the highly probable congestions.

Firm Flexibility (MW)		$F_{1,1,t}^{UREG}$	$F_{2,1,t}^{UREG}$	$F_{2,2,t}^{UREG}$	$F_{2,3,t}^{UREG}$	$F_{3,1,t}^{UREG}$	$F_{3,2,t}^{UREG}$	$F_{4,1,t}^{UREG}$	$F_{4,2,t}^{UREG}$	$F_{4,3,t}^{UREG}$	$F_{5,1,t}^{UREG}$	$F_{5,2,t}^{UREG}$	$F_{6,1,t}^{UREG}$	$F_{6,2,t}^{UREG}$
Hour	*19*	0.123	0.036	0.051	-	0.022	0.065	0.030	0.050	-	0.066	-	0.035	0.056
	20	-	0.038	0.054	-	0.023	0.069	0.027	0.045	-	0.060	-	0.032	0.043
	21	-	0.036	0.052	-	0.022	0.067	0.026	0.044	-	-	-	0.022	-
	22	-	0.039	0.056	-	0.024	0.072	0.027	0.045	-	0.039	-	0.032	0.059
Payback power (MW)		$P_{1,1,t}^{PB}$	$P_{2,1,t}^{PB}$	$P_{2,2,t}^{PB}$	$P_{2,3,t}^{PB}$	$P_{3,1,t}^{PB}$	$P_{3,2,t}^{PB}$	$P_{4,1,t}^{PB}$	$P_{4,2,t}^{PB}$	$P_{4,3,t}^{PB}$	$P_{5,1,t}^{PB}$	$P_{5,2,t}^{PB}$	$P_{6,1,t}^{PB}$	$P_{6,2,t}^{PB}$
Hour	*9*	-	-	-	-	-	-	0.020	-	-	-	-	-	-
	10	-	-	-	-	-	-	0.030	-	-	-	-	-	-
	11	-	-	0.035	-	-	0.044	0.030	-	-	-	-	-	-
	12	-	-	0.056	-	-	0.072	0.030	-	-	-	-	-	-
	13	-	-	-	-	0.006	-	-	-	-	-	-	-	-
	14	-	0.039	-	-	0.024	-	-	-	-	-	-	-	-
	15	-	-	0.056	-	-	0.072	-	0.025	-	-	-	-	-
	16	-	-	0.056	-	-	0.072	-	0.050	-	-	-	-	-
	17	-	-	-	-	0.021	-	-	0.050	-	-	-	0.009	-
	18	-	0.002	-	-	0.024	-	-	0.050	-	0.013	-	0.035	0.028
	23	-	0.039	-	-	-	-	-	-	-	0.066	-	0.035	0.065
	24	0.104	0.039	-	-	-	-	-	-	-	0.066	-	0.035	0.065
C^{F_DA}(€)								**124**						

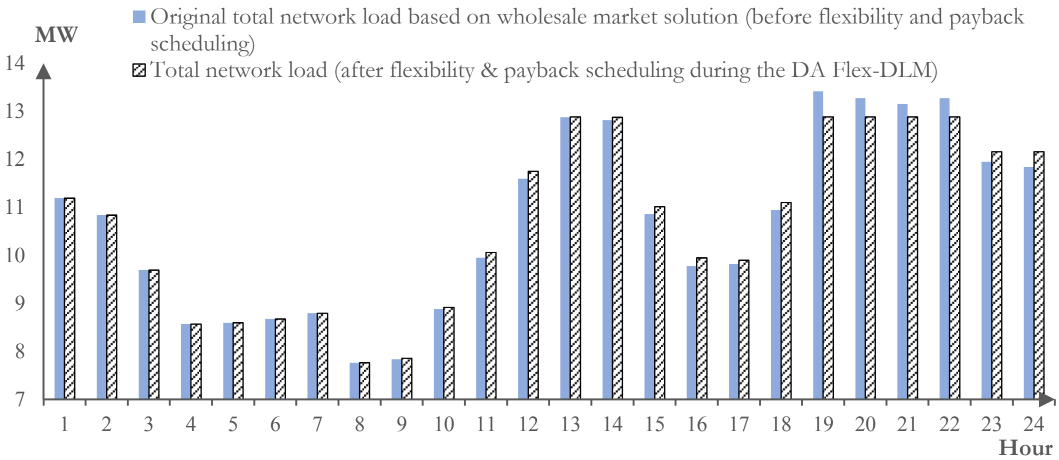


Figure 5.13 Original total network load before and after firm flexibility and payback scheduling during the DA period (MW)

- **Optimization process for the medium probability congestions**

According to the PFA, congestions at hours 13 and 14 have medium probabilities of taking place with values of 70.2% and 49.2% respectively. Since the preliminary MSA carried out by the DSO did not indicate any congestions during those hours, the DSO choses to purchase the RtU option and reserves a specific amount of flexibility that could be used during the real-time if such congestions finally taking place. In the given distribution feeder, only three buses, 2, 4 and 6, are capable of providing the RtU option and flexibility during these hours. Tables 5.14 and 5.15 illustrate the flexibility bids at both hours and the RtU fee per bid and block. The values for the RtU fee per block are assumed to be 20% of the total cost of activating the block. It should be noted that since the flexibility activation is not guaranteed in this case, the payback power cannot be scheduled at this point in time. The reserved amounts for every bid are illustrated in Table 5.16. The total amount is equal to 0.37 MW, and the total cost for reserving this quantity is 6.73 €.

Table 5.14 URBs at buses 2 & 4 in the DA-Flex-DLM.

Hour	Flex_Bus 2						Flex_Bus 4					
	$F_{2,1,MAX}^{UREG}$ MW	$F_{2,2,MAX}^{UREG}$ MW	$F_{2,3,MAX}^{UREG}$ MW	$\lambda_{2,1,t}^{UREG}$ €/MWh	$\lambda_{2,2,t}^{UREG}$ €/MWh	$\lambda_{2,3,t}^{UREG}$ €/MWh	$F_{4,1,MAX}^{UREG}$ MW	$F_{4,2,MAX}^{UREG}$ MW	$F_{4,3,MAX}^{UREG}$ MW	$\lambda_{4,1,t}^{UREG}$ €/MWh	$\lambda_{4,2,t}^{UREG}$ €/MWh	$\lambda_{4,3,t}^{UREG}$ €/MWh
13	0.046	0.053	0.020	85.22	85.50	85.68	0.035	0.042	0.037	85.04	85.22	85.77
14	0.046	0.052	0.020	89.40	89.68	89.87	0.034	0.041	0.036	89.21	89.40	89.97
$\lambda\_RtU_{n,k,13}^{UREG}$ (€)	-			0.78	0.90	0.34	-			0.59	0.72	0.64
$\lambda\_RtU_{n,k,14}^{UREG}$ (€)	-			0.82	0.94	0.35	-			0.60	0.73	0.65

Table 5.15 URBs at buses 6 in the DA-Flex-DLM.

Hour	Flex_Bus 6			
	$F_{6,1,MAX}^{UREG}$ MW	$F_{6,2,MAX}^{UREG}$ €/MWh	$\lambda_{6,1,t}^{UREG}$ €/MWh	$\lambda_{6,2,t}^{UREG}$ €/MWh
13	0.041	0.060	85.50	85.59
14	0.039	0.058	89.68	89.78
$\lambda\_RtU_{n,k,13}^{UREG}$ (€)	-		0.69	1.02
$\lambda\_RtU_{n,k,14}^{UREG}$ (€)	-		0.71	1.04

Table 5.16 Market solution for DA-Flex-DLM for the medium probability congestions.

Flexibility reserved (MW)		$F_{2,1,t}^{UREG}$	$F_{2,2,t}^{UREG}$	$F_{2,3,t}^{UREG}$	$F_{4,1,t}^{UREG}$	$F_{4,2,t}^{UREG}$	$F_{4,3,t}^{UREG}$	$F_{6,1,t}^{UREG}$	$F_{6,2,t}^{UREG}$
Hour	*13*	0.047	0.054	0.020	0.035	0.042	-	0.024	-
	14	0.046	0.052	0.020	0.034	-	-	-	-
Reservation cost (€)		**6.73**							

5.2.3 Real-time operation

During the real-time operation, deviations between the expected network load and the actual consumption are inevitable. As already explained in Chapter 4, the DSO checks the feasibility of the network for every coming hour. In real-time, forecasting network consumption on hourly basis is of high accuracy. As a result, the DSO's validation process at hour 11 forecasts an increase in the total network load at hour 12 reaching 13.5 MW, as opposed to 11.59 MW which was the original expectation based on the market solution. As a result, one of the network branches will be congested. Since the PFA and MSA carried out at the previous day did not indicate any expectancy for a congestion during hour 12, the DSO did not consider any precautions for such congestion. However, to avoid this congestion, the DSO calls for RT Flex-DLM at hour 11 to procure the needed flexibility. Considering the same payback hour conditions, the hour preferences will be adjusted in the optimization problem to ensure that the payback hour takes place after the flexibility is activated, i.e. from hour 13 to the end of the operation period. At hour 12, all six buses are capable of providing demand flexibility. Tables 5.17, 5.18 and 5.19 present the flexibility bids. The flexibility prices here are assumed to be higher than in the DA Flex-DLM due to the short time notice of activating the flexibility. The solution of the RT Flex-DLM is presented in Table 5.20, where the activated flexibility bids are shown, together with the optimal payback power and hour for every block. Also, the total cost for flexibility services during the real-time period is 51.26 € for a total trading amount of flexibility equal to 0.475 MW.

Table 5.17 URBs at buses 1 & 2 in the RT Flex-DLM for sudden congestions.

Hour	Flex_Bus 1		Flex_Bus 2					
	$F_{1,1,MAX}^{UREG}$ MW	$\lambda_{1,1,t}^{UREG}$ €/MWh	$F_{2,1,MAX}^{UREG}$ MW	$F_{2,2,MAX}^{UREG}$ MW	$F_{2,3,MAX}^{UREG}$ MW	$\lambda_{2,1,t}^{UREG}$ €/MWh	$\lambda_{2,2,t}^{UREG}$ €/MWh	$\lambda_{2,3,t}^{UREG}$ €/MWh
12	0.081	98.59	0.052	0.074	0.022	97.14	98.22	98.95
$\alpha_{n,k,t}$	0.85	-	0.80	0.95	0.70		-	
Payback hour	10-24	-	13-24	10-16	17-24		-	

Table 5.18 URBs at buses 3 & 4 in the RT Flex-DLM for sudden congestions.

Hour	Flex_Bus 3				Flex_Bus 4					
	$F_{3,1,MAX}^{UREG}$ MW	$F_{3,2,MAX}^{UREG}$ MW	$\lambda_{3,1,t}^{UREG}$ €/MWh	$\lambda_{3,2,t}^{UREG}$ €/MWh	$F_{4,1,MAX}^{UREG}$ MW	$F_{4,2,MAX}^{UREG}$ MW	$F_{4,3,MAX}^{UREG}$ MW	$\lambda_{4,1,t}^{UREG}$ €/MWh	$\lambda_{4,2,t}^{UREG}$ €/MWh	$\lambda_{4,3,t}^{UREG}$ €/MWh
12	0.028	0.085	96.42	98.22	0.031	0.052	0.021	96.42	97.14	99.31
$\alpha_{n,k,t}$	0.82	0.95	-		0.90	0.95	0.80		-	
Payback hour	12-20	10-16	-		10-13	10-18	10-24		-	

Table 5.19 URBs at buses 5 & 6 in the in the RT Flex-DLM for sudden congestions.

Hour	Flex_Bus 5				Flex_Bus 6			
	$F_{5,1,MAX}^{UREG}$ MW	$F_{5,2,MAX}^{UREG}$ MW	$\lambda_{5,1,t}^{UREG}$ €/MWh	$\lambda_{5,2,t}^{UREG}$ €/MWh	$F_{6,1,MAX}^{UREG}$ MW	$F_{6,2,MAX}^{UREG}$ MW	$\lambda_{6,1,t}^{UREG}$ €/MWh	$\lambda_{6,2,t}^{UREG}$ €/MWh
12	0.051	0.042	98.59	98.95	0.024	0.045	98.22	98.59
$\alpha_{n,k,t}$	0.88	0.92	-		0.94	1.00	-	
Payback hour	10-24	12-16	-		10-24	10-24	-	

Table 5.20 Market solution for RT Flex-DLM for a sudden congestion at hour 12.

Firm Flexibility (MW)		$\mathbf{F_{1,1,t}^{UREG}}$	$\mathbf{F_{2,1,t}^{UREG}}$	$\mathbf{F_{2,2,t}^{UREG}}$	$\mathbf{F_{2,3,t}^{UREG}}$	$\mathbf{F_{3,1,t}^{UREG}}$	$\mathbf{F_{3,2,t}^{UREG}}$	$\mathbf{F_{4,1,t}^{UREG}}$	$\mathbf{F_{4,2,t}^{UREG}}$	$\mathbf{F_{4,3,t}^{UREG}}$	$\mathbf{F_{5,1,t}^{UREG}}$	$\mathbf{F_{5,2,t}^{UREG}}$	$\mathbf{F_{6,1,t}^{UREG}}$	$\mathbf{F_{6,2,t}^{UREG}}$
Hour	*12*	0.062	0.052	0.074	-	0.028	0.085	-	0.052	-	0.051	-	0.024	0.045
Payback power (MW)		$\mathbf{P_{1,1,t}^{PB}}$	$\mathbf{P_{2,1,t}^{PB}}$	$\mathbf{P_{2,2,t}^{PB}}$	$\mathbf{P_{2,3,t}^{PB}}$	$\mathbf{P_{3,1,t}^{PB}}$	$\mathbf{P_{3,2,t}^{PB}}$	$\mathbf{P_{4,1,t}^{PB}}$	$\mathbf{P_{4,2,t}^{PB}}$	$\mathbf{P_{4,3,t}^{PB}}$	$\mathbf{P_{5,1,t}^{PB}}$	$\mathbf{P_{5,2,t}^{PB}}$	$\mathbf{P_{6,1,t}^{PB}}$	$\mathbf{P_{6,2,t}^{PB}}$
Hour	*16*	-	-	-	-	-	0.081	-	-	-	-	-	-	-
	17	-	-	-	-	-	-	-	-	-	-	-	-	-
	18	0.053	0.041	0.070	-	-	-	-	0.050	-	0.045	-	0.023	0.045
	20	-	-	-	-	0.023	-	-	-	-	-	-	-	-
$\mathbf{C^{F\_RT}}$ **(€)**		**51.26**												

Apart from the sudden congestion at hour 12, the DSO also detects that the congestions with medium probabilities at hours 13 and 14 are going to take place. Therefore, the DSO will call upon the RtU option and, since no more flexibility is required, there is no need to call for the RT Flex-DLM. Table 5.21 provides the optimal payback power and hours for the activated flexibility bids, as well as the cost for activating the flexibility, which is 30.5 €. Thus, the total cost incurred by the DSO for reserving and activating the RtU option, will be 37.23 €, which is the sum of the RtU fees, paid in the DA Flex-DLM, and the cost of activating the flexibility in the real-time period. It should be noted that the payback power could be pushed to the following day of operation if it is more feasible to the DSO and convenient to the flexibility provider, however, this assumption is not considered here. After all flexibility activations and payback power take place (from DA Flex-DLM and RT Flex-DLM), the final load profile is illustrated in Figure 5.14 against the original network load profile.

In the Flex-DLM framework, the cash flow and all trading processes carried out in the case study are depicted in Figure 5.15. The trading processes carried out by the aggregator and other agents in adjustment markets are as well described, where the prices are taken from the Spanish intra-day market [308]. Based on all transactions, the total cost of flexibility activation for the DSO is 212.49 €, which translates to a revenue for the aggregator. Regarding the aggregator, after carrying out all necessary trading processes to deliver the required flexibility across all markets, the total revenue for selling the energy consumption, corresponding to the activated flexibility, and the total cost for acquiring the payback power for all activated flexibility are 133.40 € and 119.65 €, respectively. Therefore, the aggregators' net profit will sum up to 226.23 €.

Table 5.21 Payback hours for activated flexibility bids reserved by the RtU option for hours 13 and 14.

Payback power (MW)		**Flex_Bus 2**			**Flex_Bus 4**			**Flex_Bus 6**	
		$\mathbf{P_{2,1,t}^{PB}}$	$\mathbf{P_{2,2,t}^{PB}}$	$\mathbf{P_{2,3,t}^{PB}}$	$\mathbf{P_{4,1,t}^{PB}}$	$\mathbf{P_{4,2,t}^{PB}}$	$\mathbf{P_{4,3,t}^{PB}}$	$\mathbf{P_{6,1,t}^{PB}}$	$\mathbf{P_{6,2,t}^{PB}}$
Hour	*17*	0.038	0.043	0.016	0.028	0.034	-	0.019	-
	18	0.037	0.042	0.016	0.027	-	-	-	-
Activation cost (€)		**30.5**							
$\mathbf{C^{F\_RU}}$ **(€)**		**37.23**							

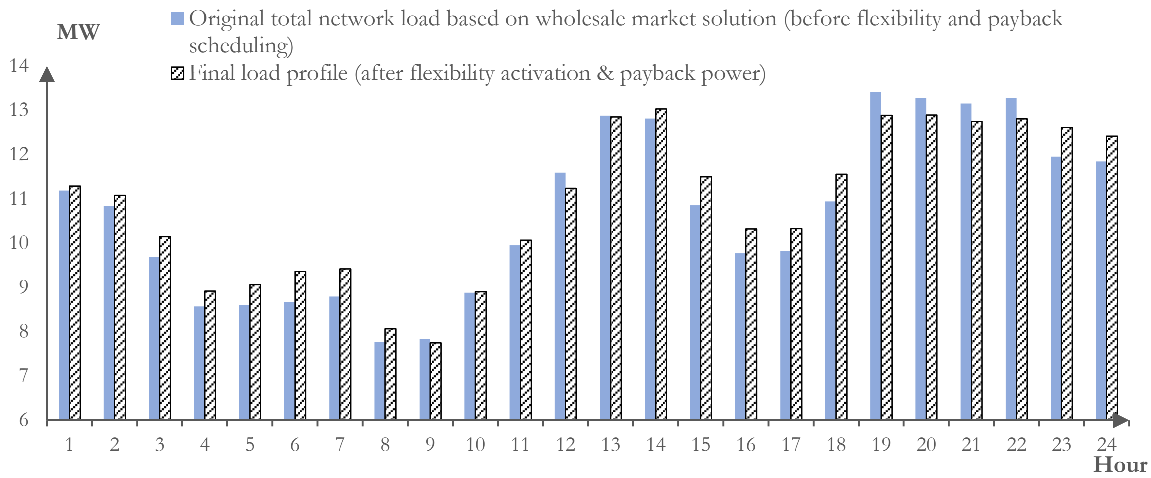


Figure 5.14 Total network load before flexibility and payback scheduling and the final load profile at the end of the operation day after all activations (MW).

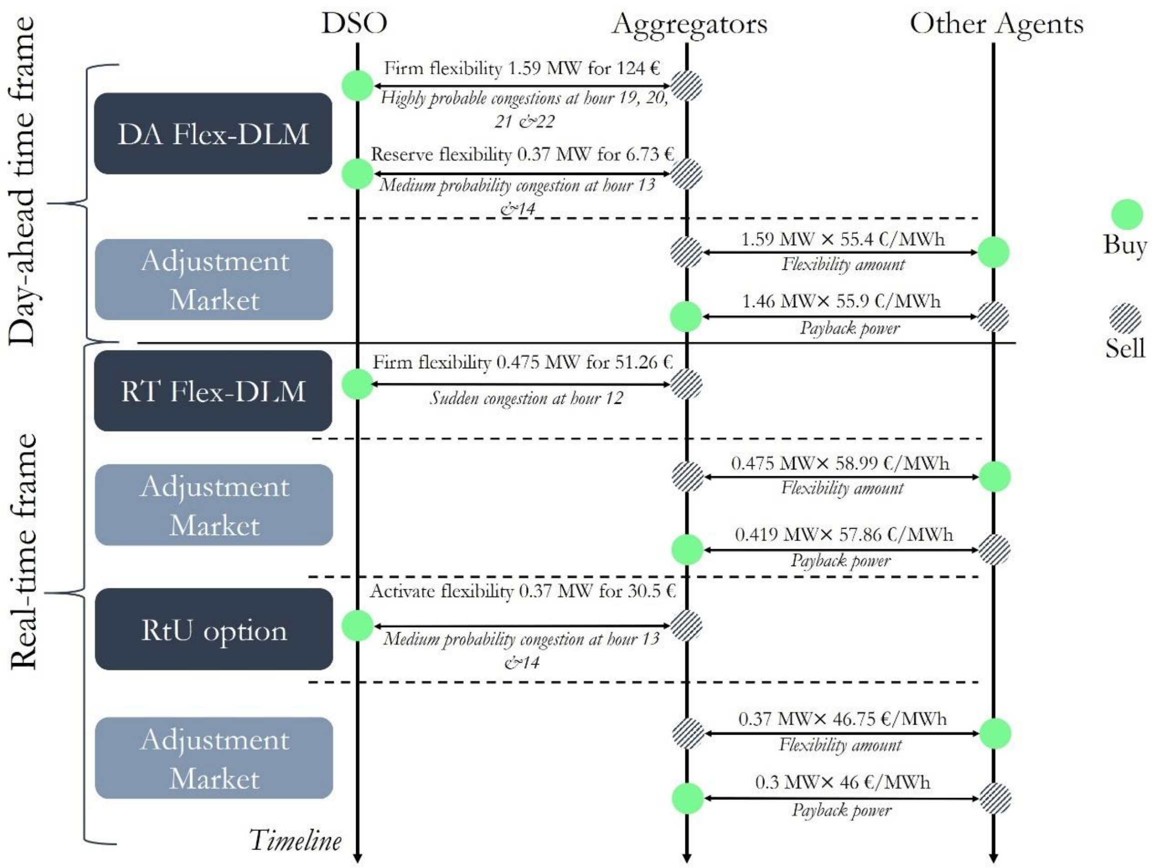


Figure 5.15 Trading processes between market agents in the flexibility market framework.

5.2.4 Deterministic vs. Probabilistic

From the case studies carried out in sections 5.1 and 5.2, several observations can be pointed out. First, the forecasting errors caused by the uncertainty of load consumption is an important issue that should not be neglected. As a result of these forecasting errors, DSOs can procure amounts of flexibility services that are either unnecessary or not sufficient, both of which will be operationally and economically inefficient. Thus, the reliance on the wholesale day-ahead market solution assessment only can be problematic, which is the case in the deterministic approach. A probabilistic approach that considers the demand uncertainty can increase the overall efficiency of the demand flexibility framework. Take for an example the last case study in section 5.2, based on Figure (5.15), the DSO's total cost for all flexibilities activated and reserved yields 212.49 €. In a deterministic approach, with no probabilistic analysis nor RTU option and real-time market, the DSO will only commit to the firm flexibility which is procured based on the wholesale market solution assessment, with a total cost of 124 €. On a lucky day, the MSA can be accurate in determining the potential congestions of the following day and no further congestions occur in real-time, thus there will be no need for flexibility portfolio optimization. However, there is a very high probability that deviations can happen in the forecasted load and generation profiles. As a result, congestions can take place in real-time, which can lead to network outages. Even with the presence of a real-time market for flexibility trading, the prices offered in such market are expected to be higher than the regular flexibility prices offered during the day-ahead flexibility market, which means more cost is incurred by the DSO. Therefore, a probabilistic analysis in the day-ahead period accompanied with the RtU option will be a safe option for the DSO to be ready for congestions with medium probabilities and to avoid high priced flexibility in the real-time flexibility market. It should be noted as well that another probable situation can take place that can result in the DSO paying unneeded cost even with considering the probabilistic approach. The RtU option allows the DSO to reserve flexibility for medium probability congestions, which gives the DSO the right to activate flexibility with the day-ahead market prices if the congestion take place, thus avoiding the need to enter a real-time flexibility market with possibly higher prices. However, due to the uncertainty of demand, the congestion may not take place in real-time, which means the DSO will have paid a reservation fee (RtU fee) and not used it.

In the end, one can look at it to be a "*trade-off*" situation for the DSO, which depends on the level of risk it is willing to take, between only committing to the market solution assessment and taking the risk of procuring high priced flexibility if needed at real-time, or considering a probabilistic approach and reserving amounts of flexibility for unsure congestions but accepting the fact that it is possible that such reservations can be not required. In such trade-off situation, it can be evident that the proposed method of evaluating the probability of congestion occurrence can help the DSO avoid cost and operational inefficiencies by decreasing the uncertainty behind congestions with low probabilities of taking place. Also, this method allows the DSO to reserve flexibility services for those congestions with medium probabilities of taking place, thus minimizing the economic losses, if compared to buying flexibility close to real-time, which can be expensive. The second observation is the importance of the real-time flexibility market. Certain events that are unforeseen and cannot be forecasted can occur during the real-time operation, and the existence of a market place that allows the DSO to quickly mitigate such outages can certainly help in increasing the reliability of the system and the efficiency of the demand flexibility framework.

5.2.5 Uncertainty of customers' behaviour

Besides the common uncertainties of the load, the behavior of the consumers towards the flexibility activation is still uncertain for the DSO. In this case, the DSO's optimal decision of activating flexibility may change from one consumer to other depending on their level of commitment to the activation request and to the amount of energy needed. In Chapter 4, section 4.5, two methods were explained that models such uncertainty. The objective is to model the worst-case scenarios that could take place in order to make the DSO prepared for unexpected behavior from the consumers. The two methods are implemented considering the same network described in section 5.2, with the same flexible buses, and only the firm flexibility transaction for the high probable congestions in the DA Flex-DLM.

- **Uncertainty of activation commitment**

The assumption made here is that the consumers cannot guarantee their compliance to the activation request of demand flexibility. As a result, the DSO can assign probabilities of commitment to every aggregated flexibility bid, which can be based on previous experience and/or historical data. These probabilities give an indication to how probable the aggregated consumers at every bid can commit to the activation request. Then, the DSO can set a minimum value that determines the blocks that the DSO can consider when clearing the market and the blocks that can be ignored. The probability values for every block are assumed in Figure 5.16 and the minimum value set by the DSO is 0.94. Thus, it can be concluded that the second block from the third flexible bus and the first block from the fourth flexible bus are below that value set by the DSO. Therefore, the DSO ignores their flexibility and optimizes its purchase and clears the market based only on the rest of the blocks at every bid.

Table 5.22 presents the DA Flex-DLM solution for the high probable congestions after considering the uncertainty of activation commitment with a total cost for activation is 126 €. It can be noticed that the blocks with probabilities below the DSO's limit are not activated. In addition, the total cost of activation in this case is slightly higher than that of the normal case, 124 €. The difference in this cost is because the DSO ignores the flexibility blocks that has a low probability of answering the activation request. With larger energy trading and more consumers to consider, the cost can increase as long as the DSO is taking into its account the probability of consumers' response. Based on the minimum value set by the DSO, its consideration for the flexibility blocks can change.

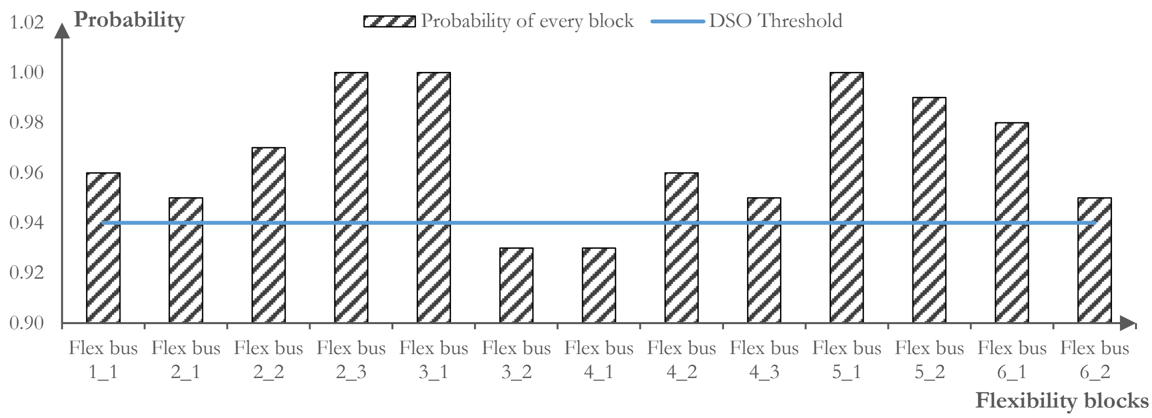


Figure 5.16 Probability of activation commitment for every block.

Table 5.22 Market solution for DA-Flex-DLM for the highly probable congestions considering the uncertainty of activation commitment.

Firm Flexibility (MW)		$\mathbf{F_{1,1,t}^{UREG}}$	$\mathbf{F_{2,1,t}^{UREG}}$	$\mathbf{F_{2,2,t}^{UREG}}$	$\mathbf{F_{2,3,t}^{UREG}}$	$\mathbf{F_{3,1,t}^{UREG}}$	$\mathbf{F_{3,2,t}^{UREG}}$	$\mathbf{F_{4,1,t}^{UREG}}$	$\mathbf{F_{4,2,t}^{UREG}}$	$\mathbf{F_{4,3,t}^{UREG}}$	$\mathbf{F_{5,1,t}^{UREG}}$	$\mathbf{F_{5,2,t}^{UREG}}$	$\mathbf{F_{6,1,t}^{UREG}}$	$\mathbf{F_{6,2,t}^{UREG}}$
Hour	*19*	0.123	0.036	0.051	0.015	0.022	-	-	0.050	0.018	0.066	0.054	0.035	0.065
	20	0.081	0.038	0.054	-	0.023	-	-	0.045	-	0.060	-	0.032	0.059
	21	-	0.036	0.052	-	0.022	-	-	0.044	-	0.058	-	0.031	0.027
	22	0.078	0.039	0.056	-	0.024	-	-	0.045	-	0.059	-	0.032	0.059
Payback power (MW)		$\mathbf{P_{1,1,t}^{PB}}$	$\mathbf{P_{2,1,t}^{PB}}$	$\mathbf{P_{2,2,t}^{PB}}$	$\mathbf{P_{2,3,t}^{PB}}$	$\mathbf{P_{3,1,t}^{PB}}$	$\mathbf{P_{3,2,t}^{PB}}$	$\mathbf{P_{4,1,t}^{PB}}$	$\mathbf{P_{4,2,t}^{PB}}$	$\mathbf{P_{4,3,t}^{PB}}$	$\mathbf{P_{5,1,t}^{PB}}$	$\mathbf{P_{5,2,t}^{PB}}$	$\mathbf{P_{6,1,t}^{PB}}$	$\mathbf{P_{6,2,t}^{PB}}$
Hour	*11*	-	-	0.035	-	-	-	-	-	-	-	-	-	-
	12	-	-	0.056	-	-	-	-	-	-	-	-	-	-
	13	-	-	-	-	0.006	-	-	-	-	-	-	-	-
	14	-	-	-	-	0.024	-	-	-	-	-	-	-	-
	15	-	-	0.056	-	-	-	-	0.025	-	-	-	-	-
	16	-	-	0.056	-	-	-	-	0.050	-	-	0.050	-	-
	17	-	0.002	-	-	0.021	-	-	0.050	-	0.016	-	0.017	0.015
	18	-	0.039	-	-	0.024	-	-	0.050	-	0.066	-	0.035	0.065
	23	0.114	0.039	-	-	-	-	-	-	-	0.066	-	0.035	0.065
	24	0.125	0.039	-	0.011	-	-	-	-	0.014	0.066	-	0.035	0.065
$\mathbf{C^{F\_DA}}$**(€)**								**126**						

- **Uncertainty of amount delivery**

In this method, the commitment to respond to the activation request is assumed. However, what can be uncertain in this case is the amount of flexibility that is needed to be delivered. A large part of such uncertainty comes from the unpredictable behavior of the consumers which can affect their load consumption and their response to the flexibility that needs to be delivered. As explained in Chapter 4, section 4.5, the uncertainty is modelled based on previous experience and/or historical data by introducing expected percentages of delivery to the power limits of the flexibility amounts of every block. These percentages represent the minimum amount of the flexibility offered that the DSO can be sure that it will be delivered by their respected consumers. In this way, the DSO optimizes its purchase of flexibility and clears the market considering less amount of flexibility offered. Table 5.23 presents the expected percentages set by the DSO and the offered flexibility at every block before and after applying these percentages. Table 5.24 presents the DA Flex-DLM solution and the amounts of flexibility activated, the payback power and optimal hour.

Table 5.23 Flexibility at buses 1, 2, 3, 4, 5 & 6 in the DA Flex-DLM for high probable congestions before and after expected percentage of delivery.

Blocks (MW)		$F_{1,1,t}^{UREG}$	$F_{2,1,t}^{UREG}$	$F_{2,2,t}^{UREG}$	$F_{2,3,t}^{UREG}$	$F_{3,1,t}^{UREG}$	$F_{3,2,t}^{UREG}$	$F_{4,1,t}^{UREG}$	$F_{4,2,t}^{UREG}$	$F_{4,3,t}^{UREG}$	$F_{5,1,t}^{UREG}$	$F_{5,2,t}^{UREG}$	$F_{6,1,t}^{UREG}$	$F_{6,2,t}^{UREG}$
$\varepsilon_{n,k,t}$		0.980	0.940	0.970	0.960	0.980	0.940	0.950	0.970	0.960	0.990	0.950	0.940	0.970
Before	*19*	0.123	0.036	0.051	0.015	0.022	0.065	0.030	0.050	0.020	0.066	0.054	0.035	0.065
	20	0.125	0.038	0.054	0.016	0.023	0.069	0.027	0.045	0.018	0.060	0.049	0.032	0.059
	21	0.120	0.036	0.052	0.016	0.022	0.067	0.026	0.044	0.018	0.058	0.047	0.031	0.057
	22	0.125	0.039	0.056	0.017	0.024	0.072	0.027	0.045	0.018	0.059	0.049	0.032	0.059
After	*19*	0.120	0.033	0.049	0.015	0.021	0.062	0.029	0.049	0.019	0.066	0.051	0.033	0.063
	20	0.123	0.035	0.052	0.016	0.023	0.065	0.026	0.044	0.017	0.059	0.047	0.030	0.057
	21	0.117	0.034	0.051	0.015	0.022	0.063	0.025	0.043	0.017	0.057	0.045	0.029	0.055
	22	0.123	0.037	0.054	0.016	0.024	0.068	0.026	0.044	0.017	0.059	0.046	0.030	0.057

Table 5.24 Market solution for DA-Flex-DLM for the high probable congestions considering the uncertainty of amount delivery.

Firm Flexibility (MW)		$F_{1,1,t}^{UREG}$	$F_{2,1,t}^{UREG}$	$F_{2,2,t}^{UREG}$	$F_{2,3,t}^{UREG}$	$F_{3,1,t}^{UREG}$	$F_{3,2,t}^{UREG}$	$F_{4,1,t}^{UREG}$	$F_{4,2,t}^{UREG}$	$F_{4,3,t}^{UREG}$	$F_{5,1,t}^{UREG}$	$F_{5,2,t}^{UREG}$	$F_{6,1,t}^{UREG}$	$F_{6,2,t}^{UREG}$
Hour	*19*	0.118	0.033	0.048	0.015	0.021	0.062	0.028	0.048	-	0.063	0.006	0.032	0.060
	20	0.007	0.035	0.051	-	0.022	0.065	0.026	0.044	-	0.057	-	0.029	0.054
	21	-	0.034	0.050	-	0.022	0.063	0.025	0.042	-	0.007	-	0.029	-
	22	0.003	0.037	0.053	-	0.023	0.068	0.025	0.043	-	0.056	-	0.030	0.054
Payback power (MW)		$P_{1,1,t}^{PB}$	$P_{2,1,t}^{PB}$	$P_{2,2,t}^{PB}$	$P_{2,3,t}^{PB}$	$P_{3,1,t}^{PB}$	$P_{3,2,t}^{PB}$	$P_{4,1,t}^{PB}$	$P_{4,2,t}^{PB}$	$P_{4,3,t}^{PB}$	$P_{5,1,t}^{PB}$	$P_{5,2,t}^{PB}$	$P_{6,1,t}^{PB}$	$P_{6,2,t}^{PB}$
Hour	*9*	-	-	-	-	-	-	0.019	-	-	-	-	-	-
	10	-	-	-	-	-	-	0.028	-	-	-	-	-	-
	11	-	-	0.033	-	-	0.042	0.028	-	-	-	-	-	-
	12	-	-	0.053	-	-	0.068	0.028	-	-	-	-	-	-
	15	-	-	0.053	-	0.003	0.068	-	0.024	-	-	-	-	-
	16	-	-	0.053	-	0.023	0.068	-	0.048	-	-	0.005	-	-
	17	-	0.002	-	-	0.023	-	-	0.048	-	-	-	0.015	-
	18	-	0.037	-	-	0.023	-	-	0.048	-	0.035	-	0.032	0.049
	23	-	0.037	-	-	-	-	-	-	-	0.063	-	0.032	0.060
	24	0.109	0.037	-	0.010	-	-	-	-	-	0.063	-	0.032	0.060
C^{F_DA}(€)		125												

5.2.6 Effect of flexibility penetration level on the DSO cost

Specific calculations of the flexibility for every consumer and the methods of aggregation carried out by the aggregators are out of the scope of this thesis and they require already established communication infrastructure and data repositories to gather the required information. However, the objective of the analysis carried out here is to show how the flexibility penetration level, or the amount of flexibility available, can be beneficial to the DSO [287]. Consider the same network explained in section 5.2, with the same flexible buses, and only the firm flexibility transaction for the high probable congestions in the DA Flex-DLM. Keeping the flexibility prices constant, four levels of flexibility penetration are tested from 10% to 50% with a 10% step, to evaluate the total savings that can be achieved by the DSO if more flexibility becomes available by the customers. Table 5.25 shows the total flexibility cleared at every bus with respect to the four penetration levels and the already penetration level 10% carried out. It can be noticed that at a low level of 10%, the DSO has no choice but to use the flexibility from all the buses. With low availability of flexibility, the DSO optimizes its operation with limited options considering the technical and locational constraints of the network. However, as the level of flexibility penetration increases, which means that more flexibility becomes available at the flexible buses, the DSO is able to better optimize its operation and decrease the cost of flexibility. For example, starting from penetration level of 40%, the DSO opts to use only the flexibility offered from the buses 2, 3 and 4 and neglect the flexibility from the rest of the buses. This means that buses 2, 3 and 4 have optimal locations in the network to solve the congestion and minimize the system losses. As a result, for the same total activated flexibility at every level, the savings achieved by the DSO at every penetration level compared to the original 10% penetration is given in Figure 5.17, which shows an expected savings of 4.5% for a 50% penetration of flexibility compared to only 10%. For larger distribution networks with possibly hundreds of customers, such savings can increase if more flexibility becomes available and more customers are involved in demand flexibility programs. This last issue can be challenging and cannot be considered as an easy task. Aggregators must be technologically advanced to provide full automation for flexibility sources at the consumers' households [281].

Table 5.25 Activated flexibility at buses with respect to penetration levels of flexibility.

Flexibility penetration level	Flex_Bus 1	Flex_Bus 2	Flex_Bus 3	Flex_Bus 4	Flex_Bus 5	Flex_Bus 6
	MW	MW	MW	MW	MW	MW
10%	0.123	0.362	0.365	0.295	0.165	0.279
20%	0	0.519	0.270	0.590	0	0.209
30%	0	0.450	0.274	0.759	0	0.105
40%	0	0.391	0.365	0.832	0	0
50%	0	0.482	0.457	0.650	0	0

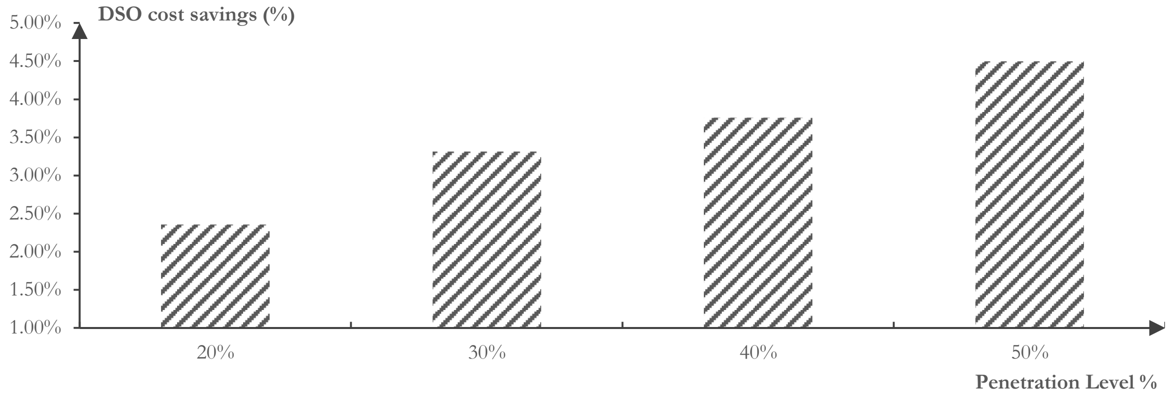


Figure 5.17 DSO's savings at every penetration level compared to 10% penetration.

5.3 Summary

Many conclusions could be drawn out of the case studies carried out in this chapter. First and foremost, demand flexibility products, UREG and DREG, can be of great value to the DSO and can offer efficient solutions to manage the common distribution-level congestions. Take for example UREG flexibility, where the DSO can benefit from the load reduction volumes offered by the consumers to mitigate congestions occurring from overloaded network lines. Also, the load increase volumes offered by DREG flexibility can help the DSO in managing voltage fluctuations caused by the variability and intermittent behavior of RES in distribution networks. The second conclusion is the importance of considering the demand uncertainty in the flexibility programs. Ignoring such aspect and using deterministic approaches to optimize the purchase of demand flexibility can easily lead to inaccurate procurement of demand flexibility amounts, either more or less than what is actually needed. In addition to this, a progressive flexibility market framework should allow trading demand flexibility during real-time. While flexibility trading during the DA period can help in mitigating some of the expected congestions, the sudden variability and the unforeseen outages in the real-time cannot be accounted for during the DA period. Beside the uncertainty of demand consumption, the DSO should as well take into account the consumers' behavior uncertainty. One of the key drawbacks of demand flexibility is its dependency on the level of compliance of the consumers to the activation request and the amount of flexibility activated. It is very important for the DSO to consider such uncertainty to avoid engaging in flexibility trading with aggregators or consumers that do not match the level of reliability maintained in the networks.

6 Cost & Benefit Analysis

One of the roles for DSOs is related to the planning of its local distribution networks. With the wide expansion of DERs and the introduction of new loads such as EVs, DSOs must take into their consideration such new network elements when planning its future expansions. Also, the deployment of demand flexibility programs can impact the future planning of the network and it must be considered. The two main issues that may be facing the DSO to equip its network and deploy demand flexibility programs are the consumers' readiness and the economic feasibility of demand flexibility. From an economic perspective, a distribution network must have the financial incentives to install the needed equipment to facilitate the deployment of demand flexibility, in order to defer capital expenditures in reinforcing the network. However, the passive behavior or unwillingness of the consumers to participate can halt such initiative. From a technical perspective, distribution networks can have customers willing to participate in the flexibility programs. From the DSO's point of view, the cost of equipping the network and cost of flexibility activations can be inefficient when compared to the cost of reinforcing the network. The issue of finding the optimal network solution can be rather complicated due to many reasons. There is not a definitive method to valorize the prices of flexibility. In addition, the long-term network planning tools are not designed to handle the levels of versatility and complexity introduced by the provision of demand flexibility programs. With the high penetration of low carbon technologies and the increase of electricity demand, the DSO is faced with challenges to maintain high reliability network levels. As a result, capital expenditures must be provided to upgrade the conventional passive distribution networks. A common method that is found in literature to assess the economic benefits of demand flexibility opposed to common conventional approaches of network upgrades is carrying out cost and benefit analysis (CBA). The CBA is able to showcase whether it is more beneficial to the DSO to participate in demand flexibility programs or to invest in upgrading its network.

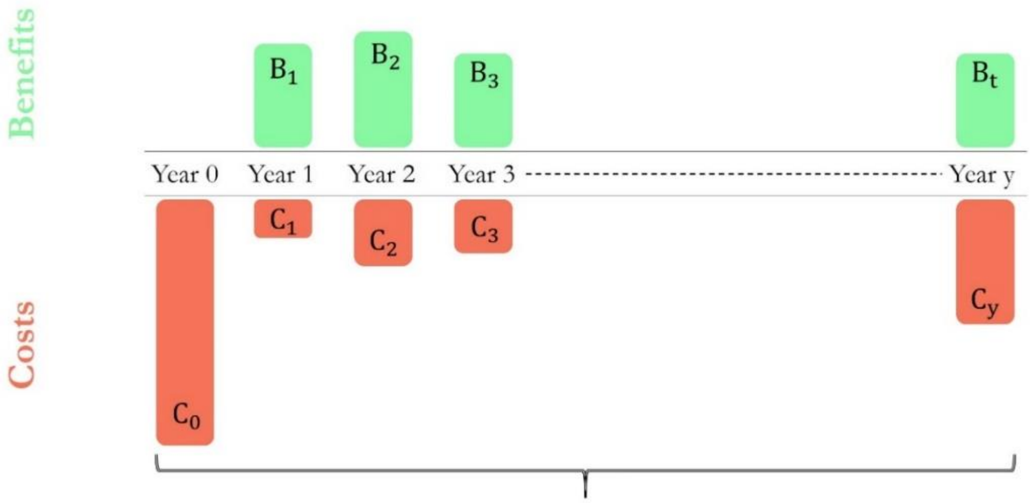
Demand flexibility have been labelled by several studies as a potential substitute to conventional grid reinforcement solutions [309], [310]. The impact of demand flexibility on system operators, especially on DSOs, has been the focus of many previous studies. In [311], a wide range of distribution network topologies simulations were presented to identify the benefits of smart grid solutions and demand response programs. Moreover, a comparison study between the need and cost of network reinforcements and smart grid solutions required to accommodate demand growth was introduced. The work emphasizes on the importance of deploying demand response programs and the efficient managing of smart grid technologies such as smart electric vehicles (EVs) charging, which can significantly decrease the total cost of needed investments. In a similar study based in France [312], a smart grid experiment was carried out that aims to investigate the benefits of load control when planning for distribution network expansion. A Swedish case study in [313] investigates the economic benefits of demand flexibility in postponing the needs for network investments. The study carried out a CBA to evaluate the feasibility of demand flexibility on a long-term basis. This issue of using demand flexibility as an alternative to avoid unnecessary grid investments or to defer high costs for balancing power in system with high RES penetration, is addressed in [314]. The paper proposes a centralized scheduling model for residential demand flexibility in a micro-grid with high RES penetration. Furthermore, it assesses the potential of current customers' devices as well as the possible future ones as sources of demand flexibility. The work suggests that loads such as storage batteries and storage heaters possess the highest potential as flexibility sources at the residential level. The work in [315] addressed the trade-off method between choosing to upgrade the network capacity and actively engaging consumers in demand response programs.

One of the recent projects that carries out detailed cost benefit analysis (CBA) for the provision of demand flexibility as an opponent to grid expansion, is the Capacity to Customers project (C2C) [316]. The UK project's philosophy is based on maximizing the usage of demand response (DR) programs, through optimal distribution network planning. In addition, the project has carried out various studies to assess the feasibility of DR programs through implementing cost control strategies to defer the needs for grid expansions [56], [317]–[320]. Based on the UK regulation, the work in [316] carried out a cost and benefit analysis (CBA) based on the Ofgem's CBA framework. The CBA analysis compared between the option of deploying demand flexibility programs and reinforcing the network with needed assets. The study computed the net present cost (NPC) of both options and accordingly choose the optimal solution.

6.1 The net present cost method

The common method used to carry out CBA is the net present value (NPV) method. The NPV evaluates the sum of net present values of cash flows for any given project or solution as shown in Figure 6.1. The basic formula of the NPV method, as seen in (6.1), is to subtract the potential cash-out (costs), denoted C_t, from the expected cash-in (benefits), denoted B_t, for every year, then discount the yearly annual net benefits and sum the total discounted values [321]. The discount factor denoted d, which is an important parameter in CBA, discount values that are generated in different time periods to the present, since individuals value their monetary gains and losses in the present higher than those in the future. Thus, as the interest rate increase, the value of the NPV decreases. The decision rule of the NPV method is to choose projects with positive values of NPV and reject those with negative values. However, having a positive NPV is not necessarily sufficient to accept a project, as there might be other projects with positive values of NPV which are socially desirable.

$$\mathrm{NPV} = \sum_{y=0}^{Y} \frac{B_y - C_y}{(1+d)^y} \tag{6.1}$$



$$\mathrm{NPV} = \frac{0 - C_0}{(1+i)^0} + \frac{B_1 - C_1}{(1+i)^1} + \frac{B_2 - C_2}{(1+i)^2} + \frac{B_3 - C_3}{(1+i)^3} \cdots\cdots + \frac{B_y - C_y}{(1+i)^y}$$

Figure 6.1 Evaluating the NPV for a given project over a project lifetime of Y years.

In literature, the methods used to address the issue of weighting the cost and benefits of demand flexibility are not complicated and most of the time they are straightforward. However, what makes one study better than the other is the level of detail provided regarding the presented options. Here, the two possible solutions considered by the DSO are the **business-as-usual** (**BAU**) solution, which resembles the DSO investing in its own network to upgrade its capacity, whether by installing new lines or transformers or building new substations, and the second option is the deployment of **demand flexibility programs** (**DFP**), where the DSO opts to take advantage of the flexibility offered by the demand side and invest in new smart infrastructure to facilitate such solution.

A comprehensive costs and benefits analysis for a given project or solution, requires identifying the assets that will be involved in the project, defining their functionalities and finally monetizing their benefits. In the Flex-DLM framework, the main beneficiary is the DSO. However, other agents can participate in the flexibility market, such as BRPs or other aggregators aiming to optimize their portfolios or avoid penalty costs. The only agent considered here is the DSO since it is the decision-maker when it comes to deciding between the BAU and DFP solutions. Quantifying the costs and benefits for the potential solution is a very important step in the CBA, but a problem can arise when it comes to monetizing some of the benefits in the case in hand. For both solutions the BAU and DFP have several social and intangible benefits that are hard to assign values to. Table 6.1 illustrates the potential costs and advantages of the BAU and DFP solutions from the perspective of the DSO.

Some of the advantages presented in Table 6.1 represents to what the DSO will gain economically from choosing a given solution, while other advantages are hard to be presented in monetary values. For example, one of the BAU solution non-monetary advantages is that it will not restrict the consumers' behavior based on the demand flexibility activations. However, one of the monetary benefits of such solution is that it will avoid the need to upgrade metering systems and IT & communication infrastructure, which can be costly. Similarly, a non-monetary advantage of the DFP solution is that it will encourage consumers to invest in more renewable sources and EVs, while a monetary advantage can be improved assets utilization. It should be noted that in the Flex-DLM framework, the parties that have monetary benefits are the aggregators and the consumers, since they receive actual payments for their flexibility services.

Table 6.1 Costs & advantages of the BAU and DFP solutions for the DSO.

	Costs	Advantages
BAU	• Capital cost of upgrading the network. • Operation and maintenance costs for new assets.	• Avoid potential outages and congestions caused by peaks. • Avoid the need to upgrade metering systems and IT & communication infrastructure, which can be a challenging task. • Avoid dealing with the uncertainty regarding consumers' commitment to demand flexibility activations. • Customers are not restricted with their consumption behavior.
DFP	• Capital cost of renewing smart meters and all necessary equipment for demand flexibility trading. • Costs of activating demand flexibility when needed.	• Postpone capital investments for upgrading the network. • Help the DSO the congestion management process, which decreases network losses, outages peaks and carbon emissions. • Improved assets utilization. • Provide better planning for future network investments. • Consumers become more active and more aware of their consumption, which eventually can reduce their electricity bills. • Encourage consumers to invest in more renewable sources and EVs, as they can be potential flexibility sources, which will have a direct impact on decreasing carbon emissions.

As seen in Table 6.1, the advantages of both solutions do not generate revenues (cash-in) to be accounted as monetary benefits. Therefore, considering the NPV method, the benefits along the years will be equivalent to zero. The work in the C2C project [316] have addressed the same problem and opted to use a similar method to the NPV, called the net present cost (NPC). The NPC method only considers the total costs of any specific project discounted to the baseline year. Thus, in this case the most economical solution would be the one with least value of NPV. The general formula for calculating the NPC for any of those solutions over a lifetime of Y with a discount rate d, is presented in (6.2), considering the total cost incurred by the distribution system operator every year *y*, denoted $\mathrm{DSO\_C_y}$.

$$\mathrm{NPC} = \sum_{\mathrm{y}=0}^{\mathrm{Y}} \frac{\mathrm{DSO\_C_y}}{(1+\mathrm{d})^{\mathrm{y}}} \tag{6.2}$$

In order to reach an optimal decision when comparing between two projects using the NPC method, or even the NPV method, the solutions must be comparable. This means that the both solutions must share the same lifespan. In the case in hand and according to the Spanish regulation, the expected lifespan for the DFP and the BAU are 12 and 40 years respectively. In order to compare mutually exclusive projects with unequal lives, another process must be carried out, which calculates the equivalent annual annuity (EAA) [322]. The EAA calculates the constant annual cash flow generated by a given project over its lifespan if it was an annuity. A typical approach to compare unequal lifetime projects is to consider reinvesting in the project with the shorter life span after its lifetime ends until it covers the longer life span project, and then the NPC or NPV are calculated and both projects are compared. In real life, this is not always applicable and the EAA solves this problem by providing a straightforward way to generate a single average value of cash flow with respect to the project lifetime, which eliminates the need for considering reinvestments. This EAA represents the per year cash flow that is equivalent to the NPV or NPC of the project. Between multiple projects with different values of EAA and considering the NPC method, the project with the lower EAA is considered the optimal. For a given project with net present cost NPC with interest rate d and total lifetime years Y, the EAA can be calculate as in (6.3).

$$\mathrm{EAA}_{\mathrm{BAU/DFP}} = \frac{\mathrm{i} \times \mathrm{NPC}}{1-(1+\mathrm{d})^{-\mathrm{Y}}} \tag{6.3}$$

6.2 Case Study

Demand flexibility has been presented as a potential tool that can assist the DSO in its day-to-day congestion management responsibilities. With different flexibility products in different distribution networks, this issue has been checked considering a sample of a single day operation. As the entity responsible for the distribution network long-term, DSOs are required to manage its own resources to accommodate the potential demand growth in the future. Demand flexibility can be an important factor in such planning process, as it can postpone the so-called business-as-usual plans of upgrading the assets of the network. However, the feasibility of demand flexibility on the long-term is an issue that needs to be assessed through carrying out a cost and benefit analysis. The two options considered for the long-term planning of the network are the choice of upgrading its network (BAU solution) and deploying demand flexibility programs (DFP solution). Realistically, demand flexibility can only defer the need for network reinforcement for a number of years, since installing new lines or building new substations is an inevitable situation. However, as previously mentioned, in certain cases demand flexibility can be inefficient due to high flexibility prices or unwillingness of the customers in the network. In the case study carried out here, it is assumed that the consumers are willing to participate in the demand flexibility programs. In addition, it is assumed that the demand flexibility capacity that can be offered by the consumers is sufficient to meet the future demand growth without the need of reinforcing the network at any point. Therefore, the DSO have the ability to assess which of both solutions will be optimal for its future operation. Based on such assessment, the DSO can determine the maximum acceptable flexibility price that it can accept that makes the DFP solution more economically efficient than the BAU solution.

In order to simplify the analysis, the deterministic approach explained in the appendix will be used. This means that the probabilistic forecasting assessment (PFA) will be ignored and only the congestions detected by the DSO in the market solution assessment (MSA), during the day-ahead period, will be considered. Also, the unexpected congestions that may take place during real-time, which can require calling for the RT Flex-DLM, will also be neglected and only the firm flexibility activated in the DA Flex-DLM will be accounted for. The distribution network previously used in Chapter 5 section 5.1.2 will be used for that purpose. It should be reminded that in that network, the DSO was facing challenges in managing the congestions occurring due to the overloaded lines. The solution proposed takes advantage of the UREG flexibility (load reduction volumes) offered by the flexible consumers in the network.

Two scenarios were carried out that depict how the demand could grow in the future. Figure 6.2 illustrates both scenarios and it shows that the network's line capacity is expected to be reached at 3% of demand growth, which occurs at year 3 for scenario 1 and at year 8 for scenario 2. For both options, BAU and DFP, an implementation time of one year is assumed. The implementation time refers to the time needed to build new substations or installing new transformers or upgrading the communication infrastructure of the network to facilitate the deployment of demand flexibility programs. This assumption can vary depending on the type of equipment being installed. Since both options need to be in operation in years 3 and 8 for scenarios 1 and 2 respectively, it means that the implementation time should start at years 2 and 7. The starting year of implementation will be referred to as the base year and the following years representing the duration of the solution are called operation years. In the following, the NPC for both options are evaluated considering a discount rate of 5.5%. The costs considered for both solutions are only related to the capital cost of upgrading the network as well as the operation and maintenance cost for the assets. Finally, it should be noted that the price inflation across the forthcoming years is neglected to simplify the analysis.

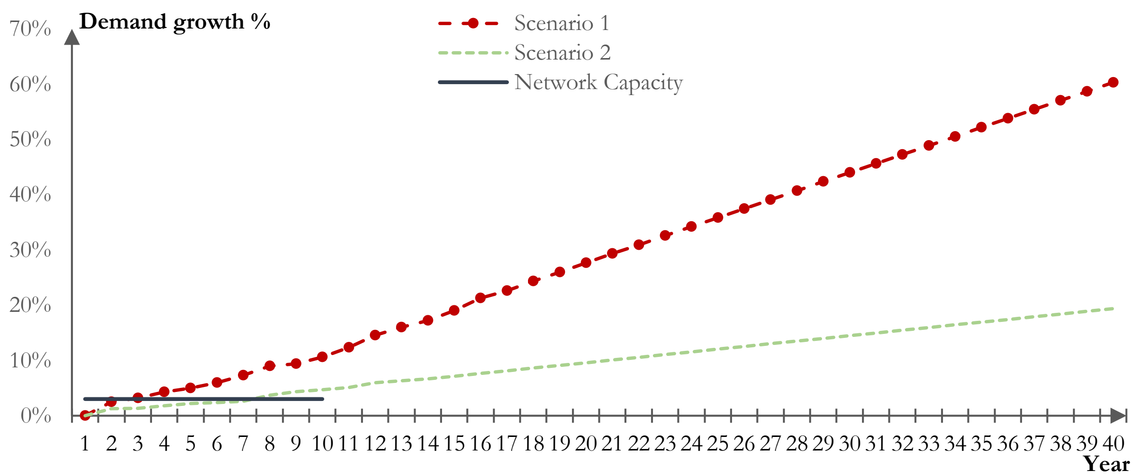


Figure 6.2 Demand growth percentage over the following years.

6.2.1 Business-as-usual solution

The option to reinforce the network is a common solution to DSOs in general to face demand growth in distribution networks. In addition, it is the option that is incentivized by regulators. However, it requires capital investments, not to mention that the full network capacity will not be utilized at all times. The technical equipment that can be involved in the process of expanding the network capacity are plenty. However, based on the distribution network geographical location and the demand growth for scenarios 1 and 2, only three kinds of assets are considered here to accommodate such growth, which are overhead cables, transformers and transformers housing. It should be noted that there can be auxiliary equipment that can be needed in addition to the assets considered here. However, the expansion planning of distribution networks is a complex process and out of the scope of the thesis. The objective here is to present a non-complex approach to carry out the cost and benefit analysis regardless of the assets considered. Figure 6.3 illustrates the distribution feeder after adding the needed reinforcements. The considered equipment consists of a new transformer that serves as a connection between the transmission and distribution network along with the overhead cables required to transfer the electricity.

Tables 6.2 and 6.3 provide the capitalized expenditures (CAPEX) and operational expenditures (OPEX) in € per unit value for every asset, which is based on the Spanish regulation [323], and their total expected cost according to the needed asset capacity for scenarios 1 and 2 respectively. It can be noticed that the transformer size required for scenario 1 is larger than that of scenario 2, which is due to the higher growth percentage of scenario 1. As per the Spanish regulation, the lifetime of conventional network equipment is 40 years. Thus, the base year, i.e. year 0, for both scenarios will be years 2 and 7 respectively. In the base year, the investment cost CAPEX will be allocated. The running cost OPEX will start from operation year 1, which are the years following 2 and 7. The cash flow, NPC and EAA for both scenarios are calculated in Tables 6.4 and 6.5 respectively.

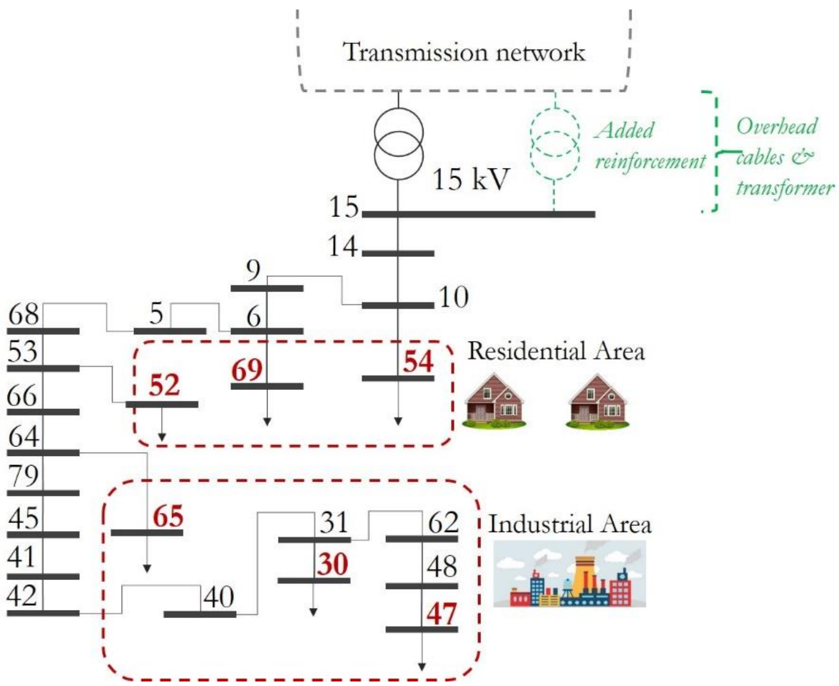


Figure 6.3 Distribution network with an added transformer and overhead cables.

Table 6.2 Technical equipment for BAU solution – scenario 1.

Equipment	CAPEX	Annual OPEX	Size	Total CAPEX	Total Annual OPEX
	€/unit value	*€/unit value*	-	*€*	*€*
Overhead Cables (km)	77,829	808	2.8 km	217,921.20	2,262.40
Transformer (MVA)	17,284	465	1.25 MVA	21,605	581.25
Transformer housing	43,855	1,004	1.25 MVA	43,855	1,004
Total cost (€)				**283,381.20**	**3,847.65**

Table 6.3 Technical equipment for BAU solution – scenario 2.

Equipment	CAPEX	Annual OPEX	Size	Total CAPEX	Total Annual OPEX
	€/unit value	*€/unit value*	-	*€*	*€*
Overhead Cables (km)	77,829	808	2.8 km	217,921.20	2,262.40
Transformer (MVA)	17,284	465	0.63 MVA	10,888.92	292.95
Transformer housing	43,855	1,004	0.63 MVA	33,684.00	771.00
Total cost (€)				**262,494.12**	**3,326.35**

Table 6.4 BAU solution cash flow, NPC & EAA for scenario 1.

Year	Expenses (€)	
	Single	*Annual*
Base year – 0	283,381.20	-
Operation year- 1	-	3,847.65
Operation year- 2	-	3,847.65
Operation year- 3	-	3,847.65
	-	
	-	
	-	
	-	
	-	
	-	
	-	
	-	
	-	
	-	
	-	
Operation year- 38	-	3,847.65
Operation year- 39	-	3,847.65
Operation year- 40	-	3,847.65
NPC (€)	**345,121.07**	
EAA (€)	**21,508.06**	

Table 6.5 BAU solution cash flow, NPC & EAA for scenario 2.

Year	Expenses (€)	
	Single	*Annual*
Base year – 0	262,494.12	-
Operation year- 1	-	3,326.35
Operation year- 2	-	3,326.35
Operation year- 3	-	3,326.35
↓	-	↓
	-	
	-	
	-	
	-	
	-	
	-	
	-	
	-	
	-	
	-	
Operation year- 38	-	3,326.35
Operation year- 39	-	3,326.35
Operation year- 40	-	3,326.35
NPC (€)	**315,869.15**	
EAA (€)	**19,685.07**	

6.2.2 Demand flexibility program solution

In the case study carried out in Chapter 5 section 5.1.2, only a sample of one day was considered for demand flexibility activation. In order to assess the feasibility of the DFP solution, the Flex-DLM framework must be implemented to facilitate flexibility trading, UREG flexibility (load reduction volumes), for every day during the 12 years lifespan of the project. The capital expenditures that can be considered by the DSO consists of upgrading the network and the customers' automation level to facilitate the trading of demand flexibility. This amount of network cost upgrading is considered 45,000 €, based on the UK study presented in [56]. This amount is a single payment made at the base year. As for the operational expenditures, they will consist of the cost of flexibility traded every year.

The expected cost for flexibility activation depends on two important factors, which are the prices of flexibility offered by the aggregators and the number of activations per year. The prices of flexibility in the case study in section 5.1.2 were values that ranges between 98.19 €/MWh to 80.98 €/MWh per block for all customers, which gives an average price of 79 €/MWh per every block of flexibility offered. Equation (6.4) calculates the average flexibility prices for a single hour. This can be considered as an approximation since it is difficult to predict the average flexibility prices for every hour during the period of 12 years. As for the number of yearly activations, it can be expected that as the demand grows, the amount of flexibility needed increases and also the cost. The objective here is to evaluate whether an average price of flexibility of 79 €/MWh makes the DFP solution a favorable solution to the DSO or not with respect to the load increase scenarios. Table 6.6 gives the average price of flexibility in €/MWh, the number of flexibility activations, total amount and cost of flexibility activated for operation year-1 with respect to scenarios 1 and 2. Such values were obtained by implementing the framework of the Flex-DLM every day during this year and solving all the encountered congestions.

$$\lambda\_\text{average}^{\text{UREG}} = \frac{\sum_{n=1}^{N^n}\left[\sum_{k=1}^{N_{n,t}^{b}} \lambda_{n,k}^{\text{UREG}}\right]}{n} \tag{6.4}$$

Figures 6.4 and 6.5 show the amount in MW and the cost in € for the total demand flexibility required yearly to mitigate the network congestions for scenarios 1 and 2. Similar to the BAU solution, it can be noticed that the cost and amount of flexibility needed for scenario 1 is higher than that of scenario 2. Tables 6.7 and 6.8 show the cash flow, NPC and EAA for both demand growth scenarios. It can be expected that the average flexibility prices increase over the years. Since there are no current regulations on how to value the prices of flexibility, the inflation rate of flexibility prices is neglected.

Table 6.6 Average price, number of activation and total amount and cost of flexibility activated during operation year-1 for scenarios 1 & 2.

	Scenario 1	Scenario 2
Average price per flexibility block offered (€/MWh)	89	89
Number of flexibility activations	113	56
Total amount of flexibility activated (MWh)	264.39	131.03
Total cost of flexibility activated (€)	23,531.07	11,661.41

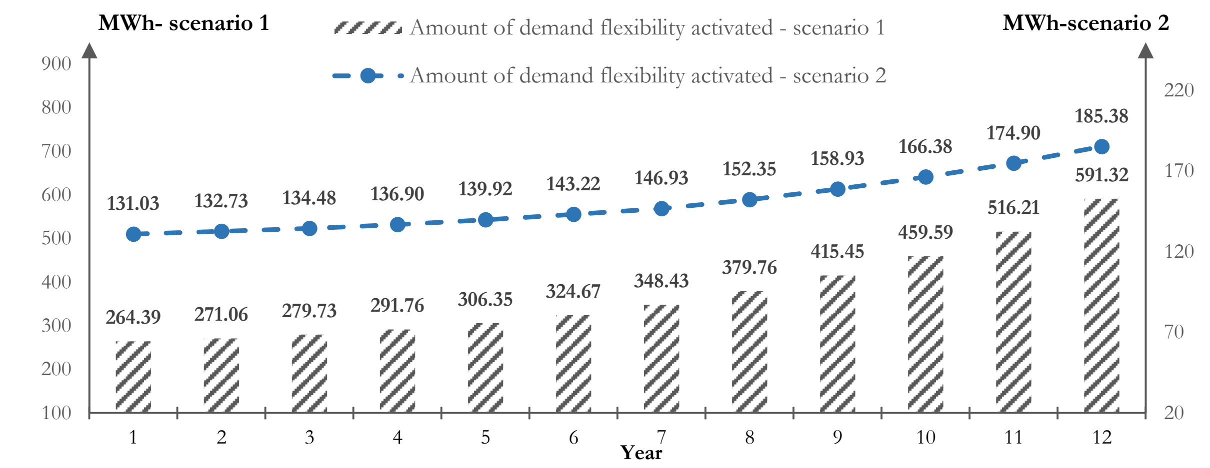


Figure 6.4 Amount of demand flexibility activation (MWh) needed across the lifetime of DFP – scenario 1 & 2.

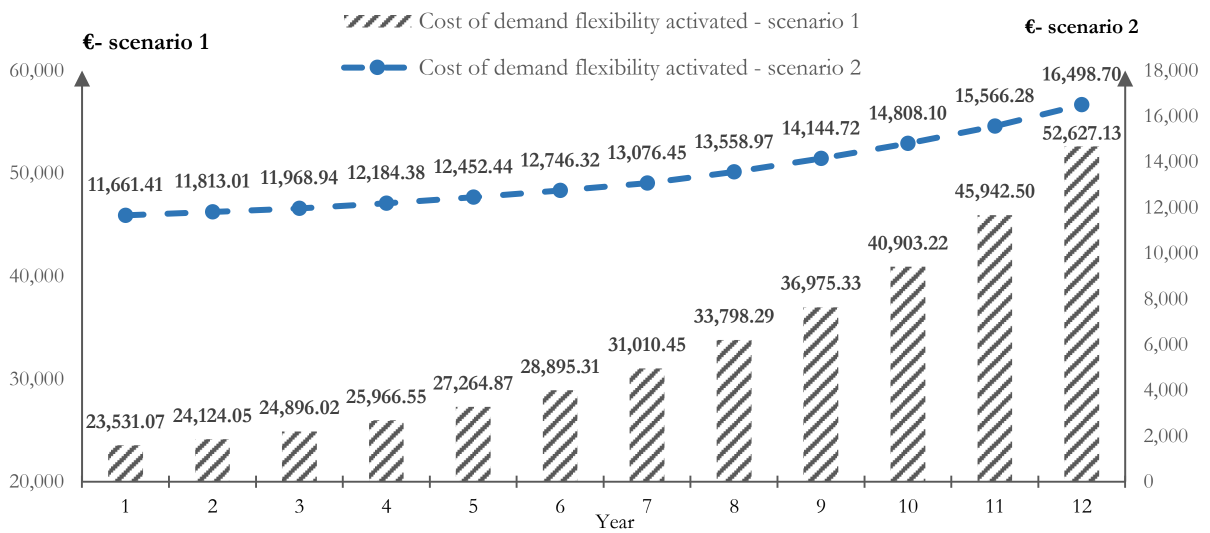


Figure 6.5 Cost of demand flexibility activation (MWh) needed across the lifetime of DFP – scenario 1 & 2.

Table 6.7 DSP solution cash flow, NPC & EAA for scenario 1.

Year	Expenses (€)	
	Single	*Annual*
Base year – 0	45,000.00	-
Operation year- 1	-	23,531.07
Operation year- 2	-	24,124.05
Operation year- 3	-	24,896.02
Operation year- 4	-	25,966.55
Operation year- 5	-	27,264.87
Operation year- 6	-	28,895.31
Operation year- 7	-	31,010.45
Operation year- 8	-	33,798.29
Operation year- 9	-	36,975.33
Operation year- 10	-	40,903.22
Operation year- 11	-	45,942.50
Operation year- 12	-	52,627.13
NPC (€)	**316,257.12**	
EAA (€)	**36,695.07**	

Table 6.8 DSP solution cash flow, NPC & EAA for scenario 2.

Year	Expenses (€)	
	Single	*Annual*
Base year – 0	45,000.00	-
Operation year- 1	-	11,661.41
Operation year- 2	-	11,813.01
Operation year- 3	-	11,968.94
Operation year- 4	-	12,184.38
Operation year- 5	-	12,452.44
Operation year- 6	-	12,746.32
Operation year- 7	-	13,076.45
Operation year- 8	-	13,558.97
Operation year- 9	-	14,144.72
Operation year- 10	-	14,808.10
Operation year- 11	-	15,566.28
Operation year- 12	-	16,498.70
NPC (€)	**158,012.71**	
EAA (€)	**18,334.09**	

After the DSO evaluates the NPC and the EAA for both potential solutions across the demand growth scenarios, a choice must be made. Figure 6.6 compares the EAA for the BAU and the DFP solutions for both scenarios. It can be noticed that for scenario 1, due to the high demand growth forecast, the EAA of the DFP solution resulted in 36,695.07 € as opposed to only 21,508.06 € for the BAU approach. Thus, the DSO is better off choosing the BAU solution and upgrading its own network as the equivalent annual annuity, is lower than the DFP solution. On the other hand, for the lower demand growth forecast of scenario 2, the DFP's EAA resulted in only 18,334.09 €, which lower than that of the BAU solution of 19,685.07 €, which makes the DFP the more economical and favorable solution to the DSO.

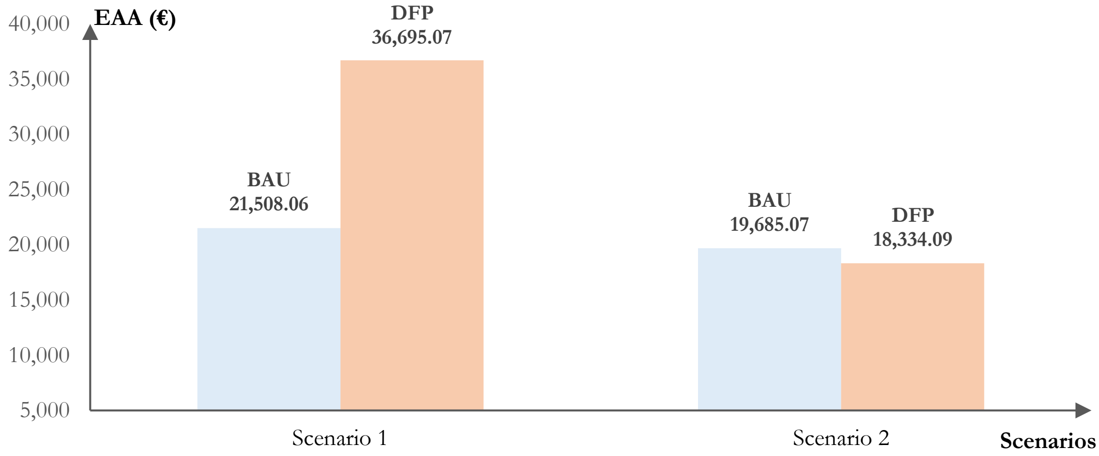


Figure 6.6 Comparing the EAA for the BAU and the DFP solutions at scenarios 1 & 2.

6.2.3 Flexibility price caps

The issue of valuing demand flexibility and assigning efficient prices, which ensures economic efficient for all involved parties, is still a topic not agreed upon. However, from the previous analysis, an estimated flexibility price cap can be determined that can make the DFP solution more economic than the BAU solution with respect to scenario 1. While the issue of flexibility pricing is out of the DSO's responsibility, it can however determine the maximum price that it can afford that will make the DFP a more economical solution than the BAU. Here, we assume that the flexibility price cap is the average flexibility prices offered per block, which is evaluated from (6.4).

In order to determine the flexibility price cap, the analysis carried out in section 6.2.2 is carried out but in a reverse order. Based on the previous assumptions, the average prices considered for flexibility was 89 €/MWh, which yields to an EAA of 36,685.07 € for the DFP compared to an EAA of 21,508.06 € for the BAU solution. The objective is to determine the maximum flexibility price that will produce a value of EAA for the DFP solution that is less than the BAU solution. This can be achieved by decrementing the average prices of flexibility and evaluating the EAA of the DFP solution. It should be mentioned that the flexibility prices have a low impact on the amount of flexibility traded. Such total amount can vary due to the location of the consumers offering flexibility, which may affect the DSO's decision of choosing one customer over the other. However, these differences are neglected, since the amount of flexibility needed by the DSO to mitigate a congestion will remain almost equal. Figure 6.7 illustrates the EAA of the BAU solution against the EAA of the DFP solution considering different average prices of flexibility with respect to scenario 1. It can be noticed that at average prices less than 50 €/MWh, the EAA of the DFP becomes lower than that of the BAU. This means that the feasibility of the DFP solution in this specific demand growth scenario depends on having average flexibility prices (flexibility price cap) less than 50 €/MWh.

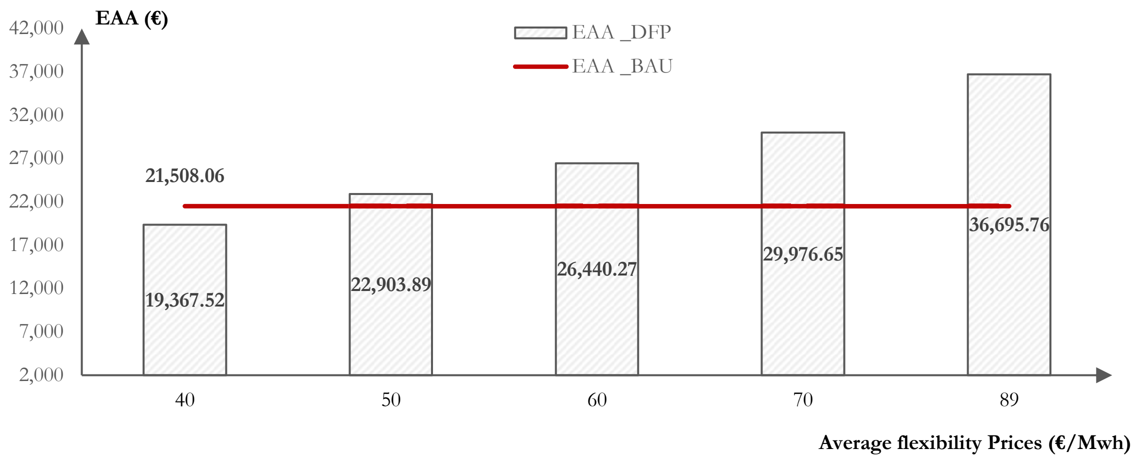


Figure 6.7 Comparing the EAA for the BAU and the DFP solutions at scenario 1 considering different average flexibility prices.

In scenario 2, the DFP solution have already proven to be a better option than the BAU solution. However, it will be interesting for the DSO as well to determine the maximum flexibility cap price that it can afford before the BAU solution becomes the more favorable one. Similarly, at different average flexibility prices, the EAA of the DFP solution is evaluated and compared to the EAA of the BAU solution, as seen in Figure 6.8. It can be noticed that at an average price of 100 €/MWh, the DFP becomes infeasible and the BAU will be the economic solution. Average prices that are below 100 €/MWh allow the DFP to be a better solution than the BAU. An important conclusion that can be drawn out of these analyses is that the applicability of the DFP solution depends on several important factors, which are the network location, the projected demand growth and the flexibility prices offered. A change in any of such factors can make one solution better than the other.

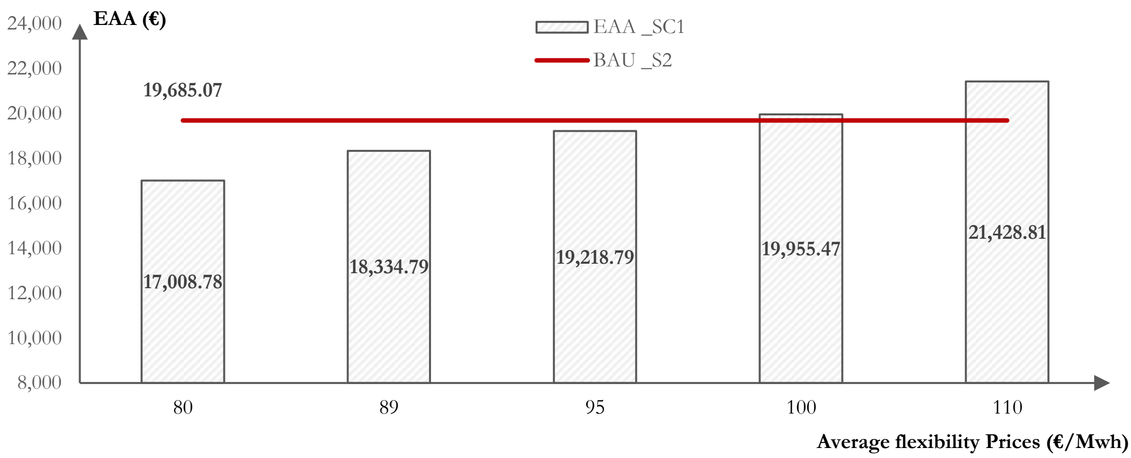


Figure 6.8 Comparing the EAA for the BAU and the DFP solutions at scenario 2 considering different average flexibility prices.

Finally, it should be noted that there could be other CAPEX and OPEX items that were not considered here beside the basic items considered in this case study. Table 6.9 shows some of these items [324].

Table 6.9 Other CAPEX & OPEX items that can be considered in the CBA for both solutions.

	DSO	
	CAPEX	**OPEX**
BAU	• Other supplementary equipment required for network upgrading such as capacitor banks, reactors and control centers.	• Labor costs • Maintenance cost
DFP	• Sunk costs of previously installed meters. • Other needed equipment to complete the smart upgrade such as distribution and energy management data systems.	• Smart meter reading. • Maintenance cost of IT and communication infrastructure. • Labor costs.

6.3 Sensitivity analysis

It can be noticed from the case study, the CBA is carried out basing its variable on forecasted values, such that of the demand growth percentage. Such forecasted values consider long period of times and they can be different than the actual values realized. These variations can affect the choice for the required capacity of the transformer or the expected cost and amount of demand flexibility to be activated. In order to achieve an optimal decision in such cases, it is important to consider the likely changes in such forecasted variables. This can be done by carrying out sensitivity analysis. The two variables considered in the sensitivity analysis are the demand growth and the interest rate.

6.3.1 Demand growth

The forecasted demand growth percentages for the load consumption in the network has a direct effect on the outcome of the CBA. Here the change in demand growth is assumed not to affect the required equipment of the BAU solution. It is common that new installed equipment for networks, such as cables and transformers, are sized to accommodate more than the potential peak consumption. However, forecasting errors that can cause changes to the estimated demand growth percentages will have a direct impact on the amount of demand flexibility needed by the DSO. Considering the demand growth of scenario 2, four levels of percentage errors that will cause an increase in the forecasted demand growth percentage are considered to be 1%, 2%, 3% and 4%. A potential increase in the forecasted demand growth will increase the amount of demand flexibility activated, which in return will increase its total cost and the EAA and NPC values. According to every demand growth error, the cost of expected demand flexibility, the NPC and the EAA are calculated, similar to what was carried out previously.

Figure 6.9 illustrates the EAA of the BAU and DFP of scenario 2 with no change in the expected demand growth, i.e. 0%. In addition, it presents the EAA of the DFP with respect to the forecasting error percentages and then these values are compared to the EAA of the BAU solution. It can be noticed, that a change up to 1% in the expected growth percentage increases the EAA value from 18,334.09 € to 18,350.01 €, but it still remains lower than the BAU solution. However, a change of 2%, or more, will make the EAA of the DFP increases to 20,478.49 which when compared to the EAA of the BAU solution of 19,685.07 €, will be a less attractive option to the DSO.

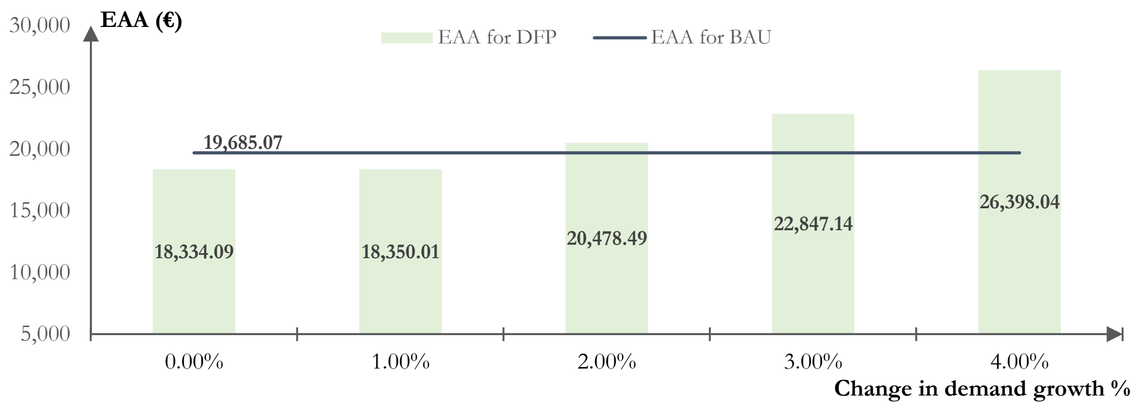


Figure 6.9 Comparing EAA of DFP (0%, 1%, 2%, 3% & 4% change in the demand growth) with the EAA of the BAU – scenario 2.

6.3.2 Discount rate

As suggested in [324], the discount rate is one of the key factors that can impact the NPC and the EAA of any given project. Selecting the best discount rate is an important practice that can vary depend on the nature of the project and it can affect its feasibility. In the case in hand, the objective is to determine the relation between the discount rate and the EAA values by considering three different values of discount rates, 2%, 5% and 10%, and then evaluating the EAA of the DFP and BAU with respect to scenario 2. As seen in Figure 6.10, discount rates that are less than 5% gives an advantage to the BAU over the DFP solution. However, a discount rate of 5% or more, similar to the analysis carried out, makes the DFP solution a more favorable option than the BAU.

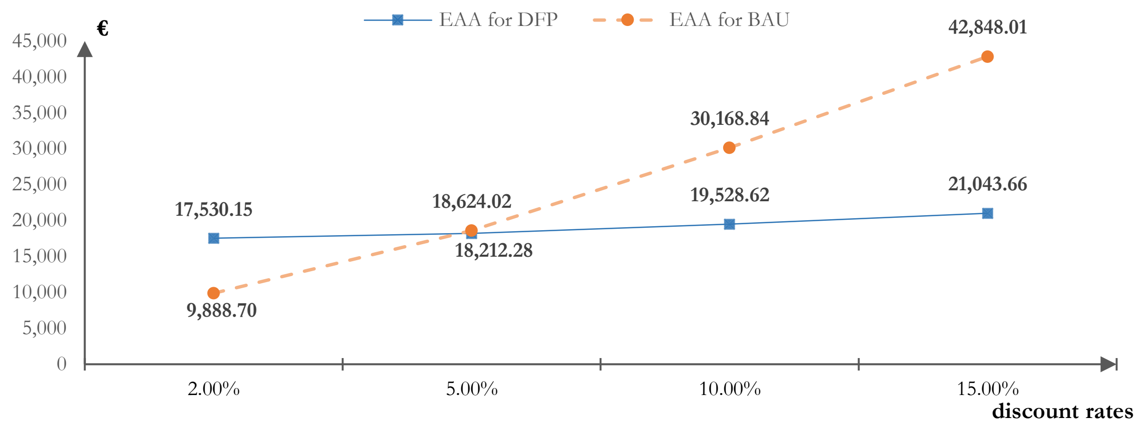


Figure 6.10 Comparing EAA of DFP and EAA of BAU at 2%, 5% & 10% discount rate.

6.4 Summary

The potential of demand flexibility programs on the long-term is undeniable and given the right circumstances and network projections and conditions, it can save DSOs capital investments for upgrading the network, or at least defer it for a period of time. When it comes to comparing the costs and benefits of both solutions, a precise analysis is required in order to reach an optimal decision. As elaborated, different projection scenarios for the load demand growth in the future, or even inaccurate values, can change the DSO's mind from implementing the DFP to carrying out BAU activities. Another key factor that was neglected in the analysis carried out, is how long does the demand flexibility can be a viable option. Basically, it was assumed in the CBA that the demand flexibility potential in the network is sufficient to uphold the forecasted demand growth and avoid any potential congestions in the future. In reality, this assumption may not be true or accurate, as demand flexibility consumers have their own limits and more demand growth does not necessarily means that more flexibility can be offered. There comes a point when upgrading the network becomes inevitable and no more postponing can be tolerated. Thus, one can assume that the success measure of implementing demand flexibility is how much time can it postpone the big investment. Therefore, a more realistic approach to the costs and benefits analysis of both potential solutions is to define the optimal long-term strategy for integrating both solutions, that is when is the best time to deploy DFP and until when it can defer the network upgrades [320]. In addition to this, a thorough risk analysis must be included to quantify the economic and physical implications for both solutions.

7 Conclusion & Future Work

This chapter concludes the thesis, discusses research findings and identifies future work.

7.1 Concluding Remarks

There is no doubt that demand flexibility is a promising tool for DSOs to use in the day-to-day operations. The barriers to full implementation of demand flexibility are several, but so as its benefits. On one hand, one of the main challenges facing the implementation of demand flexibility is the absence of regulations and policies that govern their penetration. In addition to this, current regulations only incentivize system operators for network upgrading and expansion, and there are no incentives for deploying smart grid applications or solutions such as demand flexibility programs. On the other hand, the first advantage of demand flexibility can be directed in the congestion management process that is carried out by the DSO. As discussed in the thesis, demand flexibility can take the form of either increasing or decreasing the load, which can be then aggregated and formed in flexibility bids that offer congestion relief tools for the DSOs. In the era of continuous increase of the load demand, due to new devices as well as electrification of transport and heat sectors, and the wide spread of DERs based on RES, demand flexibility can offer an efficient way to handle all the challenges imposed on the grid. Another key advantage is related to the long-term planning of the distribution network. Usually DSOs carry out thorough plans to reinforce their networks based on the potential demand growth of its networks, such conventional approach requires costly capital investments. In addition to this, the expanded network capacity and new assets are often underutilized. Integrating demand flexibility in these long-term plans can offer the DSO new ways to defer such capital investments.

The full potential of demand flexibility can only be efficiently exploited if the flexibility services are monetized like any other electricity commodity. Financial benefits and gains are the main drivers for the demand-side to participate in demand flexibility programs, hence there is a need for a fully functional market that allows for the trading of demand flexibility and well integrates with currently operating electricity markets. With respect to past studies in literature and to pilot projects, the issue of designing and implementing the flexibility market remains a key factor in all. As Market mechanisms that allow the trading of demand flexibility services is found the optimal approach to fully explore its potential, the work in this thesis proposed a framework for a decentralized local flexibility market at the distribution level (Flex-DLM).

7.1.1 Contributions

Based on what was presented in the thesis, the contributions can be summarized as follows:

- **Proposing a framework for a distribution-level flexibility market (Flex-DLM)** operating at the day-ahead (DA) and real-time (RT) periods, which aids the DSO in mitigating network congestions in the day-ahead period and sudden congestions occurring in the real-time. The merits of such framework are summarized as follows:

    1. A clear definition of the demand flexibility products, which are up- and down-regulation flexibility services, was given with mathematical formulations. Also, the possible ways these products can assist the DSO in the network congestion were identified.

    2. The rebound effect that is accompanied by demand flexibility was defined and formulated for the flexibility products offered.

    3. The grid constraints were taken into consideration within the decision process of the framework. These constraints are required to model the real power flow constraints of the network and to provide an accurate estimation to the true amount of flexibility services needed.

    4. The adjusting trading processes that are needed to be carried out by the aggregator to ensure the delivery of the demand flexibility services are discussed and mathematically formulated.

    5. The uncertainty of demand during the day-ahead period is taken into consideration. Such uncertainty is addressed by proposing probabilistic forecasting assessment process that is carried out by the DSO before calling for the DA Flex-DLM. This process allows the DSO to assess the true need for obtaining flexibility services based on the probability of congestion occurrence. Also, this process helps the DSO to classify the probability of congestion occurrence into low, medium and high. Furthermore, a new option is introduced in the market which is called the right-to-use (RtU) option. This option allows the DSO to reserve a specific amount of flexibility during congestions with medium probability, to be called upon during the real-time if needed. Also, the uncertainty behind the consumers' commitment to the flexibility activation requests were discussed and modelled.

6. The framework was checked using actual distribution networks located in Spain. The case studies were carried out considering both the deterministic and probabilistic approaches along with a comparison between them. The results showed that with efficient market mechanism, distribution network congestions can be mitigated with minimum cost. Moreover, the cases studies also discussed the impact of the penetration level of flexibility on the DSO's optimization process and the final cost of purchase. The availability of more flexibility services may be beneficial for all involved parties, as it means lower cost incurred by the DSO for efficiently operating for the grid, and more income for the aggregator and the customer.

- **An optimization process that models the Flex-DLM clearing procedure and minimizes the DSO's total cost**. Within the framework, three optimization processes take place. The first optimization process takes place in the DA Flex-DLM, where the DSO optimizes its cost for purchasing flexibility for the highly probable congestions. The second process also takes place in the same market, but for the medium probability congestions, where the DSO optimizes its cost of reserving the RtU option considering the probability of the congestion. The final optimization process takes place in the RT Flex-DLM, where the DSO buys flexibility services for unexpected congestions. Two methods were proposed to clear the flexibility market, which are deterministic and probabilistic. The difference between the two approaches was thoroughly discussed and the advantages of the probabilistic method over the deterministic method were made clear. Both methods were mathematically modelled, and a clear description of the optimization techniques used to efficiently clear the market and minimize the DSO's total cost was given.

- **A methodology for a cost and benefit analysis that acts as an investment decision tool for DSOs.** Using a non-complex approach, a CBA was carried out in order to present numerically the process carried by the DSO to efficiently select the optimal solution between implementing demand flexibility programs and the conventional network upgrades. Sensitivity analysis was carried out in this analysis to consider the impact of the likely changes of the forecasted variables of the analysis on its results.

7.1.2 Findings

The main findings of the work in this thesis can be summarized as follows:

- **Having a comprehensive framework for demand flexibility trading can facilitate the transaction of demand flexibility between buyers and sellers.** Demand flexibility as a commodity must have an efficient market mechanism that allows its trading. In addition, demand flexibility services can be a valuable tool for the DSO in managing distribution network.

- **A probabilistic model for the flexibility market framework is more efficient than a deterministic model.** As already shown, the uncertainty of demand which is present during the day-ahead period can cause inaccurate estimations for the required flexibility, which can be technically and financially infeasible. If a forecasting process is carried out, whether by the DSO or a separate entity, to ensure that there is a true need for obtaining flexibility services, then the issue of over- or under-reserving flexibility amounts can be avoided. As a result, it is better to have a probabilistic model for the flexibility market to efficiently manage the flexibility procurement procedure.

- **The penetration level of demand flexibility at the network has a direct impact on the DSO's cost of demand flexibility.** This means that the more flexibility is available by the customers, the better the DSO can optimize its flexibility purchase and the more the aggregators and customers get paid.

- **The efficiency of deploying demand flexibility programs is different for each distribution network.** The potential of demand flexibility in distribution network congestion is undeniable. However, as seen in the CBA, deploying demand flexibility programs may not be efficient for all distribution networks. Depending on the projected load demand growth, as well as the expected flexibility prices, the economic feasibility of demand flexibility can vary from one network to another. This means that it can be more economic on the long-term for the DSO to upgrade its network assets than deploying demand flexibility programs.

7.2 Future work

In the following, some suggestions for improving and further developing the work presented in this thesis:

- **Modelling more accurately the MV and LV loads for a full account of demand flexibility.**
  A detailed modelling for the load behavior of the flexibility demand is an important issue to accurately quantify the true amount of available flexibility. Due to the limitations of the available data for the work in this thesis, only the overall capacities of the network lines, line parameters and the load consumptions of the networks were available. However, the detailed information regarding the types of customers at every node and their corresponding consumption are hard to obtain, as they require communication infrastructure and data repositories. Thus, different assumptions were taken regarding the types of customers flexibility bid. A more detailed load modelling for the MV and LV flexible loads is required to exploit the full potential of demand flexibility and assess the feasibility of implementing such programs.

- **Efficient construction of the aggregated flexibility bids taking into account the customers' availability and their restrictions.**
  The work in this thesis was focused on the flexibility trading between the DSO and the aggregators through the flexibility market. To have a complete picture of

the flexibility trading process, the communication channel between the aggregator and the customers should be addressed. Particularly, how can the aggregator efficiently communicate with the flexibility customers to collect their flexibility offerings. In addition, the methods of flexibility aggregation considering all the necessary flexibility loads restriction and customers' availability are still not fully realized and need further research.

- **Considering the potential of EVs as a source of demand flexibility.**
  Here, only the household loads from the residential side customers, besides the industrial loads, were considered as flexibility sources. However, due to the decarbonization of the transport sector, electric vehicle's penetration is expected to increase vastly in the near future. Consequently, electric vehicles will have a significant impact on power systems and electricity markets. With the introduction of smart charging technology, EVs can be efficiently managed to mitigate potential network congestions, as well as benefit the electricity system through providing flexibility services.

- **Exploring the potential demand flexibility in the paradigm of peer-to-peer (P2P) trading at the distribution level.**
  Based on the concept of "sharing economy", P2P trading have emerged lately as promising system that enables multidirectional trading of energy within a local distribution network between customers and prosumers. The potential of demand flexibility services that can be traded within such new system is as well an issue that can be explored further.

- **How blockchain can facilitate the transactions of demand flexibility services in local markets.**
  The blockchain technology has been gaining much attention in the past few years since the rise of the electronic currency Bitcoin. Researchers have been investigating how to implement such technology in modern electricity systems and one concept has been the focus of many surveys which is "*smart contracts*". Based as well on how trading takes place within blockchain, smart contracts are a set of computer code which allow the negotiation, verification and enforcing of a given contract. Such contracts can eliminate third parties from transactions and allow buyers and sellers to deal directly with other. Within such new concept, demand flexibility transaction can be a secured and more efficient process and can engage consumers to participate.

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APPENDIX - A

In reality, distribution networks may contain hundreds of nodes, with possibly multiple blocks per flexibility bid. Even though it is not expected that all nodes or consumers, can provide demand flexibility, there will be a large enough number of nodes that can complicate the DSO's process of optimizing the procurement of demand flexibility services. Before exploring the approaches carried out to solve the optimization problems facing the DSO, it is important to clarify an important concept that will be used several times here, which is called the combination of bids. The idea behind it is to define the objective of the DSO in the Flex-DLM to finding a series or a group of flexibility bids with activated blocks that are capable of alleviating the network congestion with respect to the grid constraints and the rebound conditions. In a simple form, the idea of different combination of bids is inspired from the notion of a truth table. A truth table is a mathematical table which illustrates all the possible outcomes for any number of input variables. Take for example Table A.1, if there are *n* flexibility bids equals to 2, then there are $2^{n} = 4$ possible combinations of bids that can be considered. The values 1 and 0 correspond to whether the flexibility bid is active or not, respectively. If a bid is considered active, i.e. denoted 1, this means it is ready to be engaged in the market and get activated and vice versa for a bid that is considered inactive, denoted 0. In the first outcome, both bids are denoted 0, which means they are not available for flexibility (inactive). However, in the second outcome, only the first bid is available (active), which means the DSO has only this bid to consider when procuring flexibility. The same idea is applied to the rest of the outcomes. Therefore, in the problem of flexibility bids combinations, we can always eliminate the first outcome, which is all 0s, and we can assume there will be $2^{n} - 1$ possible combinations. Thus, it can be concluded that each possible combination considers some flexibility bids to be active and discards the rest, where the final possible combination considers all bids to be active. Thus, we can say that the DSO's objective is to find the optimal combination of flexibility bids.

Table A.1 Truth table for two flexibility bids.

Possible Outcomes	Bid 1	Bid 2
Outcome 1	0	0
Outcome 2	1	0
Outcome 3	0	1
Outcome 4	1	1

To further explain the concept of bids combination, an illustrative example is presented in Figure A.1, where we consider an aggregator responsible for *n* number of aggregated flexibility bids, which gives $2^n - 1$ possible combinations of bids, where every combination consists of different active flexibility bids than the other, where every bid has its own flexibility characteristics and rebound conditions. For the sake of simplicity, only a single block is considered for every flexibility bid. However, it is possible that the flexibility bids may have multiple blocks. In the first combination, only the first bid is active and the required flexibility from such bid represents only a portion from the presented block. The second combination has the second bid only active, where the needed flexibility is the full block offered. The third combination considers the second and third bids to be active, and the flexibility activated varies between both bids. Finally, the last combination considers all bids to be active, from 1 to *n,* but it can be noticed that the flexibility from the second bid is not used, even though it is available for dispatch. From the DSO's perspective, this bid may be uneconomic compared to other bids in the combination. Another reason can be its technical infeasibility, which means that activating this bid may cause a network congestion. It can be concluded that the number of aggregated flexibility bids is directly proportional to the number of combinations of bids and the problem complexity.

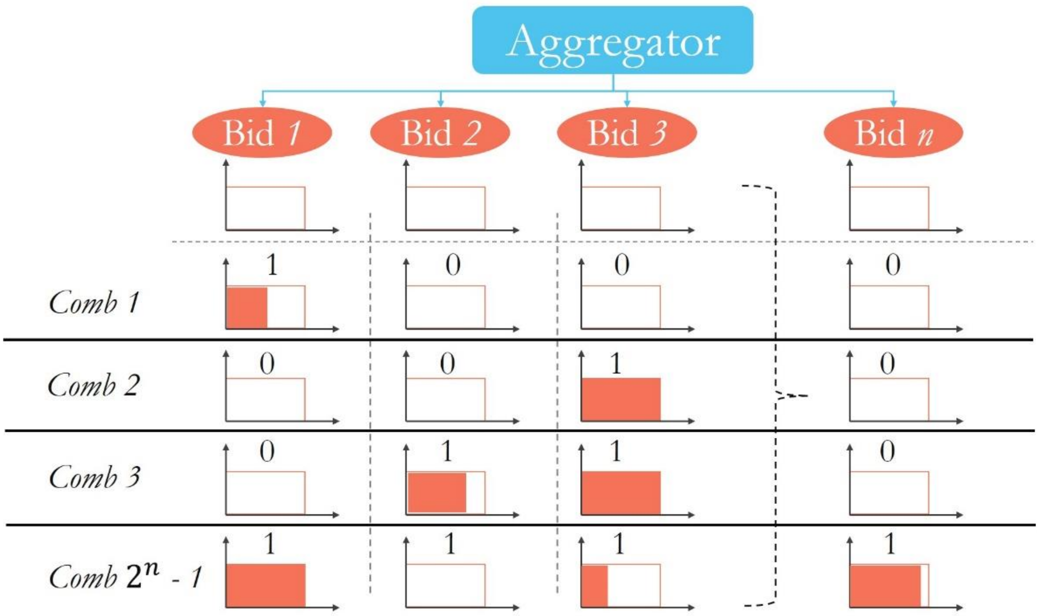


Figure A.1 Example for possible combinations of flexibility bids.

As the flexibility market operator, the DSO has the task of optimizing its purchase of demand flexibility. This can be challenging due to the intertemporal characteristic of the rebound effect. This means that before activating any flexibility bid, the DSO must first assess the possibility of further congestions occurring as a result of the rebound effect. The optimization problem described in Chapter 4, can be easy to solve for small networks with two or three aggregated flexibility bids. However, for real-life large networks, the number of flexible customers and bids can be large, which can complicate the optimization problem, as the number of possible solutions increase. An optimal approach to address such a problem must be able to capture the intertemporal complexities, while not being time consuming. In addition, it must ensure the technical feasibility of any activated flexibility bid and the rebound effect. The objective of the work here is to present an optimization approach that is time efficient given any number of buses in the network, easy to handle and model and can reach the global optimum solution.

As already mentioned in Chapter 4, during the work of this thesis, two approaches were carried out to solve the optimization problem. The first approach uses a deterministic method to optimize the DSO's cost and clear the Flex-DLM, where the probabilistic assessment of congestion occurrence, the uncertainty of consumers' participation and the RT Flex-DLM are discarded. The second approach considers all elements described in the framework of Flex-DLM. Table A.2 presents the factors considered in both appraoches. Both optimization methodologies are modeled and integrated in MATLAB. In addition, the validation process uses MATPOWER [325], which is a toolbox used to solve Power Flow (PF) and Optimal Power Flow (OPF) problems.

Table A.2 Factors considered in the deterministic & probabilistic approaches.

Factors	Deterministic approach	Probabilistic approach
DA Flex-DLM	✓	✓
RT Flex-DLM	-	✓
Rebound effect	✓	✓
Probabilistic assessment	-	✓
Consumers' uncertainty	-	✓

In order to model the whole process of flexibility transaction between the buyers and the sellers, a key step should take place before clearing the Flex-DLM, which is the process of evaluating and aggregating the flexibility of the consumers into flexibility bids. Therefore, before explaining the two appraoches carried out to clear the market, the process of calculating the available flexibility with respect to the customer considered will be explained first.

A.1 Quantifying the flexibility

In this thesis, two types of consumers were considered as a flexibility provider, which are industrial and residential customers. The method used to quantify the amount of flexibility obtained from these consumers is explained here. In order to clarify the explanation, the number of blocks *k* was not considered in the subscripts since the flexibility amounts intended to be calculated here corresponds to the total amount of flexibility offered by each type of customer [286].

- **Industrial Customers**

For the industrial customers, the amount of up and down flexibility regulation can be calculated following (A.1) and (A.2). The UREG power is computed as in (A.1), with the difference between the load at time *t* of service activation and the minimum load level for this customer. The DREG power, $\mathrm{F}_{\mathrm{ind,t}}^{\mathrm{UREG/DREG}}$, is calculated in (A.2) with the difference between the maximum load level and the load at hour *t* of service activation.

$$F_{ind,t}^{UREG} = Load_{ind,t} - MinLoad_{ind} \tag{A.1}$$

$$F_{ind,t}^{DREG} = MaxLoad_{ind} - Load_{ind,t} \tag{A.2}$$

- **Residential Customers**

Quantifying the flexibility at the residential sector can be a very complex problem due to many reasons. One of such is the massive amount of information and data required regarding every flexible appliance at every household, which can be very difficult to acquire. To overcome the lack of information and data, the load profiles of the flexible appliances are extracted from the total load profiles of the residential customers. According to [93], the average share percentage of flexible household appliances to the total consumption of the household varies between 15% to 52%. The appliances considered in this study are such as washing machines, air conditioning units, refrigerators, freezers, dryers, and space and water heating appliances. It is not common for all households to have all of these appliances; hence the share percentages vary. Next, the quantifying process of the flexibility suggested in [44], [307] is adopted here, where a value called the flexible share was defined, which indicates the percentage of the flexible appliance load that can be either reduced or increased. The use of the flexible share percentage is different when it comes to evaluating the flexibility amount. The amount of flexible load that can be shifted, i.e. UREG, is calculated by multiplying the flexible share percentage by the load of the flexible appliance. Since flexible appliances are constrained by their installed capacity, the flexible share in case of DREG flexibility is multiplied by the unused capacity of the flexible appliances, which is the difference between the total installed capacity of the flexible appliances and their actual load. Therefore, the amounts of UREG and DREG, $F_{res,t}^{UREG/DREG}$, for a single residential customer at a time *t* with N_{res_app} flexible appliances are calculated as in (A.3) and (A.4).

$$F_{res,t}^{UREG} = \sum_{res\_app=1}^{N_{res\_app}} Load_{res\_app,t}\ Flex_{Share}{}_{res\_app,t}^{UREG} \tag{A.3}$$

$$F_{res,t}^{DREG} = \sum_{res\_app=1}^{N_{res\_app}} (InstCap_{res_{app}} - Load_{res_{app},t})\ Flex\_Share_{res_{app},t}^{DREG} \tag{A.4}$$

A.2 Deterministic approach for clearing the Flex-DLM

In large networks with hundreds of flexible customers, intertemporal characteristic of the rebound effect increases the size and so as complexity of the problem. In the first method, the objective is to relax the problem by narrowing down the search space and avoid dealing with many solution possibilities. Thus, the problem is divided it to two stages, which would help reducing the execution time of the optimization problem. The concept of combination of bids plays an important role in this approach. The idea of the first stage, which is referred to as the preliminary filtering stage, is to find all feasible combinations that can relieve the network congestion. However, the rebound conditions are neglected when filtering through such combinations. This way, the size of the search space decreases. In the day-ahead time framework, where there can be multiple congested hours, this stage should yield a preliminary group of technically feasible combinations of bids for every congested hour. The function of the second stage is to evaluate the rebound conditions for all the preliminary groups evaluated from the first stage and then finally the optimal combination of bids can be chosen.

A.2.1 Stage 1: Preliminary Filtering

As explained before, there are $2^n - 1$ possible combinations of bids for an n number of aggregated flexibility bids. This means that the search space dimension of the problem relies on the number flexibility bids involved. This problem may not be complicated if the number of flexibility bids is low, as the number of possible combinations will be easy to handle. However, large networks with hundreds of flexibility bids, the search space can increase exponentially. A conventional enumerative approach of assessing all possible combinations can be used. However, this can be time inefficient for such large networks. The purpose here is to present an optimization methodology that is flexible and efficient regardless the size of the problem. Therefore, to overcome the problem of dimensionality, a fast-paced metaheuristic inspired tool is implemented, called genetic algorithm (GA). One of the advantages of the GA is its high functionality and adaptability to any type of problem. This means that it can be shaped and utilized according to the need of the problem. The objective of the GA in this stage is to use the natural processes of survival of the fittest such as selection, mutation and crossover [326], to efficiently find all the feasible combinations without having to assess every possible combination. The GA processes used in this approach can be described as follows:

- *Initialization & selection:* In the beginning, the solution space is constructed, which consists of the $2^n - 1$ possible combinations of bids. Then, an initial population of combinations is selected randomly from the solution search space, where every individual of this population represents a combination of bids. An example for an initial population of four individuals with respect to four flexibility bids is illustrated in Figure A.2. It should be reminded that the 1s and 0s in every individual of the population represents the availability of the bid.

Initial Population

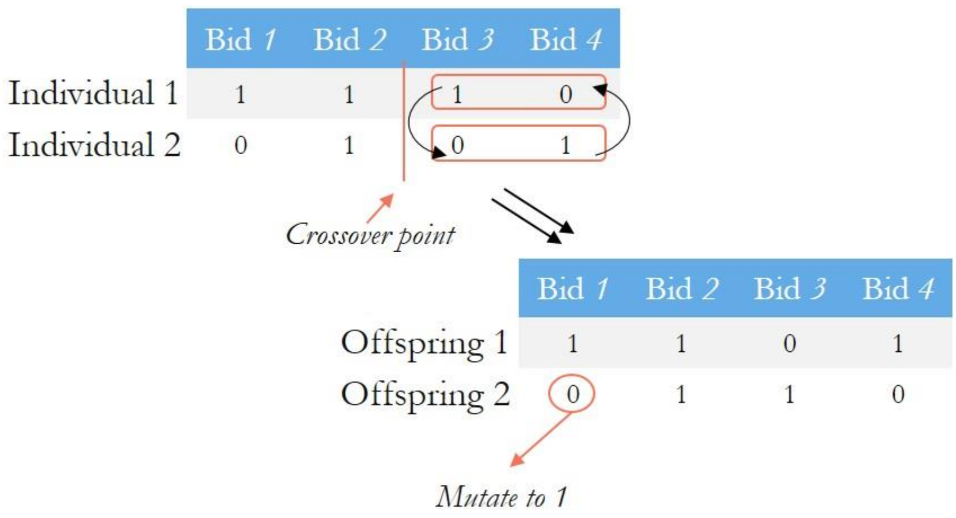
	Bid *1*	Bid *2*	Bid *3*	Bid *4*
Individual 1	1	1	1	0
Individual 2	0	1	0	1
Individual 3	0	1	1	0
Individual 4	1	0	0	1

Figure A.2 Example of initial population for four bids.

- *Fitness Evaluation:* The technical feasibility of every individual in the initial population is tested by means of running OPF analysis. This means that the flexibility offered by every combination of bids is checked if it is sufficient to alleviate the congestion considering the technical constraints of the network.

- *Storing & eliminating:* The combinations that are found feasible consist of the amount of flexibility activated from every bid and they are stored separately in the area of feasible population. Individuals with combinations that are found infeasible to resolve the congestion are eliminated and stored in an infeasible area.

- *Crossover & Mutation:* A mating process is carried out by means of crossover and mutation, where the objective is to create a new population of individuals that has similar genes to the ones found feasible in the previous process. The crossover function is one of the important processes in GA. For each pair of individuals in the feasible population, a crossover point is chosen in random and the two individuals are bisected and substituted with one other. This results in creating two new individuals (offspring), which have the same genes of their feasible parent individuals. An example is given in Figure A.3, where the first two individuals in the initial population were found feasible. Therefore, if the crossover point is randomly chosen to be after the second bid, then both individuals will be cross paired accordingly, thus producing offspring 1 & 2. Moreover, the mutation function chooses a random offspring after the crossover process and randomly flips the active status of one of the bids, which is in this case the first bid of offspring 2, where it is originally unavailable to provide flexibility, i.e. 0, it will be flipped to 1, i.e. available for flexibility.



FigureA.3 Example of two individuals resulting in two offspirng after crossover function.

- *Smart elimination:* A new process is implemented in the GA called smart elimination. Based on previous iterations, the GA is able to smartly learn the average amount of flexibility needed to relieve the congestion in question from the feasible populations. Therefore, for any new population generated from the crossover and mutation process, the smart elimination can scan through each new offspring and eliminate those who can provide a total amount of flexibility that is smaller than the average amount. In addition, this function also eliminates offspring found to be similar to previous infeasible individuals in the infeasible area. In this way, a lot of time spent unnecessarily assessing unfeasible combinations is saved. The amount of saved time here can be of great value for real large networks. After the smart elimination process is finished, the new population of individuals will be ready for fitness evaluation and then the rest of the processes are carried out as explained one after the other.

- *Stopping criteria:* It is common that GA processes terminate if the problem converges by having new population that are similar to previous iterations. Here, the GA terminates after a specific number of iterations is carried out.

A.2.2 Stage 2: Rebound Conditions Evaluation

As already mentioned, the first stage gives a group of individuals, every individual is a combination of bids, which are able to alleviate the network congestion. In the second stage, the rebound conditions for such group is assessed. The objective in this stage is twofold, first thing is to find the optimal rebound hour for every activated bid in the preliminary group. Second, is to ensure that the rebound power will not cause further congestions in the grid. In order to fulfill these two objectives, a branch and bound (B&B) technique integrated with a PF solver is implemented. The objective is to find the optimal rebound hour for every activated block in every bid in every feasible combination obtained from the first stage, given that no network constraints are caused at this particular hour. The B&B method is an optimization technique mostly suitable for discrete problems. Its objective is to search for the optimal solution in the search space by eliminating parts of this space through estimating previous values to the quantity being optimized [327], [328]. The B&B organizes the search space to take a tree structure, where every branch is expanded one-by-one until an optimal solution is found. An optimal solution in many cases can be the shortest path from one point to another. The same concept is used here to find the optimal rebound hour for all activated bids. The scenario tree is constructed where every node (tree leaf) is a possible rebound hour.

In order to clearly explain how the method is applied here, an example is given to serve that purpose. A feasible combination of bids, resulting from the first stage, is presented in Figure A.4. This combination has three activated bids, where every bid consists of one block to simplify the explanation, and their rebound conditions are given below every bid. From the point of view of the DSO and as the responsible party for choosing the optimal rebound hour, it is more efficient to the network if the payback power (load increase) is moved to valley hours (low demand), or the rebate power (load decrease) moved to peak hours (high demand). The DSO's choice of the optimal rebound hour is constrained by the rebound conditions provided by the aggregator and the consumers. Therefore, to construct the scenario tree in the B&B, the DSO will have a good advantage if the rebound hours are sorted for every bid according to the type of rebound taking place. In this example, if the flexibility activated is UREG, then the DSO should sort the payback hours from the least to the highest peak, and vice-versa if the flexibility activated is DREG. Figure A.5 illustrates the sorted payback hours for the three bids.

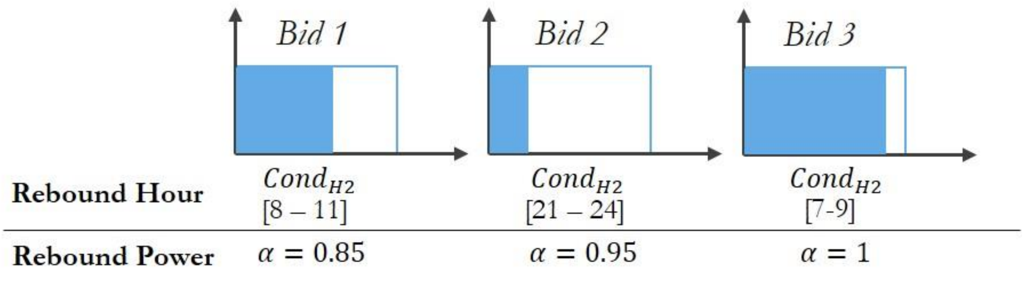


Figure A.4 A feasibe combination of three bids resulting from stage one with the rebound conditions.

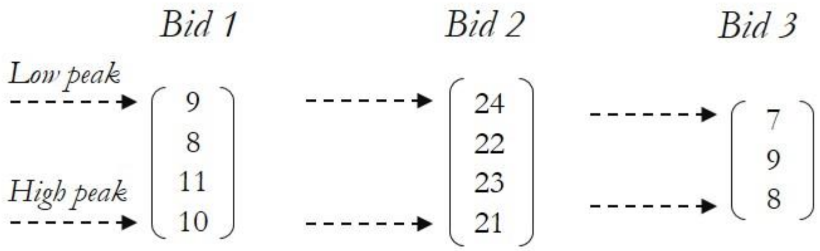


Figure A.5 Sorting the rebound hours for the three bids from the elast to the highest peak.

Considering four nodes for the first bid and sorting the hours from the least peak (left) to the highest peak (right), the scenario tree is constructed as in Figure A.6 (a). The advantage of sorting the hours is that it provides a good starting point for the DSO to find the optimal hours for all bids. First step carried out is to assess the technical feasibility of having the payback power at each hour one-by-one, until a feasible hour is found. In this example, hour 9 is found infeasible, thus this branch can be marked as infeasible in the tree. The second least peak hour is 8, which is found feasible, thus the first healthy node is found, Figure A.6 (b). Next step would be branching out from this node, which is hour 8, to the second bid. The second bid has as well four nodes and they are sorted and assessed in order to find the next healthy node. Figure A.7 illustrates this process, where the first two hours, 24 and 22, were found infeasible and the healthy node is found at hour 23.

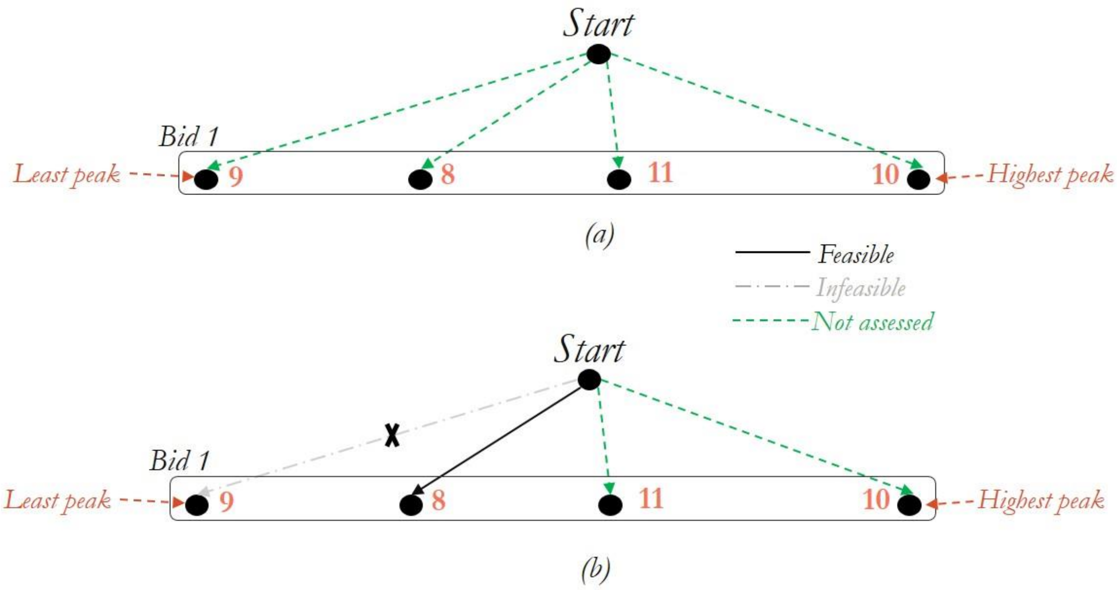


Figure A.6 Assessing the payback conditions for the first bid: (a) constructing the tree (b) Finding the healthy node.

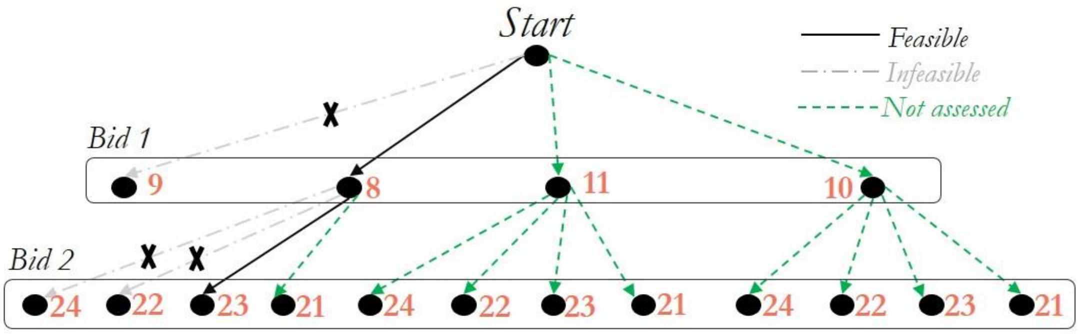


Figure A.7 Finding the healthy node for the second bid.

Finally, the same process is carried out for the final bid, which has 3 nodes, illustrated in Figure A.8. The validation process showed that at all of these hours, the payback power supplied will cause a congestion. It can be noticed that hour 8 was already found feasible to supply the payback power for the first bid. However, it is found infeasible if more payback power is added from the third bid. This situation can be a frequent event in large networks, where hundreds of aggregated bids with multiple blocks may have similar rebound conditions. Therefore, to solve this issue, the algorithm retreats to the first bid to assess hour 11, which follows hour 8, and the same process is carried out until the optimal hours for supplying back the payback power without causing network constraints are found. The amount of saved time in this example may not be high. However, for more complicated problems with hundreds of bids, this method becomes time-efficient and a substantial amount of time can be saved by ignoring nodes and branches that are unnecessary to assess in the first place. Finally, Figure A.9 illustrates the flowchart of the first method for clearing the Flex-DLM.

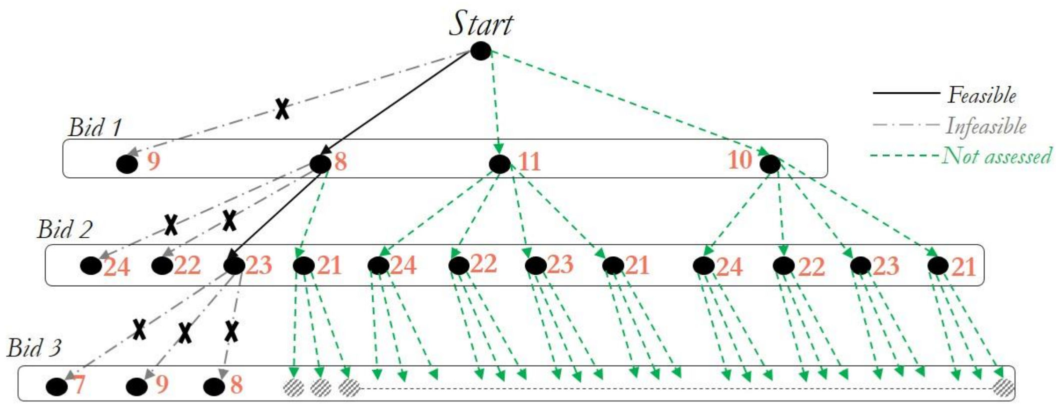


Figure A.8 Finding the healthy node for the third bid.

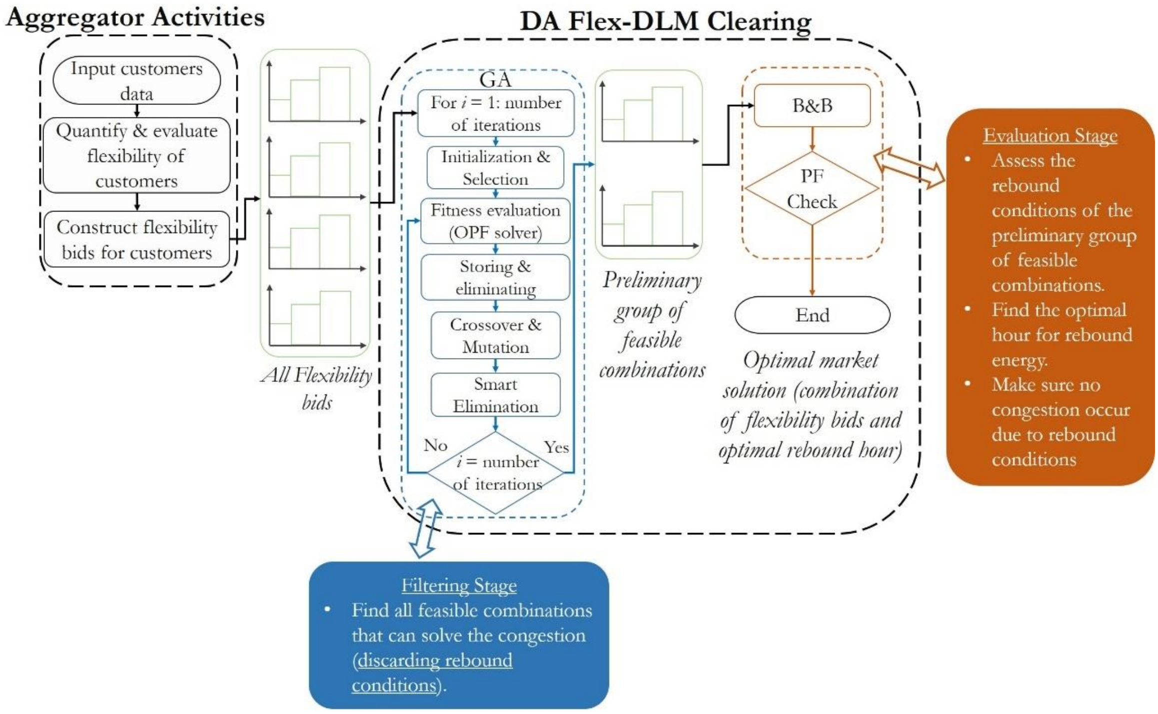


Figure A.9 Flowchart of first method.

Like any other optimization technique, this method has its advantages and disadvantages. One of the main advantages is that it is easy to implement and time-efficient. Also, the proposed method here has scalability characteristics, which can handle larger and denser distribution networks with hundreds of consumers. In addition, the proposed methodology does not require a complicated PF or OPF solver tool, as it is not limited to using MATPOWER and can be integrated with any existent program. On the other hand, there is one main disadvantage that should be highlighted. As already explained, the objective of the first stage is to obtain all the feasible combinations that can solve the network constraints in the congestion hours, without considering the rebound effect. Then, in the second stage the rebound effect for every feasible combination at every congested hour is assessed. The problem arising due to the limitation of the branch and bound method, is that it can only obtain the optimal rebound hours individually for each of the congestion hours, i.e. once at a time, instead of obtaining the optimal rebound hours considering all congestions at once. The problem with considering the rebound effect for every congested hour on individual-basis is that it does not foresee and consider hours beyond the current one being solved. Therefore, the rebound effects of congested hours occurring at later hours of the day, are not considered when finding the optimal rebound hour of congestions occurring at earlier hours of the day. Even though, the technique used in this method reaches a feasible solution at the end, this solution may not be the global optimal but a local optimum. A better approach should be able find the best rebound hours for all congested hours at the same time.

A.3 Probabilistic approach for clearing the Flex-DLM

The second method adopted in the thesis avoids the disadvantage of the first approach while considering the probabilistic assessment carried out by the DSO before entering the DA Flex-DLM. In addition, the uncertainties concerning the customer's activation and amount of delivery are modelled as well. Instead of dividing the optimization search algorithm to two stages, one for the finding the feasible flexibility bids and another for assessing their rebound conditions, the second method attempts to integrate both stages into one. Thus, the optimal flexibility bids are activated only if their rebound conditions are favorable to the network. In order to achieve this, a mixed-integer linear programming (MILP) solver was integrated with a PF solver. Since all objective functions and their respective constraints across all markets are linear functions except for the grid constraints, then the MILP solver can clear the Flex-DLM and minimize the cost of procuring the flexibility and the PF solver ensure that the Flex-DLM solution mitigates the network congestion and that the payback effect will not violate the grid constraints. This is a similar procedure to what takes place in wholesale electricity markets, where the market operator clears the day-ahead market and sends the market solution to the DSO for technical validation. The difference in the Flex-DLM is that the DSO is assumed to be the Flex-DLM operator, since it is the main beneficiary. Therefore, if the DSO may need to adjust the market solution of the technical feasibility check is found to cause problems in the grid. The unfeasibility can be a result of the rebound power causing further network constraints, or the whole market solution is violating the network voltage and power limits. In this case, an optimal solution search method is implemented much like the GA method proposed in the first method in A.2.1. The bio-inspired operations of the GA help the DSO to find higher quality solutions that are technically feasible and has the minimum cost of purchase. Figure A.10 illustrates the flowchart of the second method for clearing the Flex-DLM. The processes used in the GA to find the optimal market solution are explained as follows:

- *Initialization & selection:* The initialization process here is similar to that of the previous method. The solution space is first constructed which consists of the $2^n - 1$ possible combinations of bids. Then a random selection of individuals from such population is carried out. Every individual represents a combination of bids.
- *Fitness Evaluation:* To evaluate the fitness of the new random selection of individuals, they are sent to the MILP and PF solvers to ensure the following: 1- the available flexibility from every combination can solve the congestion; 2- the rebound conditions will not congest the network at later hours and; 3- the market solution is technically feasible.
- *Storing & eliminating:* Based on the previous function, the feasible combinations are stored, where every combination consist of the optimal amount of demand flexibility activated from every bid and their corresponding optimal rebound hour and power. Unfeasible market solutions are as well stored to be used in the smart elimination function.
- *Crossover & Mutation:* The mating and mutation functions are carried out between the feasible combinations similar to what was previously explained in the previous method. The result of this function is a set of new individuals, i.e. offspring of possible combination of bids.
- *Smart elimination:* This function is used whenever one of the new offspring individuals resembles one of the unfeasible solutions stored in a previous iteration. Repeated individuals are discarded to save computation time. Finally, the remaining non-

repeated individuals from the offspring are sent to the fitness evaluation function and the rest of the GA functions take place.

- *Stopping criteria:* The GA processes are carried out for a specific number of iterations and then the most feasible market solution.

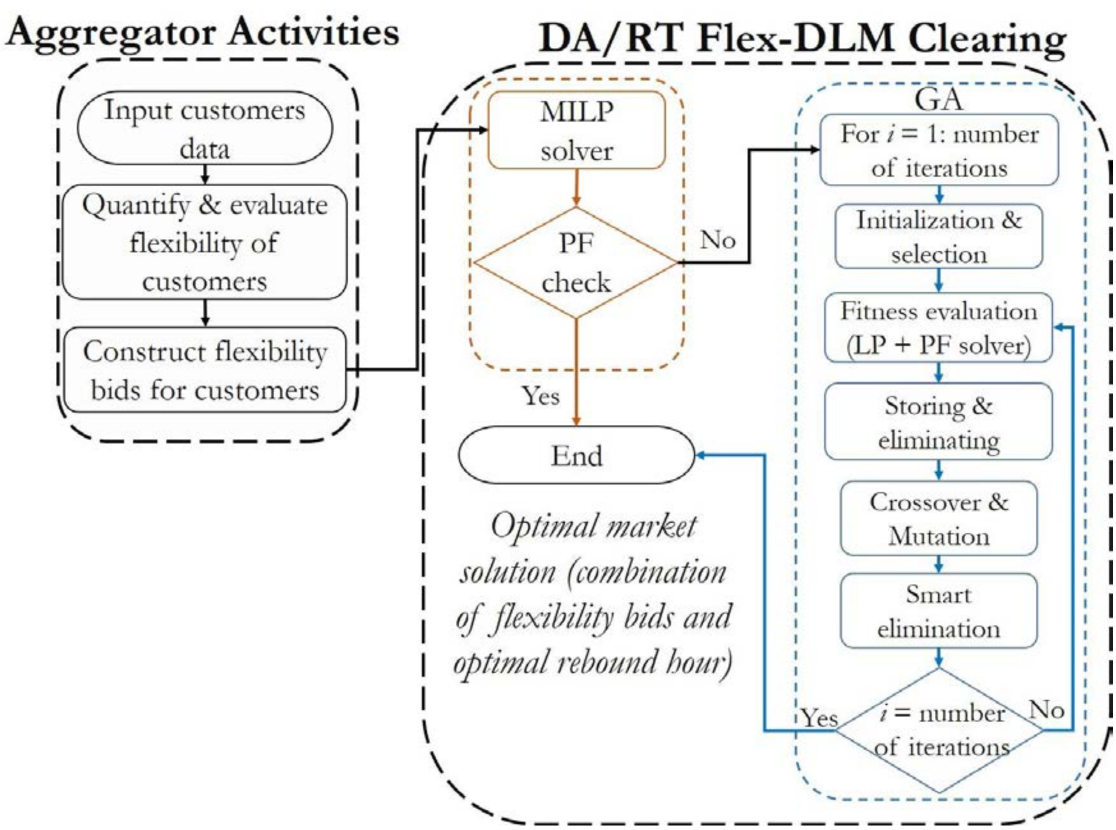


Figure A.10 Flowchart of second method.

Similar to the first method, the Flex-DLM framework is modelled in MATLAB, where the MILP solver toolbox and the PF solver, MATPOWER [325], are used. As previously discussed, the disadvantage of the first method was dividing the process of finding the optimal flexibility and their rebound conditions to two stages. This issue was avoided when the MILP solver was used to clear the Flex-DLM and find the optimal rebound hours. However, a disadvantage that is present is that with the MILP solver, the method losses its scalability advantage. For small- to medium-sized networks, the second method is able to produces optimal results with lower computation time. However, in large-sized networks, the number of variables will increase drastically, which can affect the efficiency of the MILP solver.

A.4 Uncertainties of consumers' behaviour

As previously explained in Chapter 4, two possible uncertainties related to the commitment of the consumers are modelled in this thesis. The first type is related to the uncertainty of activation commitment, where the consumers may not comply with the activation request. In which case, the DSO assigns a minimum probability of activation commitment for every flexibility block *k* and compare the aggregated probability of all blocks activated to a minimum threshold of commitment acceptance. Therefore, the probability of commitment $\mathtt{Com}_{n,k,t}$ for every block *k* at node *n* at time *t* must be at least more than or equal the threshold $\Upsilon_{\min}$. It is assumed that this threshold is set by the distribution system operator in order to maintain an overall high reliability standard to the system. Therefore, considering the same optimization formulation, an extra constraint will be added which can be written as in (A.5).

$$\sum_{t=1}^{24} \sum_{n=1}^{N^n} \left[\sum_{k=1}^{N_{n,t}^b} \mathrm{Com}_{n,k,t} \geq \Upsilon_{\min} \right] \tag{A.5}$$

The second type of uncertainty concerns the commitment to delivering the flexibility requested by the cleared market. DSOs must consider possible deviations in the flexibility activated in the DA Flex-DLM. These deviations can be modelled as minimum amounts of demand flexibility that the DSO can expect from every flexible block. By assigning a minimum delivery percentage for every block in the flexibility bids available, the DSO can hypothetically consider lower amounts of available flexibility and clear the market accordingly. For the same optimization problem and constraints, a new term will be added to the limits of the available flexibility block *k* called $\varepsilon_{n,k,t}$, which represents the expected guaranteed percentage of flexibility to be delivered. Thus, the condition will be written as in (A.6).

$$\varepsilon_{n,k,t}\ F_{n,k,t,MIN}^{UREG/DREG} \leq F_{n,k,t}^{UREG/DREG} \leq \varepsilon_{n,k,t}\ F_{n,k,t,MAX}^{UREG/DREG} \qquad \forall t, n \tag{A.6}$$

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